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SEE REPORT

SUBJECT: Forwards responses to NRC request for addl info re FSAR.
Responses will be incorporated into FSAR in future amend.

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FLORIDA POWER & LIGHT COMPANY

August 4, 1981
L-81-334

Office of Nuclear Reactor Regulation
Attention: Mr. Darrell G. Eisenhut, Director
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

RECEIVED AUG 07 1981

Dear Mr. Eisenhut:

Re: St. Lucie Unit 2
Docket No. 50-389
Final Safety Analysis Report
Requests For Additional Information

Attached are Florida Power & Light Company (FPL) responses to NRC staff requests for additional information which have not been formally submitted on the St. Lucie Unit 2 docket. These responses will be incorporated into the St. Lucie Unit 2 FSAR in a future amendment.

Very truly yours,

Robert E. Uhrig
Vice President
Advanced Systems & Technology

REU/TCG/ah

Attachments

cc: J. P. O'Reilly, Director, Region II (w/o attachments)
Harold F. Reis, Esquire (w/o attachments)

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Attachment L-81-334

List of Attachments

Resolution of Hutchinson Island Fault/Fold

Responses to questions 451.01 thru 451.08

Responses to questions 311.1 and 311.2

Responses to unnumbered Chapter 6 questions from June 6, 1981 meeting.

Revised response to question 410.19

Response commitment to question 491.2

Response to an informal NRC request to provide justification on the lack of detailed writeups for the high & low CEA withdrawal and the single part length CEA drop analysis.

Revised response to question 490.1 which includes the new FSAR section 4.2 writeup.

Responses to the open items discussed in the MEB SER review meeting on July 28, 29, 30, 1981.

Responses to Nureg 0737 items

Responses to questions 430.3, 430.66 thru 430.74

Responses to questions 410.32 thru 410.38

Responses to questions 420.01 thru 420.58

Responses to unnumbered CBS questions from meeting on June 9, 1981.

Resolution of two out of three open items for the containment fracture toughness review.

Responses to unnumbered questions concerning the Post Accident Sampling Systems.

Responses to questions 460.1 thru 460.23

Responses to questions 220.1 thru 220.37

Request: The applicant was requested to perform a literature search to conclude that there is no new information that has been produced that describes any new geologic concerns with the Hutchinson Island area.

Response: A literature serach has identified a single unpublished source that implied the existance of a fault on Hutchinson Island. This paper is a college thesis by an individaul named Armstrong. To disprove the existance of any faults on Hutchinson Island a program of marine refraction profiling of Indian River, Big Mud Creek and the Atlantic Ocean was performed.

The refraction profiling in the Indian River, Big Mud Creek and the Atlantic Ocean was completed.

The field interpretation of the data is that the fault proposed by Armstrong does not exist. There is indications of folding but not faulting. This folding has previously been identified by earlier studies prepared by Unit 1.

NRC Questions on St. Lucie FSAR

Question 451.01

> Update the discussions of the severe weather phenomena by examination of events that have occurred since 1963 for hurricanes and since 1972 and 1973 for tornadoes and waterspouts.

The update to the FSAR discussions of hurricanes, tornadoes and waterspouts was developed from the references sited at the end of this response. Because the available data for this period were not as complete as that provided in the FSAR, just the pertinent and significant issues are updated in this response.

Hurricanes

During the extended period of 1899-1980, the Florida Peninsula has been affected by 95 tropical cyclones. Of these, 39 were classified as hurricanes, 40 as tropical storms and 16 as tropical depressions (Neumann, C.J., et. al., 1978 and U.S. Department of Commerce, 1978-1980). The monthly and annual distribution of tropical cyclones affecting the Florida Peninsula is presented in Table 451.01-1. Roughly half the storms in each category passed close enough to the St. Lucie site to affect it with strong winds and/or heavy rainfall. Hurricanes have occurred most frequently in September and October in the site area.

Taking cognizance of the hurricane data since 1963, the following presents hurricanes in the site area of great intensity during recent times:

- Hurricane (unnamed) 17 September 1947 - The center of the storm reached the Florida coast at Ft. Lauderdale at about 1130 EST on 17 September. The highest wind speed recorded was 155 mph at Hillsboro Light near Pompano at 1256 EST. (U.S. Dept. of Commerce, 1947)
- Hurricane (unnamed) 26-27 August 1949 - The center of the storm reached the Florida coast at Delray Beach at about 1800 EST on 26 August. The highest wind speed reported was 153 mph at Jupiter Lighthouse before the anemometer failed. (U.S. Dept. of Commerce, 1949)

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- Hurricane King, 17-18 October 1950 - The center of the storm passed directly over Miami, Florida near midnight of 17 October with a calm center of about 5 miles in diameter. Winds at Miami Weather Bureau Office reached a speed of 97 mph from the northeast for a 5-minute period as the center approached and 122 mph from the south for a 1-minute period about 50 minutes later. (U.S. Dept. of Commerce, 1950)
- Hurricane Cleo, 27-28 August 1964 - Cleo moved north-northwest to northwest during 27-28 August with the center of the storm remaining approximately 10-20 miles inland and closely paralleling the Florida coastline. The maximum sustained winds were estimated at 100-110 mph, with gusts to 135 mph in sections of Miami. At West Palm Beach Weather Bureau Station the maximum sustained winds were 86 pmh with gusts to 104 mph. (U.S. Dept. of Commerce, 1964)
- Hurricane David, 3-4 September 1979 - The center of the storm made landfall at midday near Jupiter Island, Florida, a little north of Palm Beach. Moving north-northwest at 10 to 12 mph, David's eye passed over the coastal sections of Martin, St. Lucie, Indian River and Brevard counties. The strongest winds recorded in Florida were gusts at 95 mph at the Fort Pierce Coast Guard Station in St. Lucie County. (U.S. Dept. of Commerce, 1979)

Table 451.01-2 presents a summary of the worst hurricanes in recent times that may have affected the site area. The worst storm in recent years affecting the site continues to be the hurricane of August 1949. The previously developed meteorological parameters and wind field of the probable maximum hurricane (PMH) remain applicable to this site.

<u>Tornadoes and Waterspouts</u>

The data on tornadoes and waterspouts presented in the FSAR are still applicable to the St. Lucie site. This response provides the additional update to these reported conditions based on the data acquired for the period 1968 through 1980.

The average seasonal and annual frequency of tornadoes which have occurred in the state of Florida during the period from 1968-1980 are as follows: (U.S. Dept. of Commerce, Jan.-Dec. 1980 and U.S. Dept. of Commerce, 1968-1980).

Winter	Spring	Summer	Fall	Annual
11.8	22.5	24.4	9.5	68.2

Tables 451.01-03 presents the distribution of tornadoes by year. This table reveals that the more recent years during the 1968-1980 period had a greater number of reported tornadoes. The annual maximum number of occurrences was reported as 117 in 1980 and the minimum number of 46 in 1970. The average number of tornadoes is about double the average previously reported for the period 1955-1967. Assuming this doubling of the average number of tornadoes in the state of Florida is also true of the number within a one degree latitude-longitude square in which the site is located, then the probability of a tornado striking a point in the one-degree square in which the site is located is about 0.00363 per year or a recurrence interval of 275 years.

From the review of the intensities of tornadoes during the current update period (U.S. Dept. of Commerce, 1974-1980), no indication that a change in the Design Basis Tornado (DBT) for the site area was revealed. Therefore, the DBT presented in the FSAR is still applicable for the St. Lucie site.

The monthly distribution of waterspouts occurring within 25 miles of the St. Lucie site for the period of record 1974 to 1980 are given below:

MONTHLY DISTRIBUTION OF WATERSPOUTS
WITHIN 25 MILES OF ST. LUCIE SITE

Month	Total
January	1
February	0
March	3
April	0
May	2
June	2
July	3
August	3
September	4
October	0
November	0
December	0
Total	18

Ref: U.S. Dept. of Commerce, 1974-1980, Storm Data, NOAA, Environmental Data Service.

All of these reported occurrences appeared to fall into the "weak tornado" category. Table 451.01-4 presents the monthly distribution of waterspouts within 25 miles offshore for the total 1952 through 1980 period. The annual average for the full period is about 6.8, a decrease of about 1.3 when compared to 1952-1973 data period.

The frequency of occurrence of waterspouts and the intensity of these storms is less than tornadoes. Therefore, the parameters associated with the tornadoes are the pertinent parameters to be used in the consideration of the design and operation for a nuclear power plant in this region.

TABLE 451.01-1

MONTHLY DISTRIBUTION OF TROPICAL CYCLONES
AFFECTING THE FLORIDA PENINSULA*
(1899-1980)

Month	Hurricanes	Tropical Storms	Tropical Depressions	Total
January	0	0	0	0
February	0	1	0	1
March	0	0	0	0
April	0	0	0	0
May	0	1	1	1
June	5	3	5	6
July	2	4	1	6
August	6	10	4	14
September	15	7	4	16
October	10	12	1	17
November	1	2	0	3
December	0	1	0	1
Annual	39	41	16	96

Reference: Neumann, C.J. et al, 1978, Tropical Cyclones of the North Atlantic Ocean, 1871-1977, U.S. Dept. of Commerce, NOAA, NWS, Environmental Data Service.

U.S. Dept. of Commerce, 1978-1980, Climatological Data, National Summary, NOAA, Environmental Data Service.

*Center (Eye) of storm within 100 miles of site.

TABLE 451.01-2

WORST HURRICANES IN RECENT TIMES THAT MAY HAVE AFFECTED THE SITE AREA

Storm No.	Year	Month	Site Area	Highest Category*
4	1947	September	FL 4SE	4 No Name
2	1949	August	FL 3SE	3 No Name**
11	1950	October	FL 3SE	3 King
5	1960	September	FL 4SW	4 Donna
5	1964	August	FL 2SE	2 Cleo
3	1965	September	FL 3SE	3 Betsy

*Category Scale (mph)

2 = Winds of 96 - 110
3 = Winds of 111 - 130
4 = Winds of 131 - 155

**Reported Already in FSAR

TABLE 451.01-3

AVERAGE SEASONAL AND ANNUAL FREQUENCY OF TORNADOES[1] IN FLORIDA 1968-1980

Year	Winter	Spring	Summer	Fall	Annual
1968	9	12	16	15	52
1969	15	10	22	11	58
1970	14	7	25	0	46
1971	12	18	23	6	59
1972	10	32	24	11	77
1973	12	25	5	3	45
1974	9	28	16	1	54
1975	22	30	31	14	97
1976	5	32	24	6	67
1977	8	3	20	4	35
1978	19	36	29	7	91
1979	12	32	18	27	89
1980	6	28	64	19	117
Total	153	293	317	124	887
Average	11.8	22.5	24.4	9.5	68.2

References:

U.S. Dept. of Commerce, Jan-Dec 1980, Storm Data, NOAA, Environmental Data Service.

U.S. Dept. of Commerce, 1968-1980, Climatological Data, National Summary, NOAA, Environmental Data Service.

[1]Includes Tornadoes, Wind Storms and Waterspouts

TABLE 451.01-4

MONTHLY DISTRIBUTION OF WATERSPOUTS WITHIN 25 MILES OFFSHORE

Month	Total
January	7
February	5
March	11
April	4
May	16
June	18
July	54
August	22
September	34
October	17
November	7
December	1
Total	196

Reference: U.S. Dept. of Commerce, 1952-1980, Storm Data, NOAA, Environmental Data Service.

REFERENCES

Neumann, C.J. et al, 1978, Tropical Cyclones of the North Atlantic Ocean, 1871-1977, U.S. Dept. of Commerce, 1978 NOAA, NWS, Environmental Data Service.

U.S. Department of Commerce, 1978-1980, Climatological Data, National Summary, NOAA, Environmental Data Service.

U.S. Department of Commerce, Sept. 1947, Monthly Weather Review, Vol. 75, Weather Bureau No. 1502.

U.S. Department of Commerce, Aug. 1949, Monthly Weather Review, Vol. 77, Weather Bureau No. 1542.

U.S. Department of Commerce, Oct. 1950, Monthly Weather Review, Vol 78, Weather Bureau No. 15.

U.S. Department of Commerce, 1964, Climatological Data, National Summary, Vol. 15, Weather Bureau No. 13.

U.S. Department of Commerce, Sept. 1979, Storm Data, NOAA, Environmental Data Service.

U.S. Department of Commerce, 1968-1980, Climatological Data, National Summary, NOAA, Environmental Data Service.

U.S. Department of Commerce, Jan.-Dec. 1980, Storm Data, NOAA, Environmental Data Service.

NRC Questions on St. Lucie FSAR

Question 451.02

> The occurrence of the sea breeze circulation is discussed very briefly in Section 2.3.1. Information presented in Table 2.3-11 indicates a pronounced wind direction reversal from west to east around 10 a.m. (based on an examination of two years of onsite data) which is typical of the onset of the sea breeze. The terrain correction factors presented in Table 2.3-102 are also suggestive of local airflow conditions which exhibit significant spatial and temporal variations. Provide further elaboration of occurrences of sea breeze circulation in the vicinity of the St. Lucie site including frequency of occurrence, depth of penetration, fumigation along the transition zone, and spatial and temporal variations in sea breeze circulation. Discuss the meteorological conditions conducive to establishing sea breeze circulation in the vicinity of the site and indicate which meteorological parameters are considered necessary to characterize the sea breeze.

In coastal locations, especially on tropical coasts and on the shores of relatively large lakes, the wind direction undergoes a diurnal flow pattern called sea breeze and land breeze. This phenomena is represented by the establishment of a sea breeze a few hours after sunrise and the continuation of the onshore flow throughout the daylight hours. After sunset the onshore flow dissipates and a land breeze develops. Such a circulation pattern is developed in response to the difference in the land/water heating. On clear, warm days when the solar heating is at a maximum, the difference between the land and water temperatures provides the impetus for the development of the circulation pattern. During the night hours on clear evenings the reverse temperature configuration is established, due to radiative cooling differential between the land and water, generally with less intensity. As the solar angle becomes less, the differential heating becomes less and the sea breeze/land breeze phenomenon becomes less intense and frequent.

As a meteorological phenomenon, the sea breeze has received considerable attention and study. These studies have been both observational and theoretical. In the United States, there have been several

observational studies of sea breeze circulations, mostly concentrated along the Northeast Atlantic coastline and along the Great Lakes. These studies reveal a weak synoptic-scale pressure gradient and large temperature differential between the maximum surface air temperature inland and the sea surface temperature as conducive to establishing a sea breeze circulation. Biggs and Graves (1961) give the following observational relationship necessary for lake breeze formation along the Great Lakes:

$$\frac{|v_i|^2}{\Delta T_{max}} < 3$$

where: $|v_i|$ = magnitude of the average wind vector, irrespective of direction, in meters/second; and

ΔT_{max} = T_L - T_S in °C and ΔT_{max} positive where T_L is the maximum surface temperature inland and T_S is the average water surface temperature.

Although this empirical relationship is dimensionally inconsistent, it demonstrates the importance of a weak synoptic-scale wind so as not to disrupt or hinder the sea breeze formation, and a large temperature gradient between land and sea necessary to establish the sea breeze circulation. This relationship has been supported by subsequent theoretical investigations into sea breeze circulation (Walsh, 1974).

The direction of the gradient flow is not considered in the given empirical relationship. However, observational research shows the type of sea breeze formation is highly dependent on the direction of the gradient flow. With gradient flow reinforcing the sea breeze (moving from sea to land), the sea breeze circulation begins early in the day and penetrates up to 50 kilometers inland. Fisher (1960), conducting observational research on Rhode Island in August, detected the initial formation of the sea breeze at 1100 EST which subsequently moved on land by 1200 EST. The sea breeze reached a maximum depth of about 900 meters with maximum horizontal velocities of 15 ms^{-1} at a height of approximately 200 meters.

Frizzola and Fisher (1963) conducted similar observational studies in the New York City area in early June of 1960 and found that the sea breeze reached the coast at 1100 EST with an initial vertical extent of 150 to 270 meters and subsequently penetrated past a station 45 kilometers inland at 1500 to 1700 EST. During the evening hours, the sea breeze diminished in intensity and retreated towards the coast. Temperature and dew point changes were gradual, although local wind changes were found to be abrupt.

When the overall gradient flow opposes the sea breeze (blows from land to sea), the sea breeze causes more radical temperature, dewpoint, and wind changes inland. Subsequently, this type of sea breeze is many times termed a sea breeze front. Frizzola and Fisher (1963), studying one day with opposing gradient flow, found that the sea breeze formed later in the day and had a smaller vertical extent with less intense wind speeds than found under light, reinforcing gradient flow. Frizzola and Fisher further noted that opposing gradient flows greater than 7 to 10 ms^{-1} will, in many cases, hinder penetration of the sea breeze past the immediate coastline.

All of the observational and theoretical research notes a general clockwise rotation of the sea breeze with time as measured at one location. This clockwise rotation, due to the Coriolis force, causes the sea breeze to become almost parallel to the coastline by early evening.

The occurrence of sea breezes at St. Lucie is considered to be significant based on both the available literature and from onsite and offsite data. The climatic summary for Florida notes (NOAA, 1972):

> "During the warm season, sea breezes are felt almost daily within several miles of the coast and occasionally 20 to 30 miles inland."

As stated earlier, the occurrence of sea breezes is dependent on the magnitude of the gradient wind and the temperature difference between the maximum surface air temperature and the sea surface temperature. Wind speeds of less than approximately 5 ms^{-1} and

7-10 ms^{-1} and temperature differences of greater than 3°C and 6°C are considered necessary for sea breeze formation (William, 1974; Frizzola and Fisher, 1963)..

To estimate the frequency of sea breeze conditions at St. Lucie, values of these parameters were obtained from available representative sources. The mean maximum daily temperature recorded at Ft. Pierce (NOAA, 1964), 6.8 miles NW of St. Lucie, was considered to be indicative of maximum inland surface air temperatures in the vicinity of St. Lucie. The sea surface temperatures are based on six years of data for the coast of Florida from Cape Kennedy to Palm Beach (Williams, 1974). The wind speed frequencies for Orlando, Florida (approximately 35 miles from the coast) for the hours of 0800 to 1000 (NOAA, 1963) were considered representative of the mean gradient wind, uncontaminated by sea or land breeze flow. These data, in monthly summaries, are presented in Table 451.02-1.

The data show that the mean maximum daily temperature in the vicinity of St. Lucie can be expected to exceed the average sea surface temperature during any month of the year. Therefore, it is reasonable to expect that, on a single day, the probability of the maximum inland temperature exceeding the sea surface temperature by at least 3°C (6°F) is quite high.

The occurrence of a light gradient wind, indicative of a small pressure gradient, is also necessary for sea breeze circulation. Since the prevailing climatology of St. Lucie is dominated by the presence of the Azores-Bermuda high pressure system during most of the year, this criterion would be expected to be met during much of the year, especially during the summer months. The data for Orlando tend to confirm this fact.

Therefore, it is concluded that the probability of sea breezes during any month of the year is quite high. Further, the data tend to indicate that the summer months are the most conducive to sea breeze

formation (i.e., large temperature differential and frequent occurrence of light gradient winds).

Of the meteorological parameters measured by the onsite meteorological tower, the wind direction and speed at the two levels are the most indicative of the occurrence of a sea breeze condition. In addition, the frequency distribution of stabilities for onshore (NNW-N-SE) and offshore (SSE-S-NW) (see Table 451.02-2) indicate that unstable conditions with offshore flow is not common. Therefore, stability measured by the differential temperatures may also be useful, combined with wind direction/speed, as an indicator of sea breeze. Onsite data presented in the FSAR show diurnal variations of both wind speed and direction characteristic of sea breeze flow (Table 2.3-11). The offshore flow during the early morning hours shows characteristics of land breeze. At 1000 EST, the wind direction quickly reverses to onshore flow, a characteristic of the onset of a sea breeze. At approximately 1400, the sea breeze reaches its maximum speeds. During the early evening, the sea breeze direction begins a clockwise rotation, a pattern of temporal wind changes at a single location that has been noted in all of the observational studies cited.

Since the depth of the sea breeze has been shown to be typically deeper than the height of the tower, it is concluded that the onsite tower measures the sea breeze as it occurs at the St. Lucie site. However, no single tower can characterize the sea breeze in terms of inland penetration or the meteorological conditions outside the sea breeze circulation. Placement of secondary towers outside the sea breeze circulation to delineate the horizontal scale of the sea breeze would be difficult due to the large penetration inland of many sea breezes (from the immediate coast to 50 km inland).

The expected change in ambient temperature and dew-point temperatures are not exhibited by the St. Lucie meteorological data. No rapid change in ambient temperature nor dew-point temperatures, typical of sea breeze onset, is found in the FSAR meteorological data. Therefore, given the above considerations and conditions of sea breeze formation,

the meteorological conditions necessary to characterize sea breeze formation are a shift in wind direction, as measured at both levels on the St. Lucie tower, towards onshore directions in early to mid-morning. This wind direction condition must be combined with occurrence during the warm seasons of the year and synopic conditions of clear sky and weak gradient flows. The final consideration is a stability class that is unstable or neutral.

TABLE 451.02-1

Month	Mean Maximum Daily Temperature at Ft. Pierce (°F)	Average Sea Surface Temperature (°F)	Percentage of Winds at Orlando less than 12 mph (5.4 ms^{-1}) from 0800 to 1000
January	73.0	69	69
February	73.4	65	62
March	77.3	68	63
April	80.8	74	64
May	84.4	77	74
June	87.2	80	83
July	89.1	81	86
August	89.5	81	91
September	87.6	82	81
October	83.2	80	80
November	78.2	75	79
December	74.1	72	77

TABLE 451.02-2

DISTRIBUTION IN PERCENT OF TOTAL OBSERVATIONS

	Stability Class						
	A	B	C	D	E	F	G
Onshore (NNW-N-SE)	8.75	2.86	2.74	15.29	22.57	1.33	0.18
Offshore (SSE-S-NW)	3.27	0.97	1.22	14.19	22.14	2.74	1.15
Calm	0.00	0.00	0.02	0.09	0.39	0.09	0.00
Total	12.02	3.83	3.98	29.57	45.10	4.16	1.33

DISTRIBUTION IN PERCENT BY STABILITY CLASS

	Stability Class						
	A	B	C	D	E	F	G
Onshore (NNW-N-SE)	72.84	74.53	68.70	51.72	50.05	31.82	13.76
Offshore (SSE-S-NW)	27.16	25.47	30.84	47.99	49.08	66.13	86.24
Calm	0.00	0.00	0.46	0.29	0.87	2.05	0.00

REFERENCES

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Fisher, E.L., "An Observational Study of the Sea Breeze," Journal of Meteorology, Volume 17, No. 12, December 1960.

Frizzola, J.A., and Fisher, E.L., "A Series of Sea Breeze Observations in the New York City Area," Journal of Applied Meteorology, Volume 2, No. 12, December 1963.

Keens, C.S., and Lyons, W.A., "Lake/Land Breeze Circulations on the Western Shore of Lake Michigan," Journal of Applied Meteorology, Volume 17, No. 12, December 1978.

NOAA, "Summary of Hourly Observations, Orlando, Florida, 1956-1960," Climatography of the United States No. 82-8, 1963.

_________, "Climatic Summary of the United States - Supplement for 1951 through 1960," Climatography of the United States No. 86-6, 1964.

_________, "Climate of Florida," Climatography of the United States No. 60-8, Bradley, J.T., June 1972.

Walsh, J.E., "Sea Breeze Theory and Applications," Journal of Atmospheric Sciences, Volume 31, No. 11, December 1974.

Williams, D.T., "Predicting the Atlantic Sea Breeze in the Southeastern United States," Weatherwise, June 1974.

NRC Questions on St. Lucie Plant FSAR

Question 451.03

> As discussed in Section 2.3.2.1.3, annual average precipitation at West Palm Beach is almost double the annual precipitation measured at the St. Lucie site for the two-year period 9/76 - 8/78. Mean annual precipitation expected for the St. Lucie site is nearly 60 inches. Discuss the large difference between expected annual average precipitation at the St. Lucie site and the measured precipitation for the period 9/76 - 8/78. If this two-year period is considered anomalous with respect to precipitation at the St. Lucie site, discuss the representativeness of other meteorological parameters measured during the same period.

It is commonly recognized in coastal environments that stations somewhat removed from the shoreline experience more precipitation than those stations directly on the coast. This is mainly attributable to the convective lifting of the cool, moist air being transported inland by the sea breeze, or general onshore flow. It was shown by Gentry and Moore in 1954 that onshore flow even at night will produce appreciably more rainfall inland than on the shoreline.

With the strengthening of the Bermuda High in the summer months, the southeast Florida coast experiences onshore flow almost exclusively. And, as Table 2.3-79 shows, the preponderance of rainfall occurs with winds from the southeast quadrant.

Tables 2.3-52 and 2.3-53 show precipitation data for West Palm Beach (PBI) and St. Lucie (PSL), respectively. When mean total rainfall is separated into Winter (November through April) and Summer (May through October) groupings, the figures show the following:

MEAN MONTHLY RAINFALL BY SEASON

WINTER (NOV-APR)		SUMMER (MAY-OCT)	
PBI	PSL	PBI	PSL
2.79	2.31	7.56	2.97

As can be seen, virtually no anomaly is evident during the cooler months, but the difference is very pronounced when onshore flow is prevalent.

Other comparisons also show that the precipitation increases inland. Vero Beach is approximately half the distance from the shoreline as West Palm Beach (3 miles versus 5½ miles), and has shown annual average rainfall to be 48.63 inches over the past four years (47.01 miles for 1977-78). Miami Beach average annual rainfall is 48.29 inches over the last four years, while that of Miami International Airport is 57.06 inches.

The two years of data submitted in the FSAR is consistent with subsequent measurements at St. Lucie. Average annual rainfall for 1979 and 1980 were 39.86 inches and 32.93 inches (1979 figures reflect the passage of Hurricane David). We feel the rainfall measurements at St. Lucie site are representative of these conditions in that vicinity.

Question 451.03 (Continued)

REF: Gentry, Robert C. and Moore, Paul L., 1954: Relations of Local and General Wind Interaction Near the Sea Coast to Time and Location of Air-Mass Showers. J. Meteror., 11, 507-511.

NRC Questions on St. Lucie FSAR

Question 451.04

> On page 2.3-10 of the FSAR, the statement is made that the location of the meteorological tower is in "relatively flat terrain characterized by mangrove trees in the range of 8 to 10 feet in height." Provide the distance and direction to the nearest mangrove trees and discuss possible influences of the trees on lower level sensors on the meteorological tower.

There is a stand of mangrove trees generally to the northwest of the meteorological tower; the closest point being at the sourthern end of the stand, some 60 feet distant at a bearing of 250°. The trees are 100 feet away at 330°, then fall away to 480 feet at 360°. The stand is fairly dense, as is characteristic of mangroves, but the tops are generally low and of consistent height.

It is conceivable there would be some interference on the low-level wind sensors with winds from 250° - 330° (where the trees are within 100 feet of the tower). However, we would expect this to be minimal because of the characteristics described above, and we would expect impacts to be minimal, since all winds would be offshore.

In addition, the four sectors which generally depict the directions which would be affected by the growth (WSW-NW) account for less than 19 percent of the measured low-level winds. Since the sectors themselves comprise 25 percent of a circle, the frequency of wind from the affected directions is somewhat less than normal.

We feel the location of the low-level wind equipment permits the measurement of representative wind data for St. Lucie plant, and that any interference from nearby foliage is insignificant.

NRC Questions on St. Lucie FSAR

Question 451.05

Identify the frequency of the calibration and maintenance procedures discussed in Section 2.3.3.5

All procedures discussed in Section 2.3.3.5 are performed semi-annually. Since more than 90% data recovery is accomplished at the St. Lucie site, this schedule meets the requirements of Regulator Guide 1.23.

Furthermore, "as found" conditions are consistently within allowable limits, further indicating that this schedule is adequate to maintain the integrity of the system.

NRC Questions on St. Lucie FSAR

Question 451.06

> **Discuss the status of the onsite meteorological measurements program since August, 1978 and indicate if more recent data are available.**

Data has been collected continuously since the inception of the meteorological program at St. Lucie, and is now available through the first quarter of 1981.

NRC Questions on St. Lucie FSAR

Question 451.07

> The calculations of short-term (accident) diffusion estimates presented in Section 2.3.4 use the direction-dependent atmospheric dispersion model described in Regulatory Guide 1.145 including consideration of increased lateral plume spread during stable conditions accompanied by low wind speeds. However, the approach described in Regulatory Guide 1.145 to account for this increased lateral plume spread is not based on dispersion in a coastal environment such as St. Lucie, and clearly does not apply to atmospheric dispersion over water. Discuss the appropriateness of the use of the Regulatory Guide 1.145 methodology to the St. Lucie site considering atmospheric dispersion processes in the coastal environment in general and over-water trajectories in particular.

Wind direction meander refers to an atmospheric condition in which the lateral spread of a pollutant plume or cloud is largely or primarily due to slow fluctuations of wind direction in an otherwise steady, low speed flow. This phenomena occurs under neutral or stable atmospheric stability conditions. Meander has the effect of increasing lateral dispersion of a pollutant cloud beyond that normally associated with the existing atmospheric stability, thereby decreasing pollutant concentrations and dose assessments.

The current NRC method of treatment of meander in the calculation of short-term concentrations involves the conditional use of three equations for hourly average ground-level relative concentrations (Regulatory Guide 1.145). Under unstable conditions or wind speeds equal to or greater than 6 m/s, no meander is considered and the equation used includes a building wake correction term that is proportional to the building cross-sectional area. (The effect of the building wake correction term on the concentration is limited to a factor of three (3) or less.) Under neutral and stable atmospheric conditions with wind speeds less than 6 m/s, either the building wake correction equation or an equation that has a single factor, given the symbol Σ_y, expressing the enhanced lateral dispersion of a cloud, due to meander or wake effects or both, is used in the assessment. Σ_y depends upon distance, the lateral dispersion factor σ_y, and the atmospheric stability class in a manner prescribed in Appendix A of Regulatory Guide 1.145. This

method is an empirical formulation based on NRC staff analysis of results from an atmospheric dispersion experiment performed at an inland nuclear electric generating station (NOAA, 1977).

To address this question a search of the literature was made with particular attention paid to the experimental results used to justify the NRC treatment of meander. In addition, a more general examination of the scientific literature appraising studies performed subsequent to the work cited in Regulatory Guide 1.145 was made. The critical review of the literature of diffusion methods at coastal sites provided by Raynor, Michael, and SethuRaman (1980) greatly facilitated this effort.

UU?? 0956

The literature of coastal effects on meander formation is extremely sparse. We were not able to identify any publications on this topic that were not included in the reference list of Raynor et al., 1980. The observations that have been made were at sites fronting large bodies of water such as the Atlantic Ocean or Long Island Sound. These observations indicate that large bodies of water may reduce the magnitude of meander. However, these observations were only a noted event of interest, and systematic studies designed to verify and quantify the observations have yet to be performed.

Raynor et al., 1980 presented the following recommendations concerning the meander applied to dispersion from coastal sites: "... it is recommended that current procedures for using meander to reduce computed concentrations at wind speeds above 1 m s^{-1} should be considered tentative and subject to revision if additional data show them to be insufficiently convervative...", ? This has been considered true, in the interim period, for plume transported over-water, as well as that over-land areas. The meander for over-water plume transport conditions should have the same characteristics as that for land areas because the meander has been generated over-land and should require, because meander is a long wave length phenomenon as compared with turbulence, a greater distance to change characteristics. Therefore, the 800 meters distance in which Regulatory Guide 1.145 applies a meander adjustment term is applicable to over-water transport.

For over-land trajectory of a source located on the coastline, the application of the Regulatory Guide 1.145 meander enhanced lateral spread of the plume is less certain. The fact that coastal onshore winds are generally of higher wind speed and occur during more unstable atmospheric conditions should make

the application of Regulatory Guide 1.145 meander correction less significant for the onshore winds, therefore supporting the use of the present meander methodology during the interim period.

We find the recommendation of the use of the current procedures for the meander reduction of concentrations reasonable in light of currently available data on the subject and, therefore, applicable for the FSAR short-term (accident) diffusion estimates.

References:

- Regulatory Guide 1.145, Atmospheric Models for Potential Accident Consequence Assessments at Nuclear Power Plant, U.S. Nuclear Regulatory Commission, Office of Standards Development, Regulatory Guide 1.145, August 1979.

- NOAA, 1977, Rancho Seco Building Wake Effects on Atmospheric Diffusion, G.E. Start, J.H. Cate, C.R. Dickson, N.R. Ricks, G. R. Ackerman, J.F. Sogendorf, National Oceanic and Atmospheric Administration Technical Memorandum ERL-ARL-69, Air Resources Laboratories, Idaho Falls, Idaho, November 1977.

- Raynor, G.S., Michael P., and SethuRaman, S., 1980, "Meteorological Measurement Methods and Diffusion Models for Use at Coastal Nuclear Reactor Sites," Nuclear Safety, Volume 21, No. 6, Novermber-December 1980.

NRC Questions on St. Lucie FSAR

Question 451.08

> The terrain correction factors presented in Table 2.3-102 indicate that the straight-line annual average atmospheric dispersion model may not adequately represent the regular spatial and temporal variations in airflow in the vicinity of the St. Lucie site. However, the puff-advection model on which these correction factors are based is most useful when meteorological data from multiple sources can be used to describe spatial and temporal variations in airflow. Identify the meteorolgical data used as input to the puff-advection model, and discuss the appropriateness and reasonableness of correction factors at distances of 7.5 miles and beyond.

The puff-advection model (MESODIF) was used on the FSAR analyses to develop site-specific terrain/recirculation correction factors. These adjustments were developed for application to the straight-line airflow model to account for, on an annual basis, the airflow characteristics in the St. Lucie site vicinity that affect the atmospheric transport and diffusion conditions. For the St. Lucie coastal site, these conditions consist of sea and land breeze circulations.

The terrain/recirculation correction factors were developed from the ratio of the relative concentrations calculated using the puff-advection model and straight-line model for the meteorological data period of August 1977 through August 1978 (8760 valid observations). Although it is true that the puff-advection model can be run and is more useful with multiple source input, such a run configuration is of more importance in areas of complex topography and/or for large distances from the release point. For the St. Lucie application, the one station puff-advection analysis should be appropriate for distances less than 7.5 miles as the onsite meteorological data will contain the land and sea breeze circulations. Topographic modifications within this range should not be of significance. The appropriateness of this application is further supported by the fact that sea breeze circulations have been found to penetrate up to 50 kilometers

inland and that the expected releases from the St. Lucie site are at ground level. Therefore, the data as measured at the onsite tower should, in application in the puff-advection model, be representative of the 7.5 mile radius inland.

Of additional concern is the use of the results of the puff-advection analysis for flows offshore. The fact that meteorological data are not available over the ocean and on observations of other investigators indicating the slow adjustment of meteorological parameters to over water trajectory, the application of the one-station puff-advection analysis to the over water trajectories within 7.5 miles is appropriate and reasonable for this site.

It should be noted that terrain/recirculation factors of magnitude less than one for large distances from a source are expected and appropriate due to the physical processes involved and the nature of the two models. Also, because of the lack of major terrain considerations and the general persistence of the sea breeze circulations at coastal sites in Flordia, a one-station puff-advection analysis may be more appropriate at the St. Lucie location then at others without such ambient meteorological/terrain conditions. But because of the limitation of the puff-advection analysis to the use of one-station, the terrain/recirculation correction value calculated at large distances are more uncertain than the values calculated closer to the source of the meteorological data. Therefore, the use of the terrain/recirculation correction values calculated at large distances from the St. Lucie facility should be made with discretion.

311.1
(2.1.1.2) In conjunction with FP&L's control of all land and water use inside their property, please verify by documentation FP&L's ownership of all mineral rights and easements to the St. Lucie property.

Response:

We have reviewed our records on the approximately 1,132 acres of land acquired for the St. Lucie Plant; and according to our lawyer's opinions of title, it appears that FPL is the owner of all oil, gas, and mineral rights.

There is, however, an outstanding easement to the State of Florida having the right to excavate within 250 feet on each side of the center of the channel of the Intracoastal Waterway and to dredge materials for construction and maintenance within 1,250 feet of each side of the centerline. Additionally, by the recent conveyance of an interest to The Orlando Utilities Commission in Unit No. 2, an easement was also granted the Commission over the adjoining 388.3 acres for use of common facilities and ingress and egress.

311.2

2.1.2.1) Please revise the St. Lucie unit #2 documents by amending the appropriate sections to clarify the exclusion area and low population zone boundary designations as per Al Brauners (NRC) telecon with Mr. Errol Dotson (FP&L) on 5/11/81, and Mr. Paul Grossman (Ebasco) on 5/19/81.

Response:

See revised FSAR Amendment No. 4

Question

The blowdown of a double ended guillotine rupture of the steam line in the subcompartment analysis was derived from the RELAP 3 code. Appendix 3.6A is referred for this analysis; however, it contains only "to be submitted later."

Provide assumptions and models of the mass and energy release calculation for this main steam line rupture.

Response

Please see Appendix 3.6A which has been submitted in Amendment 3 (June 1, 1981).

No FSAR change is required for this response.

Question FSAR explains the reason why the maximum safety injection flows are conservative for calculating the containment peak pressure response by referring to CESSAR Section 6.2.1. However CESSAR Section 6.2.1, Containment Functional Design, contains many subsections and more than 100 pages.

Provide the specific subsection which directly explains the reason described above.

INSERT A

Response: An explanation of the reason for maximum safety injection flows being conservative is provided in CESSAR-P(2), paragraph 6.2.1.1.2(a), at the top of page 6.2-7. The peak containment pressure following a cold leg LOCA is basically a function of the following variables: Mass/energy release during blowdown, ECCS flow rates, containment active and passive heat removal rates, and NSSS primary side hydraulic factors.

no # St. Lucie 2 plant-specific analyses were conducted using both maximum and minimum ECCS flow rates in order to determine the most conservative case. It was found that maximum ECCS flow was conservative. The reason for this is provided in CESSAR-P, namely that maximizing the core flooding rate has maximized the steam release rate to the containment.

LOCA Analyses with Maximum Safety Injection

A containment pressure-temperature analysis is performed for the LOCA assuming maximum safety injection flow. For the purpose of this LOCA analysis, the ECCS and the Containment Heat Removal Systems are assumed to operate in the mode that maximized the containment pressure response. For the Safety Injection System, maximum safety injection flows are conservative for calculating the containment peak pressure response. ~~This is demonstrated in Subsection 6.2.1 of CESSAR[2]~~. # INSERT A For the Containment Heat Removal System, minimum system capacity is conservative for calculating the containment peak pressure response. Therefore, the Containment Heat Removal System is assumed to be affected by the most conservative restrictive single failure which is assumed to be a loss of one containment spray train. One spray train is selected because the heat removal capability of one spray is greater than the capability of two containment fan coolers. The loss of one diesel generator train is not the most restrictive single active failure since full safety injection flows are not available.

Conservative trip setpoints of 11 psig (CSAS) and 6 psig (SIAS) are utilized. The analysis setpoint considers a 1.15 second time delay after receipt of the trip setpoint to account for any equipment uncertainty or circuitry time delay. 0

The following describes the conservative assumptions made with respect to ESF system operations and parameters (see Table 6.2-6) for the LOCA maximum pressure and temperature analyses: 0

a) For a discharge leg break, the contents of three safety injection tanks discharge into the reactor vessel when Reactor Coolant System pressure drops below tank pressure. The fourth tank is assumed to inject into the broken leg and out to the containment. For a suction leg break, all four safety injection tanks are assumed to inject into the Reactor Coolant System.

b) All ECCS pumps operate at approximately run out flow (i.e. ECCS flow is assumed to be that corresponding to the instantaneous Reactor Coolant System pressure) until the start of recirculation, with 100 percent of the flow reaching the core.

c) One containment spray pump operates and sprays 2,650 gpm of water into the containment until the start of recirculation (the failure of one containment spray train) at a maximum refueling water tank temperature of 100 F.

d) One shutdown cooling heat exchanger operates during the recirculation mode of operation to cool the containment spray. The assumed UA of the heat exchanger is lower than the design minimum to minimize removal from the containment, and the heat exchanger is assumed to be supplied with cooling water flowing at 2.41×10^6 lbm/hr with the maximum recirculation component cooling water temperature 105 F.

The steam generator and pressurizer are enclosed by heavily reinforced concrete shield walls in a single large compartment below elevation 62 ft. See Figures 6.2-18 to 21 for details of the arrangement of subcompartments in this region. Pressure relief is provided by openings in the secondary shield wall to the annular areas between the secondary shield wall and the containment, and by flow through the operating floor where the steam generators pass through the floor to the upper containment.

The lower pressurizer and surge line piping are open to this region and venting is to an upper enclosed volume above elevation 62 ft. Pressure relief in this upper volume is provided by a doorway at the floor level.

Subcompartment free volumes and vent area information is discussed in Subsection 6.2.1.2.3.

6.2.1.2.3 Design Evaluation

The modified CEFLASH4 computer code was used to calculate the mass and energy release rates from postulated Reactor Coolant System pipe ruptures. This code is the same as the one containing the combination Henry-Fauske/Moody critical flow subroutine, described in Subsection 6.2.1.1.5 of the Arkansas Nuclear One Unit Two FSAR (Docket No. 50-368). The Reactor Coolant System nodalization scheme is shown on Figure 6.2-22. This nodalization scheme is modified for the pressurizer surge line break by adding a four node surge line model.

INSERT B

The subcompartment pressurization effects are dependent on the blowdown energy release rates. In order to provide adequate conservatism for design evaluation, the following methodology is used to generate short duration mass and energy release rates.

a) Subcooled and low quality break flow are computed using the Henry-Fauske correlation with a discharge coefficient of 1.0.

b) Break flow with quality above approximately 6.0 percent is computed using the Moody critical flow correlation with a discharge coefficient of 1.0.

c) The momentum flux terms are omitted when solving the conservation of momentum equation for flows within the Reactor Coolant System.

d) Initial Reactor Coolant System conditions are at 102 percent of nominal full power conditions.

e) Reactor Coolant System volumes are increased over nominal values.

f) The pressurizer water level is assumed to be above the normal full power operating water level.

The method used to calculate the mass and energy releases is similar to the one described in Subsection 6.2.1.1.4 of CESSAR (approved December, 1975).

Question The "modified CEFLASH 4" computer code was used to calculate the mass and energy release rates from postulated Reactor Coolant System pipe ruptures for subcompartment analysis. Is this "modified CEFLASH 4" the same or a different code as the CEFLASH-4A which was used for the same purpose in the approved CESSAR PSAR?

If they are different, identify the difference between two codes as related to the blowdown mass and energy releases.

INSERT B

Response: The "modified CEFLASH-4" code is different from the CEFLASH-4A code used in the approved CESSAR PSAR. However, the "modified CEFLASH-4" code produces the same mass and energy releases as the CEFLASH-4A code.

The difference between CEFLASH-4A and CEFLASH-4 (not modified) is discussed in CESSAR-PSAR. In the "modified CEFLASH-4" there is the same method for calculation of critical mass flux as there is in CEFLASH-4A. For this reason, CEFLASH-4A and "modified CEFLASH-4" produce the same blowdown release rates.

The "modified CEFLASH-4" code was used because input data were available which satisfied input requirements of that version of the code. CEFLASH-4A input has a different format and would have required re-working the input data which would have been time consuming, while the blowdown release rates would not be changed.

The modified CEFLASH-4 code was used for the Arkansas Power and Light Unit One-2 FSAR, which has been reviewed and approved by the NRC.

Question

The reason for not explicitly analyzing a failure scenario involving the Auxiliary Feedwater System (AFWS) is given as that the additional water inventory and energy involved are less than the additional inventory and energy associated with the MFIV failure case.

Clarify this statement. Why is the additional water inventory involved from a failure of AFWS less than that from the MFIV failure case. What is the AFWS failure; how does it fail?

INSERT C

Response: The AFWS failure referenced in the question would be any failure of the AFWS which allowed auxiliary feedwater to be fed to the affected steam generator during a Main Steam Line Break (MSLB). The inventory comparison with the additional inventory associated with the MFIV failure case is as follows:

The maximum inventory rate that could be added to the ruptured unit at AFWS pump run-out flows is 2000 GPM. Since the time to peak containment pressure is typically 1 minute, the corresponding maximum AFWS inventory addition is 2000 gallons, or approximately 15,600 lbm. By contrast, for the MFIV failure case, an additional inventory of 414 ft^3 (21,500 lbm) was available to the ruptured unit. Since the AFWS supplied additional inventory would be less than that via the MFIV failure, and since the AFW is cold water relative to the heated main feed water, there was no need to explicitly analyze an AFWS failure since a more conservative failure (MFIV failure) has been analyzed.

Additionally, the following facts should be noted:

1) The safety grade AFWS to be installed in St. Lucie 2 in response to post TMI requirements is designed such that no single failure will result in delivery of feedwater to a ruptured generator.

2) The revised main feedwater system provides two safety grade MFIV's in series in each line, so that isolation of main feedwater without additional inventory considerations will occur even if one of the MFIV's fails.

3) The EFAS logic and the AFWS will feed auxiliary feedwater (as required) to the intact steam generator during a MSLB. The addition of this water to the intact unit was omitted from all MSLB mass/energy release analyses since the addition of cold water to the intact unit, if considered, would cool the NSSS and hence would provide slower steaming rates from the ruptured unit to the containment.

generator. Closure of the operational MSIV provides isolation of the intact steam generator. The MFIVs and both containment heat removal trains (two containment sprays and four containment fan coolers) function for this case. The steam inventory from the faulted steam generator up to the closed MSIV on the intact steam generator expands into the containment. The feedwater inventory between the faulted steam generator and its MSIV is assumed to flow into the steam generator and is released to the containment.

Case 3 - MFIV Failure

A single failure of one MFIV during a postulated main steam line break accident is accommodated by closure of the backup feedwater isolation valves upon receipt of a MSIS or SIAS signal. The MSIVs and both containment heat removal trains (two containment sprays and four containment fan coolers) are postulated to operate. The MFIV nearest to the faulted steam generator is postulated to fail. Steam in the steam line between the break and the nearest MSIV expands into the containment. The feedwater inventory between the faulted steam generator and the feedwater backup valve flashes into the containment.

The feedwater flowrates to the faulted steam generator are calculated for various power level and single active failure cases using the calculated faulted and intact steam generator pressure responses, the feedwater pump characteristics and the feedwater isolation or regulating valve flow coefficients (see Figure 6.2-34).

A failure scenario involving the Auxiliary Feedwater System is not explicitly analyzed since the additional water inventory and energy involved are less than the additional inventory and energy associated with the MFIV failure case. ~~Otherwise, since the Auxiliary Feedwater System is manually initiated, it would have to be assumed that during a main steam line break accident the control room operator not only starts all three auxiliary feedwater pumps immediately, but also opens the isolation valves to the faulted steam generator and cross ties the auxiliary feedwater trains 2A and 2B together via valves I-MV-09-13 and I-MV-09-14. Based on the above, it is not necessary to explicitly analyze a MSLB accident and subsequent start of the Auxiliary Feedwater System.~~

Offsite power is assumed to be available for the analysis. Availability of offsite power allows the continuation of reactor coolant pump and feedwater pump flow. Maintaining reactor coolant and feedwater pump flow maximizes the rate of primary to secondary heat transfer which maximizes the rate of mass/energy release.

INSERT C

Question 410.19
(9.2.2)

In accordance with the FSAR, the St Lucie 2 design incorporates an automatic reactor trip 10 minutes after loss of the component cooling water (CCW) to the reactor coolant pumps (RCP). The FSAR also states that the trip is designed to IEEE 279-1971 requirements. The RCP's would be tripped manually on loss of CCW. The portion of the CCW system supplying cooling water to the RCP's is not safety grade. Regarding loss of cooling to the RCP, provide the following information:

a) State whether the instrumentation that alerts the operators in the control room of the cause of the reactor trip discussed above is safety grade.

b) Provide test data or other information to demonstrate that the RCP's can operate without CCW flow for a period of time compatible with operator action to trip the RCP's.

c) Assuming the reactor is in hot standby with the RCP's tripped, how long will the pump seals perform their function without CCW flow?

Response 410.19

a) The reactor trip upon a loss of component cooling water to the reactor coolant pumps is not required for reactor protection. The reactor trip upon loss of component cooling water is delayed for ten (10) minutes after it reaches the preset setpoint. Four channels of Class IE indication of component cooling water total flow from all reactor coolant pumps is provided on the RTG Board.

The instrumentation that alerts the operators in the control room of the cause of the reactor trip consists of __________ safety grade instruments & control devices. Safety grade isolation devices are also provided to isolate signals generated by safety grade equipment to a non-safety grade station annuciators and sequence of events recorder.

b) San Onofre Units 2 and 3 Reactor Coolant Pumps have been operationally tested to demonstrate satisfactory seal performance with seal cooling water shut off for 30 minutes with the pump operating. Based on the 30 minute operational test, it was demonstrated that the seals would not lose function (i.e., gross leakage) but the seal assemblies did require refurbishment following the test. It is the judgement of Combustion Engineering that the RCP seals would not lose function following a loss of power two hours in duration. Based on these test results, the similarity of these pumps with those for St. Lucie Unit 2, and the information available to the operator (see FSAR section 9.2.2.3.1), the operator is expected to have sufficient time to trip the reactor coolant pumps.

The San Onofre Units 2 and 3 pumps were also operationally tested to demonstrate satisfactory motor bearing performance with cooling water shut off and with the pump operating. The cooling water was shut off for 23 minutes and a post-test examination showed the bearings to be in excellent condition (i.e., no observable damage). Analysis of test results indicated that the pump motor could run at least 30 minutes without cooling water and remain operable.

The motor bearings for the St. Lucie Unit 2 pumps are of the same design as those in the above mentioned test. Therefore, acceptable performance of the St. Lucie Unit 2 bearings after a loss of component cooling water was demonstrated by the test of the San Onofre pumps. In addition, there have been two occurrences of loss of component cooling water at St. Lucie Unit 1 (Licensee Event Reports 335-77-23 and 335-80-29). The pump bearings have performed satisfactorily since these incidents, indicating the acceptable performance of the bearings after loss of component cooling water. 6/5/81

No FSAR change is required.

c) Tests have been performed to simulate the loss of component cooling water to the RCPs while at hot standby with the RCPs tripped. After approximately 50 hours at coolant conditions of 550^{O}F and 2250 psig, the RCP seal cartridge still performed satisfactorily with the pump idle. Some seal damage was observed during the post-test inspection; however, the maximum seal leakage during the test was only 16 gph (Reference: FP&L letter L-81-107, March 10, 1981).

TABLE 15.0-1 (Cont'd)

- C5. Reduction of Shutdown Cooling Effectiveness 2
    - Opening a shutdown cooling flow control valve above requirements
    - Leak in a non-essential component cooling water line
    - Leak in an essential component cooling water line
- C6. Partial Loss of Normal Feedwater and Reactor Coolant Flows 2
    - Loss of a non-safety 6.9kV bus
- C7. Loss of Offsite Power
    - Loss of grid

D. Reactivity and Power Distribution Anomalies

- D1. Uncontrolled Positive Reactivity Insertion
    - Sequential CEA withdrawal
    - Single part length CEA drop
    - Part length CEA subgroup drop
    - Single CEA withdrawal
    - CEA subgroup withdrawal
    - CEA group withdrawal
    - ~~Part length CEA group drop~~
- D2. Slow Positive Reactivity Insertion
    - Closure of boron flow control valve
    - Malfunction of makeup controller
- D3. Uncontrolled Negative Reactivity Insertion-Single CEA Drop
    - Single CEA drop
- D4. Uncontrolled Negative Reactivity Insertion-Other
    - Sequential CEA insertion
    - CEA subgroup drop
    - Single part length CEA drop
    - Part length CEA subgroup drop
    - CEA group drop
    - ~~Part length CEA subgroup drop~~
    - Broken CEA
- D5. CEA Ejection
    - Rupture of a CEDM nozzle or housing
- D6. Slow Negative Reactivity Insertion
    - Inadvertent boration

E. Increase in Reactor Coolant System Inventory

- E1. Primary System Mass Addition
    - Partial closure of the letdown control valve
    - Closure of the letdown control valve
    - Partial closure of a letdown isolation valve
    - Closure of a letdown isolation valve
    - Startup of charging pump(s) 2
    - Pressurizer level signal fails low or low-low

F. Decrease in the Reactor Coolant System Inventory

- F1. Decrease in primary system mass
    - Opening the letdown control valve above requirements
    - Loss of a charging pump
    - Closure of the volume control tank discharge isolation valve
    - Closure of a charging control valve
    - Pressurizer level signal fails high
    - Regenerative heat exchanger tube rupture

15.4.1.4 Limiting Loss of Shutdown Margin Event

The only Moderate Frequency event resulting in a reactivity and power distribution anomaly shown in Table 15.4.1-1 does not approach the acceptance guideline on the loss of shutdown margin specified in Table 15.0-4. 2

15.4.2 INFREQUENT EVENTS

15.4.2.1 Limiting Offsite Dose Event

None of the Infrequent events resulting in a reactivity and power distribution anomaly shown in Table 15.4.2-1 release a significant amount of radioactivity to the atmosphere. The offsite doses which would occur during the most adverse of these events are well within the acceptance guideline specified in Table 15.0-4. 2

15.4.2.2 Limiting Reactor Coolant System Pressure Event

None of the Infrequent events resulting in a reactivity and power distribution anomaly shown in Table 15.4.2-1 produce a RCS pressure greater than that produced by the Uncontrolled Positive Reactivity Insertion with a loss of offsite power as a result of turbine trip event, described in Subsection 15.4.4.2. Therefore, the conclusions of Subsection 15.4.4.2, which meet the acceptance guideline for Infrequent events, also apply to this section.

15.4.2.3 Limiting Fuel Performance Event - Uncontrolled Positive Reactivity Insertion

15.4.2.3.1 Identification of Event and Causes

All of the Infrequent event groups from the reactivity and power distribution anomalies event type and the Infrequent event combinations shown in Table 15.4.2-1 were compared to find the limiting fuel performance event. The Uncontrolled Positive Reactivity Insertion was identified as the limiting event.

The event groups and event combinations evaluated and the significance of the approach to the fuel performance acceptance guideline for each are indicated in Table 15.4.2-1. All events indicated as significant (S) produce a fuel performance within the acceptance guideline. 2

The uncontrolled positive reactivity insertion event group is more limiting than the uncontrolled negative reactivity insertion event group because the uncontrolled positive reactivity insertion event group combines significant power distortions with a rapid increase in overall power, while the uncontrolled negative reactivity insertion event group is characterized by similar power distortions, but is combined with a rapid power decrease followed by a return to the initial power level. ~~Even the addition to a uncontrolled negative reactivity insertion event of a partial flow coastdown due to a failure to achieve a fast transfer to a 6.9 kV bus does not have as adverse effect on fuel performance as the power increase resulting from the uncontrolled positive reactivity insertion events.~~ remove

An uncontrolled positive reactivity insertion can be caused by a sequential CEA withdrawal, the withdrawal of a single CEA, CEA subgroup, or CEA group or the drop of a single part length CEA or part length CEA subgroup ~~or part length CEA group~~. The part length CEA (PLCEA) sub group drop is the most limiting initiating event in the uncontrolled positive reactivity insertion event group because the PLCEA sub group drop results in the largest power distortions, most rapid power increase, and largest decrease in DNBR of all events in this group. 2

15.4.2.3.2 Sequence of Events and Systems Operation

Table 15.4.2.3-1 presents a chronological list and timing of system actions which occur following a part length CEA sub group drop. Refer to Table 15.4.2.3-1 while reading this and the following section. The success paths referenced are those given on the sequence of event diagram (SED), Figure 15.4.2.3-1. This figure, together with Table 15.0-6, which contains a glossary of SED symbols and acronyms, may be used to trace the actuation and interaction of the systems used to mitigate the consequences of this event. The timings in Table 15.4.2.3-1 may be used to determine when, after the initiating event, each action occurs. 2

The sequence presented demonstrates that the operator can cool the plant down to cold shutdown during the event. If the malfunction which causes the event initiator can be repaired without violating the Technical Specifications, then the operator may elect instead to stabilize the plant in a mode other than cold shutdown. All actions required to stabilize the plant and perform the required repairs are not described here.

The sequence of events and systems operations described below represents the way in which the plant was assumed to respond to the event initiator. Many plant responses are possible, however, certain responses are limiting with respect to the acceptance guidelines for this section. Of the limiting responses, the most likely one to be followed was selected.

Table 15.4.2.3-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient. The operation of these systems is consistent with the guidelines of Subsection 15.0.2.3.

Table 15.4.2.3-3 contains a matrix which describes the extent to which safety are assumed to function during the transient.

The success paths in the sequence of events diagram, Figure 15.4.2.3-1, are as follows:

Reactivity Control:

A reactor trip signal (RTS) is automatically generated by the Reactor Protective System on a high power level. The RTS opens the reactor trip circuit breakers to de-energizing the control element drive mechanism (CEDM) power supply bus which interrupts power to the CEDM holding coils allowing the control element assemblies to fall into the core. If cooldown is necessary; the operator adjusts the Reactor Coolant System (RCS) boron concentration to the cold shutdown concentration prior to plant cooldown by

RCS volume shrinkage. RCS pressure is gradually reduced by the pressurizer spray valves. The operator may also actuate the pressurizer heaters during cooldown, to permit using a higher spray rate and obtain better pressure control and mixing of fluid in the pressurizer. During cooldown, the charging pumps initially take suction from the boric acid makeup tank BAMT until the RCS has been increased to the cold shutdown boron concentration, at which time the charging pump suction is realigned to the refueling water tank. As the RCS pressure is reduced, the operator blocks the safety injection actuation signal to prevent its inadvertent actuation. The safety 2
injection tanks are depressurized by draining or venting and then are isolated to permit further depressurization of the RCS. After the reactor coolant pumps have been stopped, the operator uses the auxiliary spray to reduce pressurizer pressure.

Maintenance of AC Power:

Upon loss of power to the unit auxiliary transformers, their loads are transferred to the startup transformers by a fast-dead bus transfer.

15.4.2.3.3 Analysis of Effects and Consequences

a) Mathematical Models

The NSSS response to the PLCEA ~~Group~~ Subgroup Drop was simulated using the CESEC code described in Subsection 15.0.4. The transient minimum DNBR values were calculated using the TORC code which uses the CE-1 CHF correlation described in Subsection 15.0.4.

b) Input Parameters and Initial Conditions

The range of initial conditions considered are given in Subsection 15.0.3. Table 15.4.2.3-4 gives the initial conditions used in this analysis. Maximum core power, highest core inlet coolant temperature, lowest core mass flow rate, and lowest pressurizer pressure are used since these values have the most adverse impact on DNBR. The least negative Doppler coefficient and the smallest scram CEA 2
worth maximizes the heat flux increase after a reactor trip occurs, giving a lower minimum DNBR. The moderator temperature coefficient is set at the most positive value that is allowed by the Technical Specifications with part length CEAs in the core. For this 2
analysis, the thermal margin/low pressure and high local power density trips are assumed not to function.

c) Results

The dynamic behavior of important NSSS parameters following a part length CEA subgroup drop is presented on Figures 15.4.2.3-2 to 8. Table 15.4.2.3-1 summarizes some of the important results of this event and the times at which the minimum and maximum parameter values discussed below occur.

The PLCEA ~~group~~ subgroup drop causes a positive reactivity insertion resulting in a rapid increase in core power as shown on Figure 15.4.2.3-2. The power and heat flux continue to increase until the negative reactivity from the high power trip offsets the initial positive reactivity insertion. (See Figures 15.4.2.3-2 and -3). 2
The PLCEA subgroup drop also results in an increase in radial peaking factor and a more top-peaked axial power distribution. The increase in heat flux and integrated radial peak cause a large decrease in minimum DNBR. The minimum DNBR vs. time is shown on Figure 15.4.2.3-7. The negative CEA reactivity inserted after the reactor trip continues the rapid power decrease and reverses the DNBR decrease. ~~As a result of this event, 0.5 percent of the fuel pins are calculated to experience DNB and thus, for conservatism, are assumed to experience clad failure. No pins experience DNB after the first few seconds of the transient.~~

After reactor and turbine trip, and with the steam bypass control in manual, the steam generator pressure rapidly rises to the main steam safety valve setpoint and then the cycles around this valve setpoint in response to the safety valve operating characteristics (Figure 15.4.2.3-7) until the operator actuates the SBCS. 2

15.4.2.3.4 Conclusions

This evaluation shows that the plant response to a PLCEA subgroup drop produces a fuel performance which is well within the acceptance guideline specified in Table 15.0-4.

TABLE 15.4.2-1

LIST OF EVENT GROUPS AND EVENT GROUP COMBINATIONS EVALUATED IN THE INFREQUENT/REACTIVITY AND POWER DISTRIBUTION ANOMALIES MATRIX ELEMENT COMPARED TO ACCEPTANCE GUIDELINES

Event Groups and Event Group Combinations	Acceptance Guidelines: Offsite Dose	RCS Pressure	Fuel Performance	Loss of Shutdown Margin
1) Uncontrolled Positive Reactivity Insertion	I	S	S	I
2) Slow Positive Reactivity Insertion	I	S	I	S
3) Uncontrolled Negative Reactivity Insertion-Single CEA Drop (CEA Drop) + High Steam Generator Tube Leakage Rate (TL)	I	I	I	I
4) CEA Drop + Low Probability Independent Occurrence	I	I	I	I
5) Uncontrolled Negative Reactivity Insertion-Other (UNRI)	I	I	S	I
6) UNRI + TL	I	I	S	I
~~7) UNRI + Failure of one bus to Achieve a Fast Transfer to a Startup Transformer~~	~~I~~	~~I~~	~~S~~	~~I~~
8) Slow Negative Reactivity Insertion	I	I	I	I

2

S - Significant approach to acceptance guideline.
I - Insignificant approach to acceptance guideline. 2

TABLE 15.4.2.3-1

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR THE PART LENGTH CEA ~~GROUP~~ SUBGROUP DROP

Time (Sec)	Event	Analysis Set Point or Value	Success Paths: Reactivity Control	Reactor Heat Removal	Secondary System Integrity	Primary System Integrity	Maintenance of AC Power		
0.0	Part Length CEA subgroup drop	--							
0.63	Reactor trip signal generated on high power level, %	117	X						
0.94	Maximum power, %	140.6							
1.3	Turbine trip on loss of power on CEDM power supply buses	--			X				
	Fast transfer of power supply buses	--					X		
4.5	Maximum RCS pressure, psia	2272							
6.7	Main steam safety valves open*, psig	975			X				

* MSSVs cycle open and closed until operator actuates the SBCS.

TABLE 15.4.2.3-1 (Cont'd)

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR THE PART LENGTH CEA ~~GROUP~~ SUBGROUP DROP

Time (Sec)	Event	Analysis Set Point or Value	Success Paths: Reactivity Control	Reactor Heat Removal	Secondary System Integrity	Primary System Integrity	Maintenance of AC Power		
1800	1. Operator borates to cold shutdown concentration	--	X						
	2. Operator actuates steam bypass control system to commence cooldown of RCS	--			X				
	3. MSSVs close, psig	935			X				
	4. Operator actuates AFW	--			X				
	5. Operator closes MSR block valves	--			X				
--	Operator blocks MSIS, psia	>585			X				
--	In preparation to break condenser vacuum, operator:								
	1. Opens atmospheric dump valves	--			X				
	2. Closes steam bypass valves	--			X				
	3. Closes main steam isolation valves	--			X				
	Steam header pressure, psia	>400							
13,600	Shutdown cooling initiated, °F/psia	350/275		X					
--	Total steam released to the atmosphere through MSSVs and ADVs, lbm	898,000							

DISPOSITION OF NORMALLY [illegible]

FOR THE PART-LENGTH CEA-~~GROUP~~ subgroup DROP

SYSTEM	NORMAL AUTOMATIC MODE THROUGH-OUT TRANSIENT	MANUAL MODE THROUGH-OUT TRANSIENT	NORMAL AUTOMATIC MODE INOPERATIVE ON LOSS OF A.C.	MANUAL MODE INOPERATIVE ON LOSS OF A.C.	FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater System	X					
2. Turbine-Generator Control System	X					
3. Steam Bypass Control System		X				
4. Pressurizer Pressure Control System		X				
5. Pressurizer Level Control System		X				
6. Control Element Drive Mechanism Control System	X					
7. Reactor Regulating System		X				
8. Reactor Coolant Pumps		X				1
9. Chemical and Volume Control System		X				
10. Condenser Evacuation System		X				
11. Turbine Gland Sealing System		X				
12. Component Cooling Water System	X					
13. Turbine Cooling Water System		X				
14. Intake Cooling Water System	X					
15. Condensate Transfer System	X					
16. Circulating Water System		X				
17. Spent Fuel Pool Cooling System		X				
18. A.C. Power (Non-Safety)	X					
19. A.C. Power (Safety)	X					
20. D. C. Power		X				1
21. Power Operated Relief Valves		X				
22. Instrument Air System	X					
23. Waste Management-Liquid		X				

NOTES: 1. System has no automatic mode.

TABLE 15.4.2.3-3

UTILIZATION OF SAFETY SYSTEMS
FOR THE PART-LENGTH CEA ~~GROUP~~ SUBGROUP DROP

	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACKUP TO NONSAFETY GRADE SYSTEM	FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	X				
2. Engineered Safety Features Actuation Systems			X		1
3. Diesel Generators and Support Systems			X		
4. Reactor Trip Switch Gear	X				
5. Main Steam Safety Valves	X				
6. Pressurizer Safety Valves					
7. Main Steam Isolation Valves	*		X		
8. Main Feedwater Isolation Valves	*				
9. Auxiliary Feedwater System	*		X		
10. Safety Injection System					
11. Shutdown Cooling System (CCW & ICW)	*				
12. Atmospheric Dump Valve System	*		X		
13. Containment Isolation System					
14. Containment Spray System					
15. Iodine Removal System					
16. Containment Combustible Gas Control System					
17. Containment Cooling System					2

NOTES:

* Manually actuated during normal cool down

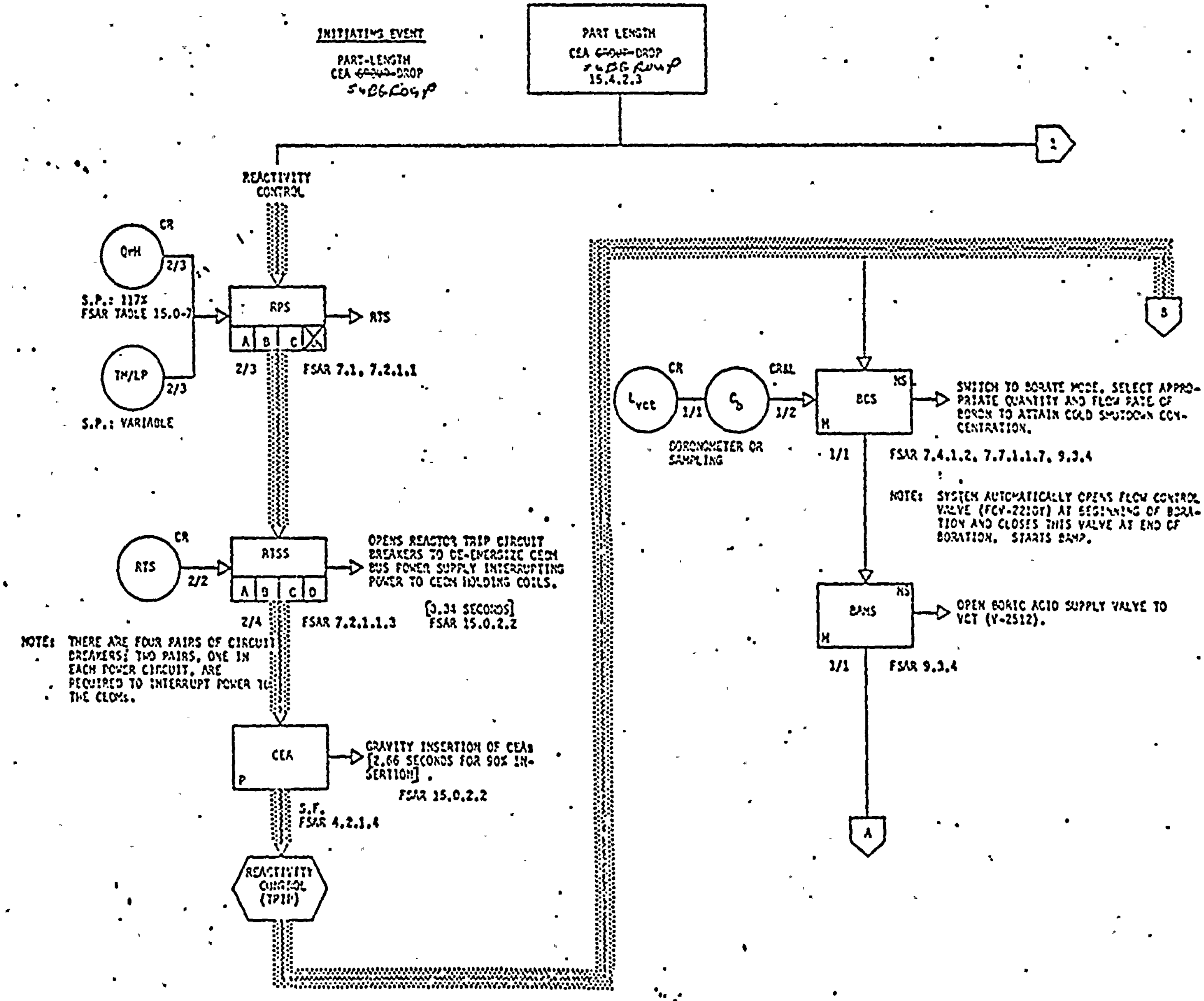
1. Permissive block of SIAS and MSIS are manually actuated to permit shutdown depressurization.
2. Normally operating system (in nonsafety mode)

Systems not checked are not utilized during this event.

TABLE 15.4.2.3-4

INPUT PARAMETERS AND INITIAL CONDITIONS
ASSUMED FOR PART LENGTH CEA ~~[illegible]~~ DROP ANALYSIS
SUBGROUP

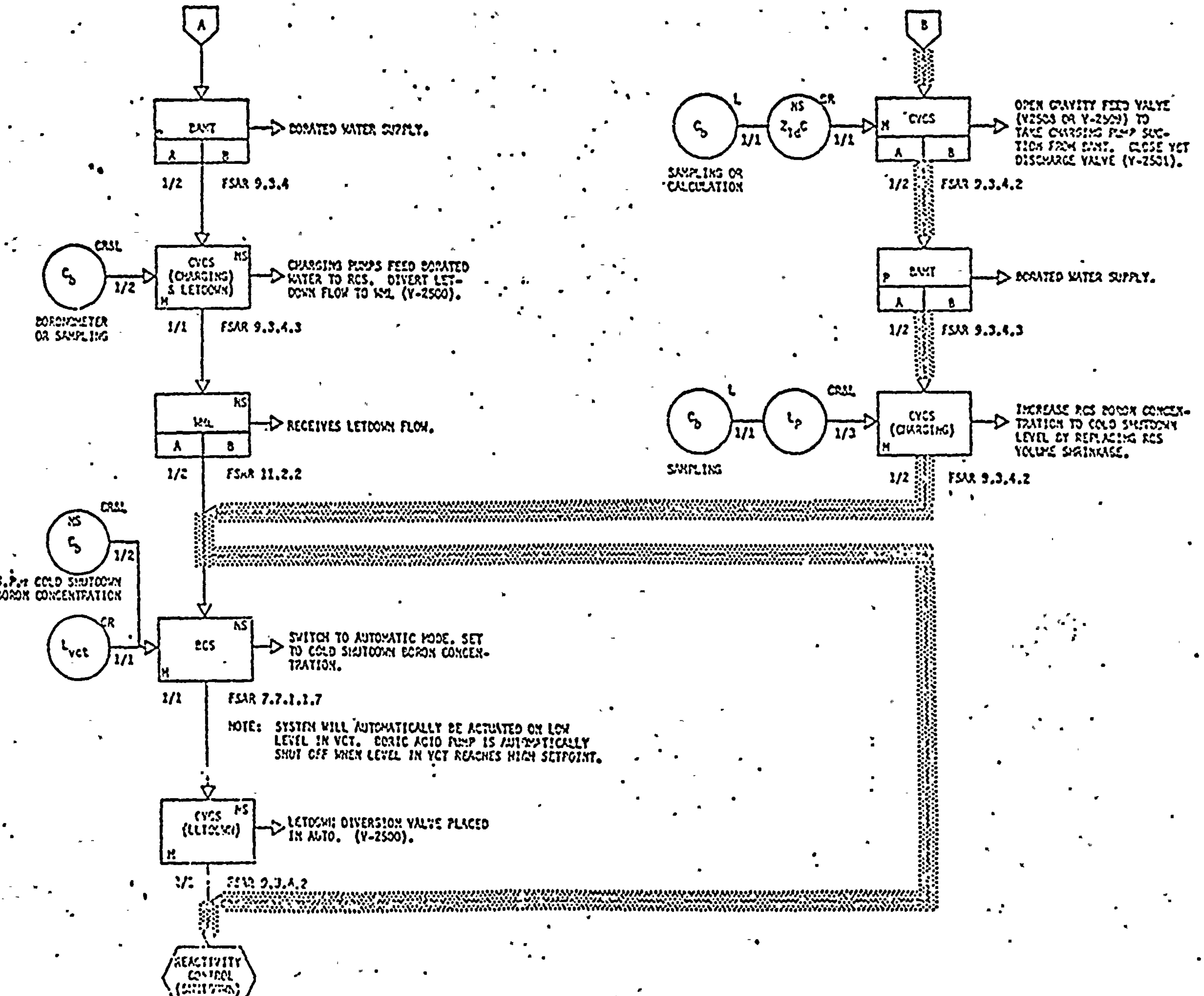
Parameter	Assumed Value	
Power Level, MWt	2630	
Core Inlet Coolant Temperature, F	551	
Core Flowrate, gpm	370,000	
RCS Pressure, psia	2150	2
Pressurizer Water Volume, % level	52.7	
Axial Shape Index	-.30	
Steam Generator Water Level, % of narrow range tap span	70	
Doppler Coefficient Multiplier	0.85	
Moderator Temperature Coefficient, 10^{-4} $\Delta\rho$/F	-0.5	
CEA Worth for Trip, 10^{-2} $\Delta\rho$	-5.5	



AMENDMENT NO. 2 (5/81)

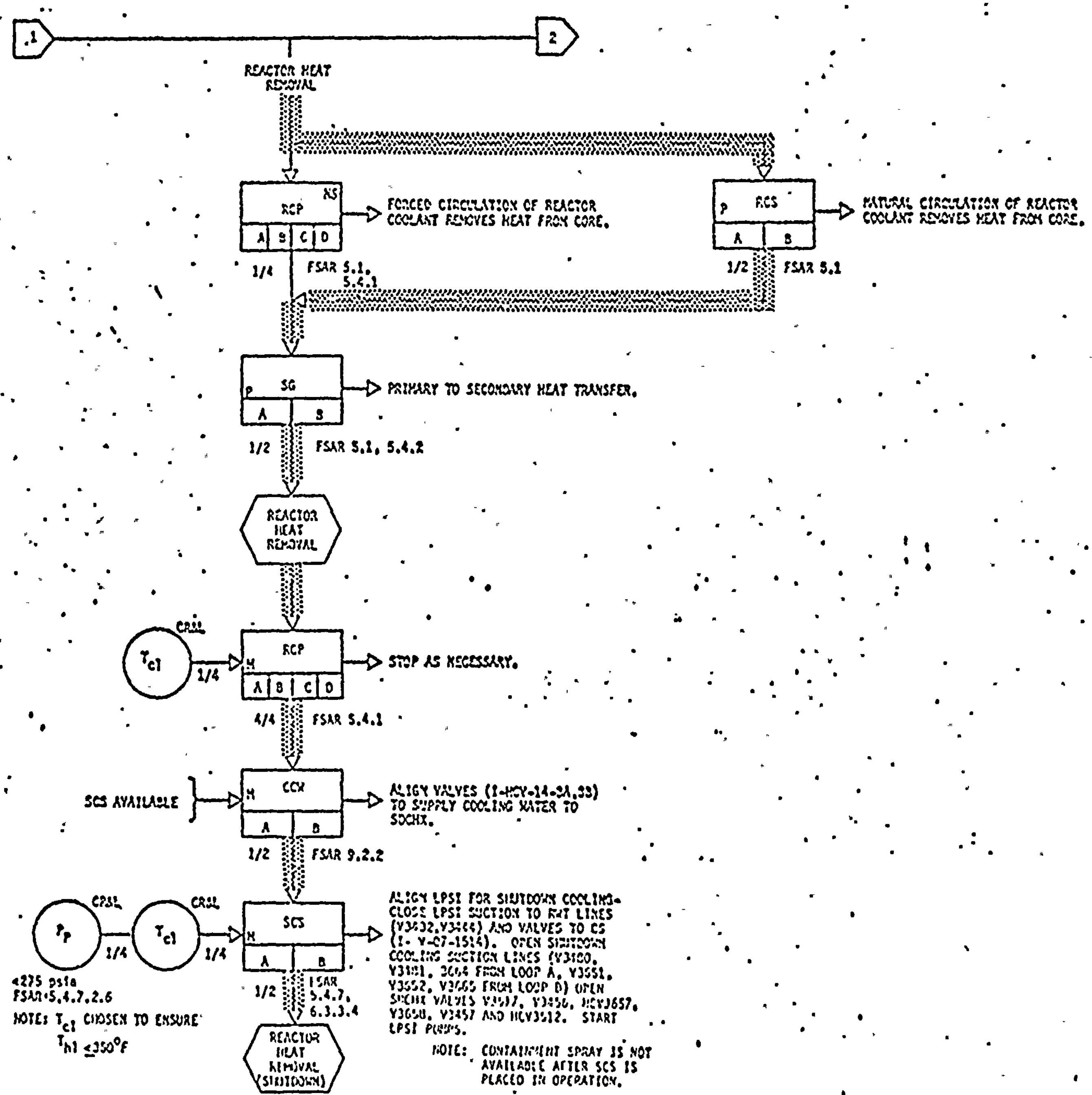
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PART LENGTH CEA ~~GROUP~~ SUBGROUP DROP
FIGURE 15.4.2.3-1c



AMENDMENT NO. 2 (5/81)

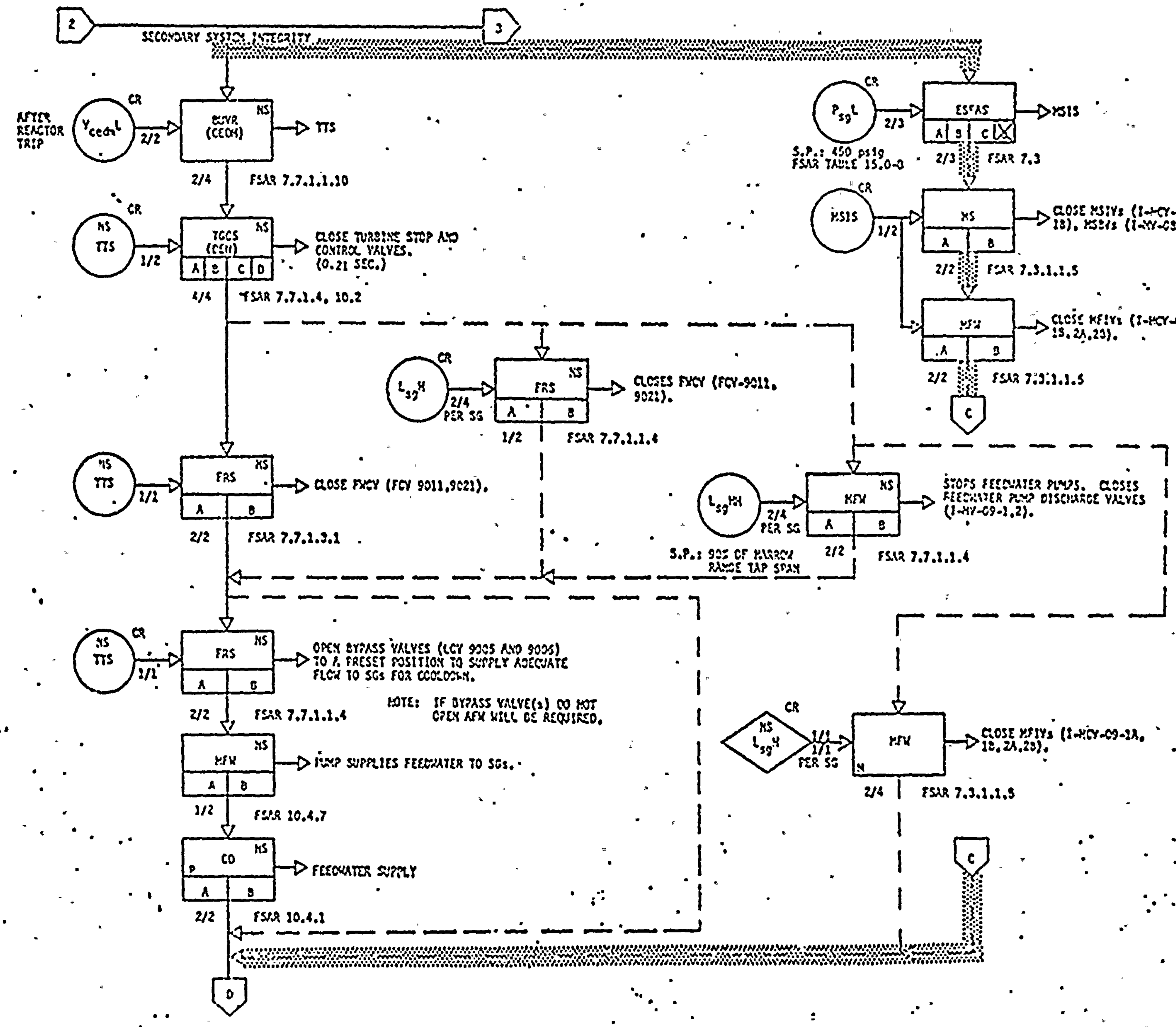
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2
PART LENGTH CEA SUBGROUP
FIGURE 15.4-11



AMENDMENT NO. 2 (5/81)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

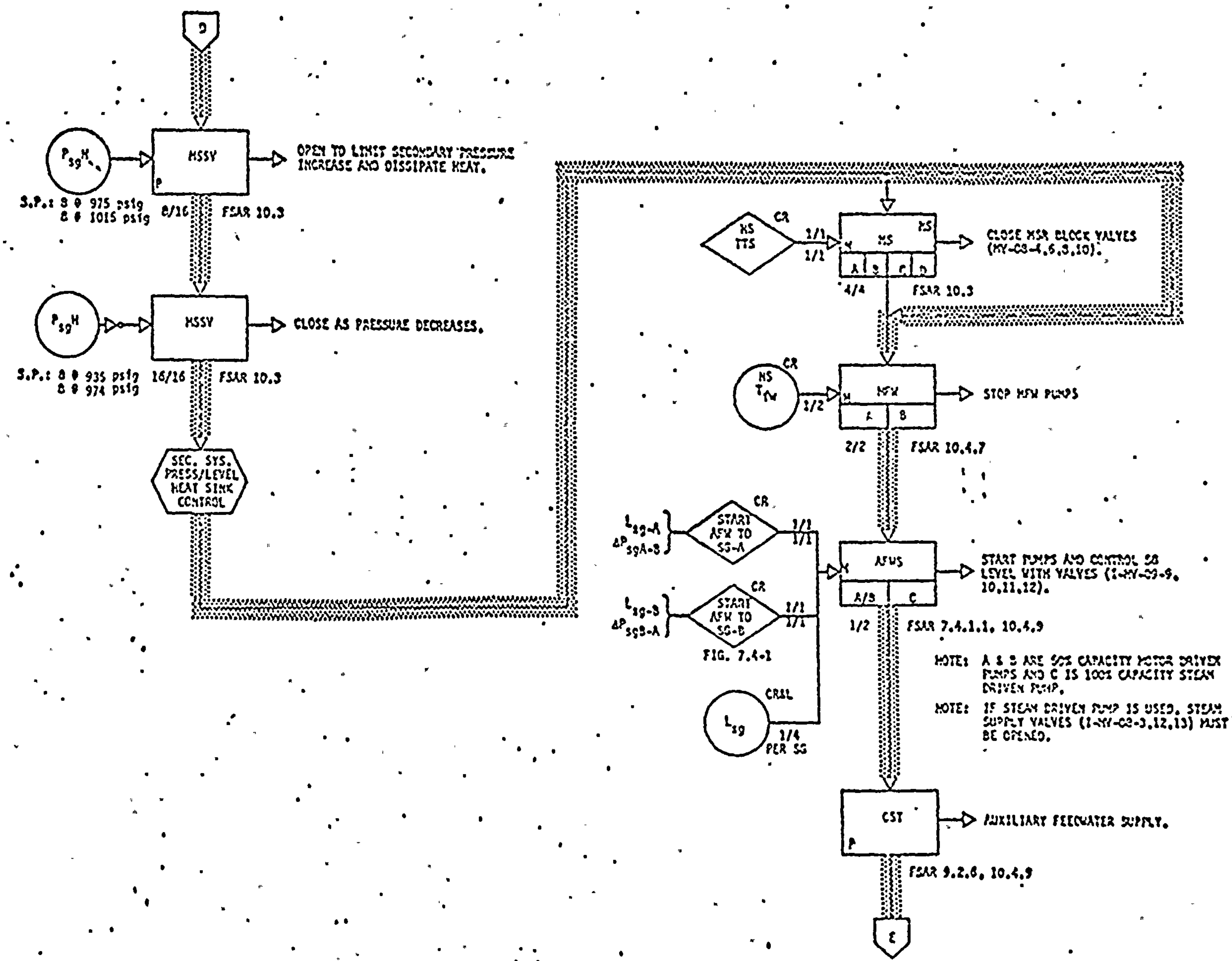
PART LENGTH CEA ~~GROUP~~ SUBGROUP DROP
FIGURE 15.4.2.3-1c



AMENDMENT NO. 2 (5/81)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

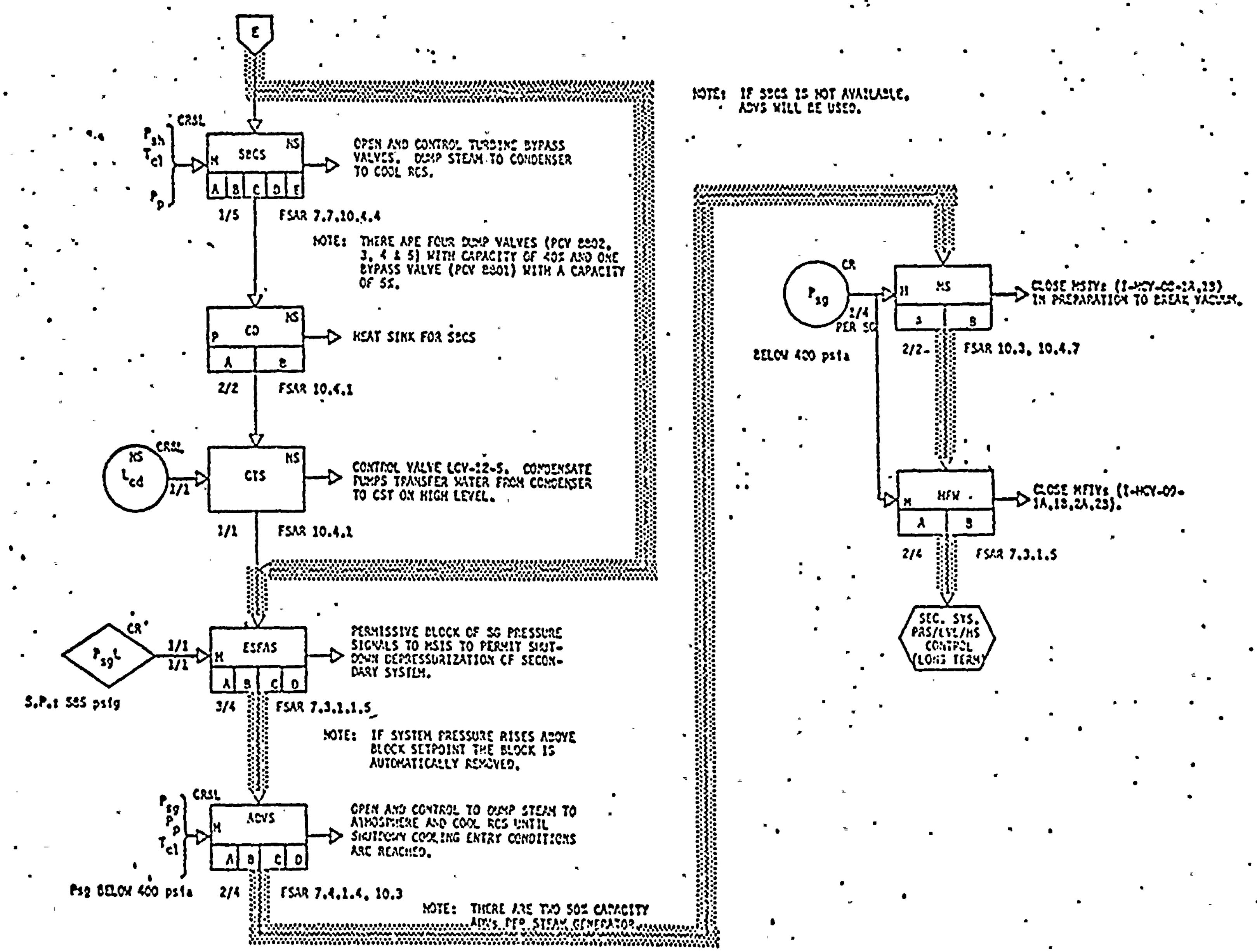
PART LENGTH CEA ~~DROP~~ SUBGROUP DROP
FIGURE 15.4.2.3-1d



AMENDMENT NO. 2 (5/81)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

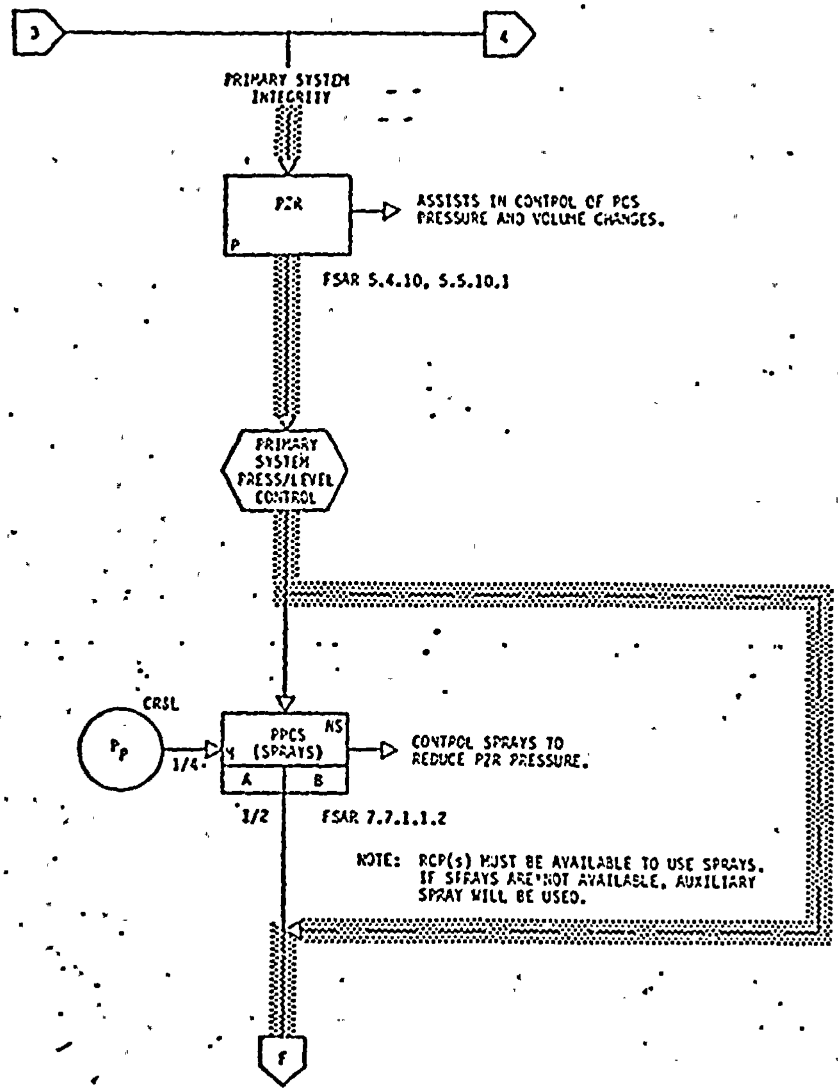
PART LENGTH CEA ~~GROUP~~ SUBGROUP DROP
FIGURE 15.4.2.3-1e



AMENDMENT NO. 2 (5/81)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

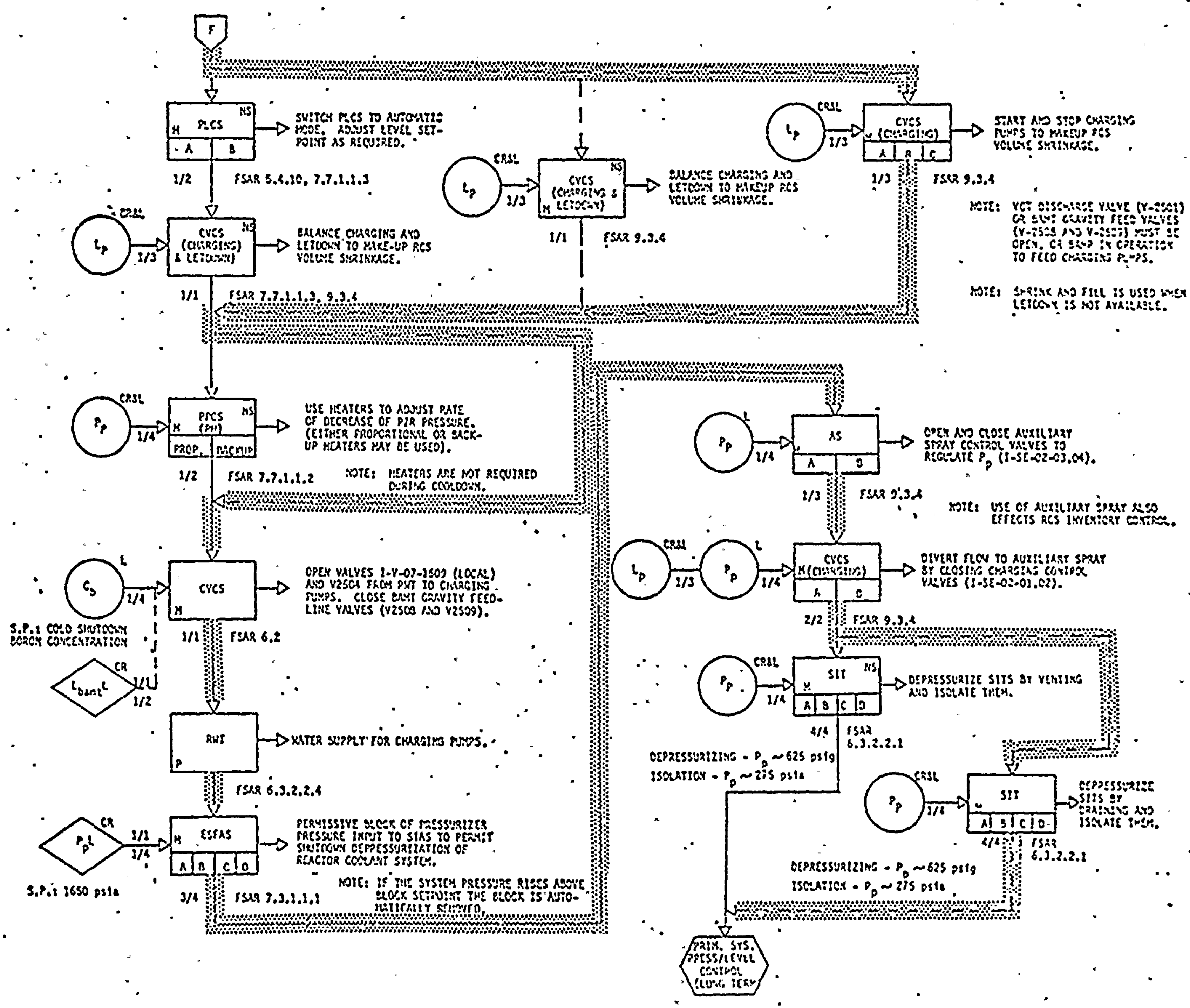
PART LENGTH CEA ~~GROUP~~ SUBGROUP DROP
FIGURE 15.4.2.3-1f



AMENDMENT NO. 2 (5/81)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

PART LENGTH CEA ~~GROUP~~ SUBGROUP DROP
FIGURE 15.4.2.3-1g



AMENDMENT NO. 2 (5/81)

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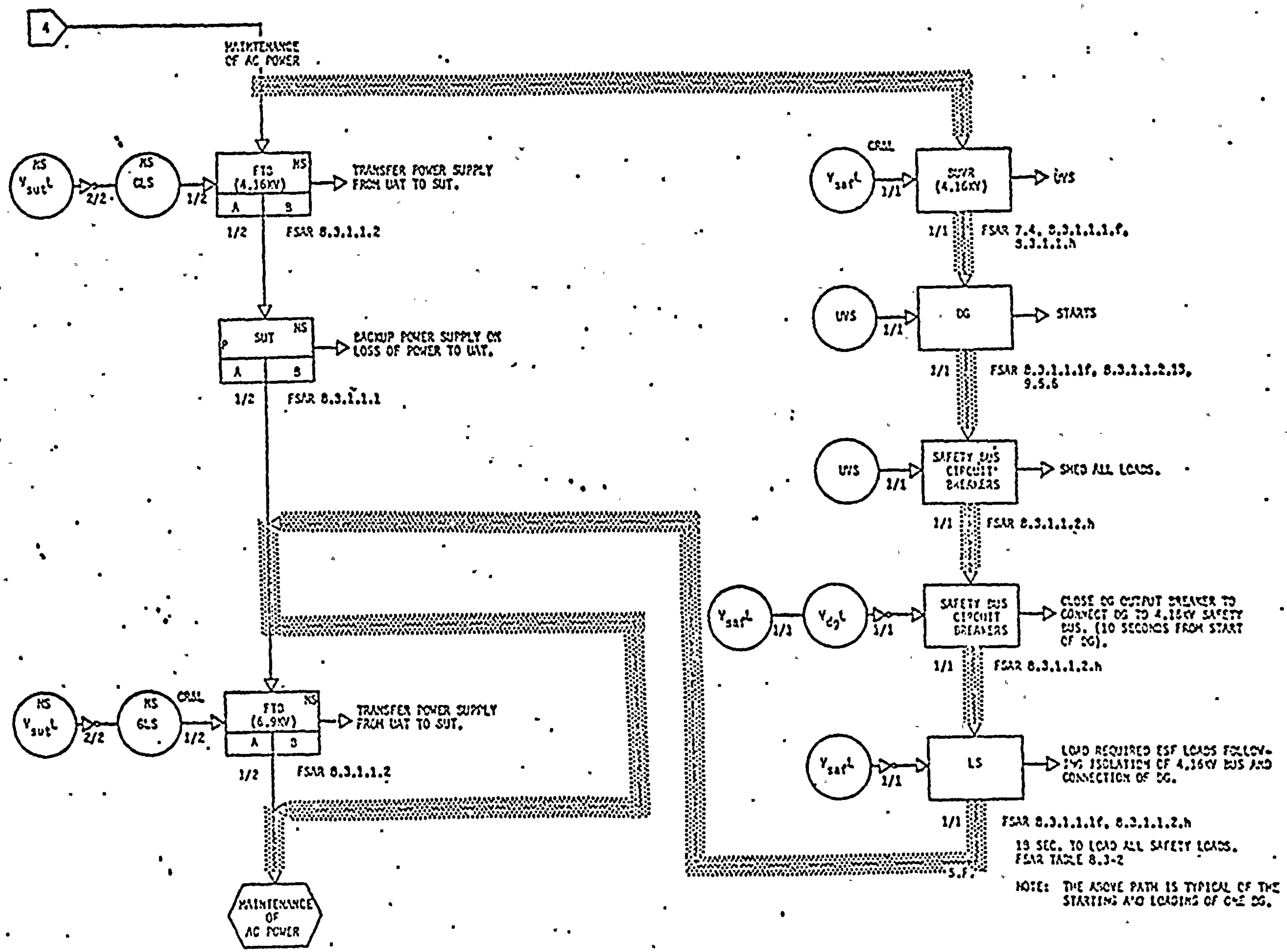
PART LENGTH CEA-~~GROUP~~ SUBGROUP DROP
FIGURE 15.4.2.3-1h



AMENDMENT NO. 2 (5/81)

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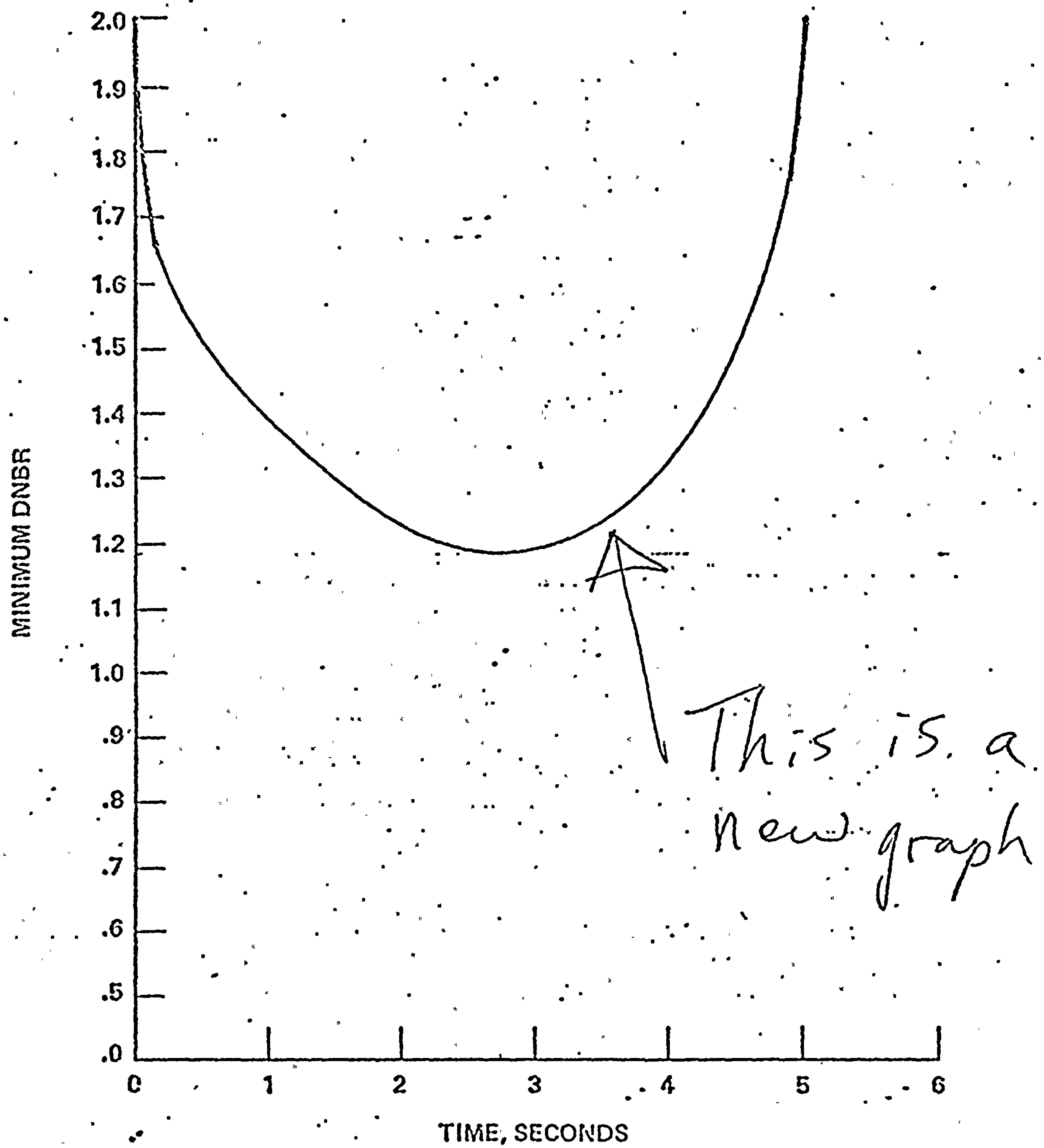
PART LENGTH CEA SUBGROUP DROP
FIGURE 15.4.2.3-1i

with



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ST. LUCIE PLANT UNIT 2

MINIMUM DNBR VS. TIME
FIGURE 15.4.2.3-7

An uncontrolled positive reactivity insertion can be caused by a sequential CEA withdrawal, the withdrawal of a single CEA, CEA subgroup, or CEA group or the drop of a single part length CEA or part length CEA subgroup ~~or part length CEA group~~. The part length CEA (PLCEA) sub group drop is the most limiting initiating event in the uncontrolled positive reactivity insertion event group because the PLCEA sub group drop results in the largest power distortions, most rapid power increase, and largest decrease in DNBR of all events in this group (see Appendix 15C for further information). |4 |2 New Revision

15.4.2.3.2 Sequence of Events and Systems Operation

Table 15.4.2.3-1 presents a chronological list and timing of system actions which occur following a part length CEA sub group drop. Refer to Table 15.4.2.3-1 while reading this and the following section. The success paths referenced are those given on the sequence of event diagram (SED), Figure 15.4.2.3-1. This figure, together with Table 15.0-6, which contains a glossary of SED symbols and acronyms, may be used to trace the actuation and interaction of the systems used to mitigate the consequences of this event. The timings in Table 15.4.2.3-1 may be used to determine when, after the initiating event, each action occurs. |4 |2

The sequence presented demonstrates that the operator can cool the plant down to cold shutdown during the event. If the malfunction which causes the event initiator can be repaired without violating the Technical Specifications, then the operator may elect instead to stabilize the plant in a mode other than cold shutdown. All actions required to stabilize the plant and perform the required repairs are not described here.

The sequence of events and systems operations described below represents the way in which the plant was assumed to respond to the event initiator. Many plant responses are possible, however, certain responses are limiting with respect to the acceptance guidelines for this section. Of the limiting responses, the most likely one to be followed was selected.

Table 15.4.2.3-2 contains a matrix which describes the extent to which normally operating plant systems are assumed to function during the transient. The operation of these systems is consistent with the guidelines of Subsection 15.0.2.3.

Table 15.4.2.3-3 contains a matrix which describes the extent to which safety are assumed to function during the transient.

The success paths in the sequence of events diagram, Figure 15.4.2.3-1, are as follows:

Reactivity Control:

A reactor trip signal (RTS) is automatically generated by the Reactor Protective System on a high power level. The RTS opens the reactor trip circuit breakers to de-energizing the control element drive mechanism (CEDM) power supply bus which interrupts power to the CEDM holding coils allowing the control element assemblies to fall into the core. If cooldown is necessary, the operator adjusts the Reactor Coolant System (RCS) boron concentration to the cold shutdown concentration prior to plant cooldown by

APPENDIX 15C

ANALYSIS OF FUEL ASSEMBLY MISLOADING 3

SUPPLEMENTARY INFORMATION

This appendix contains supplementary information in support of the limiting analyses presented in Chapter 15.

CHAPTER 15

TABLE OF CONTENTS (Cont'd)

APPENDIX 15C

15C ANALYSIS OF FUEL ASSEMBLY MISLOADING

15C.1 INADVERTENT LOADING ~~AT~~ OF A FUEL ASSEMBLY

The fuel enrichment within a fuel assembly is identified by a coded serial
number marked on the exposed surface of the top end plate of the fuel as- 3
sembly. This serial number is used as a means of positive identification for 491.4
each assembly in the plant. A tag board is provided in the main control room showing a schematic representation of the reactor core, spent fuel pool and new fuel storage area. During the period of core loading, the location of each CEA, fuel assembly, and source will be shown on this tag board by a tag carrying its identification number.

The tag board in the main control room will be constantly updated by a designated member of the reactor operations staff whenever a fuel assembly is being moved. He will be in constant communication with each area where this is occurring. Also, a licensed operator will be present in the area where fuel assemblies are being handled to ensure that the assemblies are moved to the correct locations. Fuel assemblies will not be moved unless these lines of communication are available. In addition to these precautions, periodic independent inventories of components in the reactor core, spent fuel, and new fuel storage areas will be made to ensure that the tag board is correct. Also, at the completion of core loading, the exposed surfaces of the top end plates are inspected to verify that all assemblies are correctly located. These precautions are included in the core loading procedures which are to be reviewed by appropriate plant personnel.

If, however, in spite of these precautions it is assumed that an assembly is placed in the wrong core position, then many possibilities exist. The worst situation would be the interchange of two assemblies of equal BOC K_∞, but different poison rod loading, as will be shown below.

If, in spite of the extreme precautions described above, it is postulated that a fuel assembly is misloaded, several situations may be postulated. The misloading of a fuel assembly may effect the core power distribution only slightly, for example, if assemblies of similar enrichments and reactivities are misloaded. Alternatively, the core power distribution may be affected enough so that core performance would be affected if assemblies having different enrichments or reactivities are misloaded.

In the unlikely event that two assemblies of different enrichments would be interchanged, some misloadings would be detected using ex-core startup detectors and the reactivity computer during the low power physics testing. In this testing a symmetry check is performed in which the reactivity worths of symmetrically located CEAs are compared against one another with the aid of the ex-core startup detectors and the reactivity computer. In these events of assembly misloading, this check would indicate significantly different CEA worths between symmetrically located CEAs. This asymmetry would be corroborated by symmetry checks performed for other symmetric rod groups thereby indicating a fuel misloading. Table 15C-1 shows the worths of two symmetrically located CEAs insert into the core misloaded by:

a) Interchanging a type A and Type B assembly near the core center.

b) Interchanging a Type B and Type C assembly near the core periphery.

Figures 15C-1 and 15C-2 show the loading patterns for these misloadings and the locations of the two symmetrically located CEAs.

Table 15C-1 clearly shows that detectable differences exist in the worths of two symmetrically located CEAs for each of these misloadings and therefore demonstrates the detectability of the misloading. 3 491.4

In addition, the misloading could be detected by either the ex-core detectors directly or the in-core detector channels which become operable during the power generating mode of operation. Figures 15C-3 and 15C-4 show the core power distributions for the above misloadings for an unrodded core.

As shown above, many of the fuel assembly misloadings that can be postulated are easily detectable both during the rod symmetry checks and during power range operation. However, one can postulate a small number of misloadings which are undetectable during the rod symmetry testing or even early in the cycle with in-core instrumentation during power range operation. Of this small class certainly the worst case that can be envisioned is the interchange of a shimmed assembly with an unshimmed one at the center of the core. This case may not be detectable at BOL, but may still cause local power peaking as the shims burn out. Two cases of this type of misloading accident are shown in Figures 15C-5 and 15C-6. The maximum pin power peaks occurring with these misloads are presented in Table 15C-2. The minimum DNBR associated with this power distribution is 1.61 for the worst case (Figure 15C-6). Since this is greater than the 1.19 DNBR limit, no clad damage is predicted. Furthermore, it is very probable that these misloadings will be detected early in the cycle before these maximum pin peaks are attained. Certainly the reactor operator would be alerted to the possibility of a fuel assembly misloading by the rather large power perturbations (eg, tilts on the order of eight-nine percent) which would begin to appear early in the cycle, which should be detectable by the in-core instrumentation. Tilt amplitudes are normally expected to be two percent.

In view of the foregoing, it is not expected that these misloads would significantly affect reactor safety or result in offsite consequences which are a measurable fraction of 10CFR100 guidelines.

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15C.2 ADDITIONAL INFORMATION FOR CEA MISOPERATION ANALYSES IN SECTION 15.4.2.3

Analysis of the following three uncontrolled positive reactivity insertion events was performed:

1. Single part length CEA drop (SPLD)
2. Sequential rod withdrawal (high and low power)
3. Part length subgroup drop (PLSD)

The limiting fuel performance event was found to be the PLSD. The PLSD is presented in FSAR section 15.4.2.3. The reasons that the other two events are less limiting are discussed below.

15C.2.1 <u>Single Part Length CEA Drop</u>:

Significant differences exist in the method of thermal margin protection for the SPLD as opposed to the PLSD. The PLSD will cause a reactor trip, whereas the SPLD will not. Sufficient margin exists during steady state operation such that the SPLD will not significantly approach thermal margin limits. The Technical Specifications will stipulate the appropriate time period for operator response to retrieve the rod or reduce core power to prevent a violation of the specified acceptable fuel design limit (i.e., DNBR $\geq$ 1.19).

The PLSD produces more limiting fuel performance results for the following reasons:

1. Relative to the SPLD, the PLSD results in a greater hot channel 3D power distribution increase in the region where the minimum DNBR occurs.

2. The PLSD causes a greater increase in total core power due to a greater reactivity increase than the SPLD.

The two above effects result in the part length CEA subgroup drop experiencing a larger decrease in DNBR than the single part length CEA drop. Thus, the part length CEA drop has less adverse fuel performance than the part length CEA subgroup drop which is presented in Section 15.4.2.3.

Sequential Rod Withdrawal (high and low power):

Similarly, analysis of the sequential rod withdrawal (high power and low power) shows that it is also not as limiting as the part length CEA subgroup drop. The sequential rod withdrawal has much less of a radial and axial power distribution distortion than a part length CEA subgroup drop. The sequential rod withdrawal actually flattens the planar radial power distribution at the core heights in the areas where rods are being withdrawn. At other core heights, the radial power distribution will remain the same. At no position axially will the planar radial power distribution become more peaked. The change in the axial power distribution to a more top peaked shape occurs very slowly due to the slow withdrawal rate, as compared to the part length CEA subgroup drop. The concurrent increase in core power also occurs very slowly. Thus, the degradation in DNBR margin occurs slowly.

no #

Less thermal margin degradation occurs for a slower transient since the DNBR margin degradation between time of trip and time of minimum DNBR is less than that for a faster transient.

Therefore, the part length CEA subgroup drop produces more adverse fuel performance results relative to both the part length CEA drop and the sequential CEA withdrawal (high power and low power). Thus, the part length CEA subgroup drop was presented as the infrequent category limiting fuel performance event in FSAR Section 15.4.2.3.

We urge you to provide the information that would be needed to demonstrate compliance with the SRP at your earliest convenience. To help you anticipate an imminent revision to SRP-4.2, the following comments are provided.

Revision 1 - This revision was issued in October 1978 and contains all of the basic requirements that you need to address. It will not be changed significantly by the planned revision.

Revision 2 - This revision is planned for April 1981 and is the revision alluded to in the notice of proposed rule making on SRP compliance. In SRP-4.2 this revision will (a) add acceptance criteria for mechanical response to seismic and LOCA loads, and (b) make editorial changes largely confined to adding and correcting citations to regulations and regulatory guides that are already addressed in Rev 1. The acceptance criteria for mechanical response were recently implemented as part of the resolution of Unresolved Safety Issue, Task A-2 and are given in Appendix E of NUREG-0609. Therefore, you can base your FSAR revisions on SRP-4.4 Rev 1 (current version) plus Appendix E of NUREG-0609, and last-minute changes in referencing can be made in April prior to your submittal of the additional fuel-related information.

Recent Technical Issues

The following is a list of current technical issues that have frequently been noted as outstanding issues in recent SERs and that should be given special attention in your FSAR.

1. Supplemental ECCS analysis with NUREG-0630.
2. Combined seismic and LOCA loads analysis.
3. Enhanced fission gas release analysis at high burnups.
4. Fuel rod bowing analysis.
5. Fuel assembly control rod guide tube wear analysis.
6. Fuel assembly design shoulder gap analysis.
7. End-of-life fuel rod internals pressure analysis.

Response

The response to this question is revised and is provided in Appendix 490.1A.

~~The requested cross reference identified in Option 2 is provided below.~~

~~SRP-4.2 Rev 1 Acceptance Criteria~~	~~SL2 Applicable FSAR Subsection~~
~~A. Design Bases~~	
~~1. Fuel System Damage~~	
~~(a) Stress/strain limits~~	~~4.2.1.1.1/4.2.1.2.1/4.2.1.4~~
~~(b) Fatigue~~	~~4.2.1.1.1/4.2.1.2.1~~
~~(c) Fretting~~	~~4.2.1.2.1(g)/4.2.1.4~~

SRP-4.2 Rev 1 Acceptance Criteria	SL2 Applicable FSAR Subsection
A. Design Bases (Cont'd)	
(d) Oxidation, hydriding, crud	4.2.3.2.3
(e) Bowing/irradiation growth	4.2.3.1.4/4.2.3.2.5/4.2.1.4
(f) Internal gas pressure	4.2.1.2.1/4.2.1.3.1
(g) Holddown Capability	4.2.2.1
(h) Control rod reactivity	4.2.1.4.2
2. Fuel Rod Failure	
(a) Overheating	
(1) Clad temperature	4.2.1.2.1
(2) Fuel melting	(refers to 4.4.1)
(b) PCI	
(1) Clad strain	4.2.1.2.1 (b)
(2) Fuel melting	4.2.1.2.1 (refers to 4.4.1)
(c) Hydriding	4.2.1.2.4.1
(d) Cladding collapse	4.2.1.2.5.3 (a) (2)
(e) Bursting	4.2.1.2.6
(f) Mechanical fracturing	4.2.1.2.1 (a)
(g) Fretting	4.2.1.2.1 (g)
3. Fuel Coolability	
(a) Cladding embrittlement	6.3.3.1
(b) Violent expulsion of fuel	15.4.5.1.3
(c) Generalized cladding melting	See (a)
(d) Structural deformation	4.2.3.1.2/4.2.3.1.3
(e) Fuel rod ballooning	6.3.3.1
B. Description and Design Drawings	4.2.2
C. Design Evaluation	
1. Operating experience	4.2.3.2.10
2. Prototype testing	N/A
3. Analytical Predictions	
(a) Fuel Temperatures	4.2.3.1.15
(b) Densification effects	4.2.1.2.6
(c) Fuel rod bowing	4.2.3.2.5
(d) Structural deformation	4.2.3.1.3
(e) Rupture and flow blockage	4.2.3.2.12/4.2.3.2.14
(f) Fuel rod pressure	4.2.3.2.2
(g) Metal/water reaction rate	6.2.1.3.8
(h) Fission product inventory	6.2.1.3.9

SRP-4.2 Rev 1 Acceptance Criteria	SL2 Applicable FSAR Subsection
D. Testing, Inspection and Surveillance Plans	
1. Testing and inspection of new fuel	4.2.4
2. On line fuel system monitoring	9.3.2.2/4.2.4.4
3. Post irradiation surveillance	4.2.1.5

Relative to the list of recent technical issues, the following information is offered:

Issue	Remarks
1. Supplemental ECCS analysis with NUREG-0630	This analysis will be provided in an amendent.
2. Combined seismic and LOCA analysis	See revised FSAR Subsection 4.2.3.1.2.4
3. Enhanced fission gas release analysis at high burnups	See FSAR Subsection 4.2.1.2.1 (f)
4. Fuel rod bowing analysis	See FSAR Subsection 4.2.3.2.5. CE is awaiting NRC review of Reference 53 (CENPD-225-P) and its supplements which is expected by the Fall 1981.
5. Fuel assembly control rod guide tube wear analysis	See revised FSAR Subsection 4.2.3.1.1.
6. Fuel assembly design shoulder gap analysis	See FSAR Subsection 4.2.3.1.4
7. End-of-life fuel rod internal pressure analysis	See FSAR Subsection 4.2.1.2.1 (f)

1a

Appendix 490.1A - Reformatted Section 4.2

Ib

The original response to Question 490.1 was submitted informally to the NRC on April 23, 1981. Formal submittal was included as part of Amendment 3 (June 1, 1981).

At a meeting with the NRC on May 5, 1981, the NRC asked that Section 4.2 of the FSAR be rewritten, following the format presented in the WCAP-9500 Safety Evaluation Report (SER). The reformatted version of 4.2 in this appendix closely follows the format of the WCAP-9500 SER. However, two sections were added: Material Properties (4.2.2.5) and Fuel Burnup Experience (4.2.2.6). All information in Section 4.2 of the FSAR is included in the reformatted version. In addition, both Section 4.2 and the reformatted version have been revised to include relevant information from responses to NRC questions on the SONGS (dockets 50-361 and 50-362) and WSES-3 (docket 50-382) FSARs.

The reformatted version of 4.2 has been reviewed for consistency with Section 4.2 of the FSAR and is provided here for informative purposes. Section 4.2 of the FSAR remains the quality assured control document and will be updated accordingly, as necessary in the future.

2

4.2 FUEL SYSTEM DESIGN

4.2.1 Design Bases

The fuel assemblies are required to meet design criteria for each design condition listed below to assure that the functional requirements are met. Except where specifically noted, the design bases presented in this section are consistent with those used for previous designs.

a) Condition I – Non Operation and Normal Operation

Condition I situations are those which are planned or expected to occur in the course of handling, initial shipping, storage, reactor servicing and power operation (including maneuvering of the plant). Condition I situations must be accommodated without fuel assembly failure and without any effect which would lead to a restriction on subsequent operation of the fuel assembly. The guidelines stated below are used to determine loads during Condition I situations:

1) Handling and Fresh Fuel Shipping

Loads correspond to the maximum possible axial and lateral loads and accelerations imposed on the fuel assembly by shipping and handling equipment during these periods, assuming that there is no abnormal contact between the fuel assembly and any surface, nor any equipment malfunction. Irradiation effects on material properties are considered when analyzing the effects of handling loads which occur during refueling. Additional information regarding shipping and handling loads is contained in Subsection 4.2.3.1(a).

2) Storage

Loads on both new and irradiated fuel assemblies reflect storage conditions of temperature, chemistry, means of support and duration of storage.

3) Reactor Servicing

Loads on the fuel assembly reflect those encountered during refueling and reconstitution.

4) Power Operation

Loads are derived from conditions encountered during transient and steady-state operation in the design power range. (Hot operational testing, system startup, hot standby, operator controlled transients within specified rate limits and system shutdown are included in this category.)

3

5) Reactor Trip

Loads correspond to those produced in the fuel assembly by control element assembly (CEA) motion and deceleration.

b) Condition II: Upset Condition

Condition II situations are unplanned events which may occur with moderate frequency during the life of the plant. The fuel assembly design should have the capability to withstand any upset condition with margin to mechanical failure and with no permanent effects which would prevent continued normal operation. Incidents classified as upset conditions are listed below:

1) Operating basis earthquake (OBE)

2) Selected moderate frequency events (See Table 15.0-2) 0

c) Condition III: Emergency Conditions

Condition III events are unplanned incidents which might occur very infrequently during plant life. Rod mechanical failure must be prevented for any Condition III event in any area not subject to extreme local conditions (e.g., in any rod not immediately adjacent to the impact surface during fuel handling accident).

The Condition III incidents listed below are included as a category to provide assurance that under the occurrence of a Condition III event, rod damage is minimal.

1) Selected infrequent events (See Table 15.0-2) 0

2) Minor fuel handling accident (fuel assembly and grapple remain connected).

d) Condition IV: Faulted Conditions

Condition IV incidents are postulated events which are not expected to occur, but are analyzed anyway because of their potential for release of significant amounts of radioactive material. Mechanical fuel failures and reactor coolant system damage are permitted, but the operation of the engineered safety features (ESF) and reactor protection systems to mitigate the consequences of the postulated event must not be impaired. Condition IV incidents are listed below: 0

1) Safe shutdown earthquake (SSE)

2) Selected limiting faults (Table 15.0-2)

3) Major fuel handling accident (fuel assembly and grapple are disengaged) 0

The fuel cladding is designed to sustain the effects of steady state and expected transient operating conditions without exceeding acceptable levels of stress and strain. Except where specifically noted, the design bases presented in this section are consistent with those used for previous core designs. The fuel rod design accounts for cladding irradiation growth, external pressure, differential expansion of fuel and clad, fuel swelling, fuel densification, clad creep, fission and other gas releases, initial internal helium pressure, thermal stress, pressure and temperature cycling, and flow induced vibrations.

The burnable poison rod design accounts for external pressure, differential expansion of pellets and clad, pellet swelling, clad creep, helium gas release, initial internal helium pressure, thermal stress, and flow induced vibrations. Except where specifically noted, the design bases presented in this section are consistent with those used for previous designs.

Except where specifically noted, the design bases for control element assemblies ~~presented in this section~~ are consistent with those used for previous designs.

The mechanical design of the control element assemblies is based on compliance with the following functional requirements:

a) To provide for or initiate short term reactivity control under all normal and adverse conditions experienced during reactor startup, normal operation, shutdown, and accident conditions.

b) Mechanical clearances of the CEA within the fuel and reactor internals are such that the requirements for CEA positioning and reactor trip are attained under the most adverse accumulation of tolerances.

c) Structural material characteristics are such that radiation induced changes to the CEA materials will not impair the functions of the reactivity control system.

(5)

4.2.1.1 Fuel System Damage Criteria

(a) Design Stress

Fuel Assembly

For each of the design conditions, there are criteria which apply to the fuel assembly and components with the exception of fuel rods. These criteria are listed below and give the allowable stresses and functional requirements for each design condition.

o Design Conditions I and II:

$P_m \leq S_m$

$P_m + P_b \leq F_s S_m$

Under cyclic loading conditions, stresses must be such that the cumulative fatigue damage factor does not exceed 0.8. Cumulative damage factor is defined as the sum of the ratios of the number of cycles at a given cyclic stress (or strain) condition to the maximum number permitted for that condition. The selected limit of 0.8 is used in place of 1.0 (which would correspond to the absolute maximum damage factor permitted) to provide additional margin in the design.

Deflections must be such that the allowable insertion time of the control element assemblies is not exceeded.

o Design Condition III:

$P_m \leq 1.5\ S_m$

$P_m + P_b \leq 1.5\ F_s S_m$

Deflections are limited to a value allowing the CEAs to trip, but not necessarily within the prescribed time.

o Design Condition IV:

$P_m \leq S'_m$

$P_m + P_b \leq F_s S'_m$

where S'_m = smaller value of 2.4 S_m or 0.7 S_u.

1) If the equivalent diameter pipe break in the LOCA does not exceed 0.5 square foot, the fuel assembly deformation shall be limited to a value not exceeding the deformation which would preclude satisfactory insertion of the CEAs.

2) For pipe break sizes greater than 0.5 square foot, deformation of structural components is limited to maintain the fuel in a coolable array. CEA insertion is not required for these events as the appropriate safety analyses do not take credit for CEA [illegible]

Nomenclature :

The symbols used in defining the allowable stress levels are as follows:

P_m = Calculated general primary membrane stress[a]

P_b = Calculated primary bending stress

S_m = Design stress intensity value as defined by Section III, ASME

S_u = Minimum unirradiated ultimate tensile strength

F_s = Shape factor corresponding to the particular cross section being analyzed[c]

S'_m = Design stress intensity value for faulted conditions

The definition of S'_m as the lesser value of 2.4 S_m and 0.7 S is contained in the ASME Boiler and Pressure Vessel Code (1974) Section III, Appendix F-1323.1.

Where notes a, b and c are defined as:

(a) P_m and P_b are defined by Section III, ASME Code.

(b) With the exception of zirconium base alloys, the design stress intensity values, S_m, of materials not tabulated by the Code are determined in the same manner as the Code. The design stress intensity of zirconium base alloys shall not exceed two-thirds of the unirradiated minimum yield strength at temperature. Basing the design stress intensity on the unirradiated yield strength is conservative because the yield strength of zircaloy increases with irradiation. The use of the two-thirds factor ensures 50 percent margin to component yielding in response to primary stresses. This 50 percent margin together with its application to the minimum unirradiated properties and the general conservatism applied in the establishment of design conditions is sufficient to ensure an adequate design.

(c) The shape factor, F_s, is defined as the ratio of the "plastic" moment (all fibers just at the yield stress) to the initial yield amount (extreme fiber at the yield stress and all other fibers stressed in proportion to their distance from the neutral axis). The capability of cross section loaded in bending to sustain moments considerably in excess of that required to yield the outermost fibers is discussed in Timoshenko.[1]

Fuel Handling and Shipping Design Loads

Three specific design bases have been established for shipping and handling loads. These are as follows:

a) The fuel assembly, when supported in the new fuel shipping container, shall be capable of sustaining the effect of 5g axial, lateral or vertical acceleration without sustaining stress levels in excess of those allowed for normal operation. The 5g criterion was originally established experimentally, and its adequacy is continually confirmed by the presence of impact recorders.

b) The fuel assembly shall be capable of sustaining a 5000 pound axial load applied at the upper end fitting by the refueling grapple (and resisted by an equal load at the lower end fitting) without sustaining stress levels in excess of those allowed for normal operation. The 5000 pound load was chosen in order to provide adequate lift capability should an assembly become lodged.

c) The fuel assembly shall be capable of withstanding a 0.125 in. deflection in any direction whenever the fuel assembly is raised or lowered from a horizontal position without sustaining a permanent deformation beyond the fuel assembly inspection envelope.

Fuel Rod

During normal operating and upset conditions (Conditions I and II), the maximum primary tensile stress in the Zircaloy clad shall not exceed two-thirds of the minimum unirradiated yield strength of the material at the applicable temperature. The corresponding limit under emergency conditions (Conditions III) is the material yield strength. The use of the unirradiated material yield strength as

the basis for allowable stress is conservative because the yield strength of zircaloy increases with irradiation. The use of two-thirds factor ensures 50 percent margin to component yielding in response to primary stresses. This 50 percent margin, together with its application to the minimum unirradiated properties and the general conservatism applied in the establishment of design conditions, is sufficient to ensure an adequate design.

Yield strength in the non-irradiated condition is shown on Figure 4.2-20 of Reference 13.

The cladding stress limits are ~~ident~~ based on values taken from the minimum yield strength curve at the appropriate temperatures. The limits are applied over the entire fuel lifetime, during conditions of reactor heatup and cooldown, steady state operation, and normal power cycling. Under these conditions, cladding temperatures and fast fluences can range from 70 to 750 F and from 0 to 1×10^{22} nvt, respectively.

Burnable Poison Rod

During normal operating and upset conditions (Conditions I and II), the maximum primary tensile stress in the Zircaloy clad shall not exceed two-thirds of the minimum unirradiated yield strength of the material at the applicable temperature. The corresponding limit under emergency conditions (Condition III) is the material yield strength.

Control Element Assembly

The stress limits for the Inconel Alloy 625 cladding are as follows:

Design Conditions I and II (Non Operation, Normal Operation, and Upset Conditions)

$$P_m \leq S_m$$

$$P_m + P_b \leq F_s S_m$$

Design Conditions III (Emergency Conditions)

$$P_m \leq 1.5\ S_m$$

$$P_m + P_b \leq 1.5\ F_s S_m$$

Design Conditions IV (Faulted Conditions)

$$P_m \leq S'_m$$

$$P_m + P_b \leq F_s S'_m$$

where S_m is the smaller of 2.4 S_m or 0.7S_u

For definition of P_m, P_b, S_m, S'_m, S_u, and F_s, see Subsection 4.2.1.1(a). For the Inconel 625 CEA cladding, the value of S_m is two-thirds of the minimum specified yield strength at temperature.

For Inconel 625, the specified minimum yield strength is 65,000 lb/in.^{2} at 650 F.

F_s = Mp/My where Mp is the bending moment required to produce a fully plastic section and My is the bending moment which first produces yielding at the extreme fibers of the cross section. The capability of cross sections loaded in bending to sustain moments considerably in excess of that required to yield the outermost fiber is discussed in Reference 1. For the CEA cladding dimensions, F_s = 1.33.

The CEAs are designed for a ten year lifetime based on estimates of neutron absorber burnup, allowable plastic strain of the Inconel 625 cladding and the resultant dimensional clearances of the elements within the fuel assembly guide tubes.

(b) Cladding Design Strain

Fuel Rod

Net unrecoverable circumferential strain shall not exceed one percent as predicted by computations considering clad creep and fuel-clad interaction effects.

Data from O'Donnell[4] and Weber[5] were used to determine the present one percent strain limit. O'Donnell developed an analytical failure curve for Zircaloy cladding based upon the maximum strain of the material at its point of plastic instability. O'Donnell compared his analytical curve to circumferential strain data obtained on irradiated coextruded Zr-U metal fuel rods tested by Weber. The correlation was good, thus substantiating O'Donnell's instability theory. Since O'Donnell performed his analysis, additional data have been derived at Bettis[6] [7] [8] and AECL(9)(10)

These new data are shown in Figure 4.2-1, along with O'Donnell's curve and Weber's data. this curve was then adjusted because of differences in anisotropy, stress states and strain rates; and the design limit was set at one percent.

The conservatism of the clad strain calculations is provided by the selection of adverse initial conditions and material behavior assumptions, and by the assumed operating history. The acceptability of the 1.0 percent unrecoverable circumferential strain limit is demonstrated by data from irradiated Zircaloy clad fuel rods which show no cladding failures (due to strain) at or below this level, as illustrated in Figure 4.2-1.

Uniform tensile strain in the non-irradiated condition is shown on Figure 4.2-22 of Reference 13.

Uniform tensile strain in the ~~un~~irradiated condition approaches one percent at 6×10^{20} nvt and remains relatively constant (Subsection 4.2.1.2.1).

INSERT B →

Control Element Assembly

The strain limits for the cladding are limited to values which will permit the CEAs to trip within the allowable time.

The values of uniform and total elongation of Inconel Alloy 625 cladding are estimated to be as follows:

Fluence (E > 1 Mev), nvt	1×10^{22}	3×10^{22}
Uniform elongation, %	3	1
Total elongation, %	6	3

INSERT B

Burnable Poison Rod

Net unrecoverable circumferential strain shall not exceed one percent as predicted by computations considering clad creep and poison pellet swelling effects.

(C) Strain Fatigue

Cumulative strain cycling usage, defined as the sum of the ratios of the number of cycles in a given effective strain range (Δ_ϵ) to the permitted number (N) at that range, as taken from Figure 4.2-2, will not exceed 0.8.

The cyclic strain limit design curve shown on Figure 4.2-2, is based upon the Method of Universal Slopes developed by S. S. Manson[11] and has been adjusted to provide a strain cycle margin for the effects of uncertainty and irradiation. The resulting curve has been compared with known data on the cyclic loading of Zircaloy and has been shown to be conservative. Specifically, it encompasses all the data of O'Donnell and Langer.[12]

(d) Fretting Wear

(See item (a) above).

The design limits of the fuel rod cladding, with respect to vibration considerations, are implemented within the fuel assembly design. It is a requirement that the spacer grid intervals, in conjunction with the fuel rod stiffness, be such that fuel rod vibration, as a result of mechanical or flow induced excitation, does not result in excessive wear of the fuel rod cladding at the spacer grid contact areas.

(e) Oxidation and Crud Buildup

During normal operating and upset conditions (design conditions I and II) oxidation and crud buildup have not been observed as a problem (see the following section 4.2.3). Therefore, no specific criteria have been defined.

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F) Rod Bowing

Experience has proven that any specific criterion on allowable deflections (bowing), with respect to the effects which such deflections might have on thermal hydraulic performance, is not necessary beyond the initial fuel rod positioning requirements required of the grids. This variation in spacing is accounted for in thermal-hydraulic analysis through the introduction of hot channel factors in calculating the maximum enthalpy rise in calculating DNBR. This adjustment is called the pitch, bowing, and clad diameter enthalpy rise factor, which is conservatively applied to simulate a reduced flow area along the entire channel length. The value of this factor is given in Table 4.4-1 and its application is discussed in Section 4.4.

The subject of fuel rod bowing is discussed in Reference 53, which is being reviewed by the NRC.

There is no specific limit on lateral fuel rod deflection for structural integrity considerations except which is brought about through application of cladding stress criteria. The absence of a specific limit on rod deflection is justified because it is the fuel assembly structure, and not the individual fuel rod, that is the limiting factor for fuel assembly lateral deflection.

(g) Axial Growth

Fuel Rods and guide tubes are designed with adequate clearance to the upper fuel assembly end fitting such that the clearance is maintained throughout the expected life (burnup) of the fuel. Also, the spacer grids are designed to allow axial growth without inducing unacceptable rod bowing.

There is no criterion for axial growth per se; however, the fuel rod upper plenum is designed to accomodate axial growth of the fuel without exceeding the pressure criterion in item (h).

(h) Fuel and Poison Rod Pressure

Fuel rod internal pressure increases with increasing burnup and toward end of life the total internal pressure, due to the combined effects of the initial helium fill gas and the released fission gas, can approach values comparable to the external coolant pressure. The maximum predicted fuel rod internal pressure will be consistent with the following criteria.

1. The primary stress in the cladding resulting from differential pressure will not exceed the stress limits specified earlier in this section.

2. The internal pressure will not cause the clad to creep outward from the fuel pellet surface while operating at the design peak linear heat rate for normal operation. In determining compliance with this criterion, internal pressure is calculated for the peak power rod in the reactor, including accounting for the maximum computed fission gas release. In addition, the pellet swelling rate (to which the calculated clad creep rate is compared) is based on the observed swelling rate of "restrained" pellets (i.e., pellets in contact with clad), rather than on the greater observed swelling behavior of pellets which are free to expand.

The criteria discussed above do not limit fuel rod internal pressure to values less than the reactor coolant pressure, and the occurrence of positive differential pressures would not adversely affect normal operation if appropriate criteria for cladding stress, strain, and strain rate were satisfied.

The burnable poison rod pressure criteria are that the stress criteria of item (a) are not exceeded and that the pressure criterion for fuel rods is also met for burnable poison rods.

(i) Assembly Liftoff.

As described in Section 4.2.2; the upper end fitting of a fuel assembly is designed such that a net downward force on the fuel assembly will be maintained for normal and anticipated transient flow and temperature conditions.

(j) Control Material Leaching

A criterion for control material leaching has not been specified since leaching has not been observed as a problem (see Section 4.2.3).

(k) Cladding Overheating

Damage during normal operation and anticipated operational occurrences due to cladding overheating is avoided via specification and implementation of a Specified Acceptable Fuel Design Limit (SAFDL) on DNBR in accordance with General Design Criteria 10, 20, 25, 26, and 29 of 10 CFR 50 Appendix A. However, violation of this SAFDL does not necessarily result in fuel damage.

The SAFDL on DNBR is that the minimum DNBR is such value as to provide at least 95 percent probability with 95 percent confidence that departure from nucleate boiling (DNB) does not occur on a fuel rod having that minimum DNBR during steady-state operation and anticipated operational occurrences. A value of 1.19 using the CE-1 correlation coupled with the TORC code provides at least this probability and confidence. The CE-1 correlation is described further in Section 4.4.2.2 of the FSAR.

(1) Fuel Overheating

Damage during normal operation and anticipated operational occurrences due to fuel overheating is avoided via specification and implementation of a Specified Acceptable Fuel Design Limit (SAFDL) on fuel temperature in accordance with General Design Criteria 10, 20, 25, 26, and 29 of 10 CFR 50 Appendix A. However, violation of this SAFDL does not necessarily result in fuel damage.

The SAFDL on fuel temperature is that the peak temperature of the fuel is less than the melting point (5080 F unirradiated and reduced by 58 F per 10,000 MWD/MTU during steady-state operation and anticipated operational occurrences.

4.2.1.2 Fuel Rod Failure Criteria

(a) Hydriding

Internal

A number of reported fuel rod failures have resulted from excessive moisture available in the fuel. Under operation, this moisture oxidizes the Zircaloy.

The hydrogen, which was not absorbed during normal oxidation, would then be adsorbed into the Zircaloy through a scratch in the oxide film. This localized hydrogen absorption by the cladding would shortly result in a localized fuel rod failure. Work performed at the Institute for Atomenergi, Halden Norway, of which CE is a member, demonstrated that a threshold value of water moisture is required for hydride sunbursts to occur.(64) Through a series of in pile experiments, the level of this threshold value was established. The allowable hydrogen limit in the fuel during manufacture (proprietary) complies with this requirement, ensuring that hydride sunbursts will not occur.

External

During operation of the reactor with exposure to high temperature, high pressure water, Zircaloy-4 cladding will react to form a protective oxide film in accordance with the following equation:

$$Zr + 2H_2O \rightarrow ZrO_2 + 2H_2$$

Approximately 20 percent of the hydrogen is absorbed by the Zircaloy. Based on data described in WAPD-MRP-107, the cladding would be expected to contain up to 250 ppm hydrogen following three years of exposure.

A series of burst tests were performed on Zircaloy-2 tubes containing 340 ppm and 460 ppm of hydrogen precipitated as hydride platelets in a circumferential manner.(67) Burst tests at 660 F showed that the burst test specimens with 340 ppm had normal burst ductility of 12 percent. Therefore, hydrogen normally absorbed in ZF-4 tubing will not prove deleterious to the cladding integrity and a specific design basis for external hydriding is not required.

Early work performed at AECL has shown that hydrides become ductile on heating to 390F, and at that temperature, and in concentrations up to 250 ppm (the expected concentration after three cycles), their presence has little effect on ductility. In addition, burst tests at 600F and 725F for hydrogen concentrations between 200 and 400 ppm did not show a significant dependence between burst ductility and hydrogen concentration or orientation. The potential effects of hydride orientation and concentration above 725F have not been specifically evaluated by C-E; but, provided concentrations do not exceed the range tested so far, would not be expected to be significant.

(b) Cladding Collapse

Cladding collapse by itself is not necessarily a failure mechanism. However, the design bases below are specified to prevent the gross cladding deformation associated with cladding collapse.

Fuel Rod

The clad will be initially pressurized with helium to an amount sufficient to prevent gross clad deformation under the combined effects of external pressure and long term creep. The clad design will not rely on the support of fuel pellets or the holddown spring to prevent gross deformation. 4.2-9

Burnable Poison Rod

The clad will be initially pressurized with helium to an amount sufficient to prevent gross clad deformation under the combined effects of external pressure and long term creep. The clad design will not rely on the support of pellets or the holddown spring to prevent gross deformation.

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(c) Overheating of Cladding (during accidents)

Even though the occurrence of DNB does not necessarily lead to cladding failure, radioactive gas release from the fuel-cladding gap and fuel rod gas plenum is conservatively assumed to occur when DNB is predicted to occur. The probability of DNB occurring is a function of the DNBR. The total number of rods which are predicted to experience DNB is a summation over the reactor core of the number of rods with a specific DNBR times the probability of DNB at that DNBR This method is described further in section 15.0.4.4 of the FSAR.

(d) Overheating of Fuel Pellets

The implementation of the DNBR and fuel temperature SAFDLs (see items (k) and (l) in the above Section 4.2.1.1) precludes the need for a specific failure threshold on fuel temperature, with the exception of the CEA Ejection event.

For the CEA ejection event, radioactive gases are assumed to be released from the fuel pellet to the coolant during the event if fuel melting is predicted (Regulatory Guide 1.77, May 1974). The threshold for fuel melting is assumed to be 4940 F (250 calories per gram at the fuel centerline) for all fuel rod burnups. This temperature is obtained by reducing the melting point suggested in Regulatory Guide 1.77 (5150 F) to account for a maximum expected burnup of about 35,000 MWd/T.

(e) Pellet-Cladding Interaction

Damage criteria previously specified for cladding strain (1%) and fuel pellet overheating minimize the probability of failure due to pellet-cladding interaction.

(f) Cladding Rupture

In ECCS analysis, an empirical model is used to predict the occurrence of cladding rupture. The failure temperature is expressed as a function of differential pressure across the cladding wall. Predictions of cladding rupture are used in ECCS analysis to show that the core geometry remains amenable to cooling. Therefore, there are no specific design limits associated with cladding rupture. The rupture model is a porton of the ECCS evaluation model and is discussed in Section 6.3.3.1 of the FSAR.

4.2.1.3 Fuel Coolability Criteria

Fuel coolability is maintained such that continued removal of decay heat is ensured for all anticipated operational occurrences and accidents. Except as described below, the need for specific criteria for core coolability is precluded by the design bases damage criteria discussed above. The maintenance of core coolability is discussed further in Section 4.2.3.3.

(a) INSERT D

(b) Violent Expulsion of Fuel Material

For the CEA ejection event, the radially averaged energy deposition at the hottest axial location is limited to a value less than 280 cal/gm (Regulatory Guide 1.77, May 1974) to prevent fuel rod dispersal due to the rapid reactivity insertion.

(c) Cladding Ballooning and Flow Blockage

For ECCS analysis, cladding swelling and rupture are predicted to ensure maintenance of a coolable core geometry. These models and criteria are described further in FSAR Section 6.3.3.

Insert D

(a) Fragmentation of Embrittled Cladding

For ECCS analysis, limits of 2200°F on peak cladding temperature and 17% on maximum cladding oxidation are used (see Section 6.3.3.1).

(d) Structural Damage from External Forces

The fuel assembly damage criteria (Section 4.2.1.1 above) are used in the analysis of LOCA and the safe shutdown earthquake to ensure that structural integrity and function are maintained.

4.2.2 DESCRIPTION AND DESIGN DRAWINGS

This subsection summarizes the mechanical design characteristics of the fuel system and discusses the design parameters which are of significance to the performance of the reactor. A summary of mechanical design parameters is presented in Table 4.2-1. These data are intended to be descriptive of the design; limiting values of these and other parameters will be discussed in the appropriate sections.

4.2.2.1 Fuel Assembly

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The fuel assembly (Figure 4.2-6) consists of 236 fuel and poison rods, five guide tubes, 11 fuel rod spacer grids, upper and lower end fittings, and a holddown device. The outer guide tubes, spacer grids, and end fittings form the structural frame of the assembly.

is

The fuel spacer grids (Figure 4.2-7) maintain the fuel rod array by providing positive lateral restraint to the fuel rod, but only frictional restraint to axial fuel rod motion. The grids are fabricated from preformed Zircaloy or Inconel strips (the bottom spacer grid material in Inconel) interlocked in an egg crate fashion and welded together. Each cell of the spacer grid contains two leaf springs and four arches. The leaf springs press the rod against the arches to restrict relative motion between the grids and the fuel rods. The perimeter strips contain features designed to prevent hangup of grids during a refueling operation.

The nine Zircaloy-4 spacer grids are fastened to the Zircaloy-4 guide tubes by welding, and each grid is welded to each guide tube at eight locations, four on the upper face of the grid and four on the lower face of the grid, where the spacer strips contact the guide tube surface. The lowest spacer grid (Inconel) is not welded to the guide tubes due to material differences. It is supported by an Inconel 625 skirt which is welded to the spacer grid and to the perimeter of the lower end fitting.

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The upper end fitting is an assembly consisting of two cast 304 stainless steel plates, five machined posts and five helical Inconel X-750 springs, which attaches to the guide tubes to serve as an alignment and locating device for each fuel assembly and has features to permit lifting of the fuel assembly. The lower cast plate locates the top ends of the guide tubes and is designed to prevent excessive axial motion of the fuel rods.

The Inconel X-750 springs are of conventional coil design having a mean diameter of ~~1.269~~ 1.746 in., a wire diameter of ~~.244~~ .201 in., and ~~7~~ 8 active coils. Inconel X-750 was selected for this application because of its previous use for coil springs and good resistance to relaxation during operation.

The upper cast plate of the assembly, called the holdown plate, together with the helical compression springs, comprise the holddown device. The holddown plate is movable, acts on the underside of the fuel alignment plate and is loaded by the compression springs. Since the springs are located at the upper end of the assembly, the spring load combines with the fuel assembly weight to counteract upward hydraulic forces. The determination of upward hydraulic forces includes factors accounting for flow maldistribution, fuel assembly component tolerances, crud buildup, drag coefficient and bypass flow. The springs are sized and the spring preload selected such that a net downward force will be maintained for all normal and anticipated transient flow and temperature conditions. The design criteria limit the maximum stress under the most adverse tolerance conditions to below yield strength of the spring material. The maximum stress occurs during cold conditions and decreases as the reactor heats up. The reduction in stress is due to a decrease in spring deflection resulting from differential thermal expansion between the Zircaloy fuel bundles and the stainless steel internals.

During normal operation, a spring will never be compressed to its solid height. However, if the fuel assembly were loaded in an abnormal manner such that a spring were compressed to its solid height, the spring would continue to serve its function when the loading condition returned to normal.

The lower end fitting is a stainless steel casting consisting of a plate with flow holes and four support legs which also serve as alignment posts. Precision drilled holes in the support legs mate with four core support plate alignment pins, thereby properly locating the lower end of the fuel assembly.

The four outer guide tubes have a widened region at the upper end which contains an internal thread. Connection with the upper end fitting is made by passing the externally threaded end of the guide posts through holes in the lower cast flow plate and into the guide tubes. When assembled, the flow plate is secured between flanges on the guide tubes and on the guide posts. The connection with the upper end fitting is locked with a mechanical crimp. Each outer guide tube has, at its lower end, a welded Zicaloy-4 fitting. This fitting has a threaded portion which passes through a hole in the fuel assembly lower end fitting and is secured by a Zircaloy-4 nut. This joint is secured with a stainless steel locking ring tack welded to the lower end fitting in four places.

The central instrumentation guide tube inserts into sockets in the upper and lower end fittings and is thus retained laterally by the relatively small clearance at these locations. The upper end fitting socket is created by the center guide tube post which is threaded into the lower cast flow plate and tack welded in two places. The lower end fitting socket is machined out of the lower end fitting casting. There is no positive axial connection between the central guide tube and the end fittings.

The five guide tubes have the effect of ensuring that bowing or excessive swelling of the adjacent fuel rods cannot result in obstruction of the control element pathway. This is so because:

a) There is sufficient clearance between the fuel rods and the guide tube surface to allow an adjacent fuel rod to reach rupture strain without contacting the guide tube surface.

b) The guide tube, having considerably greater diameter and wall thickness (and also, being at a lower temperature) than the fuel rod, is considerably stiffer than the fuel rods and would, therfore, remain straight, rather than be deflected by contact with the surface of an adjacent fuel rod.

Therefore, the bowing or swelling of fuel rods would not result in obstruction of the control element channels such as could hinder CEA movement.

The fuel assembly design enables reconstitution, i.e., removal and replacement of fuel and poison rods, of an irradiated fuel assembly. The fuel and poison rod lower end caps are conically shaped to ensure proper insertion within the fuel assembly grid cage structure; the upper end caps are designed to enable grappling of the fuel and poison rod for purposes of removal and handling. Threaded joints which mechanically attach the upper end fitting to the control element guide tubes will be properly torqued and locked during service, but may be removed to provide access to the fuel and poison rods.

Loading and movement of the fuel assemblies is conducted in accordance with strictly monitored adminstrative procedures and, at the completion of fuel loading, an independent check as to the location and orientation of each fuel assembly in the core is required.

Markings provided on the fuel assembly upper end fitting enables verification of fuel enrichment and orientation of the fuel assembly. The serial number is also provided on the lower end fitting to ensure preservation of fuel assembly identity in the event of upper end fitting removal. Additional markings are provided on the fuel rod upper end caps as a secondary check to distinguish between fuel enrichments and burnable poison rods, if present.

During the manufacturing process, the lower end cap of each rod is marked to provide a means of identifying the pellet enrichment, pellet lot and fuel stack weight. In addition, a quality control program specification requires that measures be established for the identification and control of materials, components, and partially fabricated subassemblies. These means provide assurance that only acceptable items are used and also provide a method of relating an item or assembly from initial receipt through fabrication, installation, repair, or modification to an applicable drawing, specification, or other pertinent technical document.

4.2.2.2 Fuel Rod

The experience upon which the fuel rod design is based is described in section 4.2.2.6 below.

The fuel rods consist of slightly enriched UO_2 cylindrical ceramic pellets a round wire Type 302 stainless steel compression spring, and an alumina spacer disc located at each end of the fuel column, all encapsulated within a Zircaloy-4 tube seal welded with Zircaloy-4 end caps. The fuel rods are internally pressurized with helium during assembly. Figure 4.2-8 depicts the fuel rod design.

Each fuel rod assembly includes both a serial number and a visual identification mark. The serial number ensures traceability of the fabrication history of each fuel rod component. The identification mark provides a visual check on pellet enrichment batch during fuel assembly fabrication.

The fuel cladding is cold worked and stress relief annealed Zircaloy-4 tubing 0.025 inches thick. The actual tube forming process consists of a series of cold working and annealing operations, the details of which are selected to provide the combination of and properties discussed in Subsection ~~4.2.1.2.2~~. 4.2.3.5(b).

The UO_2 pellets are dished at both ends in order to better accommodate thermal expansion and fuel swelling. The density of the UO_2 in the pellets is 10.38 g/cm^3, which corresponds to 94.75 percent of the 10.96 g/cm^3 theoretical density (TD) of UO_2. However, because the pellet dishes and chamfers constitute about three percent of the volume of the pellet stack, the average density of the pellet stack is reduced to 10.06 g/cm^3. This number is referred to as the "stack density". INSERT HH

The compression spring located at the top of the fuel pellet column maintains the column in its proper position during handling and shipping. The alumina spacer disc at the lower end of the fuel rod reduces the lower end cap temperature, while the upper spacer disc prevents UO_2 chips, if present, from entering the plenum region. The fuel rod plenum which is located above the pellet column, provides space for axial thermal differential expansion of the fuel column and accommodates the initial helium loading and evolved fission gases. (See Subsections ~~4.2.1.2.5.1 and 4.2.1.2.5.2~~). 4.2.3.1(h)). The specific manner in which these factors are taken into account, including the calculation of temperatures for the gas contained within the various types of rod internal void volume, is discussed in Reference 14.

4.2.2.3 Burnable Poison Rod

Fixed burnable neutron absorber (poison) rods, Figure 4.2-9 will be included in selected fuel assemblies to reduce the beginning-of-life moderator coefficient. They will replace fuel rods at selected locations. The poison rods will be mechanically similar to fuel rods, but will contain a column of burnable poison pellets instead of fuel pellets. The poison material will be alumina with uniformly dispersed boron carbide particles.

INSERT HH

Other descriptive information is:

(a) Cladding I.D. roughness is .000021 in.

(b) Dish diameter is 0.233 in.; depth is 0.017 in.
Chamfer width is 0.020 in.; length is 0.0065 in.

(c) BOL cold void volume is 1.4212 inch^3.

(d) No sorbed gases are assumed in performance analyses.

(e) Fuel rod length tolerance is 0.065 in.

(f) BOL cold shoulder gap is 0.997 in.

(g) Typical grid spacing is 15 13/16 in.

The balance of the column will consist of alumina pellets, with the total column length the same as the column length in fuel rods. The burnable poison rod plenum spring is designed to produce a smaller preload on the pellet column than that in a fuel rod because of the lighter material in the poison pellets.

Each burnable poison rod assembly includes a serial number and visual identification mark. The serial number is used to record fabrication information for each component in the rod assembly. The identification mark is unique to poison rods and provides a visual check on the pellet boron content during fuel assembly fabrication.

4.2.2.4 Control Element Assembly Description and Design Drawings

The St Lucie Unit 2 reactor contains a total of 91 CEAs of three different types. These are distributed among the fuel assemblies as shown in Figure 4.2-10. The full length five element, full length four element, and part length five element CEAs are shown on Figures 4.2-3 through 4.2-5 respectively. All five element CEAs have four control elements arranged in a 4.050 inch square array plus one element at the center of the array. The four element CEAs have their four control elements arranged in a 4.050 x 4.130 array. Each CEA interfaces with the guide tubes of one fuel assembly, with the exception of the four element CEA, which straddles two adjacent fuel assemblies. Part length CEAs are differentiated from full length CEAs by the following identifying features:

CEA Type	Engraved Identification Number (on Spider)	Grooves on Control Rod
Full length	1, 2, 3, etc. (1-in. high)	None, smooth OD
Part length	A, B, C, etc. (1-1/2-in. high)	One per rod

The control elements of a full length CEA each consist~~s~~ of an Inconel 625 tube loaded with a stack of cylindrical absorber pellets. The absorber material consists of 73 percent TD boron carbide (B_4C) pellets, with the exception of the lower portion of the corner elements, which contain silver-indium-cadmium (Ag-In-Cd) alloy cylinders.

a) CEA Cladding Dimensional Stability

Because of its high ductility and low strength, the Ag-In-Cd will not deform the CEA cladding. Buffering of the CEA following scram, which occurs when the corner element tips enter a reduced diameter portion of the fuel assembly guide tubes, is not degraded with long term exposure of the CEA to reactor operating conditions.

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b) Adequate CEA Worth

Although some reduction in CEA worth arises because of the substitution of B_4C with Ag-In-Cd, the effect is small and is accounted for.

Above the poison column is a plenum which provides expansion volume for helium released from the B_4C. The plenum volume contains a Type 302 stainless steel holddown spring, which restrains the absorber material against longitudinal shifting with respect to the clad while allowing for differential expansion between the absorber and the clad. The spring develops a load sufficient to maintain the position of the absorber material during shipping and handling.

Each full length control element is sealed by welds which join the tube to an Inconel 625 nose cap at the bottom, and an Inconel 625 end fitting at the top. The end fittings, in turn, are threaded and pinned to the spider structure which provides rigid lateral and axial support for the control elements. The spider hub bore is specially machined to provide a point of attachment for the CEA extension shaft.

Eight of the 91 CEAs are part length CEAs. The control elements of a part length CEA consist of solid Inconel 625 over the bottom 50 percent of their length, an Inconel 625 tube open to the reactor coolant over the next 40 percent and a sealed chamber containing 73 percent TD B_4C pellets in the top 10 percent. A holddown spring, similar to the spring in the full length rods, maintains the orientation of the B_4C. The CEA/PLCEA pattern is shown in Figure 4.2-10.

Each full length or part-length CEA is positioned by magnetic jack control element drive mechanism (CEDM) mounted on the reactor vessel closure head. The extension shaft joins with the CEA spider and connects the CEA to the CEDM. Full and part length five element CEAs may be connected to any extension shaft depending on control requirements. Mechanical reactivity control is achieved by positioning groups of CEAs by the CEDMs.

In the outlet plenum region, all CEAs/PLCEAs are enclosed in CEA shrouds which provide guidance and protect the CEA/PLCEA and extension shaft from coolant cross flow. Within the core, each element travels in a Zircaloy guide tube. The guide tubes are part of the fuel assembly structure and ensure proper orientation of the control elements with respect to the fuel rods.

When the extension shaft is released by the CEDM, the combined weight of the shaft and CEA causes the CEA to insert into the fuel assembly.

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SL2-FSAR

The lower ends of the four outer fuel assembly guide tubes are tapered gradually to form a region of reduced diameter which, in conjunction with the outer control element on the CEA, constitutes an effective hydraulic buffer for reducing the deceleration loads at the end of a trip stroke. This purely hydraulic damping action is augmented by a spring and plunger arrangement on the CEA spider. When fully inserted, five element CEAs and PLCEAs rest on the central post of the fuel assembly upper end fitting, the four element CEA rests on the fuel assembly upper end fitting flow ~~plate~~ bypass insert assembly.

The capability of the CEAs to scram within the allowable time is demonstrated as part of the flow testing discussed in Subsection ~~4.2.4.4~~ 4.2.4.1(d).

4.2.2.5 Material Properties

(a) Fuel Assembly

The fuel assembly grid cage structure consists of nine Zircaloy-4 spacer grids, one Inconel 625 spacer grid (at the lower end), five Zircaloy-4 guide tubes, two stainless steel end fittings, and five Inconel X-750 coil springs. Zircaloy-4, selected for fuel rod cladding, guide tubes and spacer grids, has a low neutron absorption cross section, and high corrosion resistance to reactor water environment. Also there is little reaction between the cladding and fuel or fission products. As described in Subsection 4.2.3, Zircaloy-4 has demonstrated its ability as a cladding, CEA guide tube, and spacer grid material.

The bottom spacer grid is of Inconel 625 and is welded to the lower end fitting. In this region of local inlet turbulence, Inconel 625 was selected rather than Zircaloy-4 to provide additional strength and relaxation resistance. Inconel 625 is a very strong material with good ductility, corrosion resistance and stability under irradiation at temperatures below 1000 F.

The fuel assembly lower end fitting is of cast 304 stainless steel (Grade CF-8) and the upper end fitting assembly consists of two cast stainless steel plates and five Type 304 stainless steel machines alignment posts. This material was selected based on considerations of adequate strength and high corrosion resistance. Also, Type 304 stainless steel has been used successfully in almost all pressurized water reactor environments, including all currently operating CE reactors.

X . Fuel Assembly Guide Tubes

Designation UNS #R60804

All fuel assembly guide tubes are manufactured in accordance with ~~Grade RA-2,~~ ASTM B353-~~77~~A, Wrought Zirconium and Zirconium Alloy Seamless and Welded Tubes for Nuclear Service, with the following exceptions and/or additions:

a) Chemical Properties

Additional limits are placed on oxygen.

b) Mechanical Properties

Flare:

A section of annealed tube, between two and four inches in length shall be flared with a tool having a 60 degree included angle until the outside diameter has increased by 15 percent. The flared tube shall show no cracking when examined with the unaided eye.

c) Dimensional Requirements

Dimension	Permissible Tolerance (in.)
OD	± 0.003
ID	± 0.005

X Zircaloy-4 Bar Stock

All Zircaloy-4 bar stock is fabricated in accordance with ~~Grade RA-2,~~ ASTM B351, Hot-Rolled and Cold-Finished Zirconium and Zirconium Alloy Bars, Rod and Wire for Nuclear Application, with the following exceptions and/or additions:

a) Chemical Properties

Additional limits are placed on oxygen and silicon content,

b) Metallurgical Properties

Grain Size:

The maximum average grain size is restricted.

X Zircaloy-4 Strip Stock

All Zircaloy-4 strip stock is fabricated in accordance with Grade RA-2, ASTM B352, Zirconium and Zirconium Alloy Sheet, Strip and Plate for Nuclear Application, with the following exceptions and/or additions:

a) Chemical Properties

Additional limits are placed on oxygen and silicon content.

b) Metallurgical Properties

Grain Size:

The maximum average grain size is restricted.

c) Mechanical Properties

Bend:

Each sample shall be bent using a three point type, guided bend test fixture similar to that described in MAB-192-M, Evaluation Test Methods for Refractory Metal Sheet Material, Paragraph 5.2.2, published by Division of Engineering and Industrial Research, National Academy of Sciences, National Research Council, April 22, 1963. The sample shall be bent 180 degrees using a hand anvil with a radius equal to twice the sheet thickness. After bending, each specimen shall be liquid dye penetrant inspected to assure freedom from cracking. If cracking occurs on any part of the bend samples, the coils represented shall be rejected.

d) Coefficient of Thermal Expansion

Axial direction - see Reference 2

e) Irradiation Properties:

The yield and tensile strengths are enhanced by irradiation. The stress relaxation with irradiation and operating temperatures proceeds at a rapid rate until nearly complete. The irradiation induced growth is documented.[3]

7 ~~4.2.1.1.6~~ Stainless Steel Castings

All stainless steel castings are fabricated in accordance with Grade CF-8, ASTM A296, with the following addition: 10

Chemical Properties

Cobalt content is limited.

8 ~~4.2.1.1.7~~ Stainless Steel Tubing

All stainless steel tubing is fabricated in accordance with ASTM A269, with the following addition:

Chemical Properties

Carbon content is limited on tubing to be welded. Cobalt content is limited.

~~4.2.1.1.8~~ Inconel X-750 Helical Springs

All Inconel springs are fabricated in accordance with AMS 5699B, with the following addition:

Chemical Properties

Cobalt content is limited.

Passivation prohibited.

~~4.2.1.1.9~~ Inconel 625 Bottom Spacer Grid Strip Material

Inconel spacer grid strip material is procured in accordance with the specification for nickel-chromium molybdenum columbium alloy plate, sheet, and strip, specification ASTM 443-72, with the following additional requirements: 10
ments:

a) Chemical Properties

Cobalt content is limited to one percent maximum.

b) Special Tests

A check analysis and a bend test are required.

(b) Fuel Rod 42a

Fuel Rod Cladding

0 ~~4.2.1.2.2.1~~ Mechanical Properties

a) Modulus of Elasticity

The value of Young's Modulus x 10^{-6} is specified in Reference 13.

b) Poisson's Ratio

N is the value specified in Reference 13.

c) Thermal Coefficient of Expansion

Diametral direction is the value specified in Reference 13.

d) Yield Strength

INSERT JJ

Yield strength in the non-irradiated condition is shown on Figure 4.2-20 of Reference 13.

The cladding stress limits identified in Subsection 4.2.1.1(a) are based on values taken from the minimum yield strength curve at the appropriate temperatures. The limits are applied over the entire fuel lifetime, during conditions of reactor heatup and cooldown, steady state operation, and normal power cycling. Under these conditions, cladding temperatures and fast fluences can range from 70 to 750 F and from 0 to 1 x 10^{22} nvt, respectively.

e) Ultimate Strength

INSERT JJ

Ultimate tensile strength in the non-irradiated condition is shown on Figure 4.2-21 of Reference 13.

f) Uniform Tensile Strain

INSERT II

Uniform tensile strain in the non-irradiated condition is shown on Figure 4.2-22 of Reference 13.

Uniform tensile strain in the ~~non~~irradiated condition approaches one percent at 6 x 10^{20} nvt and remains relatively constant (Subsection 4.2.1.1(a).

g) Flare

A section of annealed tube, approximately two to four inches in length is flared with a tool having a 60 degree included angle, until the outside diameter has increased by 15 percent. The flared tube is to show no cracking when examined with the unaided eye.

INSERT II

Irradiation is assumed in the Zircaloy strain limit since it lowers the allowable value. Any calculations involving permanent strain use this basis, unless they are a BOL situation.

INSERT JJ

Irradiated values for Zircaloy yield strength and ultimate strength are not used in any design calculations. This is conservative since allowable stresses would increase if irradiation were accounted for.

h) Hydrostatic Burst Test

The cladding specification requires that two samples from each lot of cladding be subjected to room temperature hydrostatic burst tests. To be acceptable, the burst pressure must exceed a minimum value based on the cladding geometry and specified tensile properties, and the circumferential ~~elongation~~ STRAIN must EQUAL OR exceed ~~a prescribed minimum value~~ 12%.

0 ~~4.2.1.2.2.2~~ Dimensional Requirements

a) Tube straightness is limited to 0.010 in./ft, and inside diameter and wall thickness are tightly controlled.

b) Ovality is measured as the difference between maximum and minimum inside diameters and is acceptable if within the diameter tolerances.

c) Outside diameter is specified as 0.382 ± 0.002 inches

d) Inside diameter is specified as 0.332 ± 0.0015 inches

e) Eccentricity is defined as the difference between maximum and minimum wall thickness at a cross-section, and is specified as 0.004 inches maximum

f) Wall thickness is specified as 0.023 inches minimum (the nominal value reported in Table 4.2-1 is based on the nominal OD and ID).

INSERT DD

0 ~~4.2.1.2.2.3~~ Metallurgical Properties

a) Hydride Orientation

A restriction is placed on the hydride orientation factor for any third of the tube cross section (inside, middle, or outside). The hydride orientation factor, defined as the ratio of the number radially oriented hydride platelets to the total number of hydride platelets, shall not exceed 0.3. The independent evaluation of three portions of the cross section is included to allow for the possibility that hydride orientation may not be uniform across the entire cross section.

0 ~~4.2.1.2.2.4~~ Chemical Properties

All fuel rod cladding is manufactured in accordance with ~~Grade RA-2,~~ Designation UNS #R60804, ASTM B353-~~77~~A Wrought Zirconium and Zirconium Alloy Seamless and Welded Tubes for Nuclear Service, except additional limits are placed on oxygen, silicon and iron content.

INSERT OD

g) Cladding length tolerance is ± 0.065 inches.

¶ It should be noted that the tolerances listed above are taken from design drawings. It is standard practice to obtain as-built cladding measurements of outside diameter, wall thickness, and ovality; and these measured values are occasionally used to reduce uncertainties in final analyses.

Fuel Rod Components

Designation UNS #R60804

0 ~~4.2.1.2.3.1~~ Zircaloy-4 Bar Stock

All Zircaloy-4 bar stock is fabricated in accordance with ~~Grade RA-2~~, ASTM B351-73, Hot rolled and Cold Finished Zirconium and Zirconium Alloy Bars, Rod and Wire for Nuclear Application, with the following exception and/or additions:

a) Chemical Properties

Additional limits are placed on oxygen and silicon content.

b) Metallurgical Properties

The maximum average grain size is restricted.

0 ~~4.2.1.2.3.2~~ Stainless Steel Compression Springs

All stainless steel springs are fabricated in accordance with AMS 5688, Revision F. The dimensions of these springs are:

Free length	9.429 in.
Outside diameter	0.312 in.
Wire size	0.063 in.
Active number of coils	68
Spring constant	20.6 lb/in.

~~4.2.1.2.4~~ UO_2 Fuel Pellet ~~Properties~~

0 ~~4.2.1.2.4.1~~ Chemical Composition

Salient points regarding the structure, composition, and properties of the UO_2 fuel pellets are discussed in the following subsections. Where the effect of irradiation on a specific item is considered to be of sufficient importance to warrant reflection in the design or analyses, that effect is also discussed.

a) Chemical analyses are performed for the following constituents:

1) Total Uranium

2) Carbon

3) Nitrogen

4) Fluorine

5) Chlorine and Fluorine

6) Iron

7) Thorium

8) Nickel

b) Limits are placed on the oxygen-to-uranium ratio.

c) The sum of the calcium, aluminum and silicon contents shall not exceed 300 ppm by weight.

d) The sum of the cross sections of the following impurities shall not exceed a specified equivalent thermal neutron capture cross section of natural boron:

1) Boron

2) Silver

3) Cadmium

4) Gadolinium

5) Europium

6) Samarium

7) Dysprosium

e) The total hydrogen content of finished ground pellets is restricted.

f) The nominal enrichment of the fuel pellets will be specified and shall be held within ± 0.05 wt percent U-235.

6 ~~4.2.1.2.4.2~~ Microstructure

a) The pellet fabrication process will maximize the pore content of pellets in a specified range. Acceptable porosity distribution will be determined by comparison of approved visual standards with photomicrographs from each pellet lot.

b) The average grain size shall exceed a specified minimum size.

6 ~~4.2.1.2.4.3~~ Density

a) The density of the sintered pellet after grinding shall be between 93.5 and 96.0 percent of theoretical density (TD), based on an UO_2 theoretical density of 10.96 g/cm^3.

b) The in pile stability of the fuel is ensured by the use of an NRC-approved out of pile test during production. The details of this test, and the associated rationale, are presented in Reference 14.

c) The effects of irradiation on the density of sintered UO_2 pellets are discussed in Reference 14.

6 ~~4.2.1.2.4.4~~ Thermal Properties

a) Thermal Expansion

The thermal expansion of UO_2 is described by the following temperature dependent equations:(15)(16)

$$\% \text{ Linear Expansion} = (-1.723 \times 10^{-2}) + (6.797 \times 10^{-4}T) + (2.896 \times 10^{-7}T^2)$$

from 25C ~~up~~ to 2200C

$$\% \text{ Linear Expansion} = 0.204 + (3 \times 10^{-4}T) + (2 \times 10^{-7}T^2) + (10^{-10}T^3)$$

above 2200C.

where T = temperature, C.

b) Thermal Emissivity

A value of 0.85 is used for the thermal emissivity of UO_2 pellets over the temperature range 800 to 2600 K.(17)(18)(19)

INSERT CC

c) Melting Point and Thermal Conductivity

The variation of melting point and thermal conductivity with burnup is discussed in Reference 14.

INSERT CC

(70)

The earlier data on emissivity of UO_2 were those of Claudson and of Ehlert and Margrave, as reported by Belle(25). Claudson reported that the emissivity decreased from 0.85 at 1000K to 0.37 at 2200K. Ehlert and Margrave measured the spectral emissivity of the polished surface of UO_2 to be approximately 0.40 in the temperature range of 2100-3000K. These determinations were made in the late 1950s by an indirect technique that compared the luminance of a tungsten filament and that of UO_2 at identical test environments. In a subsequent investigation, Cabannes, et. al., (reference 18) directly measured the reflectance of UO_2 up to 2200K as a function of wavelength. In the visible region, the emissivity increased from 0.86 to 0.94 between 300 and 1600K. At longer wavelengths, the effect of temperature on emissivity was even less, and the value approached 1.0 at a 20 μm wavelength. This increase in emissivity with temperature conflicts with the data of Claudson(1) and of Ehlert and Margrave(1), and a source of error in the technique employed in the earlier work is discussed by Cabannes, et. al. In their opinion, the low luminance of tungsten in the temperature range of the earlier investigations is an important source of error and can easily lead to the discrepancy observed between their data and the data of Claudson and of Ehlert and Margrave. (70)

The most recent determination of emissivity of UO_2 was done by Held and Wilder (reference 19). Hemispherical spectral emittance of UO_2 pellets was determined in the composition range of $UO_{1.95}$ to $UO_{2.29}$, in the density range of 73 to 97% TD and in the temperature range of 450 to 2480K. The emittance was high in all cases and ranged from about 0.7 to 0.95. No decrease in emittance was observed with increasing temperature; instead, it increased slightly. These authors also reviewed the earlier data and based on mechanistic considerations offered rationale for the relative insensitivity of emittance with temperature as observed in the more recent investigations.

A review of the more recent sources of emissivity data described above thus shows the values of 0.82 to 0.86 at 300K (reference 17 and 18); 0.86 to 0.94 between 300 and 1600K (reference 18), and a random scatter of values between 0.70 and 0.95 (reference 19) for various temperatures (450, 1000, and 1800-2550K), densities and O/U ratios. No definitive trend, therefore, is noticed with variations in temperature, density, O/U ratio or surface finish. Based on these considerations, a value of 0.85 is used for the thermal emissivity of UO_2 pellets over the temperature range of interest of 800 to 2600K.

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d) Specific Heat of UO_2

The specific heat of UO_2 is described by the following temperature dependent equations.[20]

<u>T < 2240 F</u>

$$C_p = 49.67 + 2.2784 \times 10^{-3}T - \frac{3.2432 \times \cancel{106}\ 10^6}{(T + 460)^2}$$

<u>T ≥ 2240 F</u>

1

$$C_p = -126.07 + 0.2620T - 1.399 \times 10^{-4}T^2 + 3.1786 \times 10^{-8}T^3 - 2.488 \times 10^{-12}T^4$$

3

where:

C_p = specific heat, BTU/ft^3 - F

T = temperature, F

0 ~~4.2.1.2.4.5~~ Mechanical Properties

a) Young's Modulus of Elasticity

The static modulus of elasticity of unirradiated fuel of 97 percent TD and deformed under a strain rate of 0.097 hr^{-1} is given by[21]:

$$E = 14.22\ (1.6715 \times 10^6 - 924.4T)$$

where;

E = modulus of elasticity in psi,
T = temperature in C in the range of 1000 to 1700 C.

b) Poisson's Ratio

The Poisson's Ratio of polycrystalline UO_2 has a value of 0.32 at 25 C based on Reference 66. The same reference notes a 10 percent decrease in value over the range of 25 to 1800 C. Assuming the decrease is linear, the temperature dependence of the Poisson's Ratio is given by

$$v = 0.32 - 1.8 \times 10^{-5}\ (T-25)$$

where;

v = Poisson's Ratio
T = temperature in C in the range of 25 to 1800 C.

At temperature above 1800 C a constant value of 0.29 is used for Poisson's Ratio.

(c) Burnable Poison Rod

~~4.2.1.3.~~2 Burnable Poison Rod Cladding Properties

Cladding tubes for burnable poison rods are purchased under the specification for fuel rod cladding tubes. Therefore, the mechanical, metallurgical, chemical, and dimensional properties of the cladding are as discussed in Subsection ~~4.2.1.2.2.~~ 4.2.2.5(b).

~~4.2.1.3.3~~ Al_2O_3-B_4C Burnable Poison Pellet Properties

The Al_2O_3-B_4C burnable poison pellets used in CE designed reactors consist of a relatively small volume fraction of fine B_4C particles dispersed in a continuous Al_2O_3 matrix. The boron loading is varied by adjusting the B_4C concentration in the range from 0.7 to 4.0 wt% (1 to 6.0 v/o). The bulk density of the Al_2O_3-B_4C pellets is specified to be greater than 93 percent of the calculated theoretical density. Typical pellets have a bulk density of about 95 percent of theoretical. Many properties of the two-phase Al_2O_3-B_4C mixture, such as thermal expansion, thermal conductivity, and specific heat are very similar to the properties of the Al_2O_3 major constituent. In contract, properties such as swelling helium release, melting point, and corrosion are dependent on the presence of B_4C. The operating centerline temperature of burnable poison is less than 1150 F, with maximum pellet surface temperatures close to 1090 F.

0 ~~4.2.1.3.3.1~~ Thermal-Physical Properties

a) Thermal Expansion

The mean thermal expansion coefficients of Al_2O_3[24] and B_4C[25] from 0 to 1850 F are 4.9 and 2.5 in./in. F x 10^{-6}, respectively. The thermal expansion of the Al_2O_3-B_4C two-phase mixture can be considered to be essentially the same as the value for the continuous Al_2O_3 matrix since the dispersed B_4C phase has a lower expansion coefficient and occupies only 5 v/o of the available volume. The low temperature (80 to 250 F) thermal expansion coefficient of Al_2O_3 irradiated at 480, 900, and 1300 F does not change as a result of irradiation.[26] The expansion of a similar material, beryllium oxide, up to 1900 F has also been reported to be relatively unchanged by irradiation.[27] It is therefore appropriate to use the values of thermal expansion measured for Al_2O_3[24] for the burnable poison pellets:

Temperature Range (F from 70 F to)	Linear Expansion (%)
400	0.12
600	0.23
800	0.30
1000	0.40

b) Melting Point

The melting points of Al_2O_3(3710 F)[28] and B_4C (4400 F)[29] are higher than the melting point of the Zr-4 cladding. No B_4C burns up, the lithium atoms formed occupy interstitial sites randomly distributed within the B_4C lattice, rather than forming a lithium rich phase.[30] The solid solution of lithium in B_4C should not appreciably influence the melting point of the Al_2O_3-B_4C pellets, as only a small quantity of lithium compounds (0.5 wt%) forms during irradiation. It is concluded that the melting point of Al_2O_3-B_4C will remain considerably above the maximum 1150 F operating temperature.

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c) Thermal Conductivity

The thermal conductivity of Al_2O_3-B_4C was calculated from the measured values for Al_2O_3 and B_4C using the Maxwell-Eucken relationship[31] for a continuous matrix phase (Al_2O_3) with spherical dispersed phase (B_4C) particles. Because of the high Al_2O_3 content of these mixtures and the similarity in thermal conductivity, the resultant values for Al_2O_3-B_4C were essentially the same as the values for Al_2O_3. The measured, unirradiated values of thermal conductivity at 750 F are 0.06 cal/s-cm-k for B_4C and 0.05 cal/s-cm-k for Al_2O_3.

The thermal conductivity of Al_2O_3 after irradiation decreases rapidly as a function of burnup to values of about one-third the unirradiated values.[26] The irradiated values of Al_2O_3-B_4C calculated from the above relationships are given below as a function of temperatures.[26] [32]

Temperature (F)	Thermal Conductivity (cal/s-cm-k)
400	0.015
600	0.013
800	0.010
1000	0.008

d) Specific Heat

The specific heat of the Al_2O_3-B_4C mixture can be taken to be essentially the same as pure Al_2O_3 since the concentration of B_4C is low (6.0 v/o maximum). In addition, the effect of irradiation on specific heat is expected to be small based on experimental evidence from similar materials which do not sustain transmutations as a function of neutron exposure.

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The values for Al_2O_3 measured on unirradiated samples[~~32~~ 35] [~~33~~ 36] are given below:

Temperature (F)	cal/gm-F
250	0.12
450	0.13
800	0.14
1000 and above	0.15

0 ~~4.2.1.3.3.~~2 Irradiation Properties

a) Swelling

Al_2O_3-B_4C consists of B_4C particles dispersed in a continuous Al_2O_3 matrix, which occupies more than 95 percent of the poison pellet. The swelling of Al_2O_3-B_4C depends primarily upon the neutron fluence on the continuous Al_2O_3 matrix and,

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(71)

The properties of specific heat and thermal expansion are closely related as they both increase with temperature (at expected operating temperatures, <1000F) primarily due to increases in lattice vibrations. That is, changes in specific heat with temperature nave been shown to be primarily due to the same physical processes as changes in thermal expansion with materials such as Al_2O_3 and BeO. The conclusion that the effect of irradiation on the specific heat of Al_2O_3-B_4C is small is based on measurements which show that the specific heat of BeO does not change with irradiation, and measurements that show the thermal expansion coefficient of Al_2O_3 does not change due to irradiation. Since measurements of the thermal expansion coefficient of irradiated Al_2O_3 have shown no change due to irradiation and since specific heat and thermal expansion are both dependent upon lattice vibrations, it is expected that specific heat is also not significantly affected by irradiation.

(72)

(73)

The specific heat of the Al_2O_3-B_4C mixture can be taken to be essentially the same as Al_2O_3 since the concentration of B_4C is a maximum of 3.7 w/o B_4C, and the specific heat of B_4C at operating temperature is close to the value of Al_2O_3.

The Debye temperature of Al_2O_3 determined by measurement is about 904K. There is no effect of the B_4C particles in the Al_2O_3 matrix on the Debye temperature.

secondarily, on the B^{10} burnup of the dispersed B_4C phase. Recent measurements performed on material containing about two wt% B_4C irradiated in a CE PWR to 100 percent B^{10} burnup at a fluence of 2.4×10^{21} nvt (E>0.8 MeV) revealed a diametral swelling of about one percent. Pellets similar to the burnable poison used in CE reactors with up to three wt% B_4C also sustained about 100 percent B^{10} burnup. Experimental data[34] on Al_2O_3 reveal a diametral swelling of about 0.7 percent at a fluence of 2.4×10^{21} nvt (E>0.8 MeV). Swelling of Al_2O_3 increases linearly with fluence to 1.8 percent diametral after an exposure of 6×10^{21} nvt (E>0.8 MeV).

These data show that Al_2O_3-B_4C swells somewhat more than Al_2O_3 up to a burnup of 90% B_4C (about 2×10^{21} nvt, E > 0.8 MeV) ~~B-10 fraction)~~

The CE design value of Al_2O_3-B_4C swelling rate for fluences less than 2×10^{21} is greater than the swelling rate of Al_2O_3, while after 2×10^{21} fluence the swelling rate for Al_2O_3-B_4C is considered equal to that of Al_2O_3.

The data and considerations presented above result in best estimate diametral swelling values at end of life (7×10^{21} nvt, E > 0.8 MeV) of about two percent for Al_2O_3 and from two to three percent for Al_2O_3-B_4C loading.

b) Helium Release

Experimental measurements reveal that less than five percent of the helium formed during irradiation will be released.[35] These measurements were performed on Al_2O_3-B_4C pellets irradiated at temperatures to 500 F and, subsequently, annealed at 1000 F for five days. The helium release in a burnable poison rod which operated for one cycle in a CE PWR was calculated from internal pressure measurements to be less than five percent. The design is based on a release of three to 15 percent of the helium generated. The design of the burnable poison rod will not be limited by helium pressure despite the conservative use of 15 percent release.

0 ~~4.2.1.3.3.3.~~ Chemical Properties

a) Al_2O_3-B_4C Coolant Reaction

Should irradiated B_4C particles be exposed to reactor coolant, the primary corrosion products that would be formed are boric acid (which is soluble in water), hydrogen, free carbon and a small amount of lithium compounds. The presence of these products in the reactor coolant would not be detrimental to the operation of the plant.

Observations of Al_2O_3/B_4C poison shims have revealed that long term exposure of this material to reactor coolant can result in gradual leaking out of Boron and eventual eroding away of the Al_2O_3 matrix. However, the rate of reaction is such that any

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resultant changes in reactivity are very gradual.

b) Chemical Capability

Chemical compatibility between the Al_2O_3-B_4C pellets and the burnable poison rod cladding during long term normal operation has been demonstrated by examination of a burnable poison rod from the Maine Yankee reactor. The rod had been exposed to an axial average fluence in excess of 2×10^{21} nvt (>0.821 Mev). No evidence of a chemical reaction was observed on the cladding I.D.

Short term chemical compatibility during upset and emergency conditions is demonstrated by the fact that conditions favorable to a chemical reaction between Zr-4 and Al_2O_3 are not present at temperatures below 1300 F[36]. This temperature is higher than that which will occur at burnable poison pellet surfaces during Condition II and III occurrences (Subsection 4.2.1). The reaction tween Zr-4 and Al_2O_3 described by Idaho Nuclear[37] was observed to occur rapidly only at temperatures in excess of 2500 F, well above the peak Zr-4 temperatures expected.

(d) Control Element Assemblies

~~4.2.1.4.1~~ Thermal-Physical Properties of Absorber Material

The primary control rod absorber materials consist of boron carbide pellets (B_4C) and silver indium cadmium bars (Ag-In-Cd). Inconel Alloy 625 is also used as a weak absorber over a portion of the part-length rods. Refer to Figures 4.2-3, 4.2-4, and 4.2-5 for the specific application and orientation of the absorber materials. The significant thermal and physical properties used in mechanical analysis of the absorber materials are listed in Table 4.2-2. |0

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~~4.2.1.4.2~~ Compatibility of Absorber and Cladding Materials

The cladding material used for the control elements is Inconel Alloy 625. The selection of this material for use as cladding is based on consideration of strength, creep resistance, corrosion resistance and dimensional stability under irradiation and also upon the acceptable performance of this material for this application in other CE reactors currently in operation.

a) B_4C/Inconel 625 Compatibility

Studies have been conducted by HEDL[38] on the compatibility of Type 316 stainless steel with B_4C, under irradiation for thousands of hours at temperatures between 1300 and 1600 F. Carbide formation to a depth of about 0.004 inch in the 316 stainless steel was measured after 4400 hours at 1300 F. Similar compound formation depths were observed after ex-reactor bench testing. After testing at 1000 F, only 0.001 in./yr of penetration was measured. Since Inconel 625 is more resistant to carbide formation than 316 stainless steel, and the expected pellet/clad interfacial temperature in the standard design is below 800 F, it is concluded that B_4C is compatible with Inconel 625.

~~4.2.1.4.3~~ Cladding Stress-Strain Limits

The stress limits for the Inconel Alloy 625 cladding are as follows:

Design Conditions I and II (Non Operation, Normal Operation, and Upset Conditions)

$$P_m \leq S_m$$

$$P_m + P_b \leq F_s S_m$$

Design Conditions III (Emergency Conditions)

$$P_m \leq 1.5\ S_m$$

$$P_m + P_b \leq 1.5\ F_s S_m$$

Design Conditions IV (Faulted Conditions)

$$P_m \leq S'_m$$

$$P_m + P_b \leq F_s S'_m$$

where S'_m is the smaller of 2.4 S_m or $0.7S_u$.

For definition of P_m, P_b, S_m, S'_m, S_u, and F_s, see Subsection 4.2.1.1(a). For the Inconel 625 CEA cladding, the value of S_m is two-thirds of the minimum specified yield strength at temperature.

For Inconel 625, the specified minimum yield strength is 65,000 lb/in.^{2} at 650 F.

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$F_s = Mp/My$ where Mp is the bending moment required to produce a fully plastic section and My is the bending moment which first produces yielding at the extreme fibers of the cross section. The capability of cross sections loaded in bending to sustain moments considerably in excess of that required to yield the outermost fiber is discussed in Reference 1. For the CEA cladding dimensions, $F_s = 1.33$.

The strain limits for the cladding are limited to values which will permit the CEAs to trip within the allowable time.

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The values of uniform and total elongation of Inconel Alloy 625 cladding are estimated to be as follows:

Fluence (E > 1 Mev), nvt	1×10^{22}	3×10^{22}
Uniform elongation, %	3	1
Total elongation, %	6	3

~~4.2.1.4.4~~ Irradiation Behavior of Absorber Materials

a) Boron Carbide Properties

1) Swelling: The linear swelling of B_4C increases with burnup according to the relationship:

$$\% \Delta L = (0.1)\ B^{10}\ \text{Burnup, a/o}$$

This relationship was obtained from experimental irradiations on high density (>90 percent TD) wafers[39] and pellets with densities ranging between 71 and 98 percent TD.[38][40] Dimensional changes were measured as a function of burnup, after irradiating at temperature expected in the design.

2) Thermal Conductivity: The thermal conductivity of unirradiated 73 percent dense B_4C decreases linearly with temperatures from 300 to 1600 F, according to the relationship:

$$\lambda = \frac{1\ \text{cal/cm - K-s}}{2.17\ (6.87 + \cancel{0.17}\ T)}$$

0.017

This relationship was obtained from measurements performed on pellets ranging from 70 to 98 percent TD.

The relationship between the thermal conductivity of irradiated 73 percent TD B_4C pellets and temperature given below was derived from measured values[41] on higher density pellets irradiated to fluences out to 3×10^{22} nvt (E >1 MeV).

$$\lambda = \frac{1\ \text{cal/cm - K-s}}{2.17\ \ (38 + \cancel{0.25}\ T)}$$

0.025

where T = temperature, K

Thermal conductivity measurements of 17 B_4C specimens with densities ranging from 83 to 98 percent TD, irradiated at temperatures from 930 to 1600 F showed that thermal conductivity decreased significantly after irradiation. The rate of decrease is high at the lower irradiation temperatures, but saturates rapidly with exposure.

3) Helium Release: Helium is formed in B_4C as B^{10} burnup progresses. The fraction of helium released from the pellets is important for determining rod internal gas pressure. The relationship between helium release and irradiation temperature

given below was developed at ORNL[42] to fit experimental data obtained from thermal reactor irradiations.

$$\% \text{ He release} = e^{(C-185D)} e^{\frac{-Q}{RT}}$$

where:

C = Constant, 6.69 for pellets
D = Fractional density, 0.73 for CE pellets
Q = Activation energy contant, 3600 cal/mole
R = Gas constant, 1.98 cal/mole K
T = Pellet temperature, K

This expression becomes

$$\% \text{ He release} = .208\ e^{\frac{-1820}{T}} + 5$$

when the above parameters are substituted. In this form, design values for helium release as a function of temperature are generated. The five percent helium release allowance (the last term in the expression) was added to ensure that design values lie above all reported helium release data. Calculated values of helium release obtained from the recommended design expression lie above all experimental data points[38] [43] [44] obtained on B_4C pellet specimens irradiated in thermal reactors.

4) Pellet Porosity: Experimental evidence is available[45] which shows that for pellet densities below 90 percent, essentially all porosity is open at beginning of life. Irradiation induced swelling does not change the characteristics of the porosity, but only changes the bulk volume of the specimens. Therefore, the amount of porosity available at end of life is the same as that present at beginning of life.

b) Inconel 625

1) Swelling: Available information indicates that Inconel 625 is highly resistant to radiation swelling. Exposure of Inconel 625 to a fluence of 3×10^{22} nvt ($E > 0.1$ Mev) at a temperature of 400C (725F) showed no visible cavities in metallographic examinations[48] so that swelling, if any, would be very minor. Direct measurements made after exposure of Inconel 625 to a fluence 5×10^{22} nvt ($E > 0.1$ Mev) as LMFBR conditions showed no evidence of swelling.[49] Further exposure to 6 to 10^{22} nvt ($E > 0.1$ MeV) at 500 C (932 F) showed essentially no swelling as measured by immersion density, but did show small cavities. Thus, Inconel 625 after fluences of 3×10^{22} nvt ($E > 1$ Mev) is not expected to swell.

2) Ductility: The ductility of Inconel 625 decreases after irradiation. Extrapolation of lower fluence data on Inconel 625 and 500 indicates that the values of uniform and total elongation of

Inconel 625 after 1×10^{22} nvt (E > 1 Mev) are three and six percent, respectively.

3) Strength: The value of yield strength of Inconel 625 increases after irradiation in the manner typical for metals. However, no credit is taken for increases in yield strength in the design analyses above the value initially specified.

c) Silver-Indium-Cadmium Properties

1) Swelling: Measurements performed on Ag-In-Cd rods irradiated at fluences up to 6.2×10^{21} nvt (E > 0.6 Mev) were employed to develop the following expression to predict the volumetric swelling for silver-indium-cadmium alloy:

$$\% \Delta V = \frac{0.3\phi}{10^{21}}$$

where ϕ = fluence, nvt (E > 0.6 Mev).

Linear swelling is approximately one third of the volumetric swelling.

2) Thermal Conductivity: The increase in cadmium content from five to perhaps 10 wt percent, and the formation of two to three wt. percent tin a result of long term exposures, is expected to decrease the thermal conductivity from the accepted[46] unirradiated values. Published data for unirradiated Ag-Cd binary alloys shows that thermal conductivity was decreased by about 20 percent by increasing the cadmium content from 5.0 10.0 wt percent.[46] Since irradiated Ag-In-Cd is expected to perform in much the same fashion, similarly the unirradiated values of thermal conductivity are decreased by 25 percent to account for irradiation.

3) Linear Thermal Expansion: The coefficient of linear thermal expansion for unirradiated Ag-In-Cd material is 12.5×10^{-6} in/in. F over the temperature range of 70 to 930F.[47] Published data on unirradiated[46] Ag-Cd binary alloys reveal that a cadmium increase of five percent will result in about a five percent increase in thermal expansion coefficient. The small changes in indium and tin content do not influence the thermal expansion coefficient appreciably. For simplicity, irradiated values of 13.1×10^{-6} in./in.- F is used in all design calculations.

4) Melting Point: The melting point of unirradiated Ag-In-Cd has been measured as 1470 F $\pm$ 30 F[46] (800C $\pm$ 17C). The formation of three wt percent tin due to the transmutation of indium and the increase in cadmium content to about 10 wt percent to the transmutation of silver may result in a small decrease in the melting point.

4.2.2.6 Fuel Burnup Experience

The CE fuel rod design is based on an extensive experimental data base and by an extension of experimental knowledge through design application of CE fuel rod evaluation codes. The experimental data base includes data from CE or CE/Kraftwerk Union (KWU) joint irradiation experiments, from CE and KWU operating commercial plant performance and from many basic experiments conducted in various research reactors which are available in the open literature. Each of these information sources will be discussed below. Evidence currently available indicates that Zircaloy and UO_2 fuel performance is satisfactory to exposures in excess of 55,000 Mwd/Mtu.

a) Public Information

General fuel performance information available in the open literature has provided part of the CE fuel rod design data base. Particular experiments that have been sited in the past as key references, they include:

1) Determination of the effect of fuel cladding gap on the linear heat rating to melting of UO_2 fuel rods, conducted in the Westinghouse test reactor.

2) Shippingport Irradiation Experience

3) Saxton Irradiation Experience

4) Combined Vallecitos Boiling Water Reactor (VBWR) Dresden Irradiation.

5) Large Seed Blanket Reactor (LSBR) Rod Experience

6) Joint U.S.-Euratom Research and Development Program to evaluate central fuel melting in the Consumers Power Co. Big Rock Point Reactor.

Since the information from these programs is available in the open literature, they will not be described here. However, details as to the significance of the results to CE fuel burnup experience are presented in Reference 59.

b) CE/KWU Technical Exchange

CE entered into a technical agreement with KWU beginning in 1972 for the complete exchange of information and technology relating to pressurized water reactor systems including fuel. This agreement makes available to CE the total experience of 10 years successful

operation of commercial PWR fuel in systems designed and fabricated by KWU and is most advanced of its type in the world. An essential part of this brodd based exchange involves joint sponsorship of numerous fuel testing programs.

c) Operating Fuel Experience

CE and KWU have fabricated approximately 750,000 Zircaloy clad fuel rods both internally pressurized and unpressurized over the last 10 years. Of this total 460,000 rods remain in operation (~ 220,000 CE rods) with average burnups in excess of 36,000 Mwd/Mtu. The remaining 290,000 rods have been discharged with average burnups to 36,000 Mwd/Mtu. Overall performance of this fuel has been excellent. The fuel rod reliability level, estimated from coolant activities is > 99.98 percent. This high reliability level is continually validated by extensive poolside fuel inspection programs conducted by both CE and KWU at reactor sites during refueling shutdowns.

d) Fuel Irradiation Programs

CE is involved in diversified fuel irradiation test programs to confirm the adequacy of the CE fuel rod design bases and models by experimental means. Some of these programs involve safety related research while other programs provide confirmatory data on performance capability or evaluate design and fabrication variables or methods which may improve and extend our current knowledge of fuel rod performance. Many of the programs involved joint CE/KWU sponsorship.

Some of the key fuel performance evaluation programs that will be summarized below include:

Fuel densification experiments at the Battelle Research Reactor (BRR)

Joint CE/KWU fuel densification experiments including tests in the MZFR reactor at Karlsruhe, West Germany, and the EEI experiments in the General Electric Test Reactor (GETR).

Direct participation in the Halden Project in Norway with access to all Halden base program fuel test data.

Irradiation of special instrumented fuel rods to obtain dynamic in-reactor measurements in Halden experimental rigs.

Ramp test programs on fuel rods to evaluate fuel load-follow capabilities and the pellet clad interaction/stress corrosion phenomenon in both the Studsvik and Petten test reactors. Other in-reactor experiments have been conducted in the Obrigheim pressurized water reactor.

Irradiation of special test and surveillance assemblies in operating CE reactors.

e) CE Fuel Densification Experiments

CE has conducted several experiments which provided data on the in-reactor densification behavior of various UO_2 fuel types. These include the BRR, EEI, and MZFR densification experiments, as discussed below.

f) BRR Fuel Densification Experiment

The object of this program was to examine the in pile densification behavior of various fuel types and microstructures fabricated with and without pore formers. The non pore former fuel types had initial densities of 93 percent to 94 percent theoretical with a grain size of less than 6 microns with a large fraction of pores less than 4 microns in diameter. The pore former fuel types had initial densities of 93 percent to 95 percent and were characterized by a combination of large grain size and/or large pore size. Fuel pellets of each experimental type were irradiated in six BRR capsules at linear heat ratings between 2.8 and 4.6 kw/ft for periods of up to 1500 hours. Post-irradiation examination of the BRR results showed significant differences in the densification behavior between pore former and non-pore former fuel. The pore former fuel showed little change in density (high stability) while the non-pore former fuel densified rapidly. A trend towards increased densification with lower initial density was apparent in the non-pore former fuel. It was concluded that the UO_2 microstructure played a dominant role in the kinetics and extent of in reactor densification. Consequently, fuel exhibiting the desirable microstructural features to reduce in reactor densification (i.e., large fraction of the pore volume in the large pore size range) became part of the standard CE fuel design.

g) CE/KWU Fuel Densification Experiment (MZFR)

As a follow-on to the CE experiment in the BRR, a joint CE/KWU program has been conducted in the German MZFR to evaluate the performance of several non-densifying fuel types at higher power levels for longer times and to higher burnups.

Sixteen full length fuel rods each containing a different fuel type were irradiated at powers up to 11 kw/ft for burnups up to 4000 Mwd/Mtu. Included in these rods are UO_2 and UO_2-PuO_2 fuels most of which was fabricated using techniques intended to minimize densification. Six rods employed CE fabricated UO_2 fuels, five of which included pore former additives and one fabricated without a pore former to serve as a referencable control sample. Eight rods were fabricated using KWU experimental fuel representing a wide range of sintering times and temperatures, initial densities and enrichments. The remaining two rods were fabricated using UO_2-PuO_2 fuels of two different densities, with and without a pore former additive. Each of the fuel pellet types and fuel rods was extensively characterized prior to testing to permit comparison with similar post irradiation measurements.

The results of the post irradiation examination showed that fuel types fabricated with pore formers (similar to current production fuel) experienced significantly less in pile densification compared to those fabricated without pore formers. The data also support use of a standardized out of pile resintering test developed by CE to characterize expected in pile densification at the time of fabrication. This simulation test has been submitted to the NRC and approved for use by CE in LOCA calculations.

h) EEI Fuel Densification Experiment

The prime objective of the EEI Fuel Irradiation Test Program conducted in the General Electric Test Reactor (GETR) was to isolate and characterize the in reactor densification behavior of pore former (or stable) fuel types. CE and KWU were among eleven participants in the program.

This program entitled CE to obtain densification data on nine base program fuel pellet types with varying microstructures. An additional four fuel types were fabricated by CE and KWU. These included CE fuel types, two with and one without a pore former additive and a KWU standard production fuel. The pellets in the program were well characterized prior to irradiation. Four of the fuel types were irradiated in one pressurized (53 atmospheres) capsule. Two of the fuel types were also irradiated in a separate non-pressurized capsule (one atmosphere). Each of the capsules contained thermocouples to continuously monitor capsule power generation during irradiation to assure that the desired operating conditions were maintained. Post irradiation examination of these test capsules confirmed that UO_2 fuel with specific ranges of microstructural characteristics, such as produced by pore former additives, are stable with respect to densification. The largest in reactor density changes occurred for those types having a combination of the smallest pore size, the largest volume percent of porosity less than four microns in the smallest initial grain size and the lowest initial density.[60]

i) Halden Program Participation

The experimental facilities and programs of the OECD Halden Reactor Project in Norway represent one of the most advanced efforts in quantifying the effects and interaction of the various design parameters of Zircaloy clad fuel rods through measurements made in reactor. CE has been a member of the Project since 1973. CE reviews the data generated by the project in considerable detail and utilizes the results in various fuel development programs.

The Halden test reactor has unique capability for measuring fuel rod operation during irradiation. This capability has been utilized by CE with specific experiments to provide information in the following areas:

Fuel densification phenomenon including measurements of the rate of fuel column shortening as a function of the initial fuel density, power level and fuel fabrication process.

Fuel clad mechanical interaction involving studies of the effects of pellet design (shape and density) and operating parameters on cladding deformation.

Modeling of fuel rod behavior with emphasis on heat transfer characteristics.

The first three test assemblies sponsored jointly by CE and KWU contained 24 well-characterized fuel rods. These assemblies included the following range of design and operating parameters:

Helium fill pressures from 22 to 35 atmospheres.

Initial fuel densities from 91-96 percent TD.

Linear heat ratings to 15 kw/ft.

U_{235} enrichments from six to 12 percent; nine rods fabricated with mixed-oxide fuel.

The objectives of these tests were to determine the dynamic changes in fuel rod internal pressure, fuel centerline temperature and fuel stack length during operation as a function of burnup. Two of these assemblies (six test rods each) were discharged from the reactor after receiving a peak burnup of ~24,000 Mwd/Mtu. The third rig (12 rods) will be evaluated to burnups in the range of 35,000-40,000 Mwd/Mtu. The objectives of a fourth six-rod test assembly were to evaluate the effects of such design variables as pellet-clad gap, fill-gas composition, and linear heat rating (to 15 kw/ft) on heat transfer characteristics. This experiment also provided gap conductance data on UO_2 and mixed-oxide fuel. This test was discharged from the reactor after reaching a peak burnup of ~4000 Mwd/Mtu.

Instrumentation used to measure fuel behavior during irradiation includes centerline thermocouples, internal pressure transducers, linear variable differential transformers (LVDTs) for fuel column length changes and flux monitors for axial and radial power profiles.

Hot cell examination of the three discharged test assemblies is in progress. Fuel column length change data obtained supports data generated by the EEI, BRR, and MZFR experiments and confirms the in reactor stability of CE pore former fuel types. In addition, the internal pressure monitors and centerline thermocouple data have confirmed the adequacy of the CE thermal performance design models.

In addition, to these CE/KWU test assemblies, CE has designed and irradiated three rods in the Halden high temperature, high pressure loop to simulate PWR coolant temperature and pressure conditions. Irradiation of the third rod is still in progress to an expected burnup at discharge of approximately 4000 Mwd/Mtu. The purpose of these experiments is to distinguish the effects of pellet configuration on the formation of circumferential ridging and on the elongation of the rods. Each rod contained three pellet types with one type as a standard. This program in combination with the results of other experiments gives CE a firm basis upon which to optimize fuel rod design with respect to dimensional changes and to improve fuel performance models developed to predict rod dimensional stability.

j) Power Ramp Programs

CE and KWU are participating in the Studsvik and Pathfinder/Petten programs to evaluate fuel rod performance under ramp conditions to power levels not recently attained. These can occur either after refueling or after extended periods of low power operation or during control rod maneuvers. The effects of various fuel rod design variables on power ramp limits is also investigated as a means to further optimize design. The Petten/Pathfinder program which began in 1973 is being conducted jointly by CE and KWU in the Obrigheim PWR reactor and Petten test reactor facilities. One special test assembly has been irradiated each year since 1973 in the Obrigheim reactor. Included in this assembly, which is designed to facilitate fuel rod removal and replacement, are well-characterized segmented rods or "rodlets" which are axially connected to form a complete fuel rod. These rodlets are "pre irradiated" in the Obrigheim reactor for one, two, or three operating cycles, and then separated and irradiated in a test reactor to evaluate performance under ramp conditions. To date, approximately 500 rodlets have been irradiated in Obrigheim. Forty three of these rodlets have been discharged and ramped in Petten. An additional 24 rodlets are being supplied to the Studsvik Overramp project for ramp testing in the R-2 reactor at Studsvik. Ramp tests on eight of these rodlets have thus far been completed at Studsvik. Post-irradiation, hot cell examination programs form an integral part of both the Petten/Pathfinder and Studsvik experiments to characterize fuel rod behavior, particularly with respect to dimensional stability and fission product release. These test programs are designed to distinguish between fuel rod power ramps which occur on start-up and those which might occur during reactor power maneuvering operations.

Operating flexibility of a plant requires that the fuel rods maintain integrity during periodic changes in power. Power cycling tests of this type have been jointly conducted by CE/KWU in Obrigheim and Petten. In the Petten test, a single unpressurized fuel rod was power cycled between nine kw/ft and 17 kw/ft at a power change rate of about three kw/ft/min. The fuel rod successfully completed 400 cycles and achieved a burnup of 8000 Mwd/Mtu. Power cycling tests were then conducted in Obrigheim on eight short pressurized and unpressurized fuel rods. The test fuel rods were attached to a control rod drive mechanism and driven from the low power to a high power position on a nominal cycle. Power changes from 50 percent to 100 percent at rates of 20 percent per minute for 880 cycles were included. After successfully completing the experiment, the test rods achieved a peak burnup of 30,000 Mwd/Mtu without substantial cladding deformation or fuel rod perforation.

k) Fuel Surveillance Programs

CE has conducted a number of a fuel surveillance programs on fuel in operating plants. Thus far, a total of 16 poolside fuel inspection programs of varying detail have been performed by CE (see Table 4.2-4). Over 368 assemblies have been visually examined, and dimensional measurements have also been obtained on a large number of these assemblies. Fuel bundle disassembly operations have been conducted either to obtain information of particular aspects of performance of interest or as part of test assembly surveillance programs. The results of the CE poolside inspection program have been used to verify fuel assembly operation and provide data in support of design. A pre-irradiation characterization has been completed on CE's first 16 x 16 fuel for Arkansas Nuclear One, Unit 2. An examination of this fuel at the spent fuel pool will extend the design verification to the 16 x 16 design which will be used for St. Lucie Unit 2.

4.2.3 Design Evaluation

4.2.3.1 Fuel System Damage Evaluation

(a) Design Stress

Fuel Assembly

The ~~CEA~~ guide tubes ~~were~~ are evaluated for structural adequacy using the criteria given in Subsection 4.2.1.1 in the following areas:

a) Steady axial load due to the combined effects of axial hydraulic forces and upper end fitting holddown forces.

For normal operating conditions, the resultant guide tube stress levels are expected to be less than 50 percent of the two thirds yield stress criterion.

b) Short term axial load due to the impact of the spring loaded CEA spider against the upper guide structure support plates at the end of a CEA trip.

For trips occurring during normal power operation, solid impact is not predicted to occur due to the kinetic energy of the CEA being dissipated in the hydraulic buffer and by the CEA spring.

c) Short term differential pressure load occurring in the hydraulic buffer regions of the outer guide tubes at the end of each trip stroke.

The buffer region slows the CEA during the last few inches of the trip stroke. The resultant differential pressure across the guide tube in this region gives rise to circumferential stresses which are significantly less than the stress limits in Section 4.2.1.1.

The trip is assumed to be repeated daily. However the resultant stress is too small to have a significant effect on fatigue usage.

For conditions other than normal operation, the additional mechanical loads imposed on the fuel assembly by a Safe Shutdown Earthquake (SSE), operating basis earthquake (OBE) equivalent to one half SSE, and large break LOCA and their resultant effect on the control element guide tubes are discussed in the following subsections:

0 ~~4.2.3.1.2.1~~ Operating Basis Earthquake (OBE)

During the postulated OBE, the fuel assembly is subjected to lateral and axial accelerations which, in turn, cause the fuel assembly to deflect from its normal shape. The method of calculating these deflections is described in Subsection 3.7.3.14. The magnitude of the lateral deflections and resultant stresses are evaluated for acceptability. The method for calculating stresses from deflected shapes is described in Reference 50. The fuel assembly is designed to be capable of withstanding the axial loads without buckling and without sustaining excessive stresses.

0 ~~4.2.3.1.2.2~~ Safe Shutdown Earthquake (SSE)

The axial and lateral loads and deformation sustained by the fuel assembly during a postulated SSE have the same origin as those discussed above for the OBE, but they arise from initial ground accelerations twice those assumed for the OBE. The analytical methods used for the SSE are identical to those used for the OBE.

0 ~~4.2.3.1.2.3~~ Loss of Coolant Accident (LOCA)

In the event of a large break LOCA, there will occur rapid changes in pressure and flow within the reactor vessel. Associated with the transient are relatively large axial and lateral loads on the fuel assemblies. The response of a fuel assembly to the mechanical loads produced by a LOCA is considered acceptable if the fuel rods are maintained in a coolable array, i.e., acceptably low grid crushing. ~~The methods used for analysis of combined seismic and LOCA loads and stresses is described in Reference 50.~~ INSERT M

To qualify the complete fuel assembly, full scale hot loop testing was conducted. The tests were designed to evaluate fretting and wear of components, refueling procedures, fuel assembly uplift forces, holddown performance and compatibility of the fuel assembly with interfacing reactor internals, CEAs and CEDMs under conditions of reactor water chemistry, flow velocity, temperature, and pressure. The test assembly was a 16 x 16 five guide tube design. The test was run for approximately 2000 hours. The tests results demonstrated the acceptability of the design.

Mechanical testing of the 16x16 fuel assembly and its components is being performed to support analytical means of defining the assembly's structural characteristics. The test program consists of static and dynamic tests of spacer grids and static and vibratory tests of a full size 16x16 fuel assembly.

0 Seismic plus LOCA

It is not considered appropriate to combine the stresses resulting from the SSE and LOCA events. Nevertheless, for purposes of demonstrating margin in the design, the maximum stress intensities for each individual event will be combined by a square root of sum of the squares (SRSS) method. This will be performed as a function of fuel assembly elevation and position, e.g., the maximum stress intensities for the center guide tube at the upper grid elevation (as determined in the analysis discussed in the above paragraphs for SSE and LOCA will be combined by the SRSS method. It is expected that the results will demonstrate that the allowable stresse described in paragraph 4.2.1.1 are not exceeded for any position along the fuel assembly even under the added conservatism provided by this load combination

Insert M

As demonstrated in Reference 69, an additional safety factor on the LOCA impact loads due to a postulated pressure pulse associated with steam flashing is unnecessary. Therefore, it was not included in the analysis.

The function of the spacer grids is to provide lateral support to fuel and burnable poison rods in such a manner that the axial forces are not sufficient to buckle or bow the rods and that the wear resulting at the grid-to-clad contact points will be limited to acceptably small amounts. It is also a criterion that the grid be capable of withstanding the lateral loads imposed during the postulated seismic and LOCA events.

Fuel assemblies are designed such that the combination of fuel rod rigidity, grid spacing, and grid preload will not result in significant fuel rod deformation under axial loads, and the long-term effects of clad creep (reduction in clad OD), the reduction of grid stiffness with temperature and the partial relaxation of the grid material during operation ensure that this criterion is also satisfied during all operating conditions. Moreover, inspection of irradiated fuel assemblies from the Maine Yankee (14 x 14), Calvert Cliffs (14 x 14) Palisades (15 x 15) and Ft. Calhoun (14 x 14) reactors has not shown significant bowing of the fuel rods. In view of these factors and the similarity of these designs to the St Lucie Unit 2 (16 x 16) design, it is concluded that the axial forces applied by the grids on the cladding will not result in a significant degree of fuel rod bow. Fuel rod lateral deflection is discussed further in Subsection 4.2.3.1(f).

The capability of the grids to support the clad without excessive clad wear was demonstrated by out-of pile flow testing, as described above, on the standard 16 x 16 assembly design and by the results of post irradiation examination of grid-to-clad contact points in Maine Yankee fuel assemblies which showed only negligible clad wear (51).

The capability of the grid to withstand the lateral loads produced during the postulated seismic and LOCA events is demonstrated by impact testing the reference grid design, both at room temperature and at operating temperature, and comparing the test results with the analytical predictions of the seismic and LOCA loads.

The Zircaloy-4 spacer grid material is of the same composition as the fuel rods and guide tubes with which it is in contact, thereby obviating any problem of chemical incompatibility with those components. For the same reason, adequate resistance to corrosion from the coolant is assured (see Subsection 4.2.3.1(e) for additional information relative to the corrosion resistance of Zircaloy-4 in the reactor coolant environment).

The Inconel-625 material used for the lowest spacer grid is in contact with the coolant, the 304 stainless steel lower end fitting (to which it is welded), the Zircaloy-4 fuel rods, the poison rods, and the Zircaloy-4 guide tubes. The mutual chemical compatibility of these materials in a reactor environment has been demonstrated by CEs use of these materials in fuel assemblies that have been operated in other CE reactors and for which post irradiation examination has yielded no evidence of chemical reaction between these components. In addition, experiments have also been performed at CE on Inconel type alloys and Zircaloy-4 which showed that eutectic reactions did not occur below 2200 F, a temperature far in excess of that anticipated at the lower grid location in the event of a LOCA.

0 Handling and Shipping

Compliance with the shipping and handling design criteria in section 4.2.1.1 are as follows:

5g acceleration;

Impact recorders are included with each shipment which indicate if loading in excess of 5g are sustained. A record of shipping loads in excess of 5g indicates an unusual shipping occurrence in which case the fuel assembly is inspected for damage prior to releasing it for use.

The axial shipping load path is through either end fitting to the guide tubes. A 5g axial load produces a compressive stress level in the guide tubes less than the two thirds yield stress limit that is allowed for normal condition events. The fuel assembly is prevented from buckling by being clamped at grid locations. For lateral or vertical shipping loads, the grid spring tabs have an initial preload which exceeds five times the fuel rod weight. Therefore, the spring tabs see no additional deflection as a result of 5g lateral or vertical acceleration of the shipping container. In addition, the side load on the grid faces produced by a 5g lateral or vertical acceleration is less than the measured impact strength of the grids.

5000 pound axial load; inservice experience has shown that axial loads during shipping and handling are always less than the 5000 pound limit.

0.125 in. deflection;

Fuel handling procedures required the use of a strongback to limit the fuel assembly deflection to a maximum of 0.125 in. in any direction whenever the fuel assembly is raised or lowered to a horizontal position. This limits the stress and strain imposed upon the fuel assembly to values well below the limits set for normal operating conditions. The adequacy of the 0.125 in. criterion is based on the inclusion of this limitation in specifications and procedures for fuel handling equipment, which is thereby constrained to provide support such that lateral deflection is limited to 0.125 in.

Fuel Rod

A fuel rod cladding stress analysis is conducted to determine the circumferential stress and strain resulting from normal, upset, and emergency conditions. The analysis includes the calculation of cladding temperatures and rod internal pressures during each of the occurrences listed in Subsection 4.2.1. The design criteria to be used to evaluate the analytical results are specified in Subsections ~~4.2.1.2.1.~~ Fuel rod stresses resulting from seismic events are calculated, using the methodology described in Reference 50.

4.2.1.1(a) and 4.2.1.1(b).

Burnable Poison Rod

A poison shim cladding analysis will be performed to determine the stress and strain resulting from the various normal, upset, and emergency conditions discussed in Subsection 4.2.1.1. Specific accounting will be made for differential pressure, differential thermal expansion, cladding creep, and irradiation induced swelling of the $Al_2O_3B_4C$ burnable poison material. Owing to the very low linear heat generation rates in these rods (maximum local is less than 1.5 kW/ft), the stress analyses can be accomplished using conventional strength of materials formulae, except for determining clad collapse resistance which will be done using the CEPAN computer model[22].

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Control Element Assembly

The probability for a functional failure of the CEA is considered to be very small. This conclusion is based on the conservatism used in the design, the quality control procedures used during manufacturing and on testing of similar full-size CEA/CEDM combinations under simulated reactor conditions for lengths of travel and numbers of trips greater than that expected to occur during the design life. The consequences of CEA/CEDM functional failure are discussed in Chapter 15.

A postulated CEA failure mode is cladding failure. In the event that an element is assumed to partially fill with water under low or zero power conditions, the possibility exists that upon returning to power, the path of the water to the outside could be blocked. The expansion of the entrapped water could cause the element to swell. In tests, specimens of CEA cladding were filled with a spacer representing the poison material. All but nine percent of the remaining volume was filled with water. The sealed assembly was then subjected to a temperature of 650 F and an external pressure of 2250 lb/in.^{2} followed by a rapid removal of the external pressure. The resulting diametral increases of the cladding were on the order of 15 to 25 mils and were not sufficient to impair axial motion of the CEA, which has a 0.084 diametral clearance with the fuel assembly guide tubes. This test result, coupled with the low probability of a cladding failure leading to a waterlogged rod, demonstrates that the probability for a CEA functional failure from this cause is low.

Another possible consequence of failed cladding is the release of small quantities of CEA filler materials, and helium and lithium (from the neutron-boron reactions). However, the amounts which would be released are too small to have significant effects on coolant chemistry or rod worth.

(b) Cladding Design Strain

Fuel Rod

A fuel rod cladding stress analysis is conducted to determine the circumferential stress and strain resulting from normal, upset, and emergency conditions. The analysis includes the calculation of cladding temperatures and rod internal pressures during each of the occurrences listed in Subsection 4.2.1.. The design criteria to be used to evaluate the analytical results are specified in Subsections ~~4.2.1.2.1~~ 4.2.1.1(a) and 4.2.1.1(b). Fuel rod stresses resulting from seismic events are calculated using the methodology described in Reference 50.

Burnable Poison Rod

Poison rod strain for normal operation and anticipated operational occurrences is discussed under item (a) above.

The potential for waterlogging rupture in poison rods is much lower than that in fuel rods because of the smaller thermal and dimensional changes that occur in a poison rod during reactor power increases. Refer to Section 4.2.3.2f below for a discussion of the potential for waterlogging rupture in fuel rods.

Control Element Assembly

See item (a) in the above section, Design Stress.

(c) Strain Fatigue

/fatigue analysis is performed to determine the cumulative fatigue damage of fuel rods exposed to lieftime power cycling conditions. The fatigue cycle is determined by considering combinations of normally anticipated events that would produce conservative estimates of strain in the clad. Some of the major conservative assumptions are as follows:

- Hot spot fuel radii are used in the calculations.
- The most adverse tolerance conditions on the fuel and cladding dimensions are chosen to produce maximum interactions and hence maximum clad strains.

The chosen fatigue cycle represents daily operation at both full and reduced power. Clad strains are calculated from the primary creep rate of the clad and used to calculate the effective strain ranges. The cumulative fatigue damage fraction is determined by summing the ratios of the number of cycles at a given effective strain range to the permitted number at that range as taken from the fatigue curve presented on Figure 4.2-2.

The fatigue calculation method includes the effect of clad creep to reduce the pellet to clad diametral gap during that portion of operation when the pellet and clad are not in contact. The same model is used for predicting clad fatigue as is used for predicting clad strain. Therefore, the effects of creep and fatigue loadings are considered together in determining end of life clad strain. Moreover, the current fatigue damage calculation method includes a factor of two which is applied to the calculated strain before determining the allowable number of cycles associated with that strain. This, in combination with the allowable fatigue usage factor 0.8 ensures a considerable degree of conservatism (see Figure 4.2-2).

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(d) Fretting Wear

The phenomenon of fretting corrosion, particularly in Zircaloy clad fuel rods supported by Zircaloy spacer grids, has been extensively investigated.

Since irradiation induced stress relaxation causes a reduction in grid spring load, spacer grids must be designed for end of life conditions as well as beginning of life conditions to prevent fretting caused by flow induced tube vibrations.

Examination of Zircaloy clad fuel rods after three cycles of exposure at Ft. Calhoun, two cycles of exposure at Calvert Cliffs and one cycle of exposure at Millstone Point, Maine Yankee, and St Lucie Unit 1 have shown little fretting and no fuel cladding perforations from the fretting. Based on the combination of the ex-reactor tests and the in-reactor surveillance of the fuel in the ANO-2, plant, St Lucie Unit 2 is not expected to experience fretting behavior.

FURTHERMORE,

The capability of the St. Lucie 2 16 x 16 fuel assembly to sustain the effects of flow-induced vibration without adverse effects has been demonstrated in a dynamic flow test performed in CE's TF-2 flow test facility. The test utilized prototypical 16 x 16 reactor components consisting of a 16 x 16 type fuel assembly, a CEA shroud, control element drive mechanism, and a simulation of surrounding core internals support components and was performed under extreme flow and temperature conditions. The success of this test, similar previous tests of 16 x 16 fuel assemblies, and the operation of CE's ANO-2 plant, demonstrate that flow-induced vibration will have no adverse effects on the St. Lucie 2 fuel assemblies.

(e) Oxidation and Crud Buildup

Corrosion

Zircaloy-4 fuel rod tubing has been visually examined in the spent fuel pool after three reactor cycles at Ft. Calhoun, two reactor cycles at Calvert Cliffs, and reactor cycle at Millstone, St Lucie Unit 1 and Maine Yankee. In addition oxide thicknesses were measured in the hot cell after one cycle at Maine Yankee. In all instances the oxide appearance and oxide thickness measured similar to autoclave behavior for that time and temperature.

INSERT B

Four sources of periodic excitation are recognized in evaluating the fuel assembly susceptibility to vibration damage. These sources are as follows:

a) Reactor Coolant Pump Blade Passing Frequency

Precritical vibration monitoring on previous CE designed reactors indicates that peak pressure pulses are expected at the pump blade passing frequency (~~100~~ 74 Hz), and a lesser but still pronounced peak at twice this frequency.

b) Core Support Plate Motion

Experience with earlier CE designed reactors indicates that random lateral motion of the core support plate is expected to occur with an amplitude of 0.001 to 0.002 inch and a frequency range of between two and 10 Hz.

c) Flow Induced Fuel Assembly Vibration

Flow induced fuel assembly vibration resulting from coolant flow through the fuel assembly is expected to result in vibration amplitudes of 0.004 in. or less.

d) Flow Induced Control Element Vibration

The St Lucie Unit 2 reactor vessel internals and fuel assembly design incorporates design features that ensures that the vibration of CEAs is such as to produce no significant wear in the guide tubes.

Coolant chemistry parameters have been specified that minimize corrosion product release rates and their mobility in the Reactor Coolant System. Specifically, the precore hot functional environment is controlled (pH and oxygen) to provide a thin, tenacious, adherent, protective oxide film. This approach minimizes corrosion product release and associated inventory on initial startup and subsequent operation. During operation, the recommended lithium concentration range (0.2-1.0 ppm) effects a chemical potential gradient or driving force between hot and cooler surfaces (fuel cladding and steam generator tubing, respectively) such that soluble iron and nickel species will preferentially deposit on the steam generator surfaces. The associated pH also minimizes general corrosion product release rates from Reactor Coolant System surfaces. Moreover, the specified hydrogen concentrations range (10-50 cm^3/kg STP) insures reducing conditions in the core, thereby avoiding low solubility Fe^{3+}. Additionally, dissolved hydrogen promotes rapid recombination of oxidizing species. (Recall, oxidizing species and a fast neutron flux are synergistic prerequisites to accelerated Zircaloy-4 corrosion).

During operation lithium, dissolved oxygen, and dissolved hydrogen will be monitored at a frequency consistent with maintaining these parameters within their specifications.

Post-operational examinations of fuel cladding that has operated within these specifications, has shown no significant chemical or corrosive attack of the Zircaloy cladding.

Crud layers on zirconium oxide films are usually porous and non-insulating. As an example, heavy, but non-insulating crud layers have been found in Yankee Rowe (WCAP-3317-6094, Yankee Core Evaluation Program, Final Report, 1971). With porous crud, water is free to flow through the crud and provide heat transfer by convection. Under these conditions, crud enhanced corrosion should not occur.

Because of rigorous water chemistry monitoring, heavy buildup of crud has not occurred in CE reactors. Water chemistry monitoring is a continuous process and should ensure no dense crud buildup.

(f) Fuel Rod Bowing

The function of the spacer grids is to provide lateral support to fuel and burnable poison rods in such a manner that the axial forces are not sufficient to buckle or bow the rods.

Experience has proven that any specific criterion on allowable deflections (bowing), with respect to the effects which such deflections might have on thermal hydraulic performance, is not necessary beyond the initial fuel rod positioning requirements required of the grids. This variation in spacing is accounted for in thermal-hydraulic analysis through the introduction of hot channel factors in calculating the maximum enthalpy rise in calculating DNBR. This adjustment is called the pitch, bowing, and clad diameter enthalpy rise factor, which is conservatively applied to simulate a reduced flow area along the entire channel length. The value of this factor is given in Table 4.4-1 and its application is discussed in Section 4.4.

The subject of fuel rod bowing is discussed in Reference 53, which is under review by the NRC.

(g) Axial Growth

The function of the spacer grids is to provide lateral support to fuel and burnable poison rods in such a manner that the axial forces are not sufficient to buckle or bow the rods and that the wear resulting at the grid-to-clad contact points will be limited to acceptably small amounts. It is also a criterion that the grid be capable of withstanding the lateral loads imposed during the postulated seismic and LOCA events.

on Irradiation Stability of Fuel Rod Cladding

The combined effects of fast flux and cladding temperature are considered in three ways as discussed below:

- Cladding Creep Rate

  The in-pile creep performance of Zircaloy-4 is dependent upon both the local material temperature and the local fast neutron flux. The functional form of the dependencies is presented in Reference 14 for gap conductance calculations, and in Reference 22 for cladding collapse time predictions.

- Cladding Mechanical Properties

  The yield strength, ultimate strength, and ductility of Zircaloy-4 are dependent upon temperature and accumulated fast neutron fluence. The temperature and fluence dependence is discussed in Subsection 4.2.2.5(b) ~~4.2.1.2.3.1~~. Unirradiated properties were used depending upon which is more restrictive for the phenomenon being evaluated.

- Irradiation Induced Dimensional Changes

  Zircaloy-4 has been shown to sustain dimensional changes (in the unstressed condition) as a function of the accumulated fast fluence. These changes are considered in the appropriate clearances between the various core components. The irradiation induced growth correlation method is discussed in Reference 3.

  Zircaloy-4 fuel cladding has been utilized in pressurized water reactors at temperatures and burnups anticipated in current designs with no failures attributable to radiation damage. Mechanical property test on Zircaloy-4 cladding exposed to neutron irradiation of 4.7×10^{21} nvt (E>1 MeV) (estimated) have revealed that the cladding retains a significant amount of ductility (in excess of 4 percent elongation). Typical results are shown in Table 4.2-3. It is believed that the fluence of 4.7×10^{21} nvt (E>1 Mev) is at saturation so that continued exposure to irradiation will not change the [illegible].[54]

Zircaloy components of the fuel assembly are designed to allow for dimensional changes resulting from irradiation-induced growth. Extensive analyses of in pile growth data have been performed to formulate a comprehensive model of in pile growth [3]. The in pile growth equations are used to determine the minimum axial differential growth allowance which must be included in the axial gap between the fuel rods and the upper end fittings. For determining the necessary fuel rod growth allowance, the growth correlations for fuel rod and guide tube growth are combined statistically such that the minimum initial gap is adequate to accommodate the upper 95 percent confidence level of differential growth between fuel rods and guide tubes in the peak burnup fuel assembly. For the purpose of predicting axial and lateral growth of the fuel assembly structure (thereby establishing the minimum initial clearance with interfacing components), the equations are used in a conservative manner to ensure adequate margins to interference are maintained. The manner in which the in pile growth equations are described in Reference 65.

Fuel swelling due to irradiation (accumulation of solid and gaseous fission products) and thermal expansion results in an increase in the fuel pellet diameter. The design makes provision for accommodating both forms of pellet growth. The fuel clad diametral gap is more than sufficient to accommodate the thermal expansion of the fuel. To accommodate irradiation induced swelling, it is conservatively assumed that the fuel clad gap is used up by the thermal expansion and that only the fuel porosity and the dishes on each end of the pellets are available. Thermal and irradiation induced creep of the restrained fuel results in redistribution of fuel so that the swelling due to irradiation is accommodated by the free volume (8.2 percent of the fuel volume).

For such restrained pellets, and at a total fission product induced swelling rate of 0.7 percent $\Delta V/V$ per 10^{20} fiss/cm^3, 0.54 percent would be accommodated by the fuel porosity and dishes through fuel creep, and 0.16 percent would increase the fuel diameter. Assuming peak burnup, this would correspond to using up a void volume equal to ~ 7.4 percent of the fuel volume and increasing the fuel rod diameter by a maximum of < 0.0025 inch (<0.7 percent clad strain). When these numbers were compared to the minimum available volume and the maximum allowable strain, it was concluded that sufficient accommodation volume has been provided even under the most adverse burnup and tolerance conditions.

Demonstration of the margin which exists is seen in the large seed blanket reactor (LSBR) irradiation. Two rods which operated in the 3-4 loop of the MTR offer an interesting simulation for current PWR design [50] [7] [55]. both rods were comprised of 95 percent theoretical density pallets with dished ends and clad in Zircaloy. The first of these, No. 79-21, was operated successfully to a burnup of 12.41 x 10^{20} fiss/cm^3 (48,000 MWD/MTU). The second fuel pin, No. 79-25, operated successfully to 15.26 x 10^{20} fiss/cm^3 (60,000 MWD/MTU). The linear heat rating ranged from 7.1 to 16.0 kW/ft. The wall thickness for the latter pin was 0.028-inch as compared with 0.016 inch for the former. All other parameters were essentially identical. The two rods were assembled by shrinking the cladding onto the fuel. The maximum diametral increase measured at the ridge heights for rod 79-21 was 0.005 inch, while it was less than 0.002 inch for rod 79-25. From post-irradiation examination, it was concluded that approximately 84 percent of the total fuel swelling was accommodated [illegible] of the clad and ridging at pellet interfaces. These results indicate that a comparable irradiation of the fuel elements for the 16 x 16 fuel design (cold diametral gap 0.007 inch, wall thickness of 0.025 inch, density 94.75 percent TD) would allow adequate margin for swelling accommodation.

The successful combined VBWR-Dresden irradiation of Zircaloy-clad uranium dioxide pellets provides additional confidence with respect to the design conditions for the fuel rods for this core.[56][57] Ninety-eight rods which had been irradiated in VBWR to an average burnup of about 10,700 MWd/MTU were assembled in fuel bundles and irradiated in Dresden to a peak burnup greater than 48,000 MWd/MTU. The reported maximum heat rating for these rods is 17.3 kW/ft which occurred in VBWR. Post-irradiation examination[58] revealed that diametral increases in the fuel rods ranged from 0.001 to 0.003-inch maximum. The maximum diametral change corresponds to 1.42 percent $\Delta V/V$ (or 0.12 percent $\Delta V/V$ per 10^{20} fiss/cm^3) for these 0.424-inch diameter rods. The relevant fuel parameters are listed below:

	Fuel Density (% TD)	Cold Diametral Gap (in.)	Peak Burnup (MWd/MTU)
VBWR-Dresden	95	0.004 to 0.008	>48,000
LSBR-MTR	95	0.001	50,000; 61,000
C-E design	94.75	0.007	55,000

A comparison of the design parameters above, relative to the test results, provides a demonstration of the clad strains resulting from swelling of fuel.

A ~~Another~~ possible effect of plant transients on axial growth would be to cause an axial expansion of the pellet column against a flattened (collapsed) section of the clad. However, the fuel rod design includes specific provisions to prevent clad flattening, and, therefore, such interactions will not occur.

Fuel, ~~the~~ Poison Rod, and CEA Pressure.

Prepressurization

Fuel rods are initially pressurized with helium for two reasons:

a) Preclude clad collapse during the design life of the fuel. The internal pressurization, by reducing stresses from differential pressure, extends the time required to produce creep collapse beyond the required service life of the fuel.

b) Improve the thermal conductivity of the pellet to clad gap within the fuel rod. Helium has a higher coefficient of thermal conductivity than the gaseous fission products.

In unpressurized fuel, the initially good helium conductivity is eventually degraded through the addition of the fission product gases released from the pellets. The initial helium pressurization results in a high helium to fission products ratio over the design life of the fuel with a corresponding increase in the gap conductivity and heat transfer.

The initial helium fill pressure will be 360 $\pm$ 15 psig. This initial fill pressure will be sufficient to prevent clad collapse discussed in Subsection 4.2.3.~~1~~(g) and will produce a maximum EOL internal pressure consistent with the criteria of Subsection 4.2.1.~~3~~(h). The calculational methods employed to generate internal pressure histories are discussed in Reference 14.

2 Capacity for Fission Gas Inventory

The greater portion of the gaseous fission products remain either within the lattice or the microporosity of the UO_2 fuel pellets and do not contribute to the fuel rod internal pressure. However, a fraction of the fission gas is released from the pellets by diffusion and pore migration and thereafter contributes to the internal pressure.

The rod pressure increase which results from the release of a given quantity of gas from the fuel pellets depends upon the amount of open void volume available within the fuel rod and the temperatures associated with the various void volumes. In the fuel rod design, the void volumes considered in computing internal pressure are:

a) Fuel rod upper end plenum

b) Fuel clad annulus

c) Fuel pellet end dishes and chamfers

d) Fuel pellet open porosity

These volumes are not constant during the life of the fuel. The model used for computing the available volume as a function of burnup and power level accounts for the effects of fuel and clad thermal expansion, fuel pellet densification, clad creep, clad growth and irradiation induced swelling of the fuel pellets.

3 Fuel Rod Plenum Design

The fuel rod upper end plenum is required to serve the following functions:

a) Provide space for axial thermal expansion and burnup swelling of the pellet column.

b) Contain the pellet column holddown spring.

c) Act as a plenum region to ensure an acceptable range of fuel rod internal pressure.

Of these functions, listing C is expected to be the most limiting constraint on plenum length selection, since the range of temperatures in the fuel rod, together with the effects of swelling, thermal expansion, and fission gas release can, produce a wide range of internal pressure during the life of the fuel. The fuel rod plenum pressure will be consistent with the pressurization and clad collapse criteria specified in Subsection 4.2.1.1(h). INSERT BB

4 Outline of Procedure Used To Size The Fuel Rod Plenum

a) A parameteric study of the effects of plenum length on maximum and minimum rod internal pressure is performed. Because the criteria pertaining to maximum and minimum rod internal pressure differ, the study is divided into two sections:

1) Maximum Internal Pressure Calculation

Maximum fuel rod pressure is limited by the stress criteria. Maximum end of life pressure is determined for each plenum length by including the fission gas released, selecting conservative values for components dimensions and properties, and accounting for burnup effects on component dimensions. The primary cladding stress produced by each maximum pressure is then compared to the stress limits to find the margin available with each plenum length. Stress limits are listed in Subsection 4.2.1.1(b).

INSERT AA

2) Minimum Internal Pressure/Collapse Calculation

Minimum fuel rod pressure is limited by the criterion that no rod will be subject to collapse during the design lifetime. The minimum pressure history for each plenum length is determined by neglecting fission gas release, selecting a conser-

INSERT AA

The effect of helium prepressurization on fission gas release is not considered to be directly due to the gas pressure. The important effects of prepressurization on fission gas release are the improvement in gap gas conductivity and gap conductance and the desensitization of gap conductance to gas release rates. Fuel rods with low helium prepressurization are much more responsive to even small increases in fission gas releases at high burnup. Gap conductance, in such rods significantly decreases, leading to significant increases in fuel temperature which lead to ever increasing fission gas release. This effect is well documented by Reference (1). High prepressurization with helium greatly reduces this feedback effect, and therefore, significantly changes the response of the rod. It must be concluded that an empirical burnup enhancement would be considerably different for low and high helium prepressurizations.

C-E is actively seeking and examining sources of gas release data at burnups greater than 20000 MWd/MtU, for use in determining validity or extent of burnup enhanced fission gas release.

Although C-E believes the method to be inappropriate, the maximum calculated EOL peak internal fuel rod pressure has been redone using the NRC burnup enhancement factor. Tolerances were biased to maximize internal pressure. Under these conditions the maximum EOL internal pressure is calculated to be less than the nominal primary system pressure.

INSERT BB

It is not a formal criterion that fuel rod internal pressure be less than the primary coolant pressure because no adverse effect has been identified which has, as its threshold, the occurrence of a net internal pressure acting on the cladding. However, the design of the fuel rod is such that the internal pressures produced during normal operation are expected to remain below the primary coolant pressure for the design life of the fuel.

vative combination of component dimensions and properties, and accounting for dimension changes during irradiation, including the effects of cladding creep, cladding growth, pellet densification, pellet swelling, and thermal expansion. Each minimum pressure history is input to the cladding collapse model[22] to establish the acceptability of the associated plenum length.

b) For each plenum length, there is a resultant range of acceptable initial fill pressures. The optimum plenum length is generally considered to be the shortest which satisfies all criteria related to maximum and minimum rod internal pressure including a range sufficient to accommodate a reasonable manufacturing tolerance on initial fill pressure.

c) Additional information on those factors which have a bearing on determination of the plenum length are discussed below:

1) Creep and dimensional stability of the fuel rod assembly influence the fission gas release model and internal pressure calculations, and are accounted for in the procedure of sizing the fuel rod plenum length. Creep in the cladding is accounted for in a change in clad inside diameter, which in turn influences the fuel/clad gap. The gap change varies the gap conductance in the FATES computer code[14] with resulting change in annulus temperature, internal pressure, and fission gas release. In addition, the change in clad inside diameter causes a change in the internal volume, with its resulting effect on temperature and pressure. Dimensional stability considerations affect the internal volume of the fuel rod, causing changes in internal pressure and temperature. Fuel pellet densification reduces the stack height and pellet diameter. Irradiation induced radial and axial swelling of the fuel pellets decreases the internal volume within the fuel rod. In pile growth of the fuel rod cladding contributes to the internal volume. Axial and radial elastic deformation calculations for the cladding are based on the differential pressure the cladding is exposed to, resulting in internal volume changes. Thermal relocation, as well as differential thermal expansion of the fuel rod materials also affect the internal volume of the fuel rods.

2) The maximum expected fission gas release in the peak power rod is calculated using the FATES computer code. Rod power history input to the code is consistent with the design limit peak linear heat rate set by LOCA considerations, and therefore the gas release used to size the plenum represents an upper limit. Because of time varying gap conductance, fuel temperature and depletion, and expected fuel management, the release rate varies as a function of burnup.

A fuel rod cladding stress analysis is conducted to determine the circumferential stress and strain resulting from normal, upset, and emergency conditions. The analysis includes the calculation of cladding temperatures and rod internal pressures during each of the occurrences listed in Subsection 4.2.1. The design criteria to be used to evaluate the analytical results are specified in Subsections ~~4.2.1.2.1~~. Fuel rod stresses resulting from seismic events are calculated, using the methodology described in Reference 50.

4.2.1.1(a) and 4.2.1.1(b).

Fuel rod thermal transient effects are basically manifested as the change in internal pressure, the changes in clad thermal gradient and thermal stresses, and the differential thermal expansion between pellets and clad.

Burnable Poison Rod: Pressure

poison rods

Experimental measurements reveal that less than five percent of the helium formed during irradiation will be released.[35] These measurements were performed on Al_2O_3-B_4C pellets irradiated at temperatures to 500 F and, subsequently, annealed at 1000 F for five days. The helium release in a burnable poison rod which operated for one cycle in a CE PWR was calculated from internal pressure measurements to be less than five percent. The design is based on a release of three to 15 percent of the helium generated. The design of the burnable poison rod will not be limited by helium pressure despite the conservative use of 15 percent release.

A poison shim cladding analysis will be performed to determine the stress and strain resulting from the various normal, upset, and emergency conditions discussed in Subsection 4.2.1. Specific accounting will be made for differential pressure, differential thermal expansion, cladding creep, and irradiation induced swelling of the $Al_2O_3B_4C$ burnable poison material. Owing to the very low linear heat generation rates in these rods (maximum local is less than 1.5 kW/ft), the stress analyses can be accomplished using conventional strength of materials formulae, except for determining clad collapse resistance which will be done using the CEPAN computer model[22].

Control Element Assembly Pressure

The CEAs are designed for a ten year lifetime based on estimates of neutron absorber burnup, allowable plastic strain of the Inconel 625 cladding and the resultant dimensional clearances of the elements within the fuel assembly guide tubes.

The value of internal pressure in the control elements is dependent on the following parameters:

1) Initial fill gas pressure

2) Gas temperature

3) Helium generated and released

4) Available volume including B_4C porosity

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Of the absorber materials utilized in the CEA design, only the B_4C contributes to the total quantity of gas which must be accommodated within the control element. The helium is produced by the nuclear reaction ${}_0n^1 + {}_5B^{10} \rightarrow {}_3Li^7 + {}_2He^4$, and the fraction of the quantity generated which is actually released to the plenum is temperature dependent.

INSERT FF

INSERT FF

The release of helium from the B_4C pellets is understood to be principally dependent on diffusion, as indicated by the strong temperature dependence in the equation used to calculate release fraction for St Lucie Unit 2:

$$\% \text{ released} = 208e^{-1820/T} + 5$$

Calculation of helium release from B_4C pellets is based on the maximum temperatures predicted for normal operation. While it is true that several of the anticipated operational occurrences (AOO's) produce heat generation rates (in those CEA's which remain inserted) greater than the maximum predicted for normal operation, such overpower conditions never persist for more than about 60 seconds and would not be expected to raise the pellet temperature by more than about 200 fahrenheit degrees. Temperature excursions of this magnitude and duration would not be expected to influence a diffusion controlled helium release mechanism to any appreciable extent and so are not included in the design basis for CEA internal pressure calculations.

With respect to transients which could lead to CEA plenum temperatures in excess of 1000F, there are none. The CEA plenum is always located above the active core region, and the temperature of the gas therein is principally dependent on the temperature of the surrounding coolant and gamma heating of the plenum spring. Since none of the AOO's produces substantial increases in either the gamma heating rate in the plenum or the local coolant temperature, it is not expected that the plenum temperature would increase significantly above the normal operation range of 600F to 700F.

(i) Assembly Liftoff

The analysis and testing for fuel assembly liftoff is reported in detail in Section 4.4.4.2.2. The core flow rate for St. Lucie Unit 2 is less than that which would cause assembly liftoff.

Control Material Leaching

4 ~~Another~~ possible consequence of failed CEA cladding is the release of small quantities of CEA filler materials, and helium and lithium (from the neutron-boron reactions). However, the amounts which would be released are too small to have significant effects on coolant chemistry or rod worth.

The probability for a functional failure of the CEA is considered to be very small. This conclusion is based on the conservatism used in the design, the quality control procedures used during manufacturing and on testing of similar full-size CEA/CEDM combinations under simulated reactor conditions for lengths of travel and numbers of trips greater than that expected to occur during the design life. The consequences of CEA/CEDM functional failure are discussed in Chapter 15.

A postulated CEA failure mode is cladding failure. In the event that an element is assumed to partially fill with water under low or zero power conditions, the possibility exists that upon returning to power, the path of the water to the outside could be blocked. The expansion of the entrapped water could cause the element to swell. In tests, specimens of CEA cladding were filled with a spacer representing the poison material. All but nine percent of the remaining volume was filled with water. The sealed assembly was then subjected to a temperature of 650 F and an external pressure of 2250 $lb/in.^2$ followed by a rapid removal of the external pressure. The resulting diametral increases of the cladding were on the order of 15 to 25 mils and were not sufficient to impair axial motion of the CEA, which has a 0.084 diametral clearance with the fuel assembly guide tubes. This test result, coupled with the low probability of a cladding failure leading to a waterlogged rod, demonstrates that the probability for a CEA functional failure from this cause is low.

Should irradiated B_4C particles be exposed to reactor coolant, the primary corrosion products that would be formed are boric acid (which is soluble in water), hydrogen, free carbon and a small amount of lithium compounds. The presence of these products in the reactor coolant would not be detrimental to the operation of the plant.

Observations of Al_2O_3/B_4C poison shims have revealed that long term exposure of this material to reactor coolant can result in gradual leaking out of Boron and eventual eroding away of the Al_2O_3 matrix. However, the rate of reaction is such that any resultant changes in reactivity are very gradual.

(k) Cladding Overheating

Cladding overheating is avoided for normal operation and anticipated operational occurrences by specification of NSSS design requirements, operational limitations (technical specifications), fuel design bases, and the SAFDL on DNBR.

The methodology for prediction of DNBR is discussed in detail in FSAR Sections 4.4.2.2-4.4.2.10. DNBR analysis and evaluation is described in Section 4.4.4. For anticipated operational occurrences the analysis in Chapter 15 shows that the DNBR SAFDL is met. For accidents, it is not a requirement that the DNBR SAFDL be met since it is assumed that the cladding fails if DNB occurs (see 4.2.1.1,k and since a small amount of fuel failures is acceptable as long as radiological dose and core coolability criteria are met.

(e) Fuel Overheating

Steady state fuel temperatures are determined by the FATES computer program. The calculational procedure considers the effect of linear heat rate, fuel relocation, fuel swelling, densification, thermal expansion, fission gas release, and clad deformations. The model for predicting fuel thermal performance is discussed in detail in Reference 14.

Two sets of burnup and axially dependent linear heat rate distributions are considered in the calculation. One is the hot rod, time averaged, distribution expected to persist during long term operation, and the other is the envelope of the maximum linear heat rate at each axial location. The long term distributions are integrated over selected time periods to determine burnup, which is in turn used for the various burnup dependent behavioral models in the FATES computer program. The envelope accounts for possible variations in the peak linear heat rate at any elevation which may occur for short periods of time and is used exclusively for fission gas release calculations.

The power history used assumes continuous 100 percent reactor power from beginning of life. Using this history, the highest fuel temperatures occur at beginning of life. It has been shown that fuel temperatures for a given power level at any burnup are insensitive to the previous history used to arrive at the given power level.

Fuel thermal performance parameters are calculated for the hot rod. These parameters for any other rod in the core can be obtained by using the axial location in the hot rod, whose local power and burnup corresponds to the local power and burnup in the rod being examined. This procedure will yield conservatively high stored energy in the fuel rod under consideration.

Fuel overheating is avoided for normal operation and anticipated operational occurrences by specification of NSSS design requirements, operational limitations, fuel design bases, and the SAFDL on fuel temperature.

At all times it is intended that the power distribution be controlled (by design and use of technical specifications) such that fuel overheating does not occur and the fuel temperature SAFDL is not violated. Control of the power distribution is discussed in detail in Section 4.3.2.2.

The normal-operation fuel temperature is 2986 °F (Table 4.4-1).

The analysis of anticipated operational occurrences is described in Chapter 15. Results show that fuel melting does not occur for any anticipated operational occurrence (i.e., the SAFDL is not violated).

The analysis of Chapter 15 also shows that the fuel temperature SAFDL is met for most accidents even though it is not required that this SAFDL be met for accidents. The CEA Ejection event (15.4.5) does show that some fuel melting occurs; however, radiological doses are well within limits.

4.2.3.2 Fuel Rod Failure Evaluation

(a) Hydriding

<u>Internal</u>

Failure due to internal hydriding is avoided by controlling the moisture content of the fuel during manufacture of the fuel pellets (see Section 4.2.1.2, item (a)).

<u>External</u>

Failure due to external hydriding is not expected dur to the low amount of hydrogen absorbed by the cladding (see Section 4.2.1.2, item (a)).

6) Cladding Collapse

A cladding collapse analyis is performed to ensure to ensure that no fuel rod in the core will collapse during its design lifetime. The clad calculation method[21] itself does not include arbitrary safety factors. However, the calculation inputs will be deliberately selected to produce a conservative result. For example, the clad dimensional data are chosen to be worst case combinations based either upon drawing tolerances or 95 percent confidence limits on as built dimensions; the internal pressure history is based on minimum fill pressure with no assistance from released fission gas; and the flux and temperature histories are based on conservative assumptions.

(c) Overheating of Cladding

As discussed above in Section 4.2.3.1k, cladding overheating is avoided for normal operation and anticipated operational occurrences. The analyses in Chapter 15 accounts for cladding overheating during accidents by conservatively assuming a breach of the cladding if DNB occurs. The ECCS analysis in FSAR Section 6.3.3 shows that cladding temperatures are acceptable ($<2200^{o}F$) for LOCAs.

(d) Overheating of Fuel Pellets

As discussed above in Section 4.2.3.1X, fuel overheating is avoided for normal operation and anticipated operational occurrences. The analysis of Chapter 15 also shows that the fuel temperature SAFDL is met for most accidents (i.e., fuel melting does not occur). The CEA Ejection in 15.4.5 does show a small amount (0.05%) of centerline fuel melting; however, radiological doses are well within limits.

(e) Pellet-Cladding Interaction

An in depth post irradiation examination has been conducted wherein fuel cladding chemical reactions were among those items studied. This study concluded that early unpressurized elements containing unstable fuel were more susceptible to stress corrosion attack than are the current design that utilizes stable fuel and pressurized cladding. By carefully monitoring the reactor coolant activity of operating reactors, it has been concluded that the current fuel designs are not susceptible to stress corrosion (or other types of corrosion) during normal plant operation. Since stress corrosion attack is the result of a combination of stresses imposed by the fuel on the cladding and the corrosive chemical species available to the cladding, irradiation programs are being pursued to define the conditions under which pellet clad interaction will damage the cladding. These programs are currently underway both at Halden and in the Pathfinder test program being conducted jointly with KWU in the Obrigheim and Petten reactors.

CE and KWU are participating in the Studsvik and Pathfinder/Petten programs to evaluate fuel rod performance under ramp conditions to power levels not recently attained. These can occur either after refueling or after extended periods of low power operation or during control rod maneuvers. The effects of various fuel rod design variables on power ramp limits is also investigated as a means to further optimize design. The Petten/Pathfinder program which began in 1973 is being conducted jointly by CE and KWU in the Obrigheim PWR reactor and Petten test reactor facilities. One special test assembly has been irradiated each year since 1973 in the Obrigheim reactor. Included in this assembly, which is designed to facilitate fuel rod removal and replacement, are well-characterized segmented rods or "rodlets" which are axially connected to form a complete fuel rod. These rodlets are "pre irradiated" in the Obrigheim reactor for one, two, or three operating cycles, and then separated and irradiated in a test reactor to evaluate performance under ramp conditions. To date, approximately 500 rodlets have been irradiated in Obrigheim. Forty three of these rodlets have been discharged and ramped in Petten. An additional 24 rodlets are being supplied to the Studsvik Overramp project for ramp testing in the R-2 reactor at Studsvik. Ramp tests on eight of these rodlets have thus far been completed at Studsvik. Post-irradiation, hot cell examination programs form an integral part of both the Petten/Pathfinder and Studsvik experiments to characterize fuel rod behavior, particularly with respect to dimensional stability and fission product release. These test programs are designed to distinguish between fuel rod power ramps which occur on start-up and those which might occur during reactor power maneuvering operations.

Operating flexibility of a plant requires that the fuel rods maintain integrity during periodic changes in power. Power cycling tests of this type have been jointly conducted by CE/KWU in Obrigheim and Petten. In the Petten test, a single unpressurized fuel rod was power cycled between nine kw/ft and 17 kw/ft at a power change rate of about three kw/ft/min. The fuel rod successfully completed 400 cycles and achieved a burnup of 8000 Mwd/Mtu. Power cycling tests were then conducted in Obrigheim on eight short

pressurized and unpressurized fuel rods. The test fuel rods were attached to a control rod drive mechanism and driven from the low power to a high power position on a nominal cycle. Power changes from 50 percent to 100 percent at rates of 20 percent per minute for 880 cycles were included. After successfully completing the experiment, the test rods achieved a peak burnup of 30,000 Mwd/Mtu without substantial cladding deformation or fuel rod perforation.

An analytical model to evaluate cladding response to pellet-clad interaction has been developed[68]. This analysis which is based on an advanced version of the FATES computer code, considers generalized plane-strain of a unit section of fuel and clad. All of the physical phenomena calculation methods and input variables of the present FATES program(14) are included in the new version; and in addition, models are included for elastic and plastic stresses and strains in the clad and fuel, and fuel creep. A compatible interface modeled between the fuel and clad ensures that interaction is accurately accounted for.

The treatment of power history, axial power shapes and other operating parameters is handled similar to the current FATES version with the exception that power ramp rates and cycling can be considered. The response of the fuel and clad is calculated through an iteractive process, and the interaction between the fuel and clad is established.

The resulting analytical predictions of temperatures, stresses, strains and geometric configuration are thus made available for use in conjunction with operating experience and irradiation test results in demonstrating the acceptability of the various operating conditions to which the fuel may be subjected. A detailed discussion of the methods and capabilities of the pellet-clad interaction model ~~is~~ contained in Reference 68.

and results of parametric analyses are

Analysis described above in section 4.2.3.1 for cladding strain and fuel overheating show that the criteria minimizing the probability of pellet-cladding failure are met.

(f) Cladding Rupture

The ECCS analysis of section 6.3.3 describes the analysis models and numerical results. Supplementary calculations using the models of NUREG-0630 are being performed. It is expected that results using the NUREG-0630 models will be equivalent to those presently reported in section 6.3.3.

The potential for waterlogging rupture is considered remote. Basically, the necessary factors, or combination of factors, include the presence of a small opening in the cladding, time to permit filling of the fuel rod with water, and finally, a rapid power transient. The size of the opening necessary to cause a problem falls within a fairly narrow band. Above a certain defect size, the rod can fill rapidly, but during a power increase it also expels water or steam readily without a large pressure buildup. Defects which could result in an opening in cladding are scrupulously checked for during the fuel rod manufacturing process by both ultrasonic and helium leak testing. Clad defects which could develop during reactor operation due to hydriding are also controlled by limiting those factors (e.g., hydrogen content of fuel pellets) which contribute to hydriding.

The most likely time for a waterlogging rupture incident would be after an abnormally long shutdown period. After this time, however, the startup rate is controlled so that even if a fuel rod were filled with coolant, it would "bake out", thus minimizing the possibility of additional cladding rupture. The combination of control and inspection during the manufacturing process and the limits on the rate of power change restrict the potential for waterlogging rupture to a very small number of fuel rods.

The UO_2 fuel pellets are highly resistant to attack by reactor coolant in the event cladding defects should occur. Extensive experimental work and operating experience have shown that the design parameters chosen conservatively account for changes in thermal performance during operation and that coolant activity buildup resulting from cladding rupture is limited by the ability of uranium dioxide to retain solid and gaseous fission products.

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In the event that a fuel rod does become waterlogged at low or zero power, it is possible that a subsequent power increase could cause a buildup of hydrostatic pressure. It is unlikely that the pressure would build up to a level that could cause cladding rupture because a fuel pin with the potential for rupture requires the combination of a very small defect together with a long period of operation at low or zero power.

Tests which have been conducted using intentionally waterlogged fuel pins (capsule drive core at SPERT)[61][62] showed that the resulting failures did eject some fuel material from the rod and greatly deformed the test specimens. However, these test rods were completely sealed, and the transient rates used were several orders of magnitude greater than those allowed in normal operation.

In those instances where waterlogged fuel rods have been observed in commercial reactors, it has not been clear that waterlogging was the cause, and not just the result, of associated cladding failures; and CE has not observed and is not aware of any case in which material was expelled from waterlogged fuel rods or in which the fuel cladding was significantly deformed in a normal power reactor.

It is therefore concluded that the effect of normal power transients on waterlogged fuel rods is not likely to result in cladding rupture and even if rupture does occur it will not produce the sort of postulated burst failures which would expel fuel material or damage adjacent fuel rods or fuel assembly structural components.

4.2.3.3 Fuel Coolability Criteria

(a) INSERT E

(b) Violent Expulsion of Fuel Material

The CEA Ejection analysis of Section 15.4.5 shows that, for all cases, the 280 cal/gm limit is met. The mathematical model and analytical results are presented in Section 15.4.5.1.3.

Insert E

(a) Fragmentation of Embrittled Cladding

The analysis of Section 6.3.3 shows that the 2200°F cladding temperature and 17% cladding oxidation criteria are met for all cases.

(c) Cladding Ballooning and Flow Blockage

The ECCS analysis (presented in detail in section 6.3.3) shows that acceptable results are predicted. Analyses using the models of NUREG-0630 are being performed and will be reported when complete (see the response to question 490.1). Based on analysis of similar reactor cores with similar operating conditions, it is expected that the results with the NUREG-0630 models will be equivalent to those presently reported in section 6.3.3

An experimental and analytical program was conducted to determine the effects of fuel assembly coolant flow maldistribution during normal reactor operation. In the experimental phase, velocity and static pressure measurements were made in cold, flowing water in an oversize model of a CE 14 x 14 fuel assembly in order to determine the three-dimensional flow distributions in the vicinity of several types of flow obstruction. The effects of the distributions on thermal behavior were evaluated, where necessary, with the use of a preliminary version of the TORC thermal and hydraulic code.(63) Subjects investigated included:

a) The assembly inlet flow maldistribution caused by blockage of a core support plate flow hole. Evaluation of the flow recovery data indicated that even the complete blockage of a core support plate flow hole would not produce a W-3 DNBR of less than 1.0 even though the reactor might be operating at a power sufficient to produce a DNBR of 1.3 without the blockage.

b) The flow maldistribution within the assembly caused by complete blockage of one to nine channels. Flow distributions were measured at positions upstream and downstream of a blockage of one to nine channels. The influence of the blockage diminished very rapidly in the upstream direction. Analysis of the data for a single channel blockage indicated that such a blockage would not produce a W-3 DNBR of less than 1.0 downstream of the blockage even though the reactor might be operating at a power sufficient to produce a DNBR of 1.3 without the blockage.

The results presented above were obtained through flow testing an oversize model of a standard 14 x 14 fuel assembly. Because of the great similarity in design between 16 x 16 assembly, and the earlier 14 x 14 array, these test results also constitute an adequate demonstration of the effects that flow blockage would have on the 16 x 16 assembly. This conclusion is also supported by the fact that the 16 x 16 assembly has been demonstrated to have a greater resistance to axial flow than would occur with the 14 x 14 array. The effect of the higher flow resistance to produce more rapid flow recovery, i.e., more nearly uniform flow, is analogous to the common use of flow resistance devices (screens or perforated plates) to smooth non-uniform velocity profiles in ducts or process equipment.

(d) Structural Damage From External Forces

The analysis showing that the fuel assembly can withstand the assumed structural forces will be presented in Section 4.2.3.1a.

4.2.4 Testing, Inspection and Surveillance Plans

4.2.4.1 Testing and Inspection of New Fuel

Vendor product certifications, process surveillance, inspections, tests, and material check analyses are performed to ensure conformity of all fuel assembly and control element assembly components to the design requirements from material procurement through receiving inspection at the plant site. The following are basic quality assurance measures which are performed.

(a) ~~4.2.4.1~~ Fuel Assembly

A comprehensive quality control plan is established to ensure that dimensional requirements of the drawings are met. In those cases where a large number of measurements are required and 100 percent inspection is impractical, these plans provide a high statistical confidence that these dimensions are within tolerance. Sensitivity and accuracy of all measuring devices are within ± 10 percent of the dimensioned tolerance. The basic quality assurance measures which are performed in addition to dimensional inspections and material verifications are described in the following sections.

~~4.2.4~~.1.1 Weld Quality Assurance Measures

The welded joints used in the fuel assembly design are listed below in a series of paragraphs which describe the type and function of each weld, and include a brief description of the testing (both destructive and non-destructive) performed to ensure the structural integrity of the joints. The welds are listed from top to bottom in the fuel assembly.

The CEA guide tube joints (between the tube and threaded upper and lower ends) are butt welds between the two Zircaloy subcomponents. The welds are required to be full penetration welds and must not cause violation of dimensional or corrosion resistance standards.

The upper end fitting center guide post to lower cast flow plate joint has a threaded connection which is prevented from unthreading by tack welding the center guide post to the bottom of the lower cast plate using the gas tungsten arc (GTA) process. Each weld is inspected for compliance with a visual standard.

The spacer grid welds at the intersection of perpendicular Zircaloy-4 grid strips are made by the GTA process. Each intersection is welded top and bottom, and each weld is inspected by comparison with a visual standard.

For the spacer grid to CEA guide tube weld (both components Zircaloy-4), each grid is welded to each guide tube with eight small welds, evenly divided between the upper and lower faces of the grid. Each weld is required to be free of cracks and burnthrough and each weld is inspected by comparison to a visual standard. Also, sufficient testing of sample welds is required to establish acceptable corrosion resistance of the weld region. Each guide tube is inspected after welding to show that welding has not affected clearance for CEA motion.

The lower spacer grid welds at spacer strip intersections and between spacer and perimeter strips (all components Inconel 625) have the same configuration as for the Zircaloy and are all inspected for compliance with appropriate visual standards.

The lower spacer grid (Inconel) to Inconel skirt weld is made using the GTA process. Each weld is inspected to ensure compliance with a visual standard.

The Inconel skirt to lower end fitting (304 stainless steel) weld is made using the GTA process and each weld is inspected to ensure compliance with a visual standard.

The lower end fitting is fastened to the Zircaloy guide tubes using threaded connections. The connections are prevented from unthreading by stainless steel locking rings which are welded to the lower end fitting. Each ring is tack welded to the end fitting in four places using the GTA process, and each weld is inspected for compliance with a visual standard.

The inspection requirements and acceptance standards for each of the welds are established on the basis of providing adequate assurance that the connections will perform their required functions.

~~4.2.4.1~~.2 Other Quality Assurance Measures

All guide tubes are internally gaged ensuring free passage within the tubes including the reduced diameter buffer region.

Each upper end fitting post to guide tube joint is inspected for compliance with a visible standard.

The spacer grid to fuel rod relationship is carefully examined at each grid location.

An alpha smear test is performed on the exterior surface of the fuel rods.

Each completed fuel assembly is inspected for cleanliness, wrapped to preserve its cleanliness and loaded within shipping containers which are later purged and filled with dry air.

Visual inspection of the conveyance vehicle, shipping container, and fuel assembly are performed at the reactor site. Approved procedures are provided for unloading the fuel assemblies. Following unloading, exterior portions of the fuel assembly components are inspected for shipping damage and cleanliness. If damage is detected, the assembly may be repaired on-site or returned to the manufacturing facility for repair. In the event the repair process were other than one normally used by the manufacturing facility, or that the repaired assembly did not meet the standard requirements for new fuel, the specific process or assembly would be reviewed before the process or assembly would be accepted.

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(b) ~~4.2.4.2~~ Fuel Rod

~~4.2.4.2~~.1 Fuel Pellets

During the conversion of UF_6 to ceramic grade uranium dioxide power, the UO_2 power is divided into lots blended to form uniform isotopic, chemical, and physical characteristics. Two containers are selected from the total number of containers in each lot for certification sampling. Samples are removed from each of the two selected containers and subdivided to verify specification limits (Subsection ~~4.2.1.2.4~~) 4.2.2.5(b).

Pellets are divided into lots during fabrication with all pellets within the lot being processed under the same conditions. Representative samples are obtained from each lot for product acceptance tests. Total hydrogen content of finished ground pellets is restricted (Subsection ~~4.2.1.2.4.1~~) 4.2.2.5(b).

The pellet diameters are 100 percent inspected; all other pellet dimensions meet a 90/90 confidence level. Density requirements of the sintered pellet, Subsection 4.2.2.5(b), must meet a 95/95 confidence level. Longitudinal sections of two sample pellets from each pellet lot are prepared for metallographic examination to ensure conformance to microstructure requirements (Subsection 4.2.2.5(b)). Surface finish of ground pellets is restricted to 63 microinches or less (arithmetic average) when measured in accordance with ASA Specification B46.1-1962; and shall meet a 90/90 confidence limit. Pellet surfaces are inspected for chips, cracks, and fissures in accordance with approved standards.

~~4.2.4.2.2~~ Cladding

Lots are formed from tubing produced from the same ingot, annealed in the same final vacuum annealing charge and fabricated using the same procedures. Samples randomly selected from each lot of finished tubing are chemically analyzed to ensure conformance to specified chemcial requirements, and to verify tensile properties and hydride orientation. Samples from each lot are also used for flare tests, metallographic tests, and burst tests. Each finished tube is ultrasonically tested over its entire length for internal soundness; visually inspected for cleanliness and the absence of acid stains, surface defects, and deformation; and inspected for inside dimension and wall thickness. The following summarizes the requirements

INSERT GG

The spacer grid outside dimension is specified as 8.130 ± 0.015 inches square, and all grids are checked to verify compliance with this requirement prior to their assembly into fuel assemblies.

Fuel rod channel spacing is controlled indirectly by placing requirements on the true position of individual grid cells and on the straightness of individual rods. No specific channel measurements are made on production fuel because measurements made for information showed essentially no more variation than would be expected from grid cell position tolerances which are already considered in thermal performance analyses.

1) Chemical Analysis

Ingot analysis is required for top, middle, and bottom of each ingot. Finished product is tested for hydrogen, nitrogen, carbon, and oxygen per ASTM E146-68.

2) Tensile Test at Room Temperature (ASTM E8-69)

3) Corrosion Resistance Test (ASTM G2-67)

4) Grain Size (ASTM E112-63)

5) Flare Test (Subsection ~~4.2.1.2.2.1)~~ 4.2.2.5(b))

6) Hydrostatic Burst Test (Subsection ~~4.2.1.2.2.1)~~ 4.2.2.5(b))

7) Surface Roughness

8) Visual Examination

9) Ultransonic Test

10) Wall Thickness

11) Straightness

12) Inside Diameter

~~4.2.4.2.~~3 Fuel Rod Assembly

Immediately prior to loading, pellets must be capable of passing approved visual standards. Each fuel pellet stack is weighed to within 0.1 percent accuracy. The loading process is such that cleanliness and dryness of all internal fuel rod components are maintained until after the final end cap weld is completed. Loading and handling of pellets is carefully controlled to minimize chipping of pellets.

The following procedures are used during fabrication to assure that there are no axial gaps in fuel rods.

~~4.2.4.2.3.1~~ Stack Length Gage

The operator stacks pellets onto V troughs that are gage marked to the proper fuel column height. When pellet stacking is completed, all column heights are overchecked by Quality Control. The pellets are subsequently loaded into tubes. After loading, the distance from the end of the tube to the end of the pellet column is checked with a gage.

~~4.2.4.2.3.2~~ Fluoroscopy

Finished fuel rods, prior to being loaded into bundles, are fluoroscoped to ensure that no significant gaps exist in the fuel column.

Loaded fuel rods are evacuated and backfilled with helium to a prescribed level as determined for the fuel batch. Impurity content of the fill gas shall not exceed 0.5 percent.

The fuel rod end cap to fuel rod cladding tube welds are butt welds between the Zircaloy-4 cladding tube and the Zircaloy-4 end cap machined from bar stock. The weld process is magnetic force welding (MFW). Quality assurance on the end cap weld is as follows:

a) Destructive examination of a sufficient number of weld samples to establish that the maximum allowable percent of unbonded wall thickness (15 percent) and the maximum allowable continuous unbonded region (10 percent) are not exceeded.

b) Visual examination of all end cap welds to establish freedom from cracks, seams, inclusions and foreign particles after final machining of the weld region.

c) Helium leak checking of all end cap welds to establish that no leak rate greater than 10^{-8} cm^3/s is present.

d) Corrosion testing of a sufficient number of samples to establish that weld zones do not exhibit excessive corrosion compared to a visual standard. Welds must be capable of passing a corrosion test (ASTM G2-67) with no preferential oxidation at the weld in water at 650 F, 2200 lb/in.^{2} for 3.5 days.

All finished fuel rods are visually inspected to ensure a proper surface finish (scratches greater than 0.001 inch in depth, cracks, slivers, and other similar defects are not acceptable).

Each fuel rod is marked to provide a means of identification.

(c) ~~4.2.4.3~~ Burnable Poison Rod

~~4.2.4.3.1~~ Burnable Poison Pellets

B_4C power is sampled to verify particle size and wt% boron requirements prior to its use in pellet production. Finished pellets are 100 percent inspected for diameter and must satisfy a 90/90 confidence level on other dimensions. Samples are taken from each of the pellet lots and examined for uniform dispersion of the B_4C in Al_2O_3. Conformance with density range requirements is demonstrated at a 95/95 confidence level and with B_4C loading requirements at a 90/90 level. Samples are drawn from each lot to verify acceptable impurity levels. Finally, all pellets are inspected for conformance with surface chip and crack standards.

~~4.2.4.3.2~~ Cladding

The testing and inspection plan for burnable poison rod cladding is identical to that for fuel rod cladding (Subsection 4.2.4.1(b)).

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The moisture content of poison pellets prior to loading is limited to values below that which would be required to produce primary hydride penetration of the cladding. Total moisture inventory is comparable to that which has been shown to be acceptable in fuel rods.(64) The fabrication process is such that all steps from component drying through final welding are carefully controlled so as to minimize the possibilities for excessive moisture pickup. Final verification of pellet dryness is made by destructive examination of one poison rod from each group of rods from the same drying lot.

The following procedure is used during fabrication to assure that there are no axial gaps in poison rods.

The operator stacks pellets onto V troughs that are gage marked to the proper column height. When pellet stacking is completed, all column heights are over-checked by Quality Control. The pellets are subsequently loaded into tubes. After loading, the distance from the end of the tube to the end of the pellet column is checked with a gage.

Loaded poison rods are evacuated and backfilled with helium to a prescribed level. Impurity content of the fill gas must not exceed 0.5 percent.

End cap weld integrity and corrosion resistance is ensured by a Quality Control plan identical to that used in fuel rod fabrication (Subsection 4.2.4.1(b).

Each poison rod is marked to provide a means of identification.

(d) ~~4.2.4.4~~ . Control Element Assemblies

The CEAs are subjected to numerous inspections and tests during manufacturing and after installation in the reactor. A general product specification controls the fabrication, inspection, assembly cleaning, packaging, and shipping of CEAs. All materials are procured to AMS, ASTM or CE specifications. In addition, various CEA hardware tests have been conducted or are in progress.

During manufacturing, the following inspections and tests are performed:

a) The loading of each control element is carefully controlled to obtain the proper amounts and types of filler materials for each type of CEA application (e.g., full length or part length).

b) All end cap welds are liquid penetrant examined and helium leak tested. A sampling plan is used to section and examine end cap welds.

c) Each type of control element has unique external features which distinguish it from other types.

d) Each CEA has unique serialization on the spider

(See Figures 4.2-3 through 4.2-5).

e) Fully assembled CEAs are checked for proper alignment of the neutron absorber elements using a special fixture. The alignment check ensures that the frictional force that could result from adverse tolerances is below the force which could significantly increase trip time.

In addition to the basic measures discussed above, the manufacturing process includes numerous other quality control steps for ensuring that the individual CEA components satisfy design requirements for material quality, detail dimensions, and process control.

After installation in the reactor, but prior to criticality, each CEA is traversed through its full stroke and tripped. A similar procedure will also be conducted at refueling intervals.

The required 90 percent insertion time for CEAs is 3.0 seconds under worst case conditions. Verification of adequacy will be determined by testing in the CE TF-2 flow test facility. This facility will contain prototypical 16 x 16 reactor components consisting of a fuel assembly, CEA shroud, control element drive mechanism, and a simulation of surrounding core internal support components. The test conditions simulate the worst possible core pressure differential at reactor temperature and pressure conditions, in addition to adverse control element assembly alignment.

4.2.4.2 On-Line Fuel System Monitoring

The Primary Sampling System (Section 9.3.2) is used to obtain primary coolant samples and analyze them for boron concentration, fission and corrosion product concentrations, chloride concentration, reactor coolant pH and conductivity levels.

The Secondary Sampling System (Section 9.3.2) is used to analyze the secondary system coolant for cation conductivity, pH, hydrazine and dissolved oxygen.

The Steam Generator Blowdown System (Section 10.4.8) is used in conjunction with the Chemical Feed and Secondary Sampling Systems (see Sections 9.3.2 and 10.3.5) to control the chemistry of the secondary side water and monitor the activity in the secondary side water.

4.2.4.3 Post-Irradiation Surveillance

4.2.2.6

High burnup performance experience, as described in Subsection ~~4.2.3~~ has provided evidence that the fuel will perform satisfactorily under design conditions. The current core design bases do not include a specific requirement for testing of irradiated fuel rods. However, the fuel assembly design allows disassembly and reassembly to facilitate such inspections, should the need arise.

A fuel rod irradiation program has been developed to evaluate the performance of fuel rod designed for use in the 16 x 16 fuel assembly. The program includes the irradiation of six standard 16 x 16 assemblies, two each for 1, 2, and 3 cycles, respectively, in the Arkansas Nuclear One-Unit 2 reactor (ANO-2). Each assembly will contain a minimum of 50 precharacterized, removable rods distributed within the assembly to obtain a spectrum of exposure levels for evaluation purposes in the interim and terminal examinations. Interim examination of all six assemblies is planned during refueling shutdowns after each cycle.

The ANO-2 fuel rods and specific components of the fuel rods have received a detailed pre-characterization. The program calls for substantial cladding characterization to include mechanical properties, texture, hydride orientation and out of reactor low strain rate behavior. In addition to the ID and OD dimensional data normally obtained on the clad tubing material, a minimum of 300 fuel rods will be measured to obtain as loaded dimensions. Sufficient fuel rods will be profiled to obtain diameter and ovality measurements such that changes in these parameters can be tracked by similar measurements during interim inspections. Also, a random selection of approximately 100 UO_2 pellets from each lot per batch used will be characterized dimensionally and the density distribution will be determined. About one half of these pellets will be placed in known axial locations in selected fuel rods while the remainder will be set aside as archives.

A poolside non destructive examination will be made during each of the first three refuelings at ANO-2. The six 16 x 16 assemblies with characterized rods will be removed from the reactor at each refueling and moved to the spent fuel pool for leak testing (if failed fuel is in the core) and for visual inspection. The length of the assembly and peripheral rods will be measured. During the shutdown, a target of 20 pre-characterized rods per batch will be scheduled for examination and measurement. At some time after the refueling outage, pre-characterized rods retained in discharged assemblies will be measured. A target of 100 rods will be eddy current tested after each shutdown.

a precharacterization and program for selected fuel

A post irradiation fuel surveillance program for St Lucie Unit 2 is being planned. Specific requirements of the plan will be determined based on the results of the ANO-2 ~~program. However, FP&L currently plans to perform~~ inspection when the fuel assemblies are removed from the core and placed in the spent fuel storage pool.

rods in 3-6 assemblies at each refueling,

#

There are two types of tests which can be performed for checking the worth of CEA's and CEA groups following refueling outages. The first is a rod symmetry test in which the reactivity worth of each symmetrically located CEA in a particular group is compared with that of other CEA's in that group. The second is a check on the group reactivity worth of several of the CEA groups.

The sensitivity of the individual rod symmetry check is such that a substantial loss of boron from any single element of a standard five-element CEA would probably be reflected in the test results. The group worth test is sufficiently sensitive to reveal multiple element failures within a given CEA.

The testing of CEA worth will be accomplished at the beginning of each cycle, during low-power physics testing.

An unexpected degradation of guide tubes that are under Control Element Assemblies (CEAs) was recently observed in irradiated fuel assemblies taken from operating Combustion Engineering reactors. Apparently, coolant turbulence is responsible for inducing vibratory motions in the normally fully withdrawn controls rods. When these vibrating rods are in contact with the inner surface of the guide tubes, a wearing of the guide tube wall has taken place. Significant wear has been found to be confined to the relatively soft Zircaloy-4 guide tube because the Inconel-625 cladding on the control rods is a relatively hard wear surface. The extent of the observed wear has appeared to be plant dependent, but has in some cases extended completely through the guide tube wall.

The problem of guide tube wear has been addressed on operating CE reactors through the use of stainless steel, chrome plated sleeves in the guide tube regions subject to longterm contact with the control rods. Sleeves are also to be used initially in St. Lucie 2. In addition, hardware modifications have been made in the region where flow exits from the fuel assembly and enters the CEA shroud. Since sleeves alone have been shown to be effective on other plants, the combination of sleeves and the reduced flow excitation of the control rods promises to provide acceptable operation.

a) Discussion of Hardware Modifications

1. Flow Channel Extensions - The flow channel extensions used on St Lucie 2 are similar to those installed in CE's ANO-2 plant and in San Onofre 2 and 3. Flow channel extensions are installed in the five element CEA cavities in the fuel alignment plate to extend the flow channels of the CEA shroud to the bottom of the fuel alignment plate (see Figure 4.2-11). The extensions are designed to minimize flow turbulence near the control rod tips by isolating the interior of the control rod shroud from flow exiting the fuel assembly.

2. Flow Bypass Insert - A flow bypass insert (FBPI) has been installed in each of the four element CEA shrouds on St. Lucie 2. The function of the FBPI is the same as that of the flow channel extensions, namely to direct the majority of the fuel assembly flow away from the control rods and the interior of the four element CEA shroud. The FBPI is a cylindrical casting installed in the bottom of the four-element CEA shrouds. The

casting has a right angle flow tube through its center to direct flow to the outlet plenum and four peripheral through holes for the CEA fingers (see Figure 4.2-22. The four element CEA has been modified to accommodate the FBPI, and its spider sits on top of the FBPI when the CEA is fully inserted.

b) Out-of-Pile Demonstration Program

Two separate 250 hour flow tests have been conducted using the hardware modifications described above. Full size 16 x 16 fuel assemblies were used in each case. The fuel assembly guide tubes were not sleeved. Hardware tolerances and flow conditions were purposely chosen to reflect adverse conditions.

The results of these tests showed that a dramatic reduction in control rod vibration characteristics had been achieved, compared to the original hardware configuration, and that very little guide tube wear would be predicted over the course of the fuel lifetime.

c) In-Pile Demonstration Test

The use of the out-of-pile tests to predict the in-reactor rate of guide tube wear is justified by a demonstration program recently 75 completed in the Calvert Cliffs 2 reactor (References 74 and 8). The results showed that the wear rate predicted by out-of-pile testing is consistent with that occurring in longterm reactor operation.

Because the above demonstration program was performed for geometries other than those in St. Lucie 2, ~~Waterford 3,~~ it is considered prudent to use guide tube sleeves in the fuel, which will be under CEAS, as in interim measure, until a similar demonstration program planned for Cycle 1 of San Onofre 2 has been completed.

d) Safety Analysis

Sleeving of the fuel assemblies will not result in CEA scram times in excess of those used in the existing safety analysis. Therefore, no changes are required for the analyses involving the anticipated occurrences.

The use of thin-wall 76 stainless steel sleeves in the 16 x 16 assembly design was justified previously for the Arkansas Nuclear One, Unit 2 reactor (Reference 7). The presence of the sleeves does not produce changes in the structural properties of the fuel assembly for seismic or LOCA analyses.

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TABLE 4.2-1

MECHANICAL DESIGN PARAMETERS

Core Arrangement

Number of fuel assemblies in core, total	217
Number of CEAs	91
Number of fuel and poison rod locations	51,212
Spacing between fuel assemblies, fuel rod surface to surface, in.	0.208
Spacing, outer fuel rod surface to core shroud, in.	0.214
Hydraulic diameter, nominal channel, ft.	0.0394
Total flow area (excluding guide tubes), ft^2	54.8
Total core area, ft^2	101.1
Core equivalent diameter, in.	136
Core circumscribed diameter, in.	143
Total fuel loading, Kg U	81.7×10^3
Total fuel weight, lb UO_2	204.4×10^3
Total weight of Zircaloy, lb	59,008
Fuel volume (including dishes), ft^3	325

Fuel Assemblies

Batch	No. of Assemblies	Enrichment (wt%) U-235	No. of Poison Rods per Assembly	
A	73	~~1.79~~ 1.71	0	
B	80	~~2.34~~ 2.28	16	
C	40	~~2.80~~ 2.73	0	
CO	8	~~2.80~~ 2.73	12	0
C1	16	~~2.80~~ 2.73	16	

Fuel Rod array square 16 x 16
Fuel Rod Pitch, in. 0.506

Spacer Grid (HID-1):

Type	Leaf spring
Material	Zircaloy-4
Number per assembly	9
Weight each, lb	~~1.7~~ 1.8

Bottom Spacer Grid:

Type	Leaf spring
Material	Inconel 625
Number per assembly	1

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TABLE 4.2-1 (Cont'd)

Fuel Assemblies (Cont'd)

Weight each, lb	2.6	
Weight of fuel assembly, lb	1303	
Outside dimensions:		
Fuel rod to fuel rod, in.	7.972 x 7.972	
Fuel Rod:		
Fuel rod material (sintered pellet)	UO_2	
Pellet diameter, in.	0.325	
Pellet length, in.	0.390	
Pellet density, g/cm^3	10.38	
Pellet theoretical density, g/cm^3	10.96	
Pellet density (% theoretical)	94.75	
Stack height density, g/cm^3	10.061	
Clad material	Zircaloy-4	
Clad ID, in.	0.332	
Clad OD, (nominal), in.	0.382	
Clad thickness, (nominal), in.	0.025	
Diametral gap, (cold, nominal), in.	0.007	
Active length, in.	136.7	
Plenum length, in.	8.058	
Control Element (CEA)	**Full Length**	**Part Length**
Number	83	8
Absorber elements, No. per assy.	5,4	5
Type	Cylindrical rods	Cylindrical rods
Clad material	Inconel 625	Inconel 625

TABLE 4.2-1 (Cont'd)

Fuel Assemblies (Cont'd)

Control Element (CEA)	Full Length	Part Length
Clad thickness, in.	0.035	0.035
Clad OD, in.	0.816	0.816
Diametral gap, in.	0.009	0.009
Center Element[(a)]		
Poison material	~~B_4C/Inconel~~ B_4C/Ag-In-Cd	Inconel/B_4C
Poison length, in.	~~125/8.5~~ 123/12.5	~~70/14~~ 68.5/14
Outside Elements		0
Poison Material	B_4C/Ag-In-Cd	Inconel/B_4C
Poison Length, in.	~~122/125~~ 123/12.5	~~70/14~~ 68.5/14
B_4C Pellet		
Diameter, in.	0.737	0.737
Density, % of theoretical density of 2.52 g/cm^3	73	73
Weight % boron, minimum	77.5	77.5

Burnable Poison Rod

Absorber material	Al_2O_3-B_4C
Pellet diameter, in.	0.307
Pellet length, in., min	0.500
Pellet density (% theoretical), min	93
Theoretical density, Al_2O_3, g/cm^3	3.90
Theoretical density, B_4C, g/cm^3	2.52
Clad material	Zircaloy-4

(a) Not Applicable for Four - Element CEA 0

(b) For four-element CEA configuration, see Figure 4.2-4.

TABLE 4.2-1 (Cont'd)

Burnable Poison Rod (Cont'd)	
Clad ID, in.	0.332
Clad OD, in.	0.382
Clad thickness, (nominal), in.	0.025
Diametral gap, (cold, nominal), in.	0.025 ~~.007~~ ~~O.K~~
Active length, in.	122.7 ~~136.7~~ ~~O.K~~
Plenum length, in.	8.159 ~~7.659~~

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TABLE 4.2-2

ABSORBER MATERIALS - THERMAL AND PHYSICAL PARAMETERS

1) Boron Carbide (B_4C):

Configuration	Right cylinder	
Outside diameter in.	0.737 $\pm$0.001	
Pellet length, in. nominal	2	
End chamfer	0.03" x 45° CHAMF	
Density gm/cc	1.84	
Weight % boron, minimum	77.5	
% open porosity in pellet	27	
Thermal conductivity (cal/cm-s- C):	Irradiated	Unirradiated
800 F	8.3×10^{-3}	28×10^{-3}
1000 F	7.9×10^{-3}	24×10^{-3}
Melting point, F	4,440	
% thermal linear expansion	0.23% @ 1000 F	

2) Silver-Indium-Cadmium (Ag-In-Cd):

Configuration	Cylindrical bars with central hole	
O.D. in.	0.734 $\pm$ .003	
I.D. in.	~~3/16~~ 1/4	
Length of bar, inches nominal	12 1/2	
Density, lbs/in.	0.367	
Thermal conductivity (cal/s-cm- C)	Irradiated	Unirradiated
at 300 C	0.14	0.182
at 400 C	0.148	0.196
Melting Point, F	1,470	
Linear Thermal Expansion, m/m - °F	12.5×10^{-6}	

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TABLE 4.2-2 (Cont'd)

3) Inconel Alloy 625 (Ni-Cr-Fe):

Configuration (as absorber)	Cylindrical bar
Outside diameter, inches	0.816 $\pm$0.002
Inside diameter, inches	Solid
Length of cylinder, inches	69 7/8 (Part length CEA)
Density, $lb/in.^3$	0.305
Ultimate tensile Strength, $lb/in.^2$ @ 70 F	$120\text{-}150 \times 10^3$
Specified minimum yield strength @ 650 F, kis	65
Elongation in 2 inches, percent	30
Young's modulus, $lb/in.^2$	
at 70 F	29.7×10^6
at 650 F	27.0×20^6
Thermal conductivity, Btu/hr-ft-F	
70 F	5.7
600 F	8.2
Linear thermal expansion, in./in.-F	7.4×10^{-6} (70 to 600 F)

TABLE 4.2-3

TENSILE TEST RESULTS ON IRRADIATED SAXTON CORE III CLADDING[54]

Fluence (>1 MeV) 4.7 x 10^{21} n/cm^2 (estimated)

Rod ID	Location From Bottom (in.)	Testing Temp (°F)	0.2% Yield Stress (lb/in^2 x 10^3)	Ultimate Tensile Strength (lb/in.^{2} x 10^3)	Uniform Strain In 2-in. Gage Length (%)	Total Strain In 2-in. Gage Length
BO	11-17	650	61.4	65.6	2.2	6.8
BO	26-32	650	58.1	68.9	2.4	11.3
RD	3-9	650	62.2	70.0	2.0	4.2
RD	12-18	650	60.5	65.4	1.7	5.8
MQ	12-18	675	70.4	77.4	1.9	6.1
MQ	28-34	675	66.0	75.1	1.6	6.2
FS	28-34	675	57.2	71.4	3.9	12.9
GL	12-18	675	60.5	71.5	2.4	9.3

TABLE 4.2-4

POOLSIDE FUEL INSPECTION PROGRAM SUMMARY

Reactor	Shutdown Date/Cycle	Cycle Average Burnup (Mwd/Mtu)	Inspection Program Scope
Palisades	August 1973/IA	6,800	Visual Exam, Gamma-Scanning, Crud Sampling
Maine Yankee	June 1974/I	10,400	Visual Exam, Sipping, Disassembly/Single Rod Exams, Crud Sampling
	May 1975/IA	4,450	Visual Exam, Sipping
	April 1977/Core 2 Cycle I	17,400	Visual Exam, Disassembly/Single Rod Exams
	July 1978/Core 2 Cycle II		Visual Exam
Ft. Calhoun	February 1975/I	9,000	Visual Exam
	October 1975/II	10,900	Visual Exam, Crud Sampling
	September 1977/III	7,700	Visual Exam
Calvert Cliffs-I	December 1976/I	17,000	Visual Exam, CE/EPRI Test Bundle Disassembly, Single Rod Exam
	January 1978/II	8,300	Visual Exam, CE/EPRI Test Bundle Disassembly, Single Rod Exam
	April 1979/II	9,500	Visual Exam, CE/EPRI Test Bundle Disassembly, Single Rod Exam
Millstone-II	November 1977/I	15,100	Visual Exam
	March 1979/II	9,200	Visual Exam
St. Lucie-I	July 1976/I	800	Visual Exam, Disassembly and Single Rod Exams
	March 1978/IA	12,400	Visual Exam
Calvert Cliffs - II	September 1978/I	16,200	Visual Exam

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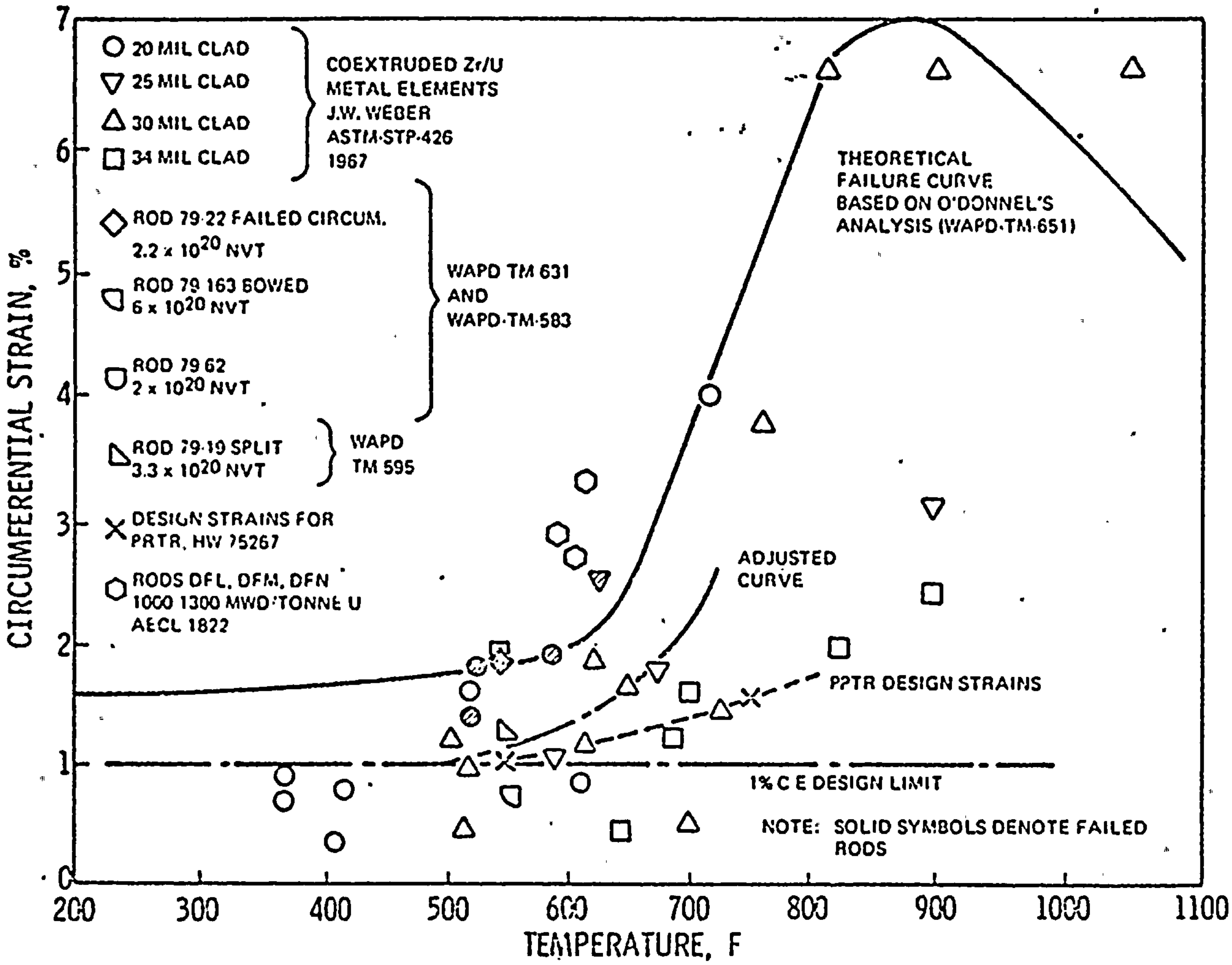

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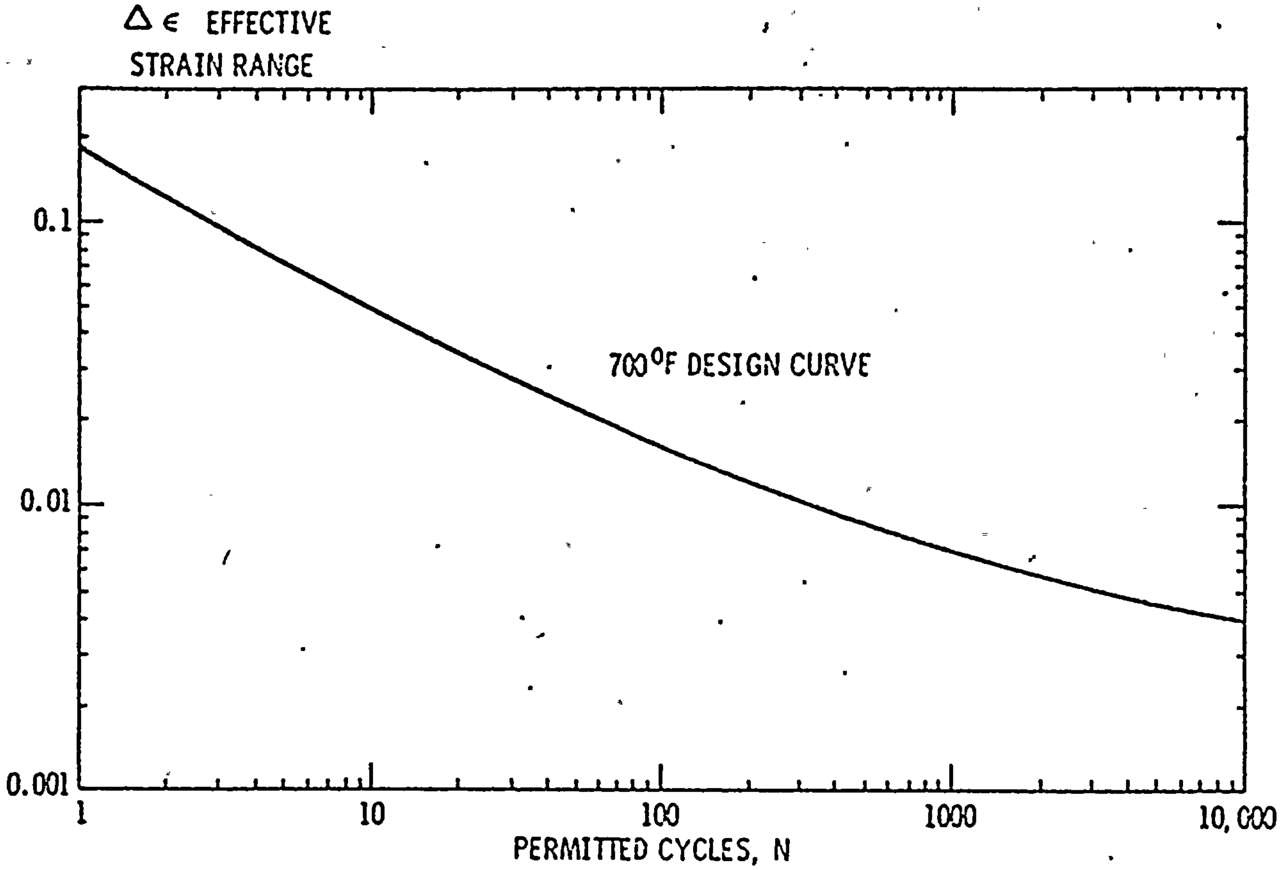
CIRCUMFERENTIAL STRAIN VS TEMPERATURE

FIGURE 4.2-1



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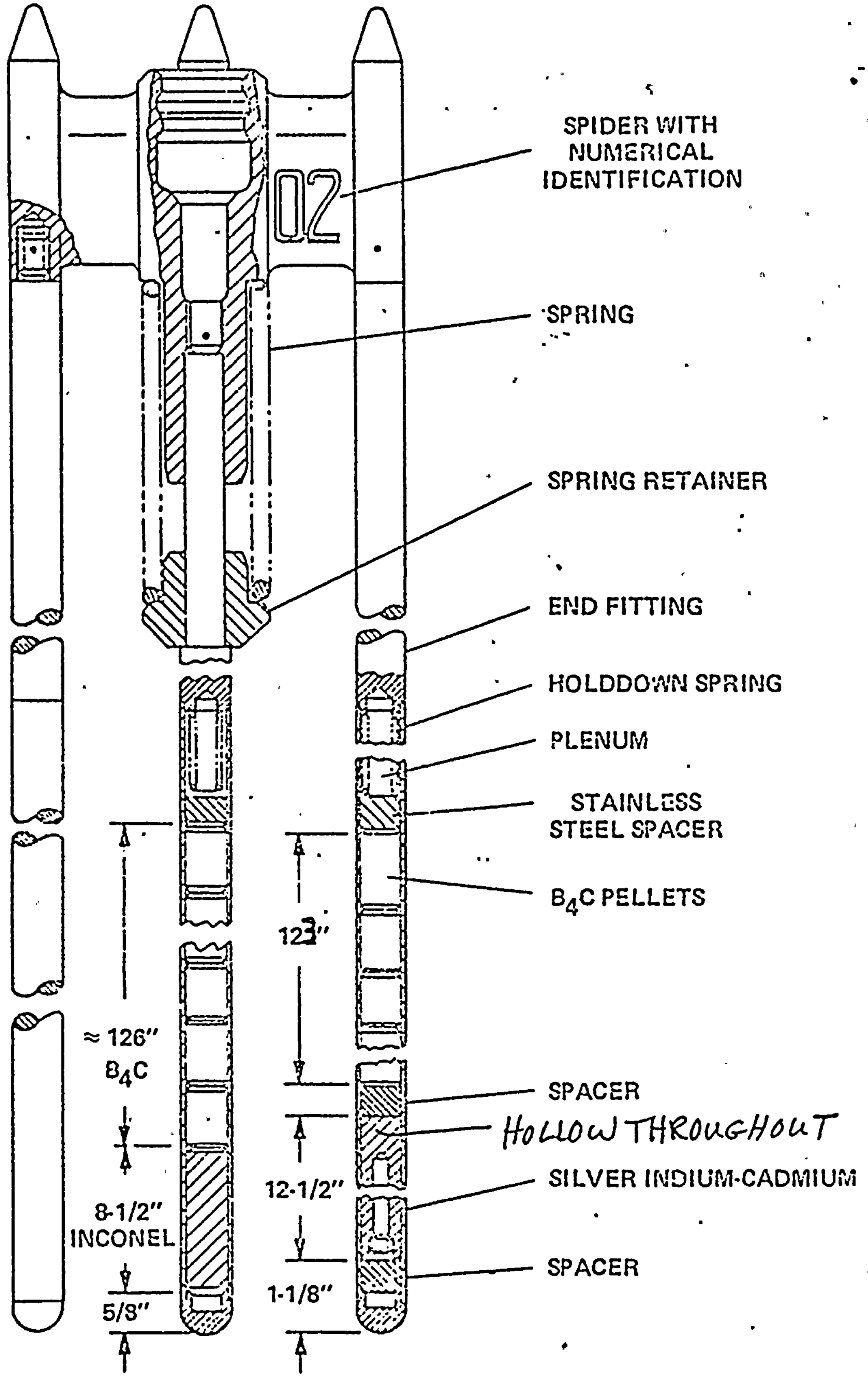
DESIGN CURVE FOR CYCLIC STRAIN USAGE OF ZIRCALOY – 4 AT 700 F
FIGURE 4.2-2

140



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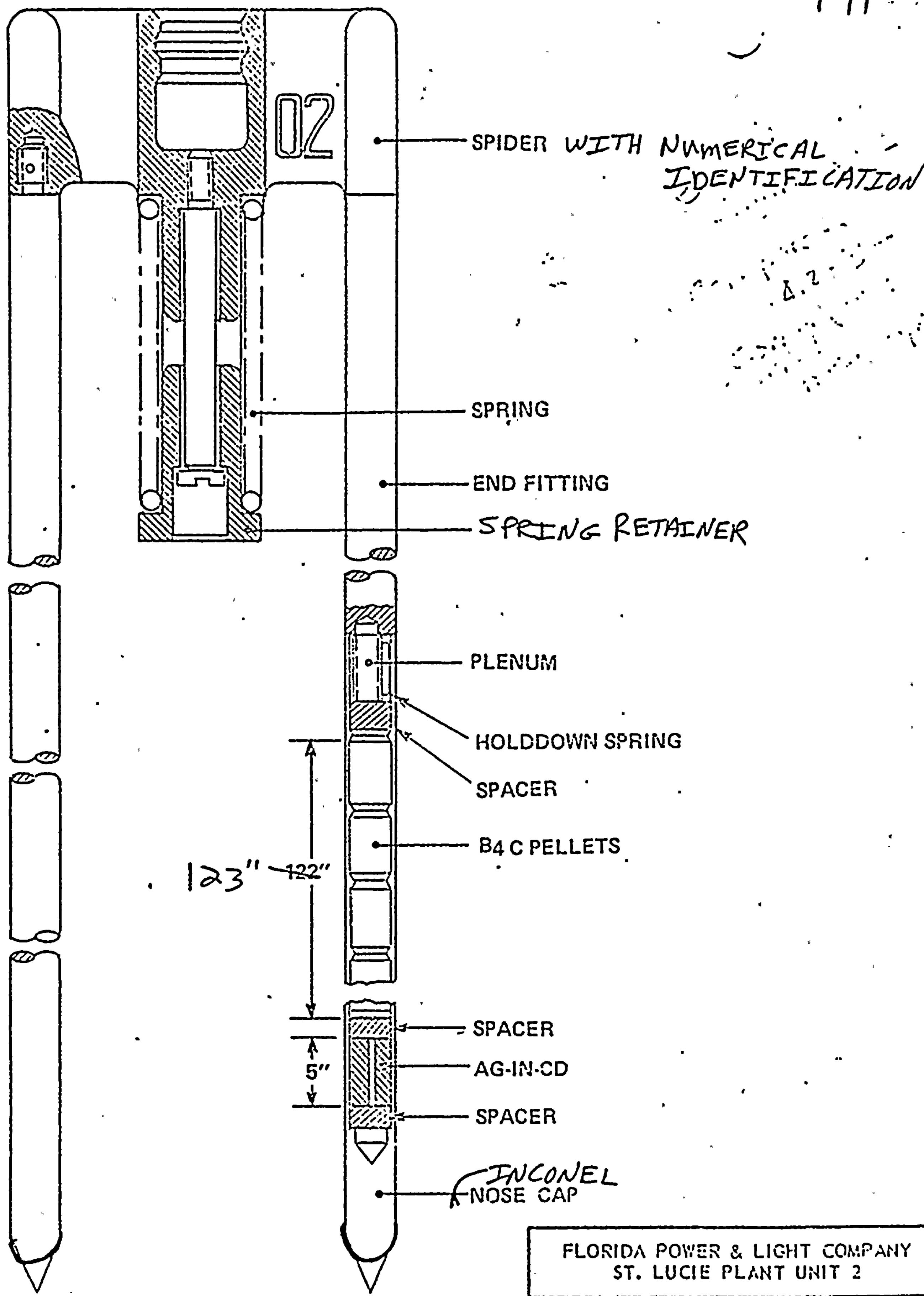
FULL-LENGTH CONTROL ELEMENT ASSEMBLY (5-ELEMENT)

FIGURE 4.2-3



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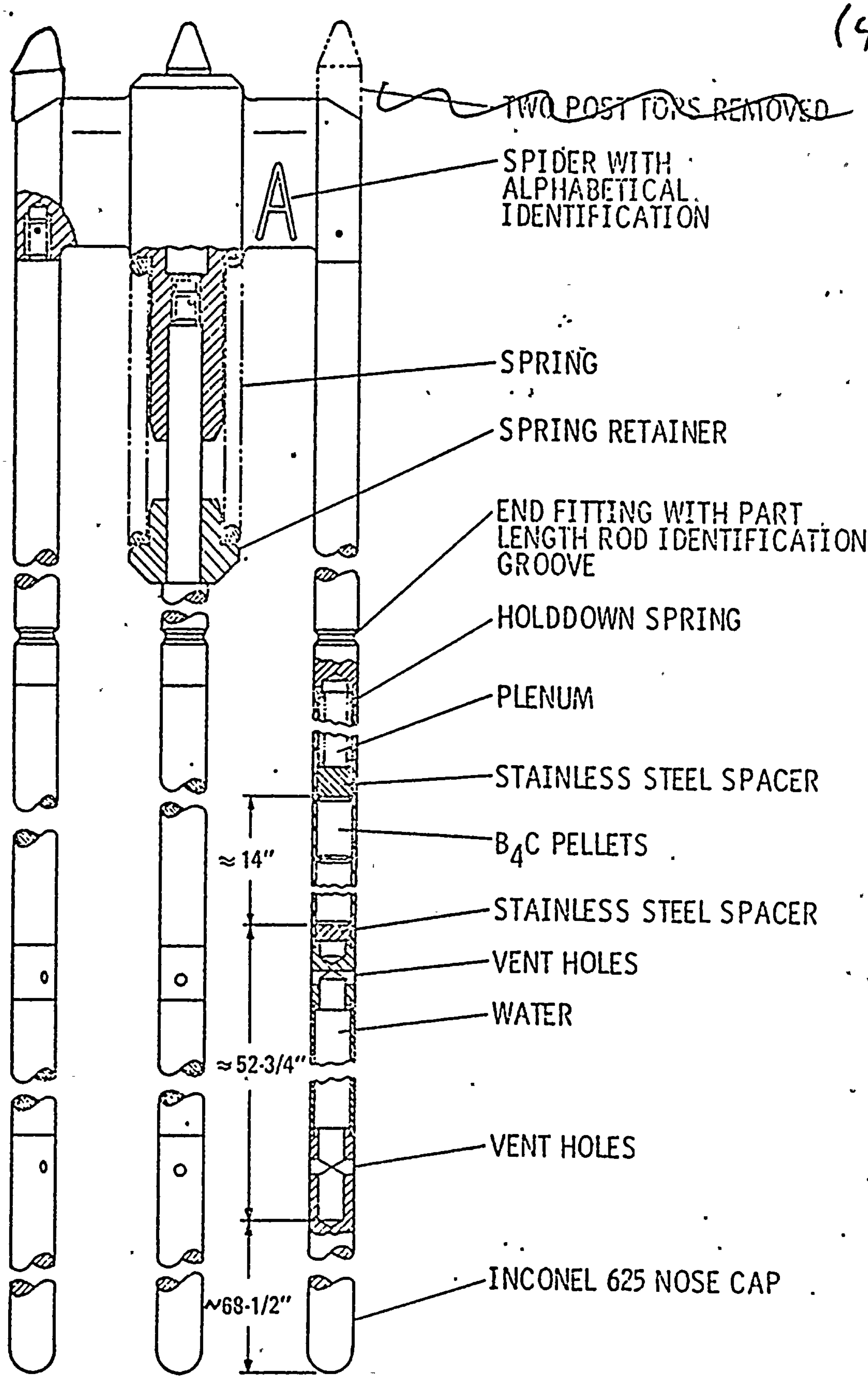
FULL-LENGTH CONTROL ELEMENT ASSEMBLY (4-ELEMENT)
FIGURE 4.2-[illegible]

(42



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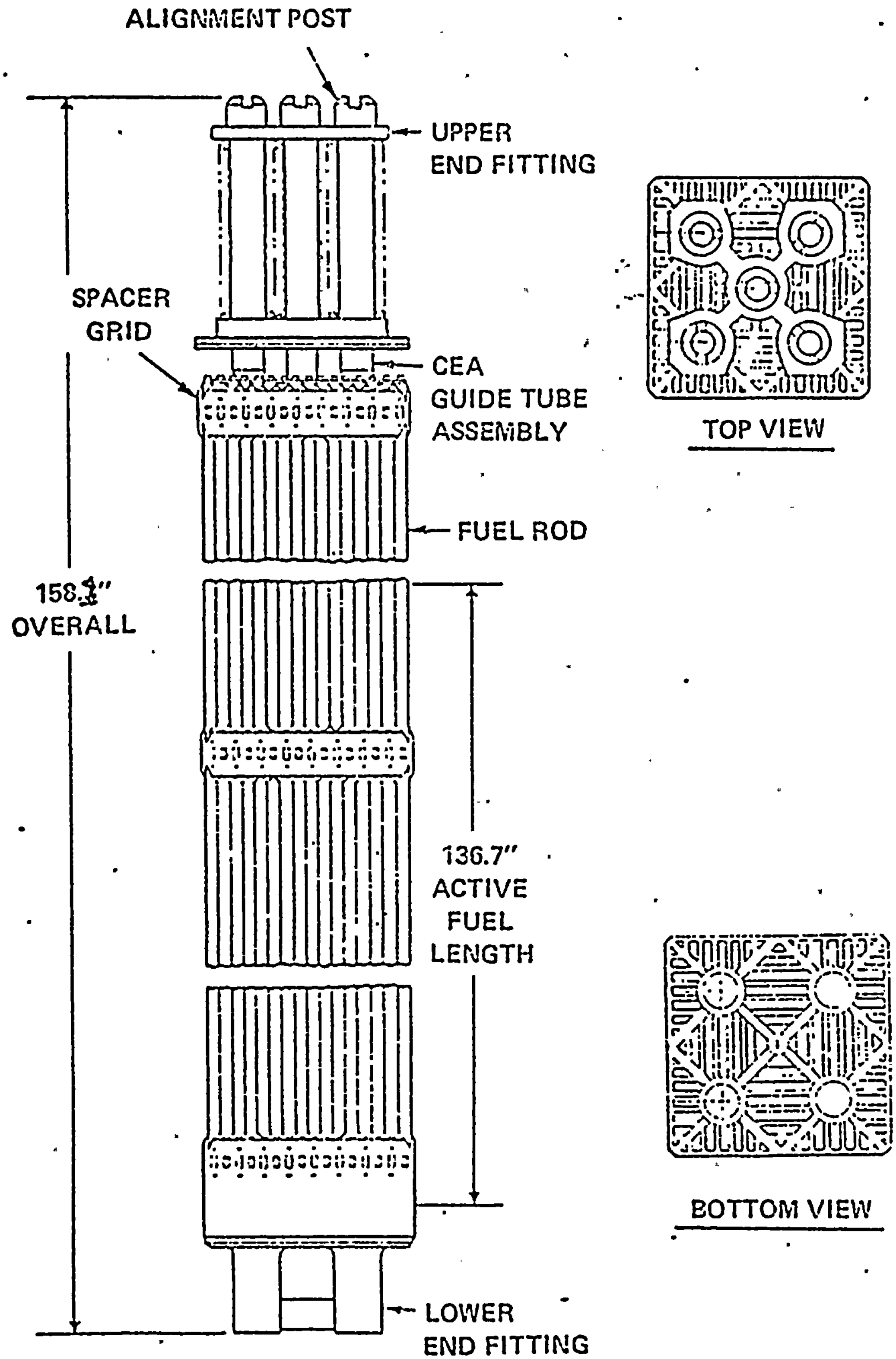
PART-LENGTH CONTROL ELEMENT ASSEMBLY
FIGURE 4.2-5



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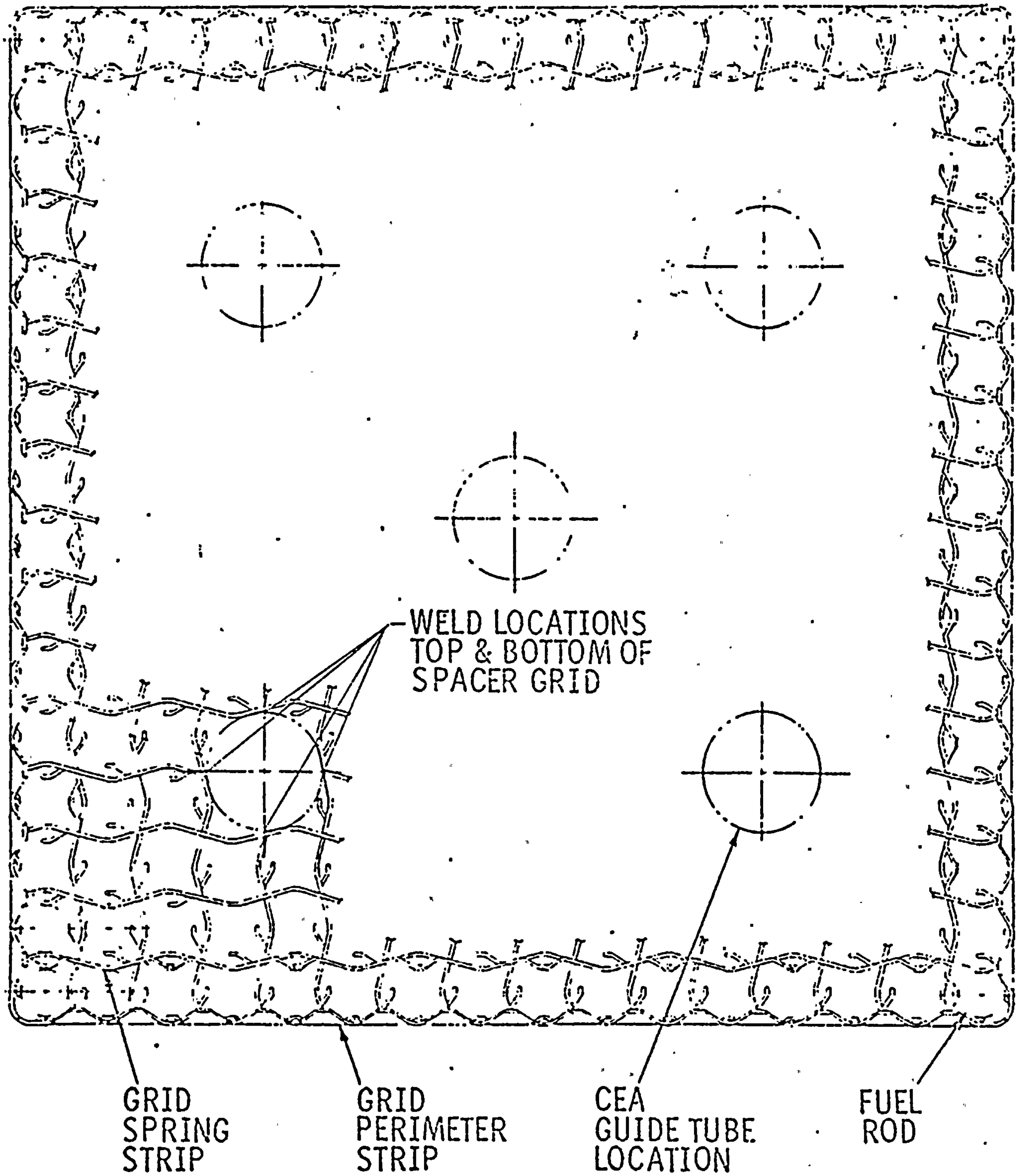
ST. LUCIE PLANT UNIT 2

FUEL ASSEMBLY

FIGURE [illegible].2-6



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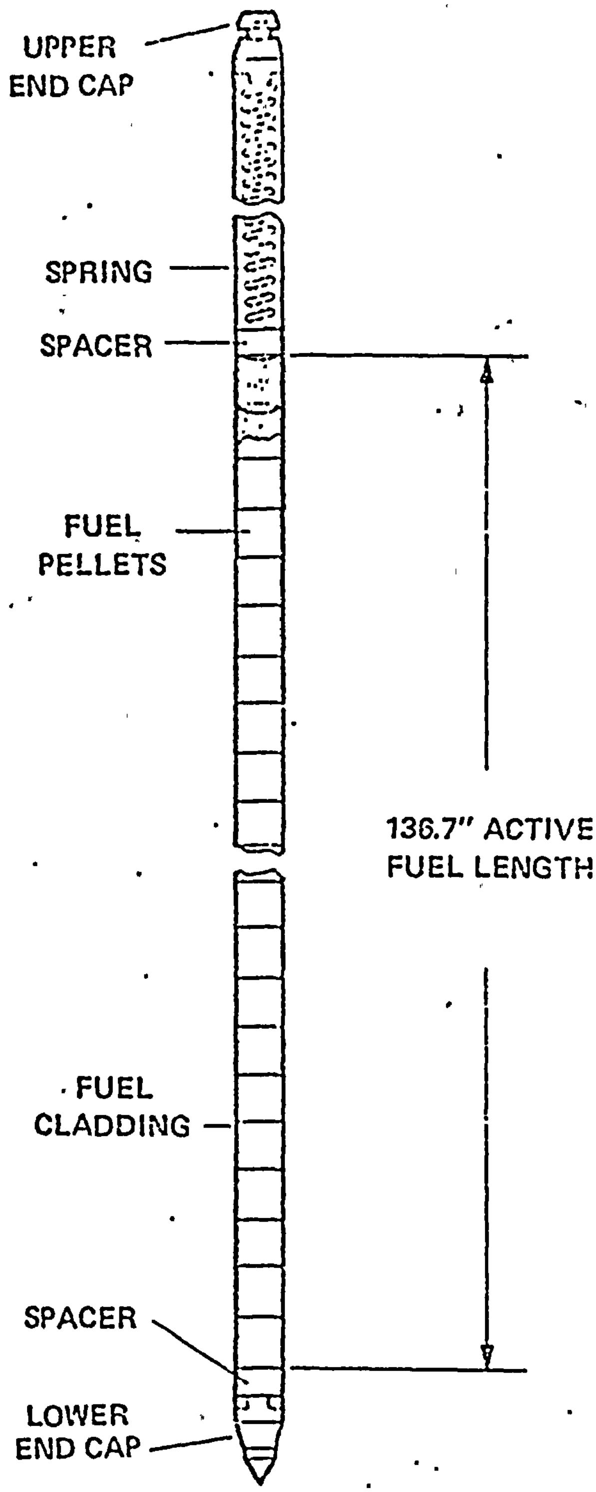
FUEL SPACER GRID

FIGURE 4.2-7



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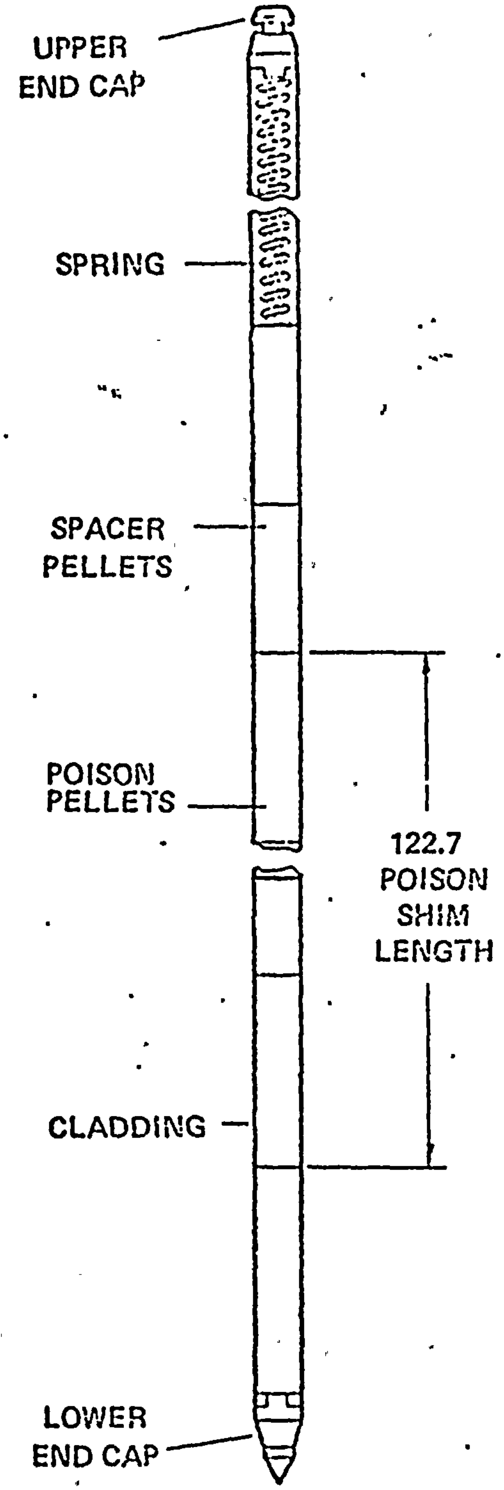
FUEL ROD

FIGURE 4.2-8



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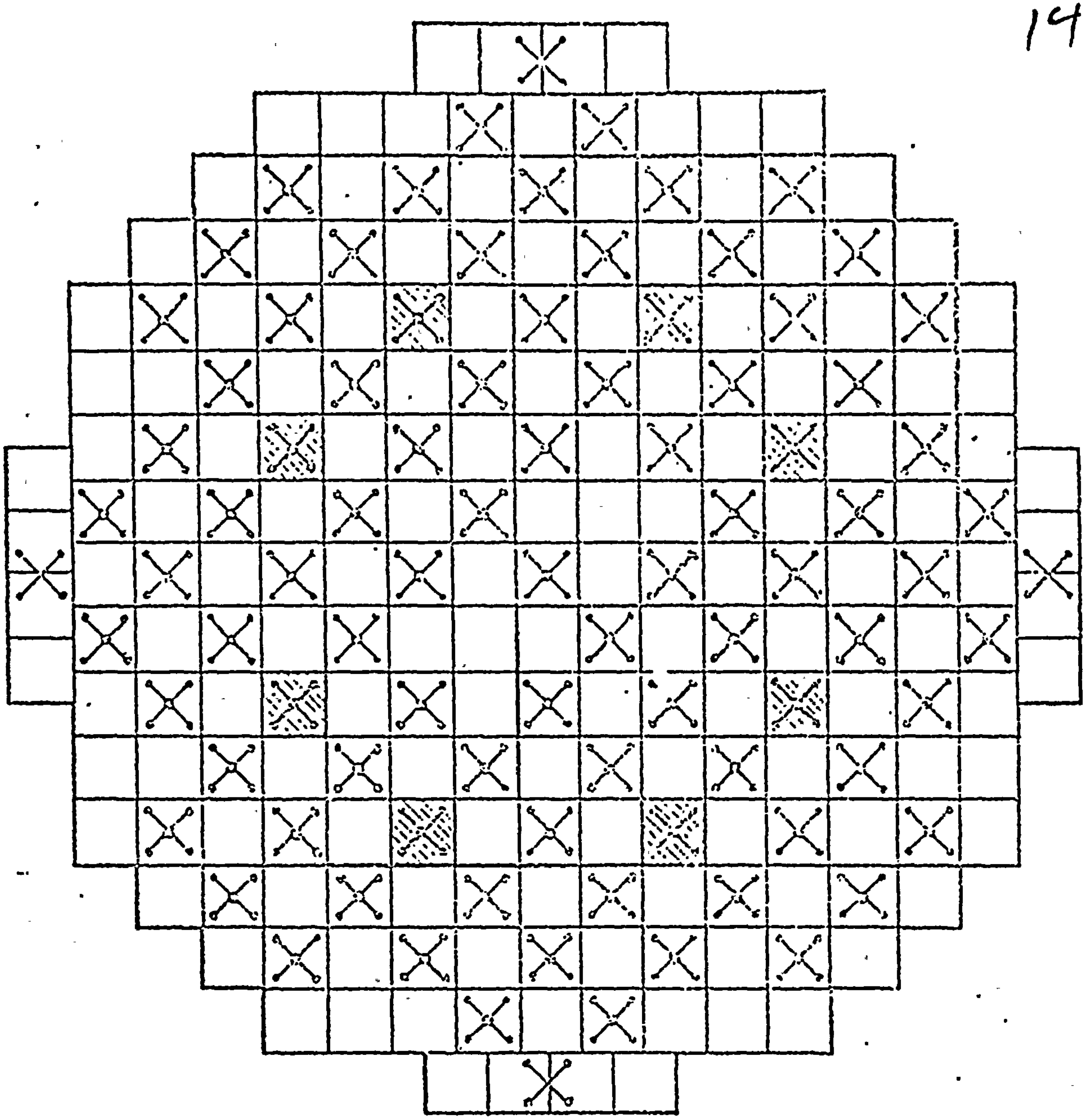
BURNABLE POISON ROD

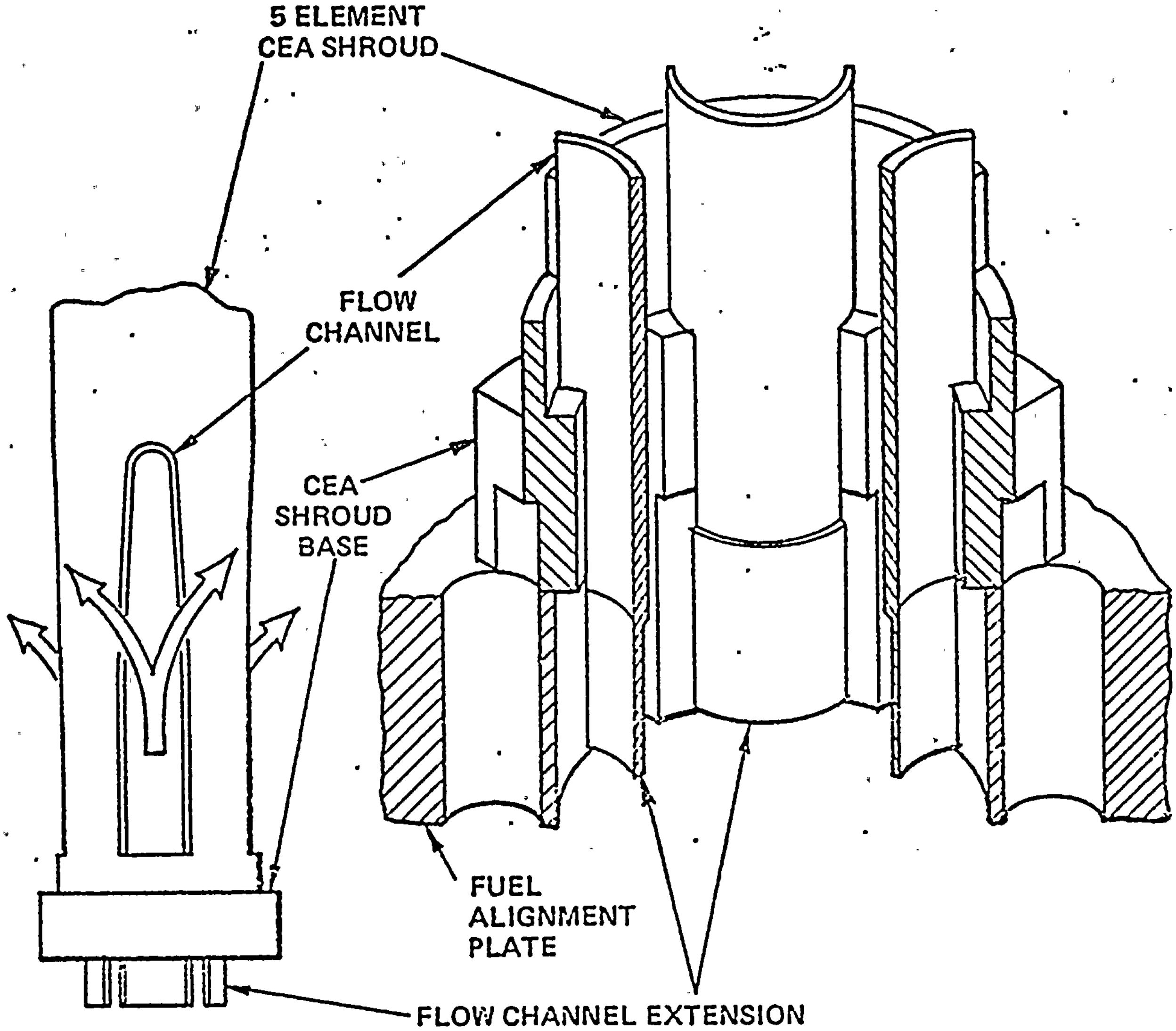
FIGURE 4.2-9



5 ELEMENT FULL LENGTH CEA's	79	
5 ELEMENT PART LENGTH CEA's	8	
4 ELEMENT FULL LENGTH CEA's	4	
TOTAL	91	CEA's

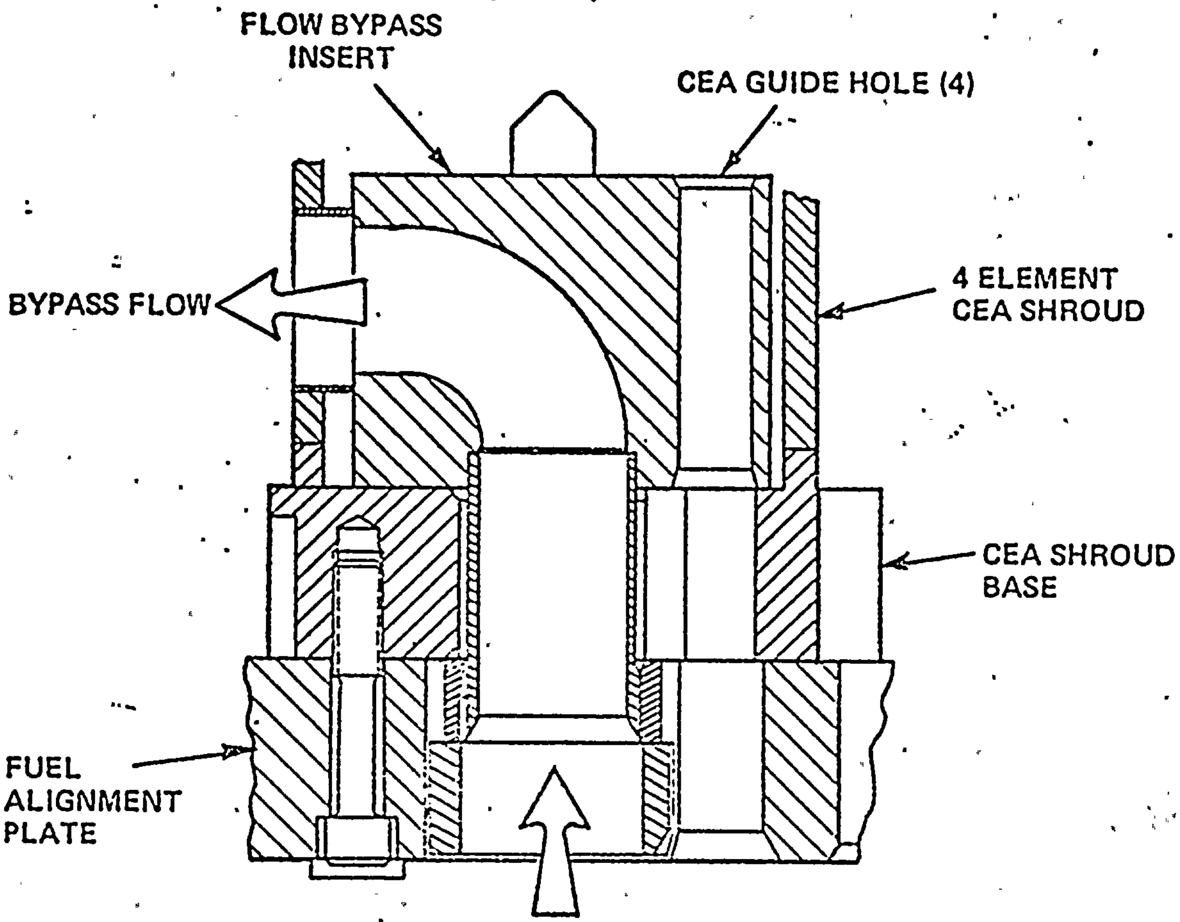
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTROL ELEMENT ASSEMBLY LOCATIONS
FIGURE 4.2-10



FLOW CHANNEL EXTENSIONS

Figure 4.2-11



4 ELEMENT CEA SHROUD FLOW BYPASS INSERT

Figure 4.2-12

Question 1

Details of the actual limited displacement break flow area and the actual break separation time at any circumferential break location are needed for this specific plant.

Response 1

Details of the actual limited displacement break flow area and the actual break separation time at any circumferential break location are provided in revised FSAR Section 3.6.2.

Question 2

It must be demonstrated that St. Lucie plant analysis system parameters fall within the design envelope of CENPD-168, Revision 1.

Response 2

The system parameters of the St. Lucie 2 plant fall within the design envelope of CENPD-168, Revision 1. See attached proposed FSAR amendment to 3.6.2.1.1.

3.6.2 DETERMINATION OF BREAK LOCATIONS AND DYNAMIC EFFECTS ASSOCIATED WITH THE POSTULATED RUPTURE OF PIPING

3.6.2.1 <u>Criteria Used to Define Break Locations for Pipe Whip Analysis</u>

Put all this IN the FSAR

3.6.2.1.1 High Energy Piping Systems

This section provides the criteria used to determine postulated piping failure locations for high energy piping systems both inside and outside containment.

a) Reactor Coolant System Main Loop Piping

1) A stress survey of the St. Lucie 2 Reactor Coolant System Main Loop Pipin performed in accordance with the methods described in CENPD 168A (Reference 1) The St. Lucie 2 Reactor Coolant System geometries and transients were employed i the analysis. The results of this analysis are presented in Figure 3.6-4. In accordance with the criteria specified in Reference (1) circumferential type pipe breaks are postulated to occur at all terminal ends and pipe breaks are postulated at all intermediate locations throughout the piping system where the range of primary plus secondary stress intensity exceeds 2.4 Sm or the cumulative usage factor exceeds 0.10.

Where all intermediate pipe break locations would be considered unlikely because the stresses and cumulative usage factors calculated for a particular run of piping between terminal ends are everywhere less than the stress and fatigue limits stated above, the two intermediate locations of highest cumulative usage factor are chosen as the most likely break locations for piping runs longer than 10 diameters total length, and for piping runs having more than one change in direction through-out the run.

2) The results presented in Figure 3.6-4 confirm the break location and types of Reference (1) for the main loop pipe.

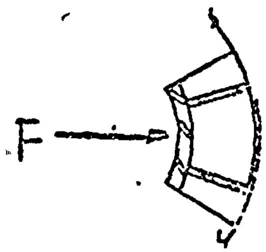
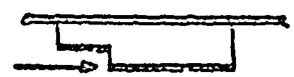
3) For the partial area guillotine type pipe breaks at the reactor inlet and outlet nozzles and the steam generator inlet nozzles, the methods of Reference (1) were employed to calculate the flow areas and opening times of the break at these locations. The stiffness values are provided in Table 3.6-2 and Figure 3.6-5.

The resultant break characteristics are shown in Table 3.6-1. The pipe whip restraint at the reactor vessel inlet is shown in Figure 3.6.3. All other guillotine breaks have been assumed to open to full area.

The break locations for RCS are shown in Figures 3.6C-2.1 and 3.6C-2.2.

TABLE 3.5-2

COLD LEG PIPE STOP STIFFNESS

DIRECTION	PIPE STOP	STIFFNESS (K/IN) STOP No. 1	STOP No. 2	STOP No. 3	REMARKS
RADIAL	2A1	300.3×10^3	295.1×10^3	299.3×10^3	
	2A2	356.2×10^3	252.9×10^3	355.9×10^3	
	2B1	222.6×10^3	222.8×10^3	221.0×10^3	
	2B2	319.2×10^3	366.7×10^3	319.3×10^3	
LONGITUDINAL	2A1	49.6×10^3	71.0×10^3	48.8×10^3	
	2A2	40.9×10^3	71.7×10^3	40.9×10^3	
	2B1	61.9×10^3	61.9×10^3	64.1×10^3	
	2B2	17.0×10^3	98.9×10^3	17.0×10^3	

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PIPE BREAK AREAS AND BREAK OPENING TIMES

PARTIAL AREA GUILLOTINES

TABLE 3.6-3

POSTULATED RUPTURE	BREAK FLOW AREA (IN^2)	RISE TIME (MILLISECONDS)
RV INLET GUILLOTINE	200.	6.
RV OUTLET GUILLOTINE	100.	20.
SG INLET GUILLOTINE	1000.	24.

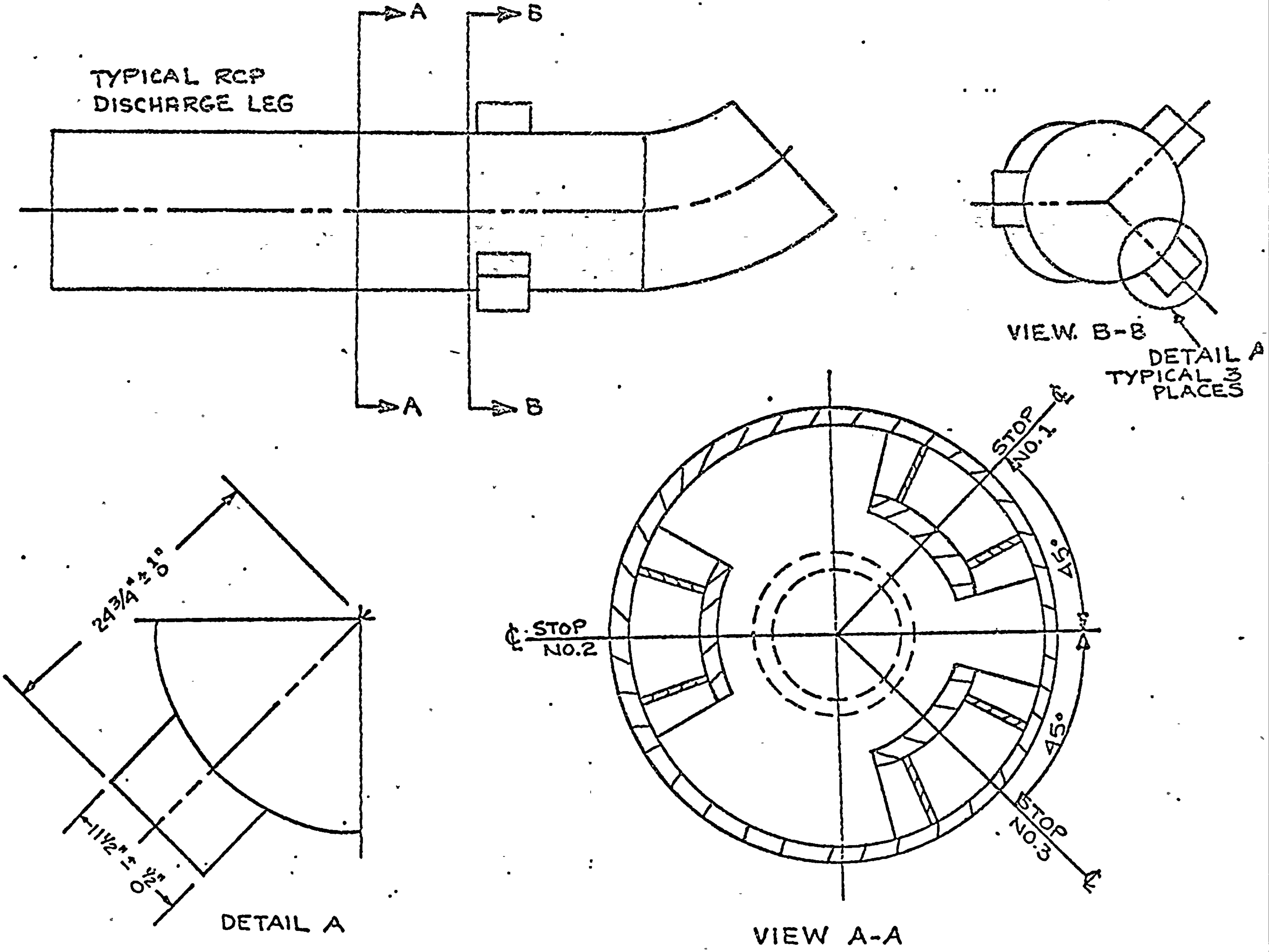
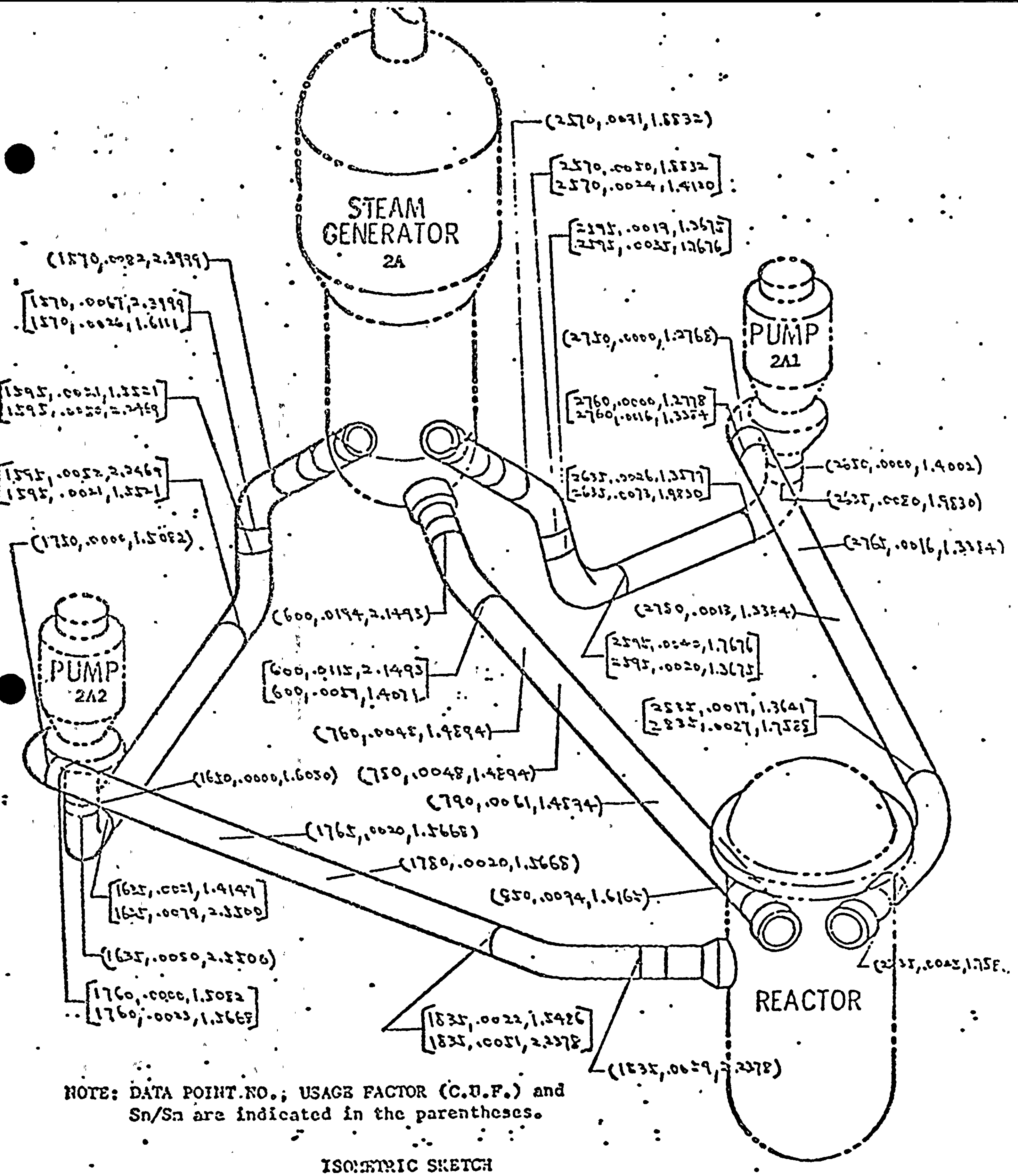


FIGURE 3.6-3

DISCHARGE LEG PIPE RESTRAINTS

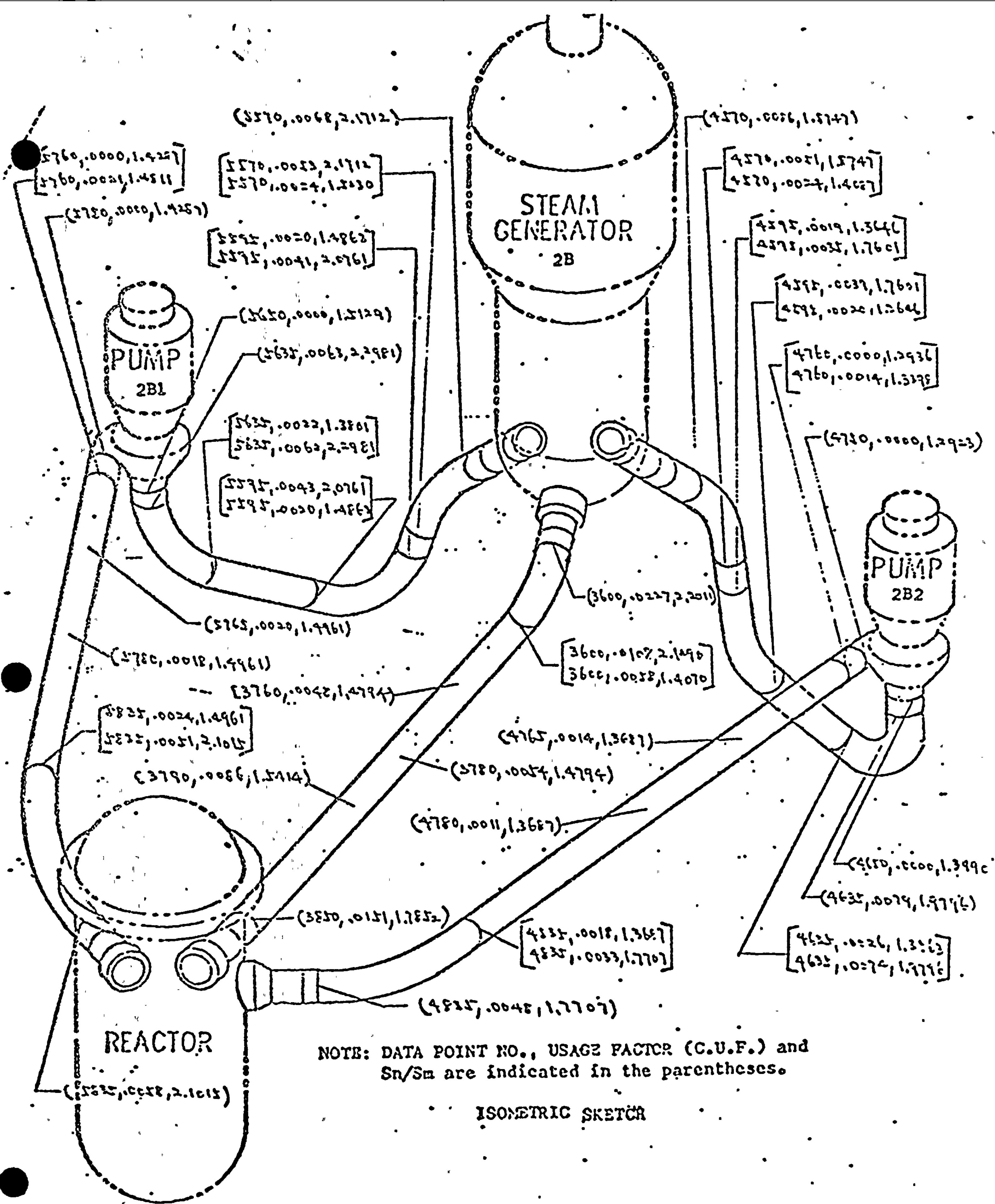


NOTE: DATA POINT NO., USAGE FACTOR (C.U.F.) and Sn/Sm are indicated in the parentheses.

ISOMETRIC SKETCH

CUMULATIVE USAGE FACTOR AND NORMALIZED PRIMARY PLUS SECONDARY STRESS INTENSITY RANGE RESULTS FOR SEISMIC LOADING (LOOP 2A)

FIGURE 3.6-4.
SHEET 1 OF 2

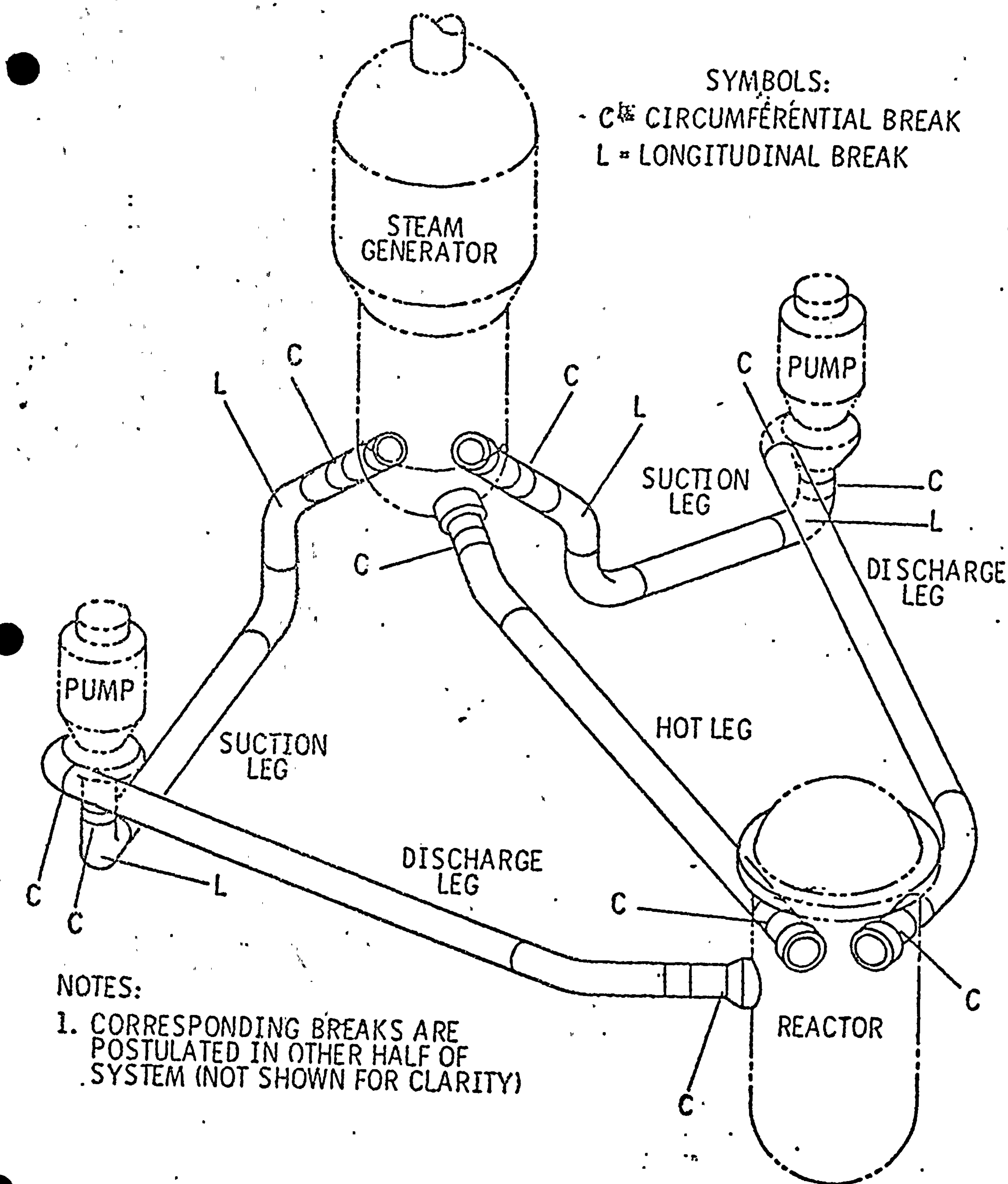


CUMULATIVE USAGE FACTOR AND NORMALIZED PRIMARY PLUS SECONDARY STRESS INTENSITY RANGE RESULTS FOR SEISMIC LOADING (LOOP 2B)

FIGURE 3.6-4
SHEET 2 OF 2

Q2

New



NOTES:

1. CORRESPONDING BREAKS ARE POSTULATED IN OTHER HALF OF SYSTEM (NOT SHOWN FOR CLARITY)

C-E Combustion Engineering Inc.	DESIGN BASIS PIPE BREAKS TYPES AND LOCATIONS	Figure 1

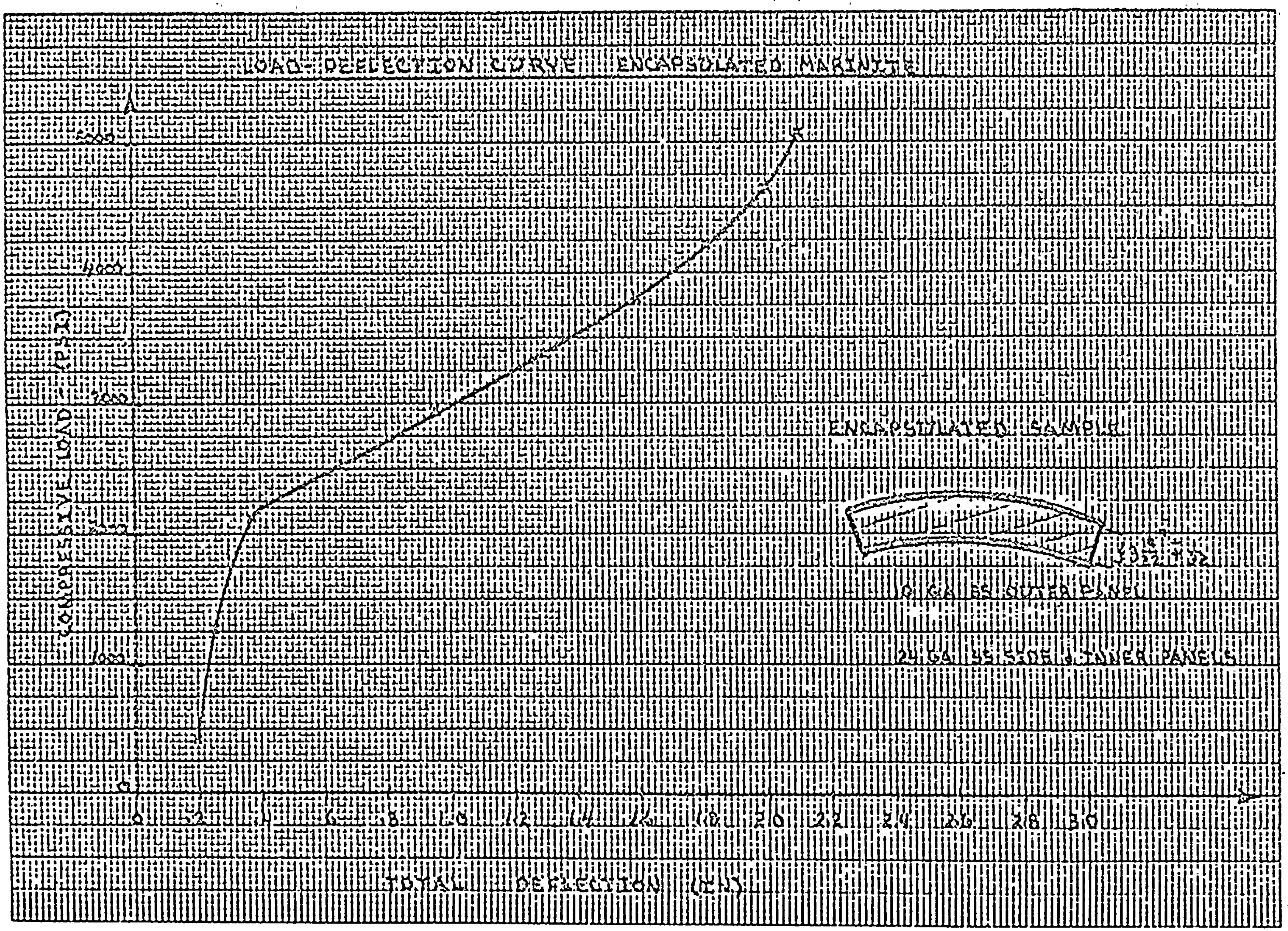

LOAD-DEFLECTION CURVE ENCAPSULATED MARINITE
COMPRESSIVE LOAD (PSI)
5000
4000
3000
2000
1000
0
ENCAPSULATED SAMPLE
18 GA SS OUTER PANEL
24 GA SS SIDE & INNER PANELS
TOTAL DEFLECTION (IN)

FIGURE 3.6-5

Question No.

5. Assurance should be provided that the criteria used to predict break location, as referenced to CENPD-168A, Revision 1 is used for reactor coolant system piping only. If this criteria is used for piping other than the RCS, additional justification must be provided.

Response

CENPD-168A, Revision 1 is used to predict break locations for Reactor Coolant loop piping only. For all other high energy piping, as indicated in Section 3.6.2.1.1(e), pipe whip analysis is performed based on "break anywhere" criteria, and jet impingement analysis is performed for breaks postulated in accordance with the criteria given in Section 3.6.2.2.1(b), (c) and 3.6.2.2.2.

Question 4

Additional items not covered by CENPD-168, and which should be provided for the reactor coolant system of the plant are the pipe whip restraint parameters such as stiffness values and gap sizes.

Response 4

The pipe whip restraint parameters (i.e. stiffness values) are provided in revised FSAR Section 3.6.2.]. Gap sizes for reactor vessel inlet break will be provided.

Ok

Questions No.

5-10 The applicant has made a commitment to provide the following items in a future amendment to the FSAR.

5 - High Energy pipe rupture analysis inside containment (Appendix 3.6A).

6 - High Energy pipe rupture analysis outside containment (Appendix 3.6B).

7 - Pipe whip restraints and break location (Appendix 3.6C).

8 - Structural details of the pipe whip restraints (Appendix 3.6D)

9 - Main Steam and feedwater dynamic analysis (Appendix 3.6E).

10 - Moderate Energy analysis (Appendix 3.6F).

Response

All information requested above has been supplied in Amendment 3 of the St Lucie 2 FSAR (issued June 81).

Question No.

11 The FSAR Section 3.6.2.2 should be clarified to show that the requirement of 0.8 $(S_h + S_A)$ is based on the sum of Equations (9) and (10) of Paragraph NC-3652 of the ASME B&PV Code, Section III and not Equation (9) and (10) individually.

Response

The stress criteria of 0.8 $(S_h + S_A)$ is compared against the sum of Equations (9) and (10) of paragraph NC-3652 and ND-3652 of the ASME Code Section III to determine break locations.

Refer to revised FSAR Subsection 3.6.2.2.1(c)(2).

Question No. 12

Provide criteria for postulated pipe breaks in both high and moderate energy piping systems in the containment penetration area.

Response

High energy pipe breaks and moderate energy leakage cracks are postulated based on the criteria of Subsections 3.6.2.2.1(c), 3.6.2.2.2 and 3.6.2.4 for piping located in the penetration area. The pipe rupture analysis does not take credit for any break exclusion region.

Refer to revised FSAR Subsection 3.6.2.5.

Question No. 13

Provide the basis for the 0.8 S_A criteria for expansion stresses which is stated in Section 3.6.2.2.2(2) of the FSAR.

Response

The basis for 0.8 S_A criteria for expansion stresses stated in Section 3.6.2.2.2(2) of the FSAR is as per Appendix B (Giambusso criteria) to BTP APCSB 3-1 item 2.(b).(2).

OK

Question No.
14

Provide a listing of the high energy systems that are considered for pipe rupture analysis. In addition provide a summary of the results of the analyses of these systems to demonstrate that essential systems, components, and supports will not be impaired as a result of high energy pipe breaks.

Response

High energy system considered for pipe rupture analysis are:

Inside Containment

1. Main Steam and Feedwater
2. Reactor Coolant (includes pressurizer surge, spray and relief).
3. Safety injection (all lines pressurized by the safety injection tanks).
4. Shutdown Coolding (high energy portion only)
5. Chemical and volume control (letdown and charging).
6. Steam generator blowdown.

Outside Containment

1. Main Steam and Feedwater
2. Chemical and Volume Control (letdown and charging)
3. Steam generator blowdown.
4. Auxiliary Steam System
5. Auxiliary feedwater system
6. Steam supply to Auxiliary Feedwater pump.

The results of the analyses of these systems are presented in Appendices 3.6A and 3.6B.

Question No.

15

When longitudinal breaks are postulated, assurance must be provided that they are chosen in the location that is likely to cause the maximum damage.

Response

Longitudinal breaks are postulated to occur at any location about the circumference of the pipe. This method identifies the location that causes the maximum damage.

Refer to Subsection 3.6.2.3(b)(2) of the FSAR.

Question No. 16

The following information is required as it pertains to the subsystem analysis before our review can be completed.

(1) The method for determining that an adequate number of degrees of freedom were used in the dynamic modeling to determine the response of all Category I and applicable Non-Category I structures and plant equipment.

Response

For piping systems, adequate mass points and corresponding dynamic degrees of freedom are selected and distributed to provide for appropriate representation of the dynamic characteristics of the subsystem. As indicated in 3.7.3.1.1.2, the maximum spacing of the mass points does not exceed one half the distance for which the frequency of a simply supported beam would be 20 H_z. Each mass prints, except for points indicated as restrained in a given direction, have 3 linear degrees of freedom. Therefore, the degrees of freedom exceeds twice the number of mode with frequencies less than 33 H_z.

The dynamic models of the cable tray and HVAC duct with their respective support structures were constructed with an adequate number of mass points in order to simulate the dynamic behavior of the subsystem. The number of mass points in the dynamic model is adequate because the number of degrees of freedom exceeds twice the number of modes with frequencies less than 33 H_z.

NSSS vendor supplied subsystems are modeled with sufficient masses (dynamic degrees of freedom) such that inclusion of additional degrees of freedom results in less than a 10% increase in responses (Analysis of the pressurizer, surge line, and spray line also meets the alternate criteria that the number of degrees of freedom is greater than twice the number of modes with frequencies less than 33 Hz).

Question No 17

Provide Justification that a sufficient number of modes were considered to assure participation of all significant modes is required

Response

The criterion for sufficiency in number of dynamic modes is that the inclusion of additional modes does not result in more than 10% increase in response. In general, this can be satisfied by including all the dynamic modes below 33 H_2, if the highest mode calculated below 33 H_2 has already fallen into the flat rigid response region of the corresponding response spectra, the effect of the remaining high modes are taken care of by adding the dynamic analysis result with an equivalent static solution in SRSS summation.

Dynamic analysis of cable tray/HVAC duct-support systems has combined all modes in the flexible region together with residual terms accounting for higher modes in the rigid region.

Criterion used to assure that sufficient modes are included in the analysis of NSSS vendor supplied subsystems is that the inclusion of additional modes results in less than a 10% increase in response. Analysis of the coupled components of the RCS included all modes less than 50 Hz (Section 3.7.3.1.2.3(b)).

Question No. 18

Provide The methods used to handle the relative displacements of Category I supports.

Response

(1) The following is a summary of the method used to handle the relative seismic displacement of support in piping systems.

a. The relative seismic displacments between supports/restraints installed on the same building structure are normally negligible in the stress analysis.

b. The relative seismic displacements between supports/restraints located in two buildings on separate mats are to be derived from the combination of co-directional maximum absolute seismic displacement of the two buildings at the supporting elevation by SRSS (square root of the sum of the squares) method.

c. The relative seismic displacements between supports/restraints located in two buildings on a common mat or attached to two structures within the same building are to be derived by taking the square root of the sum of the squares of each relative seismic displacement towards a common reference.

d. For piping connecting to equipments or primary piping system of which the available maximum seismic displacements are relative to the base support of the major equipments, the base supports are to be selected as the common reference. The maximum seismic displacement of the subject piping restraint system are to be converted into relative displacements towards the base support of connecting nozzle and the piping restraint system are then to be derived by taking absolute addition of the two relative seismic displacements which in turn are relative to the base support of the equipment.

e. The piping system will be analyzed separately with relative seismic displacement input in each of the three orthaganal coordinate directions. The resultant response (such as pipe stress, moment, force, etc) are obtained by taking SRSS of the response corresponding to each coordinate direction.

(2) Relative displacement among supports located at different floor elevations are not considered in cable tray and HVAC duct seismic analysis. Ducts are provided with flexible joints to accommodate relative displacement of the supports.

(3) For the coupled components of the RCS the relative support displacements are applied directly in the time history analysis methods described in Section 3.7.3.1.2.3. For NSSS vendor supplied multiply supported subsystems analyzed by response spectrum methods, relative support displacements are applied statically in the most unfavorable manner.

Question 19

Provide information on how significant effects such as piping inferactions, externally applied structural restraints, hydrodynamic loads and nonlinear responses are accounted for.

Response

The effects of piping interactions and hydrodynamic loads are considered in the analysis of safety Class 1, 2 and 3 components. The safety related equipment is designed to withstand the piping interaction loads that could be imposed on these components. These loads are combined with the other plant loading in accordance with FSAR Table 3.9-6. The equipment is analyzed to assure that under these loadings the operability will be assured. The summary of results for these active components is provided in FSAR Appendix 3.9A.

Interaction of the RCS main loop piping and the major components is accounted for directly in the time history analysis of the composite coupled model. Treatment of hydrodynamic effects and non-linear response of the reactor internals and fuel is discussed in Section 3.7.3.14.

Question 20

If the equilalent static load method was used, justification must be provided that the system can be represented by a simple model and that the relative motion between support points is accounted for.

Response

The piping system stress analysis does not utilize the equilivant static load method.

This piping analysis utilizes the modified equivalent static load method which is described in the response to question 23.

Cable tray and HVAC duct seismic supports were designed in the following manner:

A seismic response analysis was performed on a 3-D model, which represented a typical multiple span of cable tray (HVAC duct) and its supports. Each tray (duct) support in the model was assigned a fundamental frequency of]6 to]8 Hz in three directions. The results of this analysis was an amplication factor which was then used to determine the static equvalent "g" values for design of individual cable tray (HVAC duct) supports. Each support is designed to have a fundamental frequency of]6 to]8 Hz.

Regarding considerations of relative motion between supports see discussion for (]8) above.

For NSSS vendor supplied subsystems the equivalent static load method is limited to analysis of components which can be realistically represented as single-degreee-of-freedom systems or by simple beam or frame type models. For multiply supported components the realtive motion between supports are applied in the most unfavorable manner using static analysis procedures and responses are added to those due to inertial effects by the absolute sum method.

Question 21

The criteria and procedure given for the modeling of the seismic systems and the criteria for determining whether a component is analyzed as part of a system or independently requires amplification and inclusion of all information required by the SRP. Before our review can be completed on this section, the criteria and procedures actually used must be described. This should include the modeling procedures used and the criteria for decoupling as outlined in SRP Section 3.7.2, paragraph III.3.

Response

The criteria and procedure for the modeling of the seismic system are stated in FSAR Section 3.7.2.3.

For the reactor building in particular, studies using seismic models with and without subsystem are made to ensure the coupling effect is minimal. Models with major equipment (such as steam generators and reactor vessels) and the supporting structure (i.e. the internal structure) modeled separately and modeled together are constructed and the Computer Code STARDY NE is employed. Dynamic responses such as frequencies, accelerations, and response spectra are compared. The differences are found negligible.

The reactor internal structure response spectra as shown in Figure 3.7-15 illustrates that the peak acceleration occurs approximately at 3 Hz. The RCS loop has a fundamental of 10 Hz. Thereby the coupling effect between the reactor building and the RCS loop is insignificant.

Question 22

A discussion of the methods actually used in determining the fundamental frequencies is required in this FSAR Section. Also explain how the three ranges of equipment/support behavior (rigid, flexible, resonant) delineated are handled in the analysis. A statement or statements is required as to how these matters are considered in the analysis.

Response 22

For piping systems which are analyzed by either modal response spectra method or modified equivalent static load method, the fundamental frequencies are determined by the stiffness matrix method of natural mode analysis as described in FSAR 3.7.3.1.1.2.2. For piping systems which are analyzed by simplified seismic analysis method, the exact values of fundamental frequencies are not calculated. As described in FSAR 3.7.3.1.1.C, the piping are restrained to have fundamental mode periods less than 70 percent of the first mode period of the supporting structure. This was accomplished by comparing and modifying the restraint spacing in design with that of a simply supported beam.

Where feasible, the piping system are arranged to be in the rigid region (i.e., the fundamental frequencies are more than twice the dominant frequencies of the support structure. If the fundamental frequency of the piping system is less than twice but more than 1.43 of the dominant frequencies of the support structure, the modified Equivalent Static Load Method as delineated in FSAR 3.7.3.1.1b is used. The Modal Response Spectra Method is normally used for piping systems in the flexible or resonant region.

Frequencies for the reactor coolant system and reactor internals are calculated in accordance with the procedures described in Subsection 3.7.3.].2.3 (b) and 3.7.3.]4, respectively. The three ranges of equipment/support behavior (rigid, flexible, resonant) are not delineated for NSSS vendor supplied subsystems. (Currrent Section 3.7.3.4 describes procedures for NSSS vendor supplied subsystems).

Question No. 23

Justification has been provided for the use of the equilalent static load method for piping systems. Similiar justification is needed for all equipment for which this method was used. Also provide clarification on how the modified equivalent static load method differs from the equivalent static load method.

Response

The modified eqivalent static load method as described in FSAR Subsection 3.7.3.1.1.b, is a frequency based static analysis. It is applicable when the piping system is proved to be in the relatively rigid side of the dominant frequency of the supporting structure. At first, the fundamental frequency of the piping system is determined by the same stiffness matrix method of natural mode analysis described in FSAR Subsection 3.7.3.1.1.a.2,then a static analysis is performed using an acceleration value of 1.5 times the maxium value of the applicable floor response sectrum in the period range equal to or less than the first mode period of the piping system.

The equivalent static load method, as we interpret from SRP 3.7.3 Section II, b does not require demonstration of the fundamental frequency of the piping system, equipment ect. a factor of 1.5 is applied to the peak acceleration of the applicable floor response spectrum to obtain the equivalent static load.

As indicated in FSAR Subsection 3.7.3.1.1, the seismic analysis of Non-NSSS piping is done by using one of the three following methods:

a) Modal Response Spectra Method-- This method is based on the classical modal analysis which involves the calculation of all the significant natural frequencies and their mode shape vectors and the response combination of these modes of vibration.

b) Modified Equivalent Static Load Method (Simplified dynamic analysis) This method involves the calculation of the first mode period of the piping system to determine the applicable value of accelerations which in turn is used in the equilavent static analysis.

c) Simplified Static Method (chart method)--- This method involves the development of reference restraint spacing based on preset value of fundamental piping period to preclude the possible resonance with the support structure. The location of restraint on the piping system is determined by comparing the individual selected restraint spacing with the reference restraint spacing.

Question No. 24

Discuss the approach for combining the loads corresponding to the three components of earthquake motion when the time history method of analysis is used.

Response

For NSSS vendor supplied subsystems analyzed by time history methods, maximum components of reaction at all design points are calculated for each separate direction of seismic excitation. Maximum co-directional responses resulting from each of the three orthogonal directions of ground excitation are then combined by the square root of the sum of the squares (SRSS) method. The resultant six load components are applied simultaneously in computing the stresses for each component or structure. (See Section 3.7.3.1.2.4).

Question 25

The criteria to be used in the analysis of multiple supported equipment and components meet the staff requirements as outlined in NRC Standard Review Plan 3.7.3 Section II-9 with the exception that a committment be made to combine the support displacements in the most unfavorable combinations.

Response 25

For combination of support displacements of the piping system, see Response to 3.7.3.1 (3), Question 18.

For NSSS vendor supplied multiple supported components analyzed by the response spectrum method, the support displacements are imposed on the supported item in the most unfavorable combination using static analysis procedures. The responses due to the inertial effect and relative displacement are combined by the absolute sum method. (See Section 3.7.3.1.2.3(d) for surge (and spray) line analysis). The analysis of the multiple supported coupled components of the RCS are analyzed using time history procedures with the relative support displacements applied directly as described in Section 3.7.3.1.2.3.

Note: FSAR Section 3.7.3.9(c) currently provides commitment requested by draft SER.

7/29/81

Question No. 26

This section concerning the interaction of other piping with seismic Category I piping adequately defines how these piping systems are handled when they are a part of the same system. However, information is required as to how Non-Category I piping systems are analyzed and/or isolated from Category I piping when the systems are in close proximity so that a failure of the Non-Category I piping would not damage the Category I piping. piping.

Response

As required for safe plant shutdown, non-category I piping is seismically supported where it passes over seismic Category I piping, valves and valve operators.

Attachment #26

Buried seismic Category I piping is assumed to be distorted in the same fashion as the earth, hence a straight run of piping would assume a sinusoidal wave shape. All buried seismic Category I piping is located in Class 1 fill which provides a medium of continuous support and restraint, thus precluding unacceptable seismic displacement.

The underground duct banks containing Class 1E electrical cables are seismically analyzed.

3.7.3.13 Interaction of Other Piping with Seismic Category I Piping

In general all non-seismic Category I piping systems are designed to be isolated from any seismic Category I piping system.

Where seismic Category I piping systems are in close proximity to non-seismic systems, the excessive movement of the non-seismic Category I system due to seismic induced effects is restrained so that no failure of the seismic Category I system occurs.

If not isolated by a barrier, the adjacent non-seismic Category I piping is analyzed and supported according to the same seismic criteria as applicable to the seismic Category I piping system.

Where seismic Category I piping is directly connected to nonseismic piping, the seismic effects of the nonseismic piping are prevented from being transferred to the seismic Category I piping by placing anchors or combinations of restraints beyond the interface. The portion up to the anchor is included in the dynamic modeling of the seismic Category I piping. The attached non-seismic Category I piping, up to the first anchor beyond the interface, is also designed in such a manner that during an earthquake of SSE intensity it does not cause a failure of the seismic Category I piping.

Non-seismic lines are seismically supported where they pass over seismic Category I piping, valves and valve operators.

QUESTION 28
(Section 3.7.3.14)

A description of the linear vertical analysis and nonlinear horizontal analysis is provided. Verify whether or not a vertical nonlinear analysis is used in the event that the linear vertical analysis indicates that the response of the core may be sufficiently large to lift off the core plate. In case it is used, provide a description of the analysis.

Response:

A linear analysis has been completed. Because of the low level of excitation, the fuel does not lift off the core support plate. Therefore, a nonlinear analysis is not required.

QUESTION 29
(Section 3.7.3.14)

Provide a commitment that closely spaced modes are considered as per Regulatory Guide 1.92, in the analysis of the reactor internals and the core.

Response:

In the analysis of reactor internals and the core, closely spaced modes are considered in accordance with Regulatory Guide 1.92.

Question No. 30
3.9.2.1 Piping Preoperational and Startup Testing Program

Piping vibration, thermal expansion, and dynamic effects testing will be conducted during the St Lucie plant's preoperational and startup testing program. The purpose of these tests is to confirm that the piping, components, restraints, and supports have been designed to withstand the dynamic loadings and operational transient conditions that will be encountered during service as required by the ASME Section III Code and to confirm that no unacceptable restraint of normal thermal motion occurs. We have identified the following open issues in our review. The issues are identified by sections of the FSAR.

Many of the items required by the Standard Review Plan (SRP) Section 3.9.2 are covered only briefly or not at all in this section. The SRP Acceptance Requirements II.1a through f and items a through d of the review procedures should be addressed before this FSAR Section can be considered acceptable. The staff requires a commitment to test all high energy piping and all seismic Category I moderate energy piping, including supports and restraints for thermal expansion, steady state vibration, dynamic and transient loads.

Response

SRP Section 3.9.2 Acceptance Requirements IIa through f and Review Procedure items a through d are addressed in the revised FSAR Subsection 3.9.2.1. At the time of this response the list of snubbers (reg. wire) by SRP 3.9.2 Acceptance Criteria 1.d and list of deflection points required by SRP 3.9.2 Acceptance Criteria 1.c are not complete. These items will be furnished in a later ammendment.

3.9.2 DYNAMIC SYSTEM ANALYSIS AND TESTING

3.9.2.1 Preoperational Vibration, Thermal Expansion and Dynamic Testing on Piping

Piping vibration, thermal expansion and dynamic effect testing will be conducted during preoperational and startup testing. The purpose of these tests is to confirm, by observation or measurement, as appropriate, that the piping systems, restraints, components and supports are capable of withstanding the flow-induced dynamic loadings under steady state and anticipated transient operating conditions. In addition, thermal motions will be observed or monitored as appropriate to verify movements predicted by analysis and ensure that adequate clearances exist to allow the required normal thermal movement of systems, components and supports.

This testing program is designated to fulfill the requirements of Regulatory Guide 1.68, Revision 2. The following piping is included in the Test Program:

- ASME Code Class 1, 2 and 3 Systems
- Other high energy systems within seismic Category I structures
- High energy portions of non-safety systems whose failure could reduce the functioning of any seismic Category I plant feature to an unacceptable level
- Seismic Category I portion of moderate energy piping systems located both inside and outside containment.

Certain lines which fall in the categories above will be exempted from testing for the following reasons:

- Line is rarely used, or when used, is not related to plant shutdown
- Line is both isolated from source of vibration and has a low momentum flow
- Line is continuously supported (e.g., buried lines)
- Line cannot be tested under the operational conditions for which it is designed during preoperational or startup testing (e.g., containment spraying headers).

Test boundaries of each system subject to test will be marked on isometrics as well as corresponding allowable vibratory and thermal motion for points which are to be observed.

3.9.2.1.1 Vibrational Testing

The vibration tests are performed during those system operating modes where significant vibratory response is anticipated, based on operating experience with similar systems in nuclear power plants. Prior to implementation of the test program, a test procedure will be written which will contain a

3.9.2.1.1 (cont'd)

description of the tests; a complete listing of the systems to be tested and of the various modes of operations under which they are to be tested and the acceptance criteria for each test. For example, Table 3.9-15 gives a summary listing of possible testing modes for selected systems.

They are divided into two categories:

> Steady State - Repetitive vibrations, such as when pumps are operating, which occur for relatively long periods of time during the normal plant operations;
> Transient - Vibrations which occur during relatively short periods of time. Examples are single and multiple pump start, rapid valve opening or closing and safety relief valve operation.

To simplify the testing efforts, four (4) levels of test (based on their sophisitication) are identified:

3.9.2.1.1.1 Level 1 - Visual Observation Test

The purpose of this test is to visually determine the acceptability of the vibration for the piping subject to test.

Testing at Level 1 is judged sufficient to determine the acceptability of steady state and transient vibration for many cases, based on industrial experience with similar systems. This flexibility results in high allowable peak-to-peak displacements which might be easily observed visually. Locations having allowable peak-to-peak displacements in excess of 20 mils will be clearly observable visually and require no specific definition of their location. All locations with allowable peak-to-peak displacements less than 20 mils will be marked up on the isometrics as well as the respective distances from which these vibrations must be imperceivable to be acceptable. The distances, marked up on the isometrics, will be derived by determination of a visually observable maximum amplitude which would result in a dynamic stress less than or equal to 50 percent of the alternating stress amplitude at 10^6 cycles as shown in the ASME Code. In addition to marked points, special attention will be paid to observing:

a) Elbow spans and spans adjacent to elbows;
b) Spans with lumped masses such as valves and flanges;
c) Vents, drains, and instrumentation lines.

Simple charts, which quickly and conservatively determine allowable peak-to-peak displacement for any piping span configuration, will be provided for this purpose. Should the Level 1 test procedure lead to inconclusive results, a Level 2 test is to be performed.

3.9.2.1.1.2 Level 2 - Hand Held Amplitude Test

The purpose of this test is to determine the vibratory displacement of those piping segments for which Level 1 visual observations are inconclusive.

3.9.2.1.1.2 (cont'd)

This Test Procedure is applicable for both steady state and transient conditions. A Level 2 Test, utilizing a hand-held vibration indicator to measure peak-to-peak displacement, will be performed at prescribed locations. The locations will be chosen on the basis of dividing the piping systems into a series of representative spans. A span is defined as any part of a piping system between two consecutive restraints which function in the same direction, or a cantilever. Instruction on how to break down each piping system into different span configurations will be provided as part of the test procedure. The measurement locations and acceptable criteria for the different span configurations will be given in the Test Procedure.

Stress amplitudes due to vibration will be considered acceptable if they do not exceed 50% of S_a and 10^6 cycles as shown in Figures I-9 of the ASME B&PV Code, Section III 1971 edition up to and including the Summer 1973 addenda.

For low cycle ($<10^6$ cycles) transient vibrations, the acceptance criteria is predicated on the following:

a) If observed displacements are such that the maximum dynamic amplitude stress does not exceed 50% of S_a at 10^6 cycles as shown in Figures I-9 of the ASME B&PV Code, Section III 1971 edition up to and including the Summer 1973 addenda, then the vibration is acceptable.

b) If measured displacements are larger than a) above, then:

1) A cumulative usage factor U_v is computed from

$$U_v = i \; \frac{N_i}{N^i_{AL}}$$

where:

N_i = number of type i transients times the effective number of cycles for each type i transient, and

N^i_{AL} = allowable number of cycles for type i transient corresponding to the alternating stress, S_i, where

S_i = the maximum alternating stress produced by the type i transient.

The vibration is acceptable if U_v 0.1.

Instrumentation Requirements for Level 2 test are given in Table 3.9-16.

If the test results do not meet the Level 2 acceptance criteria, then a Level 3, Hand Held Amplitude/Frequency Test will be performed for cases of steady state vibration and Level 4, Instrumentation-Stress Test for cases of transient vibrations.

3.9.2.1.1.3 Level 3 - Hand Held Amplitude/Frequency Test

The purpose of this test is to determine the vibratory and respective peak-to-peak displacements of piping segments for which the results of the Level 2 testing are inconclusive. Portable instruments are used for this test. Acceptance criteria incorporated in the same charts used for Level 2 tests and/or computer analysis used to determine dynamic stresses, based on the measurement results, will enable a final conclusion regarding the acceptability of steady state vibration.

3.9.2.1.1.4 Level 4 - Instrumentation - Stress

This test will be performed for those transient events for which the results of Level 3 testing are inconclusive. A time history analysis of the piping system response to the transients will be performed utilizing the computer program PLAST. The location of maximum stress points, maximum displacement points and maximum restrained loads will be calculated. The results will give all necessary information to establish acceptance criteria and to select proper testing sensors. Fluid parameters will be measured if required. A data acquisition system will be used to record information during testing.

In addition, Level 4 Testing may be used for shock or pulse type transients. A computer time history analysis of the piping and support system response to the pulse is generated to optimize transducer locations. During the test, real time data is recorded for later analysis.

3.9.2.1.1.5 Corrective Action

In the unlikely event that the piping vibration exceeds the acceptance criteria for Level 3 or 4 tests, then corrective actions will be initiated. Possible corrective action includes: (1) identification and reduction or elimination of the offending force, (2) detuning of resonant piping spans by appropriate modifications to the restraint system, (3) addition of bracing to stiffen the system, and (4) changes in operating procedures to eliminate troublesome operating conditions.

Following corrective action, additional testing shall be performed to determine if the vibrations have been sufficiently reduced to satisfy the acceptance criteria and the piping stress analysis shall be revised to include the corrective measures. Corrective action will be documented in preoperational test procedures as required and will be available for NRC review.

The methodology described above is summarized in the General Flow Chart in Figure 3.9-19.

3.9.2.1.2 Thermal Expansion Testing

Thermal expansion testing will be performed to verify that the measured movements at particular locations are approximately equal to those predicted by analysis and to ensure that the piping is not restrained due to interferences with other components.

Prior to the implementation of the testing program, a test procedure will be written identifying systems to be tested and expected movements at those chosen points. A rationale will be provided for the choice of measurement points.

3.9.2.1.2 (cont'd)

Information concerning inspection and testing of snubbers is contained in the answer to Question 44. Subsection 14.2.12.1.10.T of the FSAR contains a description of the test program.

TABLE 3.9-15

LIST OF VIBRATION TESTING MODES

Piping Systems	Flow Modes for Preoperational Vibration Testing				Instrumentation Required
	Steady State	Test Level	Transient	Test Level	
Main Steam from Steam Generators to MSIV's	100% Power	1	Turbine trip at 100% power	2	(to be added)
	Full flow though atmospheric dump valves, all valves open	1	None	–	–
Main Steam to Auxiliary Feedwater Pump Turbine	Run at full pump flow	1	AFW turbine trip at full pump flow	1	None
Feedwater and Auxiliary Feedwater	Single AFW Pump Operation for Pumps 2A, 2B, 2C; recirculation mode	1	Pump start, recirculation mode FW reg valve	1	None
Intake Cooling Water Pumps Discharge Piping	Pump(s) Operating	1	None	–	None
Component Cooling Water	Pump(s) Operating	1	None	–	None
Diesel Oil Transfer Pump Discharge Piping	Pump(s) Operating	1	None	–	None
Steam Generator Blowdown	Flow at normal rate	1	Initiate flow, system cold	1	None
	Flow at maximum rate	1	None		

TABLE 3.9-15 cont'd

LIST OF VIBRATION TESTING MODES

Piping Systems	Flow Modes for Preoperational Vibration Testing				Instrumentation Required
	Steady State	Test Level	Transient	Test Level	
Reactor Coolant Main Loop	Single and Multiple Pump Operation	1	Pump(s) starts and stops	1	None
			Pressurizer Spray Valve Cycling	2	Hand-Held Vibration Amplitude Meter
Relief Valve Discharge Piping			PORV operation	4	(to be added)
Chemical & Volume Control System	Letdown flow modes	1	None	-	-
	Boric acid makeup pumps 2A and 2B	1	None	-	-
	Charging Pumps 2A, 2B and 2C Single and Multiple pump operation	2	Single and Multiple Pump starts and stops	2	Hand-Held Vibration Amplitude Meter.
Low Pressure Safety Injection	LPSI Pumps 2A and 2B operating in minimum recirculation mode	1	None	-	-
	Shutdown Cooling mode	1	None	-	-
High Pressure Safety Injection	HPSI Pumps 2A and 2B operating in minimum recirculation mode	1	None	-	-
	Safety injection mode	1	None	-	-

TABLE 3.9-15 cont'd

LIST OF VIBRATION TESTING MODES

Piping Systems	Flow Modes for Preoperational Vibration Testing				Instrumentation Required
	Steady State	Test Level	Transient	Test Level	
Fuel Pool Cooling	Pump(s) 2A and 2B operating	1	None	-	-
Containment Spray	Pumps 2A and 2B in minimum recirculation mode	1	None	-	-
Hydrazine Injection	Pumps 2A and 2B operating	1	Pump(s) start and stop	1	None

TABLE 3.9-16

INSTRUMENTATION REQUIREMENTS FOR LEVEL 2 TEST

To perform the Level 2 Test, the following instruments are needed:

1. Transducers (Accelerometers)

   Range of amplitudes up to 500 mils
   Range of frequencies: 5 - 1000 Hz
   Maximum operating temperature: 600°F

   Hand-held transducers may be used for steady state vibration measurements if testing temperature is less than 250°F. Temporarily mounted transducers are recommended for: (a) steady state tests, if piping temperature exceeds 250°F; (b) all Level 2 transient tests. Clamped brackets or magnetic bases will be used to mount transducers.

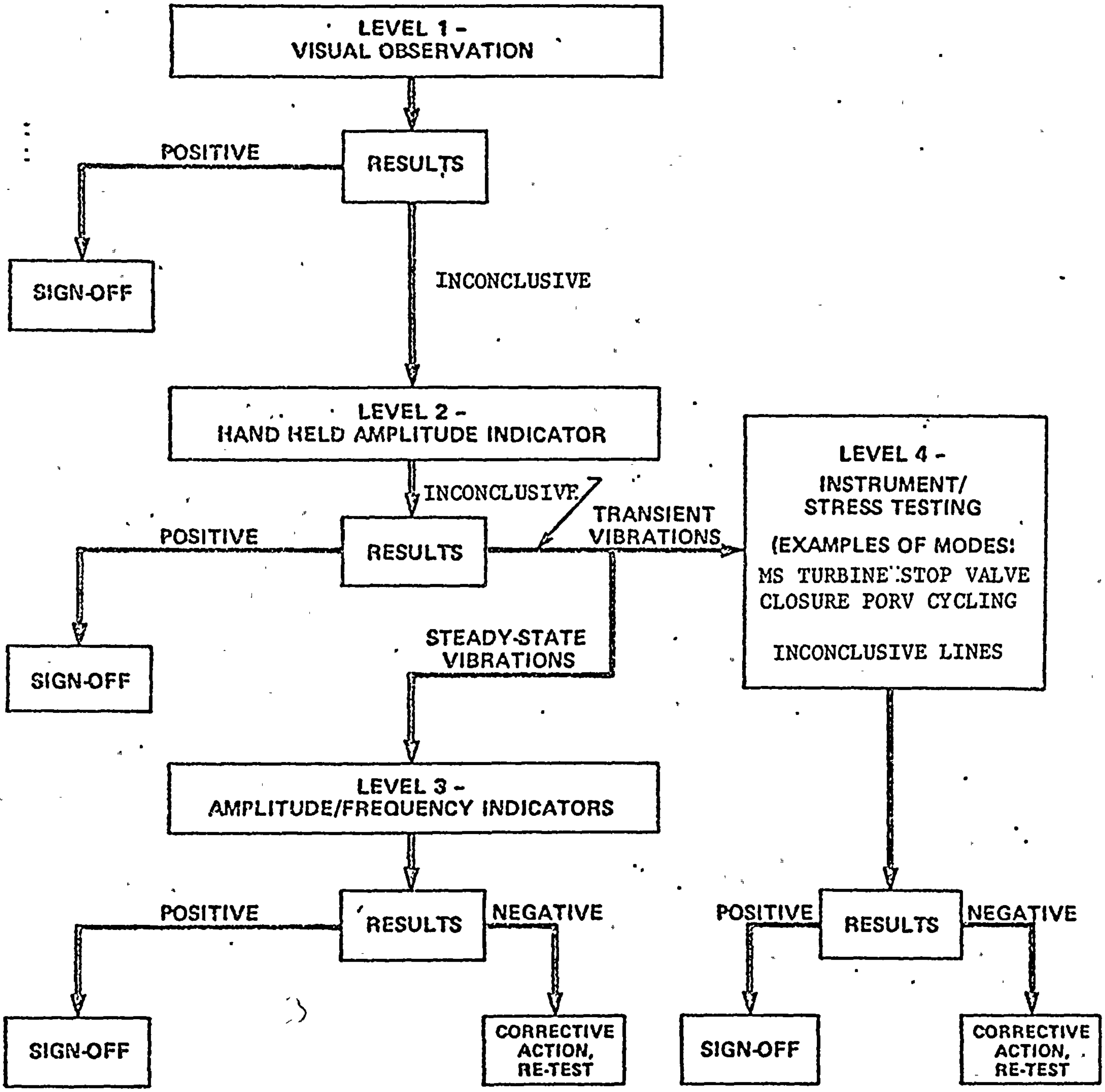
2. Hand-Held Vibration Indicators for Steady State Testing

   Each instrument shall have the following range of scales:

   (a) 0 - 10 mils (b) 0 - 20 mils (c) 0 - 40 mils
   (d) 0 - 100 mils (e) 0 - 300 mils (f) 0 - 600 mils

3. Hand-Held Peak Hold Indicator for Transient Test

   Required ranges of displacement are the same as for steady state testing in Item (2) above.



GENERAL FLOW CHART FOR PIPING VIBRATION TESTING

Figure 3.9-19

14.1.12.1.10.T PIPING THERMAL EXPANSION AND RESTRAINT

<u>Objective</u>

To verify that piping systems within the test boundaries (e.g., main steam, feedwater, safety injection, CVCS) are free to expand thermally, that spring hangers do not bottom out or unload, that snubbers do not restrict thermal movements, and that these movements are within design allowances.

<u>Prerequisites</u>

a) Verify that temporary structures and restraints that could interfere with system expansion are removed.

b) Pre-service inspection of snubbers included in this test has been completed within six months of the start of the test.

c) All other hangers and restraints affected by this test have been inspected for correct installation and adjustment.

<u>Test Method</u>

a) Verify expected piping thermal expansion at RCS temperature plateaus during hot functionals.

b) For safety-related systems whose normal operating temperature exceeds 250° F that are expected to attain operating temperature during hot functionals, verify expected snubber thermal movement and swing clearance at RCS temperature plateaus.

c) For safety-related systems whose normal operating temperature exceeds 250° F that do not attain operating temperature during hot functionals, verify by observation and/or calculation that snubbers will accommodate the projected thermal movement.

d) Monitor piping and snubber movement during cooldown.

<u>Acceptance Criteria</u>

a) There is no evidence of interference with thermal expansion of any system piping or component other than by supports shown on the piping isometric.

b) Measured thermal displacements of piping, spring hangers, and snubbers is within $\pm$ 20% or 1/4 inch (whichever is greater) of the displacement predicted by the stress analysts from the stress isometric drawings.

c) Snubber swing clearances are acceptable (i.e., snubber movement envelopes are free from obstructions).

d) System piping, spring hangers, and snubbers return to their cold position following system cool-down.

Question 31-1

Justify decoupling the horizontal and vertical components of the responses to blowdown loads.

Response

The axial and lateral internals models were uncoupled to provide more spatial detail to account for important structural characteristics in the separate models. There is a separation in the axial and lateral natural frequencies, so that the response characteristics in the separate directions are not coupled. Typical lateral natural frequencies for St. Lucie #2 range from 2 to 25 hertz. Typical vertical natural frequencies range from 25 hertz to 200 hertz. The results of the analyses show the lateral displacements to be small and, when combined with the maximum axial loads, the beam column effects are negligible. Typical peak horizontal relative displacements for St. Lucie #2 are .100 inches. Typical peak vertical displacements are approximately 1/10 of horizontal.

Question 31-2

Justify the use of results of linear analysis for the inherent nonlinear problem.

Response

The horizontal and vertical models which were used to determine the LOCA structural responses of the reactor internals were nonlinear. The CESHOCK (references 1, 2, 3) code was used to calculate the maximum component loads that resulted from the postulated hot and cold leg breaks. These analyses considered nonlinearities such as gaps, damping, friction, hysteresis and coefficient of restitution.

References:

1. "Topical Report on Dynamic Analysis of Reactor Vessel Internals Under Loss-of-Coolant Accident Conditions with Application of Analysis to C-E 800 Mwe Class Reactors," Combustion Engineering, Inc., Report CENPD-42, August 1972 (Proprietary).

2. Gabrielson, V.K., "SHOCK, A Computer Code for Solving Lumped-Mass Dynamic Systems," SCL-DR-65-34, January 1966.

3. "Structural Analysis of the 16 x 16 Fuel Assembly for Combined Seismic and Loss-of-Coolant-Accident Loadings," CENPD-178P, Combustion Engineering Propriety Report, October 1976.

Question 31-3

Present a discussion outlining the effects of system flow upon mass and flexibility properties.

Response

The effects of system flow on the dynamic response of reactor vessel internals are secondary. The hydrodynamic effect of these components is dominated by hydrodynamic coupling and hydrodynamic added mass. Both of these effects are considered in the dynamic response analyses of these components. A detached description of CE methodology for hydrodynamic mass is presented in CENPD-178-P REV 1, "Structural Analysis of Fuel Assemblies for Seismic and Loss-of-Coolant-Accident Loading" to be released in August 1981. Additional references which describe this hydrodynamic mass methodology are listed below.

1. Fritz, R. J. "The Effect of Liquids on the Dynamic Motions of Immersed Solids," Journal of Engineering for Industry, Paper No. 71-VIB-100.

2. McDonald, D.K. "Seismic Analysis of Vertical Pumps Enclosed in Liquid Filled Containers," ASME paper No. 75-PVP-56.

Question 32

We find this program acceptable provided the applicant submits a correlation of the St. Lucie Unit 2 observed vibrational characteristics with the results from the prototype reactors. If the comparison of the observed vibrational characteristics of St. Lucie with those of the prototype plants indicate the need for any corrective action, the staff will review the applicant's proposed corrective action for St. Lucie Unit 2 and provide its evaluation in a supplement to this SER.

Response

During the preoperational test program, the internals are subjected to the significant flow modes of normal plant operation. Before and after these flow tests, the internals are fully examined to determine any evidence of excessive vibrations. The observed vibrational characteristics of St. Lucie 2 will be compared to those of the prototype plants as described in Subsection 3.9.2.4. A separate report will be sent to the NRC after the final examination that will contain the results of the program as well as identify any needs for corrective action.

Question 33

The discussion of plant conditions in Subsection 3.9.3.1 of the FSAR requires clarification. The Loading Combination Method of response combination and allowable limits should be provided for all ASME Class 1, 2 and 3 components and their supports for each design and service condition.

Response

The plant conditions considered for the seismic qualification of the mechanical components are normal, upset, emergency and faulted. The Design Loading Combination for each plant condition is provided on FSAR Table 3.9-5 while the corresponding allowable stress limits are provided on FSAR Table 3.9-6 and 3.9-7. When dynamic loadings are present, the methodology of combining responses met the requirement of NUREG 0484, Revision 1, dated May 1980. As illustrated in the NUREG a summation of the static loads are combined by the absolute sum method with the combined dynamic loads. FSAR Appendix 3.9A provides the seismic loading criteria and the results of analysis which illustrates that the actual loads encountered are less than the ASME allowables.

The loading combinations and design stress limits for ASME code class and NSSS components (except valves) are presented in Table 33-1 and 33-2. The loading combinations and stress limits for valves, pumps, and all other class 2 and 3 components are presented in Tables 33-3 through 33-8.

Note: The use of emergency limits in Table 3.3-1 for other than the ATWS event is under generic discussion with respect to probability of occurrence of specific events. Refer Item 55.

TABLE 33-1

LOADING COMBINATIONS ASME CODE CLASS 1 NSSS COMPONENTS

EXCEPT VALVES (TABLE 3.9-1)

Condition	Design Loading Combination[a]
Design	PD
Normal(b)	PO + DW
Upset (b)	PO + DW + OBE
Emergency	PO + DW + DE
Faulted	PO + DW + DBE + DF

(a) Legend:

PD = design pressure

PO = operating pressure

DW = dead weight

OBE = operating basis earthquake

DBE = design basis earthquake

DE = Dynamic system loadings associated with the emergency condition (5 cycles of complete loss of secondary pressure)

DF = Dynamic system loadings associated with a postulated pipe rupture (LOCA) or steam line break

(b) As required by ASME Code Section III, Division I, other loads such as thermal transient, thermal gradient, and anchor point displacement portions of the OBE require consideration in addition to the primary stress producing loads listed.

Method of combination: NUREG 0484

TABLE 33-2

STRESS LIMITS FOR ASME CODE CLASS 1

NSSS COMPONENTS EXCEPT VALVES

(TABLE 3.9-1)

Condition	Stress Limits[a]
Normal and upset	NB 3223 and NB 3654
Emergency	NB 3224 and NB 3655
Faulted	NB 3225 and NB 3656

(a) As specified in ASME Section III, 1971 and applicable addenda.

TABLE 33-3
LOADING COMBINATIONS FOR
NSSS VALVES CLASS 1, 2 and 3

Condition	Loading
Design	PD
Normal	PO + DW + SSE + T
Upset[(1)]	PO + DW + SSE + T
Emergency[(2)]	PO + DW + SSE + T

(1) Jamesbury supplied valves only

(2) Fischer supplied valves only

PO - Operating Pressure

PD - Design Pressure

DW - Dead Weight

SSE - Safe Shutdown Earthquake

T - Transients

Note: All loads are absolutely summed

TABLE 33-4

DESIGN STRESS LIMITS FOR
NSSS VALVES CLASS 1, 2 and 3

Condition	Stress Limits(2)		
	σ_m	$(\sigma_m \text{ or } \sigma_L) + \sigma_b$	
Design	Sm	1.5 Sm	Pr
Normal	Sm	1.5 Sm	Pr
Upset	1.1 Sm	1.65 Sm	1.1 Pr
Emergency	1.2 Sm or Sy(1)	1.8 Sm(1)	1.2 Pr

Notes:

(1) Greater of 1.2 Sm or Sy

(2) For Class 2 and 3 valves Sm is replaced by S

TABLE 33-5

LOADING COMBINATIONS FOR

NSSS PUMPS CLASS 2 AND 3

Design = DP+DW+NL+SSE

DP = design pressure

DW = dead weight

NL = nozzle loads (include piping imposed thermal expansion, dead weight and seismic)

SSE = safe shutdown earthquake

Note: All loads are absolutely summed.

TABLE 33-6

DESIGN STRESS LIMITS FOR

CODE CLASS 2 AND 3 NSSS PUMPS

later

TABLE 33-7

LOADING COMBINATIONS FOR NSSS ASME CODE

CLASS 2 AND 3 COMPONENTS OTHER THAN VALVES AND PUMPS

(VESSEL AND SUPPORTS)

Condition	Design Loading Combinations[a]
Design	PD + NL
Normal	PO + DW + NL
Upset	PO + DW + OBE + NL
Faulted	PO + DW + SSE + NL[1]

(a) Legend:

PD = design pressure

PO = operating pressure

DW = dead weight

OBE = operating basis earthquake

SSE = safe shutdown earthquake

NL = nozzle loads (includes piping imposed thermal expansion, dead weight and seismic)

(1) Nozzle loads are increased by 50% for the faulted loading condition. The 50% increase for faulted nozzle loads is confirmed to be acceptable by the piping analysis.

Note: All loads are absolutely summed.

TABLE 33-8

DESIGN STRESS LIMITS FOR
CODE CLASS 2 & 3 NSSS COMPONENTS
OTHER THAN VALVES AND PUMPS
(VESSELS & SUPPORTS)

Components	Condition	Stress Limits	
		σ_m	$(\sigma_m \text{ or } \sigma_L) + \sigma_b$
Safety Injection Tank	Normal	Sm	1.5 Sm
	Upset	Sm	1.5 Sm
	Faulted	2.0 Sm	2.4 Sm
Pressure Vessels	Normal	ASME III	NC 3300 or ND 3300
		σ_m	$(\sigma_m \text{ or } \sigma_L) + \sigma_b$
	Upset	1.1 S	1.65 S
	Emergency	1.5 S	1.8 S
	Faulted	2.0 S	2.4 S
Supports	All	ASME III, NF	

TABLE 3.9-5

DESIGN LOADING COMBINATIONS FOR AE QUALITY GROUPS B AND C COMPONENTS (VESSELS, PUMPS, VALVES)

Plant Operating Condition	Design Loading Combination
Normal	a) PO + DW
Upset	a) PO + DW + OBE b) PO + DW + OBE + RVO c) PO + DW + OBE + FVC d) PO + DW + DU
Emergency	a) PO + DW + OBE + RVO + FVC
Faulted	a) PO + DW + DBE b) PO + DW + DBE + RVO c) PO + DW + DBE + FVC d) PO + DW + FC e) PO + DW + DBE(*) + FC(*)

Notation

PO - operating pressure and temperature
DW - live and dead weight (including nozzle load)
OBE - operating basis earthquake (inertia portion)
RVO - relief valve operation (including open or closed, as applicable)
FVC - fast valve operation (as applicable)
DU - other dynamic system loading associated with plant upset conditions
DBE - design basis earthquake (inertia portion)
FC - dynamic system loadings associated with plant faulted conditions

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(*) These loads are combined in accordance with NUREG 0484, Rev. 1.

TABLE 3.9-5A

DESIGN LOADING COMBINATIONS FOR A/E QUALITY GROUPS B AND C PIPING

Plant Operating Condition	Design Loading Combinations
Normal	a) PO + DW b) TO
Upset	a) PO + DW + OBE b) PO + DW + OBE + RVO c) PO + DW + OBE + FVC d) PO + DW + DU e) TI
Emergency	a) PO + DW + OBE + RVO + FVC
Faulted	a) PO + DW + DBE b) PO + DW + DBE + RVO c) PO + DW + DBE + FVC d) PO + DW + FC e) PO + DW + DBE(*) + FC(*)

Notation

PO - operating pressure and temperature
DW - live and dead weight (including nozzle load)
OBE - operating basis earthquake (inertia portion)
RVO - relief valve operation (open or closed as applicable)
FVC - fast valve operation (as applicable)
DU - other dynamic system loading associated with plant upset conditions
DBE - design basis earthquake (inertia portion)
FC - dynamic system loadings associated with plant faulted conditions
TO - thermal loads
TI - restrained thermal expansion and the relative movement of anchor points produced by the OBE

(*) These loads are combined on the basis of SRSS in accordance with NUREG 0484, Rev. 1.

Question 34

The methods of combining responses to the various loads listed in Sections 3.9.3.1 of the FSAR are not defined. We will require a description of the methods used for the combinations of responses to all dynamic loads for all NSSS and BOP supplied ASME Class 1, 2 and 3 equipment, components and their supports. Our position on this issue is outlined in NUREG-0484, "Methodology for Combining Dynamic Responses," Revision 1 dated May, 1980.

Response

See revised loading combinations in question 33.

Question 35

The response of certain reactor coolant system components and their supports to postulated asymmetric LOCA loads needs to be addressed in accordance with NUREG-0609.

Response

TABLE I provides the status of the evaluation of components, structures, and attachments to the RCS when subjected to asymmetric loads. Where the evaluation has been completed, the results have been shown acceptable.

TABLE 1: Assessment of Structures/Asymmetric Loads

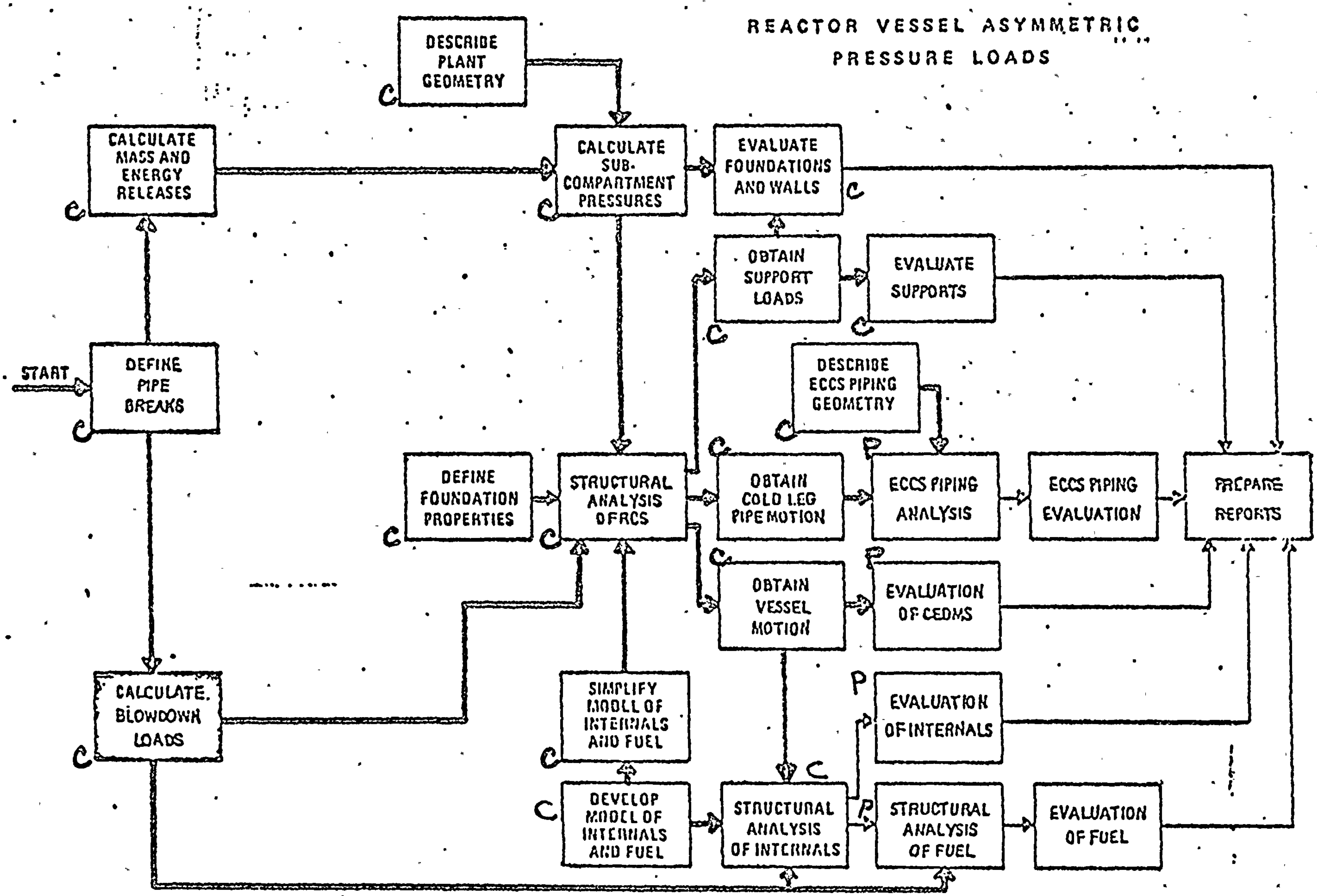
Component/Structure	Assessment Status	Evaluation Basis	Reference	Comments
Reactor Pressure Vessel	Complete	Plant Specific Analysis	FSAR 3.9.1.4.1	Complete
Steam Generators	"	"	"	"
Reactor Coolant Pumps	"	"	"	
Reactor Vessel Supports	"	"	"	
Steam Generator Supports	"	"	"	
Reactor Coolant Pump Supports	"	"	"	
Biological Shield Wall	"	"	FSAR 6.2.1.2	
Steam Gen., R C Pump	"	"	FSAR 6.2.1.2	
Compartment Wall	"	"		
RCS Main Piping	Complete	Plant Specific Analysis		

TABLE 1: Assessment of Structures/Asymmetric Loads

Component/Structure	Assessment Status	Evaluation Basis	Reference	Comments
ECCS Piping	In Progress	Plant Specific Analysis	FSAR 3.9.1.4.5	Preliminary analyses predict acceptable results. FSAR Amendment Nov. 1981.
ECCS Piping Supports & Restraints	In Progress	"	"	"
CEDMS	In Progress	"	FSAR 3.9.1.4.3	"
Reactor Internals	In Progress	"	FSAR 3.7.3.14 FSAR 3.9.2.5	Analysis nearly complete Results to date are acceptable.
Fuel	In Progress	"		Analyses expected to be completed 3/82.

ST. LUCIE UNIT 2

REACTOR VESSEL ASYMMETRIC PRESSURE LOADS



C - COMPLETE

P - IN PROGRESS

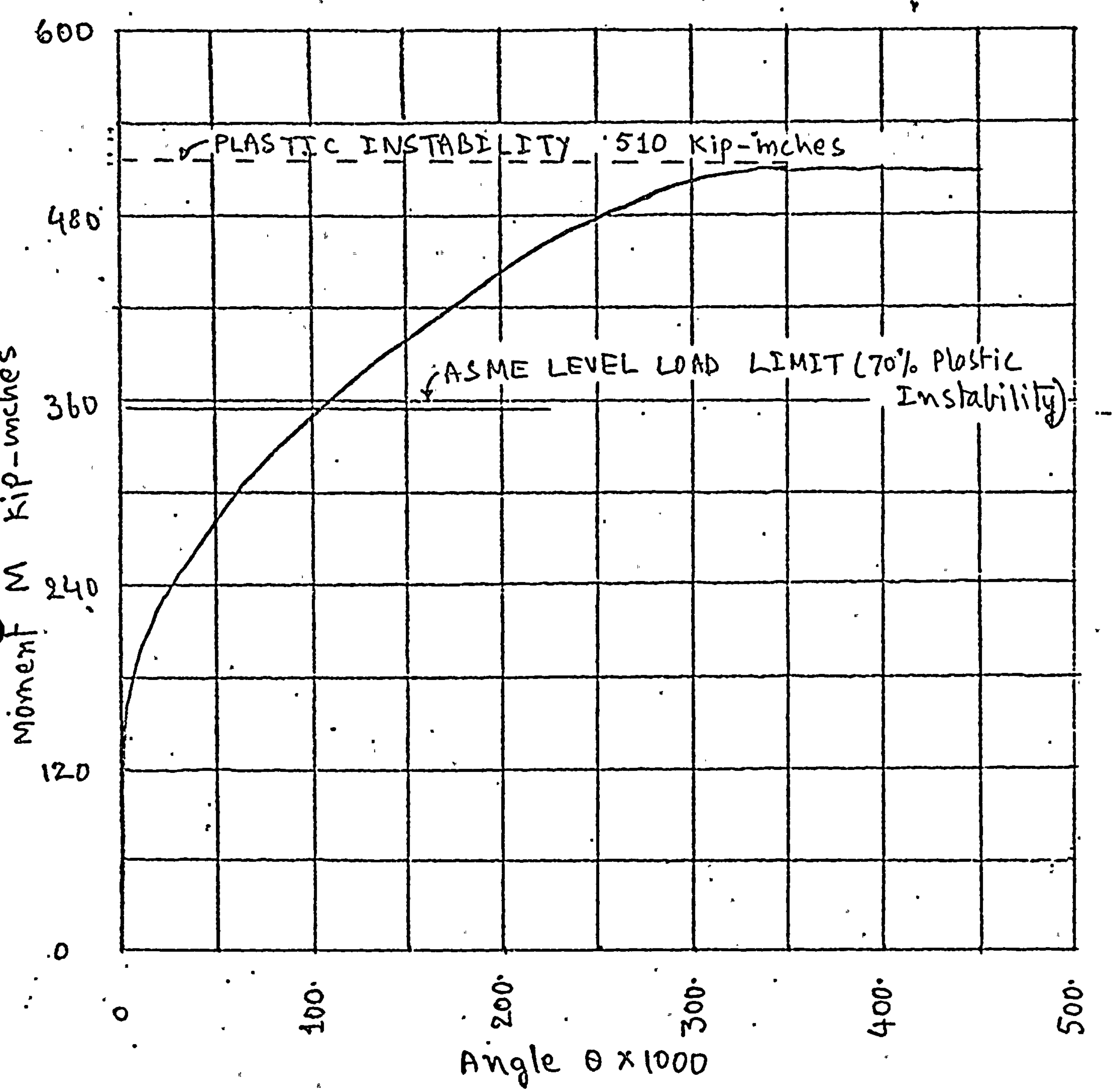
ST. LUCIE 2 CEDM

- GEOMETRY AND MOMENT CAPABILITY SIMILAR TO PALO VERDE

- PIPE BREAK + SSE HEAD VELOCITIES LOWER THAN THOSE FOR PALO VERDE

- SINCE PALO VERDE HAS BEEN DEMONSTRATED ACCEPTABLE, ST. LUCIE 2 CEDM ARE EXPECTED TO BE DEMONSTRATED TO BE ACCEPTABLE

- ANALYSIS IS EXPECTED TO BE COMPLETED BY SEPTEMBER 1, 1981



ST. LUCIE CEDM

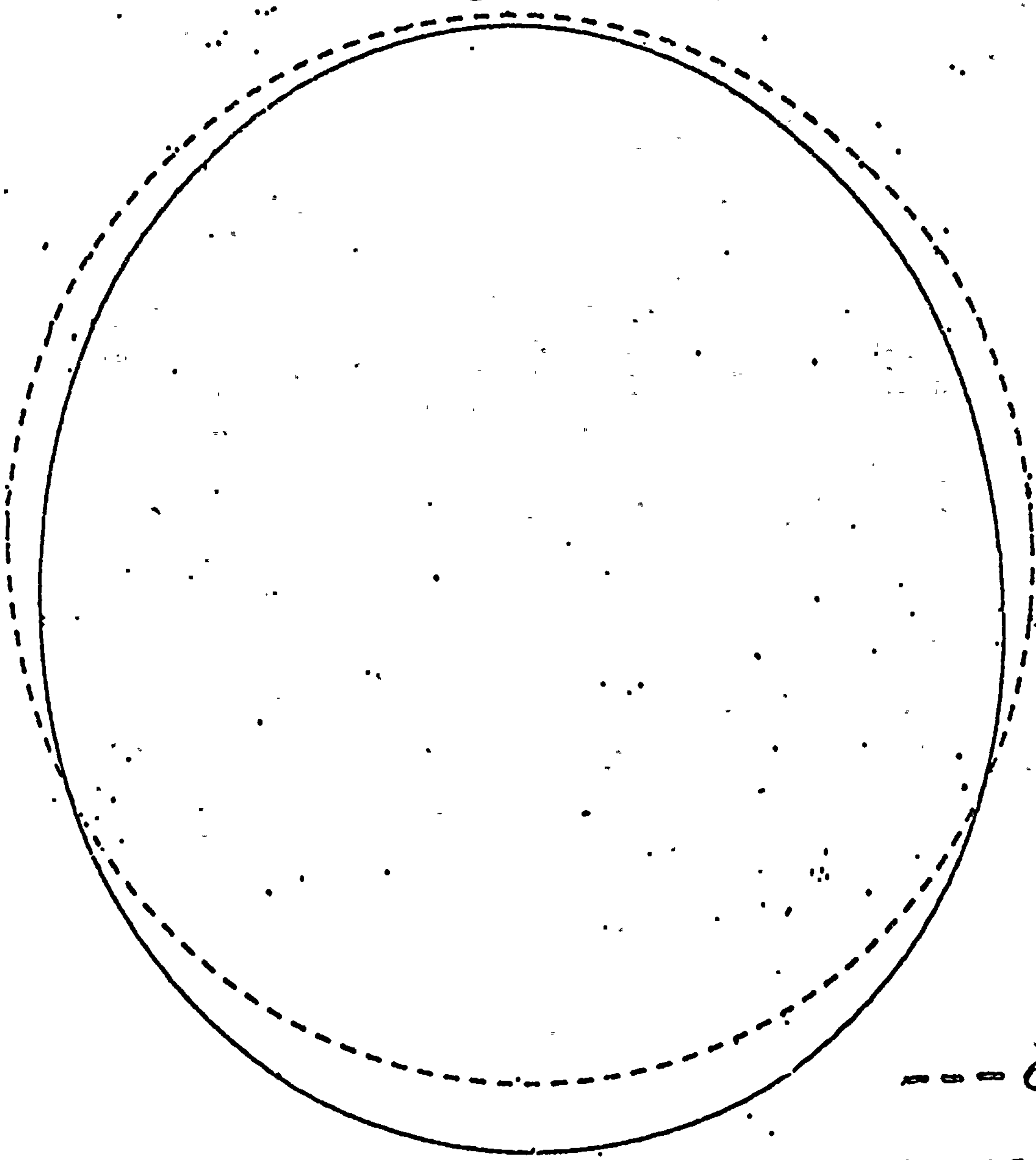
NOZZLE MOMENT CAPABILITY

ST. LUCIE 2 ECCS PIPING

- PRELIMINARY CALCULATIONS INDICATE THAT LINES 1A AND 1B ARE THE MOST SEVERELY LOADED

- COMPARISON OF INPUT MOTIONS WITH OTHER ECCS LINES PREVIOUSLY ANALYZED INDICATE THAT
    1) PLASTIC ANALYSIS IS REQUIRED.
    2) RESULTS ARE ANTICIPATED TO DEMONSTRATE ACCEPTABILITY.

- ANALYSIS IS EXPECTED TO BE COMPLETED BY SEPTEMBER 30, 1981



--- ORIGINAL SHAPE

—— DEFORMED SHAPE

EXAGGERATED BY A FACTOR OF 5

SUCTION ELBOW TOTAL CISP. AT MIDDLE SECTION

EFFECT OF MOMENT OF 60.2×10^6 IN-lb

3.9.1.4 Consideration for the Evaluation of the Faulted Condition

3.9.1.4.1 Seismic Category I NSSS Items

The major components of the reactor coolant system (RCS) are designed to withstand the forces associated with the design basis pipe breaks discussed in Section 3.6.2, in combination with the forces associated with the Safe Shutdown Earthquake and normal operating conditions. See Sections 3.9.1.1 and 3.9.3 for discussion of loading combinations. The forces associated with the postulated pipe breaks include pipe thrust forces at the break location, resultant subcompartment differential pressurization forces, and internal asymmetric hydraulic forces acting on the reactor internals. The pipe break thrust forces are determined by the methods discussed in Section 3.6.2.6.1. The time and spatially dependent asymmetric hydraulic loads acting on the reactor internals are determined by the methods discussed in Section 3.9.2.5.

A dynamic hon-linear time history analysis was performed to generate reactor vessel loads and motions due to the forces associated with the partial area pipe breaks at the reactor inlet and outlet nozzles and the steam generator inlet nozzles (See Section 3.6.2.1.1.3). The analysis used the DAGS code to perform a direct integration of the coupled equations of motion, in which the system characteristics are updated at each integration step to account for local non-linearities. These non-linearities include initial gaps and preloads at system restraints or local plastic response which may occur following a pipe break. The FORCE code post-processes DAGS response output in order to provide the loads and motions at pre-specified locations.

The analysis used a lumped parameter model including details of the reactor vessel and supports, major connected piping and components, and the reactor internals (Figures 3.9-19 through 3.9-22). This mathematical model provides a three-dimensional representation of the dynamic response of the RCS major components subjected to the simultaneous time varying pipe break forcing functions. This model is defined mathematically in terms of the ICES STRUDL II computer code to develop appropriate matrices for the elements of the three-dimensional space frame model.

The results generate reactor vessel and support loads and time history motions of RCS piping at ECCS piping juncture points, and RV shell motions at internals and CEDM support points. These motions provide input excitations for the pipe break analyses of the reactor internals, fuel, CEAS, CEDMS and ECCS piping.

The component and support loads for the Steam Generator, Reactor Coolant Pump, and Pressurizer were determined by equivalent static analyses. A load factor equal to 2.0 on the calculated thrust, jet impingement, and subcompartment pressure loads is employed to account for the dynamic response of the structure. The model employed for static analysi is shown in Figure 3.9-18

The system or subsystem analysis used to establish, or confirm, loads which are specified for the design of components and supports is performed on an elastic basis.

When an elastic system analysis is employed to establish the loads which act on components and supports, elastic stress analysis methods are also used in the design calculations to evaluate the effects of the loads on the components and supports. In particular, inelastic methods such as plastic instability and limit analysis methods, as defined in Section III of the ASME Code, are not used in conjunction with an elastic system analysis.

Analyses of the reactor coolant system components (reactor vessel, steam generator, reactor coolant pump, pressurizer, and reactor coolant piping) and their supports have been performed in accordance with the methods described above. For each component and support member, the calculated loads, in combination with the seismic loads, are below the loads specified for design, and the stresses (piping rupture in combination with SSE) are below those allowed by Section III of the ASME B&PV code for Service Level D.

3.9.1.4.2 Reactor Internals

See Sections 3.7.3.14 and 3.9.2.5

3.9.1.4.3 Control Element Drive Mechanisms (CEDMs)

The capability of the control element drive mechanisms (CEDMs) to withstand the effects of design basis pipe breaks in combination with safe shutdown seismic (SSE) loadings is evaluated by analysis. This dynamic loading is experienced by the CEDMs via the motion of the reactor vessel head. The reactor vessel head/CEDM motions due to pipe rupture and seismic loadings are calculated using the models described in section 3.9.1.4.1.

3.9.1.4.3.1 Method of Analysis

Previous studies on other CE plants (Reference 1) have indicated that the reactor vessel asymmetric load aspects of a hypothetical guillotine break produce motions which result in stresses which exceed the ASME Code Level D allowable stresses for elastic calculation. Elastic plastic dynamic analyses have demonstrated for those plants that the structural integrity of the CEDMs is not impaired by these loadings and that the ASME Code Level D allowable limits for elastic plastic calculation are not exceeded. In order to demonstrate that the integrity of the CEDMs are not impaired by pipe break and SSE loads, elastic-plastic dynamic analyses are performed.

In the elastic plastic analysis, the motions of the RV are input to the finite element model of the CEDM. Moments and deformation are computed as a function of time during the event. The moment to cause plastic instability of the most severely loaded section is computed by elastic plastic static analysis. The actual moments during the dynamic event are then compared to the plastic instability moment in order to evaluate integrity.

3.9.1.4.3.2 Models

Dynamic analysis finite element models are prepared for CEDMs near the center of the RV head and near the outer edge. The models are made up of beam type elements.

The model of the calculation of the plastic instability load is made up of shell elements in order to consider the effects of ovalization of the cylindrical section. The nozzle at the RV head is usually the most severely loaded section.

3.9.1.4.3.3 Material Properties

Recently the material properties necessary for elastic plastic analysis have been developed by the CE Metallurigical and Materials Laboratory. These properties are available for all of the materials at all of the temperatures that the CEDM normally experiences.

3.9.1.4.3.4 Loading

The effects of pipe break and SSE are transmitted to the CEDM by the motion of the reactor vessel head resulting from the analysis of Section 3.9.1.4.1.

A response spectrum is calculated for the motion of the reactor vessel head resulting from the primary system dynamic analysis for pipe break loads. This response spectrum is combined with the SSE response spectrum by taking the square root of the sum of the squares (RSS) of the ordinates of the two spectra. An artificial time history of motion is then developed from the combined acceleration spectrum and used as the input to the dynamic CEDM analysis.

Acceleration spectra resulting from pipe rupture at the RV inlet nozzle, the RV outlet nozzle, and at the steam generator inlet nozzle are compared in order to determine the most severe loading condition. If one loading condition can be identified as the most severe case, only that loading condition is used in the dynamic CEDM analysis. Other loadings are also used if they are not clearly enveloped by the most severe one.

3.9.1.4.3.5 Response

The models, material properties and RV head motion history are used in the MARC finite element program for analysis. The ANSYS program may also be used. The results of the dynamic analysis include moments, strains, stresses and deformation as a function of time. These results are presented graphically for critical regions of the CEDM. The same material properties are used in the static analysis for the plastic instability moment.

3.9.1.4.3.6 Evaluation

3.9.1.4.3.6.1 Acceptance criteria

The CEDMs are not required to operate for safe shutdown after a loss of coolant event resulting from the design basis pipe breaks. In order to comply with existing ECCS analysis methods, however, the integrity of the CEDMs must be maintained and leakage must be prevented. The ASME Boiler and Pressure Vessel Code Section III Division 1 Appendix F lists a number of criteria which assure that the pressure boundary will not be violated. These criteria include an instability limit for comparison to elastic plastic analysis results. The integrity of the pressure boundary is assured if the applied loads do not exceed 70% of the plastic instability load.

Q35 / Q47A

3.9.1.4.3.6.2 Evaluation of Integrity

The results of each dynamic analysis are compared to the results of the static plastic instability moment analysis. Integrity of the CEDMs is assured if the acceptance criteria are satisfied. Based on Reference (1) studies, it is expected that results of these analyses will demonstrate the integrity of the CEDMs. Results will be submitted in a November, 1981 amendment.

REFERENCES

1. "Reactor Coolant System Asymmetric Loads Evaluation Program Final Report", Combustion Engineering, Inc., July 1, 1980.

3.9.1.4.4

The components not covered by the ASME Code but which are related to plant safety include: (1) fuel, (2) non pressure boundary portions of control element drive mechanisms (CEDMs) and (3) control element assemblies (CEAs). Each of these components is designed in accordance with specific criteria to insure their operability as it relates to safety.

3.9.1.4.5 EMERGENCY CORE COOLING SYSTEM (ECCS) PIPING AND SUPPORTS

The capability of the emergency core cooling system (ECCS) piping and supports to withstand the effects of design basis pipe breaks are evaluated by analysis. The capability of the ECCS piping and supports to withstand the combined effects of pipe break and safe shutdown seismic (SSE) loadings are also evaluated. Pipe rupture loadings are experienced by the ECCS piping via the motion of the primary system piping, and the SSE loadings are experienced by the ECCS piping via the motion of the primary system piping and the ECCS piping supports.

The primary piping motions due to pipe rupture loadings are calculated using the models described in section 3.9.1.4.1. The seismic loadings are provided from the code stress analysis of the ECCS lines.

3.9.1.4.5.1 Method of Analysis

Previous studies on other CE plants (Reference 1) have indicated that the motion of the primary system piping at the ECCS injection nozzle due to pipe rupture loads contains frequencies which are in the range of the natural frequencies of the ECCS piping. The ECCS piping response, therefore, is sensitive to small geometry and input frequency changes. Because of this sensitivity the analysis of a pipe system may require either elastic or elastic plastic analysis.

Each ECCS pipeline to be evaluated will be analyzed by traditional dynamic elastic analysis and evaluated according to appropriate elastic stress limits for ASME Level B and Level D conditions. For pipelines where Level D limits are not satisfied, a detailed elastic plastic analysis to demonstrate integrity and functionability of the piping will be performed.

3.9.1.4.5.2 Models

The elastic dynamic analysis will be performed by using distributed mass models and the appropriate ECCS nozzle motion history. The MARC finite element program will be used for the elastic dynamic analysis for pipe rupture loads. The program will determine the motion history of the ECCS pipeline and the loads in the supports by performing the time history analysis.

Elastic plastic dynamic analysis, if required, will also be performed with the MARC finite element program. A detailed analysis of a typical pipe elbow and a typical straight section will be performed to determine the moment carrying capability, or plastic instability moment, of the elbow and pipe. This analysis also provides an elastic plastic stiffness of the elbow to be used in the pipeline dynamic analysis.

The finite element model used for the elastic plastic dynamic analysis is made up of pipe elements with modified stiffness at elbows to incorporate the ovalization effects observed in the detailed plastic elbow analyses. The stiffness and load carrying capability of the supports input to the analysis is computed by elastic or elastic plastic analysis.

3.9.1.4.5.3 Materials

The material used for the ECCS piping is ASME SA376 GRT316 stainless steel. The elastic properties required for analysis will be taken directly from the ASME Code. The elastic plastic properties will be established by scaling stress strain data available from previous CE tests to the specified code yield and ultimate stress values.

3.9.1.4.5.4 Loading

The effects of primary system pipe breaks are transmitted to the ECCS piping by the motion of the primary piping. For the evaluation of pipe break loads only, the displacement time history of the primary piping (at the ECCS injection nozzle) will be applied directly to each dynamic ECCS pipeline analysis. The displacement time history is obtained from a dynamic analysis of the reactor coolant system for postulated pipe breaks at the vessel inlet, outlet nozzles and steam generator inlet nozzle.

3.9.1.4.5.5 Response

The natural frequency of all ECCS pipelines will be determined. The results of the primary system dynamic analysis for pipe rupture at the reactor vessel inlet nozzle will be compared to the pipeline frequencies to determine which hot leg injection and which intact cold leg injection line is loaded most severely. The most severely loaded pipelines are analyzed for cold leg pipe rupture loads.

The results of the primary system dynamic analysis for pipe rupture at the reactor vessel outlet nozzle and steam generator inlet nozzle will also be compared to the pipeline frequencies. This will enable determination of the cold leg injection line which is loaded most severely. The most severely loaded cold leg injection line and the intact hot leg injection line will be analyzed for the most severe hot leg pipe rupture loads.

The analyses will result in motions and stresses in the piping and pipe support loads. Elastic-plastic analyses will in addition, result in plastic strains and deformation in the pipe and elbows.

3.9.1.4.5.6 Evaluation

3.9.1.4.5.6.1 Acceptance Criteria

The integrity and functionability of the ECCS piping must be demonstrated. Integrity and functionability are assured if the Level B (upset condition) limits of the ASME Boiler and Pressure Vessel Code Section III, Division 1, are not exceeded. If the Level B limits are exceeded, then Level D or faulted limits may be used to demonstrate that integrity is maintained. Functionability may be assured by demonstrating that the deformations of the piping are acceptable.

3.9.1.4.5.6.2 Evaluation of Integrity and Functionability

The evaluation of the effects of pipe break loads and SSE loads combined when both loadings produce only elastic stresses is by the comparison of the square root of the sum of the squares of the stresses caused by the two loadings with the elastic stress allowable.

The elastic dynamic stress results will be compared to the Level B stress limits of the ASME Code. In the event that these stress limits are not satisfied, Level D limits will be compared for demonstration of integrity. If Level D elastic limits are met, functionability will be evaluated by assessing the extent of deformation of the pipe.

The evaluation of the effects of pipe break loads and SSE loads combined in the case where significant plasticity exists in the pipe is conducted by computing the sum of the strains due to the two loadings and comparing the sum to the strain at 70% of the plastic instability load.

Integrity is demonstrated if the applied maximum moment is less than 70% of the plastic instability moment or correspondingly if the applied strain is less than the strain at 70% of the plastic instability moment.

Functionability will be evaluated by comparing the extent of deformation at the maximum loading to the deformation required to significantly affect ECCS flow.

Results will be submitted in a November 1981 amendment.

REFERENCES

1. "Reactor Coolant System Asymmetric Loads Evaluation Program Final Report, Combustion Engineering, Inc. July 1, 1980.

3.9.2.5 Dynamic System Analysis of the Reactor Internals Under Faulted Conditions

Dynamic analyses are performed to determine blowdown loads and structural responses of the reactor internals and fuel to postulated LOCA loadings and to verify the adequacy of their design. A brief description of these methods is provided below.

The LOCA maximum stress intensities in the reactor internals are determined using the combinations of lateral and vertical LOCA time-dependent loadings which result in maximum stress intensities. The maximum LOCA stresses and the maximum stresses resulting from the SSE are then combined using the root sum square method to obtain the total stress intensities.

3.9.2.5.1 Dynamic Analysis Forcing Functions

The hydrodynamic forcing functions during a postulated LOCA result from transient pressure, flow rate, and density distributions throughout the primary reactor coolant system.

3.9.2.5.1.1 Hydraulic Pressure Loads

The transient pressure, flow rate and density distributions are computed for the subcooled and saturated portions of the blowdown period during a LOCA. The computer code utilized is based on a node-flowpath concept in which control volumes (nodes) are connected in any desired manner by flow areas (flowpaths). A complex node-flow path network is used to model the Reactor Coolant System (RCS). The modeling procedure has been compared to a large scale experimental blowdown test with excellent agreement.

The laws of conservation of mass, energy and momentum along with a representation of the equation of state are solved simultaneously. The hydraulic transient of the reactor is coupled to the thermal response of the core by analytically solving the one-dimensional radial heat conduction equation in each core node.

Pre-blowdown steady state conditions in the RCS are established through the use of specified input quantities.

The blowdown loads model uses a nonequilibrium critical flow correlation for computing the subcooled and saturated critical fluid discharge through the break.

3.9.2.5.1.2 Drag Loads

A break in the primary coolant system will result in large local pressure differences across various reactor vessel internal components and an acceleration of the local fluid velocity in various regions. The acceleration of the local fluid velocity can result in higher component drag loads than occur during steady state reactor operation.

3.9.2.5.1.3 Core Loads

The total instantaneous load across the core is given by the summation of the pressure and drag forces acting parallel to the flow. The loads are obtained using a control volume approach utilizing an integrated fluid momentum equation. The drag forces are represented by the fluid shear term in this equation and consist of both frictional and form drag.

3.9.2.5.1.4 CEA Shroud Loads

During normal operation, the reactor coolant flow axially through the core into the upper guide structure. Within the upper guide structure, the coolant flow changes direction so that it exits radially through the hot leg nozzles. During a LOCA, the transverse flow of the coolant across the CEA shroud gives rise to loads which induce deflections in these shrouds.

The transverse drag forces were determined from flow model experiments which were geometrically and dynamically similar to the full-scale upper guide structure design. The measured experimental model forces were scaled-up to represent the actual forces on the upper guide structure using the computed transient flow rate and density information.

3.9.2.5.1.5 Results of Blowdown Loads Analysis

Analysis was performed of a postulated pipe break at the reactor vessel inlet nozzle. The transient pressure differences throughout the vessel are evaluated and used in the structural response calculation described below. The pressure difference across the core is also evaluated for the break.

A postulated pipe break occurring at the reactor vessel outlet nozzle was also analyzed. The pressure difference throughout the vessel is calculated. The decompression in the annulus is symmetric early in the transient because the pressure wave must travel through the core barrel internals to reach the lower plenum from where the wave propagates uniformly up through the downcomer. The axial pressure difference across the core was also calculated.

A postulated pipe break occurring at the steam generator inlet nozzle was also analyzed. The pressure difference throughout the reactor vessel was calculated. The axial pressure difference across the core was also calculated.

3.9.2.5.2 Structural Response Analyses

The dynamic LOCA analyses of the reactor internals and core determine the shell, beam and rigid body motions of the internals, using established computerized structural response techniques. The analyses consist basically of three parts: In the first part, the time-dependent shell response of the core support barrel to the transient loading is calculated using the finite-element computer code, ASHSD[8]. The second part of the analysis evaluates the buckling potential of the core support barrel for hot leg break conditions using the finite-element computer code, SAMMSOR-DYNASOR[11,12]. In the third part, the nonlinear dynamic time history responses of the reactor internals and core to vertical and horizontal loads resulting from hot and cold leg breaks are determined with the CESHOCK code, which is further described in Reference (10).

3.9.2.5.2.1 Shell Response of the Core Support Barrel

A cold leg break causes a pressure transient on the core support barrel that varies circumferentially as well as longitudinally. The ASHSD finite-element computer code is used to analyze the shell response of the CSB to the pressure transient from a cold leg break.

The CSB is modeled as a series of shell elements joined at their nodal point circles as shown in Figure 3.9-1. The length of the elements in each model is selected to be a fraction of the shell attenuation length.

A damped equation of motion is formulated for each degree of freedom of the system. Four degrees of freedom, radial displacement, circumferential displacement, vertical displacement, and meridional rotation are considered in the analysis. The differential equations of motion are solved numerically using a step-by-step integration procedure.

The circumferential variation of the pressure time-history is considered by representing the pressure as a Fourier expansion. The pressure at each elevation in the model is determined by linear interpolation. Thus, a complete spatial time load distribution compatible with the ASHSD computer program is obtained. Each load harmonic is considered separately by ASHSD. The results for each harmonic are then added to obtain the nodal displacements, resultant shell forces and shell stresses as a function of time.

3.9.2.5.2.2 Dynamic Stability Analysis of CSB

A hot leg break causes net external radial pressure on the core support barrel. A stability analysis of the CSB is performed using the finite-element computer code, SAMMSOR-DYNASOR. The effects of an initially imperfect shape based on actual out-of-roundness measurements are included in the analysis.

The CSB is modeled as a series of shell elements, as shown in Figure 3.9-2. Stiffness and mass matrices for the barrel are generated utilizing the SAMMSOR part of the code. The equations of motion of the shell are solved in DYNASOR using the Houbolt numerical procedure.

An initial imperfection is applied to the core support barrel by means of a pseudoload for each circumferential harmonic considered. The actual pressure transient loading generated by the outlet break is uniform circumferentially but varies longitudinally. The response is obtained for each of the imperfection harmonics.

Appendix F, Section III of the ASME Boiler and Pressure Vessel Code requires that permissible dynamic external pressure loads be limited to 75% of the dynamic instability pressure loads, or alternately, the dynamic instability loads must be greater than 1.33 times the actual loads. Consequently, this analysis is repeated with the imperfection applied in the critical harmonic and the pressure loading is increased beyond 1.33 times the actual loads in order to demonstrate the stability of the core support barrel.

3.9.2.5.2.3 Dynamic System Analysis of the Reactor Internals

Dynamic analyses are performed to determine the structural response of the reactor internals to postulated asymmetric LOCA loading (including reactor vessel motion effects) and to verify the adequacy of their structural design. The postulated pipe breaks result in horizontal and vertical forcing functions which cause the internals to respond to both beam and shell modes.

Detailed structural mathematical models of the reactor internals are developed based on the geometrical design. These models are constructed in terms of lumped masses connected by beam or bar elements, and include nonlinear effects such as impacting and friction. The models are developed for input to the CESHOCK code which solves the differential equations of motion for lumped parameter models by a direct step-by-step numerical integration procedure. The model definitions employ the procedures established in Combustion Engineering Topical Report CENPD-42 and, in addition, include hydrodynamic coupling effects and a detailed representation of the core support barrel to upper guide structure to reactor vessel interfaces. Separate models are formulated for the horizontal (Fig. 3.9-3) and vertical (Fig. 3.9-4) directions to more efficiently account for structural and response differences in those directions.

The models for the horizontal directions are developed in terms of lumped masses connected by beam elements. The stiffness values for the beam elements are generally evaluated using beam characteristic equations. The lumped-mass weights are based upon the mass distribution of the internals structures. Local masses such as plates and snubber blocks are included at appropriate nodes. The effect of the surrounding water on the dynamics of the internals for horizontal motion is accounted for by hydrodynamically coupling the components separated by a narrow annulus - the vessel, core barrel, core shroud, lower support structure cylinder, and upper guide structure cylinder. The clearance between the core support barrel and the reactor vessel snubbers as well as the clearance between the core shroud guide lugs and the fuel alignment plate is simulated by nonlinear springs which account for the loads generated should impacting occur. A representation of the core is included in the internals models which provides appropriate inertial and impact feedback effects on the internals response.

The vertical model stiffness values are generally calculated using bar characteristic equations. Nonlinear couplings are included between components to account for structural interactions such as those between the fuel and core support plate, and between the core support barrel and upper guide structure upper flanges. Preloads, which are caused by the combined action of applied external forces, dead weights, and holddowns are also included. Friction elements are used to simulate the coupling between the fuel rods and spacer grids.

A reduced model of the reactor vessel internals (Fig. 3.9-5) is developed for incorporation into the reactor coolant system model. The detailed nonlinear horizontal and vertical internals (plus core) models are condensed and combined into a three-dimensional model compatible with the reactor coolant system model and the computer programs through which the latter model is analyzed. The purpose of this reduced internals model is to account or the effects of the internal LOCA loads on the reactor vessel support motion and the structural loading interaction between the internals and the vessel. The reduced internals model is developed so as to produce reactor vessel support motions and loadings equivalent to those produced by the detailed internals models.

The dynamic responses of the reactor internals to the postulated pipe breaks are determined with the CESHOCK code utilizing the detailed models. Horizontal and vertical analyses are performed for both hot and cold leg breaks to determine the lateral and axial responses of the internals to the simultaneous internal fluid forces and vessel motion excitation.

The vertical excitation of the internals is calculated by the LOAD2 computer code[31] using the control volume method. In this method, the reactor internals are divided into volumes containing both structure and fluid or structure alone. The momentum equation is then applied to each volume, and a resultant force is calculated which is distributed over the structural nodes within the volume. This method takes into consideration pressure, fluid friction, momentum changes, and gravitational forces acting on each volume. The resulting load time histories are in a form consistent for CESHOCK code input.

In order to achieve an initial (prior to the pipe break) equilibrium, the initial static deflections and gaps are calculated. The resulting initial conditions and load time histories are input to the CESHOCK code and the dynamic response of the model is calculated.

The horizontal input excitations resulting from a cold leg break are the core support barrel force time history and the vessel motion time history determined from the reactor coolant system analysis. The core support barrel forces are obtained by representing the asymmetric pressure distribution time history as a Fourier expansion. The two terms ($\sin\theta$ and $\cos\theta$) which excite the beam mode of vibration are then integrated over the core support barrel and transformed into nodal force time histories.

The horizontal input excitations resulting from a hot leg break are the CEA shroud crossflow load time histories and the vessel motion time history determined from the reactor coolant system analysis. The forces applied to the shroud mass points are determined directly from the blowdown pressure time history and include the drag force and forces due to the pressure differential on the shrouds.

The results from these analyses consist of time-dependent member forces, and nodal displacements, velocities and accelerations. The load and displacement responses are used in the detailed stress analyses of the internals.

Preliminary results of reactor internals analyses indicate, on a load comparison basis, that the adequacy of the structural design of the internals will be confirmed by the detailed stress analyses. Results of the stress analysis will be submitted in a later amendment in December 1981.

31. "LOAD2 - A computer Code to Calculate Vertical Hydraulic Loads on Reactor Internals Using CEFLASH-4B Data As Input", Calculation No. 79-STA-003, G. Garner, August 24, 1979.

Q35/Q47A

3.9.5.3 Design Loading Categories

The design loading conditions are categorized below:

3.9.5.3.1 Normal Operating and Upset

The normal and upset category includes the combinations of design loadings consisting of normal operating temperature and pressure differentials, loads due to flow, weights, reactions, superimposed loads, vibration, shock loads including operating basis earthquake, and transient loads not requiring shutdown.

3.9.5.3.2 Faulted

The faulted category consists of the mechanical loading combinations of Subsection 3.9.5.3.1 with the exception that the safe shutdown earthquake (SSE) (in place of the operating basis earthquake) and the loads resulting from the loss-of-coolant accident (LOCA) are included.

3.9.5.4 Design Bases

3.9.5.4.1 Reactor Internals

The stress limits to which the reactor internals are designed are listed in Table 3.9-14.

No emergency condition has been identified for the applicable components, therefore, no appropriate stress criteria are provided.

INSERT A

~~The operating categories and stress limits are defined in Subsection NG of ASME Code, Section III.~~

The maximum stress intensities in the reactor internal components are determined utilizing the most conservative combinations of the lateral and vertical LOCA time-dependent loadings in the structural analysis. These maximum stresses and the maximum stresses resulting from the SSE are then combined absolutely to obtain the total stress intensities.

To properly perform their functions, the reactor internal structures are designed to meet the deformation limits listed below:

a) Under design loadings plus operating basis earthquake forces, deflection is limited so that the control element assemblies (CEAs) can function and adequate core cooling is preserved.

b) Under normal operating loadings, plus SSE forces, plus pipe rupture loadings resulting from a break equivalent in size to the largest line connected to the Reactor Coolant System piping, deflections are limited so that the core is held in place, adequate core cooling is preserved, and all CEAs can be inserted. Those deflections which would influence CEA movement are limited to less than 80 percent of the deflections required to prevent CEA insertion.

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Insert A

Reactor internals are designed according to Subsection NG of the ASME Code, Section III, with the exception of stamping and a code stress report.

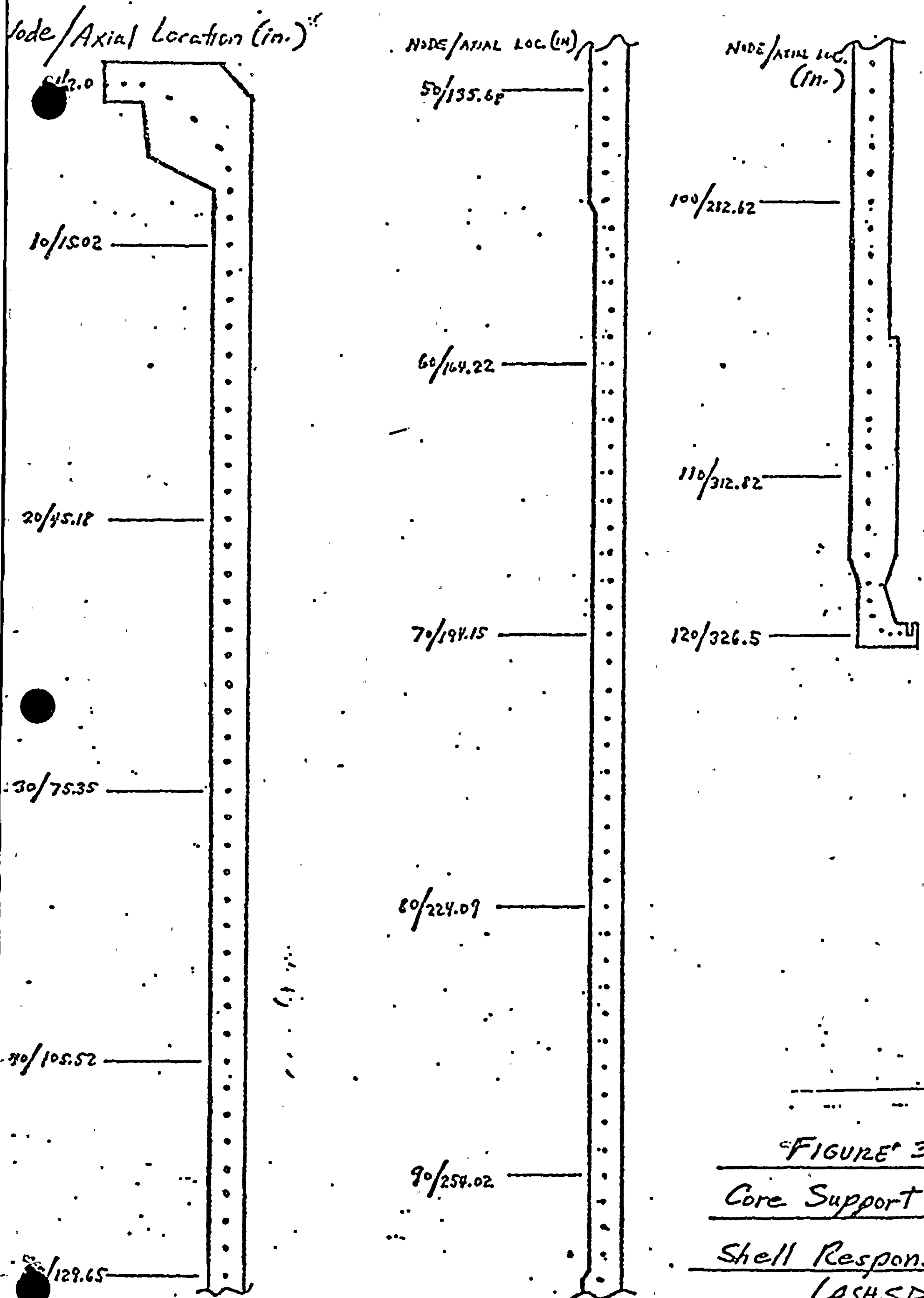


FIGURE 3.9-1
Core Support Barrel
Shell Response Model
(ASHSD)

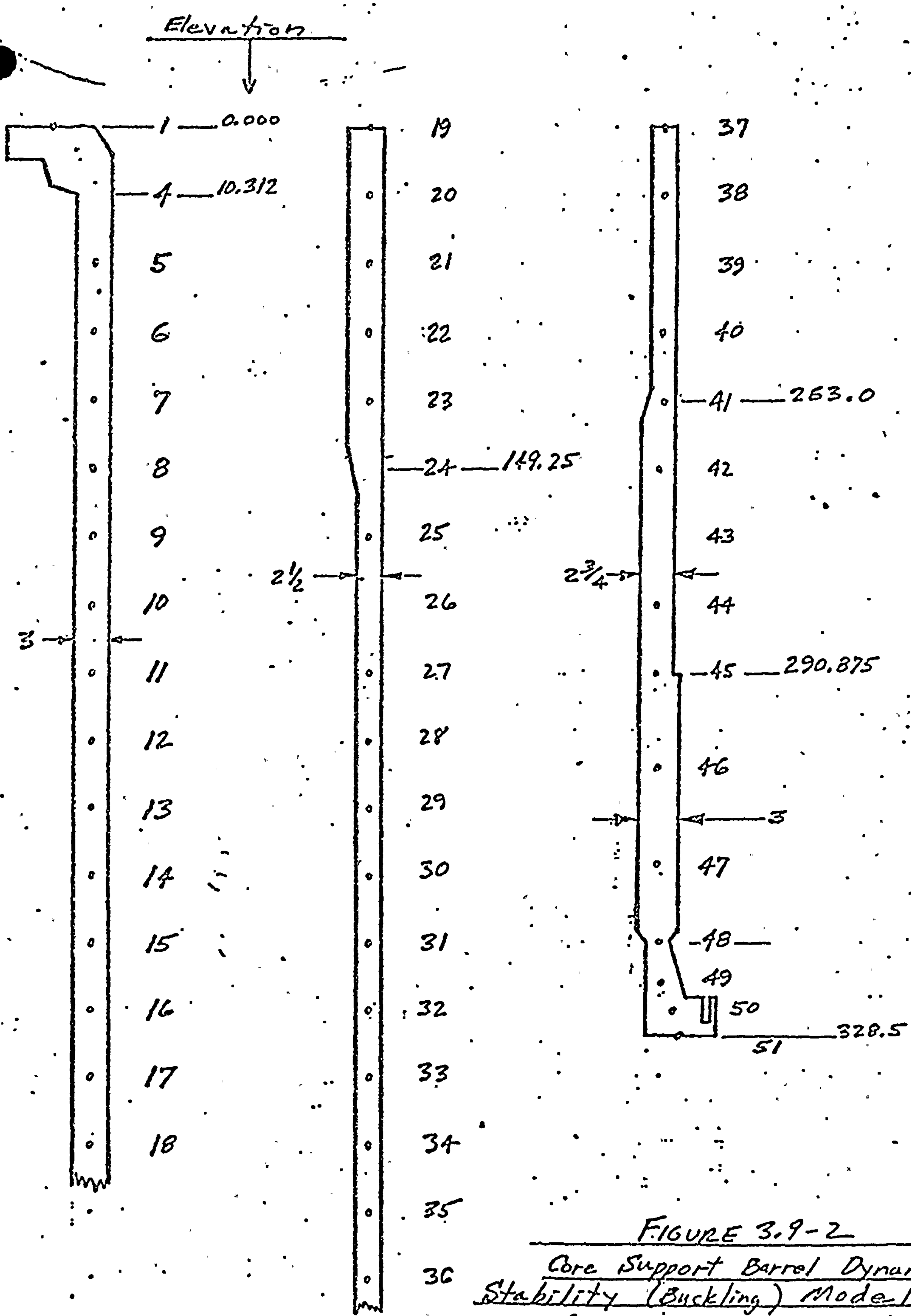


FIGURE 3.9-2

Core Support Barrel Dynamic Stability (Buckling) Model

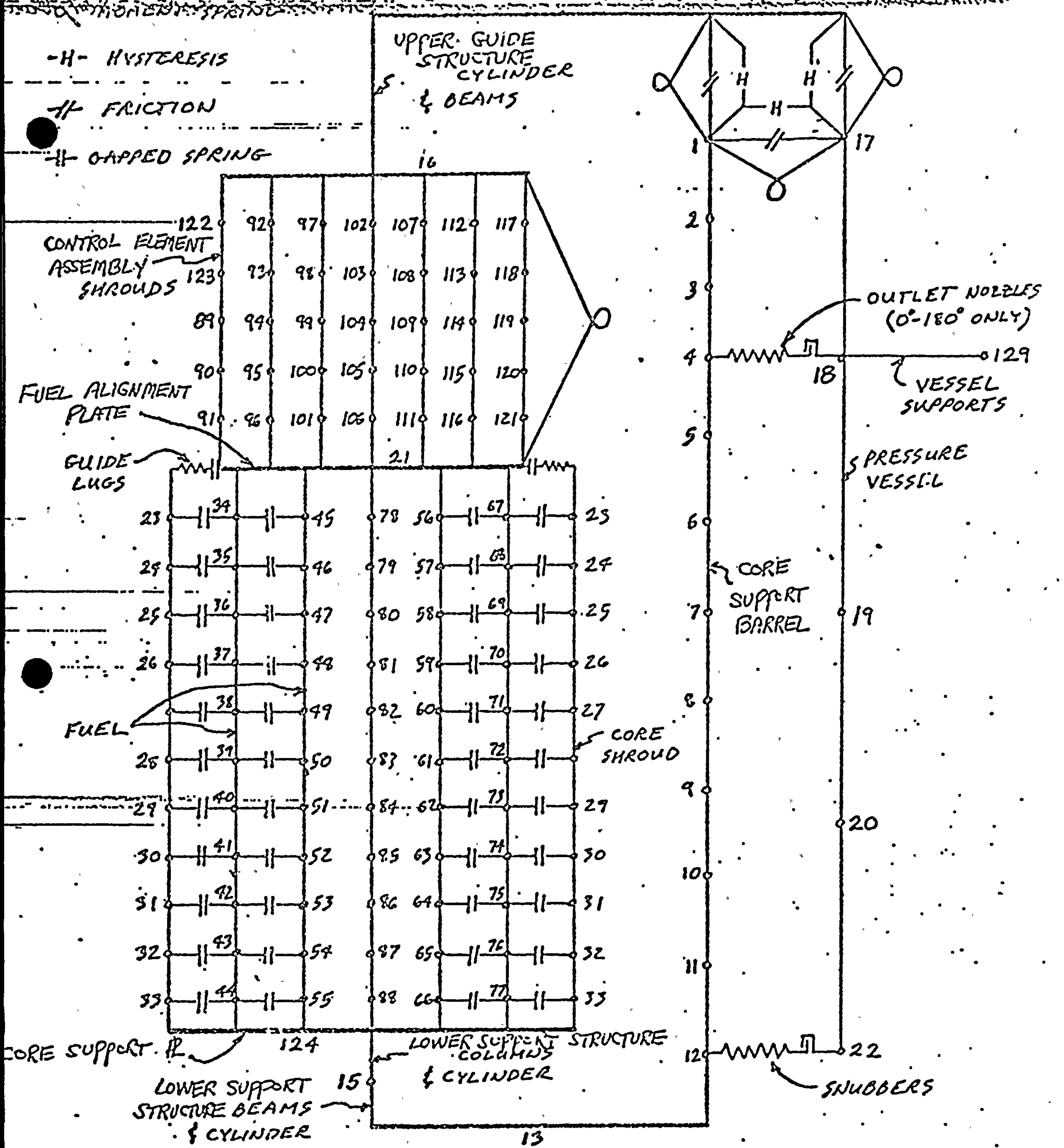


FIGURE 3.9-3

Reactor Internals Lateral LOCA Model (CESHOCK)

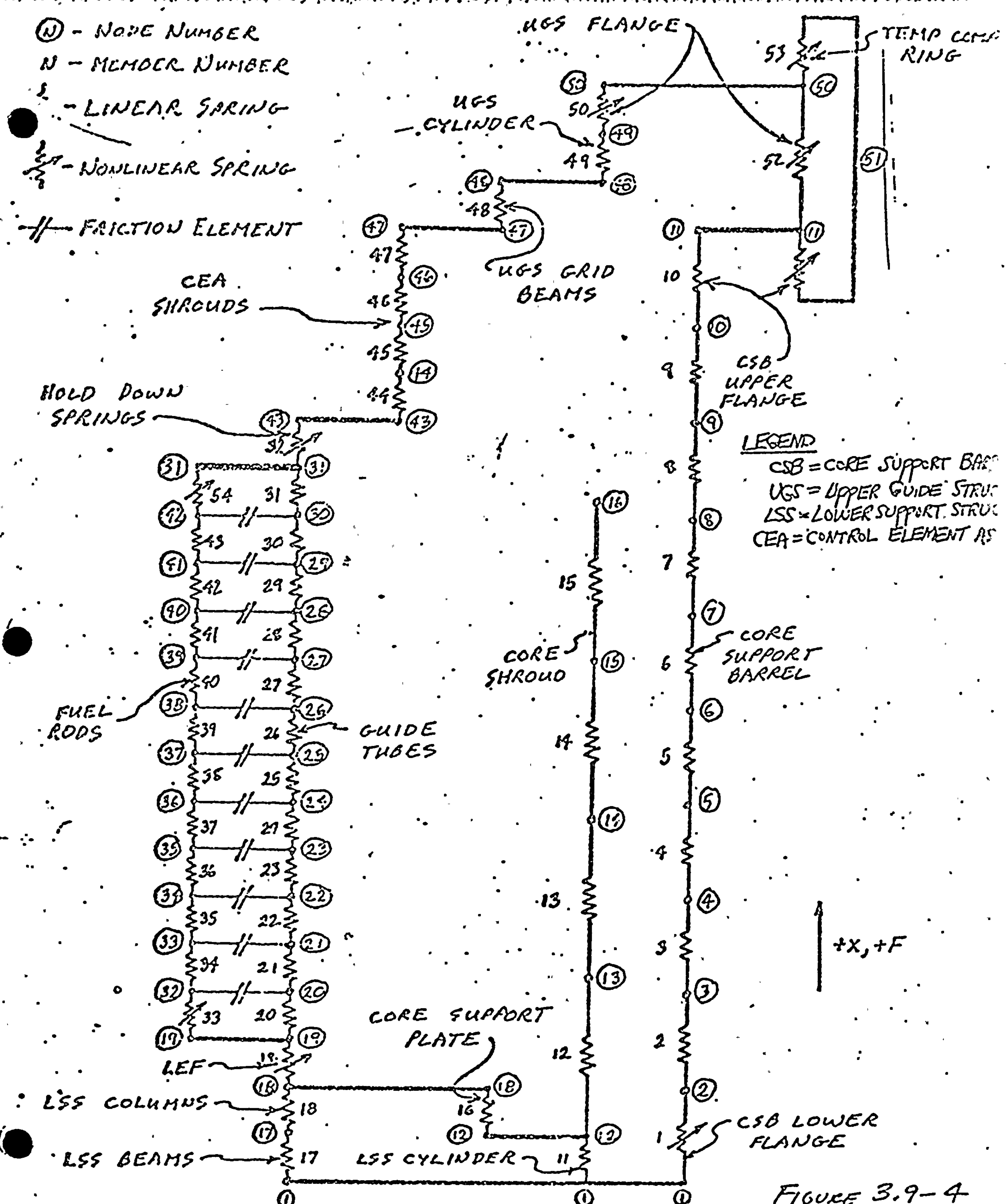
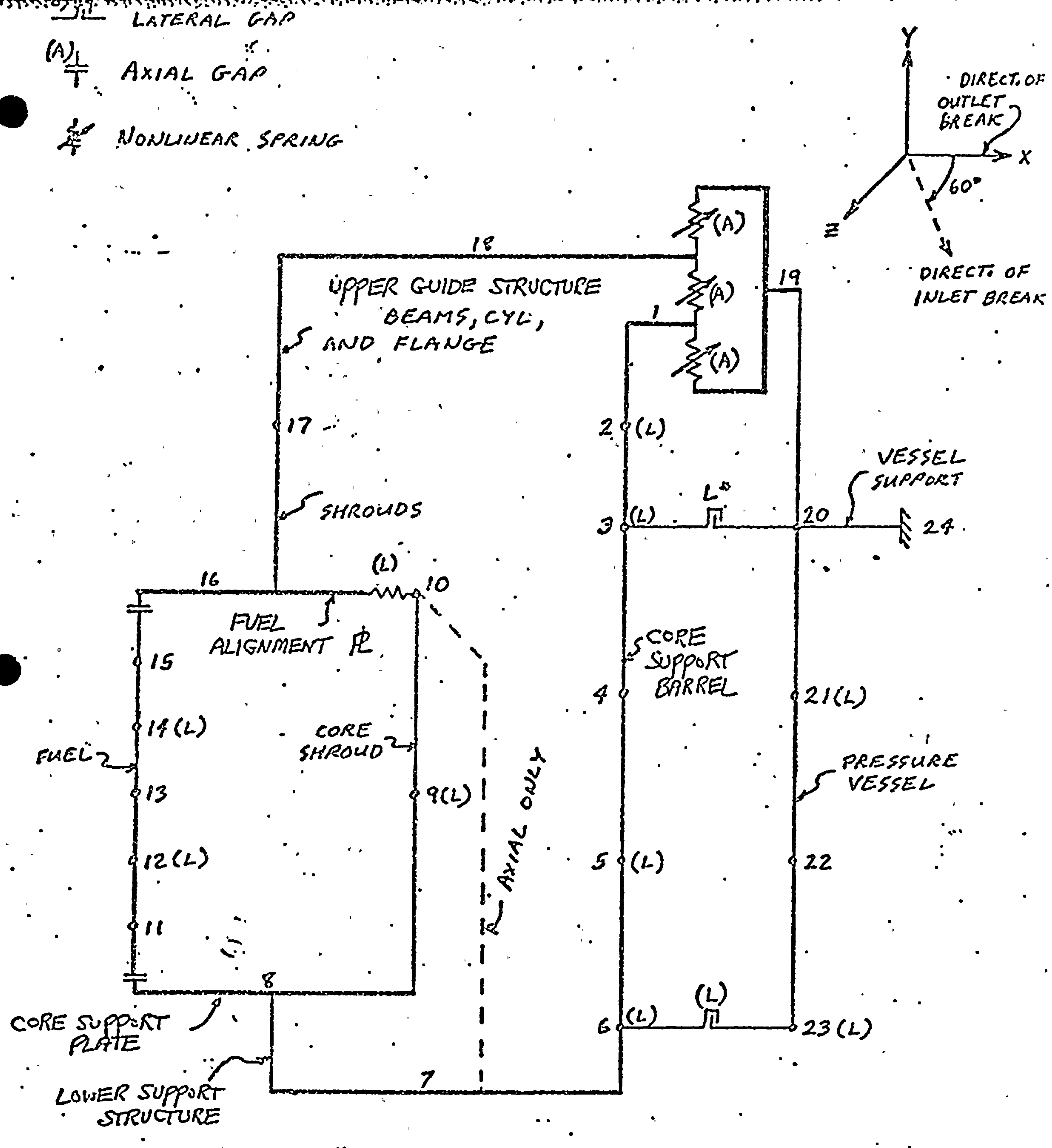


Figure 3.9-4

Reactor Internals Vertic[al]
LOCA Model

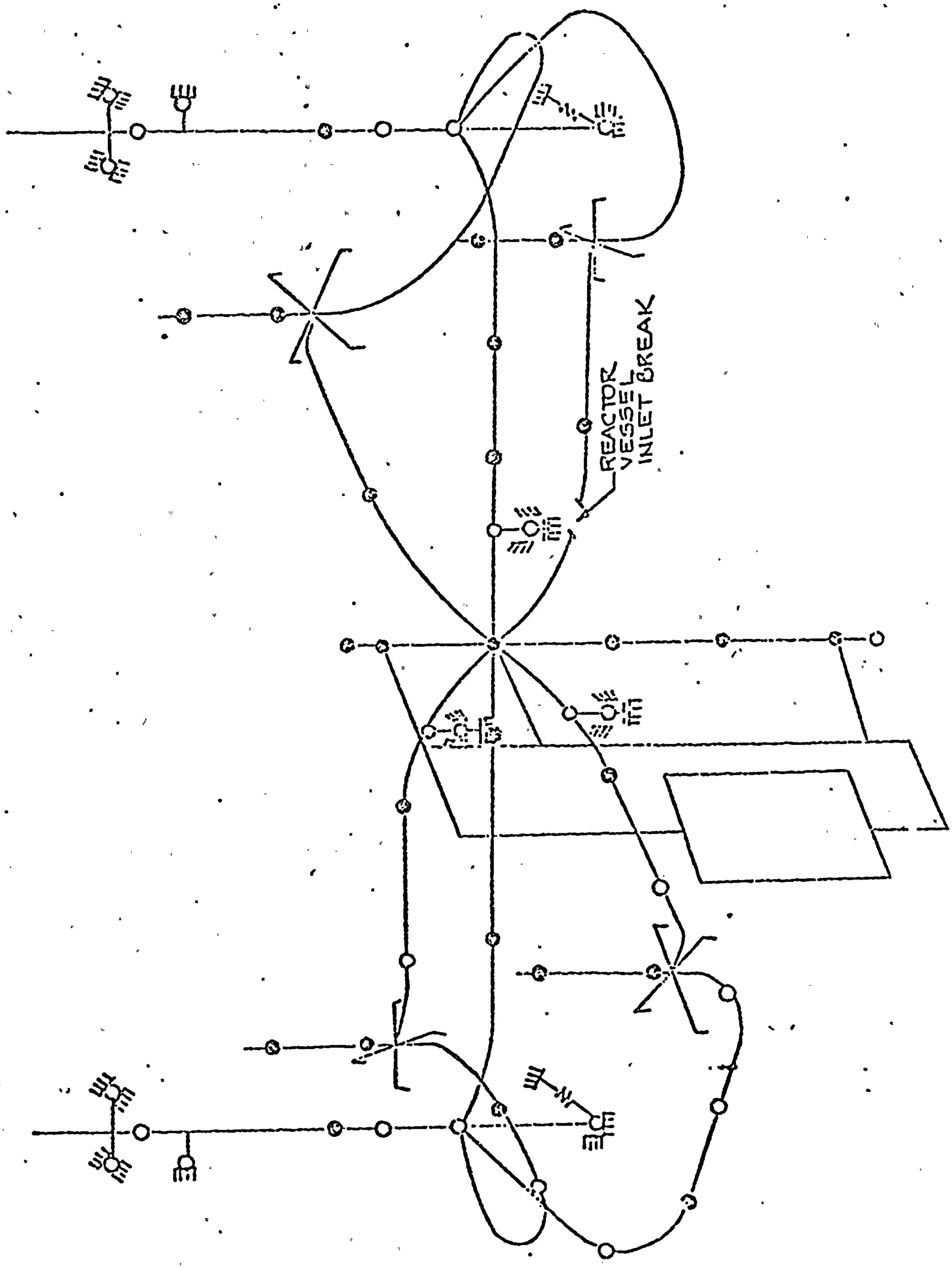


* – X DIRECTION ONLY

FIGURE 3.9-5

Reactor Internals Vertical/Horizontal

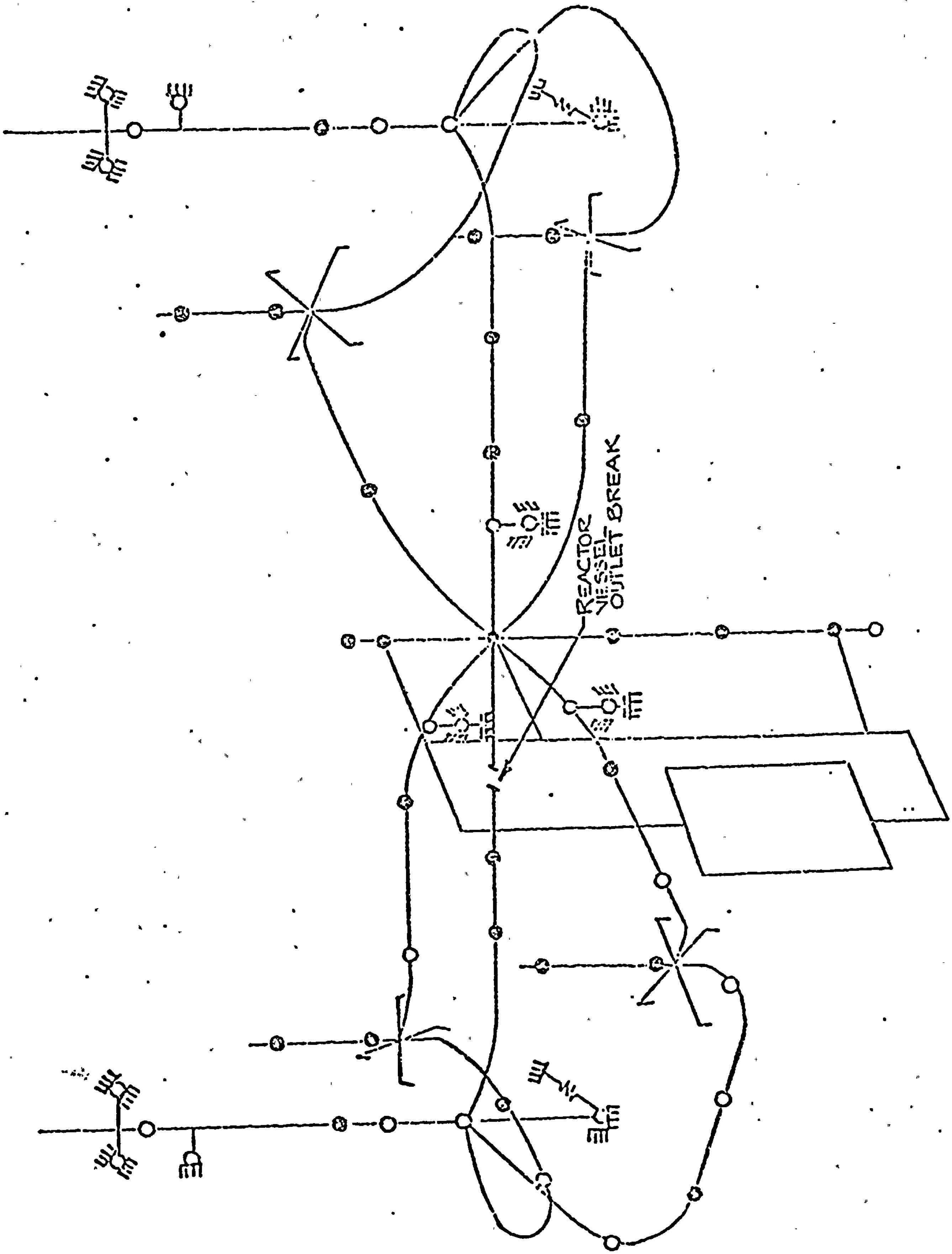
Reduced Model



RV ASYMMETRIC LOADS ANALYSIS

RV SUPPORT LOADS

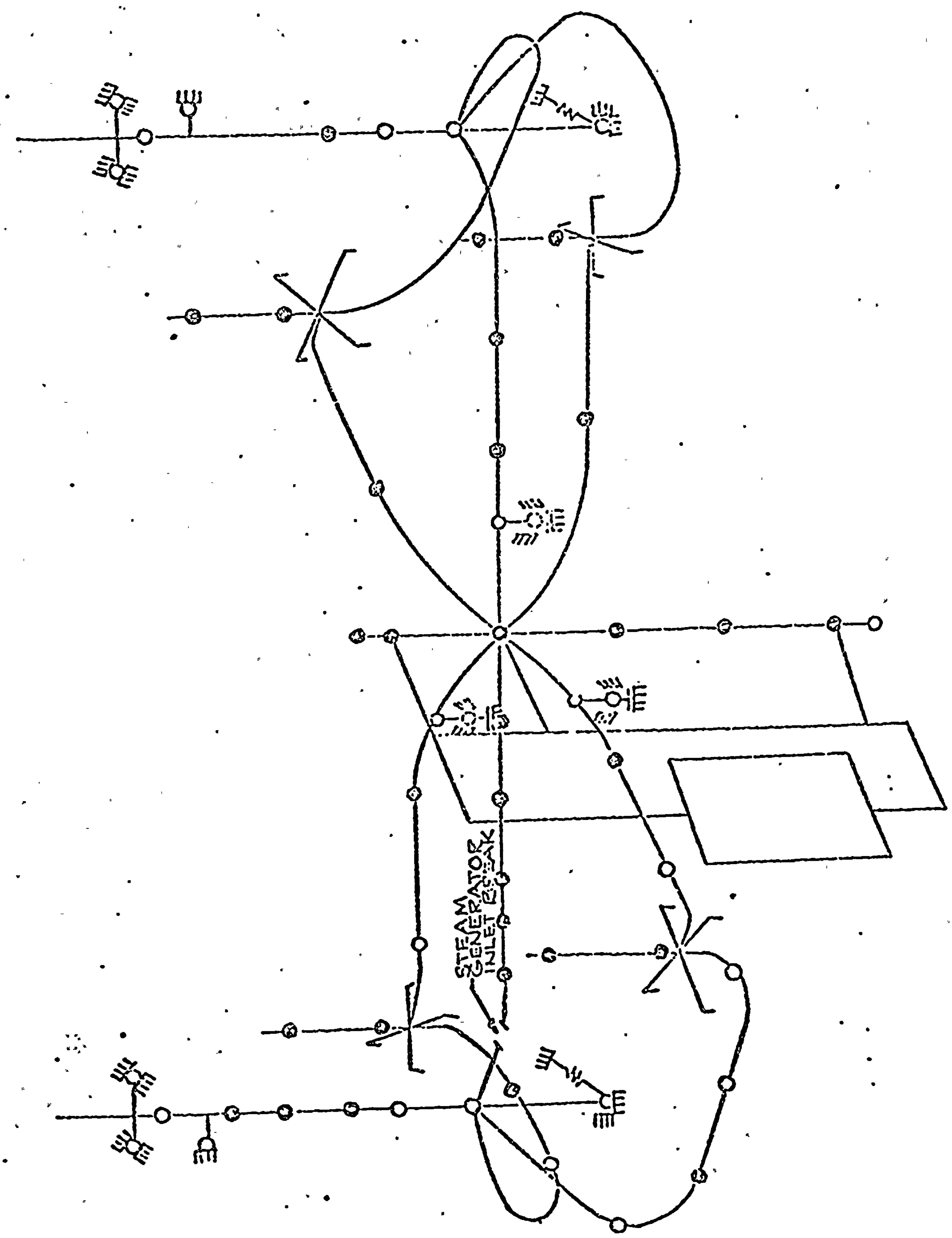
FIGURE 3.9-13



RV ASYMMETRIC LOADS ANALYSIS

RV SUPPORT LOADS

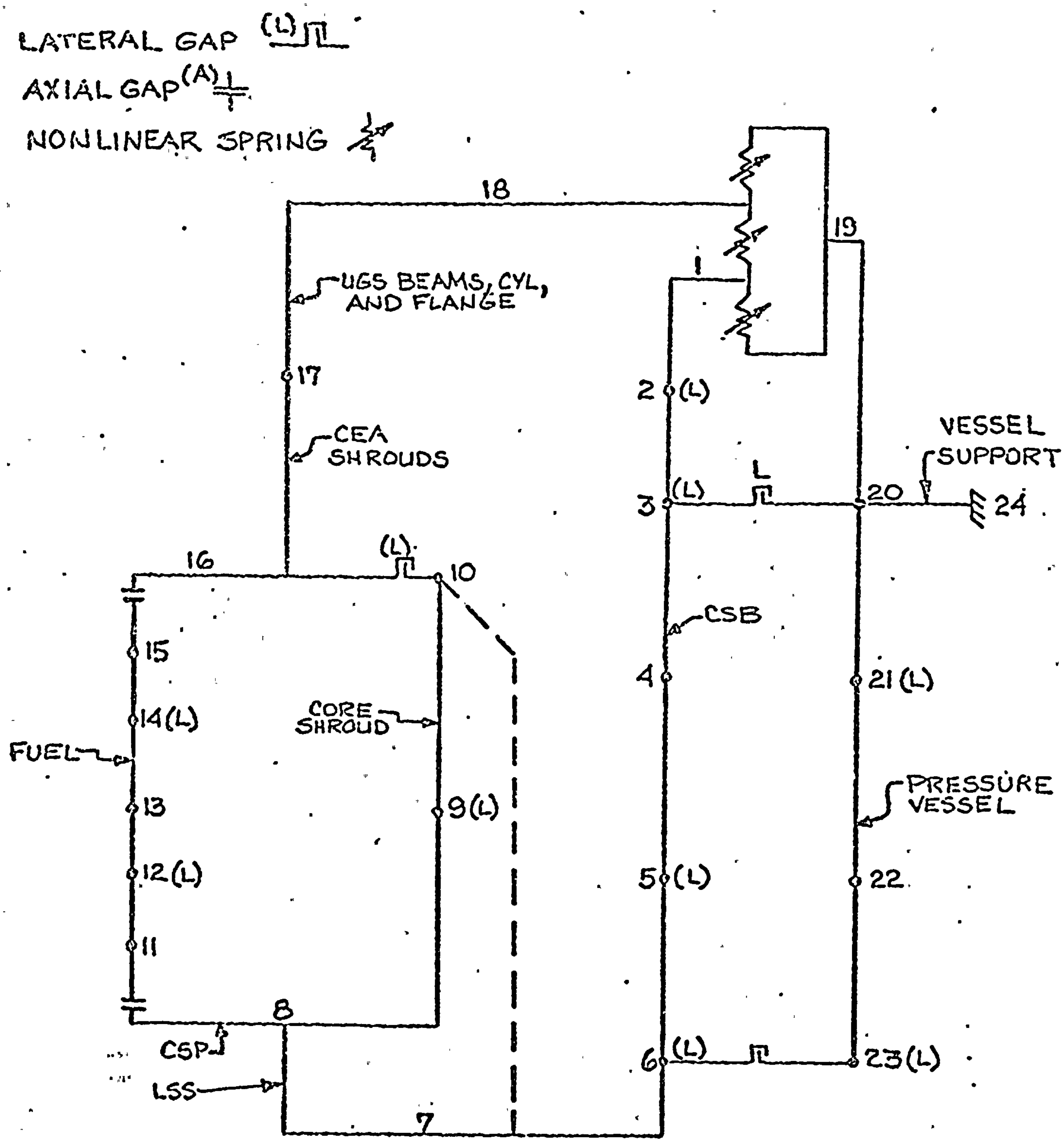
FIGURE 3.9-20



RV ASYMMETRIC LOADS ANALYSIS

RV SUPPORT LOADS

FIGURE 3.9-21



MODEL OF REACTOR INTERNALS

FIGURE 3.9-22

TABLE 3.9-2 (Cont'd)

3. Emergency Conditions

Five Cycles of complete loss of secondary pressure. This transient would follow a steam line break. A steam line break is not considered credible in forming the basis for design of the Reactor Coolant System. However, system components will not fail structurally in the unlikely event that it does happen.

4. Faulted Conditions

The loading combination resulting from the combined effects of the design basis earthquake and normal operation at full power are categorized as faulted condition .

The loading combinations resulting from the design basis earthquake, normal operation at full power and pipe rupture conditions are categorized as faulted condition. Design basis earthquake and pipe rupture loadings are combined by the SRSS method.

5. Test Conditions

Ten cycles of system hydrostatic testing at 3110 psig and at a temperature not less than 60 F above the highest component reference temperature (RT_{NDT}) or 100 F above the highest component section (RT_{NDT}) value. This is based on one initial hydrostatic test plus a major repair every four years for 36 years which includes equipment failure and normal plant cycles.

200 cycles of leak testing at 2235 psig and at a temperature not less than 60 F above the highest component reference temperature (RT_{NDT}) or 100 F above the highest pipe section RT_{NDT}. This is based on normal plant operation involving five shutdowns for head removal or valve repair per year for 40 years.

The fuel assembly is designed to be capable of withstanding the axial loads without buckling and without sustaining excessive stresses.

4.2.3.1.2.2 Safe Shutdown Earthquake (SSE)

The axial and lateral loads and deformation sustained by the fuel assembly during a postulated SSE have the same origin as those discussed above for the OBE, but they arise from initial ground accelerations twice those assumed for the OBE. The analytical methods used for the SSE are identical to those used for the OBE.

4.2.3.1.2.3 Loss of Coolant Accident (LOCA)

In the event of a large break LOCA, there will occur rapid changes in pressure and flow within the reactor vessel. Associated with the transient are relatively large axial and lateral loads on the fuel assemblies. The response of a fuel assembly to the mechanical loads produced by a LOCA is considered acceptable if the fuel rods are maintained in a coolable array, i.e., acceptably low grid crushing. The methods used for analysis of combined seismic and LOCA loads and stresses is described in Reference 50.

Insert

To qualify the complete fuel assembly, full scale hot loop testing was conducted. The tests were designed to evaluate fretting and wear of components, refueling procedures, fuel assembly uplift forces, holddown performance and compatibility of the fuel assembly with interfacing reactor internals, CEAs and CEDMs under conditions of reactor water chemistry, flow velocity, temperature, and pressure. The test assembly was a 16 x 16 five guide tube design. The test was run for approximately 2000 hours. The tests results demonstrated the acceptability of the design.

Mechanical testing of the fuel assembly and its components is being performed to support analytical means of defining the assembly's structural characteristics. The test program consists of static and dynamic tests of spacer grids and static and vibratory tests of a full size fuel assembly.

4.2.3.1.2.4 Combined SSE and LOCA

It is not considered appropriate to combine the stresses resulting from the SSE and LOCA events. Nevertheless, for purposes of demonstrating margin in the design, the maximum stress intensities for each individual event will be combined by a square root of sum of the squares (SRSS) method. This will be 3
performed as a function of fuel assembly elevation and position, eg, the maximum 490.1
stress intensities for the center guide tube at the upper grid elevation (as determined in the analysis discussed in Subsections 4.2.3.1.2.2 and 4.2.3.1.2.3) will be combined by the SRSS method. It is expected that the results will demonstrate that the allowable stresses described in Subsection 4.2.1.1 are not exceeded for any position along the fuel assembly, even under the added conservatism provided by this load combination.

4.2.3.1.3 Spacer Grid Evaluation

The function of the spacer grids is to provide lateral support to fuel and burnable poison rods in such a manner that the axial forces are not suffi-

Insert

Fuel assembly performance under asymmetric LOCA loadings is currently under evaluation. Based on previous results, it is anticipated that acceptable performance will be demonstrated. The results of the confirmatory analysis will be reported in an FSAR ammendment by May 1982.

Q35

ST. LUCIE UNIT 2

REACTOR VESSEL SUPPORT LOADS

LOCATION	LOCA ONLY	COMBINED LOCA + N.Op. + SSE	SPECIFICATION
H_1	4.291	4.74	8.00
V_1	4.697	6.47	8.50
H_2	4.100	4.71	7.00
V_2	2.642	3.75	7.00
H_3	3.904	4.44	7.00
V_3	3.216	4.29	7.00

Units -- millions of pounds

ST. LUCIE UNIT 2

STEAM GENERATOR SUPPORT LOADS

LOCATION		COMBINED LOCA + N.Op. + SSE	SPECIFICATION
Upper keys (ea.)	Z_1	1.51	2.172
	Z_2	2.00	2.172
Snubbers (ea.)	5	0.22	0.55
<u>SLIDING BASE</u>			
Vertical pads	Y_1	1.71	5.974
	Y_2	2.33	3.588
	Y_3	2.23	2.458
	Y_4	1.72	2.586
Anchor bolts (per pair of bolts)	Y_1	1.85	2.716
	Y_2	1.72	2.856
	Y_3	0.58	2.086
	Y_4	1.73	2.948
Lower stop	X_3	5.648	7.085
Lower keys	Z_{11}	3.28	3.755
	Z_{12}	1.06	2.772

Units - millions of pounds

Q35

ST. LUCIE UNIT 2

RCS COMPONENT NOZZLE LOADS

NOZZLE LOCATION	RSS MOMENTS COMBINED LOCA + N.Op. + SSE	SPECIFICATION
R V Inlet	3.47	9.93
R V Outlet	14.01	42.49
S G Inlet	6.73	21.75
S G Outlet	6.20	7.79
RCP Suction	3.90	4.45
RCP Discharge	3.98	5.42

Units - millions of pounds

Question No. 36

Provide stress limits and criteria to limit deformation and assure functional capability for Class 2 and 3 austenitic pipe bend and elbows.

Response

All Class 2 and 3 austenitic pipe bends and elbows will be reviewed to assure functional capability. Functional capability will be assured without further proof if the stresses are below the limits indicated in the General Electric Topic Report, NEDO-21985, Paragraph 2.2. For those elbows or bends which exceed those limits, additional demonstration will be provided.

Question No.

57. Section 3.9.3.3 of the FSAR should include a more detailed description of the calculation procedures, which were used in the parametric studies for closed discharge systems.

Response

The closed discharge system of the safety and relief valves from the pressurizer are analyzed by a time-history dynamic analysis. As a more conservative, less complex approach, the closed discharge system of the safety and relief valves on safety-related auxiliary system such as Safety Injection System and Chemical and Volume Control System are analyzed by a static analysis. A transient hydraulic force equal to the freely blowing reaction force acting in both directions with a dynamic load factor of 2 is applied to each straight leg of the piping system. for flashing service. For non-flashing liquid discharge system the same transient hydraulic forces are applied to the valve outlet and the first elbow and the transient hydraulic force in the downstream of the discharge piping are considered in the analysis for the maximum momentum change of the fluid.

Question No.

38. Information should be provided in Section 3.9.3.3 of the FSAR relating to the various design and service loading conditions and combinations thereof, and the corresponding stress criteria used in the design for the mounting of pressure relief valves.

Response

The Design Stress limits as delineated in FSAR 3.9.3.1.1 and Tables 3.9.6 and 3.9.7 and Design Loading table 3.9.5 are applicable to the mounting of pressure relief valves.

Question No.

39. The method of evaluating the structural response of the piping and support system stiffness in the dynamic analysis of these mountings should be discussed in Section 3.9.3.3 of the FSAR.

Response

In the dynamic analysis of the Safety/Relief valve discharge piping system, the same stiffness matrix method as described in FSAR 3.7.3.1.1.2 is used for the representation of the structural response of the piping. Supports are modeled as a spring element with a finite stiffness.

Question No.

40. A discussion which demonstrated that those components designed to the FSAR criteria have an adequate margin of safety should be submitted in the FSAR. In addition, the applicant should verify that the allowable stresses of MSS-SP-58, "Pipe Hangers and Supports" are used without the addition of a shape factor to account for bending stresses.

Response

The adequacy of the margin of safety of support and restraint design is demonstrated based on use of normal AISC and MSS-SP-58 stress limits as the design basis for all load combinations including faulted. Shape factors are not used to account for bending stress. This is discussed in the revised Subsection 3.9.3.4.

As a result of discussions of this response during the review meeting, Question 40.1 was generated. This question and its response are attached.

Question 40.1

a) Compare AISC allowables with those of ASME Code Appendix 17, Show them comparable.

b) How is reduced material yeild strength at elevated temperatures addressed when using the AISC code?

c) ASME requires CMTR's and C of C's. What material documentation does AISC require?

Response

a) The allowable stresses in the AISC Code and ASME Code Appendix XVII have been reviewed and are similar in most respects. The following differences are identified: 1) For welded tee joints the tensile stresses on the weld surface in the through thickness direction are limited to 60% of yield by AISC and 30% of yield by ASME Appendix XVII. Ultrasonic testing of both shop and field welds of this type has been specified. 2) ASME Increase Factor is 1.2 $\frac{Sy}{Ft}$, not to exceed 0.7 $\frac{Su}{Ft}$.

The Ebasco Increase Factor of 1.6 across the board will be justified for $\frac{Sy}{Su}$ values $>$ 0.73.

b) No reduction in yield strength is taken for application below 700°F in accordance with the AISC Manual of Steel Construction. (Reference: Effect of Heat on Structural Steel.) No austenitic material is used in seismic Category I component supports.

c) Ebasco practice for seismic Category I requires Certificates of Compliance and CMTR's as appropriate.

Question No.

41. Provide in a tabular form for both BOP and NSSS Code Class 1,2 and 3 component supports the load combinations, stress limits for various plant conditions.

Response

The stress limits and load combinations for various plant conditions are presented in Tables 3.9-17 and 3.9-18 for Class 1,2,and 3 supports and restraints.

For NSSS scope of supply see the Tables in Question 33.

As a result of discussions of this response during the review meetings, question 41.1 was generated. This question and its response are attached.

Question 41.1

a) Justify the use of SRSS for combination of SSEI and SSED in the faulted condition.

b) Provide the faulted allowable stresses for bolts.

c) Compare Table 3.9-5 with the loading tables of Section 3.8.3.

d) Define the materials for which allowables are given in Tables of Section 3.8.3.

Response

a) Where the fundamental frequency of the piping system is beyond the resonant region of the supporting structure the SSE will be combined in the following manner: $SSE = \sqrt{SSEI^2 + SSED^2}$

Where the piping fundamental frequency is not beyond the structural resonant region the SSE will be combined in the following manner: $SSE = |SSEI| + |SSED|$

b) Faulted allowables for bolts are as follows:

Material	A-325	A-490
Allowable Tensile Stress AK	64 Ksi	86 Ksi
% of Ultimate	53% ($\frac{1}{2}$" - 1" dia.)	58%
for the faulted condition	61% ($1\frac{1}{8}$"-$1\frac{1}{2}$" dia.)	

c) Requirements for component supports are addressed in Section 3.8.3. Any areas where disparity between AISC and ASME support requirements is significant will be identified. This will be performed so that governing loading cases address or envelope the loading cases given in Table 3.9-5.

d) Allowable stresses are based on Section 1.5 of AISC which in turn are based on ASTM material values. AISC factors of safety vary from 1.67 to 2.0 on yield strength. The development of factors of safety is documented in the Commentary to the AISC Code.

RRJ - check!

Faulted allowables for bolts are established as 1.6x AISC normal allowables.

Put in what is it → AISC, Normal Allowables, Faulted allowables, Yield.

Question No. 42

Provide the allowable buckling limits for ASME Class 1 linear and plate and shell type component supports subjected to faulted condition load. Also provide additional information concerning the design of support bolts and bolted connections.

Response

All safety-related component supporting structures are designated "Seismic Category I." Load combinations and allowable stresses are in accordance with Standard Review Plant 3.8.3 and Standard Review Plant 3.8.4. The margin of safety for these structures is inherent in the design equations in the AISC Specifications.

For linear and plate and shell type component supports subjected to the accident (faulted) load condition, the design stresses are limited to ninety (90) percent of the critical buckling stress as applicable. For design of support bolts and bolted connections, refer to the above paragraph.

CE --

a) Buckling failure mode of the RCS supports is not credible due to the design characteristics of the supports.

b) The bolts in CE scope of supply (Steam Generator Skirt to Sliding Base) are designed to be below 70% of ultimate which, for the material, is less than 75% of yield.

c) Required Preload of interface Anchor Bolts (S. G. Snubber, Pressurizer Skirt) were specified to Ebasco.

NRC Position: Any support for a Class 1, 2 or 3 component in which the buckling stress > 67% critical buckling must be justified as to why the margin against buckling failure is sufficient.

As a result of discussions of this response during the review meeting, Question 42.1 was generated. This question and its response are attached.

Question 42.1

a) What the design values for buckling stresses?

b) Commit to using 2/3 of critical buckling stress as a design limit and justify those cases where it is needed.

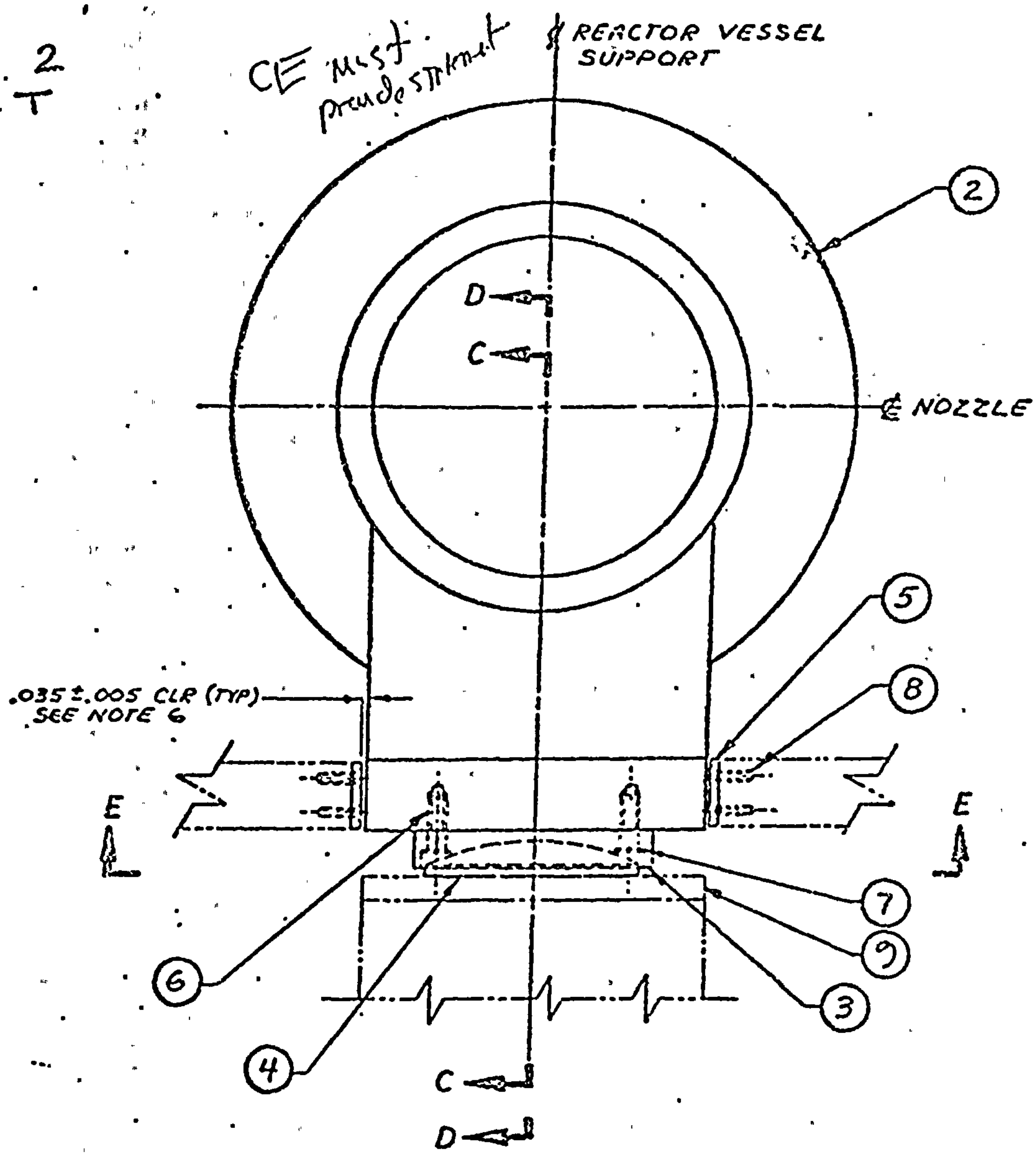
Response

a) The design values for buckling stresses are specified in Section 1.5.1.3 of the AISC code. This Section identifies a minimum factor of safety of 1.67 which is in agreement with Appendix XVII of the ASME Code, Article XVII-2110 b).

b) Cases where buckling stresses in the supports of ASME III Class 1, 2 or 3 components exceed 67% of critical buckling stresses will be justified on an individual basis that the margin against buckling is sufficient.

ST LUCIE 2
RV SUPPORT

CE must provide statement



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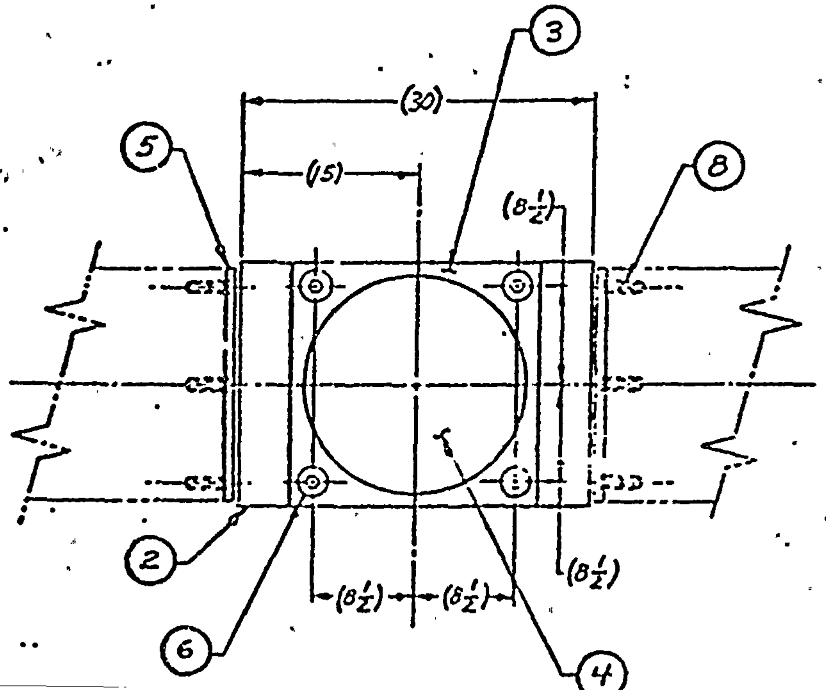

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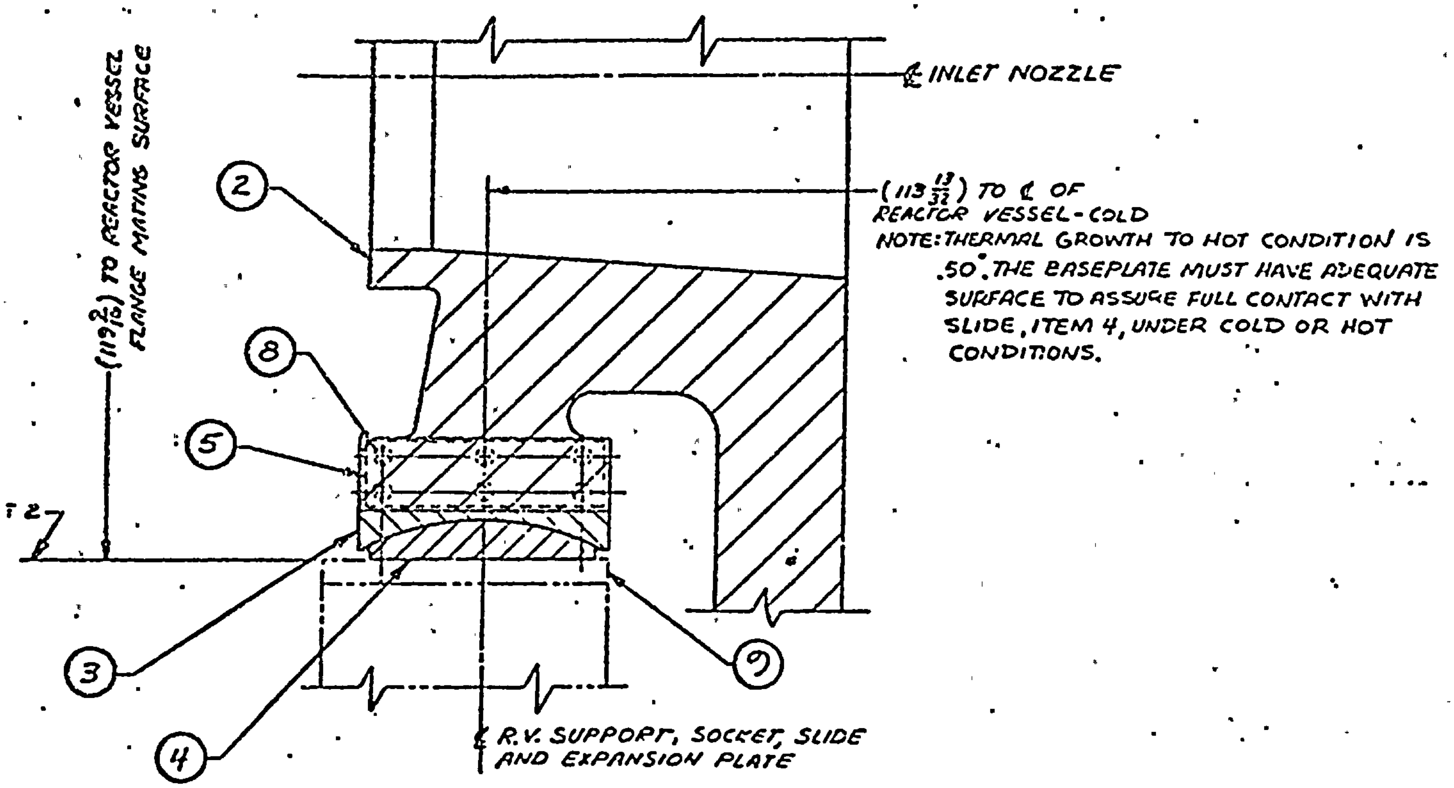
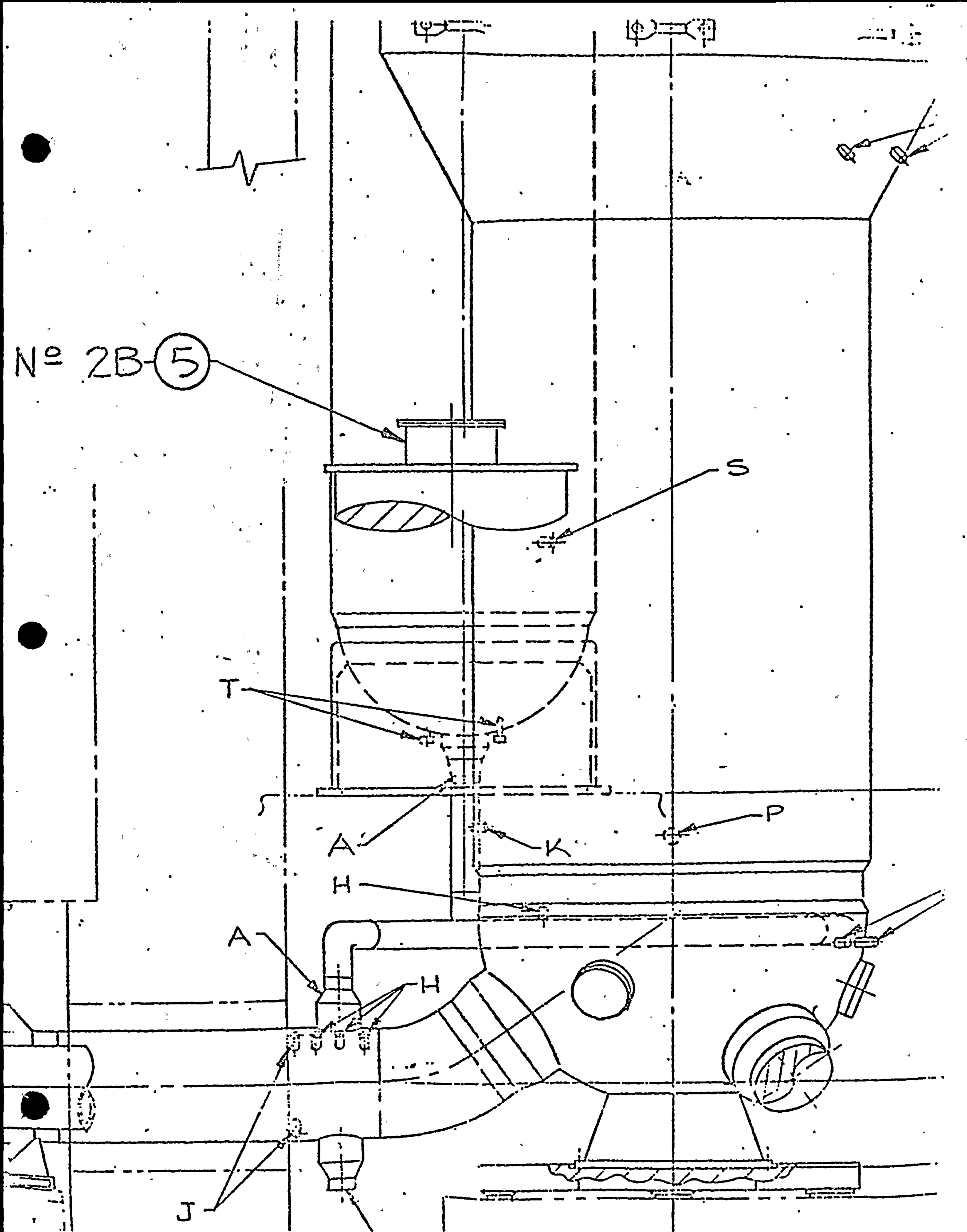
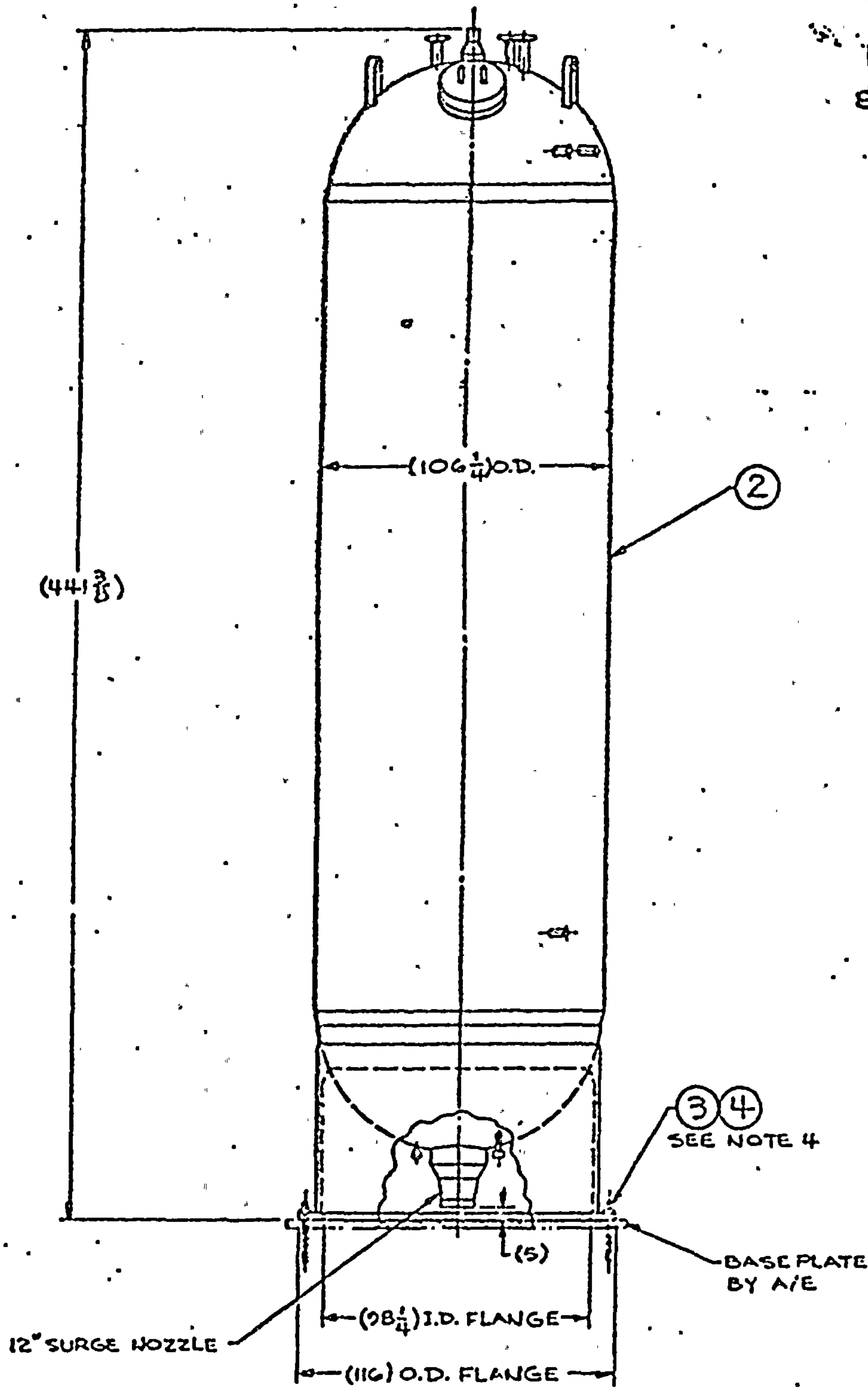
ST LUCIE 2
RV SUPPORT



SECTION C-C
SUPPORT ARRANGEMENT
AT INLET NOZZLE - 2 REQ'D

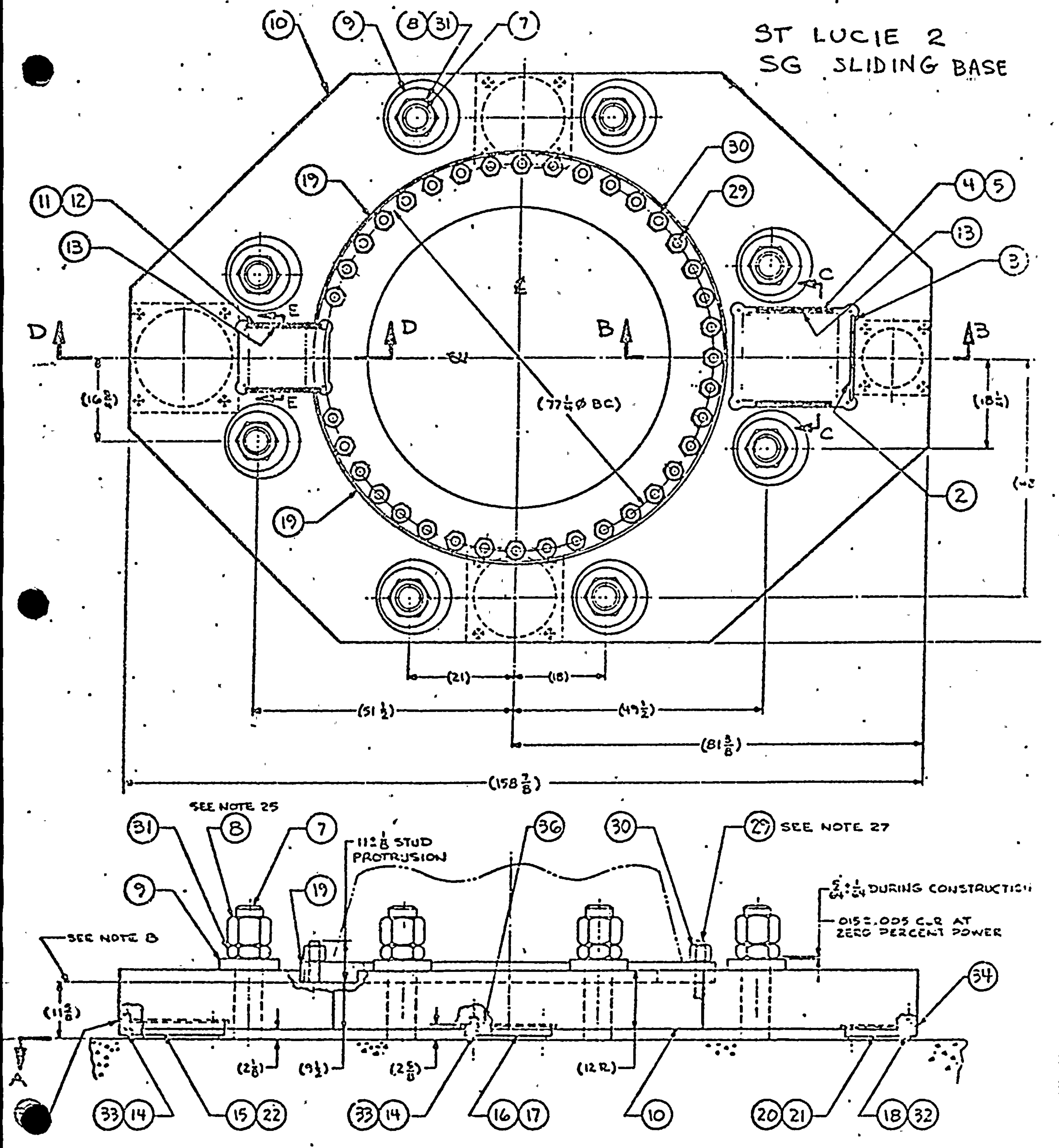

Nº 2B-5
S
T
A
K
P
H
A
H
J

ST LUCIE 2
PRESSURIZER
& SKIRT

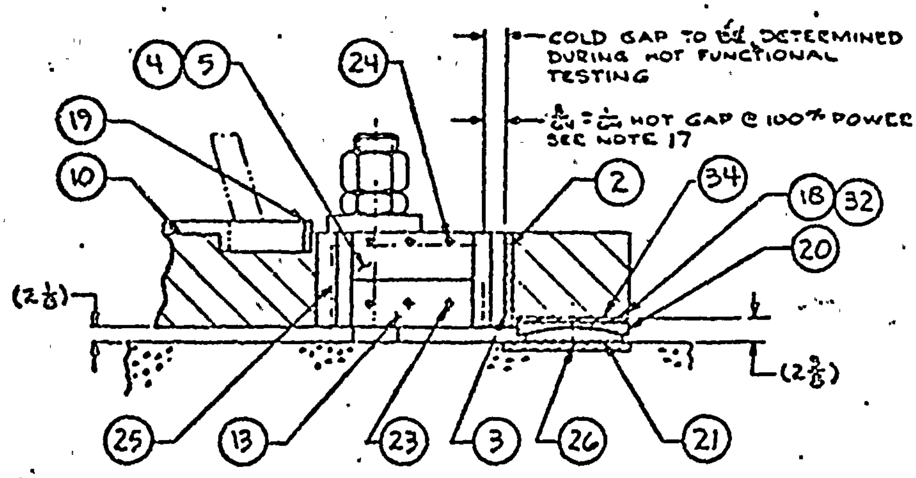


ELEVATION
1 PRESSURIZER ARRANGEMENT

ST LUCIE 2
SG SLIDING BASE



① STEAM GENERATOR SLIDING BASE INSTALLATION



SECTION B-B
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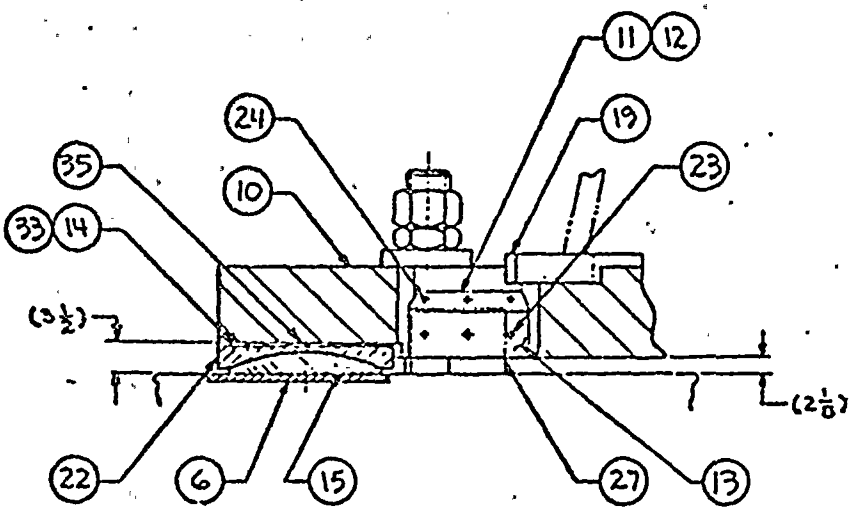

SECTION D-D
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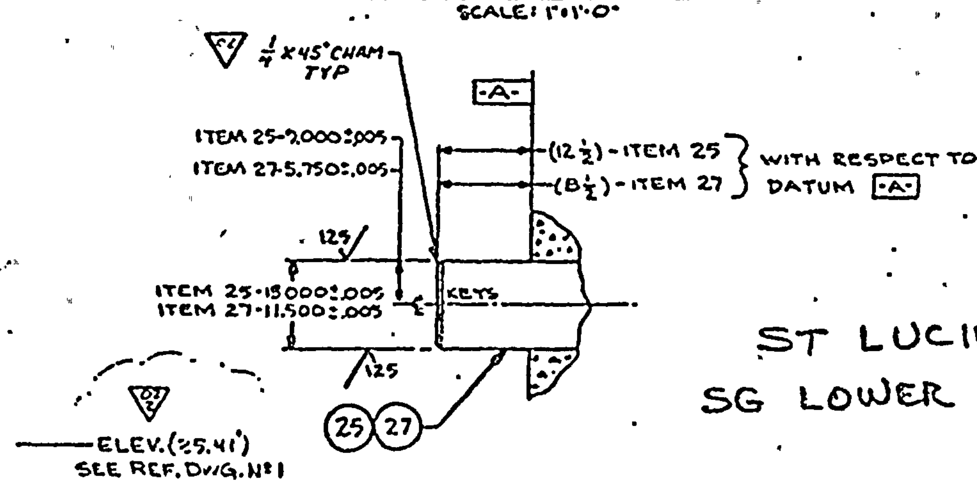
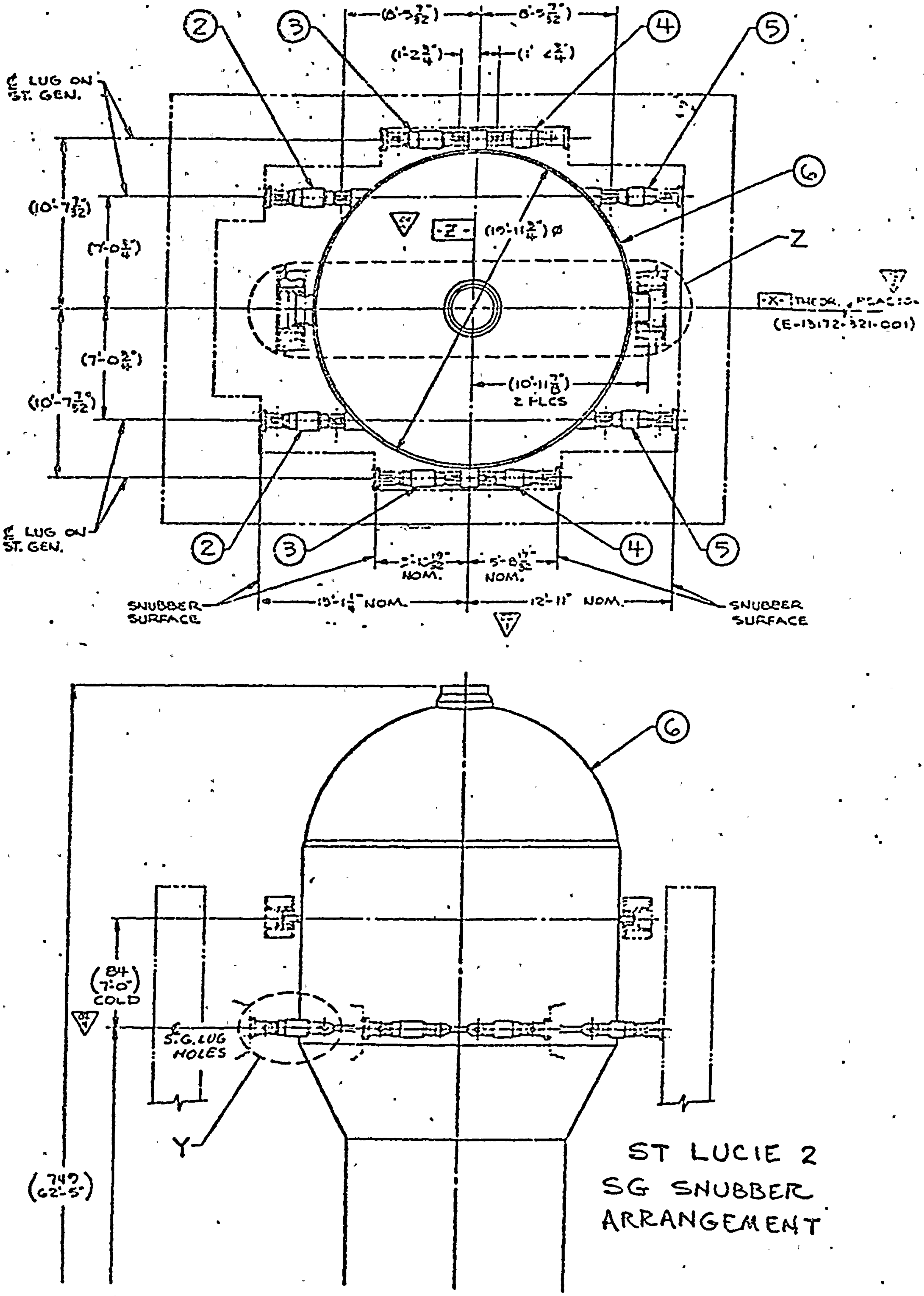
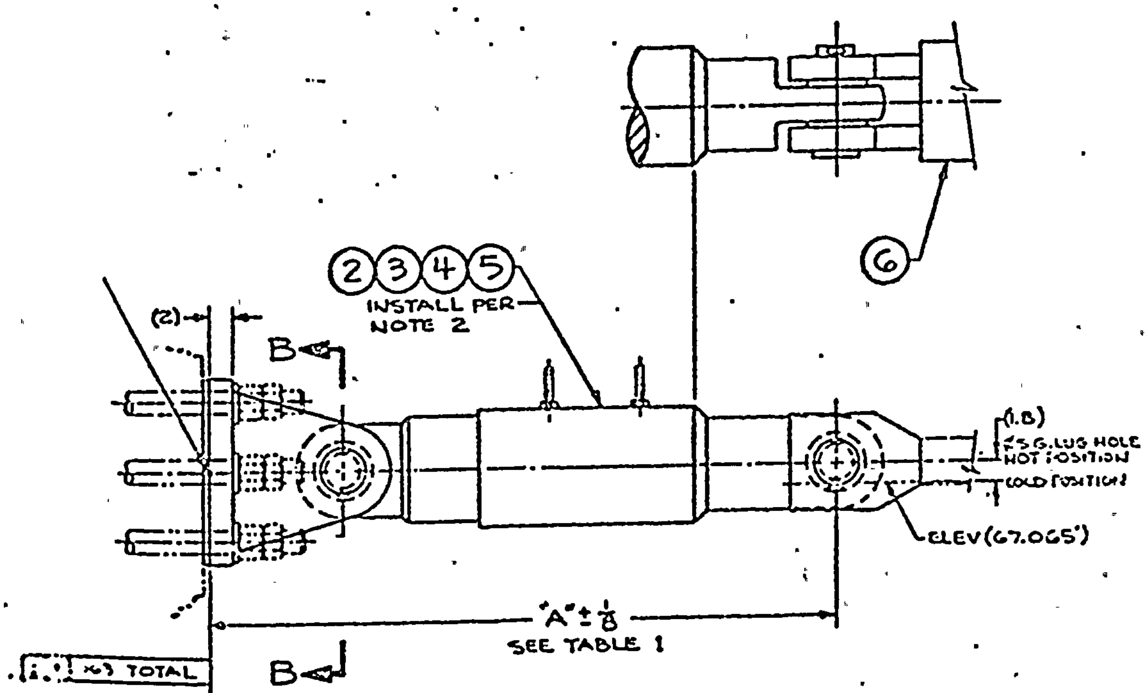


SECTION F-F
SCALE: 1"=1'-0"
SEE NOTE 6

ST LUCIE 2
SG LOWER KEY



ST LUCIE 2
SG SNUBBER
ARRANGEMENT



DETAIL Y

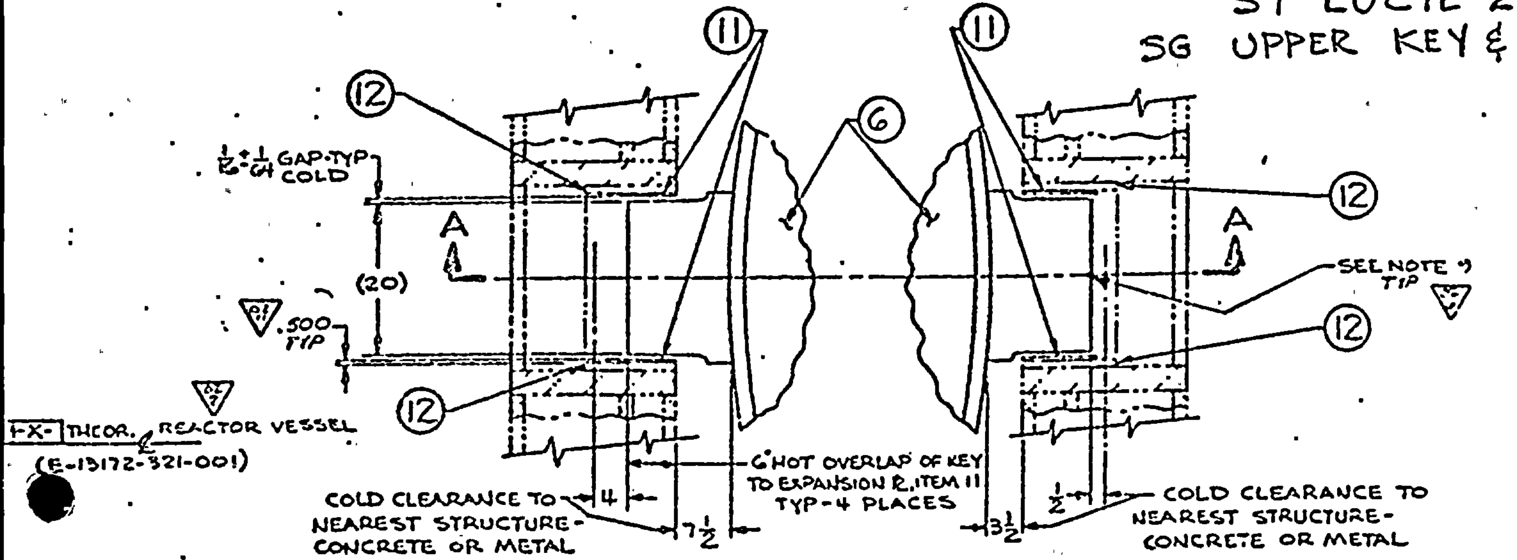
SCALE: 1/8

TABLE 1	
ITEM Nº	COLD INSTALLATION DIM "A" ± 1/64
2	4'-8 1/32"
3	4'-7 [illegible]/32"
4	4'-5 [illegible]/32"
5	4'-5 2[illegible]/32"

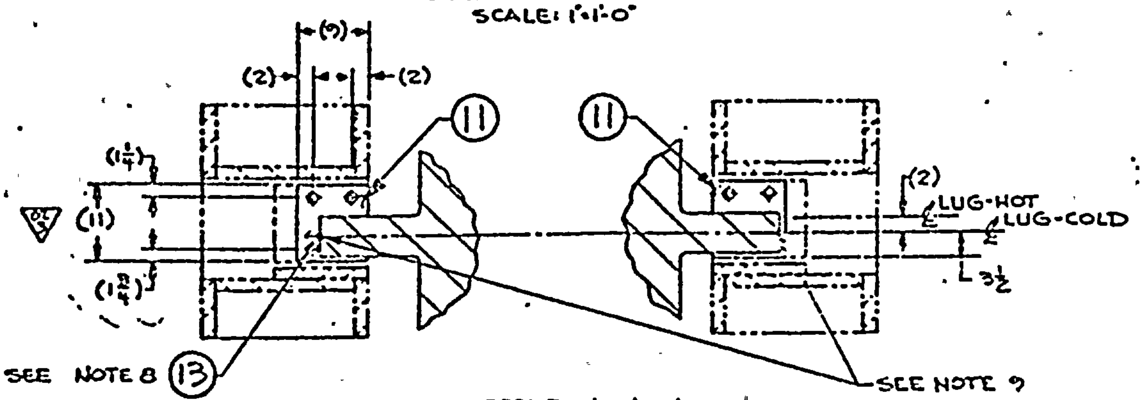
ST LUCIE 2

SG SNUBBER

ST LUCIE 2
SG UPPER KEY & LUG



DETAIL Z
SCALE: 1"=1'-0"



SECTION A-A
SCALE: 1"=1'-0"

3.9.3.4 Component Supports

For NSSS supplied components procured prior to July 1, 1974 design stress limits for ASME Code Class 1 vessel supports, piping supports and supports for the reactor coolant pumps (including the attachment welds to the vessel or piping assemblies) are defined in the component specification. For the faulted condition the stress limits are defined as: the limits of Section III, NB-3220 using an Sm value equal to the greater of 1.5 times the tabulated Sm value and 1.2 times the tabulated Sy value, but not exceeding .7 times the material tensile strength, with the values taken at the appropriate temperature. Design stress limits for other loading conditions are those identified in applicable subsections of the ASME Code.

A/E supplied supports for Code Class 1, 2 and 3 mechanical systems, components and piping are designed in accordance with codes in effect at the time of purchase order. The supports for components procured prior to July 1, 1974 are designed per AISC guidelines. For normal and upset conditions, normal AISC stress limits apply.

Supports for components procured after July 1, 1974 are designed in accordance with ASME Code, Section III, Subsection NF, with its applicable stress limits. The only supports designed to Section NF are for the following components:

Containment Spray Pumps

Intake Cooling Water Pumps

Auxiliary Feedwater Pumps

Diesel Oil Transfer Pumps

Basket Strainers

Safety Injection Tanks

SG Sliding Base and Bearings

Ion Exchangers

Bottom Loaded Filters

Fuel Pool Heat Exchanger

Shutdown Cooling Heat Exchangers

Instrument Racks

Letdown Heat Exchanger

Regenerative Heat Exchanger

(cont'd on next page)

3.9.3.4 (cont'd)

The extent of deformation of the supports is limited by the allowable stresses discussed above.

The waste gas compressor supports and anchor bolts are designed to the criteria of the AISC Manual of Steel Construction, 1970, except that the increase in the allowable stresses due to seismic and wind loads per Paragraph 1.5.6 Part 5, is not permitted.

All safety-related component supporting structures are designated "Seismic Category I." Load combinations and allowable stresses are in accordance with Standard Review Plan 3.8.3 and Standard Review Plan 3.8.4. Refer to FSAR 3.8.3 and FSAR 3.8.4. The margin of safety for these structures is inherent in the design equations in the AISC Specifications.

For linear and plate and shell type component supports subjected to the accident (faulted) load condition, the design stresses are limited to ninety (90)*percent of the critical buckling stress as applicable. For design of support bolts and bolted connections, refer to the above paragraph.

Piping supports and restraints are designed to accommodate the loading combinations shown in Table 3.9-16. The normal allowable stress limits of AISC and MSS-SP-58, as summarized in Table 3.9-15, are used in original support and restraint design for all loading combinations, including faulted. To minimize redesign and refabrication, which might result from revised stress analyses, the following criteria apply as necessary when evaluating existing restraint designs against revised faulted loading: stresses in hangers and restraints shall be less than 1.6 times AISC limits, not to exceed .96 times material yield stress, where shear yield stress is assumed to be .577 times tensile yield stress. Also, stresses shall not exceed .90*times critical buckling stress, when that is a controlling factor.

Supports are designed to the highest loadings that would result from transient conditions such as relief valve operation, fast valve closure, or system thermal gradients. Thermal stresses are considered as primary stresses for supports and as secondary stresses for components.

The operability assurance program for active components and their supports is discussed in Subsection 3.9.3.2. Preoperational tests for piping systems and their supports are discussed in Subsection 3.9.2.1.

* Cases where buckling stresses in the supports of ASME Class 1, 2 or 3 components exceed 67% of critical buckling stress will be justified on an individual basis that the margin against buckling is sufficient.

TABLE 3.9-17

Notes

1. for compact sections as defined in AISC 1.5.1.4.1

2. for other sections as defined in AISC 1.5.1.4.4 and 1.5.1.4.5

3. tables for compression values in AISC 1.5.1.3.1

4. calculated per AISC 1.5.1.3.1

5. These values are used in original design for all loading combinations including faulted. When checking an existing support or restraint design against revised faulted loads stresses are limited to the following:

   stresses in hangers and restraints shall be less than 1.6 times AISC limits, not to exceed 0.96 times material yield stress, where shear yield stress is assumed to be 0.577 times tensile yield stress. Also, stresses shall not exceed 0.90 times critical buckling stress, when that is a controlling factor. Cases where buckling stresses in supports of ASME Class 1, 2 or 3 components exceed 67% of critical buckling stress will be justified on an individual basis that the margin against buckling is sufficient.

TABLE 3.9-17

STRESS LIMITS ——— FOR PIPE SUPPORTS

Reference: MSS SP-58 & AISC Manual - 7th Edition

Shape & Use	Fb Bending	Ft Tension	Fv Shear	Fp Bearing	Tension at Pin Hole
Supplementary Steel	21,600[1] 23,760[2]	N/A	14,400	14,400	N/A
Standard Hanger Components	14,500	14,500	11,600	23,200	10,850
Plates and Bars	14,500	14,500	11,600	21,600	10,850
Rods at Threads	N/A	9,000	N/A	N/A	N/A
Rods - Plain	N/A	14,500	N/A	N/A	N/A
Pins	14,500	N/A	11,600	23,200	N/A
Pipe	15,000	15,000	12,000	See Note 3	N/A
Bars & Plates 304 Steel	11,200	11,200	8,950	17,900	8,400
Pipe 304 Steel	11,200	11,200	8,950	See Note 4	N/A
Bolts	N/A	15,000	12,000	21,600	N/A

For Notes, see next page.

TABLE 3.9-18

LOADING COMBINATIONS AND STRESS LIMITS FOR PIPING SUPPORTS

	Plant Operating Condition	Design Load Combination	Piping Support Stress Limit
ASME CODE CLASS 1	Normal Upset Emergency Faulted(1)	SW a) SW+OBE b) SW+OBE+FVC c) SW+OBE+RVO d) SW+OBE+T SW+OBE+RVO+FVC SW+ $(SSE^2 + FC^2)^{1/2}$	Refer to Table 3.9-17 ↓
ASME CODE CLASS 2 & 3	Normal Upset Emergency Faulted(1)	SW a) SW+OBE b) SW+OBE+FVC c) SW+OBE+RVO SW+OBE+FVC+RVO SW+ $(SSE^2 + FC^2)^{1/2}$	Refer to Table 3.9-17 ↓

Notation:

SW = Largest of: a) DW+Max(+)TH
b) DW+Max(-)TH
c) DW

DW = Deadweight (includes sustained mechanical loads)
OBE = Operating Basis Earthquake
SSE = Safe Shutdown Earthquake
RVO = Relief Valve - includes both open and closed systems
FVC = Fast Valve Closure
TH = Thermal expansion
SSEI= Inertia Portion of SSE
SSED= Displacement Portion of SSE
T = Transient
FC = Dynamic loads associated with plant faulted condition

(1) a) Where the fundamental frequency of the piping system is beyond the resonant region of the supporting structure the SSE will be combined in the following manner: $SSE = \sqrt{SSEI^2 + SSED^2}$

b) Where the piping fundamental frequency is not beyond the structural resonant region the SSE will be combined in the following manner: $SSE = |SSEI| + |SSED|$

Question 43

In addition, assurances must be provided that stresses due to thermal expansion, thermal gradient and differential support movements have been included.

Response

The design and service conditions for supports and restraints included thermal effects and differential support movements as primary loads.

CE - The RCS Analysis includes the effects of thermal gradient, thermal expansion, and differential movement of supports.

For class 1, 2 and 3 vessels and pumps, nozzle loads include piping thermal expansion loadings.

Vessels which are supported at both ends are provided with one fixed support and one slotted support to accomodate the axial thermal growth of the shell.

Question 44

We will also require an acceptable response to our request for preservice inspection and testing information on snubbers.

Response

Inspection and Testing of snubbers on safety-related piping or components shall be performed as follows:

1) After snubber installation is completed but not more than six months prior to the start of pre-core hot functional testing, a pre-service visual examination shall be performed to verify that:

   a) There are no visible signs of damage or impaired operability as a result of storage, handling, or installation.

   b) The snubber location, orientation, position setting, and configuration (attachments, extensions, etc.) are according to design drawings and specifications.

   c) Snubbers are not seized, frozen, or jammed.

   d) Adequate swing clearance is provided to allow snubber movement.

   e) If applicable, fluid is to the recommended level and is not leaking from the snubber system.

   f) Structural connections such as pins, fasteners, and other connecting hardware such as lock nuts, tabs, wire, or cotter pins are installed correctly.

   If the period between the pre-service examination and the start of hot functional testing exceeds six months due to unexpected situations, re-examination of items (a), (d), and (e) shall be performed. Snubbers which are installed incorrectly or otherwise fail to meet the above requirements shall be repaired or replaced and re-examined in accordance with the above criteria.

2) During pre-core hot functional testing, snubber thermal movements for safety-related systems whose operating temperature exceeds 250° F shall be verified as follows:

   a). During initial system heatup, snubber expected thermal movement shall be verified for any safety-related system which attains operating temperature. Verification shall be performed at RCS temperature plateaus of approximately 260° F, 360° F, 480° F, and 532° F. Snubber thermal movement shall be observed during cooldown and verified at ambient conditions after cooldown is completed.

b) For those safety-related systems which do not attain operating temperature, observation and/or calculation shall be used to verify that snubbers will accomodate the projected thermal movement.

c) Snubber swing clearance shall be verified for the temperature plateaus in (a) above.

Any discrepancies or inconsistencies shall be addressed as follows:

a) The snubber in question shall be removed from service or other interim action shall be taken to prevent system damage prior to proceeding to the next temperature plateau.

b) The discrepancy or inconsistency shall be evaluated for cause and corrected prior to core load.

c) The snubber in question shall be monitored again during heatup for post-core hot functionals to verify that the problem has been resolved.

QUESTION 45
(Section 3.9.4)

The thermal deflection problem of dissimilar materials is not covered and there is no information as to the allowable and actual deflections due to the various loading conditions. Design margins for stress, deformation, and fatigue should be presented and should be shown to be equal to or greater than those of other plants of similar design having a period of successful operation.

Response:

In response to the NRC questions pertaining to the design margins for functional reliability regarding the design criteria for non-pressurized components, the components outside the pressure boundaries are the coil stack, the pressure housing shroud, and the cooling shroud. All are designed to be a slip fit over the motor housing and are capable of being removed at temperature. A test was performed to verify this requirement. Dimensions and materials used for the St. Lucie II CEDMs are identical to those on operating reactors.

All failure modes of non-pressurized active components will not effect the safety function of the CEDM. The coil stack is designed and has been tested to verify its capability to withstand loss of air coolant flow for up to four (4) hours without loss of function.

Parts within the pressure boundary, such as the motor assembly, have been sized for thermal deflections caused by dissimilar material so that clearances are available above the maximum design temperature of 650°F.

Question 46

CEA Insertability

A. As stated in Proposed FSAR Amendment 3.9.1.9.3 (Question 35), insertability for the design basis pipe breaks is not required. Pressure boundary integrity will be demonstrated.

QUESTION 47
(Section 3.9.5)

Identify the highest usage factor and the location where it occurs in the reactor internals.

Response:

The highest usage factor for the reactor internals is found to occur in the core support barrel flange region and is less than .15.

Question 49

We will require an acceptable response to our request for additional information on periodic leak testing of pressure isolation valves.

Response

FPL recognizes that leak tight integrity of primary coolant system pressure isolation valves, while an integral part of IST, will be reviewed in detail separately on an advanced schedule prior to OL. A separate response, as part of IST, will be transmitted.

Question 50

The applicant should define the stress limits to which the welded attachments in the high and moderate energy piping systems are designed. Also describe the detailed stress analysis or tests which may have been performed to demonstrate compliance, including one example with a summary of the results.

Response

Stress analysis of piping is performed for various loading conditions as presented in Table 3.9-5. This analysis also determines the loads on welder attachments which are used as seismic restraints. Local stresses on piping due to welded attachments are calculated using WRC Bulletin 107. The local stressed are combined with other stresses determined by pipe stress analysis in the welded attachment location and ASME code Section III allowable Stress Criteria are satisfied. A sample calculation and the summary of results are attached.

The trunnion analysis utilizes the Cylnoz computer program to determine the adequacy of the piping system by including the local stresses into the appropriate loading combination. The loading combinations and allowable stress criteria are provided on page 5. The computer program uses the piping load in global coordinates (refer pg. 2) and transforms these loads into the following components:

(1) Radial/shear loads (P/V_L, V_C)
(2) Circum./longit. bending (M_C / M_L)
(3) Torsional moment (M_T)

The details of local stress intensity calculation for unit load application for P, V_L, V_C, M_C, M_L, and M_T are provided on page 8. Membrane and bending stresses in hoop direction due to P, M_C and M_L are calculated at four locations around the trunnion in outer and inner surface of the pipe. For example, AU and AL represent the stresses at point A upper surface and lower surface respectively. Similar calculation for membrane and bending stresses in longitudinal direction due to P, M_C, and M_L are calculated at the same eight locations of the pipe as described above. Shear stresses due to V_L, V_C, and M_T are calculated at these locations. Using the above stresses, stress intensity is calculated at each of these eight locations. The largest stress intensity value is added with pressure stress (if applicable) and normal stress in the pipe, due to corresponding load case and compared with the allowable stress. The results of the analysis, shown on page 6, conclude that the calculated stress are within the ASME allowable for all loading combinations.

Question 51

Provide the following information for an ASME Code Class 1 piping system identified in FSAR 3.6A.

(a) Calculated stress intensity, calculated cumulative usage factor and the calculated primary plus secondary stress range for each point at which these parameters we calculated.

(b) Results in tabular form and correlated with node points identified on a sketch of the system.

Response 51

The calculated stress intensity, accumulated usage factor and primary and secondary stress range is provided in Table 3.6C-1.

TABLE 3.6C-1

STRESS SUMMARY

SAFETY INJECTION SYSTEM (SC1)

Point(1)	Eq 10 Sn/Sm	Eq 9 S/ 1.55	Usage Factor
113	.437	.285	-
114	.202	.267	-
1140	.178	.250	-
115	.533	.314	0
116	.811	.609	-
117	.903	.554	0
118	1.136	.554	.0004
119	.907	.543	0
120	.975	.538	-
121	.882	.511	.03
157	.431	.256	-
158	.353	.243	-
159	-	-	-
160	.370	.215	-
169	.176	.135	-
1210	.586	.271	-
122	1.198	.561	0
123	1.226	.560	-
124	.701	.297	-
125	1.376	.554	0
126	1.395	.540	-
127	.794	.275	-
1270	.823	.287	-
1271	.844	.301	-
128	1.625	.582	-
129	1.498	.560	0
130	.568	.275	-
131	.560	.273	-
132	1.506	.530	-
133	1.638	.521	0
134	1.559	.522	-
135	1.468	.529	0
136	1.043	.522	-
336	.436	.260	-
236	.419	.248	-
237	-	-	-
238	.188	.143	-
239	.176	.135	-
137	.790	.281	-
138	-	-	-
139	1.352	.298	.0024
140(*)	2.213	.609	-
941	2.307	.674	.0010
8002(TP)	1.450	.345	-

Notes:

(1) Node Points correspond to figures 3.6C-3.8,3.9,3.10

(2) (*) Break location

(3) (TP) Terminal point

TABLE 3.6C-2

STRESS SUMMARY

SAFETY INJECTION SYSTEM (SC2)

Point Number	Stress Ratio SA	Stress Ratio Sh+SA
8001 (TP)	-	-
100	.424	.266
1000	.335	.147
101	.389	.244
102	.519	.326
103	.355	.233
1030	.417	.262
104 (*)	.633	.397
105	.402	.252
1050	.099	.062
106	.101	.064
108	.244	.155
109	.278	.177
110	.229	.147
1100	.370	.235
111	.381	.242
112	.336	.214
113	.311	.198
114	.169	.107

Notes:

(1) Node Points correspond to Figures 3.6C-3.8,3.9,3.10

(2) (*) Break Location

(3) (TP) Terminal Point

Question 52

The postulated guillotine breaks may either be based on complete severence or limited separation. The applicant should identify which type of break was assumed for all postulated guillotine breaks not included as part of CENPD-168. In case limited separation was assumed, justification should be provided.

Response 52

For all high energy system failures not included in the CENPD-168 report, the pipe rupture and jet analysis conservatively assumed guillotine breaks with complete separation.

CE - For limited area breaks see proposed amendment to FSAR Section 3.6.2.1.1 (Question 2). All other guillotine break locations are full area.

Question 53

The applicant, in describing analytical methods to define forcing functions, should indicate (a) the assumed loading conditions at the time of the postulated pipe break, and (b) the rise time for the initial pulse. If the rise time was greater than one millisecond, justification should be provided.

Response

(a) For high stress points determining the pipe stress analysis considers plant normal and plant upset conditions. The pipe rupture and jet impingement analysis assumes a normal operating condition of 100% power prior to the pipe break.

(b) The pipe rupture analysis assumed a break opening time equal to or less than one millisecond.

Question 54

What is the status of St. Lucie Unit 2 with respect to the SG feedwater ring event recently experienced at SONGS?

Response

CE agreed to set up a meeting to discuss this issue with the NRC.

Question 55

Justify the use of ASME Code Level C service limits for the small feedwater line break transient by showing that the probability of a small feedwater line break is less than or equal to that for an ATWS event (reference: NRC letter James P. Knight to Paul S. Check, dated July 29, 1981) attached)

Response

The response to Question 440.81 (f), which is attached, shows that for St. Lucie Unit 2 the probability of a small feedwater line break is less than 10^{-7} per plant year (sufficiently low to justify use of Level C service limits).

Note: In the Knight to Check memo, the review of the event probability of occurence is indicated as required to be reviewed by the NRC probabilistic review group (not MEB). The outcome of that review can affect item #33.

Q55 (2 of 4)

SL-2 Round One Questions

440.81 (f) (15.2.5) The limiting feedwater line break was not a double-ended guillotine break (DEGB), but a 0.25 $ft.^2$ small break.

The NRC will accept exceeding 110% design pressure for very low probability events, such as a double-ended guillotine break. However, for all break sizes less than a DEGB, which result in the system pressure exceeding 110% the applicant must demonstrate that the probability for these events is sufficiently low to satisfy the Level C Service categorization, as defined in Section 3 of the ASME Pressure Vessel Code.

We require the applicant to review all applicable data for justifying his position. We also require as assessment of the conservatism inherent in the analyzed events.

Response:

The feedwater line break analyzed in FSAR Section 15.2.5.2 is postulated to occur in the specific length of piping between either steam generator nozzle and the first upstream check valve. Using the methods and data contained in WASH-1400 we can estimate the recurrence frequency of such a break.

WASH 1400, Appendix III Section 6.4.2 provides an assessment of nuclear experience with large pipe (> 4") integrity. In 150 reactor years of experience, no major failures were observed in large primary or secondary piping with the one exception of one crack in the secondary loop (certainly less than .25 $ft.^2$). Based on this information WASH 1400 concludes that the pipe rupture rate for the combined primary and secondary system is $\leq \frac{1}{150} = 7 \times 10^{-3}$/plant year. (WASH-1400 also indicates that this value represents a 95% confidence estimate for ruptures vs. cracks). Since approximately 10% of this piping is "LOCA sensitive", WASH-1400 interpretes this data to show that the recurrence frequency for LOCAs due to failures of large pipes is 7×10^{-4}/plant year. Please note that this data is not limited to Double Ended Guillotine Breaks and in fact includes a crack which is much less than .25 $ft.^2$.

The total length of Main Feedwater System piping which is "sensitive" with respect to the event analyzed in Section 15.2.5.2 is 30 feet. This compares to approximately 288 feet of LOCA sensitive large piping. From this information, using the same approach as WASH-1400, we can estimate the recurrence frequency for the initiating event analyzed in Section 15.2.5.2 as $\frac{30}{288} \times 7 \times 10^{-4}$ per plant year, or $\underline{7.3 \times 10^{-5}}$ per plant year.

Thus it is shown that the initiating event which is analyzed in Section 15.2.5.2 is in fact a very low probability event that is

Q55 (3 of 3)

highly unlikely to occur in a plant's lifetime.

Additionally, the high primary system pressures reported in Section 15.2.5.2 are due to the conservatively assumed coincident occurrence of a loss of normal a/c power. WASH 1400 estimates the conditional probability of this at 1 x 10^{-3}(Ref. Appendix III, Section 6.3). From this we can easily conclude that the joint recurrence frequency for the initiating event with a concurrent loss of a/c power is <u>less than 10^{-7} per plant year</u>. Therefore, the event analyzed in Section 15.2.5.2 is indeed sufficiently low to satisfy the Level C Service categorization, as defined in Section 3 of the ASME Pressure Vessel Code.

An additional conservatism of the FSAR analysis, that should be pointed out, is that no credit is taken for PORV operation which would tend to minimize the peak primary system pressure.

Discussion of the conservatisms inherent in the analysis of feedwater line breaks will be provided by 9/30/81, including

i) modeling of steam generator heat transfer,

ii) prediction of fluid conditions at the break location,

iii) correlation for prediction of break discharge rate,

iv) treatment of steam generator low water level trip,

v) selection of plant initial conditions, and

vi) selection of the "worst" break size.

Q55 (4 of 4)

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

JUL 2 9 1981

MEMORANDUM FOR: Paul S. Check, Assistant Director for
Plant Systems, DSI

FROM: James P. Knight, Assistant Director for
Components & Structures Engineering, DE

SUBJECT: USE OF LEVEL C PRESSURE LIMIT FOR
NON-ATWS TRANSIENTS AND EVENTS

The use of Paragraph NB-3224 (Level C Service Limits) of Section III of the ASME Code permits an allowable primary membrane stress due to pressure and other mechanical loadings which is 1.2 times the allowable stress used for design loadings for austenitic materials and the greater of 1.1 times the design allowable or 0.9 Sy for ferritic materials. For PWR geometries this essentially corresponds to an increase of 1.2 x design pressure for austenitic materials, and 1.1 x design pressure or 0.9 Sy for ferritic materials.

Level C limits permitting increased pressure was introduced in the Code by the ASME Boiler and Pressure Vessel Committee at the request of the NRC to deal with an ATWS event. While other events were not specifically discussed by the Committee, we believe that it would not object to Level C limits being used for other events of about the same probability of occurrence as ATWS. We consider this to be acceptable and would permit the use of the Level C limits stated in Paragraph NB-3224 for an non-ATWS event having about the same or a lower probability of occurrence. If the probability of occurrence for the event is higher than ATWS, then the Level B limits of Paragraph NB-3223 should be used.

The Mechanical Engineering Branch is not able to evaluate whether the stated probability of occurrence of small breaks in the main feed piping as provided by Combustion Engineering is valid. It would appear that the length of line subject to the break event may be plant specific for Palo Verde, St. Lucie-2 and Waterford.

George Lear

for James P. Knight, Assistant Director for
Components & Structures Engineering
Division of Engineering

cc: See next page.

APPENDIX 1.9A

1.9A TMI RELATED REQUIREMENTS

The following item numbers correspond to those listed in NUREG-0737 "Clarification of TMI Action Plan Requirements" (October, 1980)[13]

I.A.1.1 SHIFT TECHNICAL ADVISOR

Florida Power & Light Co (FP&L) programs in response to this requirement have been developed for St. Lucie Unit 1 (Docket No. 50-335) and will also be applicable to St. Lucie Unit 2.

Chapter 13 has been revised to address this requirement. Responsibility authority, phase out plans, and reporting relationshps are in Section 13.1.2.2. Qualifications are in Section 13.1.3.1. Training is in Section 13.1.3.1 and 13.2.1.1.2 The details of the training program were submitted for Unit 1 to the NRC as required by NUREG-0737 for operating reactors.

I.A.1.2 SHIFT SUPERVISION ADMINISTRATIVE DUTIES

FP&L programs in response to this requirement have been developed for St. Lucie Unit 1 (Docket No. 50-335) and will also be applicable to St. Lucie Unit 2.

The plant procedure describing these duties is addressed in revised Section 13.5.1.3.

I.A.1.3. SHIFT MANNING

Procedures reflecting the requirements of NUREG-0737[13], limiting overtime, hours of work and minimum shift complement have been generated for St. Lucie Unit 1 and will apply to St. Lucie Unit 2 when necessary.[7]

Section 13.5.1.3 has been revised to address the procedure defining overtime policy. Section 13.1.2.3 has been revised to indicate shift manning.

I.A.2.1 IMMEDIATE UPGRADING OF OPERATOR AND SENIOR OPERATOR TRAINING AND QUALIFICATIONS

Section 13.1.3.1 has been revised to address senior reactor operator qualifications as specified by NUREG-0737.[13] Section 13.2.1.1.1 has been revised to address changes to the overall training program. License candidate certification is addressed in the revised section 13.2.1.1.1C).

I.A.2.3. ADMINISTRATION OF TRAINING PROGRAMS

Revised section 13.2.1 addresses the qualifications of the plant training staff personnel.

I.A.3.1 REVISE SCOPE AND CRITERIA FOR LICENSING EXAM

FP&L initial and requalification training program revisions to address the increased scope of the license exams have been developed for St. Lucie 1 (Docket No. 50-535) and will also be applicable to St. Lucie Unit 2. Revisied Section 13.2.1.1.1 addresses the content of the training program.

I.B.1.2 EVALUATION OF ORGANIZATION AND MANAGEMENT

The FP&L organization is described in Section 13.1.1. The principal function of the Independent Safety Engineering Group as indicated by NUREG-0737 is operating experience assessment. This function is addressed in I.C.5 below.

I.C.1 SHORT TERM ACCIDENT ANALYSIS AND PROCEDURE REVISION

Florida Power & Light Co. (FP&L) has participated in C-E Owners Group activities conducted since the Three Mile Island accident to develop improved emergency procedure guidelines and associated supporting analyses. The C-E Owners Group has completed numerous documents which have been submitted to the NRC for review. A summary of results obtained to date and current activities is approved below.

The initial C-E Owners Group analysis of Inadequate Core Cooling (ICC) is documented in report CEN-117, "Inadequate Core Cooling - A Response to NRC IE Bulletin 79-06C, Item 6 for Combustion Engineering Nuclear Steam Supply Systems". This report was submitted to the NRC staff for review on October 31, 1979, by the C-E Owners Group.

"Operational Guidance for Inadequate Core Cooling" was prepared by the C-E Owners' Group based on the analyses in report CEN-117. This operational guidance was distributed to all members of the C-E Owners Group for their use in review and possible revision of plant emergency procedures in December, 1979. A copy of this operational guidance was submitted to the NRC staff for review by the C-E Owners' Group on December 10, 1980. Updated versions of this guidance are being used in the preparation of St. Lucie Unit 2 emergency procedures. Since early 1980, the C-E Owners Group has sponsored an extensive study of instrumentation response characteristics under ICC conditions. This study was described to the NRC staff at a meeting in Bethesda, MD, on May 28, 1980. This study was completed on December, 1980, and its results have been distributed to members of the C-E Owners Group for their use. FP&L is currently evaluating

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the results of this study for use in possible revisions to plant emergency procedures. Such revisions would be based upon determination of the usefullness of specific instrumentation for detection of ICC. This evaluation and subsequent revision of plant emergency procedures as required is expected to be completed prior to the start up of St. Lucie 2.

The initial C-E Owners Group analyses of transients and accidents (non-LOCA) is documented in report CEN-128, " Response of Combustion Engineering Nuclear Steam Supply System to Transients and Accidents". This report was submitted to the NRC staff for review on April 1, 1980. The results in this report show how a typical C-E-designed plant would most likely respond to various event initiators and shows what systems are actuated following each event. The report includes results of plant simulation analyses with digital computer codes to determine transient behavior of pertinent plant process parameters, components, and systems and results of sequence of events analyses performed to identify component and system functions and alternate means to accomplish specified safety functions.

The analyses contained in report CEN-128 consider single active failure for each system called upon to function for a particular event. Passive failures and multiple system failures are not considered. The sequence of events analyses (SEA) show the various paths through an event without probabilistic considerations. Each SEA demonstrates how specified safety functions are satisfied. Sequence of events diagrams (SED) are used to show how these functions are accomplished and include single active failures in each responding system and operator failure to perform manual actions. Consequential failures are considered in the SED for the steam line break.

Since early 1980, the C-E Owners Group has conducted a program to develop analyses of transients and accidents involving multiple failures. These analyses were outlined to the NRC staff in a meeting held in Bethesda, MD, on January 31, 1980. These analyses are currently scheduled to be completed in the first quarter of 1981. The results of these analyses will provide one basis for possible revision of emergency procedure guidelines.

The initial C-E Owners Group development of emergency procedure guidelines was completed in the first quarter of 1980. These emergency procedure guidelines are documented in report CEN-128. This report was submitted to the NRC staff for review on April 1, 1980.

The emergency procedure guidelines contained in report CEN-128 were prepared based on extensive reviews of existing emergency procedures, past safety, and design analyses, the plant simulation and sequence of events analyses in CEN-128, and interviews with operations personnel at plants with operating C-E reactors. These emergency procedure guidelines were prepared to be used as a basis for reviewing, and revising if necessary, existing plant emergency procedures. These guidelines were updated based on the NRC reviews SONGS 2+3. FP&L is preparing the St. Lucie 2 emergency procedures based on these guidelines.

The NRC staff, in a letter dated July 17, 1980, sent questions to the C-E Owners Group concerning the emergency procedure guidelines documented in report CEN-128. A meeting was held with the NRC staff in Bethesda, MD, on September 11, 1980, to discuss these questions and answers to them.

..... A preliminary response

to these questions was submitted by the C-E Owners Group to the NRC staff in a letter dated December 10, 1980. The remaining responses were submitted to the NRC staff by the C-E Owners Group in January, 1981.

Since early 1980, the C-E Owners Group has conducted an extensive evaluation of specific technical characteristics of emergency procedure guidelines. These include (1) the diagnostic guidance to be provided in emergency procedure guidelines, (2) the need for a separate guideline for inadequate core cooling, and (3) the format for presentation of emergency guidance. This evaluation is currently scheduled to be completed in the first quarter of 1981. The results of this evaluation will serve as one basis for possible revision of emergency procedure guidelines contained in report CEN-128.

The C-E Owners Group agreed on December 3, 1980, to conduct a series of workshops concerning emergency procedure guidelines in early 1981. These workshops were intended to provide a formal process by which the emergency procedure guidelines documented in report CEN-128 will be revised to account for multiple failure considerations. Input to these workshops was provided by the analysis and emergency procedure guidelines studies which have been conducted by the C-E Owners Group since early 1980. The workshops were attended by staff personnel from C-E and from utilities which own C-E reactors. These workshops also provided the opportunity to explore multiple-failure scenarios beyond those which have been currently identified in the C-E Owners Group analyses of transients and accidents. LOCA was alos be considered in these workshops.

The C-E Owners Group met with the NRC staff on January 30, 1981, in order to discuss the process being used for revision of emergency procedure guidelines.

The revised emergency procedure guidelines were submitted for review to the NRC staff by the C-E Owners Group on June 30, 1981 in CEN-152 and 156.

Following completion of the NRC review of the revised emergency procedure guidelines FP&L will evaluate theneed for revision of its plant emergency procedures. The schedule in NUREG-0737 indicates that six months will be required for NRC staff review and approval and that another six months or more are to be allowed for revision and implementation of emergency procedures. Therefore, the St. Lucie Units 2 emergency procedures will be revised if necessary after December 1, 1981, and the revisions implemented at the first refueling outage after June 1, 1982.

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I.C.2 SHIFT RELIEF AND TURNOVER PROCEDURES

The FP&L program in response to this requirement has been developed for St. Lucie 1 (Docket No. 50-335) and will also be applicable to St. Lucie Unit 2. Revised Section 13.5.1.3 addresses this requirement.

I.C.3 SHIFT SUPERVISOR RESPONSIBILITIES

The FP&L program in response to this requirement has been developed for St. Lucie 1 (Docket No. 50-335) and will also be applicable to St. Lucie Unit 2. Revised Section 13.5.1.3 addresses this requirement.

I.C.4 CONTROL ROOM ACCESS

The FP&L program in response to this requirement has been developed for St. Lucie 1 (Docket No. 50-335) and will also be applicable to St. Lucie Unit 2. Revised Section 13.5.1.3 addresses this requirement. Access limitations are also addressed in the site security plan, Section 13.6.

I.C.5 PROCEDURES FOR FEEDBACK OF OPERATING EXPERIENCE TO PLANT STAFF

Procedures have been generated to reflect the requirements of NUREG-0737[13]. Sections 13.1.1.3 and 13.1.2.2k) have been revised to indicate the organizational responsibilities for this program.

I.C.6 VERIFY CORRECT PERFORMANCE OF OPERATING ACTIVITIES

Performance and procedures currently in effect at St. Lucie Unit 1 reflect the requirements of NUREG-0737[13]. This requirement will also be met at St. Lucie Unit 2. Section 13.5.1.3 has been revised to address this requirement.

I.C.7 NSSS VENDOR REVIEW OF PROCEDURES

The low-power and power ascension test and emergency procedures for St. Lucie 2 are in the process of preparation and review. The NSSS Vendor, Combustion Engineering (C-E), Inc., is assisting in the preparation of the low-power physics and power ascenion test procedures for use by FP&L during the startup of St. Lucie 2. The C-E Site Rep. is a member of the Test Working Group and participates in the review and approval of the low-power physics and power-ascension test procedures. In addition, C-E will be reviewing the specific emergency procedures listed in table I.C.7-1. Documentation will be available prior to the start of low-power testing which will verify that the NSSS vendor reviewed and approved procedures involved with the following:

Precritical tests (FSAR table 14.2-2)
Low-Power physics tests (FSAR table 14.2-2)
Power Ascension tests (FSAR table 14.2-2)
Emergency Procedures (table I.C.7-1)

Amplifying information for the Units 2&3 startup test program can be found in FSAR section 14.2, which also lists the tests involved and the test organization.

Table I.C.7-1

EMERGENCY PROCEDURES

Shutdown Resulting from Reactor trip or Turbine trip

Anticipated Transients without Scram

Blackout Operation

Control Room Inaccessibility

RCS Cooldown During Blackout

PLCEA Off-Normal Operation and Realignment

Excessive Reactor Coolant System Leakage

Excessive Reactor Coolant System Activity

Reactor Coolant Pump-Off-Normal Operation

Pressurizer Pressure and Level-Off-Normal Operation

Pressurizer Relief and Safety Valve-Off-Normal Operation

Loss of Reactor Coolant Flow

Steam Generator Tube Leak Failure

Loss of Reactor Coolant

Inadequate Core Cooling

Charging and Letdown - Off-Normal Operation

Emergency Boration

Boron Concentration Control-Off-Normal

Component Cooling Water-Off-Normal Operation

C.C.W-Excessive Activity

HPSI-Off-Normal Operation

SDC/LPSI-Off-Normal Operation

Uncontrolled Release of Radioactive Liquids

(10)

Waste Gas System-Off-Normal Operation

Uncontrolled Release of Radioactive Gas

Condensor Tube Leak

Loss of Feedwater or Steam Generator Level

Main Steam Line Break

Loss of Instrument Air

Wide Range Nuclear Instrumentation Channel Malfunctions

Linear Power Range Channel Malfunctions

Loss of Containment Integrity-Off-Normal Operations

Accidents Involving new or Spent Fuel

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I.C.8 PILOT MONITORING OF SELECTED EMERGENCY PROCEDURES FOR NTOL APPLICANTS 0

Any deficiencies identified by an NRC audit will be corrected.

I.D.1 CONTROL ROOM DESIGN

A control room design review will be performed that will satisfy the requirements of NUREG-0737[13], item I.D.1. This review will commence in 1981, and will use the draft NUREG/CR-1580. and/or NUREG-0700.

A schedule has been established that will complete the review by April, 1982.
All discrepancies found will be evaluated for their safety implication, 1
prioritized and scheduled for implementation. Those discrepancies found to be a significant Human Factors problem will be corrected prior to November, 1982. Other discrepancies found not to be significant will be considered for long term implementation and will be corrected on a schedule approved by the NRC.

I.D.2. PLANT SAFETY PARAMETER DISPLAY SYSTEM

The Safety Assessment System (SAS) (refer Apendix 7.5A) will provide the Safety Parameter Display System and all other data required in the control room, technical support center (TSC), emergency offsite facility (EOF) and the nuclear data link (NDL).

I.G.1 TRAINING DURING LOW - POWER TESTING

This training will be in accordance with Robert L. Tedesio, Assistant Director for Licensing to Dr. Robert E. Uhrig letter dated June 12, 1981. Subject, TMI-2 Action Plan Item I.G.1. Since testing was accomplished at a comparable prototype plant, SONGS-2, only the training required by this letter need be accomplished and is addressed in revised Section 13.2.1.2.

II.B.1 REACTOR COOLANT SYSTEM VENTS

~~See Section 9.3.7. (Draft write-up attached; final write-up scheduled for August 1981 ammendent)~~

A description of the Reactor Coolant System vents is provided in Subsection 9.3.7

II.B.2 . PLANT SHIELDING

A design review was conducted to evaluate the radiological environment of the plant following an accident in which significant core damage has occurred. The evaluation provides for access to vital areas and equipment needed for post accident operations. A detailed description and results of this design review is provided in Apendix 12.3H. 0

Environmental qualification of safety related equipment for post accident conditions is addressed in Section 3.11.

II. B.3 POST ACCIDENT SAMPLING

See ~~Section 9.3.6 (Draft write-up attached. Final write-up scheduled for August 1981 ammendent)~~

A description of the Post Accident Sampling System is provided in Subsection 9.3.6.

II.B.4. TRAINING FOR MITIGATING CORE DAMAGE

The programs in which mitigating core damage training is contained are addressed in revised Sections 13.2.1.1.1 a) and 13.2.1.1.2.

II.D.1. RELIEF AND SAFETY VALVE TEST REQUIREMENTS

The Electric Power Research Institute (EPRI) has developed a generic program 0 to verify the operational characteristics of PWR safety and relief valves including the effects of downstream piping on valve operation and to provide 1 assurance that these systems can perform as required to prevent overpressurization of the primary coolant boundary. The testing of PORV isolation valves is under consideration. A preliminary program plan was presented to the NRC staff in a meeting held on December 17, 1979. The program includes tests on full scale PWR relief and safety valves. Experience from foreign relief valve test programs was utilized to expedite the program. The experimental data together with foreign relief valve tests results will be used to validate a computational methodology for assessing the hydraulic/structural performance 0 of PWR safety/relief valve systems on a plant-unique basis.

The overpressure protection system of St. Lucie Unit 2 includes three ASME Code safety valves located on the pressurizer. The valves are designed to protect the Reactor Coolant System as required by Section III of the ASME Code. A description of these valves is provided in Subsection 5.4.13 and Table 5.4-8. Safety valves representative of the above valves are being tested in the EPRI Program. Also, the preliminary test matrix (as outlined in the December 17,1979 program plan) bounds the fluid conditions and transient simulations under which the St. Lucie Unit 2 safety valves are expected to operate.

The overpressure protection system also includes two power operated relief valves which serve to ameliorate transients at normal operating temperatures and also provide low temperature overpressure protection at reduced temperatures. Relief valves representative of the above valves are being tested in the EPRI Program. These valves have been specified and are being designed, developed, and tested to assure operability and capacity for the applicable liquid and steam conditions. These valves are in compliance with Section III, Class I of the ASME Code and will be qualified for post accident conditions.

The design and testing of these valves are summarized in Table 5.4-9 and 1 Amendment 1 to Subsection 5.4.13.

II.D.3 RELIEF AND SAFETY VALVE POSITION INDICATION

Acoustic flow monitors will be used for the indication of pressurizer safety relief and power operated relief valve position. Design information is presented in Subsection 7.6.3.8.

II.E.1.1 AUXILIARY FEEDWATER SYSTEM RELIABILITY EVALUATION

a) Event tree and fault tree logic techniques has been conducted as part of a reliability analysis to determine dominant failure modes and assess Auxiliary Feedwater System reliability levels. The results of this reliability evaluation is provided in Appendix 10.4.9B.

b) A standard deterministic type of safety review has been performed using as principal guidance the acceptance criteria specified in Standard Review Plan 10.4.9 "Auxiliary Feedwater System" (R1) and Branch Technical Position ASB 10-1, "Design Guidelines for Auxiliary Feedwater System Pump Drive and Power Supply Diversity for PWR Plants" (R0). The results of this review is provided in Apendix 10.4.9A 0

c) The guidelines of Enclosure 2 of NRC letter to pending OL applicants dated March 10, 1980(12) has been addressed to describe the design basis accident and transients and the corresponding acceptance criteria for Auxiliary Feedwater System. in Appendix 10.4.9A

II.E.1.2 AUXILIARY FEEDWATER INITIATION AND INDICATION 1

A safety grade automatic-initiation Auxiliary Feedwater System has been implemented for St. Lucie Unit 2 and is described in Subsections 10.4.9 and 7.3.1.1.8

II.E.3.1 EMERGENCY POWER SUPPLY FOR PRESSURIZER HEATERS 1

a) A sufficient number of pressurizer heaters and associated controls 0
necessary to maintain natural circulation at hot standby condition are 3
provided with power supply from either the offsite power source or the 0
emergency power source (when offsite power not available). Each
redundant group of heaters has access to only one Class 1E division of
power supply.

b) Any changeover of the heaters from normal offsite power to emergency 3
onsite power is accomplished manually in the control room. (See
Subsection 8.3.1.1.1)

c) Procedures and training will be established to make the operator aware
of when and how the required pressurizer heaters are connected to the 0
emergency buses. The procedures will identify a) which engineered
safety features loads may be appropriately shed for a given situation,
b) manual operation of the heaters and c) instrumentation and criteria 3
to prevent overloading a diesel generator.

d) The time required to accomplish the connection of the necessary number 0
of pressurizer heaters to emergency buses is consistent with the timely 3
initiation and maintenance of natural circulation. 0

e) Pressurizer heater motive and control power interfaces with emergency 0
buses are through devices which are qualified to safety grade 3
requirements. Safety grade circuit breakers are provided to protect
this Class 1E interface as per the St Lucie Unit 2 commitment to Regulatory Guide 1.75, "Physical Independence of Electric System" 1/75(R1) in
Section 8.3.

f) Being non-class 1E loads, the pressurizer heaters are automatically shed 0
from the emergency power source upon occurrence of a SIAS.

II.E.4.1 DEDICATED HYDROGEN PENETRATIONS 1

As discussed in Subsection 6.2.5, redundant internal hydrogen recombiners are
provided. Therefore this requirement is not applicable to St Lucie Unit 2. 0

II.E.4.2 CONTAINMENT ISOLATION DEPENDABILITY

The following items address corresponding NRC positions contained in NUREG-0737:

1) As discussed in Subsection 7.3.1.1 the containment isolation actua-
tion signal (CIAS) is initiated upon high pressure or high radiation 1
inside the containment. Therefore, the CIAS complies with the
recommendation in Standard Review Plan 6.2.4 "Containment Isolation
System" (R1) with respect to diversity in the parameters sensed for
initiation of containment isolation.

2) Using the definition in Appendix A to the Branch Technical Position APCSB 3-1 (11/24/75) (attached to the Standard Review Plan 3.6.1), essential system and components are defined as those systems and components required to shutdown the reactor and mitigate the consequences of an accident. Table 6.2-52 identifies the essential penetrations as ESF penetrations. As indicated in Subsection 6.2.4, all containment penetrations associated with nonessential systems are either administratively locked closed or automatically isolated upon a CIAS. Penetrations for systems like post accident monitoring instrumentation and RCS sampling however are provided with manual override of the CIAS to enable the operator to open the containment isolation valves and activate the systems as necessary.

3) The St Lucie Unit 2 containment isolation system complies with General Design Criteria (GDC) 55, 56 and 57. A CIAS is used to isolate nonessential systems. GDC 57 permits the use of one containment isolation valve located outside containment which is capable of automatic or remote manual operation and does not require closure on a CIAS. The penetrations that fall into this category are main steam and feedwater which are automatically isolated upon receipt of a MSIS. However, with the diversity of high containment pressure or low steam generator pressure, a MSIS is generated and isolates the main steam isolation valves and Main Feedwater isolation valves. The component cooling water lines to and from the reactor coolant pump fall under the requirements of GDC 56. An SIAS isolates these penetrations and is initiated by diverse parameters, low pressurizer pressure or high containment pressure. 1

4) The present design of control systems for automatic containment isolation valves are such that resetting the isolation signal does not result in the automatic reopening of containment isolation valves. Certain valves (eg, post accident sampling, containment radiation monitoring, instrument air) which are required to open during an accident are provided with the capability of manually overriding the automatic isolation signal. Reopening of these containment isolation valves requires deliberate operator action, and can be accomplished only on a valve-by-valve basis. The containment isolation design does not utilize "ganged" control switches for containment isolation valves.

5) The CIAS, MSIS and SIAS containment pressure setpoint is selected to account for the normal operating pressure inside containment, equipment uncertainty, setpoint drift and associated instrumentation time delay. The pressure setpoint selected is far enough above the maximum expected pressure inside containment during normal operation so that inadvertent containment isolation does not occur during normal operation from instrument drift or fluctuations due to the inaccuracy of the pressure sensor.

6) The containment purge valves will comply with the operability criteria provided in Branch Technical Position CSB 6-4 (R1) and the staff interim position of October 23, 1979. The 48" purge valves are administratively closed during normal plant operation and only opened when the reactor is in cold shutdown or refueling mode. The 8" continuous containment purge valves will be able to close under 1
the DBA pressure and flow condition loading (time dependent) within the required valve closure time limit.

The 48" purge valves are verified to be closed at least every 31 days.

7) The continuous containment purge valves close on a CIAS which, as stated in Item 1, is initiated upon a high radiation or high pressure inside containment.

II.F.1 ADDITIONAL ACCIDENT MONITORING INSTRUMENTATION 0

In order to minimize the potential for operator error, display panel controls added to the control room as a result of this action item will undergo a human 1
factor analysis.

a) The containment pressure measurement and indication capability will be upgraded to four times the design pressure of steel containment. A 0
continuous indication of containment pressure will be provided in the control room, in addition to recording (refer to Subsection 7.5.3.1)

b) A continuous indication and recording of containment water level will be provided in the control room. Narrow and wide range water level monitors will be provided to cover a range from the bottom of the reactor cavity sump to a level equivalent to 600,000 gallon capacity 0.
(refer to Subsection 7.5.3.2.) 1

c) Redundant physically separate safety related hydrogen analyzers are presently provided with a measurement range of 0 to 10 percent hydrogen concentration. The analyzers are manually operated from the control 0
room and readings are continuously displayed in a panel meter and recorded on an analog strip chart in the control room., As indicated in Sections 3.10 and 3.11 the analyzer system are seismic Category I, meets the seismic qualification of IEEE 344-1975, and environmental qualification of IEEE 323-1974. The power is supplied from Class 1E emergency bus with automatic loading onto the diesel generators. Provisions are made for periodic testing. Subsection 6.2.5.2.1 provides a detailed description of the hydrogen analyzers. 1

or 10^7 R/hr (gamma radiation only)

10^7 R/hr (gamma)

d) The NRC requirement of measuring containment radiation levels up to 10^8 R/hr (total radiation) will be met by providing containment post-accident monitors with a maxium range of ~~10^8 R/hr~~. A minimum of two such monitors will be provided; physically separated; and designed and qualified to function in an accident environment (ie, Class 1E requirements). Continuous indication and recording will be provided in the control room (refer Subsection 12.3.4.1) 6

e) Noble gas effluent monitors are presently provided in the following potential gaseous release points (maximum monitor limit):

1) Gaseous waste discharge line ($10^4 \mu Ci/cc$) 0

2) Condenser air ejector discharge ($10^{-2} \mu Ci/cc$)

3) Plant vent ($10^{-2} \mu Ci/cc$)

4) Fuel Handling Building stack ($10^{-2} \mu Ci/cc$)

5) ECCS area exhaust ($10^{-2} \mu Ci/cc$)

However, after an accident involving radiation release, the only release paths utilized are the plant vent, ECCS area exhaust ducts and atmospheric dump valves and main steam safety valves.

The system description for the high range noble gas effluent monitors are provided in Subsection 11.5.2. The high range noble gas effluent monitors are either multistage gaseous monitors (Subsection 11.5.2.1.3. or externally mounted GM tubes (Subsection 11.5.2.1.3.e).

f) Capability for continuous sampling of plant gaseous effluent for post accident release of radioiodine and particulates will be provided with onsite laboratory capabilities to analyze or measure these samples (refer Subsection 11.5.2.5) 1

A detailed description of those systems under items a, b, d, e and f will be provided in a later amendment.

II.F.2 INADEQUATE CORE COOLING INSTRUMENTS

See ~~Appendix 1.9B~~

Description of Inadequate Core Cooling Instruments is provided in Appendix 1.9B

II.G.1 EMERGENCY POWER FOR PRESSURIZER EQUIPMENT i

a) Motive and control components of the power operated relief valves (PORVs) will be supplied from either the offsite power source or the emergency power source (when offsite power is not available).

b) Motive and control components for the PORV block valves will be supplied from either the offsite power source or the emergency power source (when offsite power is not available).

c) The changeover of the PORV and block valve motive and control power from the normal offsite to emergency onsite power is to be accomplished manually in the control room. 0

d) Motive and control power connections to the emergency buses for the PORVs and associated block valves will be through devices qualified in accordance with safety grade requirements.

e) The pressurizer level indication instrument channels will be powered from vital instrument buses, supplied from either offsite power or the emergency power source (when offsite power is not available).

The PORV's are powered from 125VDC safety busses 2A and 2B and are available continously. The PORV block valves are powered from safety related 480VAC motor control centers which are powered through the onsite distribution system. Upon loss of offsite power the diesel generator is started and powers the onsite system. (refer to Section 8.3) Therefore, the PORV block valves receive reliable power in the event they are required to operate during a loss of offsite power.

The description of the operation of the PORV and PORV Block Valves is found in FSAR Section 5.2.6.

The two safety related pressurizer level instrumentation channels are powered from the safety related 120V AC motor control centers which are powered through the onsite distribution system. Upon loss of offsite power the diesel generators are started and powers the onsite system (refer to Section 8.3). The control wiring diagrams (B 327 Sheets 90,370,395,649 and 658) are submitted to the NRC (refer to Section 1.7).

II.K.1 IE BULLETINS ON MEASURES TO MITIGATE SMALL - BREAK LOCAS AND LOSS OF FEEDWATER ACCIDENTS

Per the requirements of NUREG-0737, only two concerns under this item (II.K.1) are applicable to St Lucie Unit 2. These concerns, as addressed below, are Items 7 and 9 from IE Bulletin 79-06B, "Review of Operational Errors and Systems Misalignment Identified During The Three Mile Island Incident" (April 14, 1979). 1

Item II.K.1.5 REVIEW ESF VALVES

All safety-related valve positions, positioning requirements, and positive controls were reviewed, and documented in Table 1.9A-1, to assure that valves remain positioned (open or closed) in a manner to ensure the proper operation of engineered safety features.

The provision of complete display of instrumentation is an integral part of the design of systems required for safe shutdown and accident mitigation. A major component of the display information provided in the control room is position indication for valves and HVAC dampers. Table 1.9A-1 lists all active valves and dampers that may be required to operate to achieve safe shutdown or mitigate the consequences of an accident. For most valves and dampers position indicating lights are provided on control panels in the control room. For all other valves and dampers whose failure might have adverse consequences, sufficient information is available for position determination in the control room (refer to Table 1.9A-1).

The related procedures for maintenance, testing, plant and system start-up and supervisory periodic surveillance require that these valves are returned to their correct positions following necessary manipulation and are maintained in their proper position during all operational modes. These procedures have been developed in response to this NUREG-0737 requirement for St. Lucie Unit 1 (Docket No. 50-335) and will also be applicable to St. Lucie Unit 2. Revised section 13.5.1.3 addresses these procedures. Training in the use of these procedures is addressed in the programs described in revised Sections 13.2.1.1.1 and 13.2.1.1.2.

Item II.K.1.10 - Operability Status

FP&L programs in response to this requirement have been developed for St. Lucie Unit 1 (Docket No. 50-335) and will also be applicable to St. Lucie Unit 2. As indicated in NUREG 0660 (not clarified by NUREG 0737) for units applying for operating licenses, this item is addressed in I.D.2 and I.C.6 above.

Item 2.K.2.13 THERMAL MECHANICAL REPORT-EFFECT OF HIGH PRESSURE

FP&L is participating in C-E Owners Group generic efforts to evaluate the effect of high pressure safety injection on reactor vessel integrity in response to item II.K.2.13 of NUREG-0737. FP&L will submit the required report by the end of the second quarter of 1982.

II.K.2.17 Potential For Voiding In The Reactor Coolant System During Transients:

II.K.2.17.1 Description

In order to prevent voiding in the Reactor Coolant System during normal operation St Lucie unit 2 operating procedures are written to provide a cooldown rate of 50°F/hour to 325°F and then maintain hot leg temperature at 325°F for 20.4 hours. This will allow shutdown cooling pressure to be reached without flashing of the upper head fluid in a total cooldown time of 25.7 hours. Florida Power and Light analysis to support this procedure is provided in Apendix 5.2B

In the event a void formation is identified in the Reactor Coolant System the operators are trained to implement a "Drain and Fill" procedure to mitigate voiding. The NSSS vendor has completed an extensive analysis of voiding in the Reactor Coolant System. The results show that rapid refill and drain of the reactor vessel head does not cause stress levels in excess of those occuring during a normal cooldown at 100°F/hour. The results of this analysis to support this procedure is provided in Apendix 5.2C.

Reactor Coolant System cooldown rate
~~This requirement~~ is addressed in amendment 4, Sub section 5.4.7.5

II. K:2.19 SEQUENTIAL AUXILIARY FEEDWATER FLOW ANALYSIS

~~Deleted~~ As indicated by the NRC (letter from R.A Clark, Chief Operating Reactors Branch 3, Division of Licensing to R.E Uhrig, Vice President Florida Power & Light dated July 2, 1981) This item is not applicable to ~~Westinghouse and~~ CE supplied steam generators which utilize inverted U tubes.

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II. K.3.1 - INSTALLLATION AND TESTING OF AUTOMATIC PORV ISOLATION SYSTEM

II. K.3.2 - REPORT ON OVERALL SAFETY EFFECT OF PORV ISOLATION SYSTEM

FP+L has participated in C-E Owners Group activities conducted since the Three Mile Island accident to address various aspects of PORV design and operation. These activities have included review of operating experience with PORV's on C-E reactors, development of input to the EPRI program for testing these valves, review of requirements for emergency power to the PORVs and the associated block valves, development of a recommendation for PORV position indication, review and updating of emergency procedure guidelines to assure PORV operation is adequately addressed, and development of associated operator training materials. The requirements of Action Plan Item II.K.3.2 have also been also been addressed as a C-E Owners Group activity (CEN-145, PORV FAILURE REDUCTION METHODS).

It has been concluded based on the C-E Owners Group activities that the addition of an automatic PORV isolation system on St. Lucie Unit 2 to further decrease the probability of a small-break loss-of-coolant accident caused by a stuck-open PORV is not necessary. This conclusion is based on the following considerations. First, the design of the PORV actuation logic is such that the valves are only actuated coincident with the high pressurizer pressure trip of the reactor. The PORVs are not used prior to the Reactor Protection System actuation in an attempt to avoid the reactor trip. Thus, challenges to the PORVs are reduced because the margin between the normal operating pressure and the high pressure reactor trip is maximized. The success of this design approach is evident based on the operating experience compiled to date which has only nineteen challenges to the

PORVs in 29 reactor-years of operation on C-E plants (data from a recent survey of the C-E Owners Group). It should be noted that eleven of these nineteen challenges were caused by a trubine runback feature which has been removed. The PORVs successfully reclosed in each case where they were challenged.

The second consideration for not needing an automatic PORV isolation system is that various actions have been taken which significantly improve the reliability of the PORVs and associated block valves. The elimination of the turbine runback feature mentioned previously, and the provision of a direct reliable means for indicating PORV position to the operator reduce the recurrence frequency of a small break LOCA due to PORV failure by an estimated factor of 15. Improved operator training programs, improved emergency procedures, and the provision of emergency power to the PORVs and block valves reduce the small break LOCA recurrence frequency further although the exact magnitude has not been quantified.

The final consideration for not needing an automatic PORV isolation system is that the recurrence frequency of a small break LOCA due to PORV failure has been substantially reduced by the actions mentioned previously to an estimated value which falls well within the uncertainty band of the recurrence frequencies for a LOCA due to a small pipe rupture estimated in WASH-1400. Thus, the recurrence frequency is now at an acceptably low value. The incorporation of an automatic PORV isolation system would further increase PORV system reliability. However, this action is not considered to be necessary since the recurrence frequency of PORV system failures without this feature is small.

Item II.K.3.3 - Reporting Safety Valve and PORV Failures and Challenges

FP&L will assure that any failure of a PORV or safety valve to close will be reported to the NRC promptly. All challenges to the PORV's or safety valves will be documented in the annual report.

Item II.K.3.5 - Automatic Trip of Reactor Coolant Pumps During a LOCA

As an activity for the C-E Owner's Group, Combustion Engineering is preparing predictions of the LOFT Test L3-6. Because of the importance of those tests, C-E concurs with the NRC position provided in the clarification to this Action Item and will defer a final decision on implementation of automatic trip of reactor coolant pumps until the evaluation of ECC models is completed.

II.K.3.17 REPORT ON OUTAGES OF EMERGENCY CORE-COOLING SYSTEMS LICENSEE REPORT AND PROPOSED TECHNICAL SPECIFICATION CHANGES

A detailed report will be submitted including the outage dates and length of outages for all ECC systems for five (5) years of operation. The determined causes of the outages will also be included in the report. The ECC systems or components involved in the outage, and corrective action will also be identified. Test and maintenance outages will be included in the above listing covering five years of operation. Any proposed changes to improve the availability of ECC equipment if needed will also be included in the report.

At the end of five years of plant operation for St. Lucie Unit 2 necessary data will be derived from the plant operator's log book, equipment malfunction log and the license event reports (LERS).

II.K.3.25 EFFECT OF LOSS OF AC POWER ON PUMP SEALS

FP&L has conducted a test of RCP seals under simulated loss of ac power conditions of full temperature and pressure. After approximately 50 hours at coolant conditions of 550°F and 2250 psig, the RCP seal cartridge still performed satisfactorily with the pump idle. Some seal damage was observed during the post-test inspection; however, the maximum seal leakage during the test was only 16 gph (Reference: FP&L letter L-81-107, March 10, 1981).

II.K.3.30 REVISED SMALL BREAK LOCA METHODS TO SHOW COMPLIANCE WITH ID CFR PART 50, APPENDIX K

The small break LOCA models used in the St. Lucie Unit 2 FSAR analyses are described in CENPD-137, "Calculative Methods for the C-E Small Break Evaluation Model". Following the TMI accident the C-E Owners Group submitted two reports, CEN-114-P and CEN-115-P in response to NRC requests in IE Bulletins 79-06B and 79-06C. Following a review of these reports and similar reports from other vendors the NRC issued the requirement II.K.3.30 in NUREG-0737. FP&L has been actively participating in the C-E Owners Group efforts to provide the justification of the current small break LOCA models since that requirement was issued. To date, the C-E Owners Group has submitted an analysis of the LOFT Small Break experiment L3-6 and has met with the NRC on January 6, 1981 to define the NRC concerns with the models in use. The concerns expressed at that meeting are currently being addressed as response to action item II.K.3.30 and the required report justifying the present model will be submitted during the first quarter of 1982.

II.K.3.31 PLANT SPECIFIC CALCULATIONS TO SHOW COMPLIANCE WITH 10 CFR PART 50.46

Upon completion of satisfying item II.K.3.30 of NUREG-0737 ~~(see response to question 440.36)~~, a determination as to the adequacy of the present small break LOCA model will be made. If it is found as a result of that determination that a revised small break LOCA model is necessary and the presently submitted small break LOCA results (Sub~~S~~section 6.3.3.3 ~~of the FSAR~~) are no longer valid, a revised small break ECCS analysis, applicable to St. Lucie Unit 2, will be submitted within one year after staff approval of the revised small break LOCA model.

III.A.1.1 UPGRADE EMERGENCY PREPAREDNESS

The St. Lucie Plant Emergency Plan discussed in Section 13.3 has been modified to incorporate the requirements of this task.

III.A.1.2 UPGRADE EMERGENCY SUPPORT FACILITIES

FP&L programs in response to this requirement have been or are being developed for St. Lucie Unit 1 (Docket No. 50-335) and will also be applicable to St. Lucie Unit 2

a) FP&L has designated space for a joint onsite technical support center (TSC) adjacent to the St. Lucie Unit 1 control room. A Unit 1 Plant Procedure has been approved which delineates the activation, manning and use of the TSC during emergencies. The Emergency Plan has been revised to reflect the existence of this facility and to establish the methods and lines of communication.

b) FP&L has designated an area as the joint onsite operational support center. The Emergency Plan has been revised to reflect the existence of this center and to establish the methods and lines of communication.

c) FP&L has designated an area as the joint emergency operations facility. The Emergency Plan has been revised to reflect the existence of this facility.

III.A.1.2.1 Technical Support Center (TSC)

The TSC will be located in a 1924 square foot room adjacent to the control room, Desks and office space will be provided for the NRC, and sanitary facilities will be available.

Telephone communication system is provided in between the TSC, control room . and Emergency Operations Facility (EOF) together with the dedicated telephone link with the NRC as described in subsection 9.5.2.

The Safety Assessment System (see Item I.D.2 in Appendix 1.9A) will provide the Safety Parameter Display System (SPDS) display and other technical data display required in the TSC. The TSC will have at least two color CRT's, a data logger and a console. The equipment shall receive data needed in the TSC to analyze plant conditions without interrupting the plant operation. It will be possible to access Regulatory Guide 1.97 input data and the high level display (SPDS) in all modes of operation. The operation of the TSC equipment will not degrade performance of any Safety System equipment or displays. The quality and accuracy of the instruments used will be of the same design as used for SPDS in the Control Room. The overall system reliability will be designed to achieve an unavailability goal of 0.01 during all operations above cold shutdown.

Data display system and print out devices will be adequate to provide TSC personnel unhindered access to sufficient data to perform their assigned tasks. The TSC display will include plant system variables, radiological variables, meterological information and offsite radiological information. Trend graph and time history capability will be provided.

A conceptual design for the TSC power supply is presently being developed. There are several possible power sources being considered but the final decision has not been made at this time. The intent of requirements set forth in NUREG 0696 will be met.

III.A.1.2.2 Onsite Operational Support Center (OSC)

The on-site Operational Support Center (OSC) serves as an assembly point for auxiliary operators, health physics technicians, maintenance personnel, and other plant shift personnel available to support the emergency response. Required staff will be assigned to appropriate activities by the Emergency Coordinator or his designee.

Activation of the OSC will be initiated by the Emergency Coordinator. The OSC will be in operation for an Alert, Site Area Emergency or General Emergency.

The OSC is maintained in the first floor maintenance area of the Service Building. PAX telephone communications are maintained between the Control Room and the OSC.

III.A.1.2.3 Emergency Operational Facility (EOF)

The EOF will be located in a 2500 square foot area adjacent to but separate from the cafeteria in the General Office in Miami. This area can be isolated from other company operations and the public.

The Recovery Manager will command the EOF and when notified by the Recovery Manager, designated managers with responsibility for the following functional areas will either be stationed or represented in the EOF:

- Operations
- Engineering
- Radwaste
- Health Physics
- Personnel
- Security
- Nuclear Analysis
- Scheduling
- Procurement
- Accounting
- Administration
- Licensing
- State-County Coordination

In addition, public information and governmental affairs managers will be represented.

Desk space will also be provided for State of Florida and NRC representatives in the EOF and adjacent private offices are set aside for their exclusive use.

Power to the General Office Building is normally supplied from the FPL distribution system. If power is not available from the distribution system, power is furnished by standby gas turbines which are capable of supplying all the EOF's requirements.

The Safety Assessment System (item I.D.2 of Appendix 1.9A) will be capable of transmitting all the TSC data and meteorological data to the EOF. The EOF will be provided with facilities for data acquisition, display and evaluation of radiological, meterological and plant data to determine offsite protective measures. It will have all the SPDS functions, and all other data available in the Technical Support Center.

An area in clear view of the data displays will be set aside with a conference table so that progress of the accident can be observed, discussion held, and rapid decisions made.

EOF Communications

The General Office telephone system is a Centrex exchange. Exclusive tie lines are provided to division offices, power plants and the Juno Beach Facility. In addition, dedicated private telephone lines are provided to each TSC, Control Room and Plant Manager's office.

Three CRT displays of plant parameters will be available in the EOF. Computer terminals, teletype and facsimile equipment and access to the State LGR and HRS radio networks will also be provided. In addition, the private office that has been set aside for the NRC will have telephone communications specified by the NRC staff as well as normal Bell telephone service.

The FPL General Office Communication Center is near the EOF and has capabilities for TWX, Facsimile and FPL Telenet. It will be manned 24 hours per day during an emergency.

Satellite Emergency Operations Facility

In mid-1982, the Project Management, Engineering, and Construction departments will be relocated to a new facility at Juno Beach, Florida. The Juno Beach facility will also serve as a corporate training center.

One of the training rooms in the Juno Beach facility will be arranged to permit rapid conversion to a Satellite Emergency Operation Facility (SEOF). This room has about 790 square feet. Data displays will be provided and the SEOF will be staffed by engineering and construction personnel required to assist in the accident diagnosis, management and recovery. An adjacent room has been set aside for the NRC.

By convening technical personnel at the Juno Beach SEOF rather than either plant site or the General Office, mobilization time will be reduced from several hours to about one hour. An emergency generator will provide essential services in the event of loss of normal power.

III.A.3.3 COMMUNICATIONS

Direct dedicated telephone lines for NRC notification and environmental notification will be installed similar to those already installed on St. Lucie Unit 1. The communication system is described in Subsection 4.5.2

The Emergency Procedures will be revised to reflect these additions.

III.D.1.1 INTEGRITY OF SYSTEMS OUTSIDE CONTAINMENT LIKELY TO CONTAIN RADIOACTIVE MATERIAL 1

In the unlikely event of an accident, the Containment Isolation Actuation Signal (CIAS) isolates all nonessential systems, thereby eliminating all large radioactive leakage paths from containment. The only means of leakage into the Reactor Auxiliary Building is through ESF system components (i.e., pump seals, valve leakage, etc.) and post accident monitoring sample lines. Liquid leakages collected in the ECCS room sumps are normally routed to the equipment drain tank in the Waste Management System (WMS). The normal operational mode of the ECCS room sump pumps has not been modified. On high sump water level the pumps discharge to the equipment drain tank. To prevent radioactive contaminants from entering the WMS, the ESF Leakage Collection and Return System (see Subsection 9.3.5) provides operators with a method to direct ESF leakage to the containment. This system eliminates highly radioactive liquid from entering normally "Low activity" waste hold-up tanks. Likewise, all sources of high activity sample gas (e.g., hydrogen sampling) are re-routed to the containment, thus eliminating contamination of the Waste Gas System. The above described design precludes the use of Liquid and Gaseous Waste Management Systems during an unlikely event of an accident. 1

The following systems contain high activity fluid during a postulated accident:

1) Shutdown Cooling System

2) High Pressure Safety Injection (Recirculation Phase)

3) Containment Spray (Recirculation Phase)

4) Sampling System

5) Shield Building Ventilation System

6) ECCS Area Ventilation System.

[illegible]

For these systems a baseline leak test is implemented for the purpose of establishing minimum leakage requirements for the preventive maintenance program. This baseline system leak rate test is described in Subsection 14.2.12.4N and is conducted in coordination with system preoperational testing as described in Section 14.2. Periodic integrated leak testing, at intervals not to exceed each refueling cycle is established. A method is provided to compare yearly leak test results with the baseline tests taken. A program is established to evaluate yearly results and initiate leakage reduction measures for the preventive maintenance program.

III.D.3.3 In Plant Radiation Monitoring

FP&L programs in response to this requirement have been developed for St. Lucie Unit 1 (Docket No. 50-335) and will also be applicable to St. Lucie Unit 2. The Health Physics procedures address detailed radioiodine assessment. These are generally described in Section 12.5.3. Training is an integral part of the non-licensed training program discussed in Section 13.2.1.1.2.

III.D.3.4 CONTROL ROOM HABITABILITY

Potential hazards in the vicinity of the site have been identified and evalu- 0
ated to confirm that operators in the control room are adequately protected
(refer to Section 2.2). In addition, radioactive releases have been analyzed
for their effects on control room operators (refer to Section 6.4). Liquid
source terms from within the Reactor Auxilary Building, although not factored 0
into the dose rate to the operators presented in Section 6.4, would have
insignificant impact in terms of doses because the control room itself is
located on top of the Reactor-Auxiliary Building and is well separated from
liquid source terms.

REFERENCES - APPENDIX 1.9A

1. Deleted

2. Deleted

3. Letters from H. R. Denton, NRC, to All Power Reactor Applicants and Licensees, Subject: Qualifications of Reactor Operators, dated March 28, 1980.

4. CEN - 114, "Review of Small Break Transients in Combustion Engineering Nuclear Steam Supply Systems", (proprietary) Combustion Engineering, July, 1979.

5. CEN - 115, "Response to NRC IE Bulletin 79-06C, Items 2 and 3 for Combustion Engineering Nuclear Steam Supply System", (proprietary) Combustion Engineering, August, 1979.

6. Letter from D. F. Ross Jr, NRC, to G. E. Leibler, Florida Power & Light Company, dated November 14, 1979.

7. CEN - 117, " Inadequate Core Cooling - A Response to NRC IE Bulletin 79-06C, Items for Combustion Engineering Nuclear Steam Supply Systems", Combustion Engineering, October, 1979.

8. CEN-128, "Response of Combustion Engineering Nuclear Steam Supply Systems to Transients and Accidents", Combustion Engineering, Volumes 1 and 2, April 1980.

9. U.S. Nuclear Regulatory Commission, "TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations, "USNRC Report NUREG-0578, July 1979.

10. CEN-125, "Input for Response to NRC Lessons Learned Requirements for Combustion Engineering Nuclear Steam Supply Systems," Combustion Engineering, December 1979.

11. Letter from H.R. Denton, NRC, to All Operating Nuclear Power Plants, Subject: Discussion of Lessons Learned Short-Term Requirements, dated October 30, 1979.

12. Letter from D. F. Ross Jr, NRC, to All Pending Operating License Applicants of Nuclear Steam Supply Systems Designed by Westinghouse and Combustion Engineering, Subject: Actions Required from Operating License Applicants of Nuclear Steam Supply Systems Designed by Westinghouse and Combustion Engineering Resulting from the NRC Bulletins and Orders Task Force Review Regarding the Three Mile Island Unit 2 accident, dated March 10, 1980.

13. U.S. Nuclear Regulatory Commission, "Clarification of TMI Action Plan Requirements" USNRC Report NUREG-0737, October, 1980.

APPENDIX 1.9B

ST. LUCIE UNIT 2

RESPONSE TO INADEQUATE CORE COOLING

ITEM II.F.2 OF NUREG-0737

JULY, 1981

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LIST OF APPENDICES

1.0 INTRODUCTION

1.1 PURPOSE

This document provides the FP&L partial response to the requirements of Section II.F.2 of NUREG-0737 (Reference 1) regarding the documentation of the FP&L St. Lucie 2 instrumentation for detection of Inadequate Core Cooling (ICC).

1.2 SCOPE

This report (1) identifies the instrument sensor package selected by FP&L to detect ICC in St. Lucie 2 and (2) describes the status of design and development activities being conducted by FP&L, to implement the instrumentation to be used to detect inadequate core cooling (ICC).

1.3 BACKGROUND

C-E Owners Group efforts on the evaluation of Inadequate Core Cooling have been ongoing since early 1979. Results of initial studies by the C-E Owners Group are documented in reports CEN-117 (Reference 2) and CEN-125 (Reference 3). These results are being considered in the preparation of the emergency operating instructions which FP&L will transmit to the NRC. All studies have been based on the requirements to indicate the approach to, the existence of, and the recovery from ICC.

The C-E Owners Group (with F P & L participation) has performed an evaluation of response characteristics of potential Inadequate Core Cooling (ICC) detection instrumentation. This study is, in part, an amplification of the work reported in CEN-117 in that it provided detailed analyses of the existing instruments, as well as, investigating the performance characteristics of selected new instruments. Specifically, the instruments whose response characteristics have been evaluated are the subcooled margin monitor, the heated junction thermocouple reactor vessel level monitor, core-exit thermocouples, in-core thermocouples, self powered neutron detectors, hot leg resistance temperature detectors and ex-core

neutron detectors. A summary of the details of this effort is contained in Appendix A.

Based on the results of the above instrument evaluation study, FP&L has selected an Inadequate Core Cooling Instrumentation (ICCI) package for use in St. Lucie 2, consisting of:

1) hot and cold leg Resistance Temperature Detectors (RTDs)
2) pressurizer pressure sensors
3) Core Exit Thermocouples (CETs)
4) Reactor Vessel Level Monitoring System (RVLMS) probes employing the Heated Junction Thermocouple (HJTC) concept

FP&L is in the process of evaluating appropriate transmission, processing and display hardware for use with the above ICC sensor package. This hardware will satisfy the licensing requirements of Section II.F.2 of NUREG-0737.

2.0 BASES FOR ICC INSTRUMENT SELECTION

The ICC instrumentation sensor package selected by FP&L is designed to:

1) provide the operator with an advanced warning of the approach to ICC
2) cover the full range of ICC from normal operation to complete core uncovery

The ICC detection system that employs the FP&L sensor package and displays the sensor output enables the reactor operator to monitor system conditions associated with the approach to and the recovery from ICC.

2.1 DESCRIPTION OF ICC PROGRESSION

The instrument sensor package for ICC detection provides the reactor operator a continuous indication of the progression leading to and away from ICC. To ensure the selected instrument package provides such coverage, a methodical presentation of the conditions leading to and away from ICC is developed. In this development, the progression towards and away from ICC is divided into conditions based on physical processes occurring within the RPV. Six distinct ICC conditions are identified. These are characterized as follows:

Conditions Associated with the Approach to ICC

Condition 1a Loss of fluid subcooling prior to the first occurrence of saturation conditions in the coolant.

Condition 2a Falling coolant inventory within the upper plenum, from the top of the vessel to the top of the active fuel.

Condition 3a Increasing core exit temperature produced by uncovery of the core resulting from the drop in level of the mixture of vapor bubbles and liquid from the top of the active fuel to the minimum level during the event.

Conditions Associated with Recovery from ICC

Condition 3b Decreasing core exit steam tempearture resulting from the rising of the level to the top of the active fuel

Condition 2b Vessel fill by the increase in inventory above the fuel.

Condition 1b Establishment of saturation conditions followed by an increase in fluid subcooling.

These conditions encompass all possible coolant situations associated with any ICC event progression. The conditions denoted with an "a" refer to fluid situations that occur during the approach to ICC. Conditions denoted by a "b" refer to fluid situations which occur during the recovery from ICC. Thus, "a" conditions differ from "b" conditions in the trending (directional behavior) of the associated parameters.

In order to provide indicators during the entire progression of an event, an ICC instrument system consists of instruments which provide at least one appropriate indicator for each of the physical Conditions described above.

Applying this description of the "approach to", and "recovery from" ICC to ICC instrument selection:

1) provides assurance that the selected ICC system detects the entire progression
2) demonstrates the extent of instrument diversity or redundancy which is possible with the available instruments.

Furthermore, by defining the ICC progression on a physical basis the general labels of "approach to", and "recovery from" ICC can now be associated with specific physically measurable processes. (See Section 2.2, 2.3, and 2.4).

The instrument package selected by FP&L to monitor the ICC event progression consists of (1) saturation margin monitors (SMM), (2) reactor vessel level monitors employing the HJTC design concept and (3) core exit thermocouples. The SMMs can indicate the initial occurrence of saturation (Condition 1a) and the achievement of a subcooled condition following core recovery (Condition 1b). The reactor vessel level monitors provides information to the operator on the decreasing liquid inventory in the reactor pressure vessel (RPV) regions above the fuel alignment plate (FAP), as well as the increasing RPV liquid inventory above the FAP following core recovery (Conditions 2a and 2b). The core exit thermocouples (CETs) monitor the increasing steam temperatures associated with ICC and the decreasing steam temperatures associated with recovery from ICC (Conditions 3a and 3b).

2.2 ADVANCED WARNING OF THE APPROACH TO ICC

The FP&L ICC instrumentation provides the operator with an advanced warning of the approach to ICC by providing indications of:

1) the loss of subcooling and occurrence of saturation (Condition 1a) with the SMM.
2) the loss of inventory in the RPV (Condition 2a) with the RVLMS
3) the increasing core coolant exit temperature (Condition 3a) with CETs

It should be noted that the RVLMS measures inventory (collapsed liquid level) rather than two-phase level. This measurement provides the operator with an advanced indication of the coolant level should conditions arise to cause the two-phase froth to collapse via system overpressurization, or the loss of operating reactor coolant pumps.

2.3 APPLICATION OF FP&L ICC DETECTION SYSTEM

Following an event leading to ICC the FP&L ICC detection system will provide information to the reactor operator so that he may:

1) verify that the core cooling safety function is being met,
2) establish the potential for fission product release.

Accomplishment of the core cooling safety function is verified via ICCI by observing (1) an increasing inventory level above the fuel alignment plate, (2) an increasing subcooling in the RPV and RCS piping or (3) a decreasing core exit steam superheat. The operator is informed about the progression of an event by both static and trend displays. The trending of ICC information enables the operator to quickly assess the success of automatically or manually performed mitigating actions. A chart indicating the ICCI trending during the various ICC progression conditions associated with the approach to and recovery from ICC is presented in Table 3-1.

2.4 INSTRUMENT RANGE.

FP&L uses saturation temperature and water inventory as indicators for the approach to and recovery from ICC when there is water inventory above the fuel alignment plate. These measurements characterize conditions 1a, 1b, 2a, and 2b of the ICC progression.

When the two-phase level is below the fuel alignment plate, the measurement of core exit fluid temperature represents a direct indication of the approach to, and recovery from ICC (Conditions 3a and 3b). Therefore, the FP&L ICC sensor package is sufficient to provide information to the reactor operator on the entire progression of an event with the potential of resulting in ICC.

TABLE 3-1

ICC STATUS AS AVAILABLE TO THE OPERATOR FROM ICC INSTRUMENTATION TRENDING

I. APPROACHING AN ICC CONDITION

CONDITION	SUBCOOLING MEASURED BY SMM	WATER INVENTORY MEASURED BY HJTC PROBE	COOLANT SUPERHEAT MEASURED BY CET
1a	DECREASING	CONSTANT	CONSTANT
2a	CONSTANT	DECREASING	CONSTANT
3a	CONSTANT	CONSTANT	INCREASING

II. RECEDING FROM AN ICC CONDITION

CONDITION	SUBCOOLING MEASURED BY SMM	WATER INVENTORY MEASURED BY HJTC PROBE	COOLANT SUPERHEAT MEASURED BY CET
3b	CONSTANT	CONSTANT	DECREASING
2b	CONSTANT	INCREASING	CONSTANT
1b	INCREASING	CONSTANT	CONSTANT

3.0 INADEQUATE CORE COOLING INSTRUMENTATION DESIGN DESCRIPTION

This section describes the FP&L St. Lucie 2 Inadequate Core Cooling Instrument sensor package. Associated signal transmission, processing and display hardware and software have not yet been finalized.and will be presented in a future amendment.

The reactor vessel liquid inventory above the core and the fluid conditions at various locations in the primary system will be measured by:

- Saturation Margin Monitors
- Reactor Vessel Level Monitors
- Core exit thermocouples

These instruments collectively conform to the design requirements presented in Section 2.0 and functional requirements of Section 4.0.

The St. Lucie 2 ICC instrumentation package will provide the operator with indications of the approach to, existence of and recovery from ICC.

A functional diagram of the ICC instrument package is presented in Figure 3-1. Detailed information on the associated sensors is presented in the following sections.

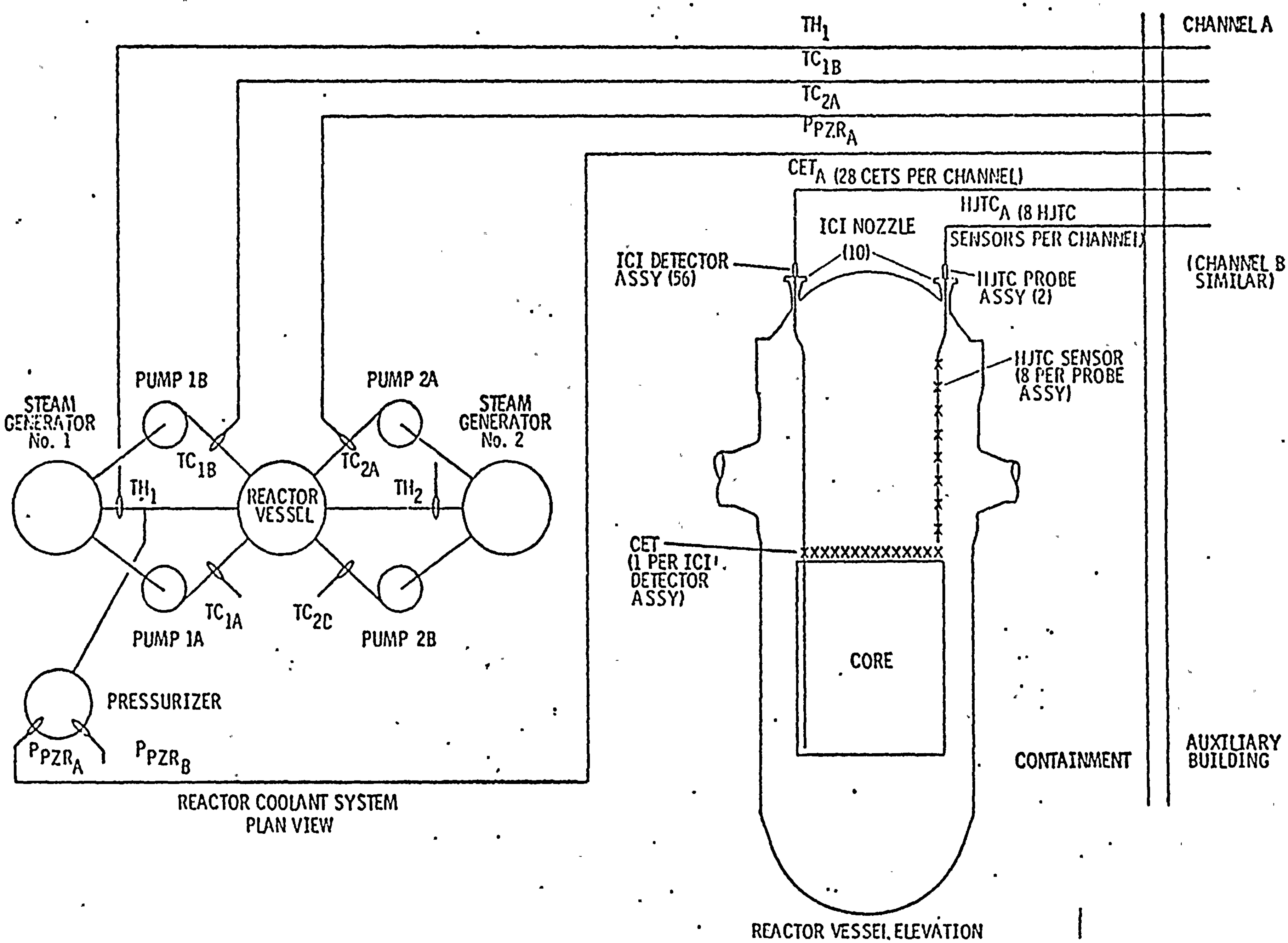
3.1 SENSOR DESIGN

3.1.1 SATURATION MARGIN MONITORING SYSTEM

The saturation margin monitor can be used to provide information to the reactor operator on (1) the approach to saturation and (2) existence of core uncovery. The specific saturation margin monitor design configuration to be implemented by St. Lucie 2 is not yet finalized. It is expected that the St. Lucie 2 SMM includes the same RCS temperature and pressure inputs as described in Appendix B plus the maximum unheated junction thermocouple temperature(UHJTC) described in Section 3.1.2 and 3.2.2.

Figure 8-1

ICC DETECTION INSTRUMENTATION



The UHJTC inputs come from the outputs of the HJTCS processing units. In summary, the sensor inputs to the SMM are:

Input	Range
Pressurizer Pressure	0-3000 psia
Cold Leg Temperature	0-710^{o}F
Hot Leg Temperature	0-710^{o}F
Maximum UHJTC Temperature (from HJTC processing)	100-1800^{o}F

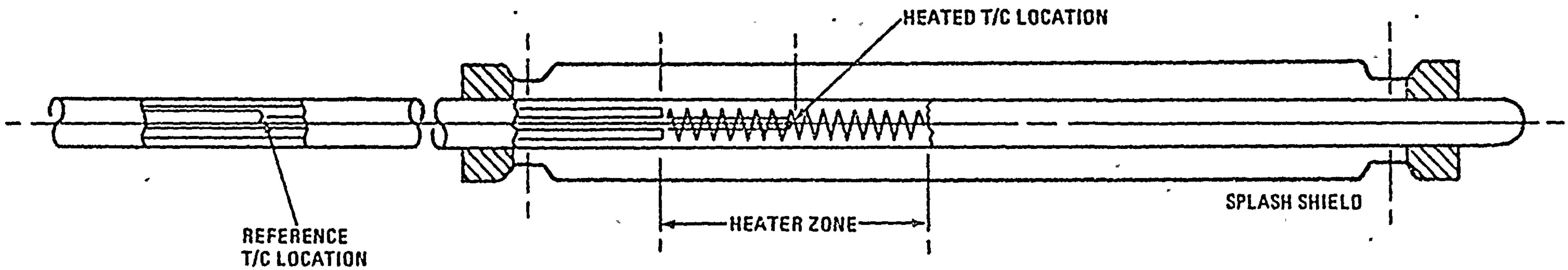
3.1.2 HEATED JUNCTION THERMOCOUPLE (HJTC) SYSTEM

The HJTC System measures reactor coolant liquid inventory above the fuel alignment plate with discrete HJTC sensors located at different levels within a separator tube ranging from the top of the fuel alignment plate to the reactor vessel head. The basic principle of system operation is the detection of a temperature difference between adjacent heated and unheated thermocouples.

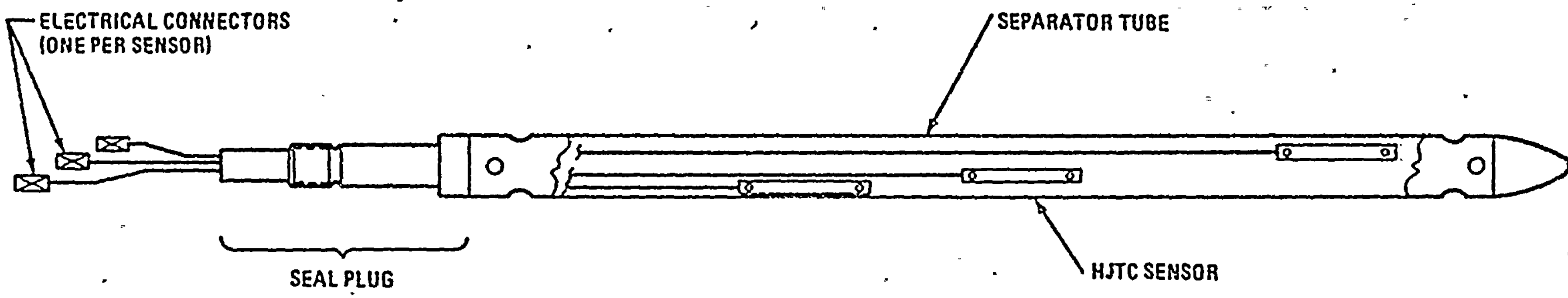
As pictured in Figure 3-2, the HJTC sensor consists of a Chromel-Alumel thermocouple near a heater (or heated junction) and another Chromel-Alumel thermocouple positioned away from the heater (or unheated junction). In a fluid with relatively good heat transfer properties, the temperature difference between the adjacent thermocouples is small. In a fluid with relatively poor heat transfer properties, the temperature difference between the thermocouples is large.

The HJTC System is composed of two channels of HJTC instruments. Each HJTC instrument is manufactured into a probe assembly. The probe assembly includes eight (8) HJTC sensors, a seal plug, and electrical connectors (Figure 3-3). The eight (8) HJTC sensors are electrically independent. Details of the axial placements of the 16 HJTC sensors have not been finalized.

Two design features ensure proper operation under all thermal-hydraulic conditions. First, each HJTC is shielded to avoid overcooling due to direct



HJTC SENSOR — HJTC/SPLASH SHIELD
FIGURE 3-2



HEATED JUNCTION THERMOCOUPLE
PROBE ASSEMBLY
FIGURE 3-3

water contact during two phase fluid conditions. The HJTC with the splash shield is referred to as the HJTC sensor (See Figure 3-2). Second, a string of HJTC sensors is enclosed in a tube that separates the liquid and gas phases that surround it.

The separator tube (See Figure 3-4) creates a collapsed liquid level that the HJTC sensors measure. This collapsed liquid level is directly related to the average liquid fraction of the fluid in the reactor head volume above the fuel alignment plate. This mode of direct in-vessel sensing reduces spurious effects due to pressure, fluid properties, and non-homogeneities of the fluid medium. The string of HJTC sensors and the separator tube is referred to as the probe assembly.

The probe assembly is housed in a stainless steel structure that protects it from flow loads. Figure 3-5 shows the two radial locations of the HJTC probe assemblies. Installation arrangements are being developed for St. Lucie 2 and will be provided in a future amendment.

3.1.3 CORE EXIT THERMOCOUPLE (CET) SYSTEM

The core exit thermocouples provide a measure of core heatup via measurement of core exit steam temperature.

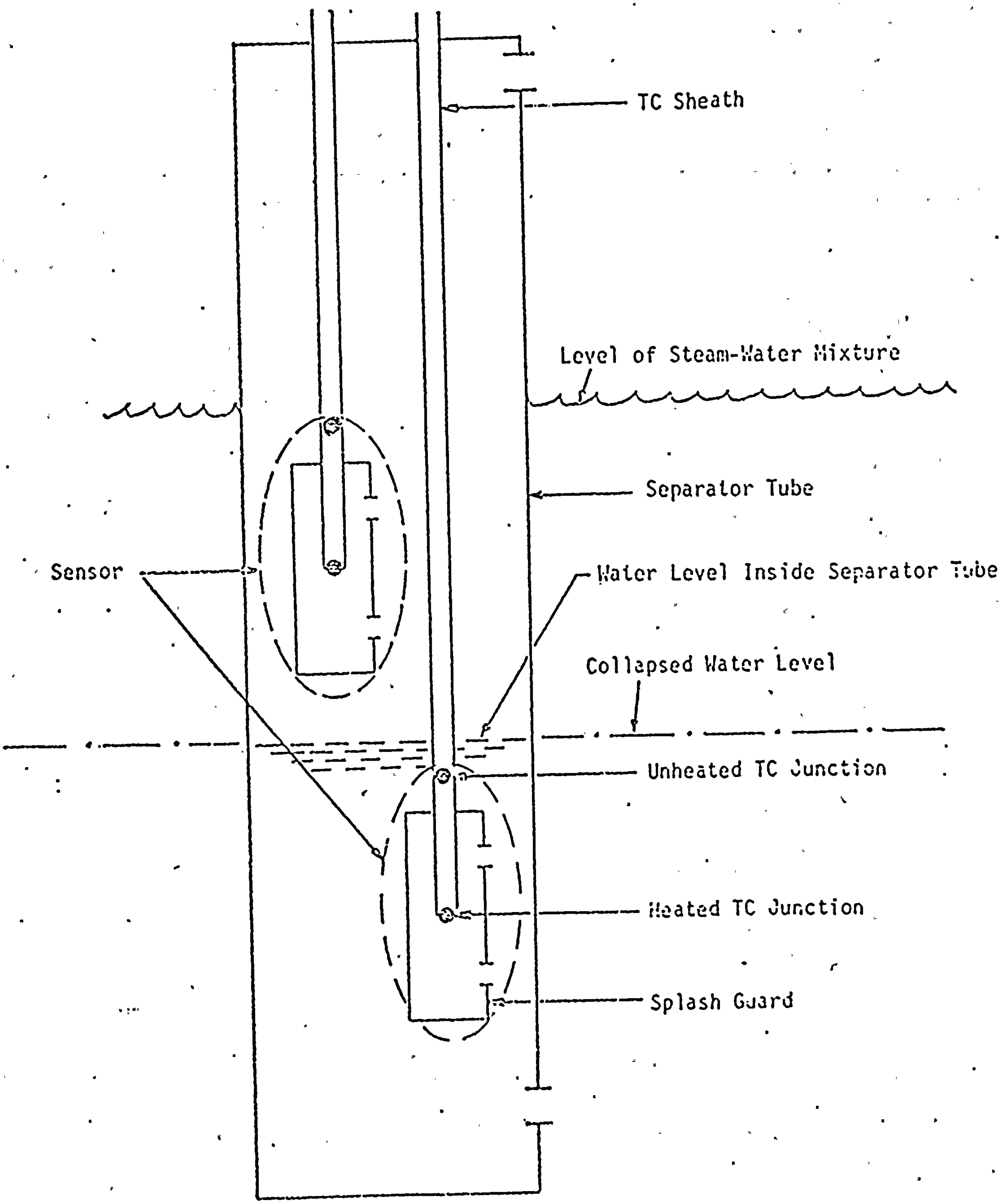
The design of the St. Lucie 2 In-core Instrumentation (ICI) system includes a Type K (Chromel-Alumel) thermocouple within each of the 56 ICI detector assemblies.

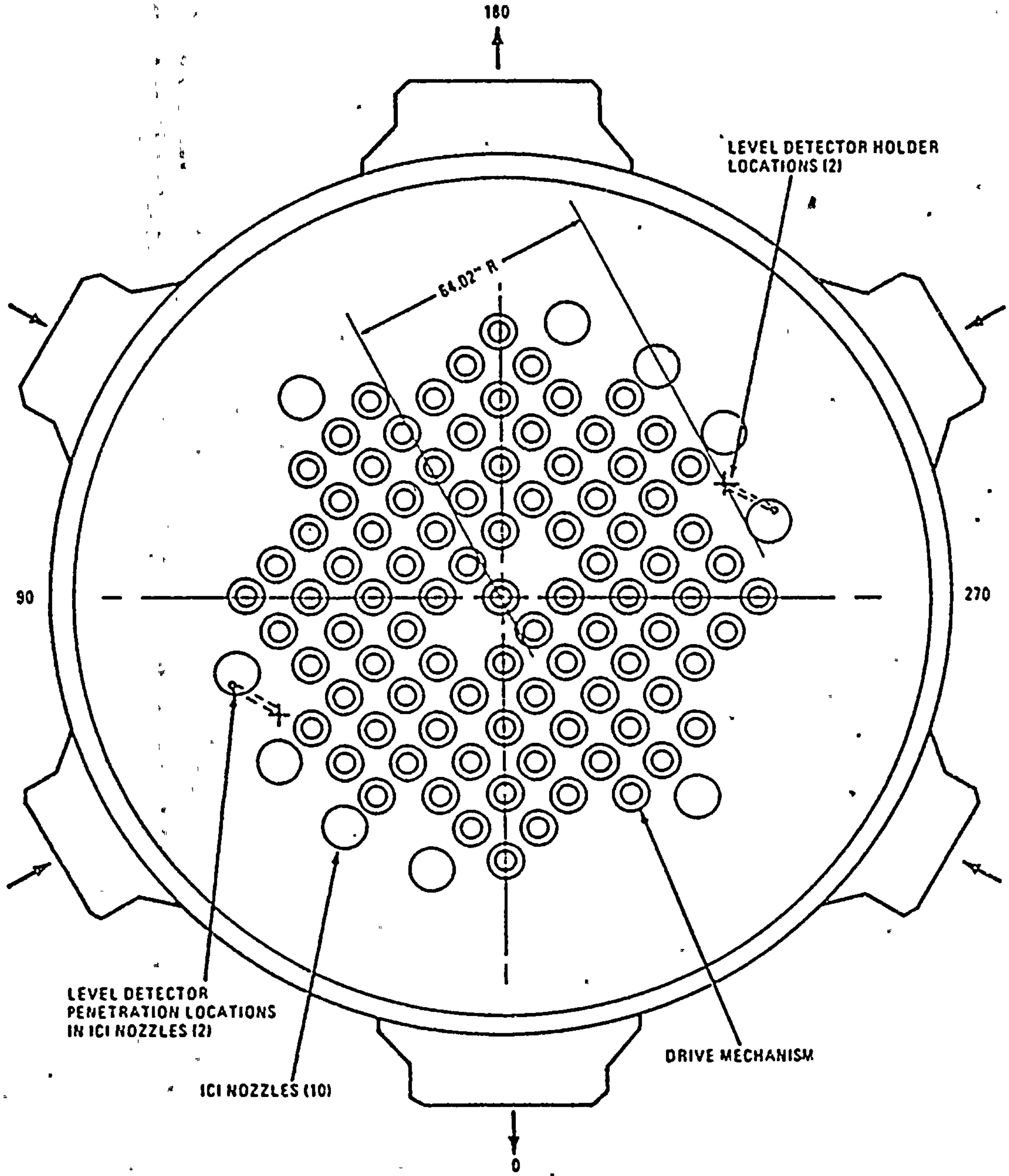
The junction of each thermocouple is located ∿ 18" above the top of the active fuel inside a structure which supports and shields the ICI detector assembly string from flow forces in the outlet plenum region. These Core Exit Thermocouples (CET) monitor the temperature of the reactor coolant as it exits the fuel assemblies. Figure 3- 6 depicts a typical ICI detector assembly, showing the CET. The core locations of the ICI detector assemblies are shown in Figure 3-7

Appendix D describes the present design of the CET system which will be used for the first cycle of St. Lucie Unit 2.

FIGURE 3-4

HJTC SENSOR AND SEPARATOR TUBE





HJTC PROBE ASSEMBLY LOCATIONS
FIGURE 3-5

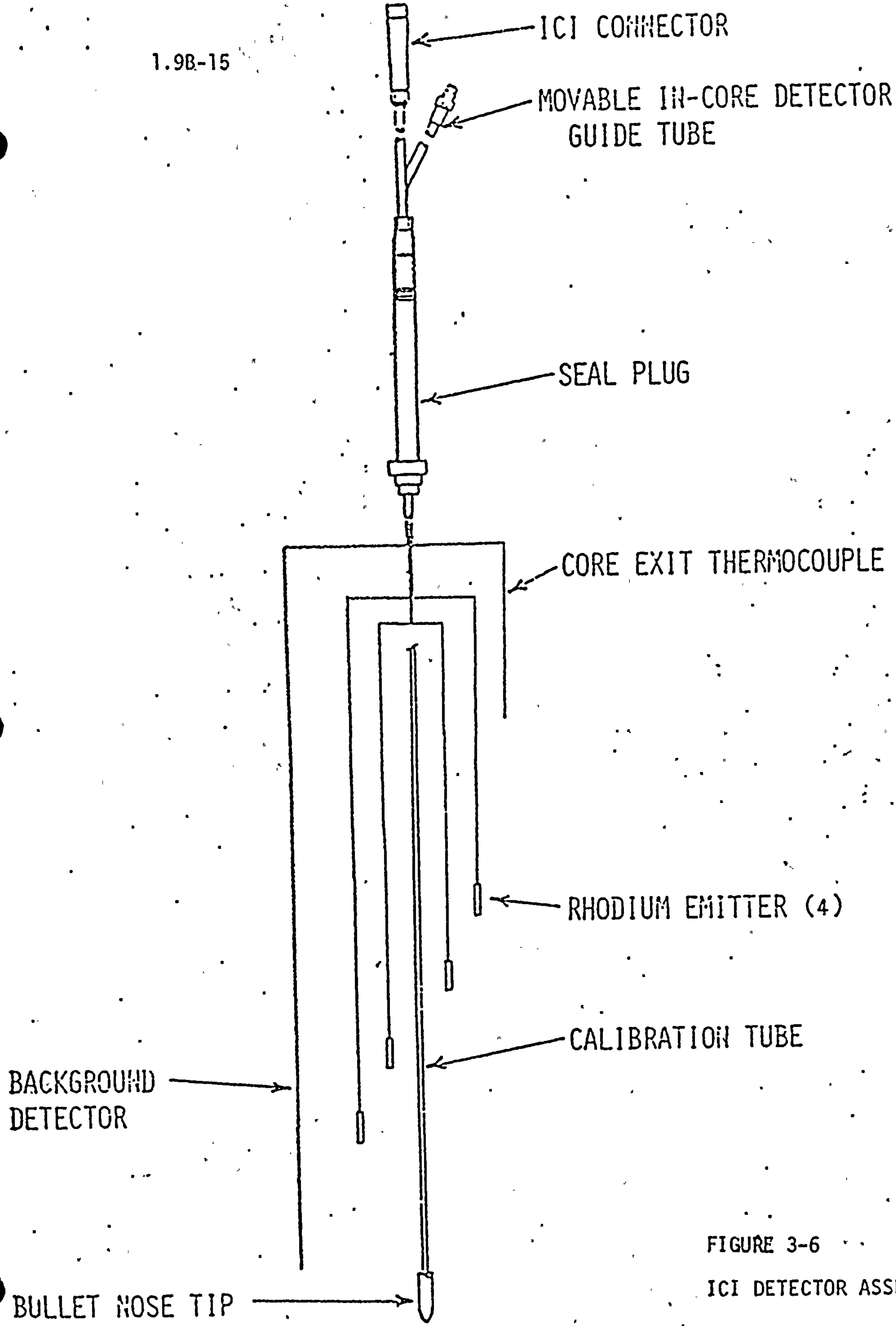
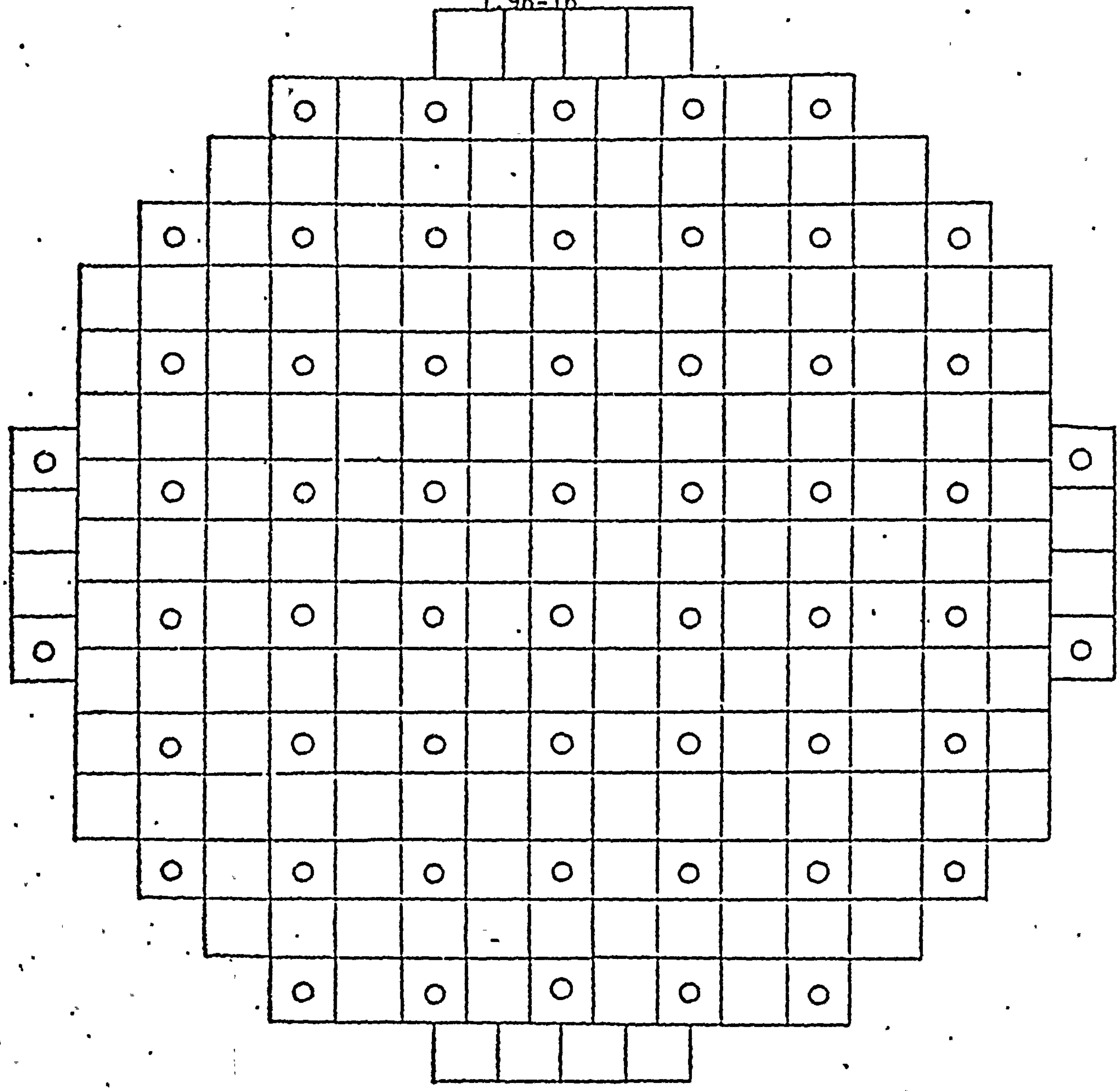


FIGURE 3-6

ICI DETECTOR ASSEMBLY




ICI Detector Assembly/Core Exit Thermocouple Location

Figure 3-7

ICI DETECTOR ASSEMBLIES/CORE EXIT THERMOCOUPLES CORE LOCATIONS

The CETs have a usable temperature range from 200°F to up to 1800°F (Reference 4).

3.2 DESCRIPTION OF ICCI PROCESSING AND DISPLAY

The following sections provide a preliminary description of the processing and display functions associated with each of the ICC detection instruments. Additional details on the complete ICCI signal processing, transmission and display equipment will be made available at a later date.

3.2.1 SATURATION MARGIN MONITOR

The SMM processing equipment will perform the following functions:

1. Calculate the subcooled margin

   The saturation temperature is calculated from the minimum pressure input and the saturation pressure is calculated from the maximum temperature input (See Section 3.1). The temperature subcooled margin is the difference between saturation temperature and the maximum temperature input. The pressure subcooled margin is the difference between saturation pressure and the minimum pressure input.

2. Process sensor outputs for display of temperature margin to saturation.

3. Provide an alarm output when subcooled margin reaches a preselected (to be determined) setpoint.

3.2.2 HEATED JUNCTION THERMOCOUPLE

The processing equipment for the HJTC performs the following functions:

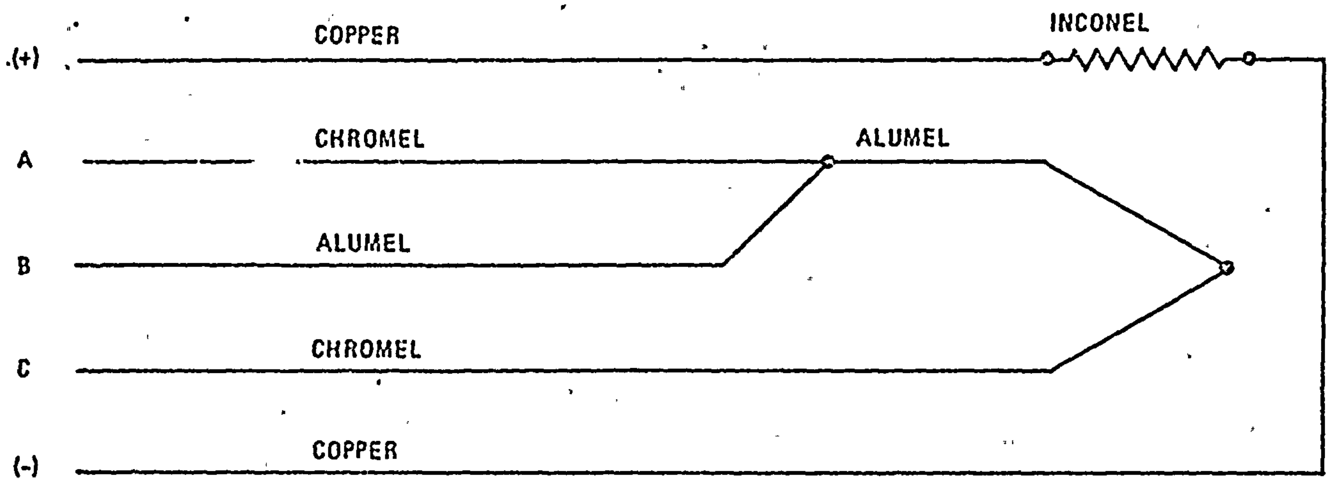
1. Determine collapsed liquid level above core.

   The heated and unheated thermocouples in the HJTC are connected in such a way that absolute and differential temperature signals are available. This is shown in Figure 3-8. When liquid water surrounds the thermocouples, their temperature and voltage output are approximately equal. The voltage $V_{(A-C)}$, on Figure 3-8 is, therefore, approximately zero. In the absence of liquid, the thermocouple temperatures and output voltages become unequal, causing $V_{(A-C)}$ to rise. When $V_{(A-C)}$ of the individual HJTC rises above a predetermined setpoint, liquid inventory does not exist at this HJTC position.

2. Determine the maximum upper plenum/head fluid temperature from the unheated thermocouples for use as an output to the SMM. (The temperature processing range is from 100^oF to 1800^oF).

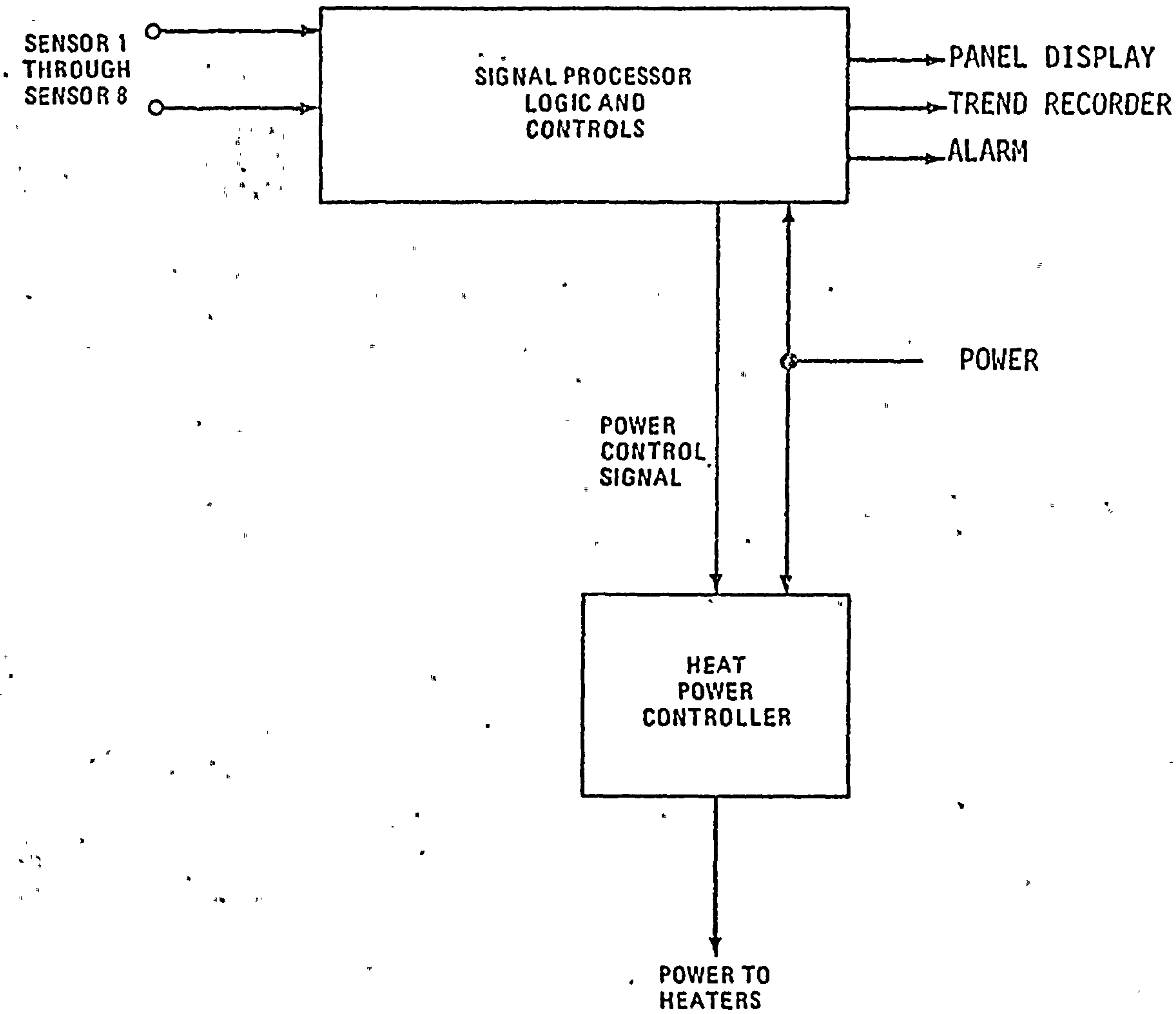
3. Process input signals to display collapsed liquid level as a function of time, and selected unheated junction thermocouple temperatures.
4. Provide an alarm output when any of the HJTC detects the absence of liquid level.

5. Provide control of heater power for proper HJTC output signal level. Figure 3-9 shows the design for one of the two channels which includes the heater power controller.



V (A-B) = ACTUAL TEMPERATURE, UNHEATED JUNCTION
V (C-B) = ACTUAL TEMPERATURE, HEATED JUNCTION
V (A-C) = DIFFERENTIAL TEMPERATURE

ELECTRICAL DIAGRAM OF H.J.T.C.
FIGURE 3-8



HJTC SYSTEM PROCESSING CONFIGURATION
(ONE CHANNEL SHOWN)
FIGURE 3-9

3.2.3 CORE EXIT THERMOCOUPLE SYSTEM

The following constitutes a preliminary description of the CET processing functions:

1. Process core exit thermocouple inputs for display.
2. Provide an alarm output when temperature reaches a preselected value.
3. Process CETs for display of superheat

These functions are intended to meet the design requirements of NUREG-0737, II.F.2 Attachment 1. A final description of the CET processing equipment will be presented in a future amendment.

3.2.4 SYSTEM DISPLAY

The display equipment will (at a minimum) be capable of trending:

(1) Temperature Margin to Saturation

(2) Collapsed liquid level (water inventory) above the fuel alignment plate

(3) Representative core exit thermocouple temperatures and saturation temperature

Details regarding the trending display will be presented in a future amendment.

4.0 INSTRUMENT FUNCTIONAL DESCRIPTION

In the following sections a functional description of the instruments of the ICC Detection System is given and the function of the instruments is related to the ICC conditions which are described in Section 2-1.

4.1 SUBCOOLING AND SATURATION

The parameters measured to detect subcooling and saturation are the RCS and UHJTC coolant temperature and the pressurizer pressure. Temperature is measured in the hot legs and the vessel upper head region.

4.1.1 INSTRUMENT RANGE AND RESPONSE TIME

In order to include all initial conditions and ICC event types, the instruments to detect initial saturation should encompass the range from the shutdown cooling entry conditions, which are the lowest temperature conditions for which the reactor primary system provides the heat removal safety function, up to the saturation conditions at the pressurizer safety valve pressure rating, which are the

highest temperature conditions which can occur while the core is covered with coolant.

The instrument response time should be fast enough so as not to limit or delay the reactor operator from taking appropriate actions.

Generic analyses done to date show that existing or planned instruments have adequate range and response.

The information which is derived from the reactor vessel temperature and pressure measurements is the amount of subcooling during the initial approach to saturation conditions and the occurrence of saturation (Condition 1a) and, the reestablishment of subcooled conditions (Condition 1b).

4.2 COOLANT INVENTORY MEASUREMENT IN REACTOR VESSEL

The Reactor Coolant System is at saturation conditions until sufficient coolant is lost to lower the two-phase level to the top of the active core. During this interval there were no existing instruments which would measure directly the coolant inventory loss. A Heated Junction Thermocouple System provides a direct measurement during this period. The parameter which is measured is the collapsed liquid level above the fuel alignment plate. The collapsed level represents the amount of liquid mass which is in the reactor vessel above the core. Measurement of the collapsed water level was selected in preference to measuring two-phase level, because it is a direct indication of the water inventory while the two-phase level is determined by water inventory and void fraction.

The collapsed level is obtained over the same temperature and pressure range as the saturation measurements, thereby encompassing all operating and accident conditions where it must function. Also, it is intended to monitor Condition 2b (following core recovery). Therefore, it must survive the high steam temperature which may occur during the preceeding core uncovery interval.

4.2.1 RANGE AND RESPONSE TIME

The level range extends from the top of the vessel down to the top of the fuel alignment plate. The response time is short enough to track the level during small break LOCA events. The resolution is sufficient to show the initial level drop, the key locations near the hot leg elevation and the lowest levels just above the alignment plate. This provides the operator with adequate indication to track the progression of Conditions 2a and 2b and to detect the consequences of his mitigating actions or the functionability of automatic equipment.

4.3 CORE EXIT STEAM TEMPERATURE

The overall intent of ICC detection is the detection of the potential for fission product release from the reactor fuel. The parameter which is related to the potential for fission product release is the fluid temperature at the core exit, rather than the uncovery of the core by coolant. After the core becomes uncovered, the fluid leaving the core is superheated steam and the trending of the superheat provides the operator with an indication of whether he is approaching or receding from an ICC condition. Unlike the measure of coolant inventory, the CET provides a direct indication of the ICC direction and severity.

The amount of superheat of the steam leaving the core will be measured by the core exit thermocouples. The time behavior of the superheat temperature is similar to the time behavior of the cladding temperature.

The core exit steam temperature is measured with the thermocouples included in the In-Core Instrument (ICI) string. They are located inside the ICI support tube, at an elevation a few inches above the fuel alignment plate. Generic calculations of a similar installation for representative uncovery

events show that the thermocouples respond sufficiently fast to the increasing steam temperature. Plant specific calculations on the St. Lucie 2 configuration will be made to verify this response.

4.3.1 RANGE AND RESPONSE TIME

The required temperature range of the thermocouples extends from 200°F, the lowest saturation temperature at which uncovery may occur up to 1200°F which gives a significant measure of superheat. The approximate upper service temperature limit is 1800°F, therefore the desired range can be met with the present thermocouple capabilities. Thermocouples are expected to function with reduced accuracy at even higher temperatures, so the range for processing the thermocouple output could extend to about 2300°F.

It is not necessary that the core exit steam temperature be measured accurately. It is only necessary to the reactor operator that his indicator of steam temperature provide an analogous trending (with a small time delay) of the fuel temperature behavior. Therefore, through the steam temperature trending the operator can monitor the consequences of his remedial actions. This information is of primary interest to the operator during core uncovery (Conditions 3a and 3b).

5.0 SYSTEM QUALIFICATION

The qualification program for the ICC Detection System instrumentation has not been completely defined. The qualification program will be based on the following three categories of ICC instrumentation:

1. Sensor instrumentation within the pressure vessel

2. Instrumentation components and systems which extend from the primary pressure boundary up to and including the primary display isolator and including the backup displays.

3. Instrumentation systems which comprise the primary display equipment.

A preliminary outline of the qualification program for each classification is given below.

The in-vessel sensors represent the best equipment available consistent with qualification and schedular requirements (as per NUREG-0737, Appendix B). Design of the equipment will be consistent with current industry practices in this area. Specifically, instrumentation will be designed such that they meet appropriate stress criteria when subjected to normal and design basis accident loadings. Seismic qualification to safe shutdown conditions will verify function after being subjected to the seismic loadings.

The out-of-vessel instrumentation system, up to and including the primary display isolator, and the backup displays will be environmentally qualified in accordance with IEEE-323-1974. Plant-specific containment temperature and pressure design profiles will be used where appropriate in these tests. This equipment will also be seismically qualified according to IEEE-STD-344-1975. CEN-99(S), "Seismic Qualification of NSSS Supplied Instrumentation Equipment, Combustion Engineering, Inc." (August 1978) describes the methods used to meet the criteria of this document.

FP&L is evaluating what is required to augment the out-of-vessel Class 1E instrumentation equipment qualification program to NUREG-0588. Consistent with Appendix B of NUREG-0737, the out-of-vessel equipment under procurement is the best available equipment. FP&L expects to complete this evaluation by the end of the first quarter of 1982.

6.0 SYSTEM VERIFICATION TESTING

This section describes tests and operational experience with ICC instruments.

6.1 RTD AND PRESSURIZER PRESSURE SENSORS

The hot and cold leg RTD temperature sensors and the pressurizer pressure sensors are standard NSSS instruments which have well known responses. No special verification tests have been performed nor are planned for the future. These sensors along with UHJTC inputs, provide basic reliable temperature and pressure inputs which are considered adequate for use in the SMM and other additional display functions.

6.2 HJTC SYSTEM SENSORS AND PROCESSING

The HJTC System is a new system developed to indicate liquid inventory above the core. Since it is a new system, extensive testing has been performed and further tests are planned to assure than the HJTC System will operate to unambiguously indicate liquid inventory above the core.

The testing is divided into three phases:

Phase 1 - Proof of Principle Testing
Phase 2 - Design Development Testing
Phase 3 - Prototype Testing

The first phase consisted of a series of five tests, which have been completed. The testing demonstrated the capability of the HJTC instrument design to measure liquid level in simulated reactor vessel thermal-hydraulic conditions (including accident conditions).

PROOF OF PRINCIPLE TESTING

Test 1 Autoclave test to show HJTC (thermocouples only) response to water or steam.

In April 1980, a conceptual test was performed with two thermocouples in one sheath with one thermocouple as a heater and the other thermocouple as the inventory sensor. This configuration was placed in an autoclave (pressure vessel with the capabilities to adjust temperature and pressure). The thermocouples were exposed to water and then steam environments. The results demonstrated a significant output difference between steam and water conditions for a given heater power level.

Test 2 Two phase flow test to show bare HJTC sensitivity to voids.

In June 1980, a HJTC (of the present differential thermocouple design) was placed into the Advanced Instrumentation for Reflood Studies (AIRS) test facility, a low pressure two-phase flow test facility at Oak Ridge National Laboratory (ORNL). The HJTC was exposed to void fractions at various heater power levels. The results demonstrated that the bare HJTC output was virtually the same in two-phase liquid as in subcooled liquid. The HJTC did generate a significant output in 100% quality steam.

Test 3 Atmospheric air-water test to show the effect of a splash shield

A splash shield was designed to increase the sensitivity to voids. The splash shield prevents direct contact with the liquid in the two-phase fluid. The HJTC output changed at intermediate void fraction two-phase fluid. The results demonstrated that the HJTC sensor (heated junction thermocouple with the splash shield) sensed intermediate void fraction fluid conditions.

Test 4 High pressure boil-off test to show HJTC sensor response to reactor thermal-hydraulic conditions.

In September 1980, a C-E HJTC sensor (HJTC with splash shield) was installed and tested at the ORNL Thermal-Hydraulics Test Facility (THTF). The HJTC sensor was subjected to various two-phase fluid conditions at reactor temperatures and pressures. The results verified that the HJTC sensor is a device that can sense liquid inventory under normal and accident reactor vessel high pressure and temperature two-phase conditions.

Test 5 Atmospheric air-water test to show the effect of a separator tube

A separator tube was added to the HJTC design to form a collapsed liquid level so that the HJTC sensor directly measures liquid inventory under all simulated two-phase conditions. In October, 1980, atmospheric air-water tests were performed with HJTC sensor and the separator tube. The results demonstrated that the separator tube did form a collapsed liquid level and the HJTC output did accurately indicate liquid inventory. This test verified that the HJTC instrument, which includes the HJTC, the splash shield, and the separator tube, is a viable measuring device for liquid inventory.

DESIGN DEVELOPMENT TESTING

The Phase 2 test program consisted of high pressure and temperature tests of the probe assembly under steady state and transient conditions. These tests, performed during May 1981 at C-E, provided design verification information for the HJTC instrument under conditions expected to occur in the reactor.

TEST SERIES 1: Single Phase Tests
The HJTC response was measured as the water level was changed by filling or draining the test vessel at different rates. Information on HJTC temperature response at various pressures and sensor heater powers was obtained.

TEST SERIES 2: Two-Phase Tests
Steam was injected at the bottom of the test vessel to produce a two-phase mixture. The HJTC response was measured as the water level was varied by filling or draining. The results were similar to the single phase tests, indicating that the HJTC can measure the collapsed water level in a two-phase environment under conditions similar to those encountered during a small break LOCA.

TEST SERIES 3: Depressurization Transient Tests
The HJTC response during a depressurization transient was determined by allowing the test vessel to blowdown from high pressure. Results of these tests are still being reviewed, additional information on this test series will be presented in a future amendment.

PROTOTYPE TESTING
The Phase 3 test program will consist of high temperature and pressure testing of the manufactured prototype system HJTC probe assembly and processing electronics. Verification of the HJTC system prototype will be the goal of this test program. The Phase 3 test program is expected to be completed by the end of 1981.

6.3 CORE EXIT THERMOCOUPLES

Testing at ORNL was performed to evaluate the response of CETs under simulated accident conditions (Reference 4). This test in addition showed that the instruments remained functional up to 2300°F. This test along with previous reactor operating experience are considered sufficient to verify the response of CETs.

7.0 OPERATING INSTRUCTIONS

The C-E Owners Group is defining a program for development of further emergency procedure guidelines and operator training materials associated with the ICC Detection System described in Section 3. This program is expected to provide these guidelines and training materials during the fourth quarter of 1981. These guidelines and training materials will be based on modifications to existing ICC guidelines.

The existing guidelines for reactor operators to use to detect ICC and take corrective action have been developed by the C-E Owners Group and submitted to NRC for review (Reference 5). These guidelines have been used to review and revise the plant emergency procedures for St. Lucie Unit 2. In addition, the C-E Owners Group has developed reactor operator training materials concerning ICC.

8.0 COMPARISON OF DOCUMENTATION REQUIREMENTS OF POSITION II.F.2, ATTACHMENT 1 AND APPENDIX B WITH STATUS REPORT

Tables 8-1 through 8-3 provide a point by point comparison of the documentation required by NUREG-0737, Item II.F.2, the requirements of Attachment 1 of Item II.F.2, and the Criteria of Appendix B of NUREG-0737 with the inadequate core cooling detection instrumentation to be installed in St. Lucie Unit 2.

TABLE 8-1
EVALUATION OF ICC DETECTION
INSTRUMENTATION TO DOCUMENTATION
REQUIREMENTS OF NUREG 0737 ITEM
II.F.2

ITEM	RESPONSE
1.a.	Description of the ICC Detection Instrumentation is provided in Section 3.0. The instrumentation to be added includes the modified SMM, the HJTC Probe Assemblies, and Improved ICI (CET) Detector Assemblies.
1.b.	The existing instrumentation systems are described in Appendices B, C, and D. This includes the SMM, HJTC Probe Holders, and ICI (CET) Detector Assemblies. Section 10.0 discusses first cycle operation of St. Lucie Unit 2 with the existing instrumentation.
1.c.	The planned modifications to the existing Unit 2 instrumentation will be made (date to be included later) Modifications include changes to the SMM, design, procurement and installation of the HJTC probe assemblies, and improved ICI Detector Assemblies (which necessitate installation of improved ICI Nozzle Flanges). The final ICC Detection instrumentation will be as described in Section 3.0.
2.	The design analysis and evaluation of the ICC Detection Instrumentation is discussed in Sections 2.0 and 4.0. and Appendix A. Testing is discussed in Section 6.0.
3.	Additional instrumentation testing is discussed in Section 6.0. Qualification testing is discussed in Section 5.0.

ITEM	RESPONSE
4.	This table evaluates the ICC Detection Instrumentation's conformance to the NUREG-0737, Item II.F.2 documentation requirements. Table 8-2 evaluates conformance to Attachment 1 of Item II.F.2 Table 8-3 evaluates conformance to Appendix B of NUREG-0737.
5.	Information on the ICC transmission, processing, and display hardware will be presented in a future amendment.
6.	Section 9.0 discusses the schedule for installation and implementation of the complete ICC Detection Instrumentation.
7.	Guidelines for use of the ICC Detection Instrumentation are discussed in Section 7.0
8.	A future amendment will discuss key operator actions in the current emergency procedures for ICC. Section 7.0 discusses the emergency procedures to be implemented upon incorporation of the complete ICC Detection System.
9.	The following describes additional submittals that will be provided to support the acceptability of the final ICC Detection Instrumentation. The schedule for submittal of this documentation will be provided in September, 1981.

1) Qualification Testing of the HJTCS.
2) Environmental and Seismic Qualification of the in-vessel and out-of-vessel instrumentation equipment.
3) Modifications to emergency procedures.
4) Proposed Changes to Technical Specification.
5) Description of ICC signal transmission, processing and display equipment.

TABLE 8-2

EVALUATION OF ICC DETECTION INSTRUMENTATION TO ATTACHMENT 1 OF II.F.2.

ITEM	RESPONSE
1.	St. Lucie 2 has 56 core exit thermocouples (CETs) distributed uniformly over the top of the core. Section 3.1.3 has a description of the CET sensors. Figure 3-7 depicts the locations of the CETs.
3.	The ICC design incorporates a minimum of one backup display with the capability for selective reading of a minimum of 16 operable themocouples, 4 from each core quadrant.
4.	The ICC design was analyzed for human factors considerations.
5.	The ICC instrumentation was evaluated for conformance to Appendix B of NUREG - 0737 (see table 8-3).
6.	The primary and backup display channels are electrically independent, energized from independent station class 1E power sources and physically separated in accordance with Regulatory Guide 1.75 up to and including the isolution devices.

7. ICC instrumentation shall be environmentally qualified pursuant to C-E owners group qualification program.

8. Primary and backup display channels are designed to provide the highest availability possible.

9. ICC monitoring system was designed and reviewed to the quality assurance provisions in App. B items.

TABLE 8-3
EVALUATION OF ICC DETECTION INSTRUMENTATION
TO APPENDIX B OF NUREG-0737

ITEM	RESPONSE
1.	The ICC detection instrumentation is environmentally and seismically qualified as specified in Section 5.0.
2.	The ICC detection instrumentation is designed such that no single failure within either the accident-monitoring instrumentation, its auxiliary supporting features or its power sources concurrent with the failure that are a condition or result of a specific accident will prevent the operator from being presented the data required to analyze core inadequate core cooling.
3.	The ICC detection instrumentation is designed such that redundant or diverse channels are electrically independent, energized from station class 1E power source and physically seperated in accordance with Regulatory Guide 1.75.
4.	Instrumentation is available prior to an accident as defined in IEEE ST D 279 and/or as specified in technical specifications.
5.	Recommendations of the following regulatory guides were considered in the design of ICC instrumentation; 1.28, 1.30, 1.38, 1.58, 1.64, 1.74, 1.88, 1.123, 1.144.
6.	Continuous indication display is provided at all times.
7.	All inadequate core cooling instrumentation is designed to provide read-out display and trending information to the operator.
8.	All inadequate core cooling instrumentation is specifically and singularly identified so that the operator can easily discern their use during an accident condition.

9. Signals from a ICC instrument intended for other use is isolated through isolation devices designated as part of the monitoring instrumentation.

10. Each ICC monitoring channel is provided with a checking variable. Instrument checking has a high degree of confidence and operational availability.

11. Servicing, testing and calibrating programs shall be consitant with operating technical specifications.

12. The System design is such as to facilitate administrative control during periods when channels are removed from service.

13. The System design is such as to facilitate administrative control of access to all set points adjustments, module calibration adjustments and test points.

14. Monitoring instrumentation is designed to minimize anomalous indications to the operator.

15. Instrumentation is designed to facilitate replacement of components or modules. The instrumentation design is designed such that malfunctioning components can be identified easily.

16. The design incorporates this requirement to the extent practical.

17. The design incorporates this requirement to the extent practical.

18. The system is designed to facilitate periodic testing of instrument channels.

9.0 SCHEDULE FOR ICC INSTRUMENTATION INSTALLATION

A schedule for the installation of the ICC Instrumentation will be provided to the NRC once the system design (including transmission, processing and display hardware) is completed. It is currently planned to complete installation of all ICC equipment (date to be included later).

10.0 OPERATION WITH INTERIM ICC INSTRUMENTATION

Procedures and training for identification of an approach to ICC on St. Lucie 2 have been developed using existing instrumentation. These procedures are currently undergoing NSSS vendor review and will be reviewed by the NRC PIRB prior to startup of St. Lucie Unit 2.

With final ICC instrumentation installation scheduled for first refueling, the plant will be operated during the first cycle using existing instrumentation. This includes two of three instrumentation systems planned for the final ICC system, which will be described in a future amendment to the FSAR. Those two are:

Subcooled Margin Monitor (SMM)
Core Exit Temperature (CETs)

The HJTCS will be absent from the interim system. This instrumentation will be integrated with:

Emergency Operating Instructions
Operator Training for ICC Recognition and Mitigation

Emergency Operating Instructions (EOI)

To be submitted in a future amendment.

Training

FP&L will complete operator training (including simulator training) prior to fuel load on use of the existing control room instrumentation related to ICC as utilized in the approved EOIs.

Based on the existing instrumentation, training and procedures for ICC recognition, FP&L is confident that St. Lucie 2 can be safety operated prior to implementation of the final ICC instrumentation (Date to be included later).

11.0 REFERENCES

1. NUREG-0737, "Clarification of TMI Action Plan Requirements," U.S. Nuclear Regulatory Commission, November, 1980.

2. CEN-117, "Inadequate Core Cooling - A Response to NRC I E Bulletin 79-06C, Item 5 for Combustion Engineering Nuclear Steam Supply Systems," Combustion Engineering, October, 1979.

3. CEN-125, "Input for Response to NRC Lessons Learned Requirements for Combustion Engineering Nuclear Steam Supply Systems," Combustion Engineering, December, 1979.

4. Anderson, R. L., Banda, L. A., Cain, D. G., "Incore Thermocouple Performance Under Simulated Accident Conditions," IEEE Nuclear Science Symposium, Vol. 28, No. 1 page 773, Figure 81.

5. Letter C-E Owners Group to NRC, "C-E Generic Emergency Procedure Guidelines," December 10, 1980.

Appendix A

Evaluation of Instrumentation for Detection of Inadequate Core Cooling

APPENDIX A

Evaluation of Instrumentation for Detection of Inadequate Core Cooling

The C-E Owners Group has conducted an evaluation of instrumentation for the potential application to the detection of Inadequate Core Cooling. The performance characteristics of selected instruments were compared for representative transients resulting in various degrees of reactor coolant system voiding. The respective instruments then were evaluated based on their developmental and post-accident qualification status, response characteristics, and signal clarity.

A.1 DESCRIPTION OF ICC EVENT PROGRESSION

The state of progression of an event resulting in ICC can be divided based on physical processes occurring within the RPV, into the following six conditions:

Conditions Associated with the Approach to ICC

Condition 1a Loss of fluid subcooling prior to the first occurrence of saturation conditions in the coolant.

Condition 2a Falling coolant inventory within the upper plenum, from the top of the vessel to the top of the active fuel.

Condition 3a Increasing core exit temperature produced by uncovery of the core resulting from the drop in level of the mixture of vapor bubbles and liquid from the top of the active fuel to the minimum level during the event.

Conditions Associated with Recovery from ICC

Condition 3b Decreasing core exit steam tempearture resulting from the rising of the level to the top of the active fuel

Condition 2b Vessel fill by the increase in inventory above the fuel.

Condition 1b Establishment of saturation conditions followed by an increase in fluid subcooling.

The instrument system used for the detection of ICC should provide the reactor operator with the current status of selected key parameters and the trending of prior status of selected key parameters as the event progresses through each of the above conditions.

A.2 SUMMARY OF SENSOR EVALUATION

The instruments evaluated in this effort were the subcooled margin monitor (SMM), resistance temperature detectors (RTDs), reactor vessel level monitor employing the heated junction thermocouples (HJTC), core exit thermocouples (CETs), self-powered neutron detectors (SPNDs), ex-core detectors and in-core thermocouples. The instruments are listed in Table A-1, where their capabilities are summarized. Significant conclusions about each instrument are given below.

A.2.1 Subcooled Margin Monitor

The Subcooled Margin Monitor (SMM), using input from existing Resistance Temperature Detectors (RTD) in the hot and cold legs and from the pressurizer pressure sensors, will detect the initial occurrence of saturation during LOCA events and during loss of heat sink events.

The usefulness of the SMM may be significantly increased by also feeding into it the signals from the fluid temperature measurements from the HJTCS and by modifying the SMM to calculate and display degrees superheat in addition to degrees subcooling. The signals from the HJTCS temperature measurements provide information about possible local differences in temperature between the reactor vessel upper head/upper plenum (location of the HJTCS) and the hot or cold legs (location of the RTDs).

With these modifications, the SMM can be used not only for detection of the approach to ICC, namely Condition 1a (loss of subcooling), but also for Conditions 3a and 3b (core uncovery) and Condition 1b (core recovery). Even with the modifications, the SMM will not be capable of indicating the existence of Conditions 2a and 2b when the coolant is at saturation conditions and the level is between the top of the vessel and the top of the core.

A.2.2 Resistance Temperature Detectors (RTD)

The RTD are adequate for sensing the initial occurrence of saturation. The hot leg(1) RTD range is sufficient to sense saturation for events initiated at power. The cold leg RTD, which have a wider range, are sufficient to sense saturation for events initiated from zero power or shutdown conditions.

The RTD range is not adequate for ICC indications during core uncovery. For depressurization LOCA events, the core may uncover at low pressure, when the saturation temperature is below the lower limit of the hot leg RTD. Initial superheat of the steam will therefore not be detected by the hot leg RTD. As the uncovery proceeds, the superheated steam temperature may quickly exceed the upper limit of the RTD range.

A.2.3 Heated Junction Thermocouple System (HJTCS)

The HJTC probe is designed to create and measure a collapsed liquid level in a localized plenum region. The height of the collapsed liquid level within the probe is sensed using pairs of heated junction thermocouples. This mode of sensing reduces spurious effects due to pressure, fluid properties, and non-homogeneities of the fluid medium.

The signal which is produced by the HJTC probe is a small electrical current similar in magnitude to, or greater than, the current produced by typical

(1) In most C-E PWRs a dual range RTD system is employed. Typically, narrow band RTDs are located in the hot legs and wide range RTDs are found in the cold leg. St. Lucie Unit 2 employs wide range RTDs in both hot and cold legs.

temperature sensing devices presently used in the reactor coolant system. This signal may be transmitted from within the reactor vessel to outside of the containment building with no intermediate electronics. Furthermore, the signal is not subject to external disturbances, such as containment environment as would be present with a hydraulic signal transmission system.

The HJTC can provide significant information to the operator for two conditions associated with an ICC event - Condition 2a, the approach to uncovery and Condition 2b, the refill. For a large small break event, the two-phase level drops to the top of the core within 5 to 15 minutes of the break initiation. In this event, the HJTC would show the rapidly decreasing coolant inventory and would quantify for the operator the status of the degrading situation which is otherwise evident to him from numerous existing instruments. For smaller breaks, the progression of the event is slower, and the HJTC can provide significant information on the effectiveness of his mitigating actions. It is probably for such long term conditions, prior to core uncovery, that the HJTC would have its greatest usefulness.

Following recovery of the core, the operator could use the HJTC to verify that the core is again covered and therefore is being adequately cooled. Through monitoring the HJTC level the operator has better indication of the correctness and effectiveness of his actions in maintaining the coolant inventory.

A.2.4. Core Exit Thermocouples (CETs)

The core exit thermocouples will show the approach to and existence of ICC after core uncovery for the events analyzed. The core exit thermocouples respond to the coolant temperature at the core exit and indicate superheat after the core is no longer completely covered by coolant. The trend of the change in superheat corresponds to the trend of the change in cladding temperature.

Existing thermocouples in C-E reactors have been qualified to industry standard accuracy for operation to 750^{O}F. However, thermocouples of this design (i.e. stanless steel sheathed, alumina insulated, Type K, Chromel-Alumel) are suitable for nuclear service to 1650^{O}F. Tests have been run on such thermocouples to simulate severe accidents (See Reference 4 of text). Results from these tests demonstrated the shunting error caused by the increase in electrical conductance of the alumina at high temperature is shown to be negligible up to 1650 ^{O}F and is acceptably small to 1800^{O}F. It is concluded that the thermocouples in operating C-E designed reactors could satisfy the minimum NRC requirement for 1650^{O}F and are adequate to 1800^{O}F

A.2.5. Self-Powered Neutron Detectors (SPND)

The SPND yield a signal caused by high temperature as the two-phase level falls below the elevation of the SPND. However, testing is required to identify the phenomena responsible for the anomalous behavior of the SPND at TMI-2. At the present, their use is limited to low temperature events (less than 1000^{O}F clad temperature) or to only the initial uncovery portion of an event.

A.2.6 Ex-Core Neutron Detectors

Existing source range neutron detectors are sensitive enough to respond to the formation of coolant voids within the vessel during the events analyzed. However, the signal magnitude is ambiguous because of the effects of varying boron concentration and deuterium concentration in the reactor coolant.

A stack of ex-core detectors gives less ambiguous information on voids and level in the vessel. The relative shape of the axial distribution of signals from a stack of five detectors shows promise as an ICC indicator, but additional development is needed.

A.2.7 In-Core Thermocouples

Although the loss of other instrumentation such as the SPND's would have to be considered, in general, it appears feasible that in-core thermocouples may be added to or substituted for some SPND in the in-core instrument string. In-core thermocouples sense the surrounding environment via radiation, as well as, steam convection. The information provided to the operator by in-core thermocouples is qualitatively the same as that provided by CETs.

TABLE A-1

INSTRUMENTS INCLUDED IN EVALUATIONS

FOR ICC INSTRUMENTATION SYSTEM

INSTRUMENTS	DEVELOPMENT STATUS	POST-ACCIDENT QUALIFICATION STATUS	INDICATION PROVIDED BY INSTRUMENT	CLARITY OF SIGNAL	CONDITIONS MONITORED
SUBCOOLED MARGIN MONITOR	EXISTS	QUALIFIED	DEGREE OF SUBCOOLING IN RCS	GOOD	1a, 1b
REACTOR VESSEL LEVEL MONITOR	UNDER DEVELOP.	WILL BE QUALIFIED	1) LIQUID INVENTORY IN UPPER HEAD 2) LIQUID INVENTORY IN UPPER PLENUM 3) AXIAL TEMPERATURE DISTRIBUTION IN HEAD AND PLENUM	GOOD GOOD GOOD	2a, 2b
CORE EXIT THERMOCOUPLES	EXIST	CAN BE DONE	1) FLUID TEMPERATURE AT CORE EXIT	GOOD	3a. 3b
IN-CORE THERMOCOUPLES	CONCEPT STAGE	CAN BE DONE	1) METAL TEMPERATURE INSIDE GUIDE TUBE WHEN RCP OFF	GOOD	3a, 3b
SELF POWERED NEUTRON DETECTORS	EXIST	CAN BE DONE	INDIRECT MEASURE OF MIXTURE LEVEL (LOW PRESSURE UNCOVERY)	POOR	3a, 3b
HOT LEG RTD (5 EACH)	EXIST	QUALIFIED	FLUID TEMPERATURE IN HOT LEG	GOOD	1a, 1b, 3a, 3b
EX-CORE NEUTRON DETECTOR (ONE, SOURCE RANGE)	EXIST	CAN BE DONE	INDIRECT MEASURE OF GROSS VOIDING INDIRECT INDICATION OF MIXTURE LEVEL IN CORE, RCP OFF	FAIR FAIR	3a. 3b
EX-CORE NEUTRON DETECTOR (STACK OF 5, SOURCE RANGE)	CONCEPT	CAN BE DONE	SAME AS ONE EX-CORE DETECTOR, BUT MORE AXIAL RESOLUTION	FAIR	3a. 3b

Appendix B

Subcooled Margin Monitor

APPENDIX B

SATURATION MARGIN MONITOR

The design of the St. Lucie Unit 2 Saturation Margin Monitor (SMM) is described in Section 3.1.1 of the accompanying report. This device will provide on-line control room indication of reactor coolant saturation conditions to the operator. The St. Lucie 2 SMM is designed to accept input from selected RTDs and the Unheated Junction thermocouple with the maximum temperature indication.

During the first cycle of St. Lucie Unit 2 operation the HJTC level probe will not be installed. Therefore, the SMM will receive its input from the RTDs alone. A detailed description of the SMM system to be used during the first fuel cycle will be presented in a future amendment.

Appendix.C

Heated Junction Thermocouple System

APPENDIX C

Heated Junction Thermocouple System

C.1 SYSTEM DESCRIPTION

The Heated Junction Thermocouple System (HJTC) that is planned to be installed in St. Lucie Unit 2 consists of two separate channels of instrumentation which meet the design requirements for a post-accident monitoring system. The sensors are internal to the reactor vessel. Details of the associated transmission, control and display hardware are currently being finalized and will be presented in a future amendment.

C.2 TECHNICAL DESCRIPTION OF THE REACTOR VESSEL INTERNALS CHANGE

The changes concern hardware modifications internal to the reactor vessel which will serve as a holder and guide path for level detector assemblies. The design of the holders will facilitate future use of the level detectors.

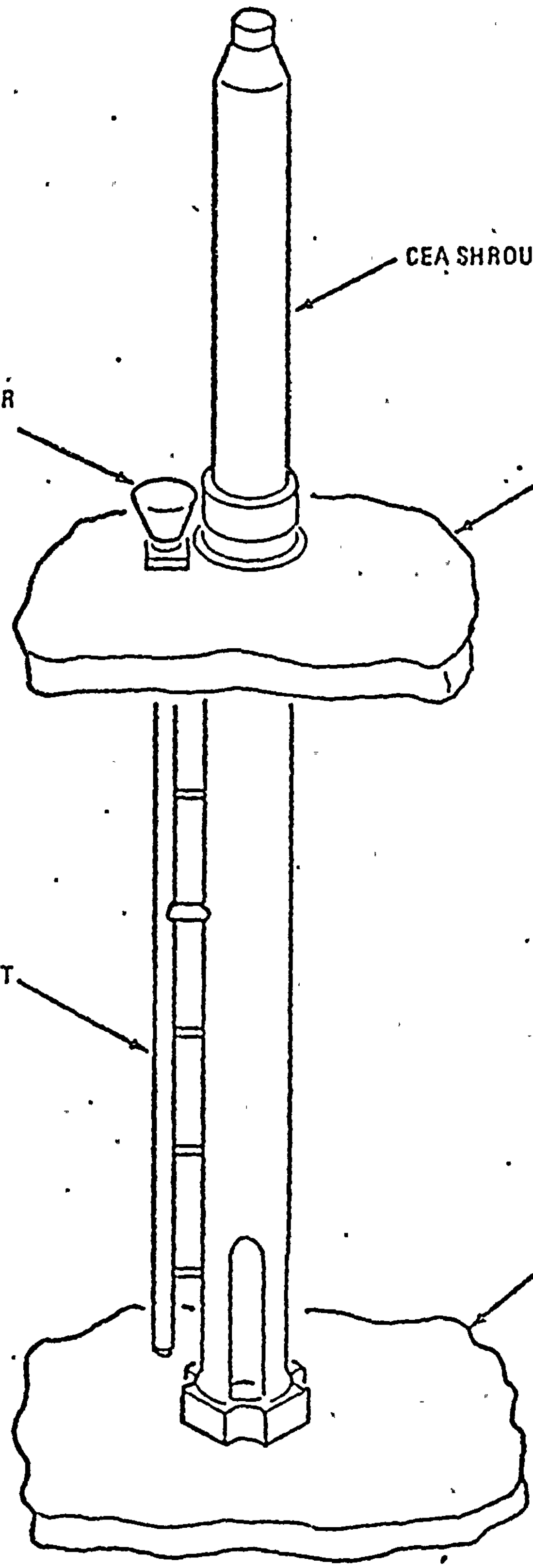
Basically, three major components are affected by the modification. These include the upper guide structure assembly, the instrument support plate assembly, and the in-core instrumentation nozzle. The upper guide structure changes include two instrument guide tubes, support brackets and lead-in funnels as shown on Figure C-1. The instrument support plate is being modified to provide a pathway for the HJTC probe assemblies as shown in Figure C-2. An additional penetration is being added in each of two ICI nozzle flanges.

When the above changes are complete, St. Lucie Unit 2 will have provisions for two HJTC probe assemblies located as shown in Figure 3-5.

C.3 IMPLEMENTATION SCHEDULE

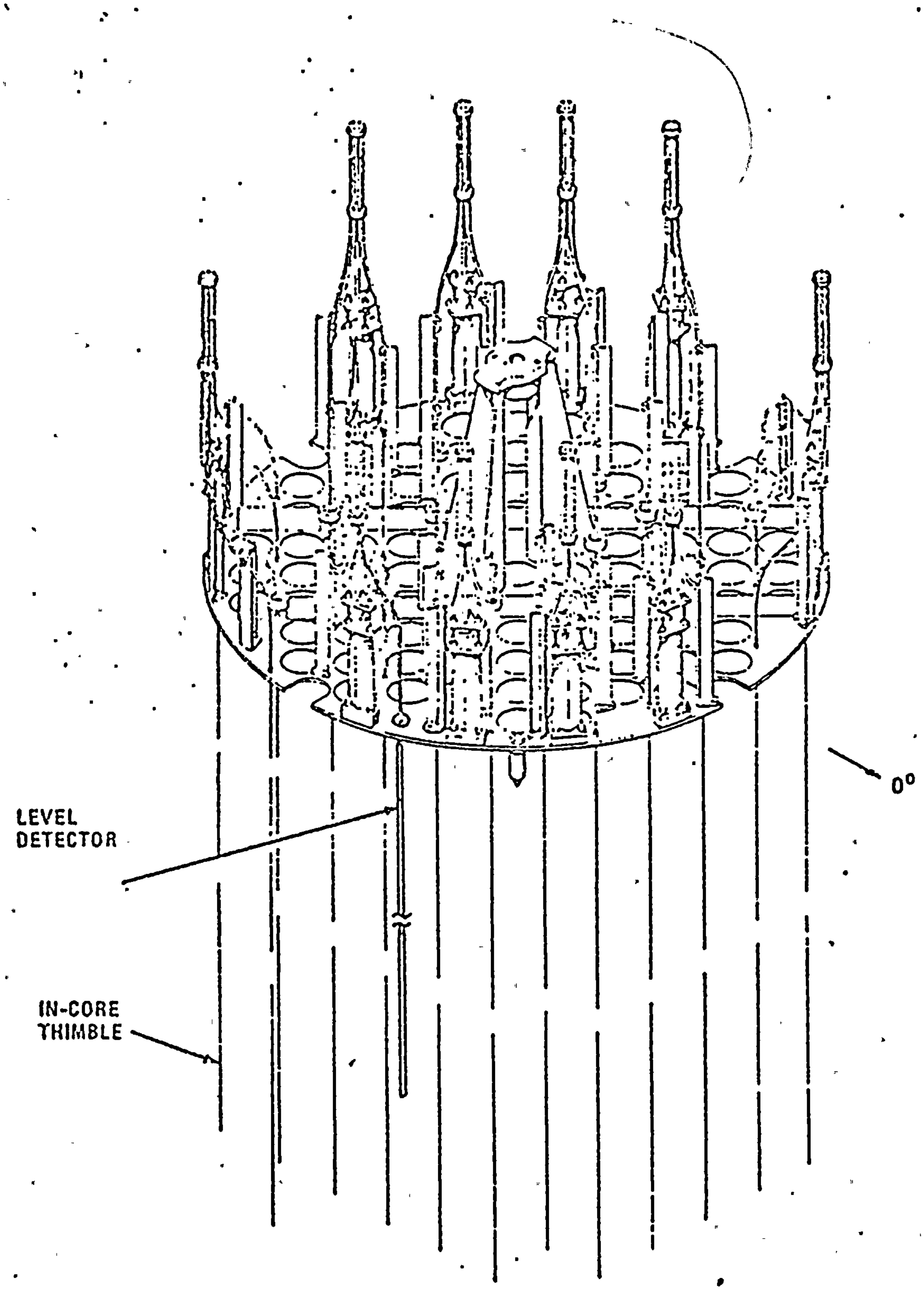
The future HJTC probe assembly to be installed in the holders is shown in Figure C-3 and described in Section 3.1.2 of the accompanying report. The HJTC probe/holder locations are depicted in Figure 3-5. The probe will be

installed in St. Lucie Unit 2 (date to be specified later). An implementation schedule for this effort will be provided in a future amendment.



1.9B-C-3

NUCLEAR GENERATING STATION ST. LUCIE UNIT 2
REACTOR VESSEL LEVEL MONITORING SYSTEM INSTRUMENT GUIDE TUBE
FIGURE C-1



NUCLEAR GENERATING STATION
ST. LUCIE UNIT 2

INSTRUMENT SUPPORT PLATE

FIGURE C-2

Appendix D

Core Exit Thermocouple System

APPENDIX D

Core Exit Thermocouple System

The basic design of the St. Lucie Unit 2 Core Exit Thermocouples (CET) is described in Section 3.1.3 of the accompanying report. The CETs are included in the 56 In-Core Instrument (ICI) Detector Assemblies as shown in Figure 3-6; the locations of which are shown in Figure 3-7.

A description of the CET processing and display to be used during the first cycle of operation of Unit 2 will be presented in a future amendment.

f) Adequate overlapping of the ranges of narrow and wide range monitors are provided.

g) Signals from the associated sensors are only used for monitoring the containment water level.

h) The availability requirement of the wide range containment water level monitors is specified in plant technical specification.

i) Testing and calibration requirements are specified in plant technical specification.

j) The instruments are specifically identified on the control panels so that the operator can easily discern that they are intended for use under accident conditions.

7.5.3.2.2 Design Description

The wide and narrow range containment level transmitters are located inside the containment. The narrow range monitor measures discrete level points from the bottom of

the reactor cavity sump (elevation -7ft.) to the top of the sump (elevation 0ft.). The wide range monitors measure discrete level points from elevation -1 ft. to elevation 26 ft. of the containment. The electronics portion of each of the sensors are located outside the containment and converts the discrete point measurement to a continuous level indication in the control rooms. The two channels of wide range level monitors are indicated in the control room, one channel is recorded. The narrow range level monitoring channel is both indicated and recorded in the control room.

7.5.3.2.3 Safety Evaluation

The redundant wide range water level monitors are safety related and designated seismic Category I. They are qualified for the design basis accident environment in which they operate per IEEE 323-1974, seismic qualification is per IEEE 344-1975. These monitors are provided strictly for monitoring purpose. ~~No safety related operator action is based on information provided by this instrument.~~

The narrow range water level instrument is primarily used during normal operation and does not serve any safety related function post accident.

Appendix 7.5A Safety Assessment System

7.5A.1 Description

The Safety Assessment System (SAS) will provide the Safety Parameter Display System (SPDS) and all other data required in the control room, Technical Support Center (TSC) and Emergency Operations Facility (EOF). This report describes that portion of the SAS which meets the SPDS requirements of NUREG 0696 "Functional Criteria for Emergency Response Facilities", February 1981. It provides a centralized, flexible, computer-base data and display system to assist control room personnel evaluating the safety status of the plant. This assistance is accomplished by providing the operator and other Emergency Response Facilities (ERFs) a high-level graphical display containing a minimum set of key plant parameters representative of the plant safety status.

All data displayed by the SAS is validated by comparing redundant sensors, ehcking the value against reasonable limits, calculating rates of change, and/or checking temperature versus pressure curves.

The displays of the SAS have been evaluated against human factors design criteria. The concepts used in the SAS design will be verified using data recorded from a similar power plant simulator.

The SAS will be operable during normal and abnormal plant operating conditions. The SAS will operate during all SPDS required modes of plant operation. The normal operation mode will encompass all plant conditions at or above normal operating pressure and temperature. When the Reactor Coolant System is intentionally cooled below normal operating values, the operator will select the Heatup-Cooldown mode which alters the limit checking algorithm for the key parameters.

The SPDS portion of the SAS will be implemented on a CRT located in an area of the control room visible to the control room operator and the senior reactor operator. This CRT contains the high-level display from which the overall safety status of the plant may be assessed. A dedicated function button panel allows the operator to select any of the high level displays and various supporting displays at any time.

The SAS is designed such that control room personnel can utilize its features without requiring additional operations personnel.

The primary display consists of bar graphs of selected parameter values, digital status indicators for important safety system parameters and digital values. The parameters indicated by

bar graphs and digital values include: RCS pressure, RCS temperature, pressurizer level, steam generator levels and steam generator pressures. Status indicators are provided for containment environment and secondary system radiation. Reactor vessel level core exit temperature, amount of subcooling and containment radiation are indicated by digital values.

In addition, there is a message area for an appropriate secondary display providing information related to off-normal value or event detection.

The bar graphs indicate wide-range values and if a parameter is outside its normal range the bar color will change. The direction (increasing or decreasing) of change is indicated by an arrow.

During normal operation, the message area will be used to display average power, reactor core average temperature, data, time, and unit time. These messages may be displayed by higher priority messages as required.

Trend graph groups of selected related parameters, showing the last thirty minutes of plant operation are available.

The SAS hardware system utilizes a symmetrical redundant component interconnection configuration to insure high availability. The functional center of the system is a pair of main processing computers located in St Lucie Unit 1 Reactor Auxiliary Building which receives multiplexed plant process data from both St Lucie Units. The input multiplexer system in each unit is in itself computer controlled and fully redundant. Both main processing computers receive the available variables specified in Regulatory Guide 1.97 "Instrumentation for Light Water Cooled Nuclear Power Plant to Access Plant and Environs Conditions during and following an Accident", December 1980 (R2), from both St Lucie Units simultaneously. Also each main computer is available at all times to functionally support the system peripherals and display devices in both plants simultaneously as well as the Technical Support Center (TSC) and the Emergency Offsite Facility (EOF).

The interface between the SAS and the input variables derived from safety related systems are isolated in accordance with the safety system criteria to preserve channel independence and integrity of the safety systems in the case of SAS malfunction. Also design provisions are included in the interface between the SAS and non-safety systems to ensure the integrity of the SAS upon failure of non-safety system.

The hardware configuration described above is shown in Figure 7.5A-1

7.5A.2 Human Factors Considerations

Human factors engineering and industrial design techniques have been effectively combined in accordance with established man-machine interface design requirements to maximize system effectiveness, reduce training and skill demands, and minimize operator error.

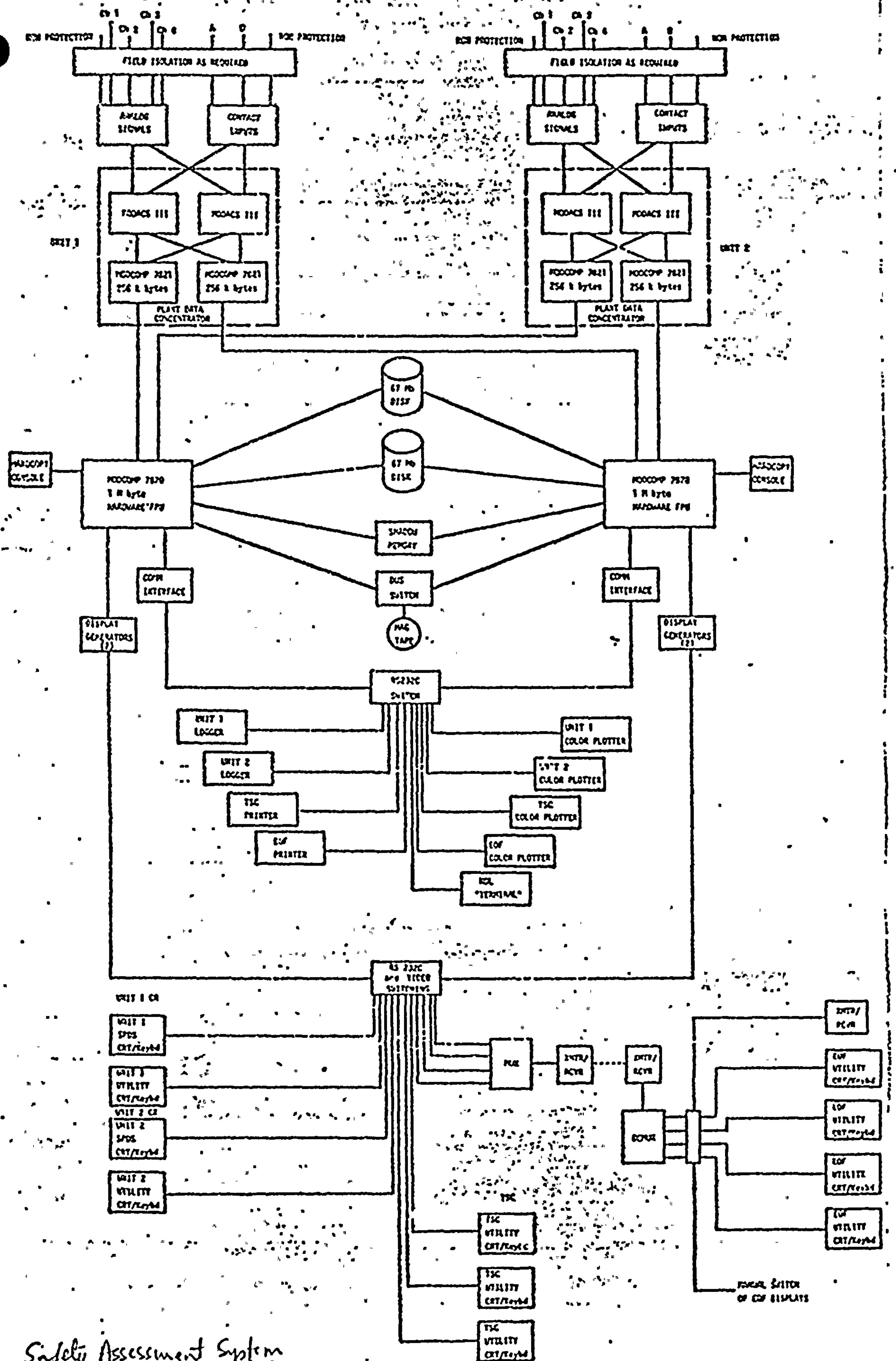
The CRT color graphic formats and functional key board designs have been developed through an interdisciplinary team of senior operational, human factors, industrial design and computer interface personnel.

Minimum use of color, combined with simplified format throughout the CRT presentaion, have been key design features to provide both normal and off-normal pattern recognition. The operator, who is the end user, has been directly involved from the conception to insure that man-machine interface goals of SAS have been satisfied. The human factor engineering standards and testing verification methods which have been used are consistent with accepted practices.

7.5A.3 Verification and Validation

The SAS is implemented on a digital computer system. The display software that controls the sensor data, key parameter construction and display formats has been developed under strict verification and validation.

During the course of software development, a set of static test cases will be developed which test the key features of each software module. Furthermore, static system test cases will be developed and used to verify the correct operability of the total system. A set of dynamic test cases will be generated by recording nuclear simultor data on magnetic tape from a number of different plant transients which test the dynamic behavior of the system under "real" conditions. A design review that compares these test results to the original functional and design specifications will be performed. A selected number of the static test cases will be "frozen" such that they could be used to verify future changes to the software. In summary, verification and validation is addressed and designed into the SAS software to provide a highly reliable product and a mechanism for identifying and controlling future changes.



Safety Assessment System

FIGURE 7.5A-1

7.6.3.8 DIRECT POSITION INDICATION OF RELIEF AND SAFETY VALVES TMI ITEM II.D.3

Acoustic valve flow monitors are used to provide direct position indication of pressurizer safety valves (SRVs) and power operated relief valves (PORVs).

7.6.3.8.1 DESIGN BASIS

a) Valve positions are monitored acoustically and indicators and alarms are provided in the control room.
b) Acoustic flow monitors are powered from a vital instrument bus and are designed as seismic Category I.
c) The acoustic flow monitors are qualified for the appropriate environment (any transient or accident which causes the relief or safety valve to open).

7.6.3.8.2 DESCRIPTION

The means of detecting pressurizer safety relief and power operated relief valve position is by continuously and automatically detecting accustical signals generated by flow noise levels through the valve.

This is accomplished by utilizing accelerometers mounted on the valve body. The accelerometer converts acoustical acceleration into an electrical charge which is converted to a voltage by the charge converter. This proportional voltage is then processed and a relative flow indication is obtained.

Five valve position monitors are provided, one for each of the three pressurizer safety relief valves and the two PORVs. A common audio-visual alarm alerts the operators when flow through any of the five valves exceeds a pre-established set point. These set points can be adjusted from the control room.

The system is powered from a 120VAC 60Hz uninterruptable power supply (UPS). An alarm is initiated upon loss of instrument power. The indicator modules are located in the Control Room Auxiliary Panel. The system is qualified in accordance with IEEE-323-1974 and 344-1975. The accelerometers and charge converters are located inside the containment and are subjected to the containment environment during and following a small break LOCA. These components are designed and tested to withstand and remain operable following the postulated accident. Various components of the acoustic valve flow monitors are identified in Table 7.6-2.

7.6.3.8.3 EVALUATION

As a backup to this reliable single channel environmentally qualified system, valve stem magnetically actuated limit switches are provided for the pressurizer PORVs and discharge temperature indication for the pressurizer safety relief valves are used. These backup methods of determining valve position are discussed in the emergency procedures.

The displays and controls added to the control room will be included in the detailed human factor engineering study taking into consideration

a) the use of this information by an operator during both normal and abnormal plant conditions
b) integration into emergency condition
c) integration into operator training and
d) other alarms during emergency and need for prioritization of alarms

TABLE 7.6-2

ACOUSTIC VALVE FLOW MONITOR COMPONENTS

Acoustical Sensors	Total number 5 tested and qualified to IEEE 344 and 323 for the containment environment.
Charge Converters	Total number 5 tested and qualified to IEEE 344 and 323 for the containment environment.
Indicator Modules	Total number 5 tested and qualified to IEEE 344 and 323 for the control room environment.
Alarm Module	Total number 1 tested and qualified to IEEE 344 and 323 for the control room environment.
Cable	furnished as Class 1E. 50 feet of low noise, high temperature cable connects each valve sensor to its charge convertor.

3.7 REACTOR COOLANT GAS VENT SYSTEM

3.7.1 Design Bases

3.7.1.1 Functional Requirements

The reactor coolant gas vent system (RCGVS) is designed to perform the following functions:

A. The primary function of the system is to allow for remote venting of the Reactor Coolant System (RCS) via the reactor vessel head vent or pressurizer steam space vent during post-accident situations when large quantities of non-condensible gases may collect in these high points.

B. As a secondary function, the system may be used in normal RCS venting procedures required for a plant outage.

3.7.1.2 Design Criteria

A. Flow Rate

The basic purpose of the vent system is to remove non-condensible gases (primarily hydrogen) from the RCS in a timely manner.

(1) The system is designed to vent non-condensible gas from the RCS in a reasonable period of time over a wide range of reactor coolant temperature and pressure conditions. Over the range of conditions considered (pressures from 250 psia to 2250 psia and temperatures from 200°F to 700°F) the system is designed to vent one-half of the RCS volume in one hour with the vented volume expressed in standard cubic feet of gas.

(2) At the upper end, flow through the vent system must be limited to avoid excessive mass loss from the reactor coolant system. By utilizing flow restricting orifices, the RCGVS is designed to:

a) Limit the coolant liquid loss through the vent to the makeup capacity. This limits the mass loss to below the definition of a LOCA in 10CFR50, Appendix A.

b) Limit the vent mass rate such that venting does not result in heat or mass loss from the RCS which would result in uncontrollable pressurizer pressure or level changes under emergency conditions. With all heaters available, the heat loss is within the heater capacity.

B. Controls

The vent system controls are designed to allow venting under accident conditions and minimize the potential for inadvertant operation. Specifically:

1) The system permits remote (control room) venting from the reactor vessel head or the pressurizer.

2) The vent system is operable following all design basis events except those requiring evacuation of the control room, and loss of all AC power (plant backout).

3) Control room position indication is provided for all power operated valves.

4) To minimize the possibility of inadvertent operation of the system, administrative controls on valve operation are provided.

5) The RCGVS is designed for a single active failure with active components powered from their respective redundant emergency power sources. Parallel vent paths with valves powered from alternate power sources are provided. The solenoid operated valves are powered from safety grade 125V DC power supplies. Power is removed from the fail closed valves, by utilizing key-locked control switches, to minimize the possibility of inadvertent operation during normal operation.

C. Piping and Arrangement

1) The vent path is safety grade and meets the same qualifications as the RCS. Redundance in the vent path is provided and essential piping and components are Seismic Category 1, Safety Class 2.

2) The system is designed not to interfere with refueling maintenance actions. System piping is flanged where required to facilitate removal of components that might interfere with refueling operation.

3) Vent paths are provided to both the quench tank and containment atmosphere. The quench tank path allows for cooling of gases and condensing water vapor by releasing the vented gases below the water level in the tank. The containment vent path terminates in the area where good air mixing and maximum cooling properties exist.

4) The vent system materials are designed to be compatible with superheated steam, steam/water mixtures, water, fission gases, helium, nitrogen, and hydrogen as high as 2500 psia and 700°F.

3.7.2 System Description

3.7.2.1 Summary

The system is designed to permit the operator to vent the reactor vessel head or pressurizer steam space from the control room under post-accident conditions, and is operable following all design basis events except those requiring evacuation of the control room or a complete loss of all AC power. The vent path from either the pressurizer or reactor vessel head is single active failure proof with active components powered from emergency power sources. Parallel valves powered off alternate power sources are provided at both vent sources to assure a vent path exists in the event of a single failure of either a valve or the power source. The system provides a redundant vent path either to the containment directly or to the quench tank. The quench tank route allows removal of the gas from the RCS without the need to release the highly radioactive fluid into containment. Use of the quench tank provides a discharge location which can be used to store small quantities of gas without influencing containment hydrogen concentration levels. However, venting large quantities of gas to the quench tank will result in rupture of the quench tank rupture disc providing a second path to containment for vented gas.

Cooling of gas vented to the quench tank is provided by introducing the gas below the quench volume. The direct vent path is located to take advantage of mixing and cooling in the containment.

The system is designed with a flow limiting orifice to limit flow such that the mass flow rate of reactor coolant system fluid out of the vent is less than the makeup capacity of a single coolant charging pump. This effectively limits the flow to less than the LOCA definition of 10CFR50, Appendix A. The vent rate limitation also assures that RCS pressure control is not compromised by venting operation. The system has the capability to vent large quantities of hydrogen gas from the RCS.

Although designed for accident conditions, the system may be used to aid in the pre or post-refueling venting of the reactor coolant system. Venting of the individual CEDMs and RCPs will still be necessary, however, pressurizer and reactor vessel venting can be accomplished with the system if desired. Vent flow can be directed to the quench tank or THROUGH A CHARCOAL FILTER TO THE CONTAINMENT PURGE HEADER for this operation to prevent inadvertent release of radioactive fluid to the containment.

As shown on P&ID, (Figure 9.3-7), non-condensible gases are removed from either the pressurizer or reactor vessel through the flow restricting orifice and one of the parallel isolation valves and delivered to the quench tank or containment via their isolation valves. Venting under accident conditions would be accomplished using only one source (reactor vessel or pressurizer)and one sink (quench tank or containment atmosphere) at a given time.

3.7.2.1.1 Normal Operation

This system is not intended for use during normal power operation and administrative controls are provided to minimize the possiblity of inadvertant operation. Additionally, power is removed from all valves during normal plant conditions.

During normal operation, leakage detection is maintained by use of the pressure instrumentation. A rise in pressure will indicate leakage past any of the system isolation valves. Small leakage rates can be determined by conducting RCS leak rate calculations. Larger leakage rates can be determined by directing leakage to the quench tank and monitoring tank level change OR TO THE ACCUMULATOR AND MONITORING SUMP INSTRUMENTATION.

3.7.2.1.2 Accident Operation

Operation of the RCGVS during accident conditions will vary depending on the rate of gas generation. For low gas generation rates, gas from within the reactor vessel or pressurizer is vented to the quench tank. Reactor and/or pressurizer vent valves are lined up and the gas released to the quench tank. Monitoring of quench tank pressure is necessary during this mode of operation. From this point the gas could be discharged to the gaseous waste management system if it is available for use.

For high gas generation rates, gases may be vented to the containment atmosphere.

The RCGVS will be operated as an on-off system to remove gas from the RCS. The volume of gas to be removed is determined by reactor vessel or pressurizer instrumentation and then the venting time is determined dependent upon this volume and system temperature and pressure.

3.7.2.2 Component Description

There are no major components in the RCGVS. The entire system consists of piping, valves, and pipe fittings. All piping and valves are constructed of austenitic stainless steels and are Nuclear Safety qualified according to the Class as indicated on Figure 9.3-7. Piping system supports and all valves are also seismically qualified. Power operated valves are solenoid operated type designed to fail close to minimize inadvertent operation. Redundancy in valve arrangement and power supply is designed to meet the single failure criterion. Part of the piping system includes orifices at the pressurizer vent and reactor vessel head vent, both sized to meet the flow requirements of system design criteria.

3.7.3 Safety Evaluation

3.7.3.1 Performance requirements, capabilities, and reliabilities

The ability to vent the RCS - either reactor vessel or pressurizer - under accident conditions is assured by providing redundant flow paths from each venting source, redundant discharge paths, and emergency power to all power operated valves. A single active failure of either a power operated valve or power supply will not prevent venting to containment (either directly or through the quench tank dependent upon failure mode) from either source.

3.7.3.2 Pipe Break Analysis

Consistent with NRC requirements, the RCGVS is designed to limit mass loss to less than a LOCA as defined in 10CFR50, Appendix A and thus a separate analysis of inadvertent system operation or pipe breakage is not required to meet 10CFR50.46.

The pressure boundary of the normally pressurized portion of the head vent system is protected from the effects of postulated pipe breaks in the main loop cold leg piping, or branch lines to the cold legs, or non-RCPB piping. The pressure boundary of the normally unpressurized portion of the vent system is protected from the effects of postulated pipe breaks in non-RCPB lines for which venting would be required.

The flow function of the vent system is protected from the effects of failures for which venting would be required.

.7.3.3 Leakage Detection and Control

The components of the RCGVS are provided with welded connections wherever possible to minimize leakage to the atmosphere. However, flanged connections are provided on the reactor vessel vent line to allow disassembly for refueling maintenance. System valves are of the packless type to minimize

leakage. Leakage past the system isolation valves into the normally unpressurized portion of the system is detected by pressure instrumentation.

7. Natural Phenomena

RCGVS components are located in containment and, therefore, are not subject to the natural phenomena described in Chapter 3 other than seismic. All components, piping and supports in the RCGVS in the Nuclear Safety Class 1, 2 and Non-Nuclear Safety piping are specified and designed as Seismic Category I. Piping has been analyzed and supported in accordance with St.Lucie 2 seismic criteria. All valves have been analyzed and tested for operability during a seismic event by manufacturers. Table 9.3-11 provides a tabulation of Seismic Category 1 valves whose operation is relied upon to mitigate the consequences of an accident.

7.3.5 Failure Modes and Effects Analysis

Table 9.3-12 shows a failure mode and effects analysis for the RCGVS. At least one failure is postulated for each safety-related component of the RCGVS. In each case the possible cause of such a failure is presented as well as the local effects, detection methods, and compensating provisions.

.7.4 <u>Inspection Testing Requirements</u>

Each component is inspected and cleaned prior to installation into the RCGVS. The instrument will be calibrated during pre-operational testing. The valves and controls will be tested for operability following installation.

Components have been specified and purchased as Seismic Category I and Nuclear Safety Class where required. Vendors have substantiated either through test, calculational and/or operational data that system components will remain operable under the design seismic loads. Vendors have tested and inspected all safety class equipment in accordance with applicable ASME and IEEE codes.

.7.5 <u>Instrumentation Requirements</u>

The system is designed to be controlled remotely from the main control room. All power-operated valves powered from emergency power sources and alternate sources are used as necessary to meet single failure criteria. Position indication (open/shut) is provided for all remotely operated valves and displayed in the control room.

.7.5.1 Pressure Instrumentation

Vent header pressure instrumentation is provided to monitor any valve leakage. Pressure indication and high pressure alarm are located in the control room.

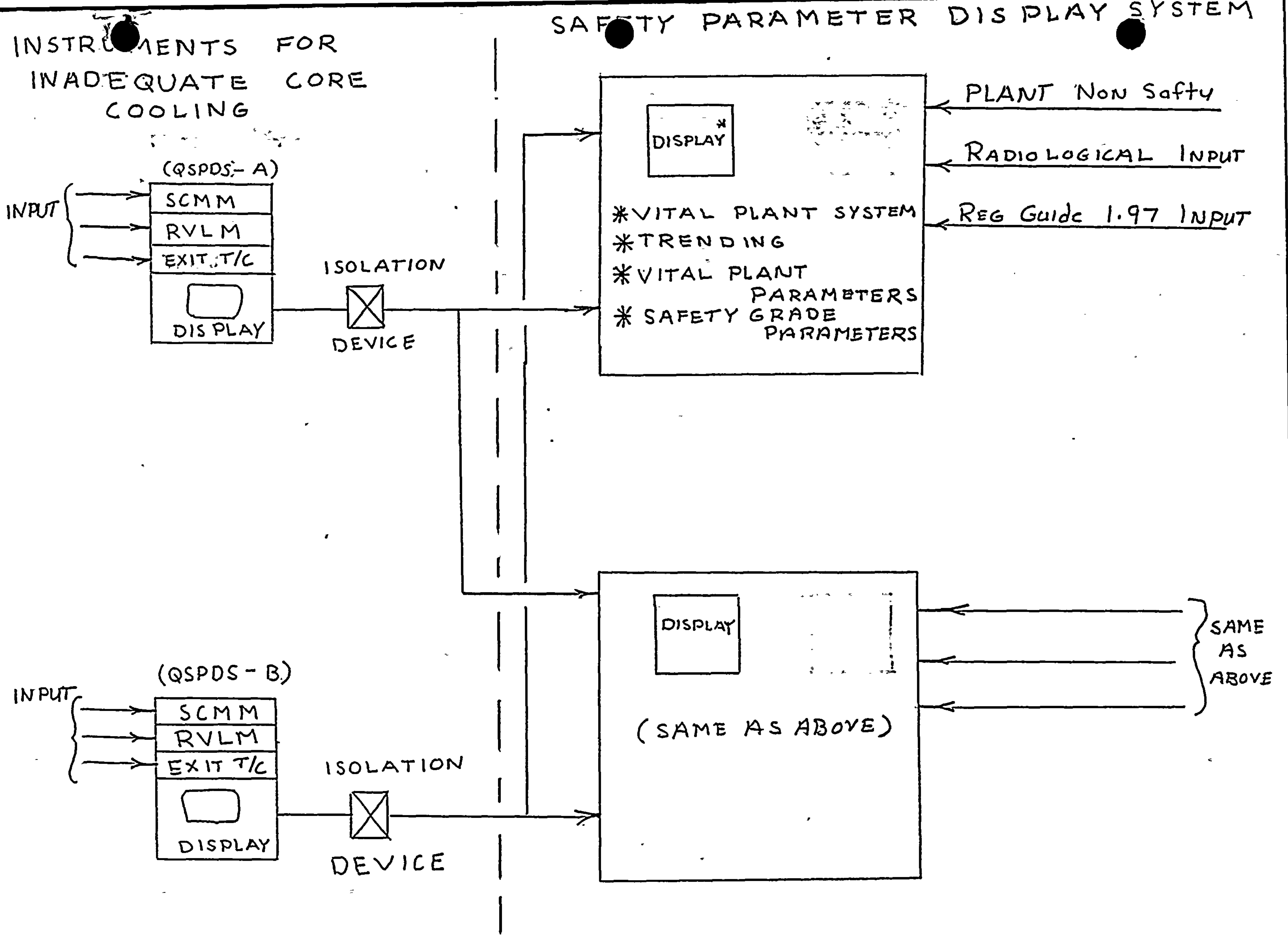


FIGURE A System INTERFACING BLOCK DIAGRAM

Apendix 5.2B

ANALYSIS OF NATURAL CIRCULATION COOLDOWN WITHOUT UPPER HEAD VOIDING

~~FOR~~

~~ST. LUCIE UNIT 2~~

DECEMBER 1980

NUCLEAR ANALYSIS DEPARTMENT
FLORIDA POWER AND LIGHT COMPANY

INTRODUCTION

An analytical evaluation of natural circulation cooldown to shutdown cooling system entry conditions without formation of voids was performed for the St. Lucie Unit 1 plant. The reactor coolant system pressure must be reduced to 275 psia for shutdown cooling initiation. Consequently to prevent the formation of voids, the upper head fluid must be cooled to a value less than the corresponding saturation temperature of 409.5°F. After that time de-pressurization to shutdown cooling system entry conditions can occur without void formation in the reactor coolant. Hot leg temperature cooldown rates of 30°F/hr and 50°F/hr to 325°F were investigated to determine the cooldown time required for the fluid temperature in the reactor vessel upper head to reach shutdown cooling entry conditions without void formation.

THERMAL-HYDRAULIC MODEL

2B-1 The analysis was performed with a detailed thermal-hydraulic model utilizing the RETRAN (Reference 1) computer code. Figure 1 presents a schematic drawing of the fluid volumes, flow junctions, and heat conductors used in the model. Table 5.2B-1 provides a description of these volumes, junctions, and conductors. Specific features of the model include: a detailed nodalization of the upper portion of the reactor vessel including a representation of the reactor vessel walls and internals; a number of automatic control systems including those for charging pumps, the letdown flow control valve and the pressurizer heaters; and a non-equilibrium thermal-hydraulic model for the pressurizer.

ANALYSIS RESULTS

An analysis of a St. Lucie Unit 1 natural circulation cooldown from full power for a hot leg temperature cooldown rate of about 30°F/hr to 325°F demonstrates that the reactor vessel upper head fluid cools to 409.5°F (shutdown cooling entry conditions) in 16.1 hours. The results are presented in Figure 52B-2 The condensate supply required for this cooldown is 218,500 gallons.

The same analysis for a hot leg temperature cooldown rate of about 50°F/hr to 325°F demonstrates that the reactor vessel upper head fluid cools to 409.5°F (shutdown cooling entry conditions) in 14.2 hours. The results are presented in Figure 52B-3. The condensate supply required for this cooldown is 193,000 gallons.

The analysis for a hot leg temperature cooldown rate of about 50°F/hr to 325°F was repeated using very conservative assumptions regarding fluid mixing in the upper reactor vessel in order to determine a bounding cooldown time for operating guidelines. The results demonstrate that the reactor vessel upper head fluid cools to 409.5°F (shutdown cooling entry conditions) in 25.7 hours. The condensate supply required for this cooldown is 270,500 gallons.

RECOMMENDATION

The above results show that for a hot leg temperature cooldown rate of 50°F/hr to 325°F, the upper head fluid can be cooled to shutdown cooling system entry conditions without void formation in approximately 14.2 hours. In order to provide additional conservatism, it is recommended that for natural circulation cooldown to shutdown cooling system entry conditions without void formation, the hot leg temperature cooldown rate be about 50°F/hr to 325°F followed by a soak at 325°F for 20.4 hours for a total cooldown time of 5.2b- approximately 25.7 hours from cooldown initiation. Figure 4 shows the recommended plant cooldown rate. The condensate supply required for this cooldown is 270,500 gallons.

REFERENCE:

(1) RETRAN-A Program For One-Dimensional Transient Thermal-Hydraulic Analysis of Complex Fluid Flow Systems, Volumes 1,2,3&4, EPRI CCM-5, December 1978.

TABLE 5.2B-1

MODEL GEOMETRY DESCRIPTION

FLUID VOLUME	DESCRIPTION
1	Combined hot leg volume.
2	Combined steam generator inlet plenum volume.
3	Combined steam generator tube volume from tube sheet to top of tube bundle.
4	Combined steam generator tube volume from top of tube bundle to tube sheet.
5	Combined steam generator outlet plenum volume.
6	Combined cold leg volume upstream of reactor coolant pump.
7	Combined reactor coolant pump volume.
8	Combined cold leg volume downstream of reactor coolant pump.
9	Reactor vessel downcomer volume.
10	Reactor vessel inlet plenum volume.
11	Core volume.
16	Volume from top of active core to fuel alignment plate.
12	Outlet plenum volume from fuel alignment plate to upper guide structure support plate.
13	CEA shroud volume.
17	Upper head volume from upper guide structure support plate to top of CEA shroud.
14	Upper head volume above top of CEA shroud.
32	Surge line volume.
34	Pressurizer volume.
51	Steam generator shell side volume.

TABLE 1 (continued)

MODEL GEOMETRY DESCRIPTION

FLOW JUNCTION	DESCRIPTION
1	Flow from volume 12 to volume 1.
2	Flow from volume 1 to volume 2.
3	Flow from volume 2 to volume 3.
4	Flow from volume 3 to volume 4.
5	Flow from volume 4 to volume 5.
6	Flow from volume 5 to volume 6.
7	Flow from volume 6 to volume 7.
8	Flow from volume 7 to volume 8.
9	Flow from volume 8 to volume 9.
10	Flow from volume 9 to volume 10.
11	Flow from volume 10 to volume 11.
17	Flow from volume 11 to volume 16.
12	Flow from volume 16 to volume 12.
13	Flow from volume 16 to volume 13.
14	Flow from volume 13 to volume 17.
15	Flow from volume 17 to volume 12.
18	Flow from volume 14 to volume 17.
35	Flow from volume 32 to volume 1.
36	Flow from volume 34 to volume 32.
37	Spray flow to volume 34.
38	Charging flow to volume 8.
39	Letdown flow from volume 6.

TABLE 1 (continued)

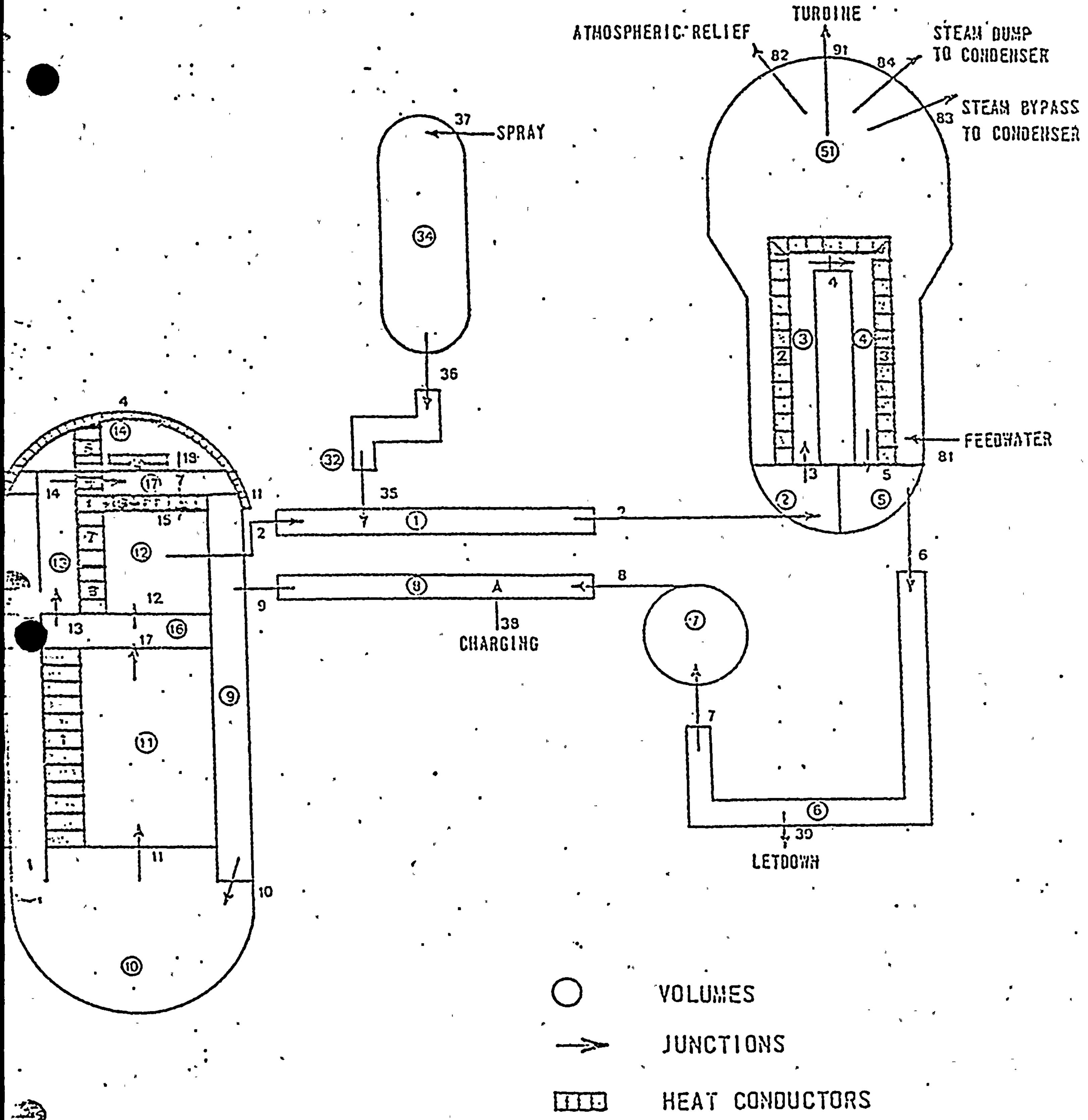
MODEL GEOMETRY DESCRIPTION

FLOW JUNCTION	DESCRIPTION
81	Feedwater flow to volume 51.
82	Atmospheric relief valve flow from volume 51.
83	Steam bypass valve flow to condenser from volume 51.
84	Steam dump valve flow to condenser from volume 51.
91	Steam flow to turbine from volume 51.

TABLE 1 (continued)

MODEL GEOMETRY DESCRIPTION

HEAT CONDUCTOR	DESCRIPTION
1	Fuel conductor connecting fuel to volume 11.
2	Steam generator tubes connecting volume 3 and volume 51.
3	Steam generator tubes connecting volume 4 and volume 51.
4	Metal in reactor vessel walls adjacent to volume 14.
5	Metal associated with upperhead drive shafts in volume 14.
6	Metal associated with CEA shrouds connecting volume 13 and volume 17.
7	Metal associated with CEA shrouds connecting volume 13 and volume 12.
8	Metal associated with CEA shrouds connecting volume 13 and volume 12.
9	Upper guide structure support plate connecting volume 17 and volume 12.
10	Metal associated with upper guide structure adjacent to volume 12.
11	Metal in reactor vessel wall adjacent to volume 17.
12	An effective conductor to allow axial heat conduction between volumes 14 and volume 17.



MODEL VOLUME, JUNCTION, AND CONDUCTOR GEOMETRY.

FIGURE 2
REACTOR COOLANT TEMPERATURE VS TIME
COOLDOWN AT 30° F/HR TO 325° F

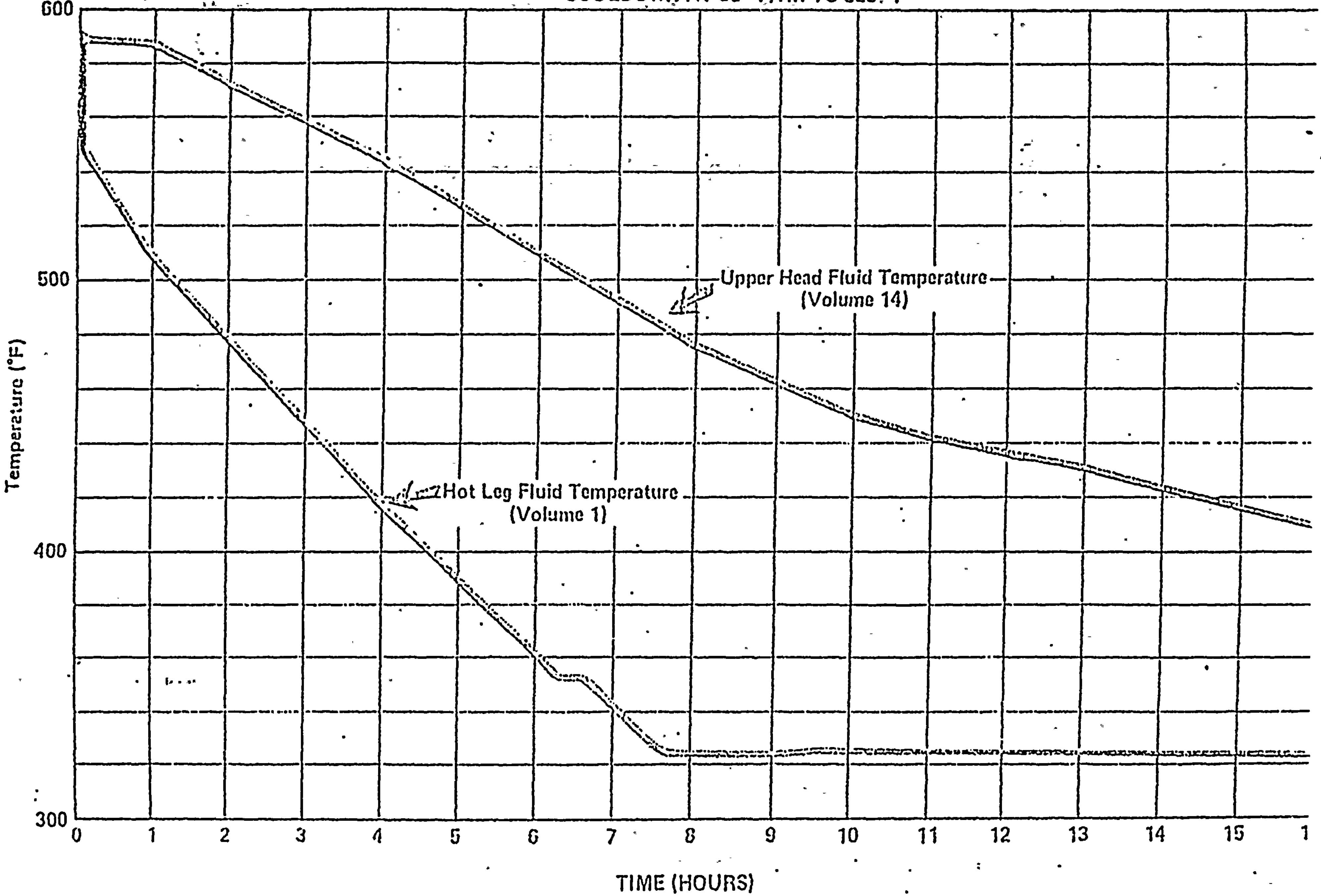


FIGURE 3
REACTOR COOLANT TEMPERATURE VS TIME
COOLDOWN AT 50° F/HR TO 325° F

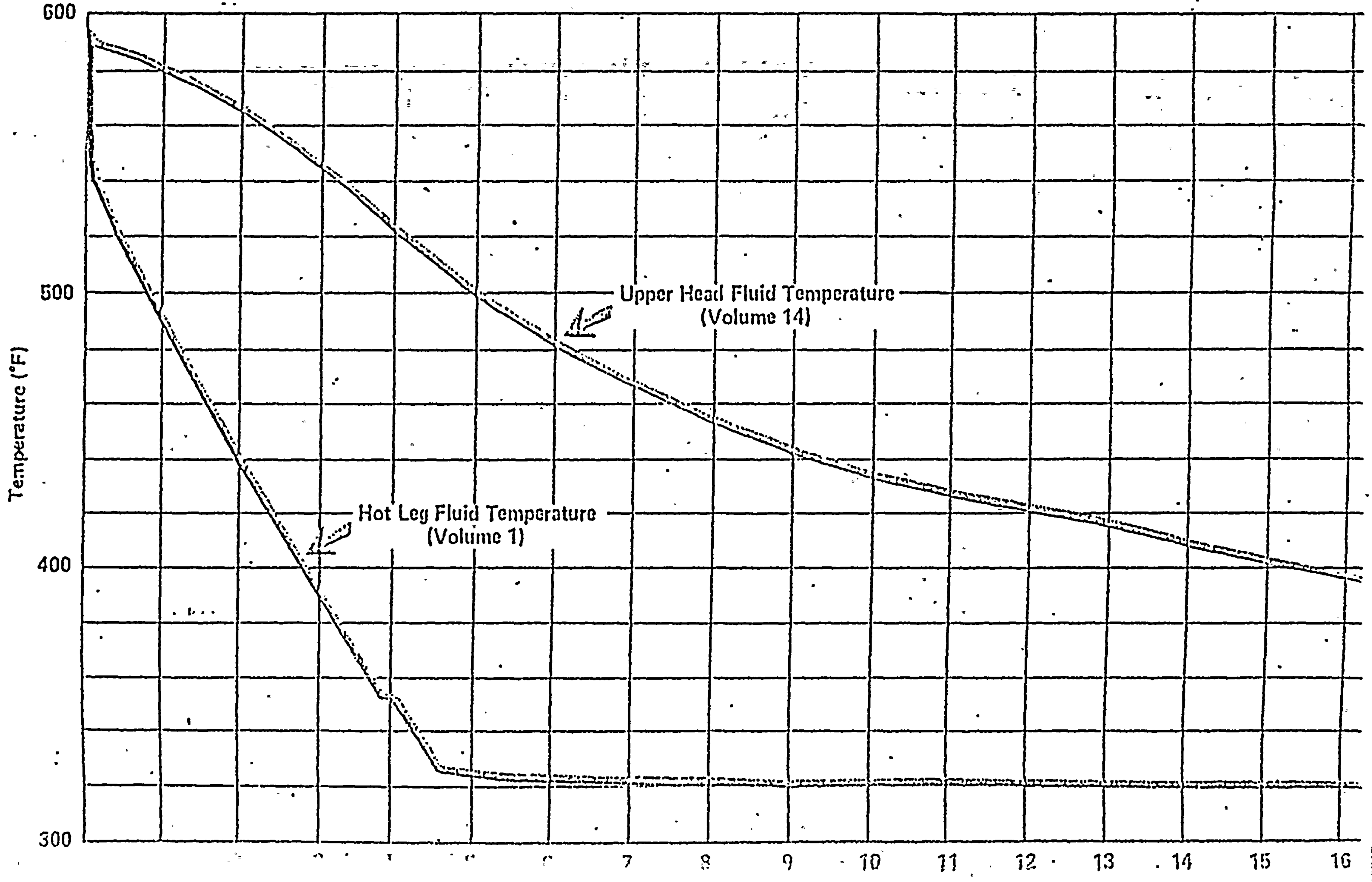
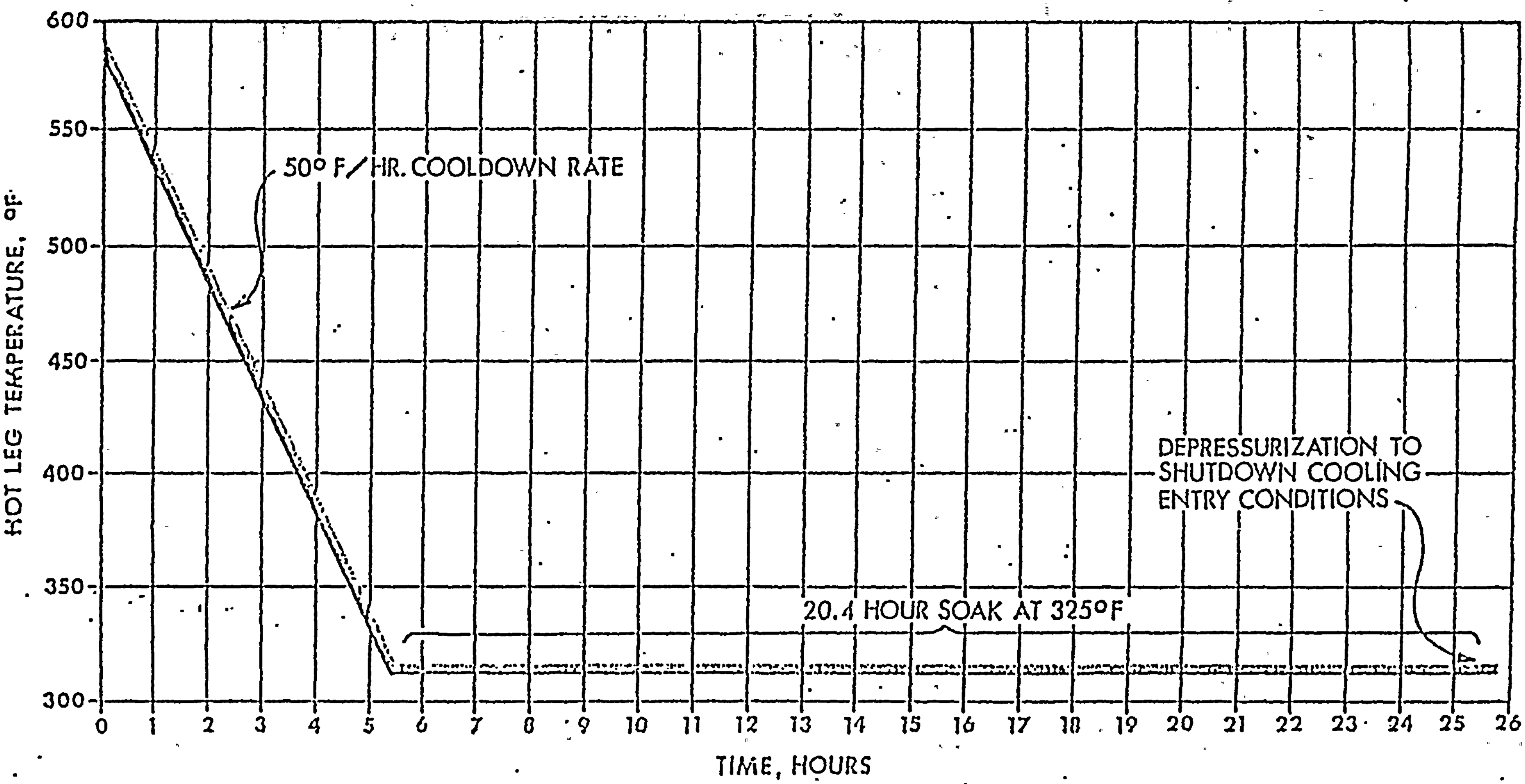


FIGURE 4

RECOMMENDED COOLDOWN GUIDELINE



APPENDIX 5.2C

Natural Circulation Cooldown

A combined thermal/stress analysis was performed to determine the range of stresses produced in the reactor vesssel head due to voiding of the upper head region. In performing the thermal analysis, "worst case" assumptions were made in defining the fluid temperature and initial vessel temperatures. The assumptions which define the thermal transient are as follows and illustrated on Figure R 5.2C-1

1. The upper head is drained down to the upper guide support structure plate in 20 minutes with both fluid and metal temperatures remaining at 600°F.

2. The water level is held at this height for 40 minutes with a fluid temperature of 300°F.

3. The head is refilled over a 20 minute period with 300°F water.

4. The upper head remains filled with 300° water for a period of time.

5. The heat transfer coefficient for the water is large (H=500 Btu/ft^2 - hr-°F).

6. The heat transfer coefficient for steam is very small (H=0. Btu/ft^2-hr-°F).

Temperatures calculated for this transient were applied to a stress analysis model. The results of this analysis indicate that the highest stresses occur in the "knuckle" region of the head near the inside radius. The magnitude of stresses produced for this transient were found to be no more severe than the stresses occurring during a normal cooldown of 100°F/hr.

In addition the results of this analysis demonstrate that:

1. A more rapid refill of the head does not cause higher stresses since the thermal conductivity through the reactor vessel wall is the limiting heat transfer mechanism.

2. The water level holddown time does have an effect on the stresses in the head. Longer holddown times decrease the stress in the "knuckle" region because of axial heat flow which removes heat from the head.

3. The thermally-induced stresses in the nozzle region of the reactor vessel are small in comparison to the stresses due to pressure loading only.

4. The deformations and rotations in the control element drive mechanism nozzles are negligible due to the thermal transient.

5. No separation occurs at the O-ring seal region of the flange, hence, no leakage occurs.

FORCING FUNCTION USED FOR

THERMAL TRANSIENT

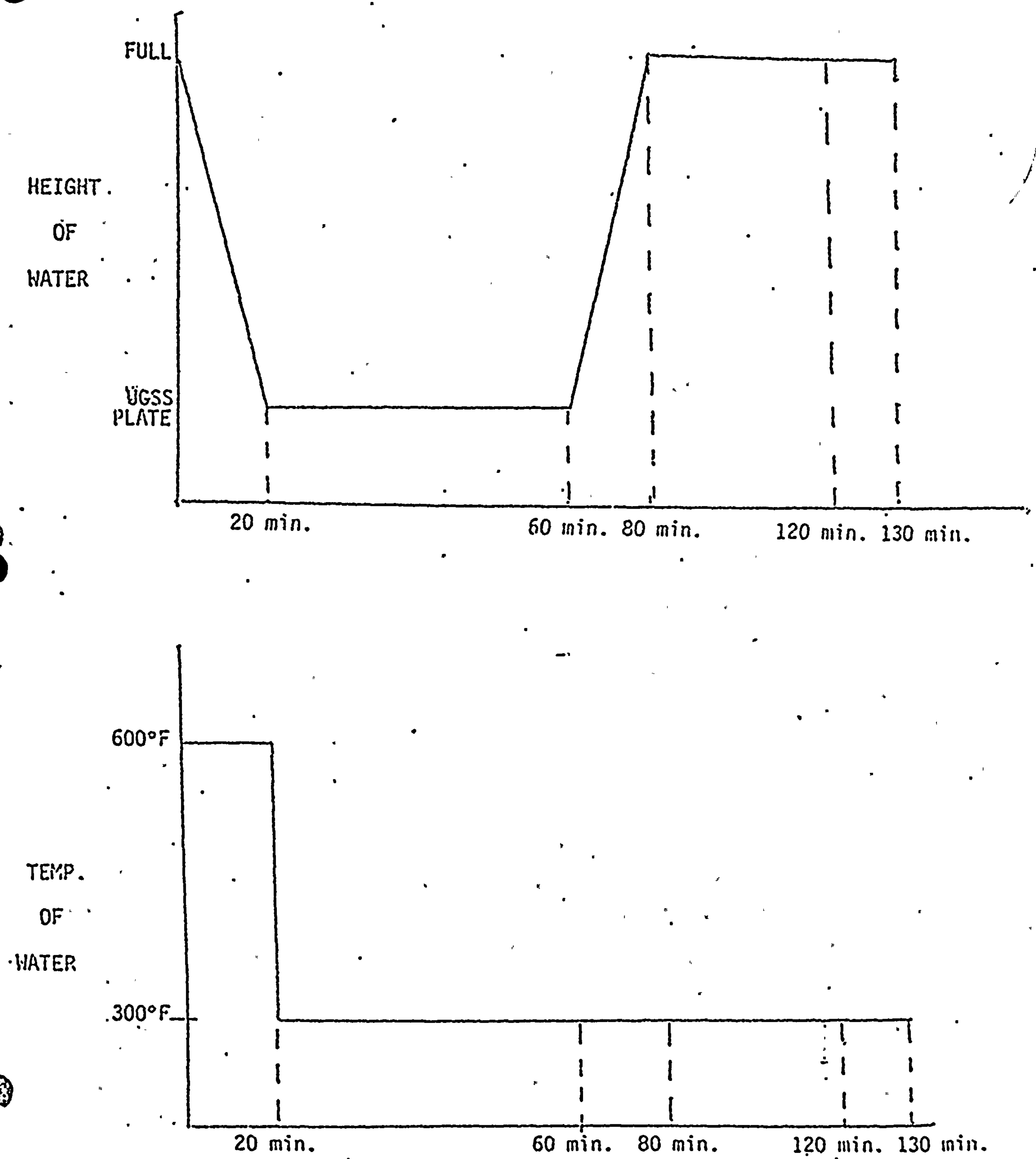


Figure 1

7.5.3 TMI RELATED ADDITIONAL ACCIDENT MONITORING INSTRUMENTATION

7.5.3.1 TMI Containment Pressure Monitors

In compliance with NUREG 0737 permanently installed wide range containment pressure monitors are provided for post accident monitoring of containment pressure.

7.5.3.1.1 Design Bases

a) Measurement and indication capability is provided over a range of -5 psig to four times the containment design pressure (175 psig)

b) Safety related redundant instrumentation channels are provided to meet the single failure criteria.

c) The redundant containment pressure monitoring instrumentation channels are energerized from independent class IE power sources, and are physically separated in accordance with regulatory Guide 1.75 "Physical Independance of Electric Systems" January 1975 (R1)

d) The containment pressure monitoring instrumentation is qualified in accordance with IEEE 323-1974 for the design bases accident environment in which they operate.

e) The containment pressure monitors are designed seismic category I and qualified per the IEEE 344-1975 criteria.

f) Continuous indication and recording of containment pressure is provided in the control room.

g) Each instrument covers the entire pressure range.

h) The monitoring instrumentation inputs are from sensors that directly measure containment pressure and provide input only to the containment pressure monitors.

i) An instrumentation channel is available during normal operation prior to an accident as specified in plant technical specification.

j) Testing and calibration requirements are specified in plant technical specification

k) The instruments are specifically identified on the control panels so that the operator can easily discern that they are intended for use under accident conditions.

7.5.3.1.2 Design Description

The containment pressure detectors are electronic transmitters (Rosemount 1153GB7) mounted outside the Reactor

Containment Building. The detectors utilize independent sensing lines which penetrate the containment. A normally open fail closed solenoid valve with remote manual control operated from the control room is provided for containment isolation for each loop. The redundant containment pressure monitoring channels are provided with indicators in the control room and one of the channels is recorded in the control room. Instrument loop accuracy is provided in Table 7.5-1

7.5.3.1.3 Safety Evaluation

The TMI containment pressure monitors are designated seismic category I and designed to the Quality Group B standard. Two more channels of containment pressure monitoring instrumentations with a range of 0 to 60 psig are provided as post accident monitors (refer to Table 7.5-1). Hence in the unlikely event when the two redundant TMI containment pressure monitor displays disagree the operator has available to his disposition these other monitoring channels for verification purposes as described in the plant technical specifications. Channel calibration and channel check are performed periodically.

7.5.3.2 <u>TMI Containment Water Level Monitors</u>

In compliance with NUREG 0737, permanently installed narrow and wide range containment water level monitors are provided for post accident monitoring. The narrow range instrument covers the range from the bottom to the top of the reactor cavity sump. The wide range instruments cover the range from the bottom of the containment to the evelation equivalent to 600,000 gallon capacity.

7.5.3.2.1 Design Bases

a) Safety related, redundant wide range water level monitors are provided to meet the single failure criteria. The wide range monitors are designed to seismic Category I requirements.

b) The redundant wide range water level instrumentation channels are energized from independent class IE power sources and are physically separated in accordance with Regulatory Guide 1.75 "Physical Independence of Electric Systems" January 1975 (R1).

c) One narrow range containment water level monitor is provided.

d) Both the narrow and wide range containment water level monitoring channels are qualified to IEEE 323-1976 for post accident environment in which they operate. Seismic qualification per IEEE 344-1975 is also provided.

e) Continuous indication and recording of containment water level is provided in the control room.

Valve No.	Description	Size (In.)	Type	Actuation Type
V1462	Reactor Vessel Vent isolation	1	Globe	Solenoid
V1463	Reactor Vessel Vent isolation	1	Globe	Solenoid
V1460	Pressurizer Vent isolation	1	Globe	Solenoid
V1461	Pressurizer Vent isolation	1	Globe	Solenoid
V1464	Quench Tank Vent isolation	1	Globe	Solenoid
V1465	Containment Vent isolation	1	Globe	Solenoid
V1466	Containment Vent isolation	1	Globe	Solenoid

Failure Modes Effects Analysis for the [illegible]ctor Coolant Gas Vent System

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remark and other Effects
Pressure Indicator PT-1140	a. spurious high pressure indication/alarm	Electro-mechanical failure, set-point drift	No impact on normal operation. Loss of ability to detect leakage into the vent system piping.	Valve position indication in the control room.	None	Post-Accident venting is not affected
	b. spurious low pressure indication	Electro-mechanical failure, set-point drift	No impact on normal operation. Loss of ability to detect leakage into the vent system piping.	Valve position indication in the control room.	None	Post-Accident venting is not affected
Quench Tank Isolation Valve V1464	a. Fails Open	Mechanical Binding, Seat Leakage	Inability to isolate quench tank from the reactor coolant gas vent system.	Valve position indication in the control room.	None	Redundant isola tion valves to the reactor vessel and pres surizer preclu uncontrolled ve ing to the quer tank.
	b. Fails Closed	Mechanical Failure, Loss of Power	No impact on normal operation. Inability to vent pressurizer or reactor to quench tank.	Valve position indication in the control room. Operator.	None	Venting to the containment is possible, if necessary.
3. Pressure Instrument Isolation Valves V1467 VPIS1140	a. Fails Open	Mechanical Binding, Seat Leakage	None	Operator	Redundant Valves	
	b. Fails Closed	Mechanical Failure	Loss of ability to detect seat leakage from the pressurizer and reactor isolation valves into the reactor coolant gas vent system piping.	Operator	None	Unlikely event since valve is normally open and has only a manual operato
4 Containment Isolation Valve V1465 V1466	a. Fails Open	Mechanical Binding, Seat Leakage	Inability to isolate reactor coolant vent system from containment.	High containment pressure and humidity if venting is in progress. Valve position indication in the control	None	Redundant isol. tion valves to the reactor vessel and pre urizer preclud uncontrolled v ing to the containment.

Failure Modes Effects Analysis for the Reactor Coolant Gas Vent System

No.	Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remark and oth Effects
		b. Fails Closed	Mechanical Failure, Loss of Power to the Valve	No impact on normal operation. Inability to vent pressurizer or reactor to containment.	Valve position indication in the control room. Operator.	Parallel-redundant isolation valve [illegible]	Venting to the quench tank if possible if necessary.
5	Pressurizer Vent Isolation Valve Y1460 Y1461	a. Fails Open	Mechanical Binding, Seat Leakage	No impact on normal operation. Inability to vent the reactor vessel without also venting pressurizer. This is satisfactory and will not impact natural circulation.	Valve position indication in control room. PT-1140 high pressure indication.	None	Redundant isolation values to containment Y1465 Y146 and quench tank Y1464 precludes uncontrolle venting to the pressur zer.
		b. Fails Closed	Mechanical Failure, Loss of Power	Inability to vent the pressurizer.	Valve position in the control room. Isolation valve. Operator.	Parallel redundant isolation valve,	Parallel isolation valve allow venting of the pressurizer.
6	Reactor Vessel Vent Isolation Valve Y1462 Y1463	a. Fails Open	Mechanical Binding, Seat Leakage	No impact on normal operation. Unable to vent pressurizer without also venting the Reactor Vessel. This is satisfactory and will not impact natural circulation.	Valve position indication in the control room. PT-1140 high pressure indication.	None	Redundant isolation values to containment Y1465, Y1466 and Y1464 precludes uncontrolled venting of the reactor vessel.
		b. Fails Closed	Mechanical Failure, Loss of Power	Inability to vent the reactor vessel.	Valve position in the control room. Operator.	Parallel redundant isolation valve.	Parallel isolation valve allows venting of the reactor vessel.

Table 9.3-

Failure Modes Effects Analysis for the Reactor Coolant Gas Vent System

Name	Failure Mode	Cause	Symptoms and Local Effects Including Dependent Failures	Method of Detection	Inherent Compensating Provision	Remark and other Effects
Position Indicator for V1462, V1463	False indication of valve position	Electro-mechanical failure.	Loss of ability to detect valve psoition in reactor vessel vent line.	Pressure gauge PT-1140 indication shows valve is opened.	None	
Position Indicator for V1460 V1461	False indication of valve position	Electro-mechanical failure.	Loss of ability to detect valve position in pressurizer vent line.	Pressure gauge PT-1140 indication shows valve is opened.	None	
Position Indicator for V1464	False indication of valve position	Electro-mechanical failure	Loss of ability to detect valve position in quench tank vent line.	Quench Tank temperature and pressure verify value position. Pressure gauge PT-1140	None	
Position Indicator for V1465 V1466	False indication of valve position	Electro-mechanical failure	Loss of ability to detect valve position in containment vent line.	Containment pressure/humidity/radiation levels verify containment valve position. Pressure gauge PT-1140	None	
Drain Valves V1469 V1471 V1486	a. Seat Leakage	Contamination, Mechanical damage	No impact on system operation.	None	Drain lines are blind flanged.	
	b. Fails Closed	Mechanical Binding	No impact on normal operations. Inability to drain affected line section.	Operator	None	
Accumulator Isolation Valve V1466	a. Fails Open	Mechanical Binding, Seat Leakage	Inability to isolate accumulator ~~reactor coolant~~ vent ~~system~~ from containment.	High containment pressure and humidity if venting is in progress. Valve position indication in the control	None	Redundant isolation valves to the reactor vessel and pressurizer preclude uncontrolled venting to the containment.
	b. Fails Closed	Mechanical Failure, Loss of Power to the Valve	Inability to use accumulator for leak detection.	Valve position indication in the control room. Operator.	None	Venting to Containment or Quench Tank still possible.

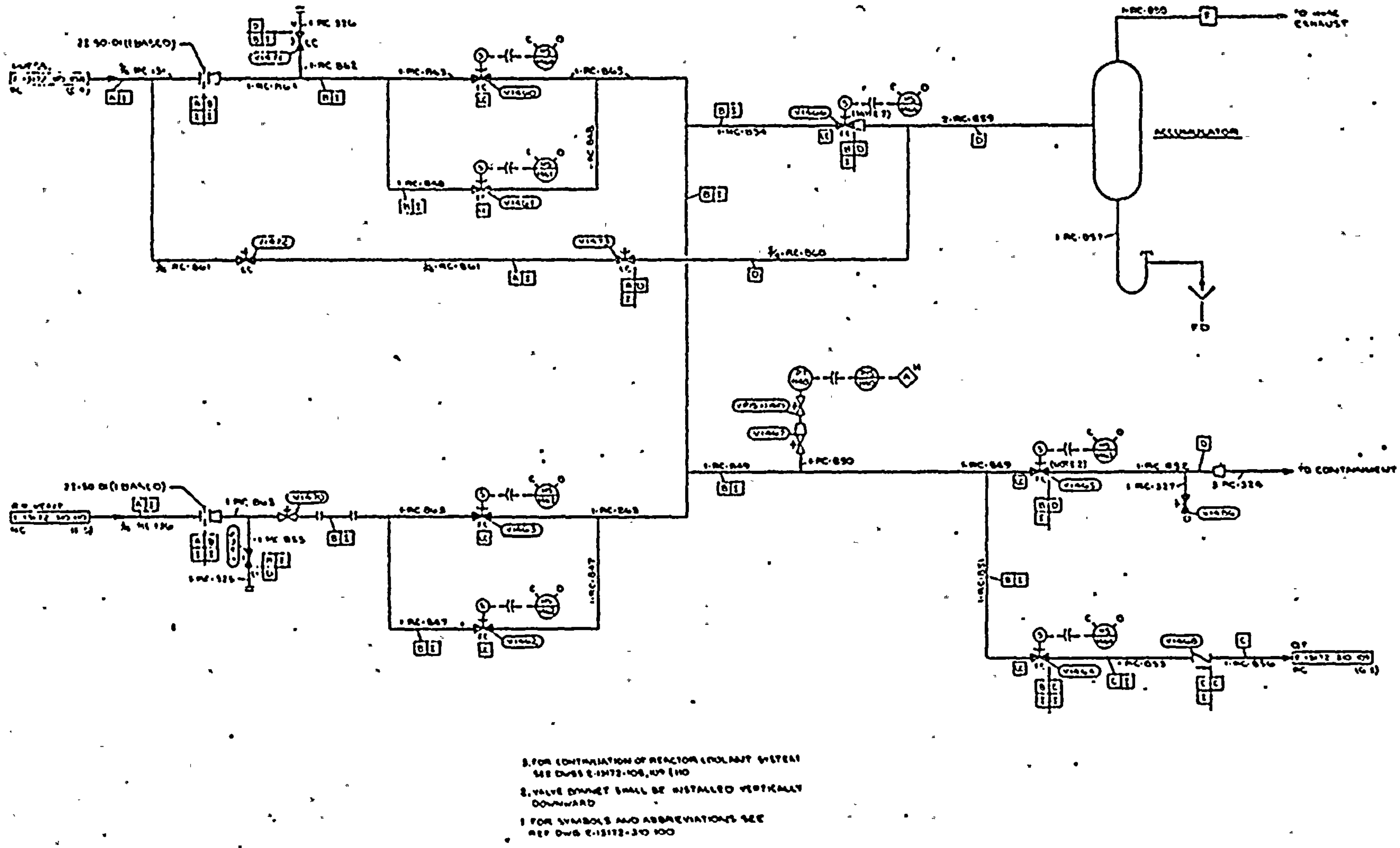

ACCUMULATOR
TO CONTAINMENT
FD
3. FOR CONTINUATION OF REACTOR COOLANT SYSTEM SEE DWGS E-13172-108, 109 & 110
2. VALVE BONNET SHALL BE INSTALLED VERTICALLY DOWNWARD
1 FOR SYMBOLS AND ABBREVIATIONS SEE REF DWG E-13172-310 100

FIGURE 9.3-7

9.5.1 FIRE PROTECTION SYSTEM

The St Lucie Unit 2 fire protection program (fire detection and extinguishing systems and equipment, administrative controls and procedures, and trained personnel) provides assurance that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment.

A Fire Hazards Analysis is presented in Appendix 9.5A.

9.5.2 COMMUNICATIONS SYSTEMS

9.5.2.1 Design Basis

The communications systems are designed to assure reliable and diverse onsite and offsite communications services for normal operation and emergency conditions under maximum noise levels, and are illustrated on Figures 9.5-1 through 9.5-5.

9.5.2.2 System Description

The onsite communication systems are as follows:

a) Private automatic telephone exchange (PAX)

b) Page/party line communication (PA)

c) Radio paging

d) Sound powered head sets

e) Site alarm signals

f) Private branch telephone exchange (PBX)

The offsite communication systems are as follows:

a) Private branch telephone exchange (PBX)

b) Two-way radio

c) Radio paging (limited range)

Insert 0

9.5.2.2.1 Onsite Communication Systems

The private automatic telephone exchange (PAX) is a system consisting of a central switching unit, telephone sets, associated equipment and wiring. The system is an extension of the existing St Lucie Unit 1 PAX system where additional switching equipment and telephone sets are connected. The PAX telephones are located throughout the plant providing dial type communication.

The page/party line communication system consists of a solid state combined speaker and handset station amplifier, speakers and associated equipment and wiring. The system provides one page and five party line channels. The page/party system for St Lucie Unit 2 is interfaced with the St Lucie Unit 1 page/party system through a merge/isolate assembly.

Access to the paging channel is provided by the handset stations or PAX telephone via interface equipment. The speakers and handset stations are located throughout the site to provide full plant coverage.

The radio paging communication system consists of a transmitter, radio receivers, antennae, remote desk sets (priority phone), remote control/ master consoles, interface equipment and wiring. The system provides tone plus voice selective radio paging signals, broadcast throughout the Unit 2 site.

The sound powered communication system consists of sound powered headsets, remote jack stations and wiring. Jack stations are located in vital areas where communication is required for remote shutdown. A dedicated headset is stored adjacent to each jack station. The system provides back-up communication in the unlikely event of a complete loss of normal communication.

The site alarm signals are incorporated into the page/party system. Site evacuation, containment evacuation and fire alarm signals are provided by tone generators. The tone generators are remotely controlled by the control room operator pushbutton stations. High containment radiation initiates a containment evacuation signal. Two emergency pushbutton stations in the containment can also initiate this signal. The tone generator signals are fed to the page/party station amplifiers and broadcast through the speaker system in the entire site. The page/party system is provided with a volume override feature to assure that maximum sound dispersion is provided in the event of site alarm.

Additional onsite communications is provided by a private branch telephone exchange (PBX) via the line to the PAX system. The PBX telephone system consists of a central switching unit, telephone sets, associated equipment and wiring. This system is an extension of the existing St Lucie Unit 1 PBX system, and is equipped to provide St Lucie Unit 2, with onsite as well as offsite communication via telephones located in the control room, remote shutdown room, offices and labs. Two lines for telemetry, load control and supervisory control are provided for the site in addition to the telephone company central office voice trunks. In the event of complete loss of all plant telephone service, a telephone line is provided for voice communication between the site and the system load dispatch office. This is in addition to the normal plant telephone service.

9.5.2.2.2 Offsite Communications Facilities

Offsite commercial telephone service is provided by a private branch telephone exchange (PBX) system as described above.

As back-up to the telephone lines, a two-way radio facility (operating on 37.7 megahertz) is maintained between the site and Florida Power & Light Company's Riviera Plant which maintains radio and telephone contact with the system load dispatch office. The system load dispatch has direct telephone lines and either patched or indirect radio contact with all plants and radio equipped vehicles in the Florida Power & Light Company system. A dedicated two-way radio communication system is also provided for plant security purposes (see Section 13.6).

The radio paging system described in Subsection 9.5.2.2.1 has limited capability for radio paging coverage beyond the site boundary.

Insert 1&2

9.5.2.3 Systems Evaluation

Communication facilities of the types described are conventional and have a history of reliable operation at Florida Power & Light Company plants.

The availability of the page party, two way radio system, and radio paging system is assured by powering the system from a vital ac bus which has three alternate supplies;

a) inverter, powered from an emergency MCC

b) voltage regulating transformer, powered from an emergency MCC

c) dc power from station battery

The Vital AC Bus is supplied from an automatic transfer switch that is normally selected to the static uninterruptable power source (SUPS). The alternate supply to the automatic transfer switch is from a 120 VAC regulator powered from the 480 VAC 2AB Bus. The automatic transfer switch will automatically transfer from the SUPS to the alternate regulated 120 VAC in the event of a SUPS malfunction.

The automatic transfer switch can be manually bypassed and the regulated 120 VAC connected to the Vital AC Bus. 4

The SUPS inverter is normally supplied by rectified power from the 480 VAC 2AB Bus with a back-up 125V DC from the 125V DC 2AB Bus. Diode logic insures that the 125V DC is available to the SUPS in the event of loss of the 480VAC 2AB Bus. The 125V DC 2AB Bus has a battery back-up to provide power in the event of a loss of the rectifier. 430.5

The availability of the PAX system is assured by powering this system from:

a) ac operated battery charger

b) 48 volt battery

The PAX internal telephone system is shared with Unit #1. The power for the PAX system is supplied from a 48V DC Battery. The battery is continuously charged with power from a power panel that is supplied from the 480VAC 1BG non-essential Bus. In the event of loss of power on this Bus, the emergency 4 diesel will automatically supply power to the Bus. Under operational con- 430.5

trol, the non-essential section of this Bus can be energized to provide for PAX system battery charging. 4 430.5

The Sound Powered Telephone System will be available for inplant communications from the Control Room and between various locations throughout the plant. This system uses voice sound power to generate the communication signal and does not require external power, making it immune to disruption in the event of loss of all onsite power.

Insert 3

~~The availability of the PAX system is assured by the inherent back-up systems provided by Southern Bell.~~

In the event of loss of the normal offsite power sources, the communications systems remain operable since they are powered from batteries. Diverse offsite and onsite communications systems ensure that plant communications are maintained. In general, each of the communications systems have their interconnection cables run in a dedicated conduit system to minimize the probability of common mode failure. The unique design features that will assure functionally operable onsite communications is decribed below.

<u>The Page Party/Site Alarm System</u> has the following features:

1) The various instruments are distributed throughout the plant. Should one instrument fail, an alternate instrument would be available within a short distance. 4 430.5

2) Each instrument is individually fused. Should a component fail that would overload the power, the individual instrument fuse would open the circuit preventing disruption to the entire system.

3) The Page Party/Site Alarm System electrical cables are routed through dedicated conduits other than in the manhole systems where it mixes with sound powered cables. Damage to the Page Party/Site Alarm conduit and cables would not disrupt other communication systems. Routing of more than two communication systems within one manhole or raceway system is not permitted to assure that the loss of any one raceway system will not jeopardize total site communications.

4) The bulk of the interconnecting cabling is sectionalized at a main terminal box by building and/or areas; in addition to that the Reactor Auxiliary, Reactor Containment and Turbine Buildings (ie: section cables) are designed to ring loops, some remote instruments are fed radially. Should an interconnecting cable be severed in any loop, the equipment would continue to function, being connected by the remaining parts of the loop.

5) In the page/party system, if a line is severed producing an open circuit the system is sectionalized into two parts; if the line is shorted service may be impaired or totally lost until it is repaired.

6) Disconnects are provided to isolate and remove any section/loop from the system. Should a malfunction introduce noise into the

entire system. If communications are disrupted the malfunctioning section/loop can be removed from the system.

7) On loss of power from the vital 120VAC Bus, the Page Party/Site Alarm signals will not function.

The Pax Telephone System has the following features:

1) Various instruments are distributed throughout the Plant. Should one instrument fail an alternate instrument would be available within a short distance.

2) The Unit 2 PAX system is connected to the Unit 1 system via 2 (two) 50 pair cables.

From the SL2 main distribution frame multipair shielded twisted pair cables are routed to telephone cabinets (terminal boxes). From the telephone cabinet to each instrument, an individual shielded twisted pair cable is run.

3) The PAX system electrical cables are routed through separate conduit from the other communications systems, other than when mixed with radio page circuits in manholes/conduits as required. Routing of more than two communications systems within one manhole or raceway system is not permitted to assure that the loss of any one raceway system will not jeopardize total site communications. 4

4) On loss of power, the PAX system will continue to operate from its back-up battery. 430.5

The Sound Powered Telephone System has the following features:

1) The system consists of two individual circuits in a single cable; should one circuit fail, the other circuit will be available.

2) The sound powered phone system cables are routed thru separate conduits from the other communications system other than when mixing with PA cables in manholes. Routing of more than two communications systems within one manhole or raceway system is not permitted to assure that the loss of any one raceway system will not jeopardize total site communications. If a line is severed producing an open circuit, the communication channel is sectionalized. If the line is shorted service may be impaired or totally lost.

3) The individual instrument is connected into the system via a telephone jack. Should an instrument fail it could be disconnected and another instrument connected.

4) The sound powered system does not require external power and is immuned to power loss.

The Two-Way Radio System has the following features:

1) The Two-Way Radio System has separate transmit and receive frequencies with a power boost repeater. The repeater has antennas in various locations within the plant. Loss of one antenna cable could degrade the coverage in that location but not disrupt the other radio communications or other communications.

2) Failure of a single radio instrument will not disrupt the radio communications or other communications.

3) Battery power loss on an individual radio will make its radio inoperable but will not disrupt the radio or other communications systems. Loss of power to the repeater will make the two-way radio system inoperable.

The Radio Pager System has the following features:

1) The radio pager system receives its input from the PAX System. Priority telephones are located in the control room and the Hot Shutdown room. Should the entire PAX System malfunction, the priority telephones can be used to page and transmit a voice message to an individual receiver.

2) To prevent a misplaced PAX telephone handset or a telephone malfunction from disrupting the radio channel, an automatic timer is employed to disconnect the circuit after a specific time period. 4

3) Various antennas are located throughout the plant for indoor and outdoor coverage. Loss of one antenna or its antenna cable could degrade the coverage in the specific area but not disrupt the radio pager system or other communications system. If a transmission line used for connecting the indoor antenna system is faulted, depending upon the nature and location of the fault, the one section ahead of the fault will become inoperative. 430.5

4) Battery power loss on an individual receiver will prevent the receiver from operating but not disrupt other communications. Loss of vital 120VAC power to the pager transmitter system will make the system inoperable.

5) The radio pager system cables are routed through separate conduits from the other communications systems other than when mixed with PAX circuits in manholes/conduits as required.

Routing of more than two communications systems within one manhole or raceway system is not permitted to assure that the loss of any one raceway system will not jeopardize total site communications.

Working stations vital to attain a safe plant shutdown are listed in Table 9.5-6. Also indicated in this table are the estimated maximum sound levels at each working station, the communications facilities provided at or in the vicinity of each working station and the maximum noise level that could exist at each working station and still maintain effective communication with the control and Hot Shutdown Rooms.

During emergency plant operation, including transients, fire, accidents and loss of offsite power conditions, the plant communications systems provide effective two-way communication between all plant personnel in all vital working stations/areas in the plant. 4 430.5

9.5.2.4 Inspection and Testing

The systems assure reliable onsite and offsite communications for normal and emergency conditions. Routine use of the communication systems provides a check of their continued availability. Pre-operation procedures will verify that there is adequate and understandable communications. 4 430.5

9.5.2.2 INSERT O

d) Emergency Notification System Auto ring down telephone (TMI Action Item III. A.3.2)

e) Health Physics Network Dial up communications link. (TMI Action Item III A.3.3)

9.5.2.2.2 INSERT 1

The Emergency Notification System Auto ringdown telephone is a dedicated telephone system linking St Lucie Unit 2 with the NRC's regional office and the NRC's operations center in Bethesda, Maryland. To operate this phone the operator need only lift the receiver causing the phones at the NRC to ring automaticly. Extensions on this phone line are located in the critical areas which would be manned during emergencies. These areas are the following:

1) Control Room
2) Shift Supervisor's Office
3) NRC Resident Inspector's Office
4) Remote Shutdwon Panel
5) Technical Support Center
6) Emergency Operations Facility

INSERT 2

The Health Physics Network is intended for use as the dedicated line between the NRC Headquarters and the St Lucie Unit 2 site for health physics data transmission during site emergencies and other significant events. Extensions of this dial-up communcations link are located in the following areas.

1) Health Physics Office
2) Shift Supervisor's Office
3) NRC Resident Inspectors Office
4) Technical support Center
5) Emergency Operations Facility.

9.5.2.3 INSERT 3

The availability of the Emergency Notification System Auto ringdown, Health Physic's Network Dial up communication link and the PBX system is assured by the inherent back-up systems provided by Southern Bell.

radioactive material during normal operations, including anticipated operational occurrences:

a) Provide continuous representative sampling, monitoring, storage of information, indication and if necessary, alarm of liquid and gaseous radioactivity levels.

b) Provide the capability, during the batch release of radioactive liquid and gaseous wastes, to alarm and initiate automatic closure of the appropriate waste discharge valves before Technical Specifications limits are approached or exceeded.

c) Provide radiation level indication and alarm annunciation to the control room operators whenever Technical Specifications limits for release of radioactivity are approached or exceeded.

11.5.1.3 Sampling System

The Sampling System provides grab samples to supplement the continuous Process and Effluent Radiological Monitoring System, and in particular is designed to provide specific information regarding specific radionuclide composition of process and effluent streams and to monitor tritium as required in Regulatory Guide 1.21 (R1). Results of routine laboratory analysis of process samples are used to monitor the operational performance of unit equipment and to provide additional information for making operating decisions.

The basis for selecting sampling locations for liquid and gaseous streams is to permit laboratory analysis for confirmation of readings from the stream monitors, to provide more precise information than may be obtained from the continuous monitors, and to verify effectiveness of processes.

Insert A

11.5.2 SYSTEM DESCRIPTION

11.5.2.1 Process and Effluent Radiological Monitoring

The requirements of the system design bases for continuous monitoring are satisfied by a system of off-line-type monitoring channels for the in-plant liquid and gaseous process lines. The system includes single-stage gaseous monitors, single-stage liquid monitors ~~and~~ three-stage particulate, iodine and noble gas monitors, high range multistage gaseous monitors and externally mounted monitors.

Continuous monitoring means that the monitor operates uninterrupted for extended periods during normal plant operation. The monitor may occasionally be out of service for maintenance, repair, calibration, etc, during which time the frequency of sampling of the particular stream may be increased, depending on the past history of the radioactivity level of the stream.

Off-line radiation detection instrumentation is associated with liquid and gaseous process and effluent streams, in order to monitor radionuclide concentrations in such streams. Radiation measurements can be obtained through measurements of gross beta/gamma activity and/or a select gamma

INSERT A

The post accident effluent release points are provided with filter assemblies to collect samples of suspended radioactive particulates and gaseous iodine. The sampling system design is such that plant personnel could remove samples, replace sampling media, and transport the sample to an onsite analysis facility with radiation exposures less than those of GDC criteria 19.

energy basis dependent upon the isotopic composition of a particular stream. The monitoring system operates in conjunction with regular and special radiation surveys and with radiochemical information for continued operation. Continual indication and recordings of radiation levels for normal operation, for anticipated operational occurrences and for a ~~reasonable~~ range of accident conditions is maintained for each channel associated with the monitoring system. Readout recording, alarm annunciation and alarm set point adjustment are centralized within an area of the control room complex.

Insert B

11.5.2.1.1 Radiation Monitoring System

The Process and Effluent Radiation Monitoring System is a digital computer-based system and consists of various monitor channels located throughout the plant. Each channel is equipped with a detector and its associated electronics, a local control and display unit, a power supply, and a microprocessor per monitor which may consist of more than one channel as in the case of airborne type monitors.

All channel information is processed through a dedicated local microprocessor per monitor and then transmitted to the computer system for the purpose of data logging, processing, editing and displaying of information obtained from the radiation sensors. Those channels identified as safety related are first indicated and recorded on digital ratemeters and strip-chart recorders located in the control room and then transmitted through an isolation device to the computer system. A schematic of the system is shown on Figure 11.5-1. A dual computer and loop configuration allows any component to fail without affecting the remainder of the system.

11.5.2.1.2 Continuous Sampler Assembly

All continuous process and effluent radiation monitors are located in an off-line sampler assembly.

Each sampling assembly consists of a sampler and the associated piping, fittings, and other components as required to transport the sample through the system. All samplers include radiation detection equipment and a check source. The monitor cabinet is a skid mounted system and includes such items as the microprocessor, a sampling pump, valves, interconnecting piping, fittings, flow and pressure indicators.

The sample chamber is sized and shielded in a 4π geometry as required to achieve the specified minimum system sensitivities. Each sampler is constructed of stainless steel and is located as close as practical to the process stream, such that sample line interference or losses are insignificant.

Samplers are designed so that they have flush capability for decontamination purposes where practicable.

Each continuous gaseous and liquid monitor is provided with a solenoid-operated check source that simulates a radioactive sample in the detector sample chamber and may be used for operational and gross

INSERT B

The radiation monitors required to operate during and after an accident are qualified to operate in the accident environment that they experience. Procedures are used to convert the instrument readings to release rates per unit time.

11.5.2.1.3

c) Three-Stage Particulate Iodine and Noble Gas (P-I-G) Monitor

Three-stage particulate, iodine and noble gas monitor consists of three detectors, one each for noble gases, airborne particulates, and iodine (refer to Figure 11.5-4). The gaseous monitor is similar to the SSGM described in b) above.

The particulate monitor is a beta sensitive plastic scintillation radiation detector, coupled to a photomultiplier tube which is protected by an electromagnetic shield. The minimum detectable limit of the monitor for Sr-90 in a 1 mr/hr background at 95 percent confidence level is 10^{-9} $\mu Ci/cm^3$, based on a sample flow rate of 2 scfm and a one-half minute counting time. The response of the detector is at least 3 x $\sqrt{\text{background}}$ above background. The movable filter increases the time to achieve the same count rate. 0

Filters for the particulate monitor are at least 99 percent efficient for particles 0.3 microns and larger. Both fixed and moving filters are utilized on the airborne monitors. Effluent-type monitors use fixed filters (except the ECCS area effluent monitors); inplant-type monitors use moving filters. Both continuous-advance and step-advance capability is provided on those monitors with moving filters mechanisms. Control may be exercised locally or remotely through the RMS computer system.

The iodine monitor is a gamma-sensitive NaI(Tl) crystal, coupled to a photomultiplier tube which is protected by an electromagnetic shield. The minimum detectable limit of the monitor for I-131 in a 1 mr/hr background at a 95 percent confidence level is 10^{-9} $\mu Ci/cm^3$, based on a sample flow rate of 2 scfm and a 3 minute counting time. The response of the detector is at least 3 x $\sqrt{\text{background}}$ above background. The resolution of the detector does not exceed 10 percent FWHM at 0.662 MeV (Cs-137). 0

A fixed filter cartridge assembly is used for the iodine channels. It is easily accessible for replacement. It is at least 85 percent efficient for the collection of iodine.

Insert C →

11.5.2.1.4 Controls and Alarms

All monitors are provided with either a local control and display unit located near the monitor or a portable indicator control box capable of accessing the monitor control features and data base. Either of the two units provide information relating to operational mode, alarm status and data output. Purging, check source actuation, valve and pump control, and various test mode actuations may be done locally and, with the exception of valve control, within the cabinets at the various operator's terminals.

The digital informaton from all channels is stored by the redundant computers and displayed at the three operator consoles on cathode-ray tube (CRT) displays. If an alarm condition is detected, a status change occurs at each of the three CRTs and logging of the alarm occurs

INSERT C

d) Multi-Stage Gaseous Monitor (MSGM)

The multi-stage gaseous monitor consists of three detectors with overlapping ranges. The low range detector is similar to the SSGM described in b) above. The mid range detector uses a solid state detector and has a range overlapping by more than one decade of the low range detector. The high range detector also uses a solid state detector and its range overlaps the mid range detector and extends to $10^5 \mu Ci/cm^3$. (see Figure 11.5-5)

e) Externally Mounted Monitor (EXT)

The Atmospheric steam dump monitor consists of gamma detecting GM tubes viewing the main steam lines and a background subtraction detector (see Figure 11.5-6). The minimum detectable limit for noble gas activity in the main steam in a 5mR/hr background at a 95 percent confidence level is $6 \times 10^{-3} \mu Ci/cm^3$, based on a one minute counting time.

A procedure is developed to correct for the low energy gammas the external monitors would not detect.

based on sample analyses and gaseous activity discharge limits. If the activity exceeds the set point, the discharge valve is automatically closed.

11.5.2.2.7 Condenser Air Ejector Monitor

The condenser air ejector monitor is a single-stage gaseous monitor as described in Subsection 11.5.2.1.3b. The monitor measures noncondensable fission product gases in the condenser air ejector discharge to detect any primary-to-secondary leakage. The presence of radioactivity in this line indicates a primary-to-secondary leak in the steam generators. The predominant isotopes would be Kr-85 and Xe-133, with presence of iodine. The function of this monitor is to alarm in the event of a primary-to-secondary steam generator tube leak.

The monitor is located on the common header downstream of the air ejector after condensers discharge. The alarm setpoint would be set slightly higher than expected plant background.

11.5.2.2.8 Plant Vent Monitor

The safety related plant vent monitors are three stage particulate, iodine and noble gas monitors as described in Subsection 11.5.2.1.3c. The primary purpose of the plant vent monitors is to continuously monitor and record the radioactivity level of plant effluent gases being discharged from the plant vent in order to assure that the plant releases do not exceed Technical Specifications limits. Isokinetic sample nozzles insure that a representative sample is withdrawn from the vent. The alarm setpoint is based on applicable discharge limits. These monitors are seismically qualified and relay information directly to the safety control panel.

11.5.2.2.9 Fuel Handling Buidling (FHB) Stack Monitor

The FHB stack monitor is a three-stage particulate, idoine, and noble gas monitor as described in Subsection 11.5.2.1.3c. The primary purpose of this monitor is to continuously monitor and record the radioactivity level of effluent gases being released via the FHB stack. The alarm set point is set slightly higher than plant background conditions since this release point is not considered a normal release mode. An ioskinetic sample nozzle is provided.

Delete and insert D

11.5.2.2.10 ECCS Area Ventilation System Exhaust Monitors

Two safety related monitors are provided to measure the airborne effluent from the ECCS area. A sample is withdrawn from the ECCS area ventilation exhaust ducts to an off line gas, particulate, and iodine monitor as described in Subsection 11.5.2.1.3c. These monitors measure airborne activity originating from the ECCS area during accident conditions. These monitors are seismically qualified and relay information directly to the safety control panel.

INSERT D

11.5.2.2.10 ECCS Area Ventilation System Exhaust Monitors

Two safety related monitors are provided to measure the airborne effluent from the ECCS area. A sample is withdrawn from the ECCS area ventilation exhaust ducts to an off line monitor. Sample nozzles insure that a representative sample is withdrawn. These monitors consist of the multistage gaseous monitors as described in Subsection 11.5.2.1.3d. The alarm setpoint is based on applicable discharge limits. These monitors are seismically qualified and are indicated and recorded in the safety control panel.

11.5.2.2.11 Plant Vent Accident Range Radiation Monitor

The plant vent accident range radiation monitor is a multistage gaseous monitor as described in Subsection 11.5.2.1.3d. Upstream of the detectors are iodine and particulate prefilters. Sampling nozzles are provided to insure that representative samples are withdrawn for accident analysis. The alarm setpoint is based on applicable discharge limits. These monitors are seismically qualified and are indicated and recorded in the non-safety portion of the auxiliary panel.

11.5.2.2.12 Atmospheric Steam Dump Exhaust Monitor

The atmospheric steam dump monitor is described in Subsection 11.5.2.1.3e. The primary purpose of this monitor is to continuously monitor and record the radioactivity level in the main steam that is discharged to the environment via the atmospheric steam dump valves. The alarm set point is set at the lowest range since this release point is not considered a normal release mode.

all process and effluent radiation monitors and the particulate and iodine filters in the gaseous monitors may be removed for laboratory analysis. The location and other data for the specific sampling points are listed in Table 11.5-2 for primary samples, Table 11.5-3 for secondary samples, and Table 11.5-4 for local and gas analyzer samples.

Sample point locations are based on one or more of the following requirements:

a) to check the performance of process equipment,

b) to alert the operator to any abnormal condition such as leakage, and/or

c) to insure effluent releases are below applicable limits.

To insure representative samples all liquid sample points are taken from vertically run pipe or from the top of horizontal run pipe. The local sample lines are as short as possible to limit the amount of purge water required before a representative sample is obtained. Vent samples are taken from straight duct runs. Liquid tanks are recirculated prior to sampling.

11.5.2.5 Review of Requirements of PERMSS

A review of the monitoring and sampling provisions in the gaseous process and effluent radiological monitoring and sampling system with the systems described in the Standard Review Plan, Section 11.5, Table 9A is tabulated in Table 11.5-5. 3

A review of the monitoring and sampling provisions in the liquid process and effluent radiological monitoring and sampling system with the systems described in the Standard Review Plan, Section 11.5, Table 1B is tabulated in Table 11.5-6.

→ Insert E

11.5.3 EFFLUENT MONITORING AND SAMPLING

For a discussion of implementation of General Design Criterion 64, Subsections 11.5.1 and 11.5.2 contain a detailed description of the means which are provided for monitoring effluent discharge paths for radioactivity that may be released for normal opertions, including anticipated operational occurrences, and from postulated accidents.

11.5.4 PROCESS MONITORING AND SAMPLING

For a discussion of implementation of General Design Criterion 60, Subsections 11.5.1 and 11.5.2 contain a detailed description of the means which are provided for automatic closure of isolation valves in gaseous and liquid effluent paths.

For a discussion of General Design Criterion 63, Subsections 11.5.1 and 11.5.2 contain a detailed description of the means which are provided for monitoring of radiation levels in radioactive waste process systems.

INSERT E

11.5.2.6 Continuous Sampling and Analysis of Plant Effluent

The post accident effluent release points are provided with filter assemblies for collection of suspended particulates and gaseous iodine. The sampler assemblies are easily removable, self supporting in nature and surrounded by a radiation shield to protect the operator. The radiation shield design assumes that 10^{2} μCi/cm^3 of gaseous radio iodine and particulates is deposited on the sampling medium for a 30 minute sampling time with an average gamma energy of 0.5 Mev. This design basis sample will be used to calculate the occupational dose to personnel during sample handling and transport, and analysis of sample. Representative sampling per ANSI N13.1-1969 will be provided at the ECCS exhaust and plant vent stack exhaust. Continuous and grab samples will be provided at these points.

The iodine adsorbing cartridge uses activated charcoal with at least 90% effective adsorption for all forms of gaseous iodine, as its active ingradient. The particulate filter is added upstream of the iodine cartridge inorder to prevent the radioactive particulates from entering the iodine cartridge.

The sampling medium for particulates is at least 90% effective for retention of 0.3 micron diameter particles.

Design of the analytical facilities and preparation of analytical procedures will consider the design basis sample.

TABLE 11.5-1

PROCESS AND EFFLUENT RADIATION MONITORS

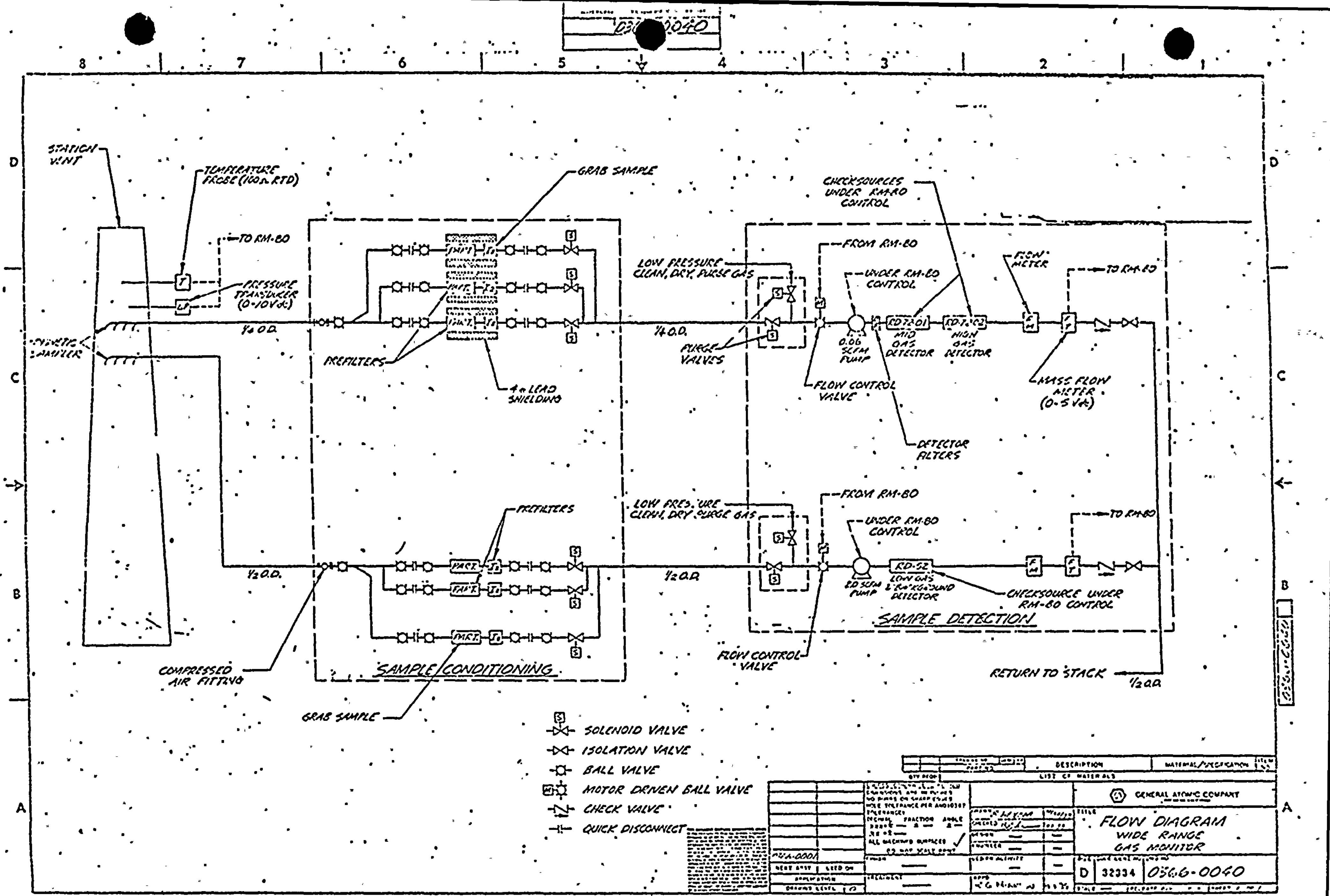
Monitors	Number	Type(1)	Location(2)	Control Function	Power Supply	Range (µci/cc)	Minimum Sensitivity(3)	Typical Alarms & Control Setpoint	At Detector	
										C
a) Component Cooling Water	2	SSL	I-1"-CC-227 I-1"-CC-231	Close surge tk vent	Safety AC bus	10^{-6} to 10^{-1}	$1.3x10^{8}$ cpm/µCi/ccCs137	$1.4x10^{-4}$ µCi/cc	2.5 mr/hr	
b) Chemical and Volume Control Letdown	1	SSL	1"-CH-432	None	Nonsafety AC bus	10^{-6} to 10^{-2}	$1.3x10^{8}$ cpm/µCi/ccCs137	$1x10^{-2}$ µCi/cc	10 mr/hr	
c) Steam Generator Blowdown	2	SSL	1"-B-107	Close blow-down valves I-FCV-23,-3, 5, -7, & -9	NonSafety AC bus	10^{-7} to 10^{-2}	$1.3x10^{8}$ cpm/µCi/ccCs137	$1x10^{-5}$ µCi/cc	1 mr/hr	
d) Liquid Waste Discharge	1	SSL	3"-WM-A29	Close discharge valves FCV-6627 X & Y	NonSafety AC bus	10^{-7} to 10^{-2}	$1.3x10^{8}$ cpm/µCi/ccCs137	$4x10^{-6}$ µCi/cc	2.5 mr/hr	0
e) Gaseous Waste Discharge	1	SSG	2"-WM-D40	Close discharge Valve V6565	NonSafety AC bus	10^{-1} to 10^{4}	$4.3x10^{7}$ cpm/µCi/ccXe133	500 µCi/cc	2.5 mr/hr	1
f) Condenser Air Ejector	1	SSG	1"-AE-47	None	NonSafety AC bus	10^{-7} to 10^{-2}	$4.3x10^{7}$ cpm/µCi/ccXe133	$3x10^{-7}$ µCi/cc	1 mr/hr	
g) Plant Vent	2	P-I-G	-	None	Safety AC bus	10^{-12} to 10^{-7} P 10^{-10} to 10^{-5} I 10^{-7} to 10^{-2} G	$8.6x10^{4}$ cpm/µCi/ccCs137 $1x10^{5}$ cpm/µCi/ccI131 $2.1x10^{7}$ cpm/µCi/ccXe133	$5x10^{-7}$ µCi/cc $5x10^{-7}$ µCi/cc $5x10^{-6}$ µCi/cc	1 mr/hr	
h) Fuel Handling Bldg. Stack	1	P-I-G	-	None	NonSafety AC bus	10^{-10} to 10^{-5} P 10^{-7} to 10^{5} I 10^{-10} to 10^{-2} G	$8.6x10^{4}$ cpm/µCi/ccCs137 $1x10^{5}$ cpm/µCi/ccI131 $2.1x10^{7}$ cpm/µCi/ccXe133	$1x10^{-6}$ µCi/cc $1x10^{-6}$ µCi/cc $1x10^{-5}$ µCi/cc	1 mr/hr	1
i) ECCS Area Ventilation System Exhaust	2	MSG ~~P-I-G~~	-	None	Safety AC bus	10^{-10} 10^{-7} to 10^{-5} P 10^{2} G 10^{-10} to 10^{-5} I 10^{-7} to 10^{-2} G 1.0 10^{2}G 10^{5}	~~$8.6x10^{4}$ cpm/µCi/ccCs137~~ later ~~$1x10^{5}$ cpm/µCi/ccI131~~ ~~$2.1x10^{7}$ cpm/µCi/ccXe133~~	~~$5x10^{-6}$ µCi/cc~~ later ~~$1x10^{-6}$ µCi/cc~~ ~~$1x10^{-5}$ µCi/cc~~	~~1 mr/hr~~ later	
j) Boric Acid and Waste Holdup Condensate Tank	1	SSL	3"-CR-6	None	Nonsafety AC bus	10^{-8} to 10^{-3}	$1.3x10^{8}$ cpm/µCi/ccCs137	$4x10^{-5}$ µCi/cc	2.5 mr/hr	

Notes:

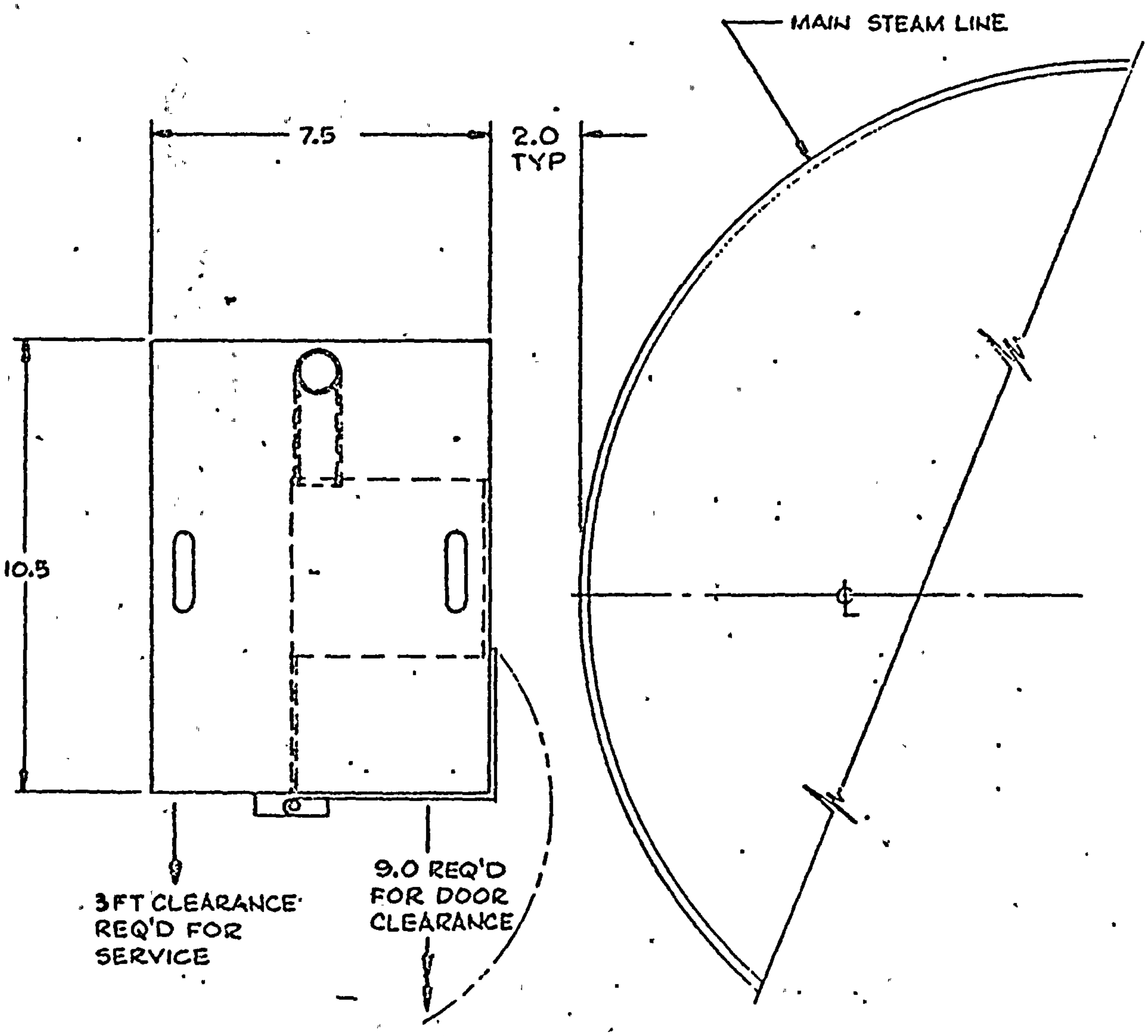
(1) SSL = Single Stage Liquid, SSG = Single Stage Gaseous, P-I-G = Particulate, iodine and noble gas (refer Subsection 11.5.2.1.3)
(2) All monitors are off-line type. Location indicates sample line take-off.
(3) Sensitivity listed is for counting time and background states. In addition, all monitors meet the sensitivities indicated in Subsection 11.5.2.1.3.

TABLE 11.5-1 (Cont'd)

MONITORS	NUMBER	TYPE(1)	LOCATION(2)	CONTROL FUNCTION	POWER SUPPLY	RANGE μCi/cc	MINIMUM SENSITIVITY	TYPICAL ALARMS & CONTROL SETPOINT	At DETECTOR
k) Plant Vent (high Range Noble Gas Monitor)	1	MSG	—	None	Safety AC bus	10^{-7} to 10^{-2} G 10^{-3} to 10^{2} G 1.0 to 10^{5} G	Later	Later	Later
l) Atmospheric Steam Dump Exhaust	3[4]	G-M tube	Main Steam[5] Trestle	None	Non safety with uninterruptable backup	10^{-1} to 10^{3}	Later	Later	Later



Multi Stage Gaseous Monitor
Fig 11.5-5



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

EXTERNALLY MOUNTED
MONITOR
FIGURE 11.5-6

12.3.4.4

in accordance with IEEE-323-1974 and IEEE 344-1975. Refer to Sections 3.10 and 3.11 for further discussion on qualification of Class 1E equipment.

Those monitors whose main function is to measure radiation following a design basis accident meet the recommendations of Regulatory Guide 1.97, "Instrumentation for Light Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following and Accident", December, 1975 (RO). The instruments are seismically qualified Class 1E.

The containment isolation signal (CIAS) monitors consist of four separate gamma-sensitive ion chambers located within the containment at 90 degree intervals along the containment vessel wall. These monitors initiate the CIAS on high radiation. The monitors are fed from four Class IE instrument power supply system buses (MA,MB,MC and MD). 0

Six spent fuel pool monitors are provided around the spent fuel pool to detect radioactivity in the event of a fuel handling accident in the Fuel Handling Building. A high radiation signal isolates the Fuel Handling Ventilation System and diverts the air to the Shield Building Ventilation System.

Delete and insert

Two containment post accident monitors are located outside the containment. These gamma sensitive ion chambers provide long term indication of radiation conditions inside the containment following an accident. 0 F

12.3.4.2 Airborne Radiation Monitoring System

12.3.4.2.1 Design Objectives

The objectives of the Airborne Radiation Monitoring System during normal operating plant conditions and anticipated operational occurrences are:

a) To inform operations personnel of airborne particulate, gaseous and iodine activity in the various buildings and structures of the plant,

b) To alarm any abnormal increases in the airborne activity levels,

c) To furnish records of gross airborne trends in the various plant areas and of the amount of radioactive releases to the environment through the plant buildings or structures during normal, or abnormal operational occurrences,

d) To help detect identified or unidentified leaks inside the reactor coolant pressure boundary (as recommended in Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection System", May, 1973 (RO)) and other areas of the plant,

e) To assist personnel in deciding whether or not breathing apparatus is necessary when entering a high activity area, and

INSERT F

Two high range post accident monitors with a maximum range of 10^7 R/hr (gamma) are located inside the containment. These monitors are widely separated so as to provide reasonable assessment of area radiation conditions inside containment and powered from independant Class 1E power supply. Table 12.3-2 provides a tabulation of the basic design description for these monitors. Figure 12.3-13a shows the location of the radiation monitors inside containment. These monitors are gamma sensitive ionization chambers capable of detecting photons with an energy range of 10 KeV to 3 MeV, with a linear energy response of $\pm$ 20%. The detectors are seismic Category I and qualified to normal operating and post accident environmental conditions inside containment and have a total integrated life of 10^9 Rads. A self testing radiation source with a continuous reading of 1 R/hr is provided within the radiation monitors for checking the operational availability of the monitors. Also there are two additional safety related radiation monitors (gamma sensitive GM detectors) located outside the containment which could be referenced by the plant operators incase the redundant displays of the high range incontainment monitors disagree.

These monitors are designed to seismic Category I and Class 1E requirements and are qualified in accordance with IEEE 279-1971, IEEE 308-1971, IEEE 323-1974 and IEEE 344-1975.

The monitors have a solenoid actuated Cs-137 check source. No local alarm or indication is provided.

12.3.4.2.3.3 ECCS Area Vent Monitors

~~Two seismically qualified monitors are provided to measure the airborne effluent from the ECCS area.~~

~~These monitors are designed to seismic Category I and Class 1E requirements and are qualified in accordance with IEEE 279-1971, IEEE 308-1971, IEEE 323-1974 and IEEE 344-1975.~~

multistage

A sample is withdrawn from the ECCS area emergency vents to an off line gas~~, particulate, and iodine~~ monitor as described in Subsection 11.5.2.1.3~~C~~ D and as shown in Figure 11.5-4. The monitors measure airborne activity and continuously sample particulates and iodine originating from the ECCS area during accident conditions.

12.3.4.2.3.4 Mobile Airborne Monitors

Portable continuous airborne monitors are available for use in potential airborne hazard areas during maintenance operations. These mobile monitors consist of a sampler assembly mounted on a cart. The sampler assembly contains gas, particulate and iodine detectors as described in Subsection 11.5.2.1.3C. The monitor can act in conjunction with the Radiation Monitoring System via plug in junction boxes located throughout the plant, or it can operate independently providing only local indication and alarm.

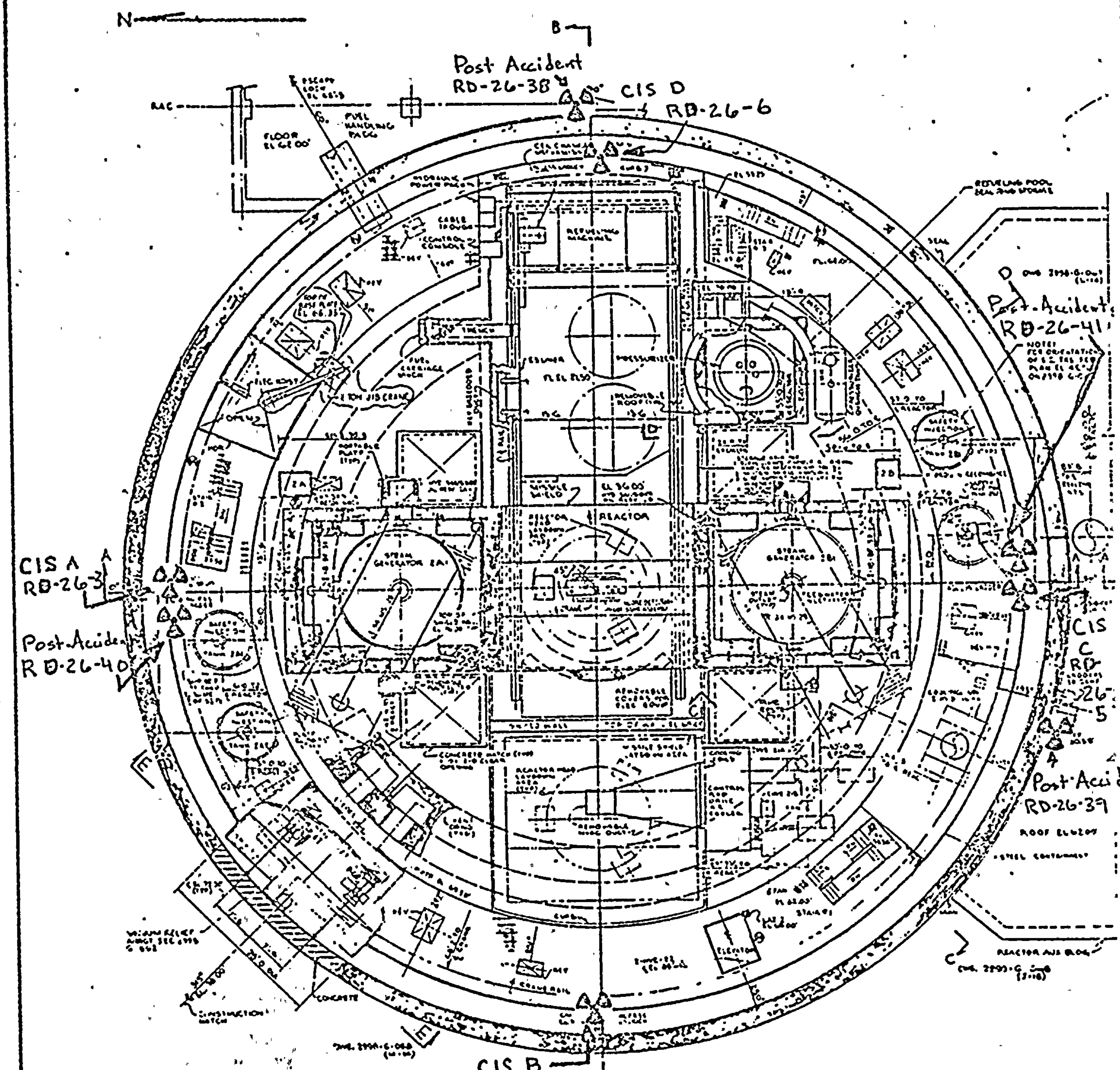
In areas that are occupied on a routine basis, surveys are conducted by patrolling personnel. A comprehensive air sampling program establishes a basis for routine surveys and portable, continuous monitor locations other than maintenance coverage. This program consists of taking grap samples for gaseous, particulate and iodine activity in all areas with a probability of airborne contamination near MPC. The program is implemented a few months prior to initial operations. Based on the data collected from this program, a routine airborne monitoring program is established. The effectiveness of this program is determined by routine data obtained, non-routine samples on an as-needed basis, and a radioassay program. Portable continuous air monitors are displayed in areas where there is personnel occupancy and a high potential for airborne activity near MPC levels.

TABLE 12.3-2 (Cont'd)

Channel	Monitored Area	Safety Classification	Range (mR/hr)	Sensitivity (mR/hr)	Accuracy (%)	Typical Alarm Setpoint (mR/hr)	Monitor Location	Detector Location
24	Ion Exchanger Valve Area A	Non-Safety	$10^{-1}-10^{4}$	1	±3	2.5	RAB el 26'	RAB el 26'
25	Ion Exchanger Valve Area B	Non-Safety	$10^{-1}-10^{4}$	1	±3	5	RAB el 26'	RAB el 26'
26	Purification Filter Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	2.5	RAB el 26'	RAB el 35.5'
27	Spent Resin Tank Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	5	RAB el 26'	RAB el 6.5'
28	ECCS Equipment Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	2.5	RAB el 5'	RAB el 10'
29	Decontamination Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	2.5	RAB el 5'	RAB el 26'
30	HVAC Room	Non-Safety	$10^{-1}-10^{4}$	1	±3	2.5	RAB	RAB el 49'
31	Chemical Drain Pump Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	2.5	RAB el 49'	RAB el 12'
32	Volume Control Tank Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	5	RAB	RAB el 26'
33	Boronometer Enclosure	Non-Safety	$10^{-1}-10^{4}$	1	±3	15	RAB el 26'	RAB el 26'
34	New Fuel Storage Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	15	RAB el 26'	FHB el 53.5'
35	Aerated Waste Storage Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	5	RAB el 5'	RAB el 5'
36	Boric Acid Concentrator Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	5	RAB el 26'	RAB el 26'
37	Fuel Pool Filter Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	5	FHB el 26'	FHB el 26'
38	Operating Deck Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	5	Containment el 39'	Containment el 85'
39	Drumming Station Area	Non-Safety	$10^{-1}-10^{4}$	1	±3	2.5	RAB el 26'	RAB el 25
40	Containment High Range	1E	$1.0-10^{7}$ (1)	later	later	later	later	later
41	"	"	"	"	"	"	"	"

Notes

(1) Gamma sensitive detector. Measurement is in Rad/hr



OPERATING FLOOR PLAN EL. 62.00'

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LOCATION OF CIS AND POST ACCIDENT RADIATION MONITO

FIGURE 12.3-13A

12.3A TMI SHIELDING STUDY

12.3A.1 Introduction

Following the requirement of NUREG 0737 item II.B.2 "Plant Shielding", a design review of the St Lucie Unit 2 plant shielding was performed. This assures safe personnel access to the vital equipment or areas required for mitigation or monitoring of an accident. Equipment qualification to radiation doses resulting from an accident is addressed in Section 3.11.

In compliance with Item II.B.2 of NUREG 0737, radiation source terms are specified, systems assumed to contain high levels of radioactivity as a result of a postulated accident are listed, vital areas requiring access are identified, and dose rates and doses in vital areas are presented. Dose rate zone maps were created to show dose rate images throughout the Reactor Auxiliary Building (RAB) at 1,10,100 and 1000 hours following an accident; they are included as Figure 12.3A-1 to 12.3A-4.

12.3A.2 Source Terms

The source terms used in determining dose rates and doses presented in Section 12.3A are consistent with the specifications of NUREG 0737. All source terms are based on the core inventory of nuclides derived for St Lucie Unit No. 2 from Table 4.3-1 of the Combustion Engineering System 80 Radiation Design Guide.[1] The St Lucie core inventory, separated for convenience into noble gases, halogens, and other nuclides, is shown in Table 12.3A-1.

Four general sets of multigroup source terms, suitable for input to shielding codes, were created from the core inventory data; two for liquid sources, one for gaseous sources, and one for plateout. The GROUP[2] code was used to transform the isotopic sources into multigroup, energy-dependent gamma sources as functions of time after release from the core.

The two sets of source terms for liquid systems are based on the assumptions of instantaneous release into the reactor coolant of the following percentage of the core inventory:

100% of the noble gases
50% of the halogens
1% of the other nuclides

Multigroup source terms calculated under these assumptions for various times after an accident (considering radioactive decay) are presented in Table 12.3A-2. The unit of the source terms is γ/sec, which can be converted to a specific source term unit of $\gamma/(cm^3\text{-sec})$ by dividing by the reactor coolant volume of 2.05×10^8 cm^3 (from Table 11.1-1). The resulting set of gamma ray source terms was used in dose rate calculations for systems postulated to contain "undiluted" reactor coolant water such as the primary sampling system, which would be required to function in the event of a "small break" LOCA, where the reactor coolant would experience little dilution by nonradioactive water.

Other systems such as the Containment Spray and Safety Injection Systems, would contain radioactive water only after exhausting the supply of nonradioactive water contained in the Refueling Water Tank, and then being switched to the recirculation mode. In that mode, commencing no sooner than twenty minutes after the start of a "large break" LOCA, these systems would draw water from the containment sump located in the Reactor Building. Source terms for recirculated (containment sump) water were created by first eliminating the noble gases from the water, in accordance with the guidelines of NUREG 0737 for recirculated, depressurized water, and then diluting the remaining 50% of the core inventory of halogens and 1% of the other nuclides by the combined volumes of the reactor coolant, the Safety Injection Tanks, and the minimum volume of the Refueling Water Tank; the total water volume being approximately 1.62×10^9 cm^3. The resulting source terms are listed in Table 12.3A-3.

The gaseous source terms were created using the NUREG 0737 assumption of instantaneous release to the containment atmosphere of the following percentages of the core inventory:

100% of the noble gases
25% of the halogens.

Time dependent source terms, shown in Table 12.3A-4, resulted from application of appropriate radioactive decay factors, leakage factors, and containment spray removal factors. These source terms were used primarily to obtain dose rates to personnel outside, but in the vicinity of, the containment, and dose rates to personnel in the vicinity of the Hydrogen Analyzers.

The final, general set of source terms was created to model the effect of plateout in the Containment. Accordingly, an instantaneous plateout of 25% of the core inventory of iodine was assumed. Time dependent source terms appear in Table 12.3A-5. These source terms were used in determining dose rates to personnel outside the containment.

Several specialized sets of source terms were also created for applications such as determining dose rates from the charcoal adsorbers of the Shield Building Ventilation System, and of the Control Room Emergency Filters.

12.3A.3 Radioactive Systems

The systems identified as potentially containing high levels of radioactivity in a post accident situation and which were considered in the shielding design review undertaken to assure access to vital areas, are listed in Table 12.3A-6. All other systems, such as the Chemical and Volume Control System, and the Waste Management System are not necessary for post-LOCA operation. Degassing of the Reactor Coolant System will be done using the Reactor Head Vent System (see Appendix 1.9A item II.B.1) rather than the letdown portion of the Chemical and Volume Control System, and the Waste Management System will be isolated and, therefore, not employed since radioactive leakages and drains will be routed back into the Containment via the ESF Leakage Collection and Return System (see Subsection 9.3.5).

12.3A.4 Vital Areas Requiring Occupancy/Access

An extensive review was undertaken to identify vital areas of the plant to which personnel access following an accident must be assured. A list of these areas (with accompanying occupancy, dose rate, and dose information) appears as Table 12.3A-7. Access routes from the Control Room to the vital areas have been noted in Figure 12.3A-5 to 13.3A-7. No access outside the control room is required for containment isolation reset and instrument panels. The diesel generators are located outside the RAB in a separate building with necessary control and indication provided in the control room. No access is required to the motor control centers and the Waste Management System post accident. As indicated in Table 12.3A-7 in cases where the review revealed that high dose rates or accumulated doses would preclude access, means for remote operation, additional shielding or plant modifications were provided.

The result of the review process was to assure that access to vital areas could be accomplished consistent with NUREG 0737 requirements of: (1) less than 15 mrem/hr (averaged over 30 days) for areas requiring continuous occupancy, and GDC-19 requirements of less than 5 rem for the duration of the accident for areas requiring irregular occupancy.

12.3A.5 Dose Rate and Dose Calculations

Dose rate calculations were performed in areas identified as vital areas, and along potential access routes. Time-dependent sources were determined as stated in Subsection 12.3A.2, and appropriate geometry factors were applied to pipe and equipment of the systems identified in Subsection 12.3A.3. The shielding effect of the equipment, fluid, and shield wall arrangement were considered. The effect of rebar, embedded plates, or any structural steel was neglected, which, when combined with the very conservative, "worst case" source terms, resulted in very conservative calculated dose rates.

Dose rates were calculated primarily by the ISOSHLD[3]* point-kernel integration code. Radiation dose maps were prepared from the dose rate data, and show dose rate ranges throughout the RAB at 1,10,100 and 1000 hours following a postulated accident. These maps, superimposed on general arrangement drawings are included as Figure 12.3A-1 to 12.3A-4.

Note: * An Ebasco version of the Code DEV/ISOSHLD was actually used.

REFERENCES: APPENDIX 12.3A

(1) Combustion Engineering, Radiation Design Guide, Rev. 4, SYS80-PE-PG (7/12/79).

(2) E. Ochoa, O. Vories, "GROUP - An Isotopic Source Generation Program". An Ebasco Code (7/10/77).

(3) R.L. Engel, et al, "ISOSHLD - A Computer Code for General Purpose Isotope Shielding Analysis", BNWL-236 (1966). An Ebasco version of the code, DEV/ISOSHLD was actually used.

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SUBJECT Table 12.3A-1: Core Inventory

Noble Gases

Nuclide	Ci	Nuclide	Ci	Nuclide	Ci	Nuclide	Ci
Kr-85m	1.90+7[a]	Kr-89	6.09+7	Xe-133	1.52+8	Xe-138	1.21+8
Kr-85	6.02+5	Kr-90	6.02+7	Xe-135m	3.07+7	Xe-140	6.22+7
Kr-87	3.48+7	Kr-91	4.44+7	Xe-135	2.73+7	Xe-143	1.48+6
Kr-88	4.97+7	Xe-131m	5.30+5	Xe-137	1.34+8	Xe-144	3.31+5

Halogens

Nuclide	Ci	Nuclide	Ci	Nuclide	Ci	Nuclide	Ci
Br-84	1.46+7	Br-89	2.19+7	I-131	7.57+7	I-135	1.41+8
Br-85	1.87+7	Br-90	1.38+7	I-132	1.10+8	I-137	6.33+7
Br-87	3.01+7	I-127	1.19+25[b]	I-133	1.52+8	I-138	3.18+7
Br-88	3.18+7	I-129	1.89+0	I-134	1.64+8		

Other Nuclides

Nuclide	Ci	Nuclide	Ci	Nuclide	Ci	Nuclide	Ci
Se-84	1.39+7	Nb-95	1.28+8	Te-131m	1.14+7	Cs-137	6.56+6
As-85	2.42+6	Zr-99	1.25+8	Te-131	6.56+7	Ba-137m	6.22+6
Se-85	8.61+6	Nb-99	1.31+8	Sn-132	1.29+7	Cs-138	1.29+8
Se-87	1.38+7	Mo-99	1.38+8	Sb-132	3.63+7	Cs-140	1.17+8
Rb-88	5.05+7	Tc-99m	1.19+8	Te-132	1.08+8	Ba-140	1.32+8
Sr-89	7.01+7	Mo-103	1.21+8	Sn-133	4.49+6	La-140	1.36+8
Rb-90	6.19+7	Tc-103	1.23+8	Sb-133	4.07+7	Cs-143	2.52+7
Sr-90	4.89+6	Ru-103	1.24+8	Te-133m	5.45+7	Ba-143	1.00+8
Y-90	5.13+6	Tc-106	5.11+7	Te-133	8.68+7	La-143	1.13+8
Rb-91	7.97+7	Ru-106	3.50+7	Cs-134	1.43+7	Ce-143	1.14+8
Sr-91	8.61+7	Sn-129	8.04+6	Sb-134	7.26+6	Pr-143	1.12+8
Y-91m	4.96+7	Sb-129	2.50+7	Te-134	1.15+8	Cs-144	7.71+6
Y-91	9.13+7	Te-129m	6.49+6	Sb-135	4.55+6	Ba-144	7.46+7
Sr-95	9.19+7	Te-129	2.37+7	Te-135	5.99+7	La-144	9.84+7
Y-95	1.21+8	Sn-131	2.22+7	Cs-135	1.90+1	Ce-144	9.00+7
Zr-95	1.27+8	Sb-131	6.11+7	Cs-136	4.00+6	Pr-144	9.06+7

(a) Read as 1.90×10^7 curies.

(b) I-127 is stable. Number given is total atoms

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SUBJECT Table 12.3A-2: Undiluted Reactor Coolant Source Terms

Grp.	Effective Energy, MeV	Multigroup Gamma Source Terms, γ/sec, at t = ... After Accident[(a)]											
		0	30 min	1 hr	2 hr	10 hr	1 day	100 hr	7 day	30 day	1000 hr	6 months	1 year
1	.150	9.31+18[(c)]	5.58+18	5.41+18	5.26+18	4.73+18	4.27+18	2.81+18	1.94+18	1.07+17	3.05+16	4.92+15	3.19+15
2	.250	4.84+18	2.24+18	1.79+18	1.48+18	6.39+17	2.72+17	7.62+16	5.42+16	6.41+15	2.38+15	2.25+13	3.26+[illegible]
3	.350	2.41+18	1.94+18	1.70+18	1.44+18	1.15+18	1.07+18	8.06+17	6.28+17	8.66+16	3.18+16	4.23+12	1.60+[illegible]
4	.475	1.01+19	4.46+18	3.79+18	3.33+18	2.20+18	1.31+18	1.51+17	5.88+16	2.74+16	2.14+16	1.74+15	1.59+[illegible]
5	.650	6.14+18	2.74+18	2.20+18	1.49+18	2.63+17	1.54+17	1.16+17	9.59+16	3.49+16	2.72+16	1.12+16	7.55+15
6	.825	9.67+18	5.96+18	4.44+18	2.61+18	3.86+17	2.06+17	8.67+15	7.30+16	5.00+16	4.23+16	9.31+15	4.23+15
7	1.000	1.84+18	9.86+17	8.88+17	7.43+17	2.57+17	6.72+16	2.48+15	6.11+14	6.90+13	6.57+13	4.97+13	4.15+13
8	1.225	4.52+18	2.17+18	1.86+18	1.45+18	5.92+17	1.93+17	8.55+15	1.97+15	4.68+14	3.19+14	9.67+13	7.31+13
9	1.475	2.83+18	4.96+17	4.30+17	3.34+17	7.28+16	2.63+16	2.19+15	3.92+14	1.79+14	1.77+14	1.56+14	1.34+[illegible]
10	1.700	2.33+18	1.40+18	1.08+18	8.13+17	3.20+17	9.59+16	8.63+15	2.67+15	1.96+11	1.57+9	0	0
11	1.900	1.95+17	7.34+16	5.28+16	3.26+15	2.70+15	1.47+14	1.93+13	4.00+12	1.16+7	1.79+4	0	0
12	2.100	9.26+17	3.47+17	1.95+17	1.21+17	1.50+16	4.63+14	3.09+6	0	0	0	0	0
13	2.300	1.19+18	9.30+17	8.20+17	6.39+17	8.79+16	2.74+15	1.83+7	0	0	0	0	0
14	2.500	6.32+17	2.26+17	1.84+17	1.28+17	2.95+16	7.38+15	3.07+14	9.44+13	6.94+9	5.55+7	0	0
15	2.700	1.91+16	2.42+15	1.23+15	3.29+14	1.05+10	1.45+2	0	0	0	0	0	0
16	3.000	7.27+17	9.33+14	1.54+12	9.26+6	0	0	0	0	0	0	0	0
17	3.500	1.46+17	6.74+14	8.91+13	1.57+12	0	0	0	0	0	0	0	0
18	4.000	7.11+17	1.83+16	9.50+15	2.58+15	7.40+10	8.40+2	0	0	0	0	0	0
19	5.000	1.77+17	2.62+7	0	0	0	0	0	0	0	0	0	0

(a) 100% core noble gases, 50% halogens, 1% other nuclides

(b) To obtain specific source terms ($\gamma/(cm^3\text{-}sec)$), divide by reactor coolant volume of $2.05\times10^8\ cm^3$

(c) Read as 9.31×10^{18} γ/sec

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SUBJECT Table 12.3A-3(a): Recirculated (Containment Sump) Water Source Term:

Grp.	Effective Energy, MeV	Multigroup Gamma Source Terms, γ/(cm³-sec) at t = ... After Accident											
		0 (b)	30 min (c)	1 hr	2 hr	10 hr	1 day	100 hr	7 day	30 day	100 [illegible]	6 mon	1 y[illegible]
1	.150	0	9.25+7	8.68+7	8.01+7	6.26+7	5.04+7	3.11+7	2.40+7	7.79+6	5.89+6	3.04+6	1.97+[illegible]
2	.250	0	9.36+7	9.06+7	8.70+7	8.05+7	7.32+7	4.67+7	3.35+7	3.96+6	1.47+6	1.39+4	2.01+[illegible]
3	.350	0	1.14+9	1.00+9	8.44+8	6.96+8	6.59+8	4.98+8	3.88+8	5.34+7	1.96+7	2.61+3	9.88+[illegible]
4	.475	0	2.03+9	1.98+9	1.89+9	1.36+9	8.11+8	9.29+7	3.62+7	1.69+7	1.31+7	1.02+6	4.14+[illegible]
5	.650	0	1.66+9	1.33+9	9.03+8	1.55+8	9.27+7	7.15+7	5.92+7	2.15+7	1.68+7	6.9'+6	4.66+[illegible]
6	.825	0	3.46+9	2.56+9	1.48+9	2.23+8	1.27+8	5.35+7	4.51+7	3.09+7	2.61+7	5.75+6	2.61+[illegible]
7	1.000	0	5.08+8	5.48+8	4.59+8	1.59+8	4.15+7	1.53+6	3.77+5	4.26+4	4.06+4	3.07+4	2.56+4
8	1.225	0	1.34+9	1.15+9	8.98+8	3.66+8	1.19+8	5.28+6	1.22+6	2.89+5	1.97+5	5.97+4	4.51+[illegible]
9	1.475	0	1.65+8	1.42+8	1.09+8	3.16+7	1.58+7	1.35+6	2.42+5	1.10+5	1.09+5	9.63+4	8.09+4
10	1.700	0	7.24+8	6.25+8	4.95+8	1.97+8	5.92+7	5.33+6	1.65+6	1.21+2	0	0	0
11	1.900	0	4.52+7	3.26+7	2.01+7	1.67+6	9.08+4	1.19+4	2.47+3	0	0	0	0
12	2.100	0	0	0	0	0	0	0	0	0	0	0	0
13	2.300	0	3.43+6	1.55+6	4.02+5	1.30+1	0	0	0	0	0	0	0
14	2.500	0	5.38+7	4.83+7	4.11+7	1.77+7	4.56+6	1.90+5	5.83+4	4.28+0	0	0	0
15	2.700	0	1.49+6	7.59+5	2.03+5	6.48+0	0	0	0	0	0	0	0
16	3.000	0	0	0	0	0	0	0	0	0	0	0	0
17	3.500	0	4.16+5	5.50+4	9.69+2	0	0	0	0	0	0	0	0
18	4.000	0	1.13+7	5.86+6	1.59+6	4.57+1	0	0	0	0	0	0	0

(a) 50% core halogens, 1% other nuclides diluted in 1.62×10^9 cm³ water

(b) Recirculation does not begin before 20 minutes following accident

(c) Read as 9.25×10^7 γ/(cm³-sec)

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SUBJECT Table 12.3A-4: Containment Atmospheric Source Terms

Grp.	Eff. En., MeV	Multigroup Gamma Source Terms, γ/sec, at t=... After Accident (a),(b)								
		0	2 min	46 min	1 hr	2 hr	8 hr	1 day	4 days	30..!
1	.150	6.44+18 (c)	6.37+18	5.64+18	5.57+18	5.38+18	4.82+18	4.20+18	2.79+18	8.71+15
2	.250	8.35+18	8.15+18	6.00+18	5.75+18	5.06+18	2.84+18	7.94+17	8.88+15	2.43+14
3	.350	1.21+18	1.19+18	2.20+17	2.08+17	1.76+17	9.43+16	4.89+16	3.38+16	3.38+15
4	.475	5.81+18	5.53+18	1.35+18	1.08+18	6.01+17	1.37+17	6.23+16	5.35+15	1.12+14
5	.650	1.77+18	1.75+18	2.80+17	2.63+17	2.24+17	1.48+17	8.82+16	3.68+16	4.65+14
6	.825	4.55+18	4.46+18	7.71+17	6.99+17	4.99+17	1.45+17	6.38+16	3.05+16	1.12+14
7	1.000	4.83+17	4.82+17	4.53+16	4.32+16	4.05+16	2.88+16	1.63+16	7.07+15	2.62+13
8	1.225	1.35+18	1.33+18	1.01+17	9.08+16	7.06+16	3.42+16	9.39+15	3.92+14	3.89+5
9	1.475	5.46+17	5.43+17	3.59+17	3.39+17	2.66+17	6.73+16	9.82+15	4.09+15	1.49+13
10	1.700	1.73+18	1.63+18	1.89+17	1.27+17	5.45+16	1.74+16	3.20+15	1.92+12	0
11	1.900	2.33+16	2.33+16	2.29+15	2.20+15	2.18+15	2.07+15	1.79+15	9.40+14	3.51+12
12	2.100	1.14+18	1.06+18	3.61+17	3.00+17	1.96+17	3.95+16	7.11+14	1.05+7	0
13	2.300	1.71+18	1.69+18	1.41+18	1.33+18	1.03+18	2.29+17	4.21+15	6.23+7	0
14	2.500	3.41+17	3.36+17	2.04+17	1.80+17	1.07+17	5.89+15	3.15+14	1.89+11	0

(a) 100% core noble gases, 25% halogens

(b) To obtain specific source terms, (γ/(cm³-sec)), divide by Containment free volume of 7.10×10^{10} cm³ (2.506×10^{6} ft³).

(c) Read as: 6.44×10^{18} γ/sec.

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SUBJECT Table 12.3A-5: Containment Plateout Source Terms

Grp.	Eff. En. MeV	Multigroup Gamma Source Terms, γ/sec, at t=... After Accident (a) 0	2 min	46 min	1 hr	2 hr	8 hr	1 day	4 days	30 days
1	.150	1.54+16 (b)	1.54+16	1.54+16	1.53+16	1.53+16	1.49+16	1.41+16	1.09+16	1.17+15
2	.250	3.62+16	3.62+16	3.62+16	3.60+16	3.60+16	3.51+16	3.32+16	2.58+16	2.75+15
3	.350	1.05+18	1.03+18	8.00+17	7.48+17	6.13+17	4.91+17	4.62+17	3.59+17	3.83+1[illegible]
4	.475	1.65+18	1.65+18	1.59+18	1.57+18	1.50+18	1.05+18	6.28+17	5.57+16	5.91+[illegible]
5	.650	1.59+18	1.57+18	1.26+18	1.19+18	1.01+18	8.17+17	7.14+17	3.90+17	5.2[illegible]
6	.825	3.88+18	3.80+18	2.50+18	2.23+18	1.47+18	7.94+17	6.60+17	3.25+17	1.27+15
7	1.000	4.83+17	4.82+17	4.59+17	4.52+17	4.26+17	1.97+17	1.72+17	7.53+16	2.96+14
8	1.225	1.35+18	1.33+18	1.02+18	9.50+17	7.39+17	1.31+17	9.89+16	4.18+15	4.40+[illegible]
9	1.475	1.27+17	1.27+17	1.25+17	1.25+17	1.24+17	1.13+17	9.26+16	4.35+16	1.68+14
10	1.700	6.96+17	6.87+17	5.30+17	4.95+17	3.86+17	3.43+16	3.37+16	2.07+13	0
11	1.900	2.33+16	2.33+16	2.31+16	2.31+16	2.31+16	2.16+16	1.89+16	1.00+16	3.97+13
12	2.100	0	0	0	0	0	0	0	0	0
13	2.300	0	0	0	0	0	0	0	0	0
14	2.500	3.92+16	3.91+16	3.62+16	3.53+16	3.19+16	3.31+15	3.31+15	2.03+12	0

(a) 25% core iodine
(b) Read as 1.54×10^{16} γ/sec

Table 12.3A-6: Systems Potentially Containing High Levels of Radioactive Material

Containment Spray System

Safety Injection System
- Low Pressure Safety Injection
- High Pressure Safety Injection

Shutdown Cooling System

Post Accident Sampling Systems
- Liquid Sampling
- Hydrogen Analyzer

Ventilation Systems
- Shield Building Ventilation System
- Control Room Emergency Ventilation System
- ECCS Area Ventilation System

Containment Building

Table 12.3A-7: Areas Identified in Shielding Review as Requiring Accessibility Following an Accident

Area	Location	Occupancy Requirements	Maximum Dose Rate and Dose	Remarks
(1) Control Room	RAB EL 62.00' Figure 12.3A-4. NW Corner.	Continuous	< 15 mrem/hr 1 hr after accident < 5 rem for duration of accident	Door shown in wall between Control Room Emergency Filter Room (containing 2HVE-13A,B) and Control Room kitchen is relocated to The East end of wall.
(2) Technical Support Center	Unit No. 1 Control Room Envelope	Continuous	< 15 mrem/hr. 1 hr after accident < 5 rem for duration of accident	Units 1 and 2 share The TSC
(3) Valve Station: LPSI Pump Suction Isolation Valves. V-3432, V-3444	RAB EL -0.50'. Figure 12.3A-1. ECCS Room.	2 men for 10 minutes	> 6,000 rem/hr 1 hr after accident ~ 1,000 rem per person	Manual valves are fitted with motor operators operated from the Control Room. Therefore, access will no longer be required
(4) Valve Station: Containment Spray Discharge Header Isolation Valves. I-V07161, I-V07164	RAB EL 19.50' Figure 12.3A-2. Penetration Area	2 men for 10 minutes	> 5,000 rem/hr 1 hr after accident ~ 840 rem per person	Same as Item (3)

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CHKD. BY ______ DATE ______

CLIENT ______

PROJECT ______

SUBJECT ______

OFS NO. ______

DEPT. NO. ______

Table 12.3A-7: Continued

Area	Location	Occupancy Requirements	Maximum Dose Rate and Dose	Remarks
(5) Hydrogen Analyzer Cubicle	RAB EL 43.00'. Figure 12.3A-3. SE part of HVAC Room.	Infrequent Access up to 6 hrs at a time for maintenance to one analyzer. Also, short (few minutes) access to obtain grab sample.	~ 220 mrem/hr 1 hr after accident ~ 1.3 rem per maintenance period	Special shielding is designed to accomodate the Hydrogen Analyzers so that required access can be maintained. Refer Subsection 6.2.5 for a description of Hydrogen Analyzers.
(6) Post Accident Sampling System (PASS)	RAB EL 19.50'. Figure 12.3A-2. South wall of RAB.	Infrequent Access to collect grab sample.	< 100 mrem/hr 1 hr after accident ≤ 100 mrem per visit	Refer Subsection 9.3.6 for description of PASS.
(7) Sample Analysis Areas (Health Physics Area)	RAB EL 19.50'. Figure 12.3A-2. NW part of RAB	Frequent.	< 100 rem/hr 1 hr after accident > 5 rem for duration of accident	High dose rate precludes use of Health Physics area. Therefore, all sample analysis and health physics monitoring will be done from a trailer located outside the RAB

FPL to verify

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EBASCO SERVICES INCORPORATED
NEW YORK

BY ____ DATE ____
CHKD. BY ____ DATE ____
CLIENT ____
PROJECT ____
SUBJECT ____
OFS NO. ____
SHEET 17 OF ____
DEPT. NO. ____

Table 12.3A-7: Continued

Area	Location	Occupancy Requirements	Maximum Dose Rate and Dose	Remarks
(8) ECCS Vent Monitors	RAB EL 43.00'. Figure 12.3A-3. East side of RAB.	Infrequent access to collect particulate filters for analysis	< 100 mrem/hr 1 hr after accident < 100 mrem per visit	Special shielding is designed to accommodate the ECCS Vent Monitors so that required access can be maintained. See Section 11.5 for a description of the monitors.

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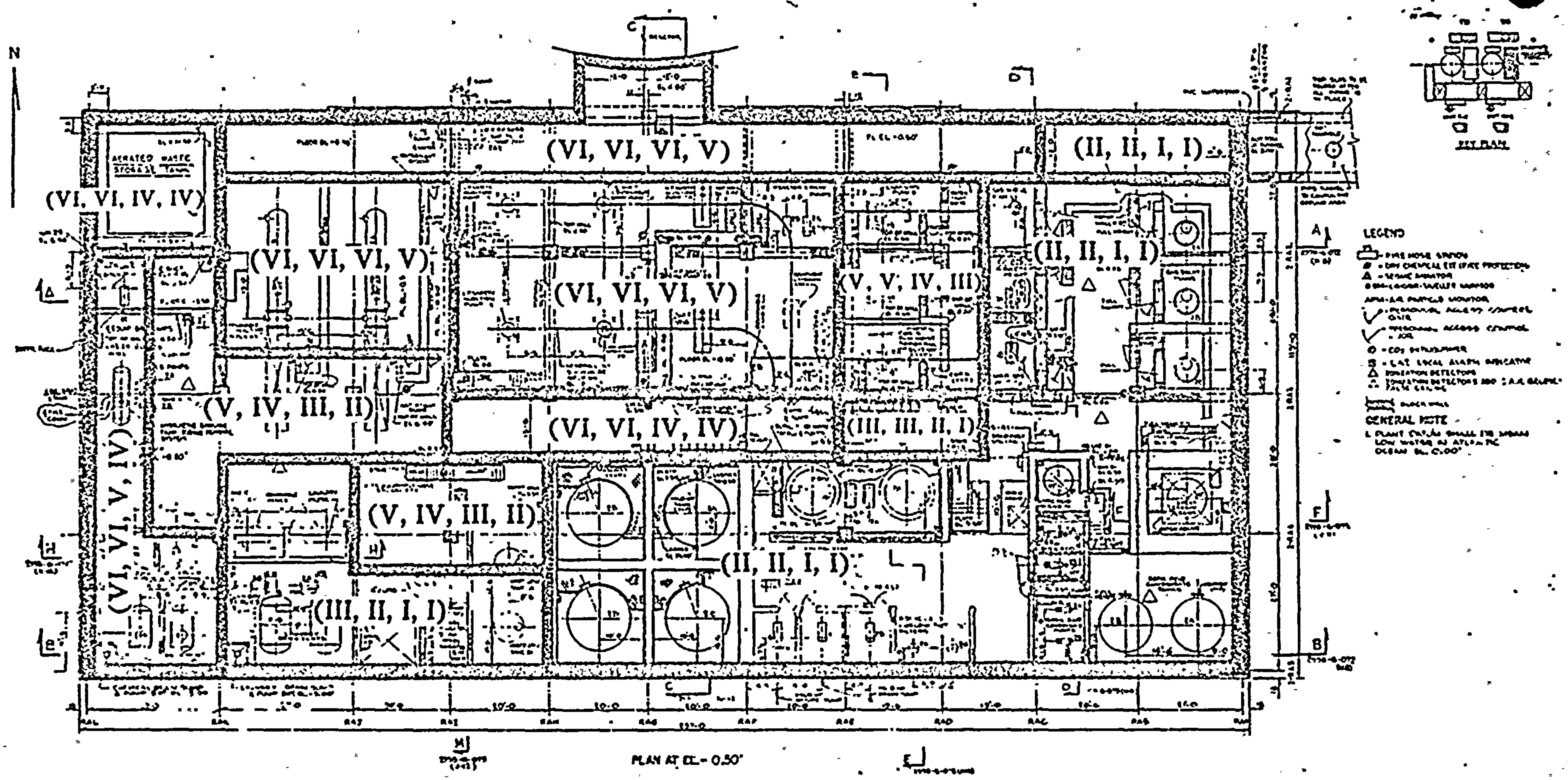
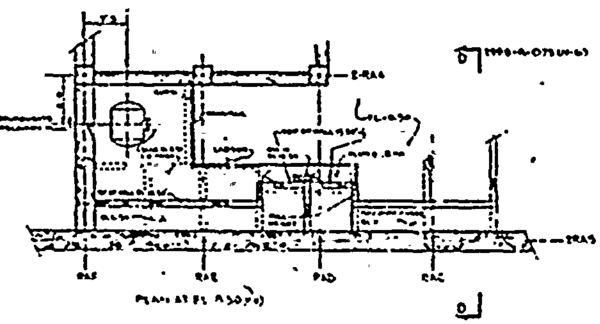
BY ____ DATE ____
CHKD. BY ____ DATE ____
CLIENT ____
PROJECT ____
SUBJECT ____

EBASCO SERVICES INCORPORATED
NEW YORK

OFS NO. ____
SHEET 18 OF ____
DEPT. NO. ____





LEGEND:

ZONAL DOSE RATE CLASSIFICATION

ZONE	UPPER LIMIT DOSE RATE (MR/HR)
I	<15 MR/HR
II	15-100 MR/HR
III	100-1000 MR/HR
IV	1-10 R/HR
V	10-100 R/HR
VI	>100 R/HR

a. ROMAN NUMERALS IN PARENTHESIS CORRESPOND TO DOSE RATES AT VARIOUS TIMES AFTER THE ACCIDENT . . .

(X, X, X, X)

AFTER 1 HR
AFTER 10 HR
AFTER 100 HR
AFTER 1000 HR

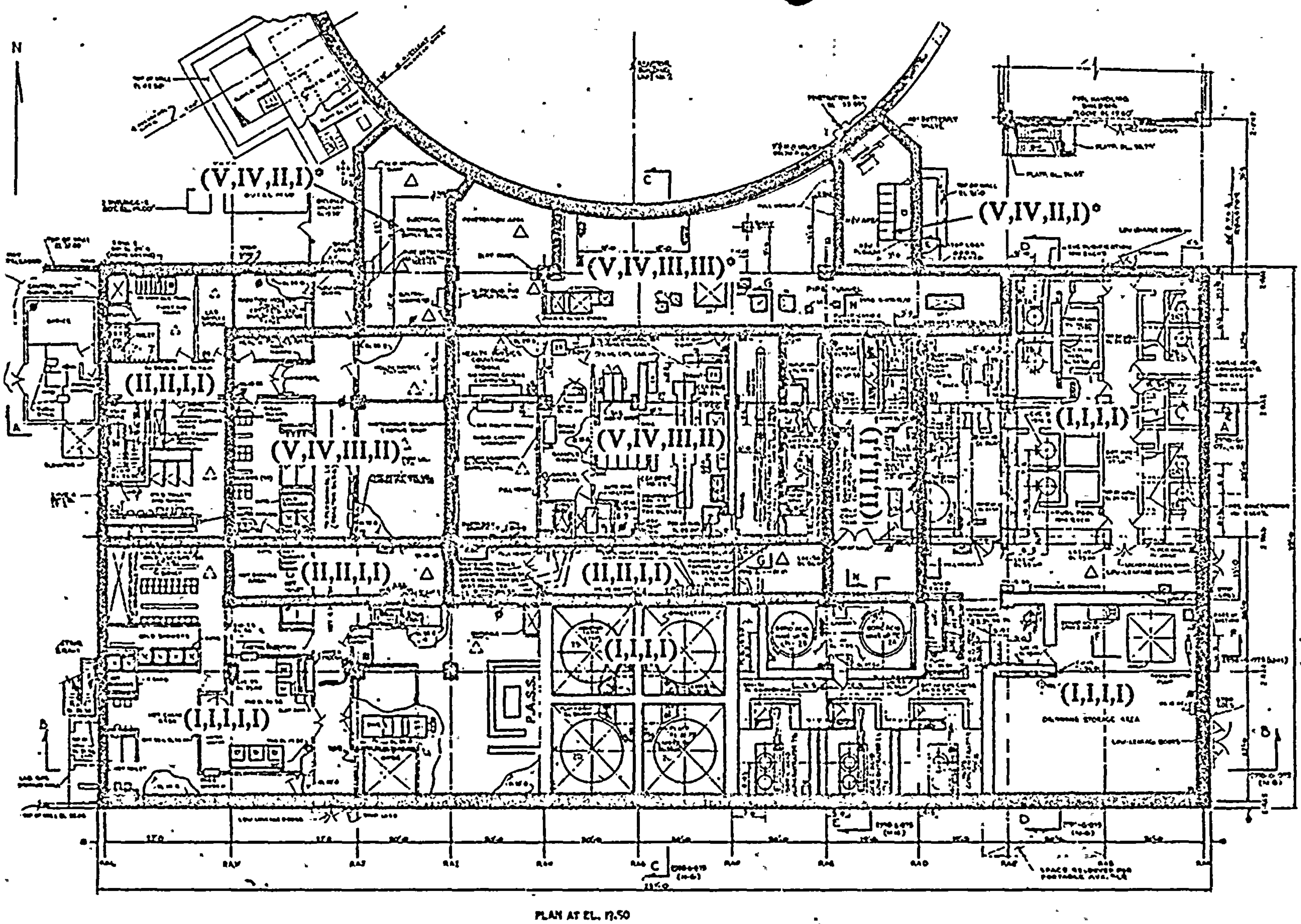
NOTES:

DOSE RATES FROM NON-TMI SOURCES NOT INCLUDED

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

TMI RADIATION ZONE MAP

FIGURE 12.3A-1



LEGEND:

ZONAL DOSE RATE CLASSIFICATION

ZONE	UPPER LIMIT DOSE RATE (MR/HR)
I	< 15 MR/HR
II	15-100 MR/HR
III	100-1000 MR/HR
IV	1-10 R/HR
V	10-100 R/HR
VI	>100 R/HR

a. ROMAN NUMERALS IN PARENTHESIS CORRESPOND TO DOSE RATES AT VARIOUS TIMES AFTER THE ACCIDENT...

(X, X, X, X)

AFTER 1 HR
AFTER 10 HR
AFTER 100 HR
AFTER 1000 HR

°DOSE RATES HIGHER IN VICINITY OF PENETRATIONS AND OF RADIOACTIVE PIPES.

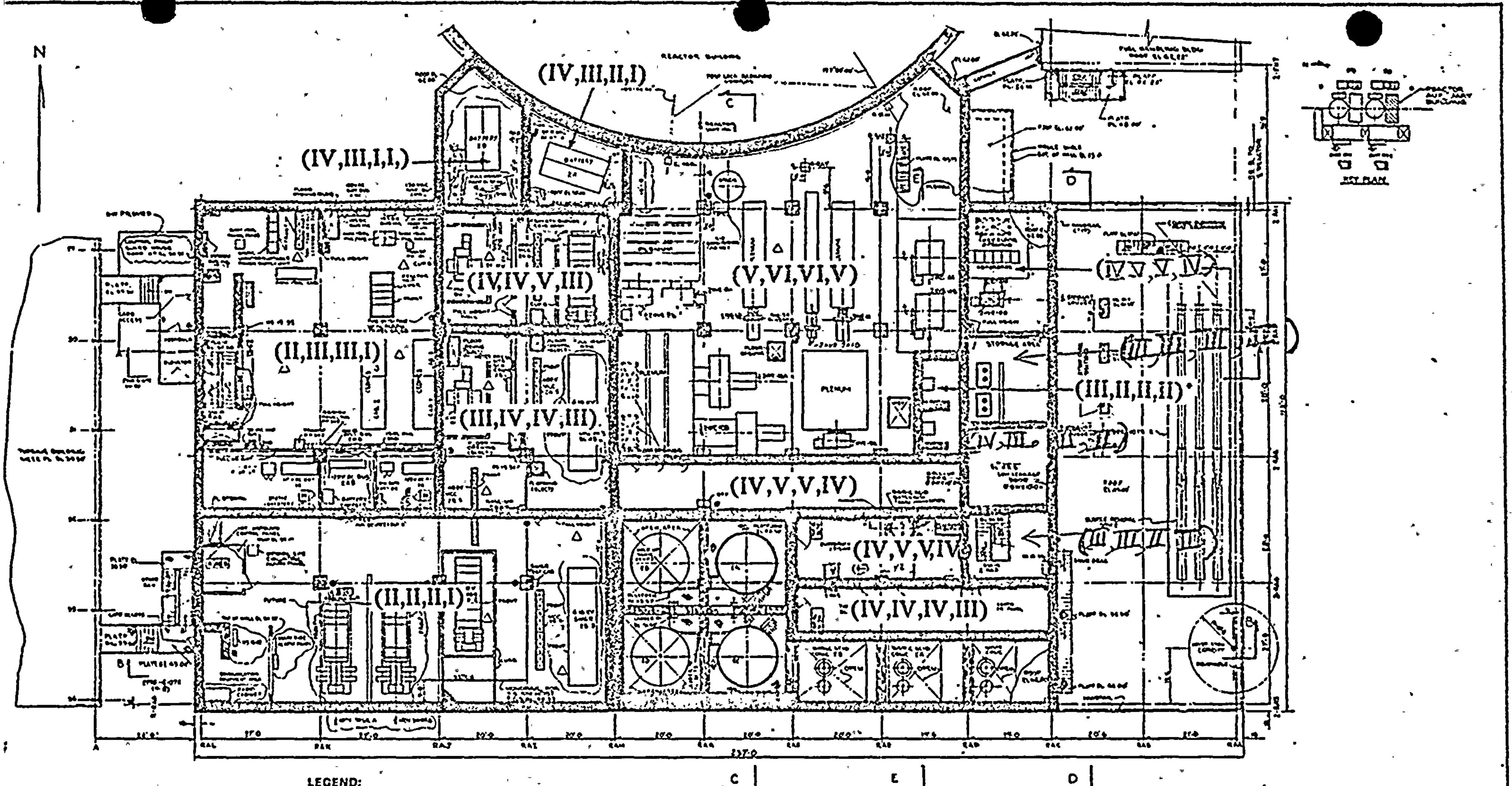
NOTES:

DOSE RATES FROM NON-TMI SOURCES NOT INCLUDED

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

TMI RADIATION ZONE MAP

FIGURE 12.3A-2



PLAN AT EL. 43.00'

LEGEND:

ZONAL DOSE RATE CLASSIFICATION

ZONE	UPPER LIMIT DOSE RATE (MR/HR)
I	<15 MR/HR
II	15-100 MR/HR
III	100-1000 MR/HR
IV	1-10 R/HR
V	10-100 R/HR
VI	>100 R/HR

a. ROMAN NUMERALS IN PARENTHESIS CORRESPOND TO DOSE RATES AT VARIOUS TIMES AFTER THE ACCIDENT...

(X, X, X, X)

AFTER 1 HR
AFTER 10 HR
AFTER 100 HR
AFTER 1000 HR

*ASSUMING HYDROGEN ANALYSER IN OCCUPIED CUBICLE IS NOT OPERATING, WHILE OTHER ONE IS.

NOTES:

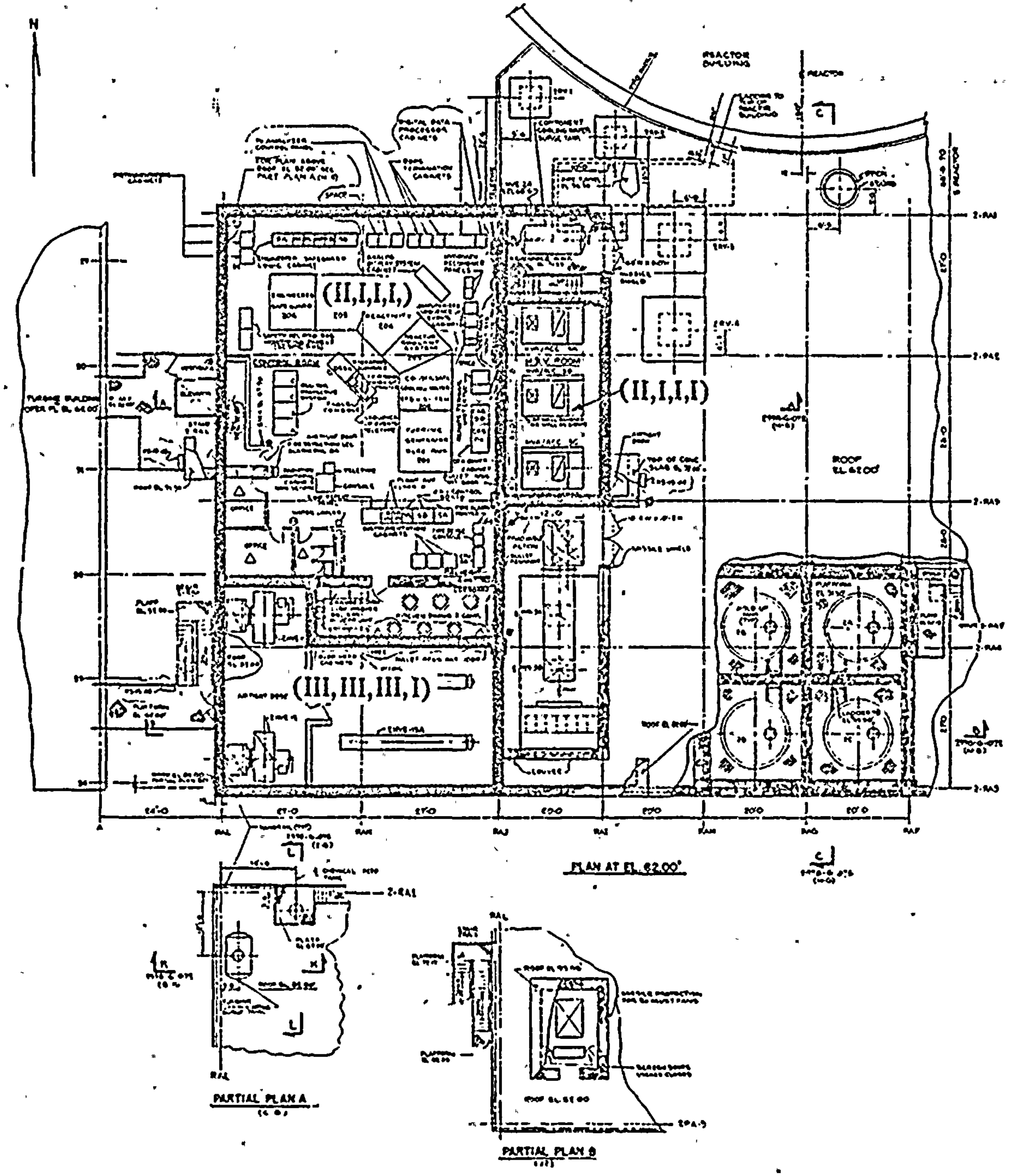
DOSE RATES FROM NON-TMI SOURCES NOT INCLUDED

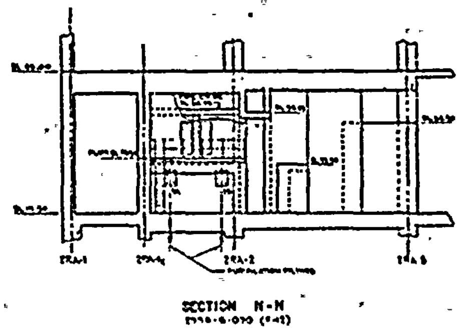
(Revised)

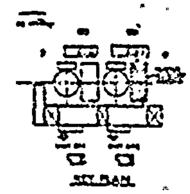
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

TMI RADIATION ZONE MAP

FIGURE 12.3A-3







LEGEND:

ZONAL DOSE RATE CLASSIFICATION

ZONE	UPPER LIMIT DOSE RATE (MR/HR)
I	< 15 MR/HR
II	15-100 MR/HR
III	100-1000 MR/HR
IV	1-10 R/HR
V	10-100 R/HR
VI	>100 R/HR

a. ROMAN NUMERALS IN PARENTHESIS CORRESPOND TO DOSE RATES AT VARIOUS TIMES AFTER THE ACCIDENT.

(X, X, X, X)

AFTER 1 HR
AFTER 10 HR
AFTER 100 HR
AFTER 1000 HR

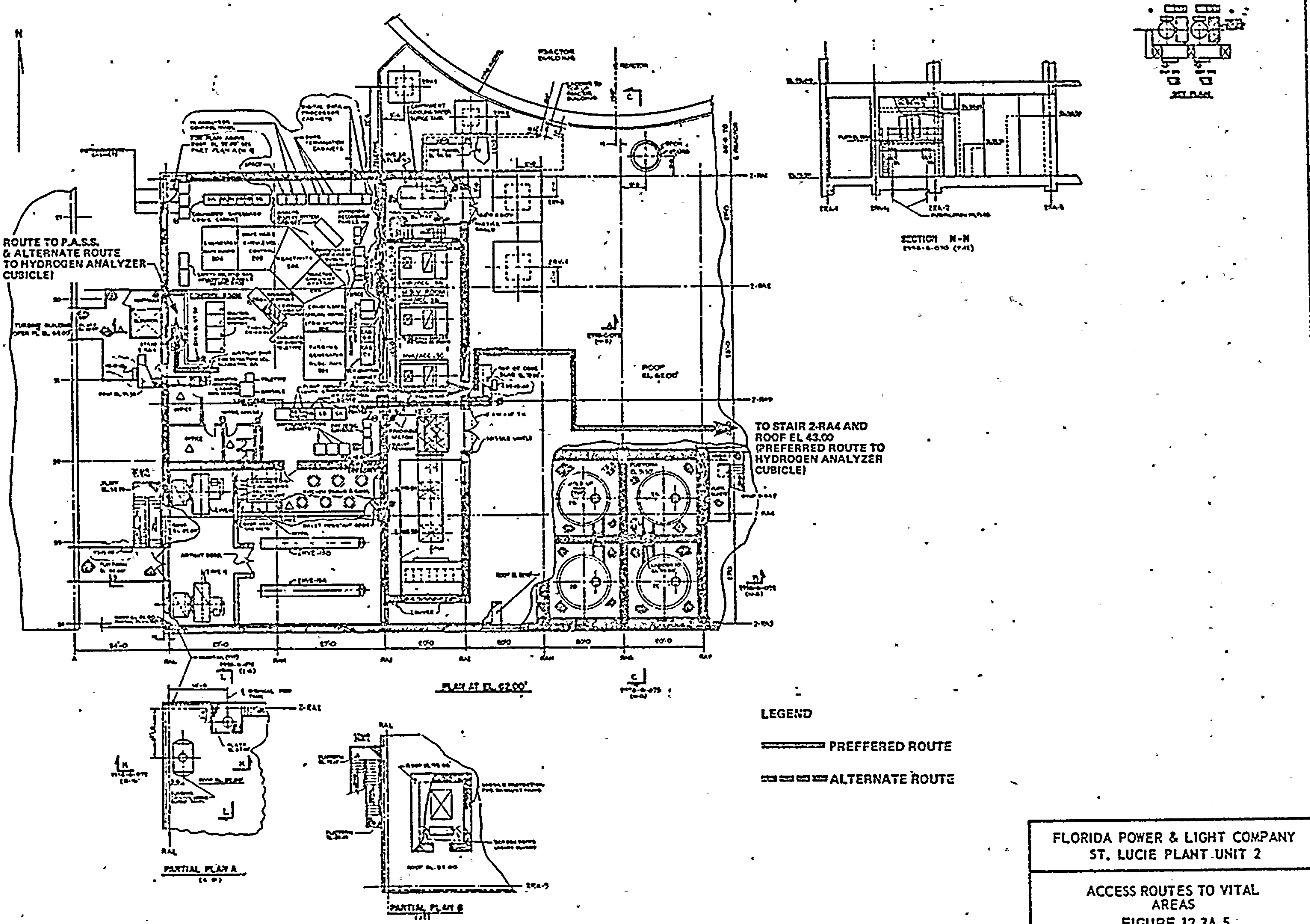
NOTES:

DOSE RATES FROM NON-TMI SOURCES NOT INCLUDED

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

TMI RADIATION ZONE MAP

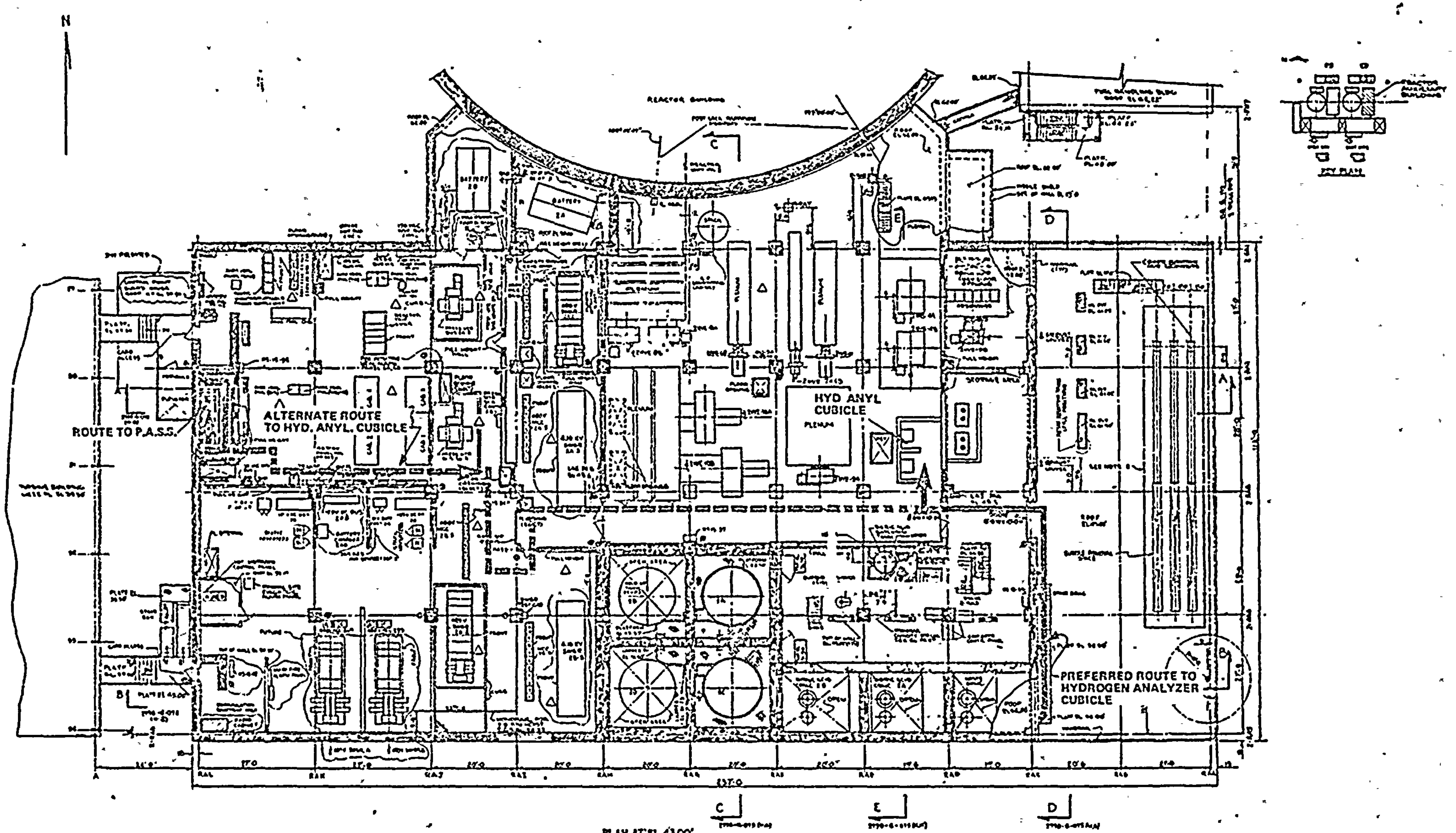
FIGURE 12.3A-4



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ACCESS ROUTES TO VITAL AREAS

FIGURE 12.3A-5



(Revised)

LEGEND

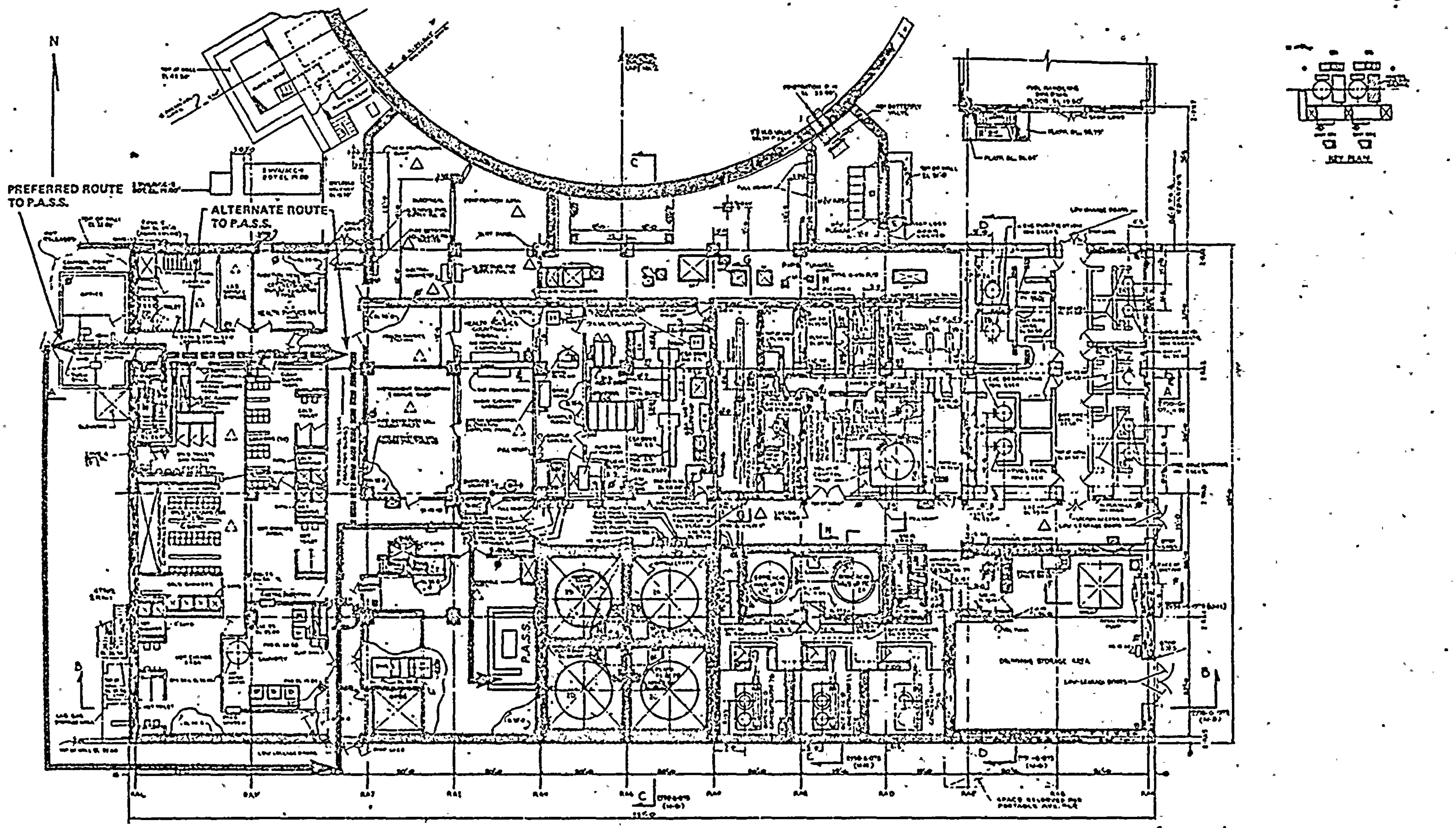
PREFFERED ROUTE

ALTERNATE ROUTE

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ACCESS ROUTES TO VITAL AREAS

FIGURE 12.3A-6



PLAN AT EL. 19.50

LEGEND

PREFFERED ROUTE

ALTERNATE ROUTE

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ACCESS ROUTES TO VITAL AREAS

FIGURE 12.3A-7

MA: T.L.K

CONDUCT OF OPERATIONS

CHAPTER 13

LIST OF TABLES

CONDUCT OF OPERATIONS

CHAPTER 13

LIST OF FIGURES

Draft 1

SL2-FSAR

CHAPTER 13

13.0 CONDUCT OF OPERATIONS

13.1 ORGANIZATIONAL STRUCTURE OF APPLICANT

13.1.1 MANAGEMENT AND TECHNICAL SUPPORT ORGANIZATION

FPL utilizes a Project Management Team approach to integrate the varied activities required to successfully complete the St. Lucie Unit 2 project.

The Project Management Organization is the responsibility of a Vice President who reports to an Executive Vice President. The Project General Manager reports to the Director of Projects and is responsible for coordinating all groups involved with the project both inside and outside the company. The Project Team is composed of staff representatives from supporting FPL departments and the architect-engineer. FPL team members report to the Project General Manager on a line basis. Team members representing the architect-engineer, for plant design and construction support, are responsible to the Project General Manager through contractual obligation. These Project Team members are responsible for bringing to the Project the expertise of their resident departments. Respective department heads are responsible for the quality of technical services provided by Project Team Members.

After St. Lucie Unit 2 becomes operational, the Project Management Organization has the responsibility for managing the implementation of certain specific modifications to the operating unit.

A brief description of FPL Engineering, Quality Assurance, Licensing, Construction and Operating (Power Resources) Departments is given below. These functions are the responsibility of an Executive Vice President, who reports directly to the President. The reporting relationships are shown on Figure 13.1-1.

The organization of the Project Team is shown on Figure 13.1-2.

Project design and engineering support is the responsibility of the Chief Engineer, Power Plant Engineering, who reports to the Vice President of Engineering, Construction & Projects who reports to the Executive Vice President. The Power Plant Engineering Department, through the Engineering /D
Project Manager, and members of the Project Team, provides independent analyses and evaluations of key safety related aspects of architect-engineer and vendor designs and performance commensurate with licensing requirements, assures integration of nuclear design and operating experience from the Power /R
Resources Department, evaluates problems and NRC action concerning other utilities which could affect FPL plants, and assists in evaluating bids for future nuclear plants.

Corporate quality assurance, nuclear plant licensing management, and coordination of research and development are the responsiblity of the Vice President-Advanced Systems & Technology, who reports directly to the Executive Vice President. Corporate Quality Assurance and Licensing Management are represented on the Project Team. Details of the Quality Assurance Department organization are contained in Section ~~17.2.~~ [illegible] Topical [illegible] [illegible] report (FPL-TQAR) 1-76A, Rev 4

The Power Plant Construction Department is the responsiblity of the Director of Construction, who reports to the Vice President of Engineering, Construction and Projects, who reports to the Executive Vice President. This department provides construction methods, handles construction contracts, and provides quality control and labor relations personnel.

Power plant operation and maintenance are the responsibility of the Vice President-Power Resources who reports to the Executive Vice President. The Manager of Power Resources-Nuclear is responsible for all matters concerning the operation and maintenance of nuclear power plants. The Assistant Manager Power Resources-Nuclear is responsible for those operation and maintenance matters specifically related to the St. Lucie Plant. The Manager Power Resources-Nuclear Services reports to the Manager of Power Resources-Nuclear and is in charge of the nuclear support staff. The Nuclear Support Staff of the Power Resources Department is established to furnish technical support in those areas of technical expertise that are unique to nuclear power plants. The Manager of Power Resources-Services reports to the Vice President-Power

Resources and is responsible for staff technical support in areas common to both nuclear and fossil plants. The Services staff is composed of Operations, Maintenance, Administration, Instrument and Control, and Test and Performance groups which provide in-house technical support to operating plants in a broad spectrum of engineering, technical and scientific disciplines. Specific technical support areas assigned to various section supervisors are indicated on Figure 13.1-3 along with the authorized staffing level for each section. Actual staffing levels may vary dependent upon the support required. Regulatory requirements for plant support specified in ANSI/18.1-1971 ~~ANS-3.1-1978~~, Regulatory Guide 8.3, "Film Badge Performance Criteria" February 1973 (RO) and ANSI 8.7 are fulfilled by the Power Resources staff sections. During preliminary design, engineering and construction activities that are the responsibility of Project Management, Power Resources is represented by the Power Resources Team Member.

The Power Resources and Power Plant Engineering Departments have been expanded to support the design and operation of Turkey Point Units 3 and 4 and St. Lucie Units 1 and 2. /R

13.1.1.1 Specific Design and Operating Activities

The following paragraphs summarize the degree to which certain design, construction and preoperational activities are accomplished and describes the specific responsibilities and activities for technical support to operation. /R

13.1.1.1.1 Principal Site-Related Engineering Work

a) Meteorology

A meteorological monitoring program was established at the site to provide those meteorological factors that bear upon plant design, operation and safety. The program has been conducted by Dames & Moore and is discussed in Section 2.3. Direction and supervision of the program is provided by FPL.

b) Geology & Hydrology

Law Engineering of Atlanta, Georgia performed the geologic and seismologic studies of the site.

During construction, Ebasco Services, Inc. soils engineers inspected the excavation and mapped any significant geologic features encountered. Geology, hydrology and seismology is discussed in detail in Sections 2.4 and 2.5.

c) Demography

Ebasco Services, Inc., performed demographic studies relative to population within 50 miles of the plant as discussed in Subsection 2.1.3.

d) Environmental Effects

A preoperational monitoring program for St. Lucie Unit 2 was developed to enable the collection of hydrothermal, biological and water quality data necessary to determine possible impacts on the environment due to construction activities and to establish a preoperational baseline from which to evaluate future environmental monitoring data. This program is described in the Environmental Report and is performed by Applied Biology, Inc. and FPL.

e) Design of Plant and Auxiliary Systems

An evaluation of engineering progress as of December 31, 1979 indicated overall completion of design and engineering of 95.2 percent.

f) Review and Approval of Plant Design Features

Design control for review is performed in accordance with the quality assurance program in FPL Topical Quality Assurance Report (FPLTQAR) 1-76A, Rev 4

g) Site Layout with Respect to Environmental Effects and Security Provisions.

A preoperational monitoring program for St. Lucie Unit 2 was developed to enable the collection of physical, chemical, and ecological parameters necessary to determine possible impacts on the environment due to construction activities and to establish a preoperational baseline from which to evaluate future environmental monitoring. Applied Biology Inc. has carried out the biological and water quality monitoring programs. /D

Security provisions in accordance with applicable NRC regulations are incorporated into overall site development by developing security criteria and incorporating these criteria into design drawings and specifications by FPL and Ebasco Services, Inc. Details of security provisions are provided in the security program in Section 13.6.

h) Development of Safety Analysis Reports

Overall responsibility for preparation of the FSAR rests with Power Plant Engineering. Preparation of the individual sections was assigned to the cognizant technical groups within FPL or to Ebasco Services, Inc. for balance of plant systems, and Combustion Engineering for Nuclear Steam Supply System (NSSS) systems. /D

i) Review and Approval of Material and Component Specifications

All safety related project specifications are reviewed in accordance with the quality assurance program in FPL Topical Quality Assurance Report (FPLTQAR) 1-76A, Rev 4

j) Procurement of Materials and Equipment

As of December 31, 1979, approximately 84.6 percent of the overall total procurement effort is completed.

k) Management and Review of Construction Activities

Management and review of construction activities are performed by the FPL Construction Department and Project General Management.

13.1.1.1.2 Preoperational Activities

a) Development of Human Engineering Design Objectives and Design Phase Review of Proposed Main Control Room Layouts.

The human engineering design objectives were developed jointly between FPL project team members and Ebasco Services, Inc. engineering design personnel and conform to NUREG 0770. /R

The control room layouts are designed to include all the features and components necessary for monitoring and controlling the operations of the nuclear power plant with a high degree of reliability. The control boards and panels act as a major tool in the operator's interface with all the plant systems. They house control, instrumentation, display and annunciation equipment and are arranged within the control room to facilitate the operator's task of control and protection. In addition, the control room layouts include advanced concepts such as video displays, computer based data acquisition, logging and analysis.

The basic human engineering design objectives were to improve the operator's ability to maintain communication with all the systems in the plant. The control boards utilize a modular design concept with compact miniaturized devices for more efficient functional display. The operator, having the control board information on a smaller area, will have better control of the plant operation.

b) Development and Implementation of Staff Recruiting and Training Program.

The staffing plan and implementation schedule is presented in Table 13.1-1. The training program is presented in Section 13.2.

c) Development of Plans for Initial Testing /R

The St. Lucie Unit 2 Startup Group has the responsibility for the integrated operations of the Startup Program. The scope of the testing to be accomplished during the test program is defined in Section 14.2.

d) Development of Plant Maintenance Programs

Plant maintenance programs for St. Lucie Unit 2 are developed by the FPL Power Resources Department by upgrading and expanding, as needed, the existing programs for St. Lucie Unit 1.

13.1.1.1.3 Technical Support for Operations

Technical services and backup support for the operating organization are also discussed in Subsection 13.1. Backup and support for the operating organization in the specific capabilities of operating experience assessment, /A
nuclear, mechanical, structural, electrical, thermal-hydraulic, meteorology and materials, instrumentation and controls, plant chemistry, fueling and /R
refueling, operation engineering and analysis is available in FPL's Power Plant Engineering Department in addition to the staff support available within /D

the Power Resources General Office Group.

Maintenance and backfit construction support is available through FPL's Power Plant Construction Department, providing management of contractor forces, in addition to the staff support available within the Power Resources General Office Group.

13.1.1.2 Organizational Arrangement

The FPL General Office Management and Support Department Organization is shown on Figures 13.1-1 through 13.1-7.

As shown on Figure 13.1-1, all departments, with their respective Vice Presidents, with responsiblity for the design, licensing, construction, quality assurance and operations, report to an Executive Vice President, who reports to the President of FPL.

Qualifications for key individuals within the organization are provided in Subsection 13.1.1.3.

For specific activities, FPL may elect to enter into a continual arrangement with a consulting organization in order to secure specific or specialized expertise or to solicit a recommendation on a course of action. FPL may also enter into contractural arrangement for construction services provided by a contractor for specific improvement or modification work. Extended organizations will be responsible to cognizant personnel within FPL.

After St. Lucie Unit 2 begins operation, the Project Management Organization may manage the implementation of specific major modifications of the plant or may manage a modification program for the unit if the program is extensive. The operations of the Project Management Group is discussed in Subsection 13.1.1.

13.1.1.3 Headquarters Staffing

For personnel within the FPL General Office Management and Support Departments who have duties and responsibilities relevant to St. Lucie Unit 2, as reflected in the organization charts of Subsection 13.1.1.2, summaries of function, expertise and education are presented below.

H.J. Dager, Jr.
Vice President
Engineering, Projects & Construction

Educational Background:

1975, Stanford Executive Program, Stanford University

1949-1951, University of California, Berkeley, CA
M.S., Bioradiology (Major: Nuclear Physics)

1948-1949, U.S. Navy Postgraduate School, Annapolis, MD
(Major: Nuclear Engineering - No Degree)

1942-1945, United States Military Academy, West Point, New York, B.S., Military Engineering

Experience:

Nuclear

H.J. Dager has participated in nuclear work since 1948 with active involvement in planning, engineering, construction and operation of over twenty nuclear reactors. H.J. Dager was licensed to operate four different nuclear reactor power plants.

1945-1955	U.S. Army, Corps of Engineers, Platoon Leader, Company Commander, Assistant Division Engineer, Nuclear Engineer - Far East Command, Chief Special Studies Section Engineer Research and Development Laboratories.
1955-1956	Westinghouse Electric Corp.; Bettis Laboratory, Senior Engineer, Shippingport Project.
1956-1958	General Electric Co. Project Engineer Lockheed. Project (3 test reactors).
1958-1959	General Electric, Project Engineer Humboldt Bay, PG&E (50 Mev BWR).
1959-1962	General Electric, Manager Special Projects, Test Reactors, Control System N.S. Savannah, Control & Safety System Indian Point 1, High Temperature He Loop.
1962-1963	General Electric, Shift Supervisor, Big Rock Point, Consumers Power Co.
1963-1964	General Electric, Manager Shift Operations, Japan Power Demonstration Reactor.

1964-1967	General Electric, Principal Project Engineer (Project Manager) Southwest Experimental Test Oxide Reactor.
1967-1972	General Electric, Project Manager, Cooper Project, Nebraska Public Power District - Iowa Power and Light.
1972-1973	Nebraska Public Power District, Assistant General Manager for power supply, generation engineering, and quality assurance.
1973-Jan, 1976	FP&L; Manager of Power Resources - Nuclear; responsible for startup preparations and operation of all nuclear power plants in FP&L system.
Jan. - Sept. 1976	Asistant to Group Vice President.
1976 - Present	Vice-President-Engineering, Projects and Construction.

Other

Mr. Dager is presently Vice President of Engineering, Projects and Construction. He is responsible for the design and construction of major capital additions to the FP&L System.

Other responsible positions held include Manager, Power Resources - Nuclear; Assistant General Manager, Nebraska Public Power District; Project Manager, General Electric Company and Captain, U.S. Army Corps of Engineers.

J.W. Williams, Jr.
Director of Projects*

A. Function, Responsibilities and Authority:

Primarily accountable for directing and coordinating the activities of the assigned Project General Managers, the manager of New Projects and the Manager of Project Control Services to meet the objectives of the Project Management organization and FP&L Management.

Overall responsibility for developing, establishing, implementing and monitoring policies, guidelines, procedures and technical and administrative aspects of all project related activities to insure assigned projects meet Project Management and corporate goals and objectives.

*A project, for the purpose of defining the role of the Director of Projects, typically encompasses the planning, design, construction, start-up and associated activities required for the completion and commercial operation of any new power generation facility but may include any task assigned by management.

Overall responsibility for obtaining management approval of project strategies, plans and budgets, for reporting both progress and status of assigned projects, for effecting timely management action to ensure the continued progress of project activities and for obtaining completion of projects within approval budget, schedule and technical specification constraints and in compliance with regulations and agreements made with outside organizations and agencies.

B. Educational Background:

BChE University of Florida, Gainesville

FP&L Training Instructor on Steam Generator & Turbine Technology	1955-63
Nuclear Power Reactor - University of Florida	1966
Nuclear Fuel Management - NUS	1966
Radiological Health - PHS	1966
Reactor Safety & Hazards Evaluation, PHS	1967
Advanced Nuclear Technology - University of Florida	1967
Stanford Executive Program Stanford University	1975

Specific Nuclear Courses:

Nuclear Power Reactor - University of Florida, 1966

Nuclear Fuel Management - NUS, 1966

Radiological Health - PHS, 1966

Reactor Safety & Hazards Evaluation - PHS, 1967

Advanced Nuclear Technology - University of Florida, 1967

C. Experience:

Nuclear

J.W. Williams, Jr. has participated in FP&L's nuclear program since 1966, with active involvement in the preliminary planning and construction phases of the nuclear plant Turkey Point Units 3 and 4, and completed the above courses in nuclear technology which relate to licensing.

Experience:

Other

Mr. Williams is presently Director of Projects, providing direction for six projects and Project Control Services Department; directs work of eight managers or assistant managers and is supported by 34 other personnel.

Other responsibilities and positions held include: Plant Betterment Foreman, Plant Results Foreman and Assistant Plant Superintendent-Operations and Plant Superintendent for Palatka Plant; Assistant Plant Supervisor-Operations and Plant Superintendent at Cutler Plant; Plant Superintendent for Turkey Point Plant Units 1 and 2 with responsibilities of a safe and successful start-up, and subsequent operation and maintenance of the plant, along with providing supervision for plant personnel; Manager, Quality Assurance including development and implementation of methods and systems to collect, record, monitor and report data for quality assurance affected items.

Project General Manager - St. Lucie Project, providing coordination and control of activities necessary to complete the project within schedule, budget and technical specification constraints.

W.B. Derrickson
Project General Manager (PGM)

A. Function, Responsibilities and Authority:

Primarily accountable for directing and coordinating the timely performance by all departments involved in the completion of a nuclear power plant within a designated time span and within the approved budget limitations and all technical specifications.

Coordinates and participates in decisions and activities relating to design, permitting, purchasing, licensing, construction and start-up of the nuclear plant project assigned to him. Establishes schedules for, and monitors, each of the activities of the departments and groups so as to achieve the objectives relating to quality, cost and operating date of the project.

Administers the project planning and scheduling system through which all areas relative to the construction of the nuclear plant and startup is planned and scheduled from authorization to commercial operation.

The PGM must be cognizant of all deviations from established objectives in construction of the nuclear power plant, initiate action to correct the deviation and the steps necessary to prevent the occurrence of subsequent deviations; resolve conflicts between all parties at the construction site and the various departments of the Company; secure or render timely decisions which will aid the Company and the Contractor to meet time schedules; maintain a close

relationship with Division Managers and other Division and District personnel regarding the interface of construction plans and Division activities; review actual and potential problem areas on a continuing basis so as to identify, isolate and arrive at the best method of problem solution; keep interested parties advised of progress and of deviations from schedules and budgets; and coordinate activities between construction forces and all other departments to insure a smooth transition of the completed project to the commercial operation of the plant.

B. Education:

BSEE - University of Delaware 1964

C. Experience:

Nuclear

Mr. Derrickson joined FP&L in 1970 as an electrical start-up engineer at Turkey Point. He then progressed to Electrical Start-up Supervisor and in 1972 to Start-up Coordinator. In the latter position he assumed responsibility for all start-up activities for Turkey Point Unit 4. In 1973 he transferred to the Plant Construction Department and was appointed Project Construction Supervisor for St. Lucie Unit 1. In 1974 Mr. Derrickson returned to the General Office as Superintendent of Nuclear Plant Construction.

In 1975 he was appointed Assistant Project General Manager of the St. Lucie Project, Units 1 and 2.

In 1976 a need for management attention to work at Turkey Point arose and Mr. Derrickson was appointed Project General Manager for major facility modifications.

In 1976 a vacancy arose on the St. Lucie Project and Mr. Derrickson was appointed to his current position as Project General Manager of St. Lucie Unit 2 and Unit 1 modifications.

D. Experience:

Other

Prior to joining FP&L, Mr. Derrickson worked for four years as an Electrical Maintenance Engineer for Delmarva Power & Light Company. In this capacity he spent one year at the Indian River Delaware Plant and three years at the Vienna Maryland Plant. His chief activities were planning, scheduling and supervising periodic maintenance on plant equipment, supervising facility modifications and short term load forecasting and generation scheduling.

The two years at Hercules Inc. were spent in the design and startup of chemical plants. Activities centered mainly in the instrumentation area. During the two years he worked on various projects at five plants.

At Sun Shipbuilding and Drydock Company the responsibilities were in the R&D area. The primary project was to develop a computer control system for automatic ship navigation.

G.B. Bradshaw
Asst. Project General Manager

A. Function, Responsibilities and Authority:

Assists the Project General Manager in directing and coordinating the timely performance by all departments involved in the completion of a nuclear power plant within a designated time span and within the approved budget limitations and all technical specifications.

Aids in decisions and activities relating to design, permitting, purchasing, licensing, construction and start-up of the nuclear plant project assigned to him. As assigned, establishes schedules for and monitors, each of the activities of the departments and groups so as to achieve the objectives relating to quality, cost and operating date of the project.

Also participates in administering the project planning system through which all areas relative to the construction of the nuclear plant is planned and scheduled from authorization to commercial operation.

He must be cognizant of all deviations from established objectives in construction of the nuclear power plant, initiate action to correct the deviation and the steps necessary to prevent the occurrence of subsequent deviations; resolve conflicts between all parties at the construction site and the various departments of the Company; review actual and potential problem areas on a continuing basis so as to identity, isolate and arrive at the best method of problem solution; keep the PGM advised of progress and of deviations from schedules and budgets; and coordinate activities between construction forces and all other departments to insure a smooth transition of the completed project to the commercial operation of the plant.

B. Education:

Bachelor of Science, Mechanical Engineering 1964
Master of Science, Nuclear Engineering, University of California, 1965
Management Certificate, University of California Extension, 1975

C. Experience:

Nuclear

Registered Professional Nuclear Engineer in the State of California, Mr. Bradshaw was licensed to operate a research reactor and was employed half time by the University of California at Los Angeles

as a licensed nuclear research reactor operator assisting in numerous scientific experiments. Since 1973 has been involved in the Project Management and Project Engineering of nuclear power generation units.

Presently, Assistant Project General Manager for the St. Lucie Unit 2 nuclear power plant. Responsible for management and project direction of utility activities on 850 MWe nuclear plant. Activities include application of cost and schedule control techniques for the entire project effort, coordination of the utility functional department activities and interfaces with the architect-engineer and construction organization. He assisted in the evolution, planning, organizing and implementation of new utility management concepts for improving control of project costs and schedule on large projects.

Other

General Atomic Company, San Diego, California Manager, Applied Fuel Engineering. Responsible for design control, licensing support, fuel cycle environmental effects, presentation of testimony at licensing hearings, project control systems and coordination of all project support activities within the Fuel Engineering Division for the large High Temperature Gas-Cooled Reactor (HTGR).

Fuel Project Engineer-Assigned to the Philadelphia Electric Fulton Generating Station Project for twin 1160 MWe HTGRs and the Delmarva Power and Light Summit Station Project for twin 770 MWe HTGRs, both with fuel contract values in excess of $100 million. Responsibilities included coordination of all fuel activities related to design, development, licensing, contract provisions and project control of the projects.

Staff and Senior Engineer, Special Nuclear Systems Division. Responsible as a Task Leader and Principal Engineer for the design, development and test of direct energy conversion space nuclear power systems. Performed thermal design, electrical performance predictions, reliability assessment and evaluation of flight data.

TRW Systems, Redondo Beach, California
Member of the Technical Staff. Responsible for the design and development of high temperature radioisotope heat sources; carrying out R&D programs; performing radiation effects studies on satellite power systems; and, evaluating mobile nuclear reactors. Obtained Air Force patent on heat source.

Additionally, published 20 Technical Papers on Energy Conversion Technology
1 - Technical Paper on Cost of Nuclear Plant Delays
1 - Technical Paper on Licensing and Construction of St. Lucie Nuclear Plant

G.R. Gram
Asst. Project General Manager

A. Function, Responsibilities and Authority:

Assists the Project General Manager in directing and coordinating the timely performance by all departments involved in the completion of a nuclear power plant within a designated time span and within the approved budget limitations and all technical specifications.

Aids in decisions and activities relating to design, permitting, purchasing, licensing, construction and start-up of the nuclear plant project assigned to him. As assigned, establishes schedules for and monitors, each of the activities of the departments and groups so as to achieve the objectives relating to quality, cost and operating date of the project.

Also participates in administering the project planning system through which all areas relative to the construction of the nuclear plant is planned and scheduled from authorization to commercial operation.

He must be cognizant of all deviations from established objectives in construction of the nuclear power plant, initiate action to correct the deviation and the steps necessary to prevent the occurrence of subsequent deviations; resolve conflicts between all parties at the construction site and the various departments of the Company; review actual and potential problem areas on a continuing basis so as to identify, isolate and arrive at the best method of problem solution; keep the PGM advised of progress and of deviations from schedules and budgets; and coordinate activities between construction forces and all other departments to insure a smooth transition of the completed project to the commercial operation of the plant.

B. Education:

BS in Aerospace Technology, 1969, Kent State University Worked as co-op for Ford Motor Company as a Quality Control Engineer.

C. Experience:

Nuclear

February, 1979 to present, Assistant Project General Manager on St Lucie Unit 1 Backfit and Betterment. Joined FP&L in 1973 as Backfit Construction Supervisor for Turkey Point Backfit. Before his present appointment held Area Construction Supervisor and Project Construction Supervisor position at PTP. From 1971 to 1973, was an Installation Service Engineer for General Electric in Turbine Generator Erection area for both fossil and nuclear units.

W. B. Lee
Director of Construction

Education: B.S. General Engineering and Physics, Univ. of Richmond, 1948.

Work Experience :

Mr. Lee has more than 30 years experience in engineering and construction for fossil and nuclear plants. He has spent the last 25 years in the nuclear electric generation area, from engineering and design to project and construction management; involved in over 30 nuclear fueled electric generation plants world wide. He served in the United States Navy in World War II and the Korean conflict.

In 1953 he joined Bettis Atomic Power Laboratory where he worked on the prototype of the USS NAUTILUS and the first commercial atomic plant at Shippingport.

In 1966 he was assigned to the Commercial Atomic Power Divisions and became Project Manager for the Carolina Power and Light 800 Megawatt nuclear station turnkey project. From 1966 to 1969 he was assigned as Executive Vice-President and General Manager of WEDCO Corporation, a wholly-owned subsidiary of Westinghouse, established to perform all engineering and construction of the Indian Point nuclear project. In 1972 he was named Vice President, Facilities Construction for Offshore Power Systems (a joint venture of Westinghouse and Tenneco). Since March, 1975, he has been with FP&L as Director of Construction.

B. J. Escue
Site Manager, St Lucie Unit 2 Construction

EDUCATION

Junior College - One semester of Petroleum Engineering (1950) - N.E. Junior of L.S.U., Monroe, Louisiana.
College - Graduated 1954 from U.S. Merchant Marine Academy, Kings Point, N.Y. (B.S.).

MISCELLANEOUS

U.S. Coast Guard License as Third Asst. Engineer (Diesel & Steam), Active.
Class I Contractor License for Monroe County, Florida. 1966 - 1968.
Allowed to expire.

SUMMARY OR QUALIFICATIONS

Mar. 1976 - Present - Site Manager, St. Lucie Plant - Unit 2 Responsible for construction.

Oct. 1972 - Mar. 1976	-	Project Manager of Construction in Facilities Construction Dept, responsible for all Platens and Waterfront Construction. This includes engineering, budgets and construction and ascertaining that the Construction Manager was following his contractual responsibilities.
Feb. 1971 - Oct. 1972	-	Site Manager for W NES of two 4-loop reactor sites (2 plants on each site). This work consisted of maintaining a staffed office of experienced engineers to provide technical assistance to the customer in all phases from the receipt and warehousing of equipment through installation and test.
June 1968 - Feb. 1971	-	Manager of Construction of the Carolina Power & Light Co. Three-Loop Nuclear Plant (Robinson Plant), responsible for a staff of engineering specialists, Q.A. engineers, civil, cost and scheduling personnel.
Apr. 1967 - June 1968	-	Construction Superintendent for W HTD to field erect water distillation plant for U.S. Steel at Clairton, Pa. Supervised all of the work pertaining to assembling the Flash Evaporator and setting all major equipment with mill-wrights.
May 1966-April 1967	-	Construction Superintendent for W HTD to field erect world's largest Desalt Plant (Single Unit 2.62 MGD) at Key West, Florida for Florida Keys Aqueduct Commission.
July 1965-May 1966	-	Bettis Atomic Power Laboratory, Pittsburgh, Pa. Cognizant Engineer for PWR-2 omega seal welding machine which is used to perform all omega seals on reactor vessel head automatically.
July 1961-June 1965	-	Bettis Resident Engineer's Office Shippingport Atomic Power Station PWR Project (Pressurized Water Reactor) Shippingport (Beaver County), Pa. Mechanical Engineer.
Dec. 1958-June 1961	-	Bettis Resident Engineer's Office for construction of U.S.S. Enterprise, Newport News Shipyard and Drydock Co., Newport News, Virginia. Mechanical Engineer.

March 1957-Nov. 1958	-	A-1-W Project, Naval Reactors Facility, Idaho Falls, Idaho (Prototype of U.S.S. Enterprise). Hired as Chief Operator Trainee for A-1-W and underwent operational training at S-1-W (Operational Prototype of U.S.S. Nautilus) for a short time prior to entering plant construction group for A-1-W. Job consisted of following construction, intallation of equipment, and testing as per specifications and drawings.
Dec. 1954-Dec. 1956	-	U.S. Navy

J. E. Vessely
Director of Quality Assurance

B.B.A. - Industrial Engineering & Management, University of Miami - 1952
U.S. Army - Marine Engineering - 1952-53
Manufacturing Management Training Program - General Electric Co. - 1953-56
Statistical Quality Control - General Electric Co. - 1960
Plastics Engineering - General Electric Co. - 1960
Management Courses at University of Florida - 1966-67
Nuclear Power Reactors - Georgia Tech - 1975
Nuclear Power Reactor Safety - Massachusetts Institute of Technology - 1975
Stanford Executive Program-Grad. School of Business, Stanford University - 1978
Professional Engineer in Quality Engineering - State of California - 1979

1952 - 1953	U.S. Army - Marine Engineering - responsible for main power and all general maintenance work
1953 - 1956	General Electric Co. - Manufacturing Management Training Program
1956 - 1962	General Electric Co. - Manager, Advanced Manufacturing Engineering - new electronic product design for Atomic Energy Commission
1962 - 1967	General Electric Co. - Manager, Quality Programs - development, implementation, and evaluation of reliability and quality program activities for Apollo/NASA
1967 - 1973	General Electric Co. - Manager, Washington, D.C. Program Office - Program Manager for the following types of programs: Quality and Reliability, Configuration Control, Data Management, Information Systems
1973 - 1974	FP&L - Senior Quality Assurance Engineer - System Development
1974 - 1975	FP&L - Assistant Manager of Quality Assurance - System Development
1975 - 1978	FP&L - Manager of Quality Assurance
1978-Present	FP&L - Director of Quality Assurance

Member of:

American Society of Mechanical Engineers
Committee on Quality Assurance (Governing Body for ANSI Standards)
Chairman 1978 - 1981

Subcommittee on Personnel Qualifications
N45.2.23 Quality Assurance Work Group

American Nuclear Society

American Society for Quality Control
Nuclear Division - Advisory Council
Nuclear Division - Area 15 Regional Councilor
Nuclear Division - 1979 Conference Chairman
Edison Electric Institute - Prime Movers

Southeastern Electric Exchange
Quality Assurance Committee

International Atomic Energy Agency (IAEA)
U.S. Representative for Standard on "Quality Assurance for Fuel Cladding Design and Manufacture"

Electric Power Research Institute (EPRI)
Rotating Electrical Machinery Task Force

J. William Brown
Manager, Quality Assurance, Applications

B.S., Industrial Management - Auburn University - 1954
Manufacturing Training Program - General Electric Co. - 1959
Professional Business Management - 1966

1950-1952	U.S. Steel Co. - Co-op Student
1955-1957	United States Air Force - Research & Development Command, 1st Lt.
1957-1974	General Electric Co.
	- Manager, Inventory Control
	- Manager, Purchasing
	- Reliability Engineer
	- Senior Quality Assurance Analyst
1974-1975	FP&L Senior Quality Assurance Engineer, Procurement Group
1975-1979	Assistant Manager of Quality Assurance, Systems
1979-Present	Manager, Quality Assurance, Applications

Member of:

American Society for Quality Control (ASQC)

Qualifications:

Certified Principal Auditor - June, 1975
Professional Engineer, QA - 1978

Theodore Essinger
Assistant Manager of Quality Assurance, Design

M. E. Stevens Institute of Technology - 1953
M.B.A. Management, Xavier University - 1962
Manufacturing Training Program, General Electric Co. - 1959
Reliability Engineering, General Electric Co. - 1962

1953-1956	United States Air Force-Pilot and Ground Safety Officer
1957-1963	General Electric Co. - Manager, Large Jet Engine Test
1963-1966	Westinghouse Electric Corp. - Manager, Quality Assurance, Atomic Equipment Division (Commercial and Navy Nuclear Program)
1966-1968	Toledo Scale Co. - Manager, Quality Control
1968-1972	Control Data Corp. - Manager Quality Assurance, Military Systems Division (Poseidon Submarine and F14 Phoenix Programs)
1972-1973	Hazeltine Corp. - Director, Quality Assurance
1973-1975	FP&L Assistant Manager of Quality Assurance - Procurement
1975-Present	FP&L Assistant Manager of Quality Assurance - Design

Member of:

American Society for Quality Control
(Senior Member, Chairman of Local Chapter)

American Society of Mechanical Engineers

Edison Electric Institute
Chairman of Design Sub-Committee of Quality Assurance Task Force

Qualifications:

Professional Engineer, #QU2627
Certified Principal Auditor, June, 1975
Certified Quality Engineer, #1873-1969

Alan E. Siebe
Assistant Manager of Quality Assurance - Systems

BS, U.S. Naval Academy, Annapolis, MD, 1965
MBA, University of Miami, 1978
U.S. Naval Nuclear Power School and Nuclear Prototype, 1966
U.S. Naval Submarine School, 1967

1965-1973	Commissioned Officer, U.S. Navy; USS Mariano G. Vallejo SSBN658: Assigned as Reactor Control Officer, Electrical Officer, Main Propulsion Assistant, Radiological Controls Officer and Communicator. Commander Submarine Flotilla Seven: Assigned Assistant Operations Officer USS Lafayette SSBN616: Assigned as Engineer Officer. Responsible for nuclear power plant operations, maintenance and overhaul.

1973-1974	FP&L: Quality Assurance Department, Quality Assurance Engineer. Responsible for management audits of nuclear power plants and supporting departments.
1974-1975	FP&L: Licensing Department, Sr. Licensing Engineer. Responsible for preparation and review of nuclear plant licensing documents and for licensing hearing preparations.
1975-1979	FP&L: Quality Assurance Department, Assistant Manager of Quality Assurance for Operating Plants.
1979-Present	FP&L: Quality Assurance Department, Assistant Manager of Quality Assurance - Systems.

Member of:

American Nuclear Society
Southeastern Electric Exchange QA Committee (Committee Chairman)
N45.2.6 Work Group for ANSI Standard on Qualifications of Inspection, Examination and Testing Personnel for Nuclear Facilities

American Society for Quality Control, Energy Division

Registration:

Registered Professional Engineer (State of California)

N. T. Weems
Assistant Manager of Quality Assurance for Construction

B. S. Electrical Engineering	Vanderbilt University 1949
Graduate study in Engineering Management	University of South Florida

1951-1957	Western Electric/Bell Telephone Labs Test Planning Engineer
1957-1963	General Electric Co. Neutron Devices Department Manager Test Equipment Engineering
1968-1971	General Electric Co., Nuclear Instrumentation Department Manager of Quality Assurance
1972-1973	J. A. Jones Construction Co. Corporate Manager of Quality Assurance
1973-1975	Motorola, Communications Division - Manager of Quality Assurance
1975-1975	Project Management Corp. Manager Quality Engineering & Improvement
1975-Present	FP&L Assistant Manager of Quality Assurance for Construction

Member of:

National Society of Professional Engineers
Florida Engineering Society
American Society for Quality Control
Institute of Electrical and Electronics Engineers

American Nuclear Society

Qualification:

Registered Engineer - Florida #8751

Robert F. Englmeier
Assistant Manager of Quality Assurance Procurement

BSME Virginia Polytechnic Institute - 1955
Manufacturing Training Program, General Electric Company - 1962
Manufacturing Problems Analysis Course, General Electric Company - 1966
Business Administration, International Correspondence School - 1972
Nuclear Power Reactor Safety, Georgia Tech - 1977

1955-1958	United States Air Force - Pilot and Communications Officer
1958-1960	General Electric Company - Manufacturing Engineer
1960-1962	General Electric Company - Manufacturing Training Program
1962-1966	General Electric Company - Producibility Engineer
1966-1971	General Electric Company - Unit Manager, Shop Operations
1971-1974	General Electric Company - Manager Shop Operations
1974-1975	FP&L Senior Quality Assurance Engineer
1975-Present	FP&L Assistant Manager of Quality Assurance Procurement

Member of:

American Society of Quality Control
American Society of Quality Control (Energy Division Secretary 1976-77)
American Society of Quality Control (Energy Division Secretary 1978-79)
American Society of Quality Control (Energy Division Vice-Chairman 1978-79)
Coordinating Agency for Supplier Evaluation (Chairman Nuclear Section) Atomic Industrial Forum

Qualifications:

Lead Auditor June 12, 1975
Certified Professional Engineer of California QU 3653

W. H. Rogers, Jr.
Chief Engineer - Power Plants

A. Function, Responsibilities and Authority

Responsible for directing Power Plant Engineering Department to ensure design of efficient, economical and reliable power plants meet Company's requirements for power generation. This includes changes to existing units as well as installation of new units. Responsibilities include establishing and implementing design criteria, meeting codes and regulations, formulating and implementing engineering policies, practices and problems, resolving engineering problems, establishing equipment, technical specifications and equipment acceptance, and all similar engineering functions. Also responsible for the Nuclear Analysis Department involved in areas of Neutronics, Nuclear Fuel, Management Safety Analysis and the Nuclear Fuel Cycle.

The Chief Engineer-Power Plants has authority for administration and technical guidance of the Power Plant Engineering and Nuclear Analysis Departments. He is a Registered Professional Engineer.

B. Educational Background

BSME Rensselaer Polytechnic Institute
Graduate courses, Heat Transfer, Brooklyn Polytechnic Institute
Westinghouse, Nuclear Power Seminar
Nuclear Fuel Management, NUS
Nuclear Power Reactor, University of Florida
Radiological Health, PHS
Reactor Safety & Hazards Evaluation, PHS
Advanced Nuclear Technology, University of Florida
Nuclear Power Reactor Safety, Massachusetts Institute of Technology.

C. Experience

(1) Nuclear

Design and construction of Turkey Point Nuclear Units 3 and 4 and St. Lucie Nuclear Units 1 and 2.

(2) Other - For five years worked for Foster Wheeler Research and Development in steam generation equipment. For 27 years worked for FP&L on design and construction of nuclear and oil fired power plants and gas turbine units.

Total of 32 years in engineering areas, related to the electric utility.

E. H. O'Neal
Assistant Chief Engineer - Power Plants

A. Function, Responsibilities and Authority

Responsible for directing and coordinating Power Plant Engineering Department efforts in project related areas. Handles the departmental functions and affairs in the absence of the Chief Engineer. Directs engineering Project Managers to ensure the design of efficient, economical and reliable power plants to meet the Company's requirements for power generation. Other functions parallel those of the Chief Engineer. He is a Registered Professional Engineer.

B. Educational Background

BSME University of Florida
Graduate courses conducted by University of Florida in Elements of Vibration, Nuclear Engineering, Advanced Nuclear Technology and Nuclear Power Reactors.

C. Experience

(1) Nuclear - Engineering Project Management for St. Lucie Units 1 and 2 for seven years prior to being promoted to Assistant Chief Engineer.

(2) Other - Worked for General Electric Co. for 1 1/2 years on jet engines and steam turbines. For 29 years worked for FP&L on design and construction of nuclear and oil fired power plants.

Total of 30 years in engineering areas related to the electric utility.

L. F. Pabst
Manager Plant - Mechanical & Nuclear Engineering

A. Function, Responsibilities and Authority

Responsible to direct and coordinate Mechanical/Nuclear power Plant Engineering design to optimize cost, availability, maintainability, efficiency and operability. The principle accountabilities are as follows:

(1) Organize and manage Plant Mechanical/Nuclear Engineering and select, develop and evaluate the mechanical/nuclear personnel to ensure that technical and project competence meet the mechanical/nuclear engineering design objectives.

(2) Coordinate and direct Plant Mechanical/Nuclear Engineering in establishing design criteria and in providing the expertise for decision making in the areas of plant system; for new power plants to ensure the design optimizes cost, availability, maintainability, efficiency and operability.

(3) Train, coordinate and direct Plant Mechanical/Nuclear Engineering personnel in the efficient technical performance of procurement activities such as vendor technical qualification, specifications, bid reviews, change control, acceptance activities, etc.

(4) Direct mechanical/nuclear engineering personnel in ensuring mechanical/nuclear designs comply with local, state and federal codes, rules and regulations.

(5) Coordinate and direct personnel in the evaluation and authorization of architect-engineer activities; provide FP&L direction of courses of action and evaluation of the technical and cost aspects of scope changes; and evaluate and implement as required inputs from Power Resources, Nuclear and General Engineering, Construction and others within FP&L.

(6) Direct the preparation of FP&L Power Plant Standards for the purpose of standardizing documentation, design, construction practices, storage of equipment and testing.

(7) Direct mechanical/nuclear personnel in providing technical assistance to operating power plants for design modifications, tests, or problem solving.

B. Educational Background

BSME University of Florida
Graduate courses conducted by the University of Florida in Indoctrination to Nuclear Engineering, Nuclear Engineering Laboratory, and Advanced Nuclear Technology.
Completed Westinghouse Reactor Training Program and qualified on the Saxton Reactor. Trained at Turkey Point as student and instructor and qualified for Senior Reactor Operator License on Turkey Point Nuclear Units.

C. Experience-Nuclear

Worked in nuclear related work at FP&L for 13 years in the operating and engineering departments. Worked for eight years for FP&L in start-up, testing and special projects on modern fossil fuel generating units. Total of 21 years in engineering areas related to the electric utility.

D. M. Van Tassell, Jr.
Manager - Plant Electrical Engineering

A. Function, Responsibilities, and Authority

The basic function of the Manager Electrical Engineering is to direct and coordinate electrical power plant engineering

design to optimize cost, availability, maintainability, efficiency and operability.

The principle responsibilities of this position are:

(1) Organize and manage Plant Electrical Engineering and select, develop and evaluate the electrical personnel to ensure that technical and project competence meet the electrical engineering design objectives.

(2) Coordinate and direct Plant Electrical Engineering in establishing design criteria and in providing the expertise for electrical decision making in the areas of auxiliary power systems, controls and instrumentation for new power plants to ensure the design optimizes cost, availability, maintainability, efficiency, and operability.

(3) Train, coordinate and direct Plant Electrical Engineering personnel in the efficient technical performance of procurement activities such as vendor technical qualification, specifications, bid reviews, change control, acceptance activities, etc.

(4) Direct electrical engineering personnel in ensuring electrical designs comply with local, state and federal codes, rules and regulations.

(5) Coordinates and direct personnel in the evaluation and authorization of architect-engineer activities. Provide FP&L direction and courses of action and evaluation of the technical and cost aspects of scope changes, and evaluate and implement as required inputs from Power Resources, Nuclear and General Engineering, Construction and others within FP&L.

(6) Direct the preparation of FP&L Power Plant Standards for the purpose of standardizing documentation design, construction practices, storage of equipment and testing.

(7) Direct electrical personnel in providing technical assistance to operating power plants for design modifications, tests or problem solving.

B. Educational Background

Received a Bachelor of Science in the Power Option of Electrical Engineering from Drexel University in 1962. Continued education by completing successfully a Rectifier Circuit Theory Course, an Electronic Course, a Review Mathematics Course for Engineers, a Material Applications Course for Engineers and a High Voltage Dielectric Behavior Course while with the General Electric Company. Also completed successfully the Power System Analysis Course at FP&L.

C. Experience

(1) Nuclear

(a) Directly related

Upon joining FP&L in April, 1971, until November, 1973 was directly responsible for the electrical design review of FP&L Nuclear Generating facilities under construction.

From November, 1973 to the present has been responsible for the supervision of all electrical work and design review performed on all FP&L power plants both nuclear and fossil.

(b) Other

During the time he was with General Electric's relay department worked on several jobs associated with nuclear power.

(2) Other

From 1950 through a portion of 1967 was employed by the General Electric Company; during this period a series of positions of increasing responsibility were held. Served as a tester of AK circuit breakers; requisition engineer for control switches, indicating lamps and wiring devices; requisition enginner for protective relays; requisition engineer for power rectifier equipment; design engineer for type AKD load center equipment; and magnetic design engineer for the relay department.

From 1967 through a portion of 1969, was employed by the Electromagnetic Compatibility Branch of ITT - Federal Electric Company at NASA - Kennedy Space Center. Was employed as an engineer and served for one year as Branch Chief.

From 1969 to early 1971 was employed by the Electric Utilities Branch of Trans World Airlines at NASA - Kennedy Space Center. Was first employed as a System Engineer on the NASA Power System and served the last year as supervisor of engineering responsible for auxiliary systems consisting of standby diesel generators, protective relays, the supervisory control system and fault and transient recorders.

Total of 25 years in engineering.

H. H. Jabali
<u>Supervisor - Plant Civil Engineering</u>

A. Function, Responsibilities and Authority

Supervise and manage the Civil engineering section within Power Plant Engineering Dept. Direct civil engineering personnel in preparing design modifications and additions at operating power plants and in providing technical assistance in the civil areas to other FP&L departments. Establish scope and design criteria of power plants in the civil, structural and architectural areas and directs the engineering activities of the architects engineers and consultants to ensure implementation thereof.

B. Educational Background

BSCE, 1968, University of Miami
MSCE, 1970, University of Miami
Major: Structures
Minor: Applied Mathematics
MS Theoretical & Applied Mechanics, 1971, Northwestern University
Major: Solid Mechanics

C. Experience

(1) Nuclear

Worked for Sargent & Lundy Engineers in structural design work for nuclear plants for five years. Worked for FP&L in civil design areas and Supervisor, Civil Engineering for three years.

(2) Worked in structural research and development areas for three years in Academic - Teaching & Research area.

Total of eight years in engineering areas related to the electric utility.

F. G. Flugger
<u>Supervisor Plant Licensing Engineering</u>

A. Function, Responsibility and Authority:

Responsible for ensuring that nuclear plant designs are in compliance with NRC regulations. Responsible for regulatory design features in new plant design and for modifications to existing nuclear plants.

Responsible for development and implementation of the Power Plant Engineering Department's QA Program. Approval of design in areas involving NRC jurisdiction.

B. Educational Background

Bachelor of Marine Engineering
MS in Engineering Science (AEC Fellow)
Graduate work beyond MS, 42 credits
MIT Reactor Safety Course
NUS Advance Nuclear Fuel Management Course

C. Experience-Nuclear

(a) Directly related

Worked for six years with Consolidated Edison Company in nuclear engineering and management areas. Worked for two years on nuclear projects for Long Island Lighting. Worked for NUS Corporation for 1-1/2 years in nuclear areas. Worked on nuclear plants in engineering and design for FP&L for six years. This is a total of 16 years in nuclear related work.

(b) Other

Worked for two years in other work related to utilities.

Total 18 years utility experience.

J. R. Tomonto
<u>Manager - Nuclear Analysis</u>

A. Function, Responsibility and Authority:

Responsible in providing direction of the Nuclear Analysis Department in the following areas: Technical assessments of nuclear fuel designs, nuclear plant safety systems and preparation of reload licensing reports. Functional reviews of vendor supplied nuclear physics, thermal, hydraulic and safety designs of nuclear cores to ensure that they meet operational, regulatory and quality assurance requirements. Perform safety analyses to support plant operation and recommend procedures to meet established criteria. Perform analyses of reload nuclear fuel designs to ensure that all parameters are within established limits. Develop procedures and methods used to verify that nuclear plant power distributions are within technical specification limits. Assist and augment nuclear plant Reactor Engineering staffs during refueling, start-ups and special test evaluations. Authority is in the administration and technical guidance of the Nuclear Analysis Department.

B. Educational Background

BS in physics, Villanova University, 1954 MS in Reactor Physics, Rensselaer Polytechnic Institute, 1959.

Advanced Reactor Engineering Program conducted by the Knolls Atomic Power Laboratory, 1960-62. Engineering Management Skills Course, 1969. Doctoral Student in Nuclear Engineering, N.Y. University, 1967 to 1970.

Gulf Corporation Management Training Program, 1973.

C. Experience

(1) Nuclear

Manager, Nuclear Analysis Department, FP&L, Miami, Florida, March, 1974 to present. Manager, Nuclear Engineering Department Gulf United Nuclear Fuels Corporation, Research and Engineering Division, Elmsford, N.Y., January, 1970 to March, 1974. Manager, Nuclear Development Section, United Nuclear Corporation, Elmsford, N.Y., March, 1964 to January, 1970. Nuclear Physicist, Knolls Atomic Power Laboratory, Schenectady, N.Y., November 1959 to March, 1964. Nuclear Engineer, Alco Products, Inc., Nuclear Power Engineering Division, Schenectady, N.Y., June, 1958 to November, 1959.

(2) Other

Electrical Engineer, Airborne Instrument Laboratory, Modoe Division, Thornwood, N.Y., June, 1957 to September, 1957. Chief Engineer, DD775, U.S. Navy, Norfolk, Va., June, 1954 to June, 1957.

C. S. Kent
Engineering Project Manager - St Lucie Nuclear Units 1 and 2

a) Function, Responsibilities, and Authority

Responsibilities for coordinating Power Plant Engineer design/ review activities. Responsible for engineering budgets and schedules. Responsible for directing the architect-engineer and NSSS vendors.

b) Educational Background

BS Chemistry - Florida Southern College
MSE Nuclear Engineering, University of Florida

c) Experience

1) Nuclear

Worked in design and project engineering related areas for FP&L in nuclear plant related assignments for 10 years.

2) Other

Two years

Total of 12 years utility experience.

Dr. Robert E. Uhrig
Vice President - Advanced Systems and Technology

B.S. (with honors) Mechanical Engineering, University of Illinois 1948
M.S. Theo. and Applied Mechanics, Iowa State University 1950
Ph.D. Theo. and Applied Mechanics, Iowa State University 1954

1948 - 1951	Iowa State University Teaching Staff
1951 - 1952	Institute for Atomic Research, Iowa State University, Research Asst.
1952 - 1954	Institute for Atomic Research, Iowa State University, Graduate Asst.
1954 - 1956	Department of Mechanics, U. S. Military Academy, West Point (on active duty with U. S. Air Force)
1956 - 1960	Institute for Atomic Research, Iowa State University Associate Professor of Theoretical and Applied Mechanics and Nuclear Engineering, Nuclear Reactor Supervisor, Group Leader of Nuclear Engineering, Group III
1960 - 1967	University of Florida, Professor and Chairman, Department of Nuclear Engineering Sciences
1967 - 1968	Department of Defense - Deputy Assistant Director for Research (on leave of absence from University of Florida)
1968 - 1973	University of Florida, Dean, College of Engineering and Director, Engineering and Industrial Experiments Station

1973 - Present FP&L - Vice President - Advanced Systems and Technology

Registered Professional Engineer - Florida and Iowa States

Member of:

American Society for Engineering Education
American Nuclear Society
American Society of Mechanical Engineers
National Society of Professional Engineers
American Association for Advancement of Sciences
American Institute for Aeronautics and Astronautics
Florida Engineering Society

O. F. Pearson, III
Director, Licensing and Environmental Planning Department

Education: Georgetown University Law Center - Juris Doctor
Cornell University - Master of Engineering (Nuclear)
Cornell University - Bachelor of Engineering Physics
Harvard University - Completed a program for Management Development

Experience: 1966-1972: Reactor Engineering Branch Head in the Division of Naval Reactors.

1972-1973: Executive Assistant to Vice President Power Plant Engineering and Construction.

1973-1975: Executive Assistant to Vice President Strategic Planning, FP&L.

1976 - Present: Director of Licensing and Environmental Planning, FP&L.

Member of: American Bar Association
District of Columbia Bar
The Florida Bar
AIF Steering Committee on Licensing and Safety
AIF Environmental Committee
American Nuclear Energy Council

J. A. DeMastry
Assistant Manager, Nuclear Licensing

Education: Ohio State University - Graduate School
Metallurgical Engineering - One Year
Ohio State University - B.Sc. 1953

Experience: 1974 - Present: Assistant Manager, Nuclear Licensing

To plan, coordinate and direct overall company licensing program in order to obtain and maintain the various nuclear

regulatory licenses and approvals necessary for nuclear power plant siting, construction and operation.

General Experience: Twenty-three years experience in nuclear licensing, engineering management, reactor plant design, nuclear fuel development, nuclear marketing, nuclear safety, general nuclear technology and quality assurance. Experience in preparing plant licensing documents. Last 10 years experience has been at various levels of engineering management such as nuclear applications. Specific experience in design of reactor containment. Experienced in developing materials and components for use in nuclear reactors. Active in studying liquid metals and their interactions with materials and components. Experience in fracture mechanics studies of metals and ceramics, welding and effect of welds on materials properties. Administered mechanical properties laboratories concerned with studying the effects of environmental such as temperature, radiation, vacuum, etc. on materials and components. Author and/or coauthor of more than 30 technical papers and in access of 50 technical reports. Active in professional societies.

August L. Heil
Assistant Manager for Neutronics and Fuel Management

BS, Metallurgy and Materials Science, Carnegie Mellon University

1950 - 1968 Supervisor, Core Manufacturing, Westinghouse Bettis Laboratory; fabrication of reactor fuel and core components for the Naval Nuclear Program including Shippingport. Development of new fabrication processes and preparation of in-pile fuel test samples.

1968 - 1970 Supervisory Engineer, Nuclear Materials and Equipment Corporation; process engineering responsibility for the fabrication of the portable military type reactor cores and qualification fuel assemblies for commercial reactors.

1970 - 1974 Project Manager, Westinghouse Nuclear Fuel Division; project management and administration of the commercial nuclear fuel contracts in the southeast.

1974 - Present FP&L, Nuclear Analysis Department Assistant Manager for Neutronics and Fuel Management

Member of: ANS and ASME

J. E. Carson
Manager of Fuel Supply

BSEE, Duke University, 1949
University of Florida Extension Nuclear Engineering, 1966
NUS Nuclear Fuel Management, 1969

1949 - 1955	City of Danville, Virginia, Power Engineer; engineering electrical power transmission and distribution
1955 - 1957	FP&L; Senior Field Engineer; distribution engineering and commercial service
1957 - 1964	FP&L; Assistant Supervisor; transmission and distribution construction supervision, metering, overhead, underground, trouble
1964 - 1968	FP&L; Industrial Relations Supervisor; labor contract administration and negotiations
1968 - Present	FP&L; Manager of Fuel Supply; oil, gas and nuclear fuel procurement and contract administration
Member of:	ANS, IEEE, Federal Power Commission Technical Advisory Committee on Fuels

13.1.2 OPERATING ORGANIZATION

13.1.2.1 Plant Organization

Figure 13.1-8 provides a chart showing the title of each position, the number of operating shift crews, and the positions for which reactor operator and senior reactor operator licenses are required. Table 13.1-1 displays plant staffing changes to the existing St. Lucie Unit 1 organization to accommodate operation, administration and maintenance of St. Lucie Unit 2. These changes follow manpower requirements to support St. Lucie Unit 2 and may vary slightly dependent upon project progress and schedule.

13.1.2.2 Plant Personnel Responsibilities and Authorities

The function, responsibilities, and authorities of plant positions are described below. These positions are indicated on the organizational chart of Figure 13.1-8.

a) Plant Manager

The Plant Manager reports to the Assistant Manager Power Resources-Nuclear (refer to Figure 13.1-3) and has direct responsibility for operating and maintaining the plant in a safe, reliable and efficient manner. He is responsible for protection of the plant staff and the general public from avoidable radiation exposure and/or any other consequences of an accident at the plant. He bears the responsibility for compliance with the facility operating license. He has the authority to take any action necessary, without consultation, to prevent or mitigate the consequences of an accident.

b) Operations Superintendent

The Operations Superintendent reports to the Plant Manager and acts in his behalf during his absence. He is responsible to the Plant Manager for operating and maintaining the plant in a safe, reliable, and efficient manner. He will assume the duties and responsibilities of the Plant Manager as the primary alternate to that position.

c) Operations Supervisor

The Operations Supervisor has the responsibility for directing the actual day-to-day operation of the unit and holds a Senior Operator License. He reports directly to the Operations Superintendent and directs the plant operating staff. He coordinates operations related activities with all departmental supervisors. He assumes all of the Operations Superintendent's responsibilities and authority in his absence. He is responsible for overall supervision of fuel handling operations. He has the authority to shut down the unit, initiate the Emergency Plans, and issue standing orders on a day-to-day basis.

d) Plant Supervisor

The Plant Supervisor is responsible for the actual operation of the plant on his assigned shift. He reports to the Operations Supervisor and directs the activities of the operators on his shift. He must be cognizant of all maintenance activities being performed while he is on duty. The Plant Supervisor on duty has the authority to shut down the unit if, in his opinion, conditions warrant this action. He has the authority and responsibility to initiate the Emergency Plans and to issue standing orders for operation in conjunction with the Operations Supervisor. The Plant Supervisor is the Emergency Coordinator when the Emergency plan is in effect. During fuel handling operations he may direct the operation or operate fuel handling equipment. Responsibilities are specified by an administrative procedure. /A

e) Watch Engineer

The Watch Engineer is the working operating foreman and is responsible for plant operations on his shift. He reports to the Plant Supervisor. Upon assignment he may assume the responsibilities of Plant Supervisor. During fuel handling operations he shall direct or operate fuel handling equipment. He is also the fire team leader /D and maintains proper qualifications for this position. The Watch

Engineer on duty has the authority to shut down the unit if in his opinion conditions warrant this action. He has the authority to initiate the Emergency Plans. Responsibilities are specified by an administrative procedure. /A

f) Control Center Operator

The Control Center Operator operates controls and monitors instruments located in the control room containing reactor, turbine-generator and transmission line control boards, and under direct or general supervision directs the operation of all plant equipment as required to maintain proper operating conditions. He executes or directs the execution of orders received from the Plant Supervisor, Watch Engineer, and Dispatcher. He has the authority to shut down the unit if in his opinion conditions warrant this action. During fuel handling operations, he may operate fuel handling equipment under general supervision. He may operate radiation survey instruments. Responsibilities are specified by an administrative procedure. /A

g) Shift Technical Advisor

The Shift Technical Advisor provides an independent, dedicated concern for the safety of the St. Lucie Plant. This is accomplished by providing diagnostic support in an advisory capacity only to Operations personnel during off-normal events and by advising the Plant Supervisor on actions to terminate or mitigate the consequences of such events. The Shift Technical Advisor is responsible to the Technical Supervisor. Responsibilities are specified by an administrative procedure. The Shift Technical Advisor position may be eliminated if the Plant Supervisor meets the Shift Technical Advisor education, training and qualification guidelines. /A

h) Nuclear Operator /R

The Nuclear Operator operates nuclear reactor auxiliary equipment and turbine-generator auxiliary equipment under the direction of a licensed Operator or Senior Operator. He performs inspections of operating equipment and systems including but not limited to the Reactor Coolant System, Chemical and Volume Control System, Component Cooling Water, Shutdown Cooling and Spent Fuel Pool Cooling Systems, Waste Management System, engineering safety features systems and components, radiation detection equipment, containment and radioactive area ventilation and purge systems, Primary Water Makeup System, refueling water tank, gas supply systems, liquid and gas sampling and analysis equipment, and chemical feed addition equipment. He performs operating adjustments and services, records operating data, and operates radiation survey instruments. During fuel handling operations he may operate fuel handling equipment under the supervision of a licensed operator. He may operate other plant auxiliary equipment under the direction of a Plant Supervisor, Watch Engineer, or Control Center Operator. Responsibilities are specified by an administrative procedure. /A

i) Nuclear Turbine Operator /R

The Nuclear Turbine Operator operates turbine controls and serves as turbine-generator attendant. He acts under the direction of a licensed operator or senior operator, may be assigned additional duties, can assist the Nuclear Operator, performs operating adjustments and services, and records operating data. He is a member of the fire team and is properly qualified for this position. Responsibilities are specified by an administrative procedure. /A

j) Auxiliary Equipment Operator /R

The Auxiliary Equipment Operator operates plant auxiliary equipment, such as the Water Treatment Plant and the Intake Cooling Water System equipment. He may operate other plant auxiliary equipment under the

direction of a Plant Supervisor, Nuclear Watch Engineer, or a Control Center Operator.He is a member of the fire team and is properly qualified for this position. Responsibilities are specified by an administrative procedure. /A

k) Technical Supervisor /R

The Technical Supervisor reports to the Plant Manager and is responsible for supervision of the staff engineers and directs activities concerning technical analysis and advisory services. The Technical Supervisor is responsible for the operating experience feedback function. /A

l) Reactor Supervisor /R

The Reactor Supervisor conducts or supervises tests, accumulates and evaluates data and maintains records of the performance of the ~~all~~ plant ~~equipment~~ including core performance and fuel records. He reports to the Operations Superintendent. He has the responsibility to recommend that the unit be shut down if in his opinion conditions warrant this action. He has the authority to initiate the Emergency Plans.

m) Health Physics Supervisor /R

The Health Physics Supervisor conducts or supervises surveys and monitoring programs to detect, measure, and assess radiation levels within the facility and maintains records and reports of all radiation surveys and monitoring programs. He instructs or assists in the instruction of all personnel in the basic principles of radiation protection. He assists or supervises decontamination operations.

He has the responsibility to recommend that the unit be shut down if in his opinion conditions warrant this action, and he has the authority to initiate the Emergency Plans. The Health Physics

Supervisor reports to the Operations Superintendent. He also has an authorized direct line of communication to the Power Resources Staff Health Physics Section Supervisor and to the Plant Manager. These lines of communication give him access to upper management to assure that exposures are as low as reasonably achievable.

n) Instrument and Control Supervisor /R

The Instrument and Control Supervisor reports to the Maintenance Superintendent and is responsible for supervision of maintenance, calibration and installation of all instrument and control equipment and for maintenance of instrument and control records. He has the authority to shut down the unit if in his opinion conditions warrant this action, and he has the authority to initiate the Emergency Plans.

o) Chemistry Supervisor /R

The Chemistry Supervisor conducts or supervises the chemical and radiochemical analyses of water~~,~~ and gas~~, and solid~~ samples. He evaluates test results and directs corrective measures incident to the analyses. He has the authority to initiate the Emergency Plans.

p) Maintenance Superintendent /R

The Maintenance Superintendent reports to the Plant Manager and is responsible for supervison of the maintenance of all equipment and facilities and for maintaining all required maintenance records.

q) Assistant Superintendent-Mechanical Maintenance /R

The Assistant Superintendent-Mechanical Maintenance reports to the Maintenance Superintendent and is responsible for supervision of the mechanical maintenance of all equipment and facilities and for maintaining all mechanical maintenance records.

r) Assistant Superintendent-Electrical Maintenance /R

The Assistant Superintendent-Electrical Maintenance reports to the Maintenance Superintendent and is responsible for supervision of the electrical maintenance of all equipment and facilities and for maintaining all electrical maintenance records.

s) Quality Control Supervisor /R

The Quality Control Supervisor reports to the Plant Manager and is responsible for the coordination of the overall quality control (QC) effort within the St. Lucie Plant organization. Refer to FPL Topical Quality Assurance Report (FPLTQAR) 1-76A Rev 4 for a more detailed description of the Quality Control Supervisor's responsibilities.

The following describes the line of succession of authority and responsibility for the overall station operation in the event of unexpected contingencies of a temporary nature:

a) Plant Manager
   1) Operations Superintendent
   2) Operations Supervisor

b) Operations Superintendent
   1) Operations Supervisor
   2) Plant Supervisor
   3) Watch Engineer

c) Operations Supervisor
   1) Plant Supervisor
   2) Watch Engineer

13.1.2.3 Operating Shift Crews

The normal operations shift for two units consists of a Plant Supervisor, Watch ~~Engineer,~~ two Control Center Operators, ~~a~~ Shift Technical Advisor, Nuclear Operator and Turbine Operator. The Plant Supervisor is directly responsible to the Operations Supervisor for all operations on his shift. Personnel will hold NRC licenses as shown in Figure 13.1-9. /A

During and following initial core loading, a licensed Senior Operator will be on site at any time fuel is being handled in the refueling facilities and/or in the reactor, or when fuel is in either reactor.

During fuel handling operations on either unit, one senior reactor operator is assigned the responsibility of fuel handling with no other concurrent duties. A licensed operator operates the refueling machine and another licensed operator monitors fuel handling operations from the control room of the affected unit. The other refueling stations are manned by licensed and non-licensed operators as required to perform the evaluation.

The minimum shift crew has five members dedicated to fight fires during a control room inaccessibility situation. The minimum shift crew composition is given in ~~Table 13.1-2 for St. Lucie Units 1 and 2.~~ Section 6.2.2, Facility Staff, of the Technical Specification. Licensed personnel are shown on Figure 13.1-8. /R

St. Lucie Unit 1 presently schedules qualified radiation protection men (RPM) on shift 24 hours per day, seven days per week. This schedule will be expanded to include Unit 2 when necessary.

13.1.3 QUALIFICATIONS OF NUCLEAR PLANT PERSONNEL

FPL complies with Regulatory Guide 1.8, "Personnel Selection and Training" September 1975 which generally endorses ANSI N18.1-1971. This Regulatory Guide is addressed by FPL TQAR 1-76A, Rev. 4. /R

13.1.3.1 Qualifications Requirements

ANSI N18.1-1971 describes the minimum qualifications for several of the management, operating, technical and maintenance position categories specified in Subsection 13.1.2. In addition to these qualifications, senior reactor operator license candidates will have one year of experience as a reactor operator or equivalent experience. Table 13.1-~~3~~2 provides the correlation between the position titles specified in ANSI N18.1-1971and the actual St. Lucie Plant Staff positions. /A

Qualifications for personnel not specifically addressed in ANSI N18.1-~~1981~~ 1971 are specified below: /R

The Shift Technical Advisor shall have a bachelor's degree or equivalent in a scientific or engineering discipline. Specific training is provided in response and analysis of the plant for transients and accidents; details of the design, function, arrangement and operation of plant systems; and response of instrumentation and controls in the Control Room. /A

13.1.3.2 Qualifications of Plant Personnel

The qualifications of incumbents in key plant supervisory positions and all licensed personnel are summarized in resume format below. The qualifications of the Startup Superintendent whose responsibilities are discussed in Section 14.2 are also included. /:

Alfred D. Schmidt
Vice President - Power Resources

BME, University of Florida, 1942
Nuclear Engineering course, University of Florida
Management of Radiation Accidents course, EPA, 1972
FP&L Management Development courses, 1972 - Present
Carnegie - Mellon Program for Executives, 1973

1937 - 1942	FP&L; Co-op student
1942 - 1945	FP&L; Junior Engineer, Operation Department
1946 - 1948	FP&L; Betterment Engineer; Sarasota, Lauderdale and Miami Plants
1949 - 1951	FP&L; Assistant Plant Superintendent; Miami Plant
1951 - 1954	FP&L; Plant Superintendent; responsible for operating and maintaining the fossil fuel units, Palatka Plant
1954 - 1957	FP&L; Superintendent of Operations, Power Plants; responsible for safe, efficient operation of all power generating plants in FP&L system
1957 - 1970	FP&L; Regional Superintendent of Power Plants; responsible for operation and maintenance of all units in his region
1970 - 1972	FP&L; Superintendent of Generating Stations
1972 - Present	FP&L; Vice President - Power Resources; responsible for the safe and efficient operation and maintenance of all power plants, including staff support. Since 1978 also responsible for the System Operations, System Protection and Power Supply Technical Services groups.

Registered professional engineer.

Member of: ASME, NSPE, EEI, EPRI

J. Russell Bensen
Assistant to the Vice President - Power Resources

BME, Tulane University, 1946
Nuclear Engineering and Nuclear Engineering Laboratory courses, University of Florida, 1966
Nuclear Fuel Management course, NUS, 1966
Advanced Nuclear Technology courses, University of Florida, 1967
Westinghouse Reactor Operation Training Program and Design Lecture Series, Waltz Mill and Saxton, Pa. 1968-1969
Management of Radiation Accidents Course and Environmental Radiation Laboratory, EPA 1972
FP&L Management Development courses, 1973 - Present

1947 - 1948	FP&L; Water Tester; Miami Beach Plant
1948 - 1949	FP&L; Instrument Mechanic, Miami Plant
1949 - 1951	FP&L; Betterment Engineer, Results Department; Miami Plant
1951 - 1954	FP&L Assistant Plant Superintendent - Operation and Maintenance; Miami Plant
1954 - 1955	FP&L; Assistant Plant Superintendent - Maintenance; Cutler Plant
1955 - 1957	FP&L; Superintendent of Maintenance; Power Plants; responsible for maintenance of all steam generating power equipment in FP&L system
1957 - 1967	FP&L; Regional Superintendent of Power Plants; responsible for operation and maintenance of five power plants in his region
1967 - 1972	FP&L; Regional Superintendent of Power Plants - Nuclear
1972 - 1973	FP&L; Manager of Power Resources - Nuclear; responsible for startup preparation and operation of all nuclear power plants in FP&L system
1974 - 1976	FP&L; Assistant to the Vice President of Power Resources
1976 - 1978	FP&L; Manager Power Resources - Nuclear
1978 - present	FP&L; Assistant to the Vice President - Power Resources

Registered Professional Engineer

Member of: ASME, ANS, NSPE

Lewis E. Cooke, Jr.
<u>Manager Power Resources - Service</u>

BME, University of Florida, 1942

1942 - 1945	U. S. Navy (LCDR RCT) 0
1945 - 1948	FP&L; Operations and Betterment Engineer, Sarasota Plant
1948 - 1950	FP&L; Betterment Engineer, Lauderdale Plant
1950 - 1964	FP&L; Assistant Supt., Lauderdale Plant
1964 - 1973	FP&L; Plant Supt., Cape Canaveral Plant, responsible for all operations and maintenance.
1973 - 1974	FP&L; Plant Manager, Cape Canaveral Plant, responsible for all operations and maintenance at that plant.
1974 - Present	FP&L; Manager of Power Resources - Services

Registered Professional Engineer - State of Florida

Member of: ASME, NSPE

Joseph W. Dickey
Manager - Power Resources - Services

BSCHE - Massachusetts Institute of Technology - 1966
MSCE - Massachusetts Institute of Technology - 1967
University of Virginia - Colgate Darden Graduate School of Business
Administration - The Executive Program - 1978

1967 - 1968	FP&L; Assistant Plant Engineer, Port Everglades Plant
1968 - 1971	FP&L; Plant Engineer, Port Everglades Plant
1971 - 1972	FP&L; Assistant Superintendent - Operations, Port Everglades Plant
1972 - 1973	FP&L; Assistant Superintendent, Temporary assignment to Industrial Relations Department
1973 - 1976	FP&L; Plant Manager, Lauderdale Plant, responsible for all plant operations, maintenance and administration
1976 - 1980	FP&L; Assistant Manager - Power Resources Fossil, responsible for all plant operations, maintenance and administration for Port Everglades, Lauderdale, Ft. Myers, Manatee and Cutler plants
1980 - present	FP&L; Manager - Power Resources - Services.

Registered Professional Engineer - Florida
Member of:

ASCE, NSPE, FES
EEI Prime Movers Committee
EEI Steam & Combustion Turbine Subcommittee
EEI Gas Turbine Operations Task Force
EPRI Advance Power Systems Task Force

M Grosswald
<u>Power Resources Section Supervisor - Maintenance Management Section</u>

Management Development Courses 1973 - 1978

1957 - 1958	FP&L; Helper, Miami Plant
1958 - 1966	FP&L; Mechanic, Miami Beach Plant
1966 - 1973	FP&L; Maintenance Foreman, Cutler Plant
1973 - Present	FP&L; Power Resources Section Supervisor; Maintenance Management

C. E. Branning
<u>Power Resources Supervisor - Operating Section</u>

BSME, University of Florida, Gainesville, Florida, 1954
USAF, Primary and Basic Multi-Engine Flying School - Reese AFB, Texas, 1955
Academic Instructor's Course - Lackland AFB, Texas, 1956
Management and Development Program, FP&L TOP Courses, 1955 - Present

1951	FP&L; Helper at the Miami Plant (Summer Employment)
1953	General Motors Plant Layout, Chevrolet Gear and Axle Co., Detroit, Michigan
1954	FP&L; Student Engineer, Field Service Representative, Coral Gables Office
1954 - 1955	FP&L; Field Engineer, Riviera Plant
1955 - 1957	U.S.A.F., Rated Pilot, Candidate School Instructor, Advanced to rank of 1st Lieutenant
1957 - 1960	FP&L; Plant Test Engineer, Riviera Plant; Conducted plant equipment performance tests, supervised installation and operation of systems added to existing plant
1960 - 1966	FP&L; Plant Engineer, Riviera Plant. Supervised Results Department for water testing and treatment, plant instrumentation and control, performance testing and evaluation.
1966 - 1970	FP&L; Assistant Plant Superintendent, Riviera Plant. Responsible for Plant Operations and Results Departments.
1970 - 1972	FP&L; Start-Up Coordinator at Turkey Point Plant. Responsible for coordination of Mechanical, Electrical and Instrument Control Start-Up Groups in the flushing, cleaning, pre-operational testing, and other activities necessary to make the plant ready to receive fuel.
1972 - 1974	FP&L; Plant Manager, Turkey Point Plant
1974 - Present	FP&L; Power Resources, Section Supervisor - Operations

E. D. Scrogin
Power Resources Section Supervisor - Administration

Associate of Arts, University of Florida, 1938
Bachelor of Mechanical Engineering, University of Michigan, 1941
FP&L Management Development courses, 1973 - Present

1941 - 1945	U. S. Navy (Commander-Ret.); ship repair Supervisor
1945 - 1947	Blalock Machinery & Equipment Co.; Sales Engineer
1947 - 1948	FP&L; Special Employee, Sarasota Plant, training
1948 - 1949	FP&L; Special Employee, Cutler Plant, training
1949 - 1969	FP&L; Plant Superintendent; experience in the operation, maintenance and supervision of modern oil and gas fueled steam power plants; participated in startup of six high pressure boiler and turbine generator units.
1969 - 1972	FP&L; Power Resources Department Supervising Engineer; Supervised Procedures Writing Group, Turkey Point Plant
1972 - Present	FP&L; Power Resources Section Supervisor - Administration

Registered Professional Engineer

Member of: ASME, FES, NSPE

R. A. Watson
Power Resources Section Supervisor - Tests and Performance

Washington Comptometer School, 1936
B. S. Chemistry, University of Maryland, 1942
Navy Communications and Radio, 1943
Radiological Monitoring, U.S. Department of Interior, 1961
Meteorological Aspects of Air Pollution, U. S. Public Health Service, 1965
Nuclear Engineering and Nuclear Engineering Laboratory courses, University of Florida, 1966
Basic Radiological Health, U. S. Public Health Service, 1966
Radionuclide Analysis by Gamma Spectroscopy, USPHS, 1966
Advanced Nuclear technology, University of Florida, 1967
FP&L Management Development Courses, 1972 - 1973

1942 - 1946	U. S. Navy; (Lt.) Communications Department
1945 - 1948	National Bureau of Standards, Analytical Chemist
1948 - 1949	U. S. Navy; (Lt.) Communications Department
1949 - 1952	Armed Forces Security Agency, Research and Analytical Chemist in Organic and inorganic Chemistry
1952 - 1972	FP&L; Production Test Group, Power Supply Department, Assistant Engineer, Engineer, Senior Engineer, Production Test Supervisor. Established analytical chemistry laboratory for fuel analysis. Consult with Plant Resources Department on water for treatment and control procedures. Set up programs for evaluating fuel additives. Design sampling and analytical programs for environmental analysis of air and water. Work with Environmental Engineering Department in setting up long range sampling and test programs for surface and ground water. Design, construct, purchase, calibrate and operate varied instrumentation used for equipment acceptance and performance tests. Set up computer programs for calculation and reporting of results. Coordinate activities of power plant personnel and consultants in obtaining climatological and meteorological data.
1972 - Present	FP&L; Power Resources Section Supervisor - Tests and Performance

Member of: Health Physics Society

M. S. Gonzales
<u>Power Resources Section Supervisor - Instrument & Control and Electrical Maintenance</u>

BEE, University of Havana, 1953
Advanced Nuclear Technology course, University of Florida, 1967
FP&L Management Development courses, 1973 - Present

1956 - 1961	Cuban Electric Company; Junior Engineer to Results Engineer
1961 - 1966	Bailey Meter Company; Foreign Service Engineer; control systems design and electric power plants startup
1966 - 1967	FP&L; Plant Engineer, Results Department; Turkey Point Plant; Calibration checks and startup of instruments and controls, Turkey Point Units 1 and 2
1967 - 1973	FP&L; Assistant Plant Superintendent; Turkey Point Plant; checkout and documentation of all instrumentation and controls, Turkey Point Units 3 and 4
1973 - Present	Power Resources Section Supervisor; Supervises Power Resources I & C and Electrical Staff

Registered Professional Engineer

Member of: ASME, ISA

Clarence O. Woody
<u>Manager Power Resources - Nuclear</u>

U. S. Army, Corp of Engineers Electrician, 1956
ICS Electrical Engineering/Plant Electrician, 1957 - 1960
Electronic Technology, MCC, 1964
FP&L Electrical Apprenticeship, 1961
University of Miami, MBA, 1977
Massachusetts Institute of Technology - Reactor Safety, 1978
FP&L Management Development course, 1972 - present

1956 - 1962	U. S. Army: Staff Sergeant (E5) Active and Reserve status; U. S. Corps of Engineers Electrician Instructor, Ft. Leonardwood, MO; U. S. Sig. Corps Active Reserve responsible for signal equipment on company level as Supply Sgt.
1956 - 1957	FP&L; entrance level position through Auxiliary Equipment Operator in two fossil fuel plants - Miami Beach and Miami
1957 - 1960	FP&L; Plant Apprentice Electrician under the standard apprentice training program - completed April, 1961. Instructor in program 1965 - 1969

1960 - 1964	FP&L; Journeyman Electrician, Cutler Plant performing all types electrical maintenance. Approximately 30 percent of this time spent at other plants on major overhaul work.
1965 - 1969	FP&L; Chief Electrician, Cape Canaveral Plant: primary responsibility for check out, startup and maintenance of all electrical devices and controls on two 400 MW fossil fuel units; maintained all equipment and administered department personnel.
1969 - 1972	FP&L; Assistant Superintendent, Cape Canaveral Plant: Responsible for all mechanical and electrical equipment and personnel administration of said department.
1972 - 1973	FP&L; Superintendent of Maintenance, Port Everglades Plant: Duties involved all mechanical-electrical and instrument responsibilities.
1974 - 1976	FP&L; Assistant Manager of Power Resources Fossil: Responsible for the operation and administration of four fossil fuel plants.
1976 - 1978	FP&L; Assistant Manager Of Power Resources Nuclear: Responsible for operation, maintenance and administration of one nuclear plant.
1978 - present	FP&L; Manager of Power Resources Nuclear: Responsible for operations, maintenance and administration of all nuclear generation.

K. N. Harris
<u>Assistant Manager Power Resources - Nuclear</u>

Graduate - Academy of Aeronautics, Long Island, N.Y. 1959
Industrial Electronics course, Central Technical Institute 1963
Awarded SRO-912, 1967, SRO-1612, 1972
Management Development courses, 1972 - Present
Stanford Executive program August 1977
Master of Business Administration - University of Miami 1981

1961 - 1966	Combustion Engineering, Naval Reactor Division; Assistant Shift Supervisor; qualified as Engineering Officer of the Watch, trained naval personnel on SIC, nuclear prototype plant; supervisor of off-hull operations. Responsible for operation & maintenance of all SIC prototype support systems.
1966 - 1970	Connecticut Yankee Atomic Power Company; Shift Supervisor and Refueling Supervisor; participated in plant construction, initial startup and full commercial power operation; held AEC Senior Operator license.

1970 - 1972	FP&L; Power Resources Department: Assistant Plant Superintendent - Operations, Turkey Point Plant; attended Nuclear Operators Training Program and received AEC SRO Turkey Point 3 and 4. Responsible for Plant Operations.
1972 - 1978	FP&L; Power Resources Department; Plant Manager. Responsible for operations, maintenance and administration of the St. Lucie Plant.
1978 - Present	FP&L; Assistant Manager Power Resources - Nuclear.

~~George E. Liebler~~
<u>Manager Power Resources - Nuclear Services Three Mile Island Task Force Coordinator</u>

BSEE, Rensselaer Polytechnic Institute, 1938
Management Development courses 1953, 1954
Nuclear Engineering and Advanced Nuclear Technology courses, University of Florida 1966, 1967
Nuclear Power Reactor Safety course, MIT, 1967
Westinghouse Reactor Operation Training Program and Design Lecture Series, Waltz Mill and Saxton, Pa., 1968 - 1969

1939 - 1943	FP&L; Fireman and Watch Engineer, Bradenton Plant
1946 - 1954	FP&L; Betterment Engineer, Plant Engineer, Assistant Plant Superintendent, Miami Beach Plant
1954 - 1960	FP&L; Plant Superintendent, Palatka Plant, supervised startup
1960 - 1967	FP&L; Plant Superintendent, Port Everglades Plant, supervised startup, responsible for operation and maintenance of fossil fuel units
1967 - 1972	FP&L; Coordinating Engineer, Production Department, nuclear training program and participated in hot functional tests and startup of Ginna Nuclear Plant, Acting Plant Superintendent, responsible for startup of Turkey Point Unit 3
1973 - 1979	FP&L; Manager Power Resources - Nuclear Services
1979 - present	FP&L; Three Mile Island Task Force Coordinator

Registered professional engineer

Member of: ASME, IEEE, ANS, NSPE

H. N. Paduano, Jr.
Manager of Power Resources - Nuclear Services

BCHE, University of Virginia, 1964
U. S. Navy Nuclear Power School, 1965
Environmental Management of Nuclear Power Plant, 1972
FP&L Management Development, 1973 - Present

1964 - 1969	U. S. Navy, Nuclear Power School, Nuclear Plant Watch Officer, Electrical Division Officer, Nuclear Ship Superintendent, construction and testing of reactor plant
1969 - 1972	Westinghouse Electric Corporation, Fluid Systems Engineer, PWR Systems Division. Systems design, multi-project systems field follow-up during plant construction, startup and hot functional testing; member of team that established modifications to ECCS to meet AEC interim criteria
1972 - 1973	Potomac Electric Power Company, Senior Fluid Systems Engineer, Nuclear Engineering Management Group responsible for directing activities incident to Nuclear Steam Supply System licensability, radwaste systems, Emergency Core Cooling System, steam generators and miscellaneous reactor auxiliary systems
1973 - 1977	FP&L; Power Resources Specialist, Nuclear Projects
1977 - 1979	FP&L; Power Resources Section Supervisor - Plant Support; Provides technical assistance to operating nuclear power plants in the areas of trouble shooting maintenance, safety evaluations, responses to NRC questions, and special project coordination.
1979 - present	FP&L; Manager of Power Resources - Nuclear Services; responsible for the overall direction of the Power Resources General Office Nuclear Staff.

Harvey F. Story
Power Resources Supervisor - Health Physics

BCHE Georgia Institute of Technology, 1967
Summer Course, Radiochemistry, University of Missouri at Rolla, 1968
Summer Course, Radioisotope Methodology, Texas A & M University, 1969
MNE, Texas A & M University, 1970
Advanced Health Physics Course, Atomics International, 1975
FP&L Management Development courses, 1973, 1975

1967 - 1969	Columbus College; Chemistry Instructor
1970 - 1971	FP&L; Plant Test Engineer, Procedures, preparation and review of preoperational and operating procedures

1971 - 1973	FP&L; Plant Supervisor, Health Physics, Turkey Point Plant, Assistant to Plant Health Physicist, wrote health physics procedures, assumed Health Physicist's responsibilities during his absence
1973 - 1974	FP&L; Health Physics Supervisor, St. Lucie Plant, initial planning of St. Lucie Plant Health Physics Department
1974 - Present	FP&L; Power Resources Section Supervisor - Health Physics

Member of: Health Physics Society and Power Reactor Health Physicist's Group American Board of Health Physics - Health Physics certification

Gregory A. Patrissi
<u>Power Resources Fire Protection Administrator</u>

A.S. Fire Science Technology, Springfield Technical College, 1972
B.S. Fire Protection Administration, University of New Haven, 1976
Industrial Fire Protection Equipment Operation Course, Industrial Risk Insures Institute, 1977
Nuclear Power Facilities Loss Prevention Course, NELPIA, 1977

1964 - 1968	U. S. Army; Aviation Electronics Specialist
1969 - 1978	Hartford Fire Department, Hartford, Conn., Fire Fighter
1977 - 1978 (part time)	Nuclear Energy Liability - Property Insurance Association; Fire Protection Engineer
1978 - Present	FP&L; Power Resources Fire Protection Administrator

Member of: National Association of Fire Science and Administration, National Fire Protection Association, Fire Protection Engineers Association - Southeastern Chapter, Dade County Chief Fire Officers Association, South Florida Fire Safety Association, International Association of Fire Service Instructors, Society of Fire Protection Engineers.

C. M. Wethy
Plant Manager

BME, University of Miami, 1952
Nuclear Engineering Course, University of Florida, 1966
Westinghouse Reactor Operator Training Program, 1968
Turkey Point Operator Training Program, 1970
MBA, University of Miami, 1975
Business Law, Miami-Dade Community College, 1975

1943 - 1945	United States Navy; Aircraft Carrier
1950 - 1954	FP&L; Cutler Plant, Helper, Water Tender and Instrument Mechanic
1954 - 1968	FP&L; Production Test Group
1968 - 1975	FP&L; Turkey Point Plant, Reactor Engineer, Assistant Plant Superintendent - Technical, and Operating Superintendent
1975 - 1976	FP&L; Power Resource Operations and Maintenance consultant for South Dade Nuclear Project and member of evaluation team for nuclear plant to be built in De Soto County
1976 - 1978	FP&L; St Lucie Unit 2 Power Resources Team Member
1978 - Present	Plant Manager - St Lucie Plant.

Registered Professional Mechanical Engineer, State of Florida, 1967
NRC Senior Operator License - Turkey Point Units 3 and 4, 1972
Registered Professional Nuclear Engineer, State of California, 1977

Member of: ASME, American Nuclear Society, Florida Engineering Society, National Society of Professional Engineers, and Air Pollution and Control Association.

J.E. Bowers
Maintenance Superintendent

Advanced Engineering course, U. S. Maritime School, 1946
Management Training and Mathematics courses, Appalachia Power Co., 1958, 1959, 1967
Applied Electronics course, Indiana & Michigan Electric Corp., 1963
Business Management Motels, Inc., 1966
Electronics Course, RCA, 1969
Management Seminar course, FP&L, 1972

1955 - 1958	Indiana & Kentucky Electric Corp., Asst. Control Room Operator; Auxiliary Equipment Operator
1958 - 1959	Appalachia Power Co.; Control Room Operator/ Unit Foreman
1959 - 1967	Indiana & Michigan Electric Co.; Unit Foreman; Assistant Shift Engineer

1967 - 1969	Pan American World Airways; Load Dispatcher, Supervisor, Coordinator and Scheduling
1967 - 1970	United Engineers and Constructors; Nuclear Start-up Engineer, Construction and design standards verification, Dresden Units 2 and 3; preoperational testing & start-up, nuclear and steam systems
1970 - 1972	FP&L; Mechanical Start-up Group; Plant Supervisor; Turkey Point Unit 3.
1972 - 1973	FP&L; Asst. Plant Superintendent - Maintenance, Turkey Point; Maintenance Supervisor of Units No. 3 and 4
1973 - Present	FP&L; Power Resources Department; Maintenance Superintendent, St. Lucie Plant

A. J. Collier
Instrumentation and Control Supervisor

Army Electronics School, 1949
Army Nuclear Power Plant Operator & Instrumentation Course, 1957 - 1958
Forboro Process Instruments, 1959
Rensselaer Polytechnic Institute, Nuclear Power Plant Operators Training Program, 1967
GE, Boiling Water Technology, 1968
GE, Nuclear & Process Instruments, 1968

1945 - 1957	U. S. Army; Communications, Electronics; Instructor
1957 - 1966	U. S. Army; Nuclear Power Program, Senior Instructor Instruments & Control; Shift Supervisor & NCOIC PWR Simulators
1966 - 1967	Martin Marietta Corp.; Shift Supervisor, PWR
1967 - 1971	Millstone Point Co.; Instrument & Control Supervisor
1971 - 1972	FP&L; Plant Supervisor, Instrument & Control; Turkey Point Plant
1972 - 1973	Millstone Point Co.; Instrument & Control Supervisor
1973 - Present	FP&L; Instrument & Control Supervisor, St. Lucie Plant

M. B. Vincent
Assistant Superintendent - Electrical Maintenance

B. S Electrical Engineering, University of Florida, 1971
Various vendor technical schools
FP&L - Nuclear Power Engineering Program, 1976
FP&L - Management Development Cources, 1974 - present

1971 - 1976	FP&L; Overhead and underground distribution engineer. Responsible for designing elec-

	trical service facilities for new and existing residential and commercial customers.
1976 - 1978	FP&L; Electrical Startup and Maintenance St. Lucie Plant
1978 - Present	FP&L; Assistant Superintendent - Electrical Maintenance

T. A. Dillard
Assistant Superintendent - Mechanical Maintenance

BSME, Letourneau College, 1969

1969 - 1973	Westinghouse Power Generation Service, Field Engineer, Service Specialist, Start-up Engineer Turkey Point Units 3 and 4
1973 - 1974	FP&L; Plant Supervisor, Maintenance Department; Sanford Plant
1974 - Present	FPL; Assistant Superintendent - Mechanical Maintenance, St. Lucie Plant

R. R. Jennings
Technical Supervisor

BSME, Vanderbilt University, 1969
General Electric Co., Operations Management Course, 1972

1969 - 1973	Knolls Atomic Power Laboratory; Shift Supervisor; qualified as Engineering Officer of the Watch and Plant Engineer. Trained naval and civilian personnel in operation, maintenance and testing of S3G, nuclear submarine prototype plant. Senior Training Assistant; prepared various training materials and procedures for safely conducting emergency drills for student and staff training; responsible for man loading and work priorities.
1973 - 1976	FP&L; Start-up Engineer, St Lucie Plant Mechanical Start-up. Responsible for startup testing of various emergency core cooling safety related systems and containment/Shield Building Ventilation Systems.
1976 - 1977	FP&L; Staff Engineer, St Lucie Plant Technical Staff Department
1977 - Present	FP&L; Supervisor, St Lucie Plant Technical Staff Department

Member ASME

John Cordon West
Security Supervisor

B. A. Political Science, St. Mary's College, 1973.
Various military courses including: Area Intelligence Specialist, Defense Against Methods Entry, Investigative Photography, Counterintelligence Agent

1955 - 1975	U. S. Army; CW3 retired, Personnel Specialist, Area Intelligence Agent - Japan and Vietnam, Instructor - U. S. Army Intelligence School, Defense Against Methods Entry and Photo Technician, Senior Counterintelligence Agent
1975 - 1979	FP&L; Senior Security Supervisor - Construction for the Martin County and St. Lucie Unit 2 units.
1979 - Present	FP&L; Security Supervisor St. Lucie Plant.

G. M. Vaux, Jr.
Quality Control Supervisor

BS, Physics, University of New Mexico, 1969
Nuclear Power and Electrician's Mate courses, U. S. Navy

1956 - 1965	U. S. Navy; Electrician's Mate First Class, Instructor at S3G nuclear plant, certified as Operator, S5W and S3G nuclear plants
1965 - 1966	Eberline Instrument Corp.; Electronic Technician
1966 - 1970	Schlumberger Well Services; Field Engineer
1970 - 1972	General Electric Co., Idaho Falls; Plant Engineer at S5G nuclear plant, certified as Senior Reactor Operator
1972 - 1973	FP&L; Plant Supervisor, Mechanical Start-up Group, Turkey Point Units No. 3 & 4
1973 - 1974	FP&L; Staff Engineer; St. Lucie Plant
1974 - Present	FP&L; Quality Control Supervisor, St Lucie Plant

Member of ANS, ASQC

J. H. Barrow
Operations Superintendent

Bachelor of Mechanical Engineering, Alabama Polytechnic Institute, Auburn, Alabama, 1957
Introduction to Nuclear Engineering and Nuclear Engineering Laboratory, University of Florida, Gainesville, Fl., 1966
Management Development Course, Basics of Supervision, 1967
Westinghouse Reactor Operator Training Program, Waltz Mill and Saxton, Pa., 1968

Westinghouse Design Lecture Series, Monroeville, Pa., 1969
Completed the on-site training program, Turkey Point Unit 2, Westinghouse Senior Review Series, and passed the Westinghouse examination for Senior Operator. Combustion Engineering Co., Nuclear Steam Supply System Lectures, 86 hours, 1974

1957 - 1958	FP&L; Engineer on Rotation, Results Department, Miami Plant
1958 - 1959	FP&L; Plant Test Engineer, Results Department, Cutler Plant
1962 - 1966	FP&L; Plant Test Engineer - Maintenance, Lauderdale Plant
1966 - 1967	FP&L; Assistant Plant Engineer - Maintenance, Lauderdale Plant
1967 - 1968	FP&L; Assistant Plant Superintendent - Maintenance and Operation, Lauderdale Plant
1968	Operator training for the Saxton Nuclear Experimental Corporation, Saxton, Pa.
1972	FP&L; Received Senior Reactor Operator's License for Turkey Point Unit 3
1973	FP&L; Received Senior Reactor Operator's License for Turkey Point Unit 4
1973 - Present	FP&L; Operations Superintendent, St Lucie Plant; Holds SRO License, St. Lucie Unit 1

R. J. Frechette
Chemistry Supervisor

Machinist Mate, Submarine, Nuclear Power and Engineering Laboratory Technician courses, U.S. Navy (1965 - 1974) IRCC 60 Credits in various math and science courses

1965 - 1974	U. S. Navy; Nuclear Plant Mechanical Operator, Engineering Laboratory Technician on SIC prototype - S5W (SSN - 625) nuclear plants. Staff instructor (1971 - 1974) at SIC Prototype.
1974 - 1979	FP&L; Plant Coordinator chemistry department during Start-up of St Lucie Unit 1 and operating since 1976. Assistant plant technician, Plant technician, Results technician, and Senior technician.
1979 - Present	FP&L; Chemistry Department Supervisor, St Lucie Plant

H. F. Buchanan
Health Physics Supervisor

BS, Adelphi University, 1968

1962 - 1968	Brookhaven National Laboratory, Brookhaven, New York Health Physics Training, Technician and Senior Staff Health Physicist Technician
1968 - 1971	United Nuclear Corp., Health Physicist - Nuclear Materials Management
1971 - 1977	Yankee Atomic Electric Company, Nuclear Services Division, Senior Engineer - Radiation Protection Group. Supported seven plants in areas of licensing, FSAR preparation, auditing, computerized record keeping, OSHA, Title 10 - Code of Federal Regulations and overseeing all Health Physics Training. Responsible for establishing and implementing policy for the "ALARA" program, all Emergency Planning and the entire TLD personnel exposure monitoring program.
1977 - Present	FP&L; St. Lucie Plant, Health Physics Supervisor.

Member of Health Physics Society, Power Reactor Health Physics Group, Working Group N343, American National Standard Internal Dosimetry Standards for Mixed Fission and Activation Products, Atomic Industrial Forum Working Group on Occupational Exposure.

R. K. Ryall
Reactor Supervisor

BS - Physics, Florida Institute of Technology, 1972
MBA Program, Florida Institute of Technology, presently enrolled

1973 - 1974	FP&L; Engineer Trainee, Reactor Engineering Department, assist Reactor Engineer in initial core loading and physics testing, Turkey Point Plant
1974 - 1975	FP&L; Plant Test Engineer, Assistant Plant Engineer, Reactor Engineering Department; St. Lucie Plant
1975 - Present	FP&L; Reactor Supervisor, St. Lucie Plant

Senior Operator License, St. Lucie Unit 1, 1979
Member of ANS

P. L. Fincher
<u>Training Supervisor</u>

Combustion Engineering Co., Nuclear Steam Supply System lectures, 86 hours, 1974

1961 - 1962	Aerode, Inc., Miami; Inspector
1962	Fansteel Metallurgical Corp., No. Chicago; Hydraulic Press Operator
1962 - 1969	U. S. Navy; Machinist Mate First Class
1969 - 1973	FP&L; Plant Results Technician, Nuclear Control Center Operator; Turkey Point Plant Units 3 and 4 - SRO License
1973 - 1975	FP&L; Nuclear Plant Supervisor, St. Lucie Plant
1975 - Present	FP&L; Training Supervisor, St. Lucie Plant, Holds SRO License, St. Lucie Unit 1.

C. A. Wells
<u>Operations Supervisor</u>

Westinghouse Senior Operator Review Series, 1971
Combustion Engineering Co., Nuclear Steam Supply System Lectures, 86 hours, 1974

1954 - 1966	FP&L; Helper, Auxiliary Equipment Operator, Plant Results Technician; Palatka Plant
1966 - 1970	FP&L; Turbine Operator, Control Center Operator, Turkey Point Plant
1970 - 1973	FP&L; Watch Engineer; Licensed Senior Reactor Operator, Turkey Point Units No. 3 and 4
1973 - Present	FP&L; Operations Supervisor; St. Lucie Plant

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G. J. Boissy
<u>Startup Superintendent</u> 0

University of Orlando, one year, 1964
U. S. Navy, IC "A" School, Nuclear Power School, Nuclear Power Training Unit, Noise and Vibration Analysis School, 1964 - 1969. U. S. Navy Submarine School Grantham School of Engineering, Electronics Engineering course, 1973 Diploma Electrical Engineering (Power Option), ICS School of Engineering, 1976 Leader Development Institute - Kepner Tregoe, 1977 Bachelor of Industrial Technology, Florida International University, 1980 0

1960 - 1965	U. S. Navy; IC Technician 1st Class
1965 - 1967	U. S. Navy; Motor Room Engineering Supervior; USS Moctobi
1967 - 1970	U. S. Navy; Electrical Operator and Electrical Instructor, S5G facility; Electrical Operator and Control Panel Operator, U. S. S. George W. Carver SSBN 656; Reactor Plant Shutdown Manuevering Area Watch, S5G and S5W, Plants Certified Operator on S5G and S5W

1970 - 1973	FP&L; Plant Test Engineer, Turkey Point Plant Electrical Startup
1973 - Present	FP&L; Electrical Department, Assistant Superintendent, Electrical Maintenance; St. Lucie Unit 2, Startup Supervisor, Startup Superintendent

Member of IEEE, Power Engineering Society, and ASME Subcommittee on Equipment Performance Testing.

DAVID A. SAGER - Operations Supervisor

EDUCATION:

Bachelor of Science Naval Engineering	U.S. Naval Academy	1968
Master of Science Mechanical Engineering	U.S.N. Post Graduate School	1969
Master of Business Administration	Florida Institute of Technology	1979

EXPERIENCE:

1970-1975
U.S. Navy
Engineering Officer of the Watch, Damage Control Assistant, Reactor Control Officer, Operations Officer, Sonar Officer, Submarine School Officer Instructor.

1975-1977
FPL Quality Assurance, St. Lucie Plant

1977-1981
FPL Senior Engineer, St. Lucie Plant Technical Staff, licensed senior reactor operator.

1981-Present
FPL Operations Supervisor

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N. G. ROOS - Quality Control Supervisor

EDUCATION:

U. S. Navy Submarine, Nuclear Power and Prototype Schools

EXPERIENCE:

1954-1957
U.S. Navy
Diesel Submarines Eng. Dept.

1957-1965
U.S. Navy
(Enlisted) Nuclear Submarines-Qualified Engineering Officer of the Watch.

1966-1974
U.S. Navy
(Officer)-Naval Reactors Representative Office: Technical Assistant; Project Engineer

1975-1981
FPL
Quality Control Engineer, St. Lucie Plant, Senior Reactor Operator License, St. Lucie Unit 1.

1981-Present
Quality Control Supervisor, St. Lucie Plant

C. A. Pell

B.S., Physics, University of Central Florida, 1975
Advanced FORTRAN Course, Control Data Corporation, 1976
Computer Applications and Reactor Design Codes course,
Rensselaer Polytechnic Institute, 1978

1975 - 1976	FPL; Engineer Trainee, Core Modeling, PRN, General Office.
1976 - 1978	FPL; Associate Analyst, Reactor Support and Core Modeling, PRN, General Office.
1978 - 1980	FPL; Plant Engineer II, Reactor Engineering Department, St. Lucie Plant.
1980 - 1981	FPL; Plant Engineer I, Reactor Engineering Department, St. Lucie Plant; coordinated refueling, reload physics testing, core analysis code applications, and participated in plant efficiency and stretch power efforts.
1981 - Present	FPL; Reactor Supervisor, St. Lucie Plant.

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MICHAEL GARRY ALTERMATT - Nuclear Watch Engineer

EDUCATION:

1965-1967
Liberal Arts Degree Program - Completed equivalent 40 semester credits

1967-1973
U.S. Navy Nuclear Machinist Mate and Power training

1973-1981
Mathematics Degree Program - Completed equivalent 40 semester credits

1973-1975
FPL St. Lucie Unit #1 Cold License Program

EXPERIENCE:

1967-1973
U. S. Navy Nuclear Program

1973-1981
St. Lucie Reactor Control Operator, Nuclear Watch Engineer

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WILLIAM J. BLOESER - Reactor Control Operator

EDUCATION:

3 years college - Electronics technology, Aerospace technology.

Factory schools from Bendix Corp , and King Radio Dealing with Electronics Equipment.

EXPERIENCE:

Worked in Navy and civilian avionics field, in navigation, communication, radar, autopilot repair and calibration and installation.

6/76 to Present
FPL-Electrician, Instrument and Control Specialist, Senior Plant Technician, Reactor Control Operator.

~~Currently~~ In training for reactor operator license.

J. R. BOWEN - Reactor Control Operator

EDUCATION:

High School Graduate

Bachelor of Science in Marine Engineering

Massachusetts Maritime Academy - 1978

Third Asst. Engineer License (USCG)

EXPERIENCE:

1978-1979
One Year sea experience on steam powered ships as a watch engineer. 600 PSI Boilers driving steam propulsion turbines and auxiliaries.

1979-1980
Auxiliary Equipment Operator at FPL Ft. Myers Plant

1980-1981
Reactor Control Operator at FPL St. Lucie Plant.

In training for Reactor Operator License. ~~Expected license date March, 1982.~~

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ANN V. BRAMHALL - Reactor Control Operator

EDUCATION:

High School Graduate

AA Degree Edison Community College - 1971

BA Mathematics - Florida Atlantic University - 1973

Post Grad. Courses - Florida Atlantic University - 1974

EXPERIENCE:

1975-1980
FPL Power Plant Laboratory Technician

1980-Present
Reactor Control Operator at FPL St. Lucie Plant.

In training for Reactor Operator License. ~~Expected licensing on PSL Unit #1 in March 1982.~~

C. L. BURTON - Nuclear Plant Supervisor

EDUCATION:

High School Graduate -- ~~Oldham County High School, Oldham County, Kentucky~~.

College: University of Kentucky - 40 semester hours

U.S. Navy - Electronics Technical and Nuclear Power Training

FPL St. Lucie Plant "Cold Licensed Operator Training Program"

Combustion Engineering - One week "PWR Simulator Training Course" covering accident analysis

EXPERIENCE:

1969-1975
U. S. Navy Reactor Operator

1975-Present
FPL St. Lucie Nuclear Control Center Operator, Watch Engineer, Shift Supervisor

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CHARLES F. CALLAHAN - Reactor Control Operator

EDUCATION:

High School Graduate

Southeastern Community College 39 Credit Hours - 1978 to 1980

U. S. Navy Nuclear Power Training

EXPERIENCE:

1973-1977
U.S. Navy Reactor Operator

1977-1980
Carolina Power & Light, Brunswick Units #1 & 2 Auxiliary Operator.

1980-Present
FPL St. Lucie Plant Reactor Control Operator

In training for Reactor Operator License; ~~expected licensing in Sept. 1981.~~

CHARLES RUSSELL GRIFFITH - Reactor Control Operator

EDUCATION:

Attended Western Kentucky U. for 2 semesters (Aug. '71-May '72)

Attended two IRCC night classes (Aug. '80-Dec. '80)

USN Nuclear Power Program

EXPERIENCE:

1976 to 1980
U. S. Navy Reactor Operator

1980 to Present
FPL St. Lucie ~~Unit #1 Hot License Class (May '80-May'81) Expected licensing in Sept. 1981~~ Plant Reactor Control Operator

In training for Reactor operator License

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ROBERT HAMILTON CLEMENTS - Reactor Control Operator

EDUCATION:

1971-1972
27 hours Central Florida Community College, Radiological Health

1981
6 hours Indian River Community College, Communications, Algebra

1973-1974
Navy Machinist Mate Nuclear Power Training

EXPERIENCE:

1972-1979
U.S. Navy Machinist mate, engineering watch supervisor

1979
Ingalls Shipbuilding; submarine test engineer (Nuclear & Non-nuclear)

1979-1980
FPL Power Plant Mechanic

1980-Present
FPL Reactor ~~Operator Hot License Candidate~~ St Lucie Plant Reactor Control Operator

In training for Reactor operator License

CARL G. CRIDER - Reactor Control Operator

EDUCATION:

3 years College (Ohio State, IRCC, Florida Institute of Technology)

1974-1979
Pursuing Industrial Engineering - B.S.I.E.

16 months Hot License Training - FPL

EXPERIENCE:

1971-1974
Four Years - Hydraulics Specialist apprentice-(Ford Motor Co.)

1975-1980
Power PLant Mechanic (FPL St. Lucie Nuclear Plant)

1980-Present
FPL Reactor Operator

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J. CHARLES COUTURE - Reactor Control Operator

EDUCATION:

~~Graduated~~ High School ~~1975~~ Graduate

~~Attempted~~ General Engineering at Florida Community Colleges PBJC & BCC - completed 1½ years.

Extra curricular training during high school in television production electronics

EXPERIENCE:

Television production technical support, (electronic) for 1 CATV and 2 Cable TV stations

FPL - 2 years Mechanical Maintenance Dept.
3 years Operating experience in operating positions: Auxiliary Operator
Boiler Attendant
Turbine Operator
Fossil Control Center Operator (1 year)

1980-Present
Reactor Control Operator ~~at~~ FPL St. Lucie Plant. In training for Reactor Operator License. Expected licensing on Unit ~~#1 in March~~ 1982.
& new line

PAUL MICHAEL CURRY - Reactor Control Operator

EDUCATION:

1973-1977
University of California at Irvine - B.S. Physics

1975-1976
Fullerton College - Statistics, Business Math Courses.

1978-1979
Southern California Edison Reactor Operator Training Program

1978
Atomics International-1 week reactor training program (L-85 Reactor) Certificate received. Included 4 start-ups.

EXPERIENCE:

1978-1979
Southern California Edison Co. San Onofre Nuclear Generating Station. Reactor Operator trainee. Approx. 4 start-ups performed.

1981 to Present
FPL Co. Reactor Control Operator. In training for Reactor Operator License. ~~Expected licensing on Unit #1 in Sept., 1981.~~

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JOSEPH BURNUM DELRUE - Reactor Control Operator

EDUCATION:

High School ~~June 1976 graduated~~ Graduate

Michigan Technological University-BSEE 1980

~~University of Toledo-Summer 1979~~

Monroe County Comm. College (Mich) Summer 1978.

EXPERIENCE:

1978
Consumer's Power Plant Company-J. R. Whiting Plant Maintenance

1979
Detroit Edison Company - Monroe Power Plant Student Engineer

1980-1981
FPL-Ft. Myers Plant Assistant Plant Engineer

1981-Present
FPL St. Lucie Plant Reactor Control Operator. In training for Reactor Operator License. ~~Expected licensing on Unit #1 in March, 1982~~.

RICHARD S. GOLDSTEIN - Reactor Control Operator

EDUCATION:

28 credits State University of New York - Stony Brook Jan. '75-Sept. '75.

EXPERIENCE:

1979-1980
FPL Itinerant Electrician

1980-Present
St. Lucie Reactor Control Operator. ~~Expected licensing on Unit #1 in March, 1982~~
In training for Reactor Operator License

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DENNIS D. DRYDEN - Reactor Control Operator

EDUCATION:

~~Stockton High, Stockton, Kansas, Graduated High School 1973~~ High School Graduate

Ohlone Jr. College, Fremont Ca, 9/73 to 2/74, English, Psychology, Philosophy

Basic Electricity Electronics School, San Diego, CA - USN 5/74-7/74

Interior Communications "A" School, San Diego, CA - USN 7/74-10/74

Naval Academy Prep School, Newport, R.I., USN 10/74-6/75

U.S.N.A. Annapolis, MD, 7/75-10/75

Nuclear Power School, Mare Island, CA - 10/75-5/76

S5G Prototype, NRF Idaho 6/76-5/77

EXPERIENCE:

1974-1977
U.S. Navy-Nuclear Power Program

1981
St. Lucie Unit 1 Licensed Reactor Operator

GREGORY A. EVANS - Reactor Control Operator

EDUCATION:

High School Graduate~~, Glendora High School, Glendora, CA.~~

Completed the following Navy Schools:

Navy Nuclear Power ~~School-Graduated in the upper 50%~~ and
~~Navy Nuclear Prototype (S5G) Prototype Training-Graduated in the upper 8%~~
Training
Interior Communication ~~Electrician Class "A" school-Graduated in the upper 25%~~
S8G Trident design course.
~~Completed other miscellaneous Navy courses such as Basic Electricity and Electronics, Sound and Vibration analysis, oxygen analysis, etc.~~

Completed the following Utility Schools:

FPL Licensed Operator Training Program 1980
Combustion Engineering PWR Simulator Training Program: 5 weeks of operations practice including, normal and emergency/off-normal operations and startup certification.
FPL Senior Reactor Operator Training 1981.

EXPERIENCE:

1975-1980
United States Navy
Nuclear Power Program Electrician

1980-Present
FPL Co. Reactor Control Operator, ~~Licensed at Operator Level on Unit #1 at PSL.~~
Senior Reactor Operator license

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MICHAEL BRUCE GILMORE - Reactor Control Operator

EDUCATION:

High School Graduate~~-Riviera Beach High School, Riviera Beach, FL.~~

Related Technical Training:

Hot License Operator Training at FPL St. Lucie Plant-1978
Combustion Engineering "PWR Simulator Training Course," including Reactor Startup Certification-1979.

EXPERIENCE:

1971-1972
Apprentice Electrician-Gilmore Electric Co.

1972-1975
Mechanic's Helper, Auxiliary Equipment Operator, Boiler Attendant, Turbine Operator

1975-1978
FPL St. Lucie Plant Nuclear Turbine Operator, Nuclear Control Center Operator

ROBERT S. GLAZE - Plant Coordinator

EDUCATION:

High School Graduate~~-Lyman High School, Longwood, Fl 1969~~

College-Seminole Junior College 1969-1971 A.A. Liberal Arts

FPL Co. St. Lucie Plant "Cold License Operator Training Program" 1975

Combustion Engineering "Nuclear Steam Supply System" lecture series 1974
Combustion Engineering 8-week "PWR Simulator Training Course" covering general plant technology and operation
Combustion Engineering 1-week "PWR Simulator Training Course" covering accident analysis

Mr. Glaze has participated as required in the St. Lucie Plant "Licensed Operator Requalification Program.

EXPERIENCE:

1971
U.S. NAVY

1971-1972
Walt Disney World-Host

1972
Central Exterminating Co., Maitland, FL-Termite Pretreatment

1972-1973
Helper Sanford Plant-FPL

1973-1976
FPL Co. St. Lucie Plant, Nuclear Control Center Operator at St. Lucie Plant

1976-1980
Licensed Nuclear Control Center Operator involved in the power operation of St. Lucie Unit #1. SRO ~~License~~ Senior Reactor Operator License

1980-1981
FPL St. Lucie Plant Training Instructor. Conducting training for licensed operator requalification training program and initial hot license operator training.

THOMAS A. GONZALEZ - Reactor Control Operator

EDUCATION:

High School Graduate-Weequahic High School, Newark, NJ 1957

College-Santa Maria Jr. College AA Degree 1963

FPL Co. Turkey Point Plant "Cold License Operator Training Program"

FPL Co. St. Lucie Plant "Cold License Operator Training Program"

Combustion Engineering 8-week "PWR Simulator Training Course" covering Plant Technology and Operation

Combustion Engineering one-week "PWR Simulator Training Course" covering Accident Analysis

EXPERIENCE:

1958-1966
USAF, teletype operator, supply specialist and ground controlled approach radar technician

1968-1970
Instrument Technician at Pratt & Whitney Aircraft.

1971-1972
FPL Plant Results Technician, Aux. Equipment Operator, Boiler Attendant

1972-1974
FPL Co. Turkey Point Plant Nuclear Operator

1974-Present
Nuclear Control Center Operator at St. Lucie Plant

WILLIAM L. HAGAR - Reactor Control Operator

EDUCATION:

High School Graduate

Correspondence Course (Navy): Math Part I 1976
Math Part IIA 1977
Math Part IIB 1977
Diesel Engines 1976
Ship's Store Afloat 1977

U.S. Navy Machinists Mate and Nuclear Power Training

EXPERIENCE:

1973-1981
U. S. Navy Nuclear Power Program Machinist Mate

1981-Present St Lucie plant
FPL ~~Co.~~ Reactor Control Operator in Training for Reactor Operator License.

~~Expected licensing on Unit #1 in March, 1982.~~

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WILLIAM BRADFORD HALL - Reactor Control Operator

EDUCATION:

BSME-University of Florida 1968

Airframe & Power Plant Mechanic 1975

EXPERIENCE:

FPL
5 years Fossil Plant Experience
2 years performance testing
2 years plant retrofit
1 year maintenance planner

~~Currently~~ In training for Reactor Operators License ~~at St. Lucie Unit #1~~
Expected licensing in March, ~~1982~~.

O'BRIEN D. HAYES - Nuclear Plant Supervisor

EDUCATION:

High School Graduate ~~1964~~

~~College~~ Lincoln College (Northeastern University) 1 year-no degree obtained

U.S. Navy Nuclear Power School-1967

FPL Co. St. Lucie Plant "Cold License Operator Training Program" 1975

Combustion Engineering 1-week "PWR Simulator Training Course" covering Accident Analysis

FPL Co. St. Lucie Plant "Licensed Operator Requalification Program"

EXPERIENCE:

1964-1966
Chatam Mfg. Co.-Lab Technician Textile Chemistry

1966-1974
U.S. Navy Nuclear Power Program Machinist Mate. Qualified Engineering Officer of the Watch.

1974-1975
Stone & Webster Eng. Corp., Engineering Associate

1975-Present
FPL Co. St. Lucie Plant Control Center Operator, Shift Supervisor

R. L. HAYES - Plant Engineer I

EDUCATION:

Florida Atlantic University, Boca Raton, FL, B.S.M.E. 1974

EXPERIENCE:

1974
Rogers & Associates, Inc., Engineers and Surveyors, Palm City, Fl Business and Operations Manager

1973-1974
Various landscape architects in Palm Beach and Broward Counties. Free Lance Design Engineer

1973
American Irrigation, Inc., Boynton Beach, FL Design Engineer

1975-1977
FPL St. Lucie 1 Technical Staff Mechanical Engineer SRO License No. SOP-2957

1977-1980
KoHa, Inc., President, Ft. Pierce, Fl. Owner of Sporting Goods and Marine business

1980-Present
FPL Co., St. Lucie Plant (CE-PWR) Shift Technical Advisor/Staff Engineer/License Training Instructor SOP 3771

PROFESSIONAL ACTIVITIES:
American Society For Mechanical Engineers
Registered E.I.T., Florida Certificate No. 199ET76

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GERALD J. IMBRIALE - Reactor Control Operator

EDUCATION:

U.S. Navy Electrician and Mate School Nuclear Power Training

FPL Co. St. Lucie Plant Reactor Operator Hot License Training Program

Combustion Engineering PWR Simulator Training course: 5 weeks of operations practice including normal/emergency operations.

EXPERIENCE:

1976-1980
U.S. Navy: Nuclear Power Electrical Operator

1980-Present
FPL Co. St. Lucie Plant Reactor Control Operator, in training for Reactor Operator License.

HUGH H. JOHNSON JR. - Reactor Control Operator

EDUCATION:

High School Graduate

U. S. Navy Electronics and Nuclear Power Training

EXPERIENCE:

1977-1980
U. S. Navy Reactor Operator

1980-~~Present~~ St Lucie Plant new line
FPL Co. Reactor Control~~y~~ Operator, In training for Reactor Operator License ~~on~~
~~PSL Unit #1. Expected licensing in March, 1982.~~

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GEORGE R. B. KAASA - Reactor Control Operator

EDUCATION:

High School Graduate

Clinical Laboratory Course-U.S. Army-1970

EXPERIENCE:

1978-1980
Duke Power Co.-Power Plant Technician Nuclear & Fossil

1980-1981
Turkey Point Plant Nuclear & Fossil Maintenance Mechanic.
1981 - present
St. Lucie Plant Reactor Control Operator, In training for Reactor Operator
License ~~on Unit #1. Expected licensing in March, 1982.~~

DENNIS J. KRING - Plant Coordinator

EDUCATION:

~~Washington~~ High School ~~- South Bend Indiana~~ Graduate

United Electronic Institute - Louisville, Kentucky ~~- No Degree~~

U.S. Army Basic Electronics Training Course-1967
Advanced Intercept Equipment Course-1967
Instructor Training Course-1969

Auxiliary Equipment Operator Training at FPL Turkey Point Plant 1971

Nuclear Operator Training at FPL Turkey Point Plant 1972

Watch Engineer Training at FPL St. Lucie Plant 1974

Hot License Operator Training at FPL St. Lucie Plant 1978-1979

C.E. "PWR Simulator Training Course," including Startup Certification-1979

EXPERIENCE:

1966-1970
U.S. Army Intercept Equipment Repairman

1970-1978
FPL Mechanics Helper, Aux. Equipment Operator, Nuclear Operator, Watch Engineer

1978-Present
Sr. Plant Technician responsible for developing and conducting training programs for all non-licensed and licensed operator positions. NRC Operator Licensed on Unit #1.

CHARLES D. MARPLE - Nuclear Watch Engineer

EDUCATION:

High School Graduate ~~Garfield High School, Akron, Ohio 1969~~

College-Brevard County College-61 credit hours in Elect. Eng. Tech.

FPL Co.-Introduction to Steam Power

FPL Co. St. Lucie PLant "Hot License Operator Training Program"

C.E. one week "PWR Simulator Training Course", including Startup Certification

EXPERIENCE:

1973
FPL Apprentice mechanic, boiler attendant

1974-Present
FPL St. Lucie Nuclear Operator, Nuclear Control Center Operator, Nuclear Watch Engineer.

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RICHARD L. McELROY - Reactor Control Operator

EDUCATION

High School Graduate

U. S. Navy and Nuclear Power Training

~~Civilian:~~ Indian River Comm. College 1980-Present
Associate of Science (Mohegan Comm.College)1980

EXPERIENCE:

1976-1981
U. S. Navy Reactor Operator

1980-Present
FPL Co. Inst. & Cont. Spec.
Reactor control operator, in training for Reactor Operator License on Unit #1.
~~Expected Licensing in March, 1982.~~

D. W.MIKELL - Nuclear Plant Supervisor

EDUCATION

~~South Broward~~ High School ~~1947~~ Graduate

Electrical School-U.S. Navy 1949

International Correspondence School-Mech. Engineer Course 1956

Westinghouse Reactor Operator Training Program
Westinghouse Senior Reactor Operator Training Program

C.E. Co. Nuclear Steam Supply Lectures 86 hours 1974
One week training in Reactor Theory at University of Florida
Three weeks training at C.E. Simulator in Windsor, CT.

EXPERIENCE:

1947-1948
FPL Co.-Auxiliary Operator-Lauderdale Plant

1948-1950
U.S.N. Electrician's Mate

1950-1951
Mikell Plumbing Co.-Hollywood, Fl: Plumbers Helper

1951-1972
FPL Co.-Auxiliary Operator, Fireman AA, Turbine Operator, Control Center Operator, Watch Engineer

1972-1973
Turkey Point Plant Nuclear Watch Engineer during much of the low power physics testing and initial operation

1974-1977
Participated in writing operating procedures for St. Lucie Plant Unit #1. Operated Unit #1 through initial startup and operation. Senior Reactor operator License

1978-Present
St. Lucie Plant Outage Coordinator, Responsible for scheduling and coordination of all outage activities for St. Lucie Plant.

MILTON H. MOSLEY - Reactor Control Operator

EDUCATION:

~~Rock Hill~~ High School-~~Rock Hill S. Carolina~~ Graduate

Sacramento State University

Miami Dade Jr. College

Indian River Comm. College

Miscellaneous U.S. Air Force Tech. Schools

FPL Reactor Theory Course

Observation Training at Turkey Point Plant

University of Florida Reactor Theory Review

C.E. Nuclear Steam Supply Lecture Series

C.E. Simulator Training Program

FPL 21 week series-Systems Training

12 week supervised self-study program covering the following:
Principles of Reactor Operation, General Operating Characteristics, Control Station Instrumentation, Safety and Emergency Systems, Standard and Emergency Operating Procedures, Plant Operation and Transient Response, Reading and Interpreting Control Instrumentation.

EXPERIENCE:

2 months helper at Turkey Point Plant. Involved in Rx preparation and initial cold load.

8 months Aux. Equip. Operator at Turkey Point. Operating Aux. equipment

7 months Turbine Operator, Miami Fossil Plant. Operating turbine generator and secondary equipment.

6 years St. Lucie Nuclear Plant. Cold license, NCCO Class and NCCO for cold hydro and hot Ops. Senior Reactor Operator Licensed on Unit #1.

JAMES EDWARD O'NEIL - Reactor Control Operator

EDUCATION:

University of Hartford-1967-1968 Math Major

Hartford State Technical College 1969-1971-AS-Nuclear Engineering Technology

FPL Co. Reactor Operator Hot License Training Program 1980-1981

EXPERIENCE:

1972-1975
Knolls Atomic Power Lab Windsor, CT. Radiation Controls Tech.(H.P.)

1975-1980
FPL Health Physics Tech.

1980-Present
Reactor Control Operator St. Lucie Unit #1.

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L. W. PEARCE - Nuclear Plant Supervisor

EDUCATION:

~~Crescent City~~ High School ~~1965~~ Graduate

St. John's River Junior College 1967

Westinghouse Operators Training Program 1970
Westinghouse Senior Operators Training Program 1972

C.E. Nuclear Steam Supply System Lectures 86 hours 1974
C.E. Simulator Training 60 hours 1974

FPL Co. on-site training program 1975

EXPERIENCE:

1968-1970
FPL Helper, Aux. Equip. Operator, Boiler Attendant

1970-1973
FPL Turkey Point Plant Nuclear Control Center Operator, Watch Engineer

1973-Present
FPL St. Lucie Plant Nuclear Watch Engineer, Plant Supervisor

MICHAEL ALLEN PERRY

EDUCATION:

2 Years Of College (EE Major) 1970-1972 ~~No Degree~~

U. S. Navy Electronics and Nuclear Power training

EXPERIENCE:

1972-1978
U. S. Navy Reactor Operator

1978-1980
Operator (non-license) at CP&L Brunswick Plant

1980
2/3 of Hot License Class at CP&L

1981-Present
~~FPL Reactor Operator Hot License Candidate~~
FPL St Lucie Plant Reactor Control Operator.
In training for Reactor Operator License

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ALDO LOUIS RAMIREZ - Reactor Control Operator

EDUCATION:

U. S. Navy Machinist Mate and Nuclear Power training

EXPERIENCE:

1977-1979
U. S. Navy Nuclear Power Program

1980-Present
FPL Co. Maintenance Mechanic. Reactor Control Operator, In Training for Reactor Operator License ~~on PSL Unit #1. Expected Licensing in March, 1982.~~

LAWRENCE H. RICH - Nuclear Watch Engineer

EDUCATION:

High School Graduate ~~-Munster High School, Munster, Indiana 1968~~

FPL Co. St. Lucie Plant "Hot Licensed Operator Training Program" 1976-1977

C.E. one week "PWR Simulator Training Course", including startup certification.

EXPERIENCE:

1968-1972
U.S.N.
Machinist Mate Second Class-operated and maintained steam power components and auxiliaries.

1972-1977
FPL Apprentice Mechanic, Nuclear Operator, Nuclear Control Center Operator (unlicensed)

1977-Present
St. Lucie #1 Licensed Reactor Operator, Nuclear Watch Engineer

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JAMES J. SHANNON JR.

EDUCATION:

U. S. Navy Machinist Mate and Nuclear Power Training

Broward Community College (Assoc.in Business Administration) 1977

Johnson Pneumatic Controls School 1979

EXPERIENCE:

1965
USS Destroyer Forrest Sherman DD931 Steam Plant Operator

1967-1971
USS Submarine Nathan Hale SSBN 623(g), Steam Plant & Primary systems operator.

1981
FPL Boiler Attendant

1981-Present
St. Lucie Nuclear Plant, Reactor Control Operator ~~Trainee.~~
Inc. training for Reactor Operator License

MARK D. SHEPHERD - Plant Coordinator

EDUCATION:

High School Graduate ~~Farmingham North H.S., Farmingham, Mass.~~

1981-Bachelor of Professional Studies in Training Management in Nuclear Technology, Memphis State University

Seminole Community College, Sanford FL, Earned Associate of Arts degree 1978

Northeastern University, Boston, MA, earned 65 hours College of Engineering. ~~Final average 3.0. Disenrolled to complete military obligation.~~

U.S. Navy Electronics and Nuclear Power Training

FPL Co. Senior Reactor Operator Training Program.

C.E. PWR Simulator training program: Four weeks of operations practice including normal, off-normal and emergency operations and reactor startup certification.

EXPERIENCE:

1974-1978
U.S. Navy Reactor Operator. Qualified as Engineering Watch Supervisor

1979-1980
Instructor, Center for Nuclear Studies, Memphis State University, Memphis Tennessee. Responsible for the development, delivery and administration of various programs of study related to the Nuclear Industry.

1980-Present
Instructor FPL Co. St. Lucie Plant.
Senior Reactor Operator License

LAWRENCE A. SPALDING - Nuclear Watch Engineer

EDUCATION:

High School Graduate~~-Miami Jackson High School 1962-~~

College-University of Florida 1963-1966, 72 credit hours

George T. Baker Aviation School, Miami, Fl, Airframe and Power Plant License #1551561 and Private Pilot's License #1548856, 1962

FPL Co. St. Lucie Plant "Cold License Operator Training Program", 1975

C.E. Nuclear Steam Supply System" lecture series 1974.
C.E. 8 week "PWR Simulator Training Course" covering general plant technology and operation.
C.E. 1 week "PWR Simulator Training Course" covering accident analysis.

Mr. Spalding has participated as required in the St. Lucie Plant "Licensed Operator Requalification Program".

EXPERIENCE:

1966-1972
U.S. Coast Guard Reserves

1967-1973
Pan American World Airways-airframe and power plant mechanic

1973
FPL Co. Turkey Point Plant aux. equip. operator.

1973-Present
FPL Co. St. Lucie Plant Nuclear Control Operator, Nuclear Watch Engineer

JEFFREY A. SPODICK - Plant Supervisor II

EDUCATION:

High School Graduate ~~Forrest Hill High School 1966~~

~~College~~: Palm Beach Jr. College AA in Liberal Arts 1968

FPL Co. St. Lucie Plant "Cold License Operator Training Program"

Mr. Spodick has participated as required in the "Licensed Operator Requalification Program" at St. Lucie Plant.

U.S. Navy Electronics and Nuclear Power Training

EXPERIENCE:

1971-1974
U.S.Navy Reactor Operator

1975-1977
FPL-Nuclear Control Center Operator. Senior Reactor Operator License

1977-Present
FPL Co. St. Lucie Plant training staff instructor. Responsible for preparation and conduct of licensed operator training programs.

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DEWARD K. SPURGIN - Reactor Control Operator

EDUCATION:

~~DeLand Senior High School 1966~~ High School Graduate

Daytona Beach Community College-No Degree

Embry Riddle Aeronautical Inst. Aircraft Airframe/Power Plant Certification 1969

Seminole Community College-completed requirements for AA in Education-~~Graduation not applied for-1977.~~

Related Technical Training:
- Licensed Reactor Operator training at St. Lucie Plant 1978-1979
- C.E. "PWR Simulator Training Course," including Reactor Startup Certification-1979

EXPERIENCE:

1972-1978
FPL Mechanic's Helper, Aux. Equipment Operator, Apprentice Electrician

1978-Present
Nuclear Control Center Operator at FPL St. Lucie Plant.

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ROBERT A. STORKE - Nuclear Watch Engineer

EDUCATION:

High School Graduate - Clearwater ~~High School 1960~~

FPL Co.St. Lucie Plant "Hot License Operator Training Program" 1976-1977

C.E. one week "PWR Simulator Training Course" including Reactor Startup Certification, 1976.

EXPERIENCE:

1960-1968
U.S. Air Force
Jet Engine Mechanic and Jet Engine Technician. Test run various types of aircraft, operated engine test cells and ground equipment, included trouble shooting, repair and overhaul of various types of jet engines.

1972-1977
FPL Auxiliary Equipment Operator, Boiler Attendant, Nuclear Turbine Operator, Nuclear Control Center Operator (unlicensed)

1977-Present
St. Lucie Unit #1 Licensed Reactor Operator, Nuclear Watch Engineer

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KEVIN HALL THOMAS - Reactor Control Operator

EDUCATION:

Palm Beach Jr. College 1969-1971 Business Courses approx. 50 semester hours.

U.S.Navy Electrician and Nuclear Power Training

Palm Beach County Journeyman Electrician Licensed 1978

Air Conditioning/Refrigeration/Heating Correspondence Course Certificate 1980

EXPERIENCE:

1972
U.S. Navy
Served aboard USS Alamogordo ARDM2 as a power plant electrician.

1974-1977
U. S. Navy Nuclear Power Program Electrician

1978-1980
FPL Electrician

1981-Present
Reactor Control Operator. In training for Reactor Operator License ~~on PSL Unit #1. Expected licensing in March, 1982.~~

KATHLEEN DOLORES WARD - Reactor Control Operator

EDUCATION:

Certificate Lowell Tech. Institute Health Physics Training, 1971

Degree Lowell Tech. Institute B.S. in Health Physics 1975.

License (Pending) Reactor Operator St. Lucie Unit I 1981.

Degree presently in progress, Florida Institute of Technology, M.B.A.

EXPERIENCE:

1975-1978
Dosimetry Engineer Yankee Atomic Electric Co., Nuclear Services Div., Radiation Protection Group.

1978-1979
Radiation Physicist Yankee Atomic Electric Co., Nuclear Services Div., Environmental Laboratory Group.

1979-1980
Health Physics Senior Tech. St. Lucie Unit 1.

1980-Present
Reactor ~~Operator Training St. Lucie Unit #1.~~ Control operator

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ROGER D. WELLER - Reactor Control Operator

EDUCATION:

McCluer High School, Florissant, MO 1973.

Related Technical Training:

U. S. Navy Machinists Mate and Nuclear Power Training

Utility: FPL Licensed Operator Training Program-1980
C.E. PWR Simulator Training Program: 5 weeks operations practice including normal and emergency/off-normal operations, and startup certification.

EXPERIENCE:

1973-1980
U.S. Navy Nuclear Power Program Machinist Mate qualified as engine room supervisor

1980-Present
Reactor Control Operator at FPL St. Lucie Plant

JEFF A. WEST - Reactor Control Operator

EDUCATION:

1967-1972-B.S.E.E. Univ. of Tenn. (Control Systems & Computers)

1972-1974-30 hours graduate work on MSEE @ Univ. of Tenn. Space Institute. Topic: Network Theory. Joined Navy prior to completing degree

1980-Present-15 hours completed on MBA at Florida Institute of Technology. Estimated degree date December 1982.

1972 Engineer In Training Certificate

FPL St. Lucie Unit #1 Shift Technical Advisor Training Program.

EXPERIENCE:

1975-1979
Navy Nuclear Power Program, qualified Engineering Officer of the Watch

1980
FPL St. Lucie Unit #1 Shift Technical Advisor

[illegible]

1980-Present
FPL St. Lucie Plant Reactor Control Operator, In Training for Reactor Operator License on Unit #1.

NORRIS D. WEST - Nuclear Plant Supervisor

EDUCATION:

Andrew Junior College 1 year 1960

U.S. Navy Electrician and Nuclear Power Training, 1960-1962

Bettis Atomic Power Laboratory, 1962

C.E. Nuclear Steam Supply System Lectures, 86 hours, 1974.

C.E. Simulator Training, 60 hours, 1974

Participated in the St. Lucie Plant On-Site Training Program

FPL Reactor Operator Training Program PTP-1970-71

FPL Senior Reactor Operator Training Program PSL-1973-74

EXPERIENCE:

1960-1967
U.S. Navy Nuclear Power Program Electrician

1968-1974
FPL Helper, Auxiliary Equipment Operator, Reactor Operator, Nuclear Watch Engineer

1974-Present
FPL Nuclear Watch Engineer, Nuclear Plant Supervisor; St. Lucie Plant.

KENNETH J. WIECEK - Nuclear Watch Engineer

EDUCATION

High School Graduate-~~Hialeah Senior High School 1961~~

Pittsburgh Institute of Aeronautics AA Degree 1970

FPL Co. St. Lucie Plant "Cold License Operator Training Program"

C.E. "Nuclear Steam Supply System" Lecture series
C.E. 8 week "PWR Simulator Training Course" covering plant technology and operation
C.E. one week "PWR Simulator Training Course", covering Accident Analysis.

University of Florida 3 week course in Reactor Operation and Reactor Theory

Mr. Wiecek has participated as required in the St. Lucie Plant "Licensed Operator Requalification Program".

EXPERIENCE:

1962-1967
U.S.Navy Aircraft Hydraulics Mechanic Second Class Air Crew member on HU-46D Helicopter

1967-1968
U.S. Naval Printing Office, printers apprentice

1970-1973
Pratt & Whitney Aircraft. Jet Engine Test Cell Mechanic

1973
FPL Co. Riviera Plant, Mechanics helper

1973-Present
St. Lucie Plant Nuclear Control Center Operator, Nuclear Watch Engineer

W. S. WINDECKER - Supervisor Planning & Scheduling

EDUCATION:

~~Fultonville Union Free~~ High School ~~1949~~ Graduate

FPL Co. Training Opportunities Program courses in mathematics, physics, chemistry, steam generators and auxiliaries, steam turbine and auxiliaries, simplified electricity.

Westinghouse Reactor Training Program, Turkey Point Plant

C.E. Nuclear Steam Supply Systems Lectures, 86 hours, 1974.

Reactor Theory Review, University of Florida, 40 hours

Participated in the St. Lucie Plant on-site training program FPL Co. Reactor Theory Course, 3 weeks.

EXPERIENCE:

1957-1970
FPL Co. Helper, Auxiliary Equipment Operator, Fireman, Turbine Operator, Control Center Operator, Watch Engineer

1970-1973
FPL Co. Control Center Operator and Watch Engineer, Turkey Point Plant

1973-1979
FPL Co. Watch Engineer and Nuclear Plant Supervisor, St. Lucie Plant

1979-Present
PSL Unit #2 Planning & Scheduling Supervisor

TABLE 13.1-1

ST. LUCIE OPERATING ORGANIZATION
STAFFING PLAN

	Months to Fuel Load 30	18	6	0	Commercial Operation
Maintenance Dept. (Include itinerant and special crew personnel)					
I & C Maintenance Engineers. & Tech	8	8	8	8	14
I & C Spec.	18	21	28	28	28
Electrical Maintenance					
Engineers & Techs.	7	7	7	10	10
Chief Elec.	3	4	4	4	4
Elec. Journeymen	12	15	19	21	21
Appr. Elec.		1	2	2	2
Mechanical Maintenance					
Engineers & Techs	11	12	14	14	14
Maintenance Foreman	4	5	6	6	6
Machinist	2	2	2	2	2
Mechanic	25	25	35	47	53
Appr. Mech.	9	9	12	17	19
Helpers	14	14	15	20	26
Technical Department					
Engineers & Techs.	10	11	12	12	12
Security Department					
Asst. Security Supervisor	1	1	1	1	1
Administrative Department					
Asst. Admin. Supervisor	1	1	1	1	1
Clerks	6	6	6	6	6
Quality Control Dept.					
Engineers & Techs.	14	15	15	15	17
Operations Department					
Chemistry					
Engineers & Techs.	12	15	16	16	16
Health Physics					
Engineers & Techs.	7	8	8	12	12
Radiation Protect Men	7	7	7	14	14
Reactor Engineer					
Engineers & Techs.	3	3	3	4	4
Training Department					
Instructors	4	4	4	4	4
Draftsman	1	1	1	1	1

TABLE 13.1-1 (Cont'd)

	Months to Fuel Load 30	18	6	0	Commercial Operation
Operations					
Plant Supervisor	6	6	6	6	6
Watch Engineer	6	6	6	6	6
Control Center Operator	29	29	34	34	34
Nuclear Operator	9	9	12	15	15
Turbine Operator	6	11	11	11	11
Auxiliary Equip. Operator	5	5	5	5	5
Outage Coordination					
Technicians	1	1	1	1	1
Start-Up					
Engineers & Techs.	39	53	56	46	9

TABLE 13.1-2

MINIMUM SHIFT CREW COMPOSITION

ST. LUCIE UNITS 1 AND 2

LICENSE CATEGORY		APPLICABLE MODES** 1,2,3 & 4	5 & 6
Plant Supervisor Nuclear	SRO	1	1*
Nuclear Watch Engineer	SRO	1	1*
Nuclear Control Center	RO	2	2
Shift Technical Advisor		1	0
Nuclear Operator		1	1
Turbine Operator		1	1

/A

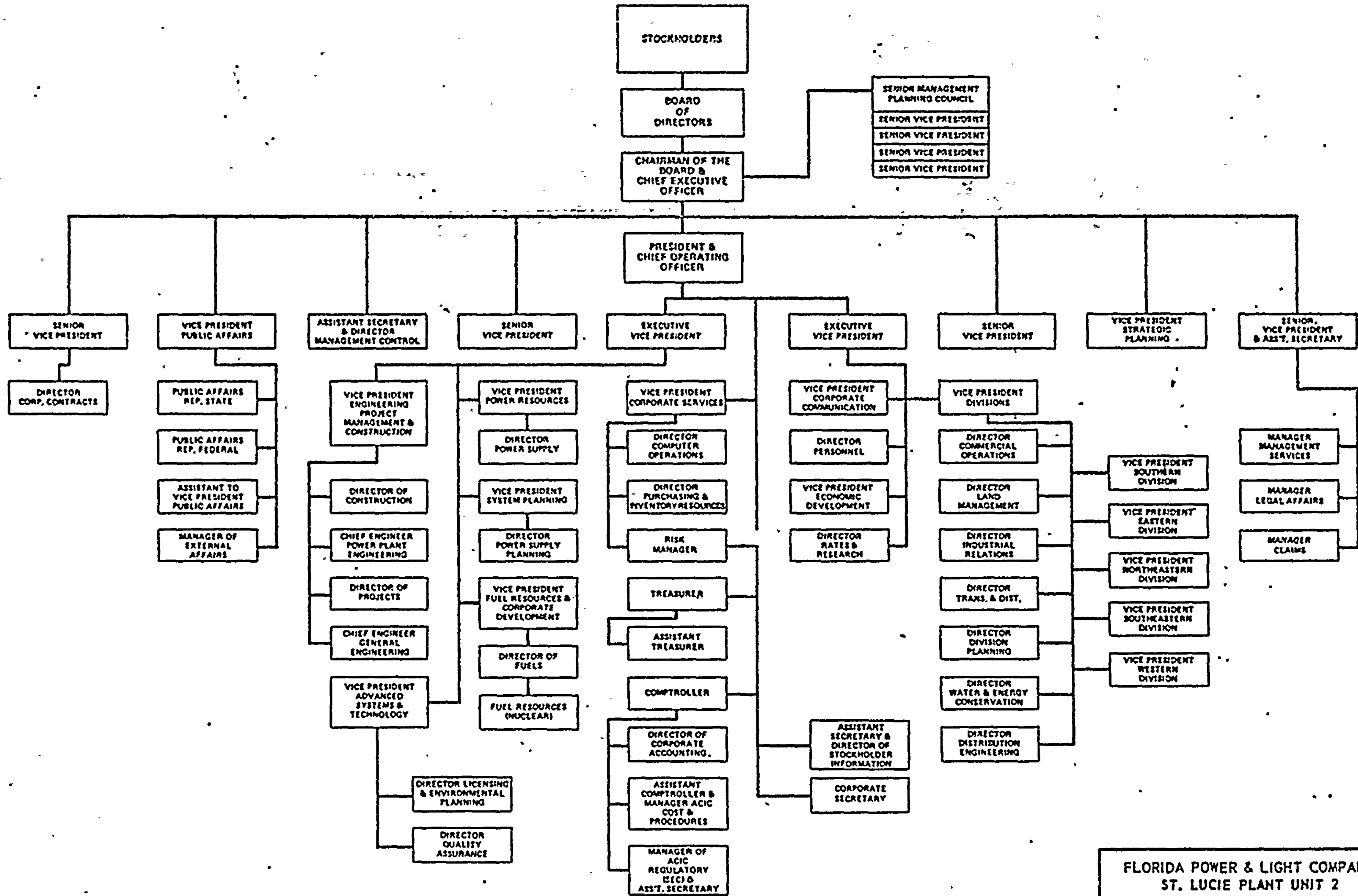
*Does not include the licensed Senior Reactor Operator or Senior Reactor Operator Limited to Fuel Handling, supervising CORE ALTERATIONS after the initial fuel loading.

**As defined in the Technical Specifications

TABLE 13.1-X2

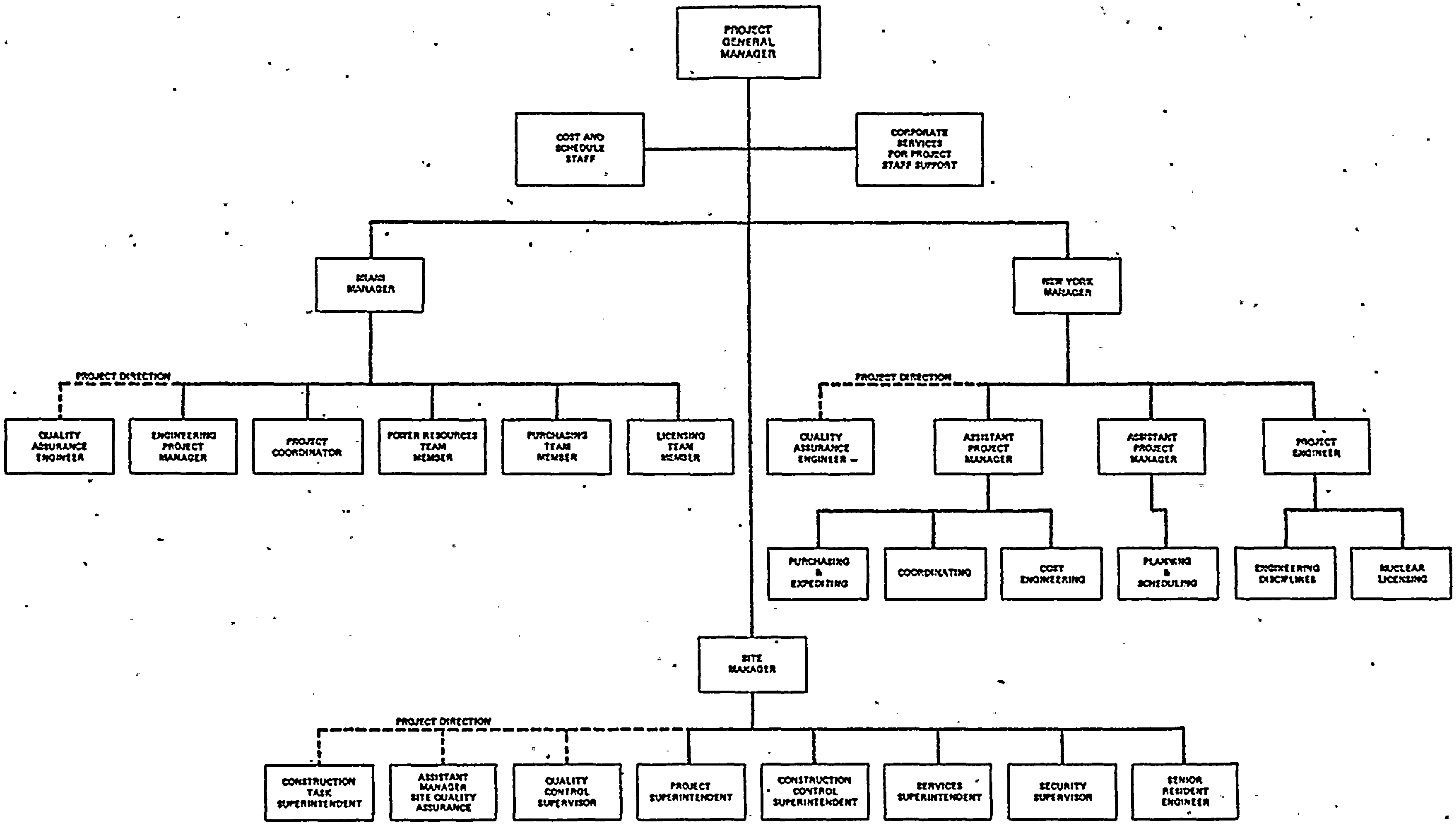
CORRELATION OF ST. LUCIE PLANT STAFF POSITIONS
WITH ANSI N18.1-1971 TITLES

ANSI N18.1-1971 Position Title	ANSI N18.1-1971 Section No.	ST. LUCIE PLANT STAFF Position Title
Plant Manager	4.2.1	Plant Manager Operations Superintendent
Operations Manager	4.2.2	Operations Supervisor
Maintenance Manager	4.4.3	Maintenance Superintendent Assistant Superintendent Mech. Maint. Assistant Superintendent Elec. Maint.
Technical Manager	4.2.4	Technical Supervisor
Reactor Engineering and Physics	4.4.1	Reactor Supervisor
Instrumentation & Control	4.4.2	Inst. & Control Supervisor
Radiochemistry	4.4.3	Chemistry Supervisor
Radiation Protection	4.4.4	Health Physics Supervisor
Supervisor Requiring NRC License	4.3.1	Plant Supervisor Watch Engineer
Supervisor not Requiring NRC License	4.3.2	Training Supervisor Quality Control Supervisor Security Supervisor
Operators	4.5.1	Reactor Control Operator Unlicensed Operator
Technicians	4.5.2	Technician
Repairmen	4.5.3	Mechanic Instrument & Control Spec. Electrician



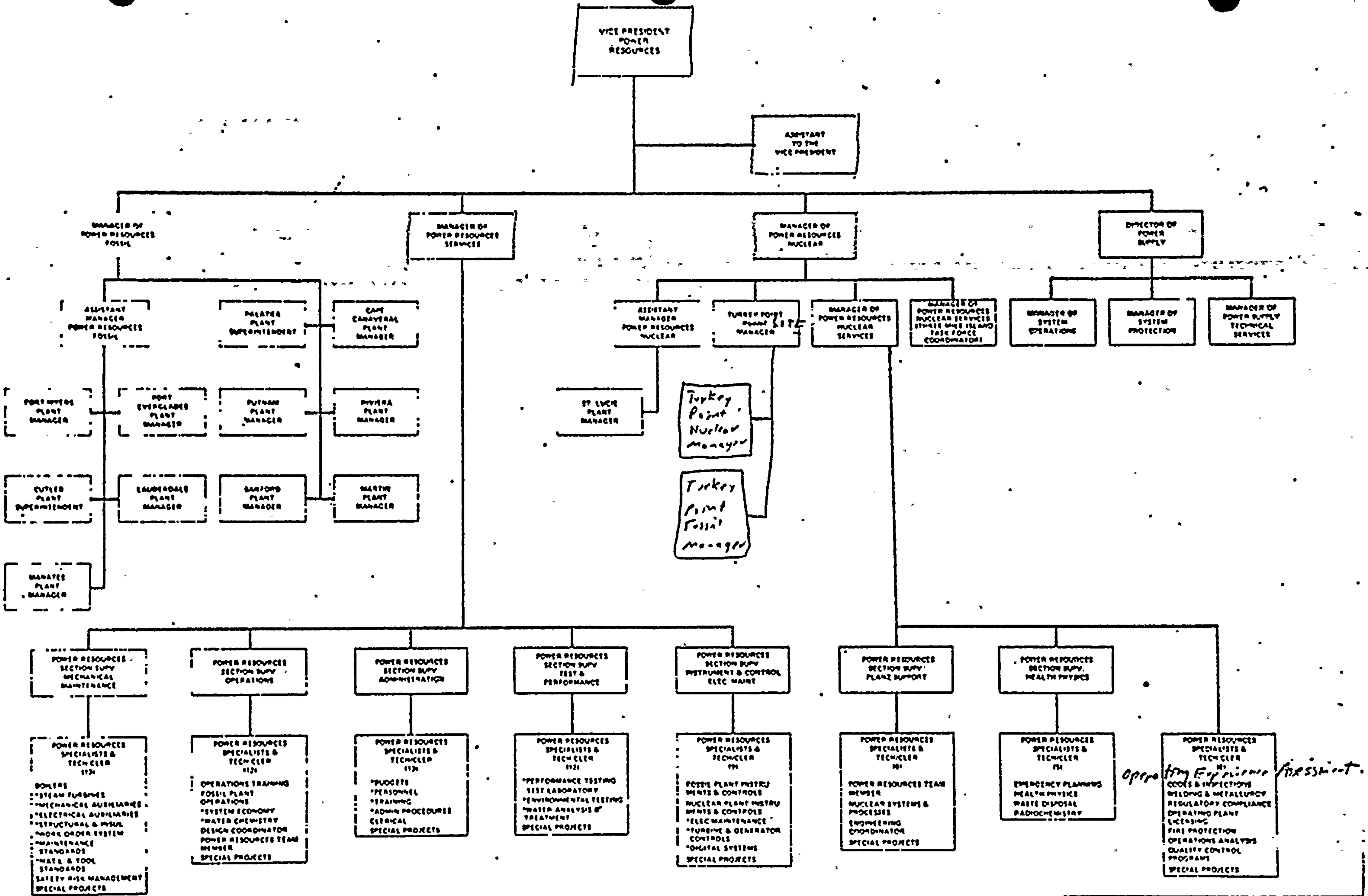
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ORGANIZATION CHART
GENERAL ORGANIZATION
FIGURE 13.1-1



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

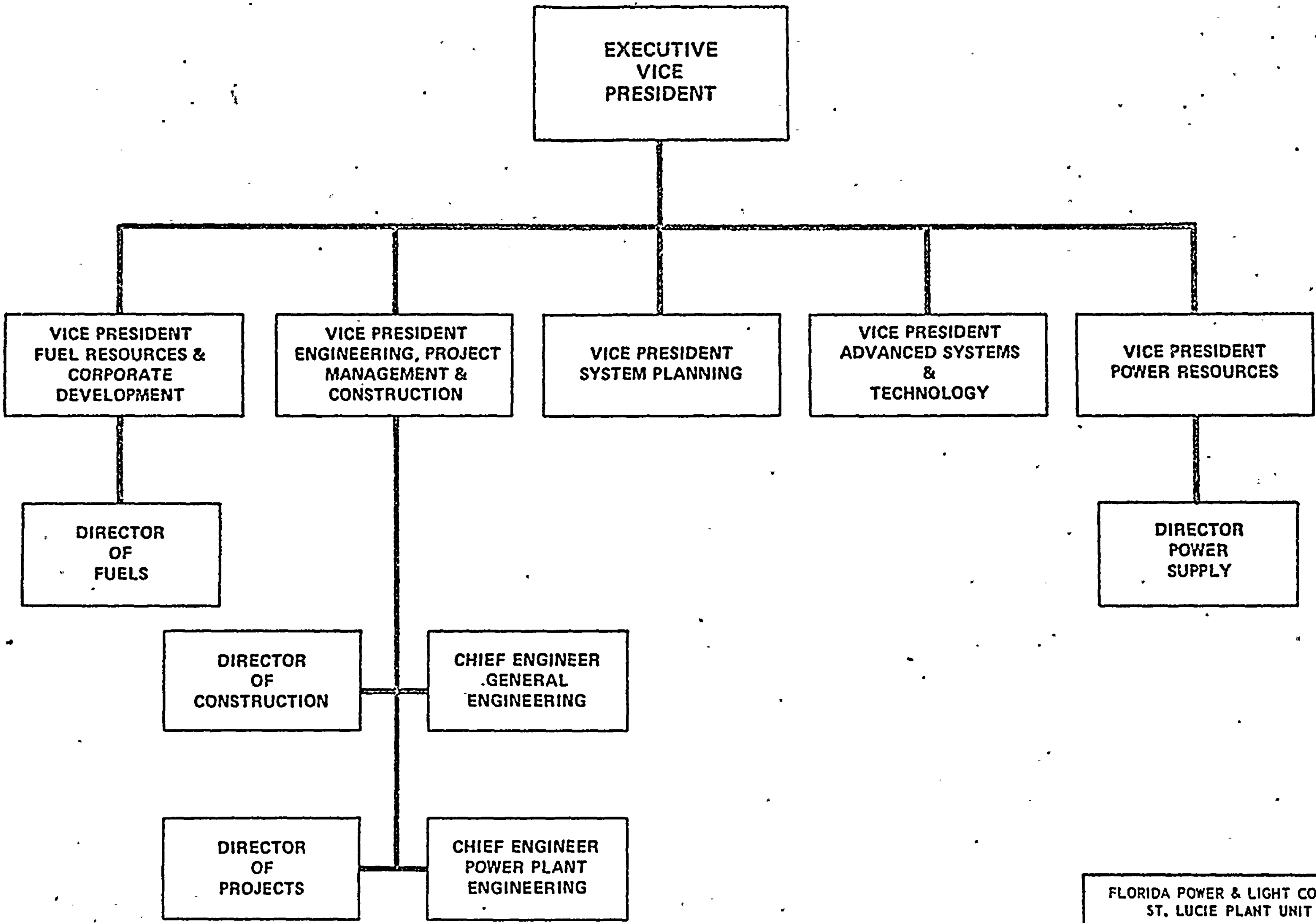
ORGANIZATION CHART
ST. LUCIE UNIT 2 PROJECT TEAM
FIGURE 13.1-2



*INCLUDES NUCLEAR FACILITIES STAFF SUPPORT

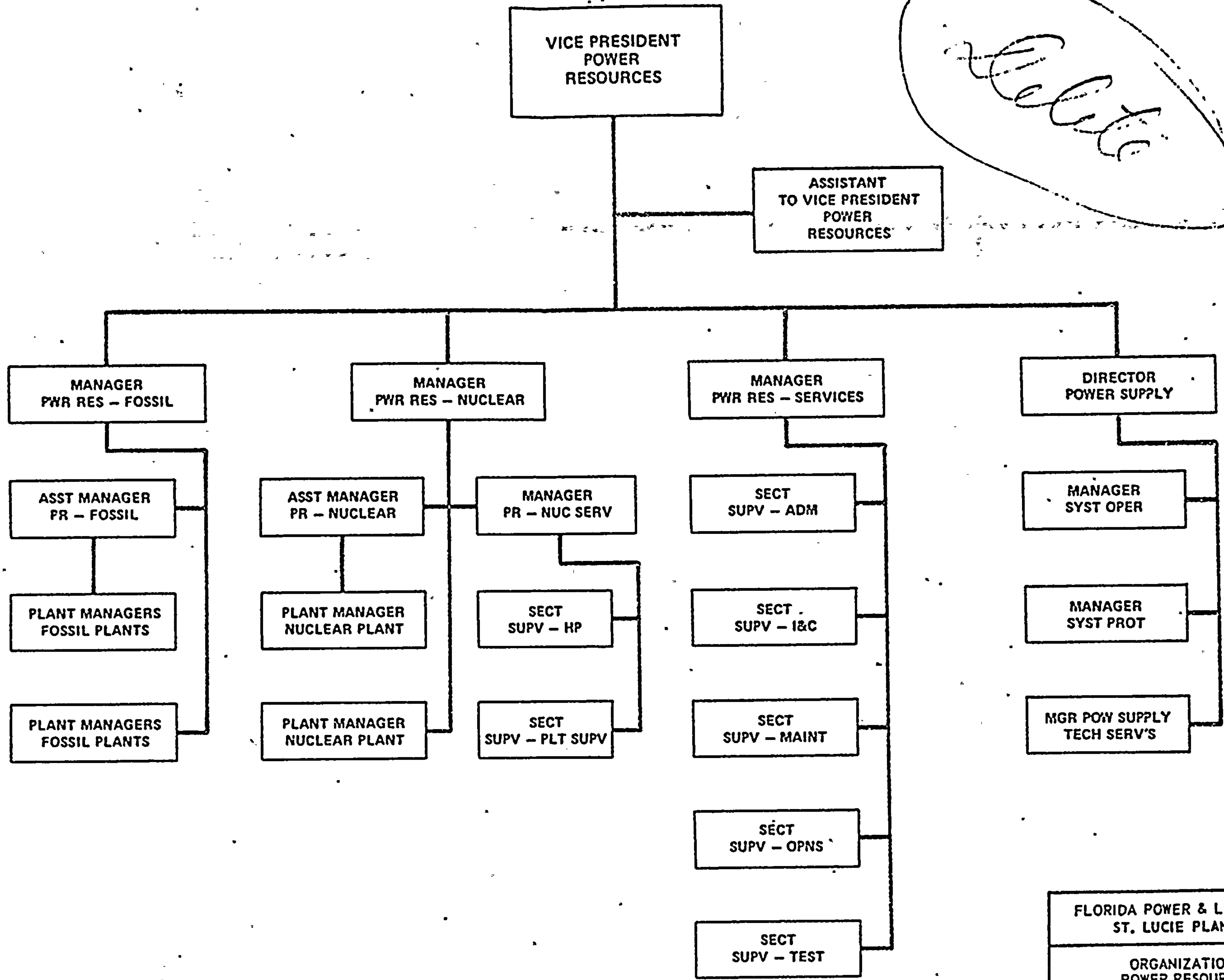
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ORGANIZATION CHART
POWER RESOURCES
FIGURE 13.1-3



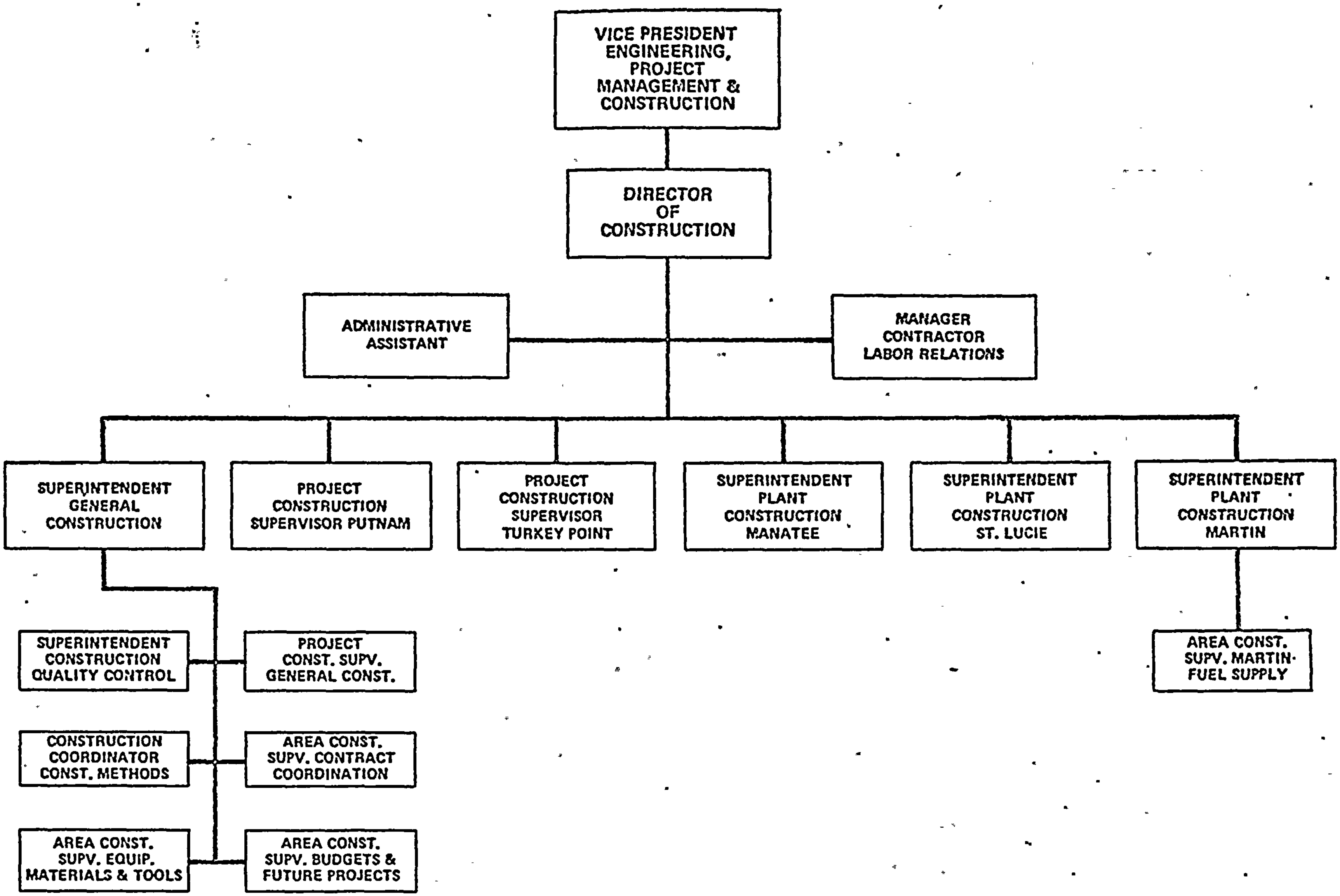
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ORGANIZATION CHART
OPERATIONS
FIGURE 13.1-4



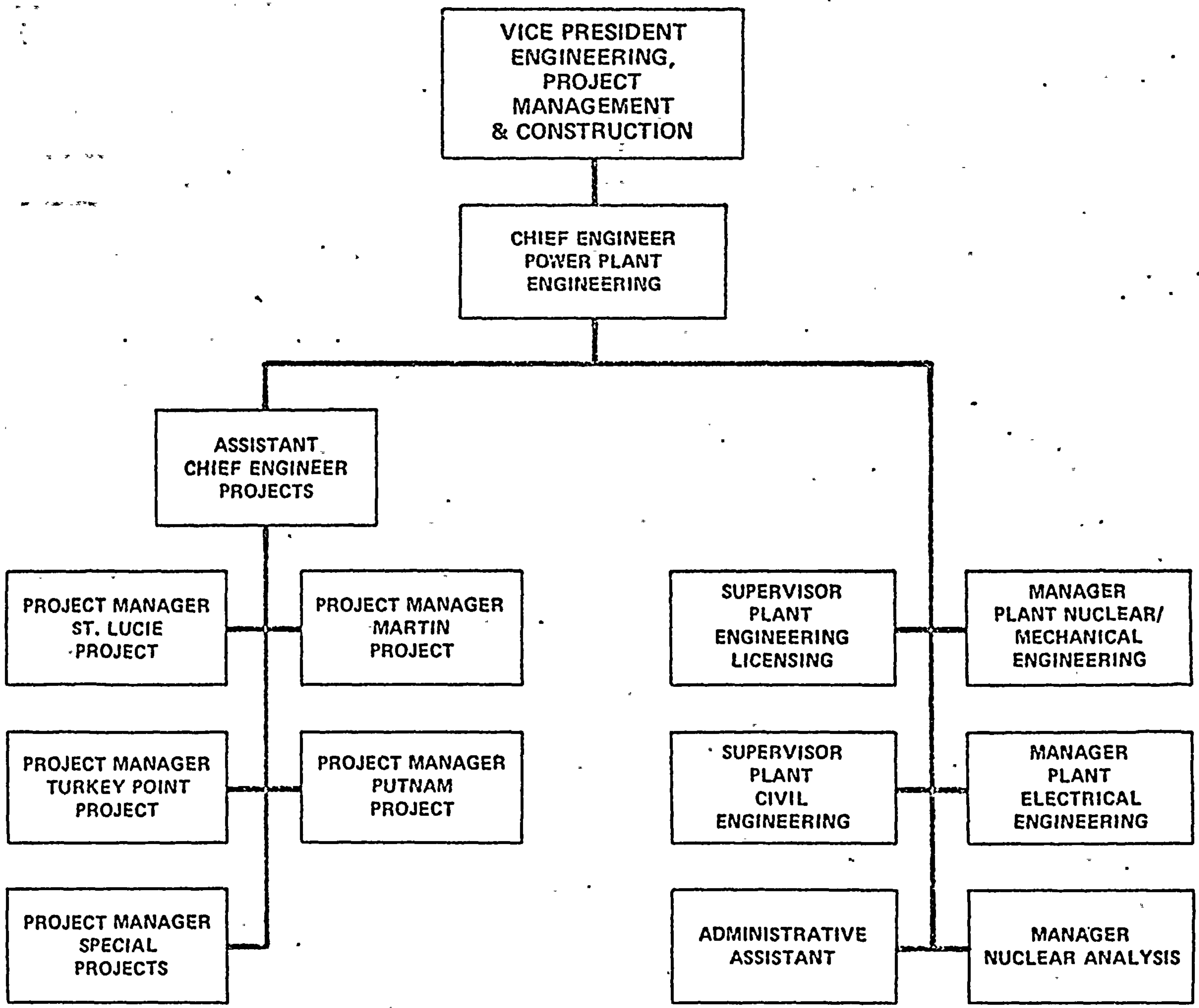
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ORGANIZATION CHART
POWER RESOURCES DEPT.
FIGURE 13.1-5



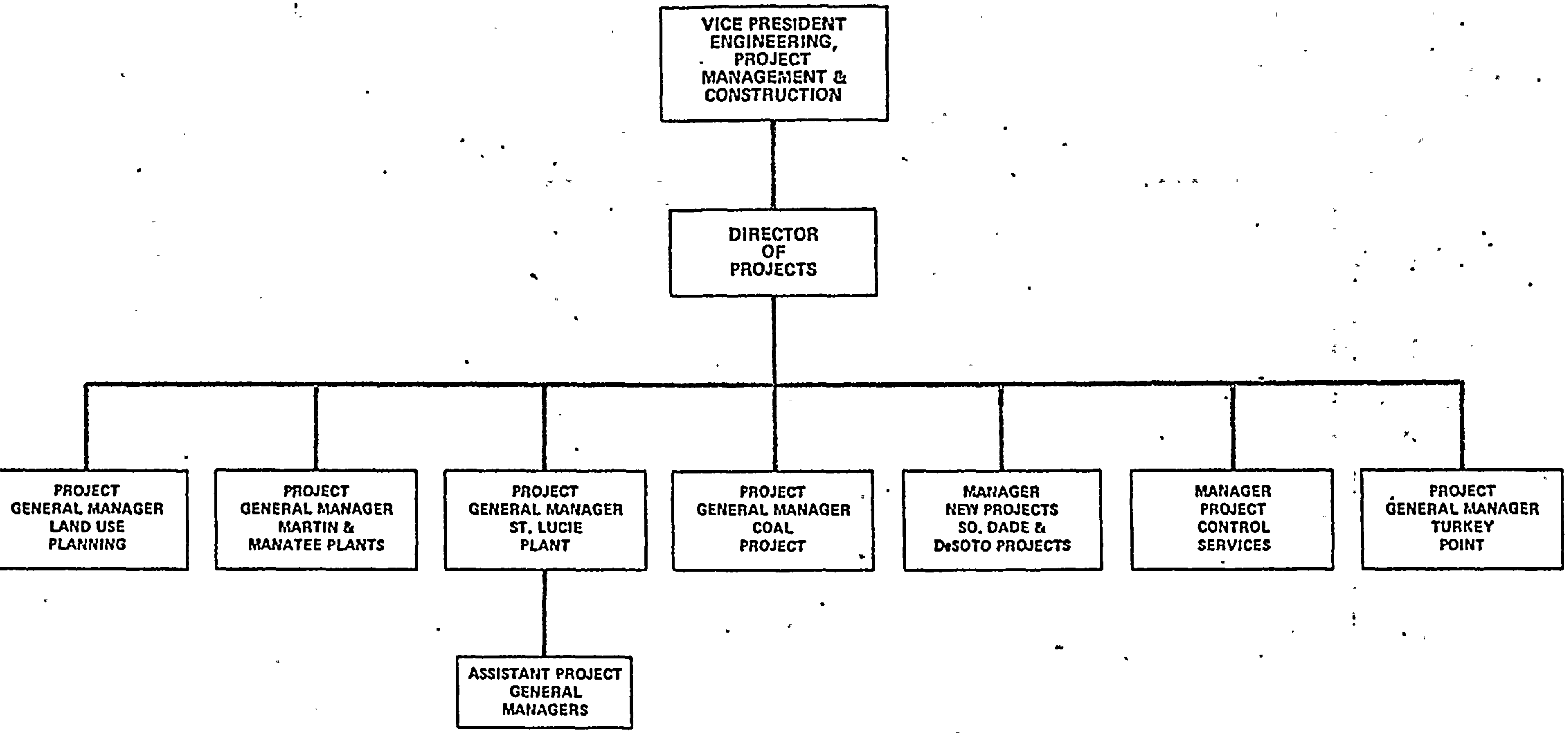
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ORGANIZATION CHART
PLANT CONSTRUCTION
FIGURE 13.1-6



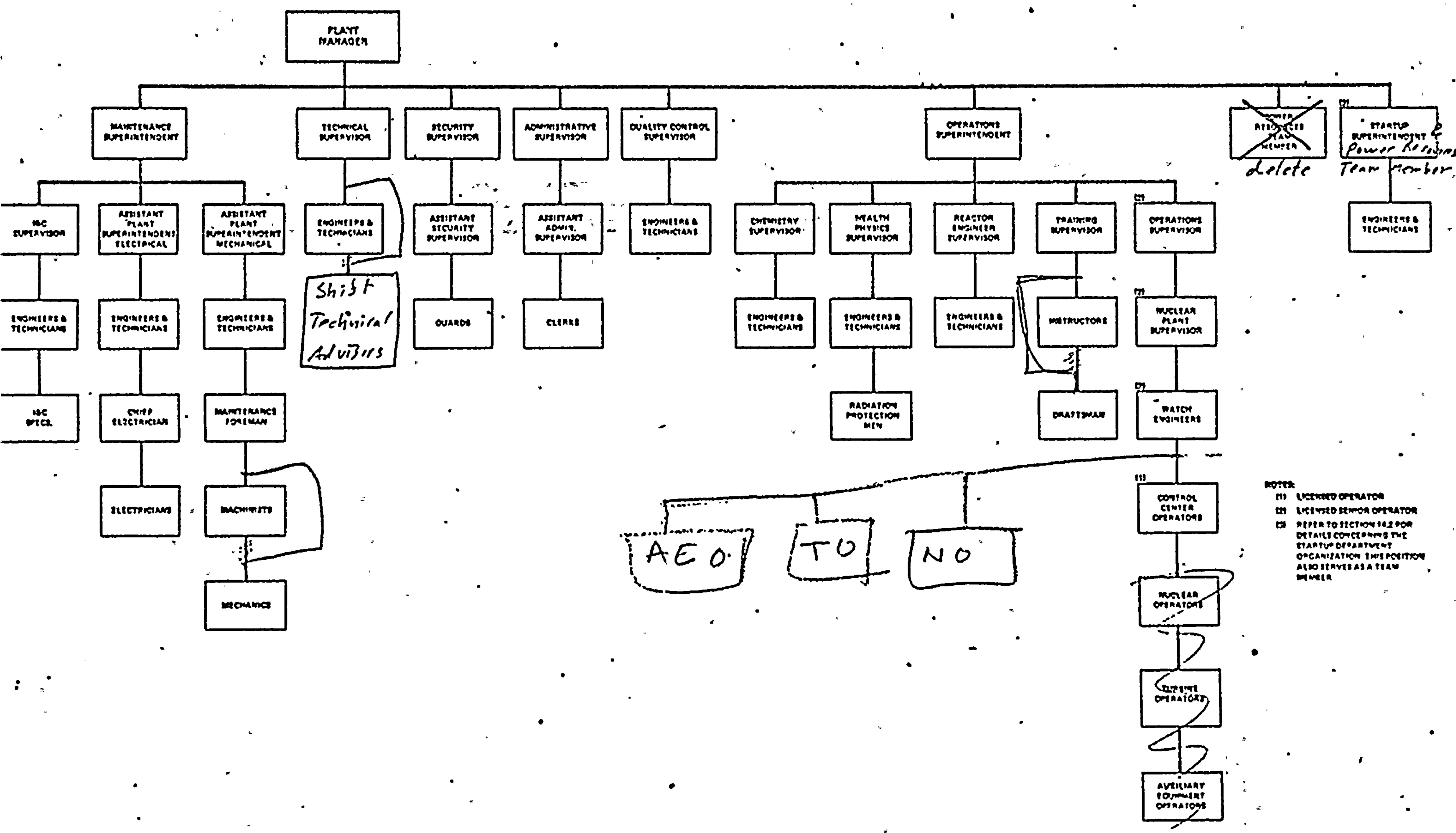
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ORGANIZATION CHART
POWER PLANT ENGINEERING
FIGURE 13.1–7



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ORGANIZATION CHART
PROJECT MANAGEMENT
FIGURE 13.1-8



NOTES:
(1) LICENSED OPERATOR
(2) LICENSED SENIOR OPERATOR
(3) REFER TO SECTION 14.2 FOR DETAILS CONCERNING THE STARTUP DEPARTMENT ORGANIZATION. THIS POSITION ALSO SERVES AS A TEAM MEMBER

AMENDMENT NO. 0 (12/80)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

ORGANIZATION CHART
PLANT ORGANIZATION
FIGURE 13.1-2

13.2 TRAINING

Plant personnel have a combination of education, training, experience, health and skills so that their decisions and actions that affect the plant are such that the plant is operated in a safe and efficient manner. The training program supplements the individual's background to give him the required knowledge and ability.

13.2.1 PLANT STAFF TRAINING PROGRAM

The overall objective of the training program is to provide technical development, specialized training and operating experience to FPL operating and maintenance personnel. The Plant Manager is responsible for the conduct and administration of the initial onsite training program and for the training of replacement plant personnel. Plant training programs are conducted under the direction of the plant training staff. Those programs conducted for licensed operator candidates will be supervised by personnel with Senior Operator Licenses on Unit #1. Where special knowledge or expertise is available, non-licensed instructor personnel may be used for teaching portions of license training programs. The Plant Training Supervisor provides /A direction and assistance to departmental personnel where needed to insure implementation of training plans.

FPL has over 10 years of nuclear unit startup and operating experience with Turkey Point Units 3 and 4 and St. Lucie Unit 1. Functional and ongoing training programs, primarily conducted onsite, are developed for the St. Lucie Plant and are based on the guidance of Regulatory Guide 1.8 "Personnel Selection and Training" May 1977 (R1-R) which generally endorses ANSI N18.1-1971. ~~(later approved by ANSI as ANSI/ANS 3.1-1978). c~~

13.2.1.1 Program Description

13.2.1.1.1 Licensed Personnel Training Objective

It is planned that cold license personnel for St. Lucie Unit 2 will be drawn from personnel licensed on St. Lucie Unit 1 and that all licensed personnel at the St. Lucie Plant will be licensed on both units. To this end, all of the initial group of cold license candidates will have obtained an NRC reactor operator or senior reactor operator license on St. Lucie Unit 1. Cold license candidates will be drawn from the following list of personnel who currently hold NRC operator licenses on Unit #1 or are in training for licensing on Unit #1. See section 13.1.3 for experience summaries of these personnel. /R

J. H. Barrow	Operations Superintendent (SRO)
D. A. Sager	Operations Supervisor (SRO)
C. L. Burton	Nuclear Plant Supervisor (SRO)
F. G. Davis	Nuclear Plant Supervisor (SRO)
O. D. Hayes	Nuclear Plant Supervisor (SRO)
L. W. Pearce	Nuclear Plant Supervisor (SRO)
N. D. West	Nuclear Plant Supervisor (SRO)
M. G. Altermatt	Nuclear Watch Engineer (SRO)
C. D. Marple	Nuclear Watch Engineer (SRO)
L. M. Rich	Nuclear Watch Engineer (SRO)
L. A. Spalding	Nuclear Watch Engineer (SRO)
R. A. Storke	Nuclear Watch Engineer (SRO)
K. J. Wiecek	Nuclear Watch Engineer (SRO)
W. J. Bloeser	Reactor Control Operator
J. R. Bowen	Reactor Control Operator
A. V. Bramhall	Reactor Control Operator
C. E. Callahan	Reactor Control Operator
R. H. Clements	Reactor Control Operator
C. J. Couture	Reactor Control Operator
C. G. Crider	Reactor Control Operator
P. M. Curry	Reactor Control Operator
J. B. Delrue	Reactor Control Operator
D. D. Dryden	Reactor Control Operator
G. A. Evans	Reactor Control Operator
M. B. Gilmore	Reactor Control Operator
R. S. Goldstein	Reactor Control Operator
T. A. Gonzalez	Reactor Control Operator
C. Griffith	Reactor Control Operator
W. L. Hagar	Reactor Control Operator
W. B. Hall	Reactor Control Operator
G. J. Imbriale	Reactor Control Operator
P. B. Isaacs	Reactor Control Operator
H. H. Johnson	Reactor Control Operator

G. R. B. Kassa	Reactor Control Operator
R. L. McElroy	Reactor Control Operator
M. H. Mosley	Reactor Control Operator
J. E. O'Neil	Reactor Control Operator
M. A. Perry	Reactor Control Operator
A. L. Ramirez	Reactor Control Operator
J. J. Shannon	Reactor Control Operator
D. K. Spurgin	Reactor Control Operator
K. H. Thomas	Reactor Control Operator
K. D. Ward	Reactor Control Operator
R. D. Weller	Reactor Control Operator
J. A. West	Reactor Control Operator
P. L. Fincher	Training Supervisor
B. W. Mikell	Outage Coordinator
N. G. Roos	Quality Control Supervisor
R. L. Hayes	Plant Engineer
J. A. Spodick	Plant Supervisor
R. S. Glaze	Plant Coordinator
D.J. Kring	Plant Coordinator
M. D. Shepherd	Plant Coordinator
W. S. Windecker	Planning & Scheduling Supervisor

Following licensing on St. Lucie Unit 1, a minimum of three months operating time will be provided, if possible, for these personnel to gain operating experience prior to cold licensing on St. Lucie Unit 2. Subsequent hot license candidates will be trained for St. Lucie Units 1 and 2 concurrently. /A

Initial Training

a) The training program for license candidates follows the format for hot license training used for St. Lucie Unit 1 but also includes information pertinent to Unit 2 licensing. Special classes emphasizing differences between the two units are held for those personnel already licensed on St. Lucie Unit 1. Refer to Subsection 13.1.2 for a description of position titles and license status.

The licensed operator training program encompasses the following outline for Cold License Candidates:

Phase I: Hot license training on Unit #1 in accordance with St. Lucie Plant Administrative Procedure "Hot License Operator Training Program".

Phase II: Three months of Unit #1 operation, where possible, to gain operation experience prior to cold licensing on Unit #2.

Phase III: Unit #1/#2 differences training program. A training program describing design differences between units 1 and 2 will be prepared and presented to each candidate covering the following areas:

(a) Core Mechanical Design
(b) Core Thermal and Hydraulic Design
(c) Reactor Physics
(d) Instrument and Control Systems Design
(e) Mechanical Systems Design
(f) Electrical Systems Design
(g) NSSS Response
(h) Safety Analysis and Technical Specifications
(i) Operating and Emergency Procedures
(j) Startup Test Program

Time will be available during this phase for candidates to accomplish appropriate field study and equipment familiarization.

Phase IV: Simulator training: Since all cold license candidates will have been licensed on Unit #1, no special simulator training will be given for Unit #2 cold license training. Normal annual simulator requalification sessions will serve this purpose. Simulator examinations may be conducted by the NRC at the end of these sessions. Sequencing of simulator sessions will be dependent upon availability of the simulator and may occur out of sequence with the program phases.

Phase V: Screening and NRC licensing examinations: An examination similar in type and content to an NRC

examination will be given at the completion of the program to determine each candidates readiness to take the NRC examination.

The schedule for the above training is indicated by Fig. 13.2.1 The scheduled start dates and activity durations may change if the core load date changes.

b) Prior Experience Credit

Some license candidates may have received training in military service, other reactor locations, college, or other specialized training. For these individuals some of the training program may be eliminated based upon review of credentials, transcripts, or testing at the plant site. This will be done on a case by case basis and must be approved by the Training Supervisor and Plant Manager. The following list represents those areas of training which may be eliminated:

1) Reactor Theory
2) Principles of Reactor Operation
3) Thermodynamics
4) Heat Transfer
5) Fluid Mechanics

c) Training Program Evaluation

Periodic examinations are given throughout the program to gauge the candidate's progress and overall performance. The Training Supervisor determines the frequency of these examinations. A final comprehensive exam is given to each candidate to determine his readiness for the NRC examination. This examination is comparable to an NRC examination, both in scope and content. Grade criteria for the final comprehensive examination shall be an overall score of $\geq$80% and $\geq$70% on each examination category. License candidates are certified as ready by NRC examination by the Vice President - Power Resources. (The specific items include I.A.2.1, I.A.2.3, I.A.3.1, I.G.1, and II.B.4)

d) TMI action plan (NUREG 0737) items have been integrated into Unit #1 training activities. Since cold license candidates will have been licensed on Unit #1 these requirements will have been met. As additional requirements are established, they will be factored into Unit #1/2 training activities concurrently.

13.2.1.1.2 Non-Licensed Personnel Training

Non-licensed operators are trained for their positions through a combination of classroom lectures, on-the-job training and participation in the system checkout and plant startup effort. These training programs will be defined in ~~plant~~ Administrative Procedures.

Shift Technical Advisor training is described in Administrative Procedures "Shift Technical Advisor Training Program" and "Shift Technical Advisor Requalification Program". The Shift Technical Advisors will participate in the classroom portion of the licensed operator differences training program. /A

The Mechnical and Electrical Maintenance Supervisors and supporting staff receive training in appropriate maintenance procedures when assigned to the St. Lucie Plant. They participate in maintenance functions during the startup and checkout of St. Lucie Unit 2 systems and equipment. They participate in a lecture series conducted by FPL pertaining to appropriate mechnical and electrical maintenance functions.

~~The Reactor Engineer has received extensive experience and training at St. Lucie Unit 1. He attends appropriate sections of the operator training program including the NSSS lecture series.~~ /D

Instrumentation and control, radiochemistry and health physics technicians are assigned several months prior to initial fuel loading and are trained as required in their respective responsibilities. For radiochemistry and health physics personnel the training includes mitigation of accidents involving a degraded core. /A

Selected supervisory and maintenance personnel attend applicable portions of the ~~NSSS lecture series~~ Licensed Operator Differences Training Program. Maintenance personnel meet the requirements of the FPL/IBEW Joint Apprentice Training Program. /A

Handouts from this program ~~of the NSSS lecture series~~ are used by St. Lucie Plant departments as deemed applicable to job functions in ~~an~~ on-going departmental training programs for the St. Lucie staff.

All personnel receive training ~~in radiation protection and emergency procedures prior~~ to fuel loading.

Personnel who are not required to hold an NRC operator's license, including supervisors, engineers, technicians, operators, maintenance personnel and others, whose duties require them to work within the radiation controlled area or on systems associated with the nuclear plant, receive training in Radiation Protection. Upon completion of this training the individuals concerned are required to pass an examination signifying that they have basic understanding of the principles involved. Personnel with previous training are required to pass this examination but may not participate in the formal training program. All plant personnel are required to either have read the plant Radiation Protection Manual or attend the Radiation Protection course. The Radiation Protection course covers the following subject material:

a) Radiation and Radioactive Materials
b) Biological Effects of Radiation and Exposure Limits
c) Radiation Detection and Personnel Monitoring
d) Principles of Protection
e) Site Emergency Plan and Radiation Protection
f) Radiation Control Area Work Guidelines

Personnel assigned to the St. Lucie Plant, in an administrative capacity and whose duties would preclude their presence within the Radiation Control Area, receive training in Radiation Protection. The Radiation Protection Training Program provided for these individuals covers the same material as the non-licensed personnel training program although not as detailed and generally on a more basic level. Emphasis is placed on the site emergency plan and the St. Lucie Plant Radiation Protection manual.

Industrial safety and first aid training is provided as part of the general employee training program. Each employee is issued a copy of the FPL Safety Rule Book which covers first aid practices and safe work practices related to the utility industry. Included in this book are the latest first aid techniques and industrial emergency procedures. Employees may also attend first aid classes.These standards and procedures are developed and administered by the Joint Advisory Safety Committee. This program is /1
augmented by the Plant Safety Program which will include regular monthly meetings with emphasis placed on the nuclear plant aspects as well as the latest industrial safety practices.

All new plant personnel assigned to the St. Lucie Plant are given an orientation to general plant facilities, Health Physics policies, quality assurance, and the emergency and security plans. This orientation is usually conducted during the first week of employment at the St. Lucie Plant and provides them with the minimum practical training they need until they can attend the Radiation Protection class or complete the Radiation Protection Program examination.

13.2.1.1.3 Fire Protection Training

Fire protection training is described in Subsection 9.5.1.

13.2.1.2 <u>Coordination With Preoperational Tests and Fuel Loading</u>

Table 13.2-1 shows the schedule of each part of the Training Program in relation to the schedule for preoperational testing and expected fuel /D loading. This schedule also shows expected time frames for examinations and any vendor supplied training. Should fuel loading be delayed from the date indicated, the licensees will supplement the St. Lucie Unit 1 operating staff as well as support St. Lucie Unit 2 startup and preoperational testing activities. Section 14.2 describes the pre operational and startup test program.Section 14.2.12.4.I specifically addresses natural circulation training. /A

13.2.2 REPLACEMENT AND RETRAINING

13.2.2.1 <u>Licensed Operators - Requalification Training</u>

The requalification training program for licensed operators complies with Section 5.5 of ANSI~~/ANS-3.1-1978,~~ 18.1-1971 "American National Standards for Selection and Training of Nuclear Power Plant Personnel," to implement the requirements of Appendix A of 10CFR55. This program is described in Administrative Procedure, "Licensed Operator Requalification Program". /A

13.2.2.2 Non-Licensed Personnel Retraining - Refresher Training

Plant personnel not included in the Licensed Personnel Training Program receive refresher training in radiation protection and occupational safety as a part of the FPL ongoing safety program. Training programs are established for each department to ensure that its personnel maintain familiarity with their job specifics and keep abreast of changes in the plant equipment, policies and procedures which could affect their job function. This training is conducted periodically at a frequency specified by the respective department heads.

13.2.2.3 Replacement Training

13.2.2.3.1 Replacement Training - Licensed Personnel

A continuing training program during the life of the plant assures that each replacement employee who requires an NRC operator license receives the same general material, follows the same fundamental program used for the initially licensed personnel and knows his specific duties and responsibilities for normal and emergency operations. Personnel from other FPL plants are considered for these replacement positions on a selective basis. The supervisory and technical staff are the primary source of instructors for the continuing training program, but outside assistance may be obtained as necessary to assure competent replacement personnel.

13.2.2.3.2 Replacement Training - Non-Licensed Personnel /R

Training programs are established by each department to insure that new personnel are trained sufficiently to meet the minimum requirements for their job. These programs provide new personnel with the required familiarity with the job specifics, such as plant equipment, procedures, and policies affecting their job function.

13.2.2.~~X~~4 Plant Drills

Drills are conducted periodically to provide training in plant evolutions such as site evacuation, response to fires, breaches of security, and emergency medical response. /A

13.2.3 APPLICABLE NRC DOCUMENTS

The following NRC regulations, regulatory guides and reports are discussed in the referenced sections:

	Section
10 CFR Part 50	3.1
10 CFR Part 55	13.2
10 CFR Part 19	12.5
Regulatory Guide 1.8	13.1, 13.2
Regulatory Guide 1.101	13.3
Regulatory Guide 8.2	12.5
Regulatory Guide 8.8	12.1
Regulatory Guide 8.10	12.5
Regulatory Guide 8.13	12.5

TABLE 13.2-1

ST LUCIE PLANT EMPLOYEE TRAINING SCHEDULE

1		Preoperational Testing 51 Weeks		Hot Functional Testing 7 Weeks				Preparation for Fuel Loading 22 Weeks	
2	Basic Nuclear Concepts Training 20 Weeks	St Lucie Plant System Training 21 Weeks	*N S S S	On Shift Training Unit #1 9 Weeks	*S I M	*R E V	#1 Exam	Operational Experience on Unit #1 12 Weeks	#2 Exam
3		St Lucie Plant System Training 21 Weeks	*N S S S	On Shift Training Unit #1 9 Weeks	*S I M	*R E V	#1 Exam	Operational Experience on Unit #1 12 Weeks	#2 Exam
4		Unit #2 Systems & Plant Differences Training as Part of Requal. Program	*N S S S	Unit #2 Systems & Plant Differences Training as Part of Requal. Program					#2 Exam
5		Unit #2 System Lectures - Participation in Preoperational Test Program Will Provide the Necessary Training of Unlicensed Operators.							
6	Ongoing Departmental Training and Retraining Programs		*N S S S	Ongoing Departmental Training and Retraining Programs					
80	70	60 50	40		27			22	10

Weeks to Core Load

Functional Groups

1 Plant Schedule
2 License Candidates with no Prior Exp.
3 License Candidate with Prior Exp.
4 Personnel Currently Licensed on St Lucie Unit 1
5 Non-Licensed Operators
6 Non-Licensed Support Personnel

* Requires two weeks

ST. LUCIE PLANT TRAINING SCHEDULE

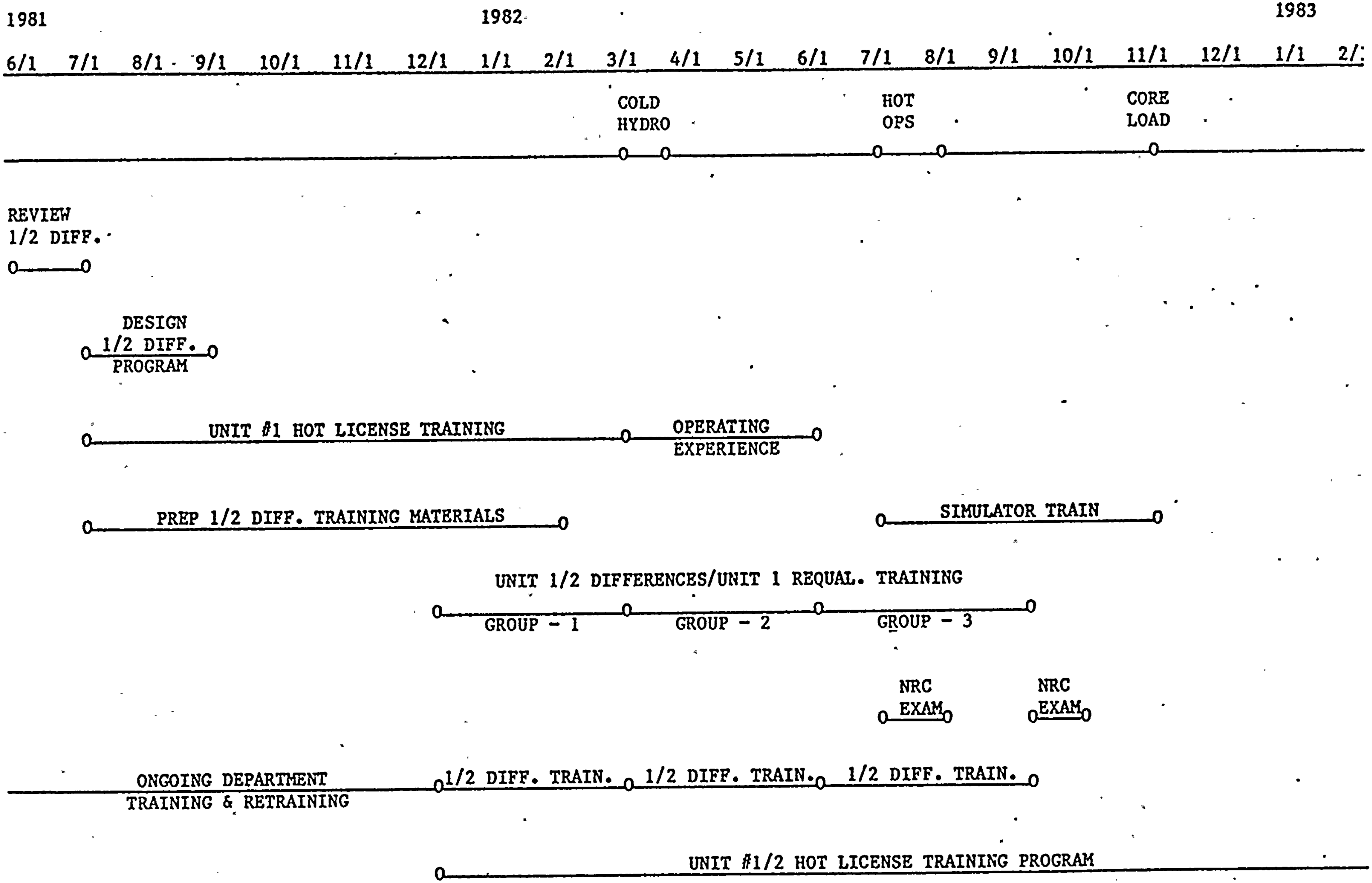


FIG 13.2-1

13.3 EMERGENCY PLANNING

The St Lucie Radiological Emergency Plan is a separate document which has been previously submitted for St Lucie Unit 1, Docket No. 50-335. This extant Plant Emergency Plan will be applicable to both St Lucie Units 1 and 2 since it will be revised prior to Unit 2 fuel load to incorporate St Lucie Unit 2 design information as appropriate, utilizing the guidelines of NUREG-0654, Rev. 1 (November, 1980) "Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Prepardness in Support of Nuclear Power Plants". The revised St Lucie Radiological Emergency Plan will be provided in a separate volume entitled "St Lucie Plant Radiological Emergency Plan".

FPL Topical Quality Assurance Report (FPL TQAR) 1-76A, Rev 4

13.4 REVIEW AND AUDIT

Conduct of reviews and audits of operating phase activities is described in Section 6.0, Administrative Controls, of the Technical Specifications as specified below. ~~Section 17.2, quality assurance (QA) during the operations phase,~~ provides general objectives and character of the review and audit program.

13.4.1 ONSITE REVIEW

Onsite review is addressed in Section 6.5.1 of the Technical Specifications.

13.4.2 INDEPENDENT REVIEW

Independent review of operating activities is described in Section 6.5.2 of the Technical Specifications.

13.4.3 AUDIT PROGRAM

The audit program used to verify compliance with the administrative controls and quality assurance program is described in Sections 6.5.2.8 and 6.5.10 of the Technical Specifications.

13.5 PLANT PROCEDURES

This section describes administrative, operating and maintenance procedures that are used by the operating organization to ensure that routine operating, off-normal and emergency activities are conducted in a safe manner. This section is based on the Procedures Program utilized for FPL's St. Lucie Unit 1, an operating unit.

The following is a list of categories of procedures to be utilized for St. Lucie Unit 2:

a) Administrative Procedures
b) Chemistry Procedures
c) Emergency Plan Implementation Procedures
d) Environmental Test Procedures
e) General Maintenance Procedures
f) Health Physics Procedures
g) Instrument and Controls Department Procedures
h) Letters of Instruction
i) Maintenance Procedures
j) Off-normal and Emergency Procedures
k) Operating Procedures
l) Pre-operational Procedures
m) Security Procedures
n) Quality Instructions

In order to simplify procedures writing and to increase operators familiarity, basic formats are chosen for the procedure writing effort, as described below.

General Administrative and Security Procedures:

1.0 Title
2.0 Review and Approvals
3.0 Scope
4.0 Precautions
5.0 Responsibilities

6.0 References
7.0 Records and Notifications
8.0 Instructions

Operational Procedures

1.0 Title
2.0 Review and Approvals
3.0 Purpose
4.0 Precautions and Limits
5.0 Related Systems Status
6.0 References
7.0 Records Required
8.0 Instructions

Off-Normal and Emergency Procedures;

1.0 Title
2.0 Review and Approvals
3.0 Purpose and Discussion
4.0 Symptoms
5.0 Instructions
6.0 References
7.0 Records Required

Letters of Instruction:

1.0 Title
2.0 Approvals
3.0 Purpose and Discussion
4.0 Instructions

Quality Instructions:

1.0 Approvals
2.0 Purpose

3.0 Scope

4.0 Responsibilities

5.0 Instructions

Because of the nature of plant operations, any specific task may involve selected procedures from the categories (a) through (n), as listed above. This overlap is necessary to successfully integrate the required work activity with necessary controls and provide adequate documentation. Where required these procedures will cross-reference administrative, operation, maintenance or other procedures.

13.5.1 ADMINISTRATIVE PROCEDURES

13.5.1.1 Conformance with Regulatory Guide 1.33

The St. Lucie Plant procedure program described in this section complies with Regulatory Guide 1.33, "Quality Assurance Program Requirements (Operations)" November 3, 1972, as described in FPL TQAR 1-76A, ~~Revision~~ Rev 4.

13.5.1.2 Preparation of Procedures

The plant staff prepares, within approximately six months prior to core load, the procedures necessary for plant startup, operation and emergencies. Section 14.2 describes the startup and preoperational test procedure program. The cognizant plant supervisor ensures that these procedures are properly reviewed by the Facility Review Group (FRG) and approved by the Plant Manager.

Procedures shall be adhered to and any changes necessary are handled as follows:

a) Routine changes must be submitted on Change Form for FRG review and Plant Manager approval.

b) Temporary changes approved by two members of the Plant Staff, one of which holds a senior operating license. Temporary changes may not be

made which change the intent of the procedure. Temporary changes must be reviewed, within 14 days (or as specified in the license) by the FRG and approved by the Plant Manager.

Changes to procedures which conflict with the operating license are not made without NRC approval.

13.5.1.3 Procedures

"Duties and Responsibilities of Operators on Shift" prescribes the minimum number of licensed operators per shift, control room access and access limitation criteria, shift and relief turnover procedures and operator's authority and responsibilities, e.g., SRO directing return to power, shutting down the plant when safety of the reactor is in jeopardy, adherence to license requirements, review of routine data, etc. This procedure will contain the requirements of 10CFR.50.54 (i), (j), (k), (e) and (m). Guidance concerning shift supervisor administrative duties contained in a Corporate directive issued by the Vice President-Power Resources has been incorporated into this procedure. Figure 13.5-1 shows those areas specified as "at the controls". "Overtime Limitations for Licensed Operators" defines the overtime policy. /A

Normally there shall be no Administrative Procedures providing for special orders of a transient or self-cancelling character.

Administrative procedures, as a minimum, shall be provided which address the administrative control of valves, locks and switches and for the control and use of jumpers and disconnected loads in safety related systems.

To control work, as a minimum, procedures are provided which cover: Removal of safety related equipment from service and restoration; verification of performance of operating activities; plant work orders; the preventive maintenance program; maintenance of seismic category I system; control of backfit work; preliminary and conditional acceptance of system by FPL Power Resources, and the Facility Review Group. /A

Administrative procedures are provided covering the ASME code testing of pumps and valves; the schedule of periodic tests, checks and calibration; the reactor engineering schedule of periodic tests and reports; and the schedule of maintenance surveillance requirements.
References to logbook usage and control are provided for procedures in other categories.

Normally there are no Temporary Procedures in the Administrative Procedures Category.

13.5.2 OPERATING AND MAINTENANCE PROCEDURES

13.5.2.1 Operating Procedures

Operating procedures describing control room activities will be prepared for all areas for pressurized water reactors specified by Appendix A of Reg. Guide 1.33.

Operating procedures cover the normal operation of all systems and components and off-normal operation of safety related systems and are classified into these two categories. The Operations Supervisor is responsible for the generation of operating procedures.

Operational procedures cover the normal operation of a unit from a cold shutdown condition to power and return to cold shutdown. Additional procedures cover startup, operation, testing, and shutdown of individual /A systems and components. These include check lists for establishing the necessary condition of system components to perform the specific procedure, and precautions to be followed during the procedure.

Off-normal/emergency operating procedures cover the range of equipment and system troubles. These are procedures that describe actions to be taken when equipment malfunctions or to prevent a perturbation from resulting in a situation of more serious consequence. Typical conditions included are excessive system leakage, pump failure, loss of off-site power, instrument air failure, and a stuck or faulty control element assembly. The Combustion Engineering Operating guidelines will be incorporated where applicable. /A

The operating procedures describing control room activities address all areas specified by Appendix A of Reg. Guide 1.33 for pressurized water reactors. /R

Alarm Response Procedures are in the form of an annunciator verification list indicating the actions to be performed should off-normal conditions occur in the operation of systems or equipment. This list provides the guidelines for a preplanned course of response to alarms under certain conditions; however, the particular situation governs the extent to which each action is carried out. These guidelines include (a) the possible cause of the alarm; (b) alarm set points and signal source; (c) immediate action to be taken by the operator; and (d) subsequent action based on off-normal procedure. /R

~~Temporary Procedures~~

Temporary control room operating procedures are used only to a limited extent. These are in the form of letters of instruction. Letters of instruction are issued depending upon specific plant operating conditions. Example of such procedures may include personnel authorized to hold clearances, jurisdiction of systems during startup, or pump base line data collection.

13.5.2.2 Other Procedures

Other procedures are included with the categories listed in Subsection 13.5.1.3.

The responsibility for the initiation, development and implementation of these procedures are as indicated below.

The Operations Department is responsible for:

a) Health Physics Procedures

The general objective and character of these procedures is described in Section 12.5. These procedures describe radiation protection and the Health Physics Department Supervisor is responsible for ensuring these procedures are followed.

b) Emergency Plan Implementation Procedures

The general objective and character of these procedures support the St. Lucie Site Emergency Plan and are described therein. The Emergency Plan is contained in a separate volume. These procedures describe emergency preparedness and are the responsiblity of the Operation Superintendent.

c) Chemistry Procedures

Chemistry procedures are provided for chemical and radiochemical control activities. They include, for example, the nature and frequency of sampling and analyses; instructions for maintaining coolant quality within prescribed limits; and limitations on concentrations of agents that could cause corrosive attack, foul heat transfer surfaces, or become sources of radiation hazards due to activation.

Procedures shall also be provided for the control, treatment, and management of radioactive wastes and control of radioactive calibration sources. The Chemistry Supervisor is responsible for ensuring these procedures are followed.

The Maintenance Department is responsible for:

a) Maintenance Procedures

Maintenance procedures are written for maintenance of equipment expected to require frequent attention and do not have sufficient details in the instruction manuals. Examples of such equipment are control rod drives, pump seals, important filters and strainers, diesel generator sets, major valves and steam generators. As experience is gained in operation of the plant, routine maintenance is altered to improve equipment performance, and procedures written for repair of equipment are improved, if required. Since the probability of failure is usually unknown and the time and mode of

failure are usually unpredictable for most equipment, specific procedures cannot be written for repair of most equipment before failures. /R

Radiation protection measures are prescribed before the task begins as necessary.

Permission to release equipment or systems for maintenance is granted by responsible operating personnel. Prior to granting permission, such operating personnel verify that the equipment or system can be released, and, if so, how long it may be out of service.

After permission is granted, equipment is made safe for work. Measures provide for protection of equipment and workers. Equipment and systems in a controlled status are clearly identified. Strict control measures for such equipment is enforced.

Conditions considered in preparing equipment for maintenance include, for example, shutdown margin; method of emergency core cooling; establishment of a path for decay heat removal; temperature and pressure of the system; valves between work and hazardous materials; electrical hazards; and physical barriers, as required.

The procedures contain enough detail to permit the maintenance work to be performed safely and expeditiously.

Instructions are included for returning the equipment to its normal operating status. Operating personnel place the equipment in operation and verify its functional acceptability. Special attention is given to restoration of normal conditions, such as removal of signals used in maintenance or testing, and to systems that can be defeated by leaving valves or breakers mispositioned or by leaving switches in "Test" or "Manual" positions. All jumpers are controlled. When placed into service, the equipment receive special surveillance until a run-in period has ended.

The Instrument and Control Department Supervisor, the Assistant Superintendent Electrical Maintenance, and the Assistant Superintendent Mechanical Maintenance are responsible for ensuring their respective procedures are followed.

b) General Maintenance Procedures

General Maintenance Procedures are provided to cover welding, inspection, personnel training and other concerns generic to the implementation of a comprehensive maintenance program. The Maintenance Superintendent is responsible for ensuring these procedures are followed.

c) Instrument and Control Department Procedures

Instrument and Control Department Procedures are provided for testing and periodic calibration of plant instrumentation such as interlocks, alarm devices, sensors, signal conditioners, and protective circuits. The procedures have provisions for meeting surveillance schedules and for assuring measurement accuracies adequate to keep safety parameters within operational and safety limits. The Instrument and Control Department Supervisor is responsible for ensuring these procedures are followed. The general objective and character of these procedures are described in Section 17.2.

Other Plant Staff Departments are responsible for:

a) Quality Instructions

Quality Instructions are provided to cover plant quality related matters including material control. The Quality Control Supervisor is responsible for ensuring these procedures are followed. The general objectives and character of these procedures are described in Section 17.2.

b). Security Procedures

Plant Security Procedures describe specific plant related security matters. The Security Supervisor is responsible for ensuring these procedures are followed. The general objectives and character of these procedures are described in Section 13.6 and in the St. Lucie Plant Security Plan.

430.3. (8.2) Describe in detail how the requirements of GDC 5, "Sharing of Structures Systems and Components," are satisfied when the startup transformers for St Lucie Units 1 and 2 are paralleled, specifically when one startup transformer is out of service and the remaining startup transformers are paralleled to facilitate continued operation. Demonstrate that the remaining startup transformers have the capacity and capability of performing all required safety functions in the event of an accident in one unit, with simultaneous orderly shutdown of the other unit.

Response

GDC 5, "Sharing of structures, Systems and Components" concerns components important to safety and that must perform a safety function. The startup transformers for St Lucie 1 and 2 do not perform a safety function and are not safety related. Each unit is supplied with two (2) separate start-up transformers each sized with sufficient capacity for an orderly shutdown and cool down or the mitigation of a DBA in its respective unit. During normal plant operation each start-up transformer is in standby and two (2) are available for each unit. In the unlikely event that one (1) startup transformer is taken out of service provisions are provided to allow one startup transformer to be available for both units. Should it be necessary for one unit to claim that startup transformer, administrative and operator procedure will prevent that transformer from being overloaded.

Furthermore, should all preferred power be lost, both St Lucie Unit 1 and 2 have their own 100 percent capacity redundant diesel generator sets which are available for safe shutdown.

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REQUESTS FOR ADDITIONAL INFORMATION FOR ST LUCIE UNIT 2

430.66
(8.2)

Provide physical layout drawings of the circuits that connect the onsite distribution system to the preferred power supply, and plant layout drawings depicting the physical separation between redundant portions of the onsite distrubution system.

Response

430.66

Utilizing the main one line wiring diagram (FSAR Figure 8.3-1) we have color coded both Figure 8.3-1 and the associated physical design drawings. The drawings indicate the physical path between both the low voltage side of the start up transformer and of the unit auxiliary transformer to the respective 4.16 kV switchgears (2A2, 2A3/2B2, 2B3) and on to the onsite emergency power source, the diesel generator.

These marked drawings indicate not only the preferred power source and its connection to the emergency buses, but also indicate the separation between the redundant portions of the onsite electric distribution system which meets R.G. 1.75 as discussed in section 8.3.1.2.

The attached list provides the drawings by title that are being presented.

For purposes of presentation, colors were chosen to indicate the preferred power connection and not on the basis of FSAR Section 8.3.1.3. For the safety related portion, the color scheme presented in Section 8.3.1.3 is applicable.

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DRAWING LIST

2998-G-272	Main One Line Wiring Diagram
2998-G-340	Turbine Building Ground Floor, Conduit Trays & Grounding - Sh 2
2998-G-342	Turbine Building Ground Floor Conduits, Trays & Grounding
2998-G-352	Arrangement-Switchgear Room Reactor Auxiliary Building
2998-G-356	Turbine Areas Underground - Conduits and Grounding Sh 2
2998-G-358	Trubine Areas Underground Conduits & Grounding Sh 4
2998-G-374	Reactor Aux Bldg Penetration Area Conduit Trays & Grounding Sh 1
2998-G-377	Reactor Auxiliary Building -Underground Conduit & Grounding Sh 1
2998-G-388	Diesel Generator Building Conduit, Grounding & Lighting
2998-G-408 Sh 1	Yard Duct Runs and Lighting Plan - Scetions & Details Sh 1
2998-G-408 Sh 2A	Yard Duct Runs and Grounding - Plans Sections and Details Sh 2A
2998-G-409 Sh 2x	Transformer Yard - Plan Transformer Fire Protection & 5KV & 6.9KV non seg Bus Dust

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430.67 Describe the instrumentation and controls provided to the operator
(8.2) to determine the status of the preferred power system.

Response:

Preferred (offsite) power from the start-up transformers, or from the unit auxiliary transformers is distributed to the non-safety related loads by two 6.9 kV buses (2A1 and 2B1) and by two 4.16kV buses (2A2 and 2B2). Power is also distributed from the two 4.16 kV buses 2A2 and 2B2 to the safety related 4.16kV buses 2A3 and 2B3, which supply all safety related loads. Upon a loss of the preferred power sources, the tie breakers between the non-safety and safety buses automatically open, and the emergency diesel generator automatically start, are brought to speed and begin supplying power to the safety buses (2A3, 2B3). The FIG. 8.3-1 (main one-line wiring diagram) depicts the preferred power system arrangemnt.

Adequate Instrumentation and controls are provided on Reactor Turbine Generator Control Board 201 to assure the operators are fully aware the status of the power system (see attach table) ~~see~~ Interconnecting breakers, tie breakers status (open or close) is clearly displayed by red or green lights, located right above the related breaker control switch. A mimic bus display is used to interconnect all major buses, generator and diesel generators so that the operators have a complete overall view about the system status.

Synchronization between incoming power and running power is achieved through an automatic synchronizer to assure frequency and voltage are compatible before initiating transfer of power.

Current and voltage information of each bus is metered and displayed on the RTG 201 board as determined from potential and current transformers at the respective switchgears. Refer to the attached table for a description. Frequency, voltage, current and MW output of the main generator, emergency diesel generators are also closely monitored and displayed. Interlocks and announication alarms are used to the practical extent to prevent any abnormal power system lineup.

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1/2

RT6B 201

~~SAFETY RELATED~~ DISPLAY INSTRUMENTATION & CONTROLS PREFERRED POWER

INSTRUMENTS

Tag No.	Parameter	Function	Instrument Range
VM-888I	Incoming Volts	Indication	0-150
VM-888R	Running Volts	"	0-150
SYN-888	Synchroscope	"	-
AM-918	6.9 kV Bus 2A1 Amp	"	0-2000
VM-918	6.9 kV Bus 2A1 Volts	"	0-9000
AM-916	4.16 kV Bus 2A2 Amp	"	0-3000
VM-916	4.16 kV Bus 2A2 Volts	"	0-5250
AM-917	4.16 kV Bus 2B2 Amps	"	0-3000
VM-917	4.16 kV Bus 2B2 Volts	"	0-5250
AM-919	6.9 kV Bus 2B1 Amp	"	0-2000
VM-919	6.9 kV Bus 2B1 Volts	"	0-9000

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2/2

CONTROLS

Tag No.	Item Description	Lamps for each Switch Color
CS-904	6.9 kV Start-up Transf 2A	G,R
CS-905	6.9 kV Start-up Transf 2B	G,R
CS-906	4.16 kV Start-up Transf 2A	G,R
CS-907	4.16 kV Start-up Transf 2B	G,R
CS-912	6.9 kV Aux Transf 2A	G,R
CS-913	6.9 kV Aux Transf 2B	G,R
CS-914	4.16 kV Aux Transf 2A	G,R
CS-915	4.16 kV Aux Transf 2B	G,R
CS-934	4.16 kV Bus Tie 2A2-2A3	G,R
CS-935	4.16 kV Bus Tie 2B2-2B3	G,R
CS-936	4.16 kV Bus Tie 2A3-2A2	G,R
CS-937	4.16 kV Bus Tie 2B3-2B2	G,R

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JUL 17 198[illegible]

430.68. (8.2) Provide the capacity of each of the three 240 kilovolt transmission circuits that terminate at Midway Station from the St. Lucie switchyard and demonstrate that each circuit has the capacity and capability of performing all required safety functions in event of an accident in one unit, with simultaneous orderly shutdown of the other unit.

Response

Each 240 Kilovolt transmission circuit connecting the St Lucie Unit 2 switchyard and the Midway station consists of 1-3400 Kcmil ACSR/AW 120/37 conductor per phase and is rated 952 MVA. The estimated load in the event that one (1) unit is at the initial point of orderly shutdown while the second is mitigating a design basis event, is approximately 68 MVA or 7.1% of one (1) transmission line capacity. Therefore, one (1) transmission line is more than adequately sized to handle the combined safe shutdown and accident mitigation loads of the St Lucie Site.

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430.69
(8.2) Provide load flow diagrams and voltage and frequency curves associated with the results of the grid stability analysis presented in Section 8.2.2 of the FSAR.

Response

Refer to attached figures.

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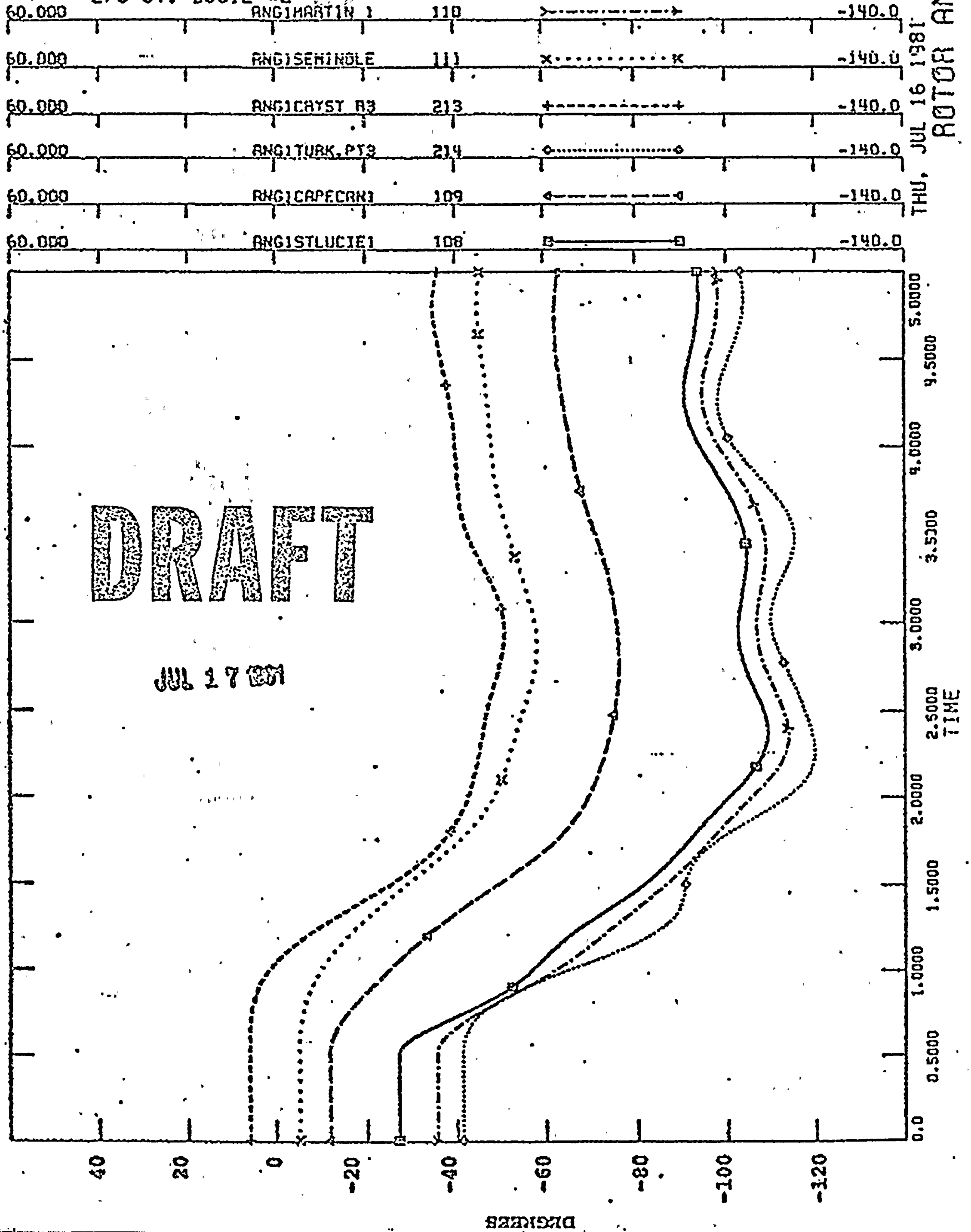
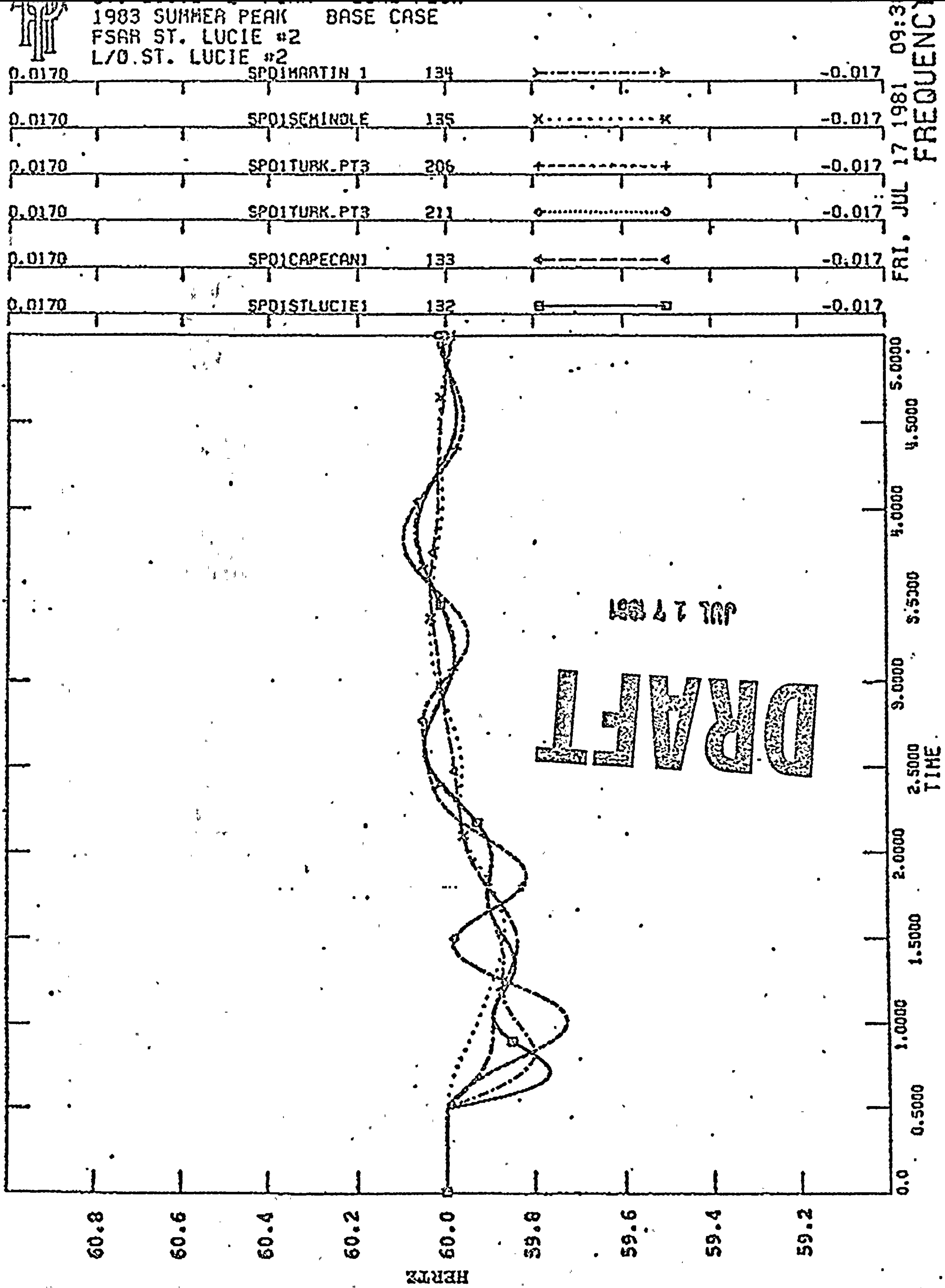
ST. LUCIE #2 FSAR LOAD FLOW
1983 SUMMER PEAK BASE CASE
FSAR ST. LUCIE #2
L/O ST. LUCIE #2




1983 SUMMER PEAK BASE CASE
FSAR ST. LUCIE #2
L/O.ST. LUCIE #2
FRI, JUL 17 1981 09:3
FREQUENCY
0.0170 SPO1MARTIN 1 134 -0.017
0.0170 SPO1SEMINOLE 135 -0.017
0.0170 SPO1TURK.PT3 206 -0.017
0.0170 SPO1TURK.PT3 211 -0.017
0.0170 SPO1CAPECAN1 133 -0.017
0.0170 SPO1STLUCIE1 132 -0.017
DRAFT
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TIME
0.0
0.5000
1.0000
1.5000
2.0000
2.5000
3.0000
3.5000
4.0000
4.5000
5.0000
HERTZ
60.8
60.6
60.4
60.2
60.0
59.8
59.6
59.4
59.2

FIGURE 8-1-1.2

ST. LUCIE #2 FSAR, LOAD FLOW
1983 SUMMER PEAK BASE CASE
FSAR ST. LUCIE UNIT # 2
L/O LAUD-PLANTATION-BROWARD 138KV (L/O LOAD)

FRI. JUL 17 1981 09:38
FREQUENCY

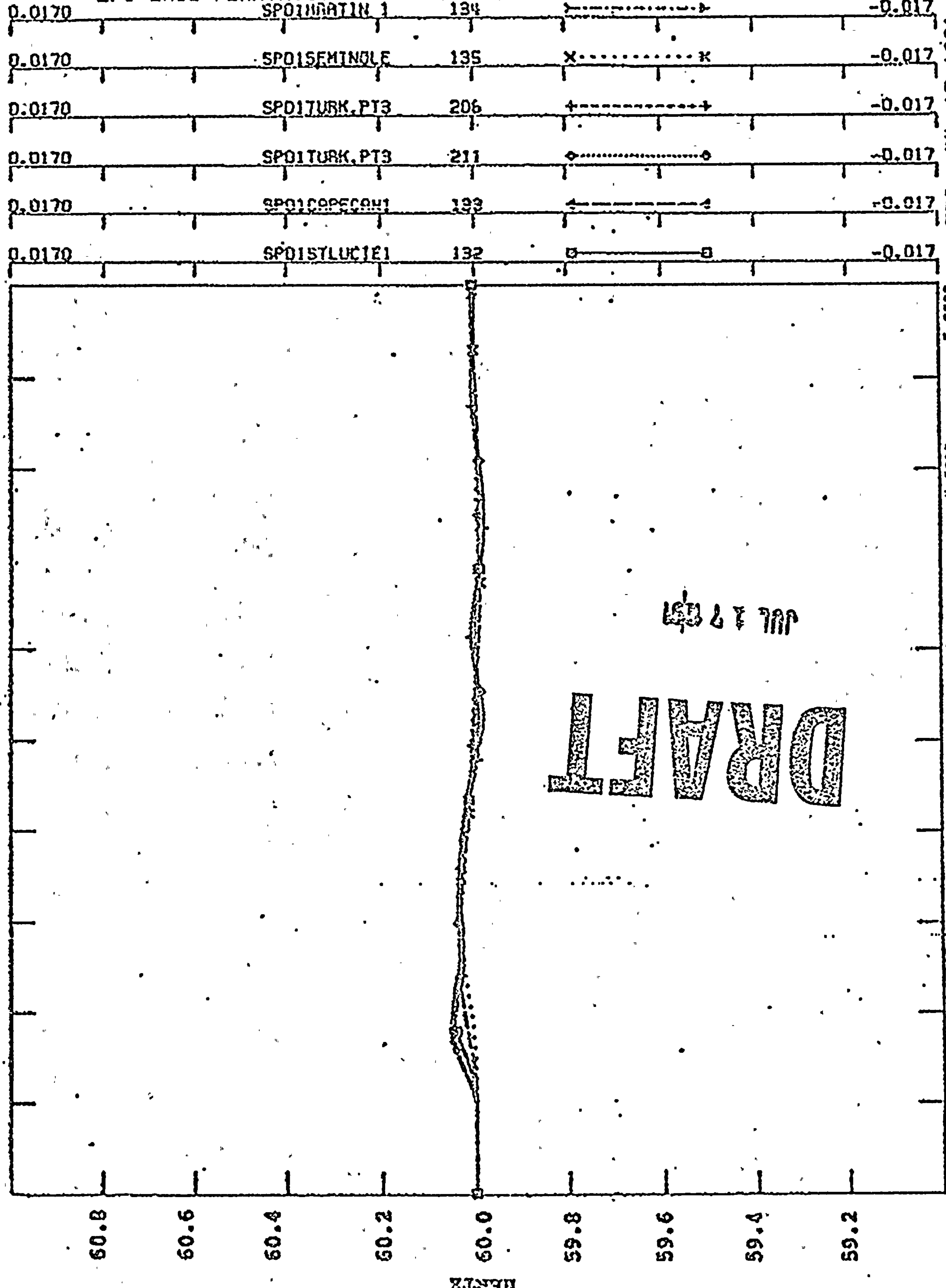


FIGURE 8-1-2.2

ST. LUCIE #2 FSAR LOAD FLOW
1983 SUMMER PEAK BASE CASE
FSAR ST. LUCIE UNIT # 2
L/O LAUD-PLANTATION-BROWARD 138KV (L/O LOAD)

THU, JUL 16 1981 13:46
ROTOR ANGLE

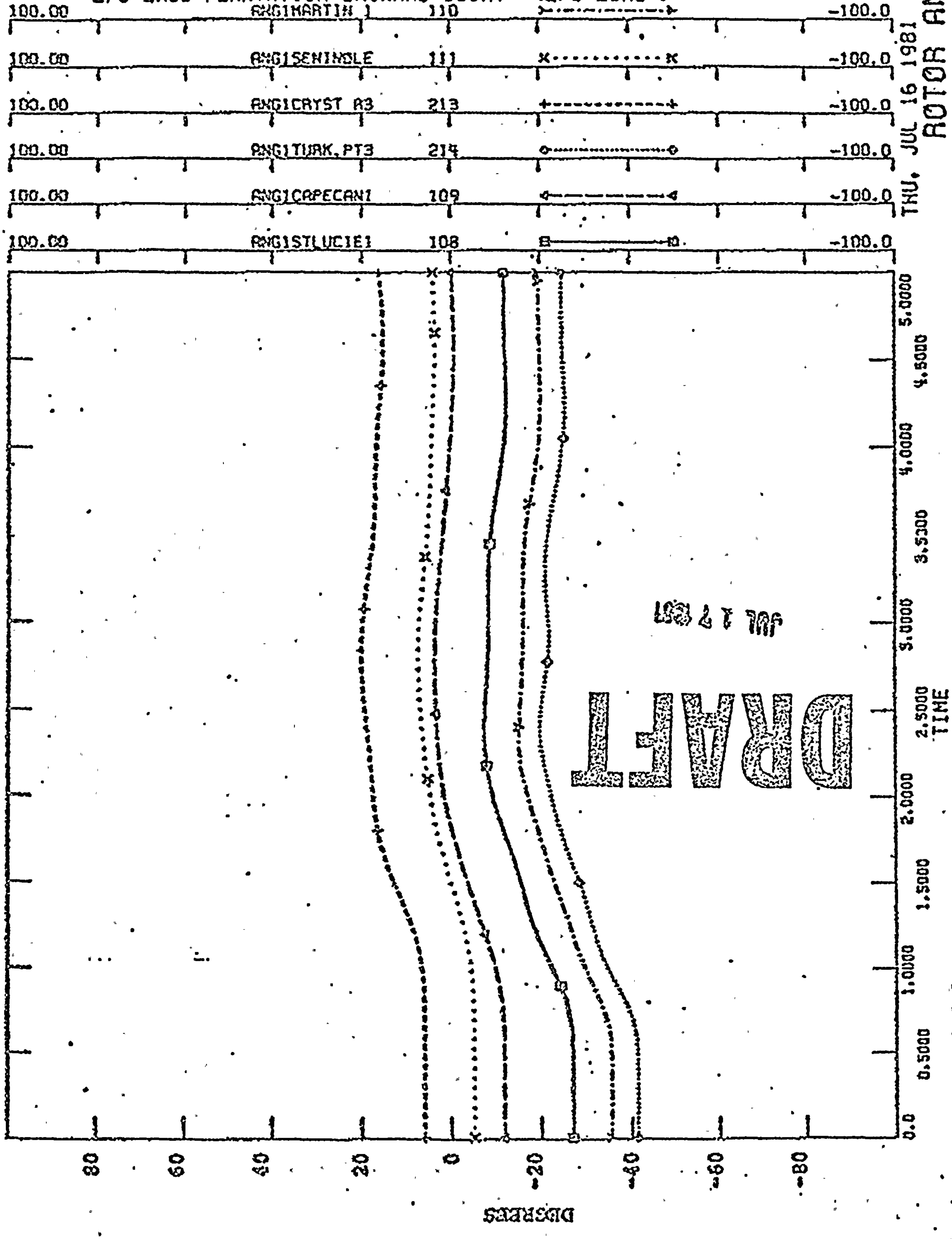
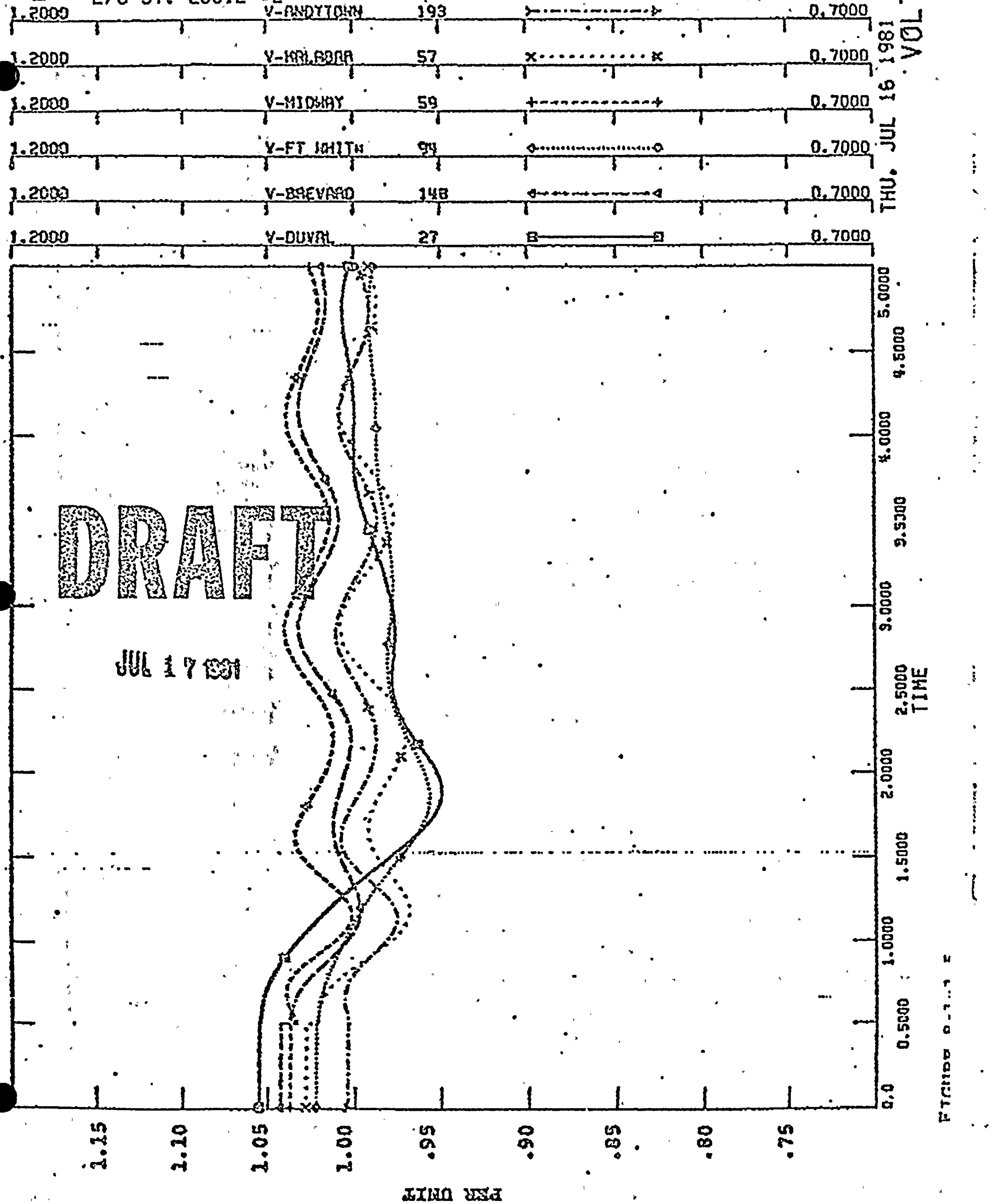


FIGURE 8-1-2.1

ST. LUCIE #2 FSAR LOAD FLOW
1983 SUMMER PEAK BASE CASE
FSAR ST. LUCIE #2
L/O ST. LUCIE #2



1983 SUMMER PEAK BASE CASE
FSAR ST. LUCIE #2
L/0 ST. LUCIE #2

THU, JUL 16 1981 14:28
VOLTAGE

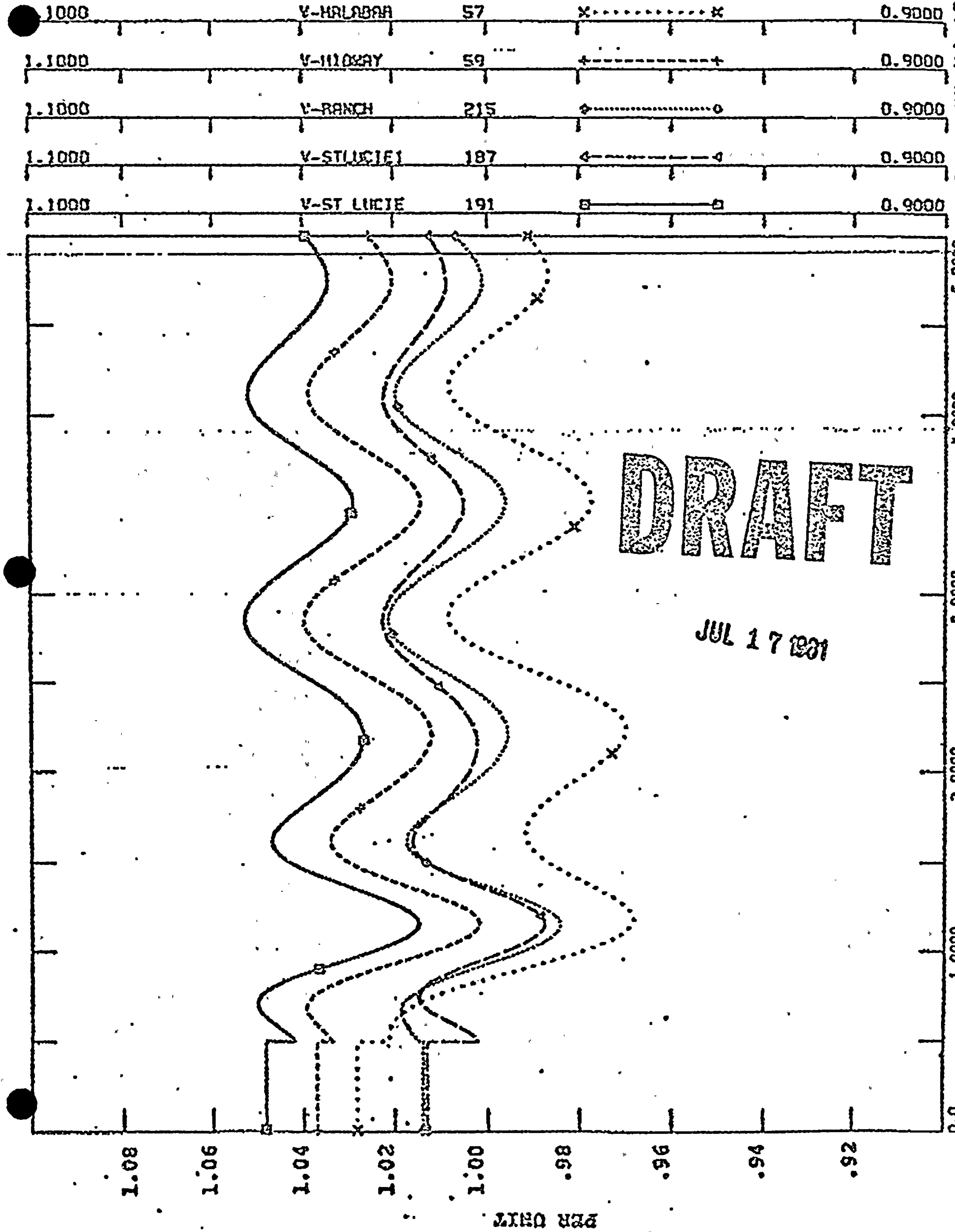


FIGURE 8-1-1.4

ST. LUCIE #2 FSAR LOAD FLOW
1983 SUMMER PEAK BASE CASE
FSAR ST. LUCIE #2
L/O ST. LUCIE #2

THU. JUL 16 1981 14:26
POWER FLOWS

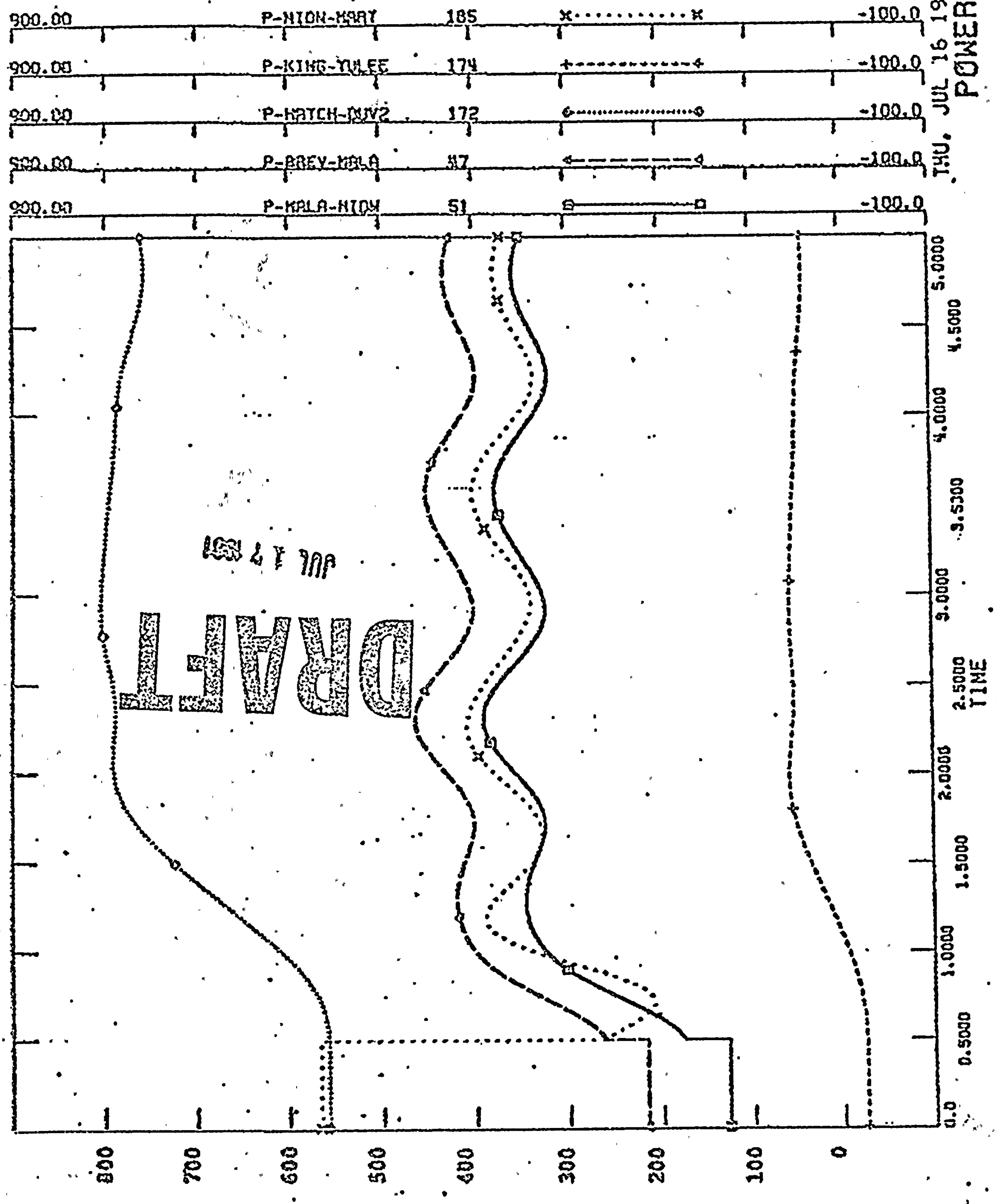


FIGURE 8-1-1.3

1983 SUMMER PEAK BASE CASE
FSAR. ST. LUCIE UNIT # 2
L/O LAUD-PLANTATION-BROWARD 138KV (L/O LOAD)

FRI. JUL 17 1981 POWER FLOW

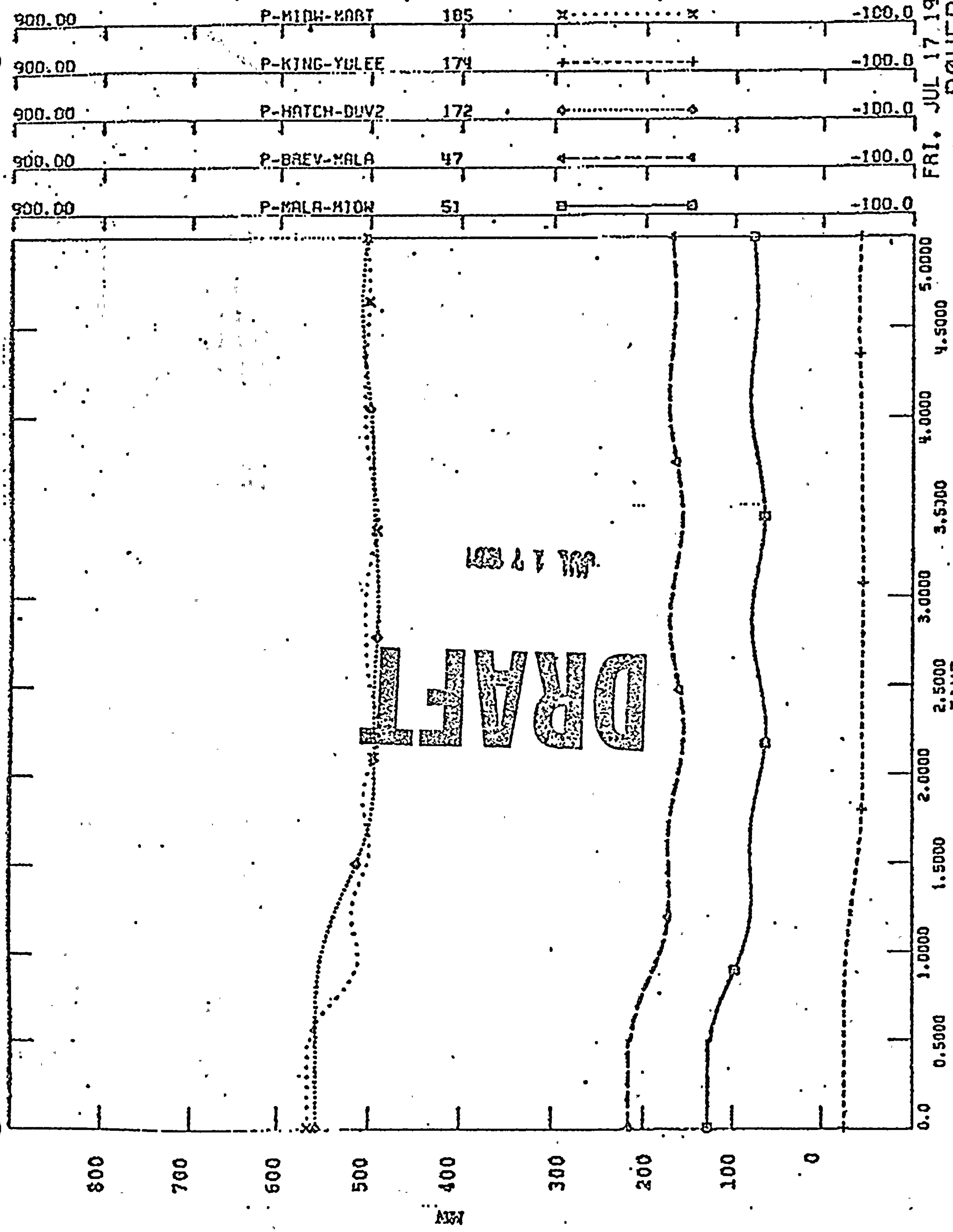


FIGURE 8-1-2.3

1983 SUMMER PEAK ; BASE CASE
FSAR: ST. LUCIE UNIT # 2
L/O LAUD-PLANTATION-BROWARD 138KV (L/O LOAD)

THU, JUL 16 1981 13: VOLTAG

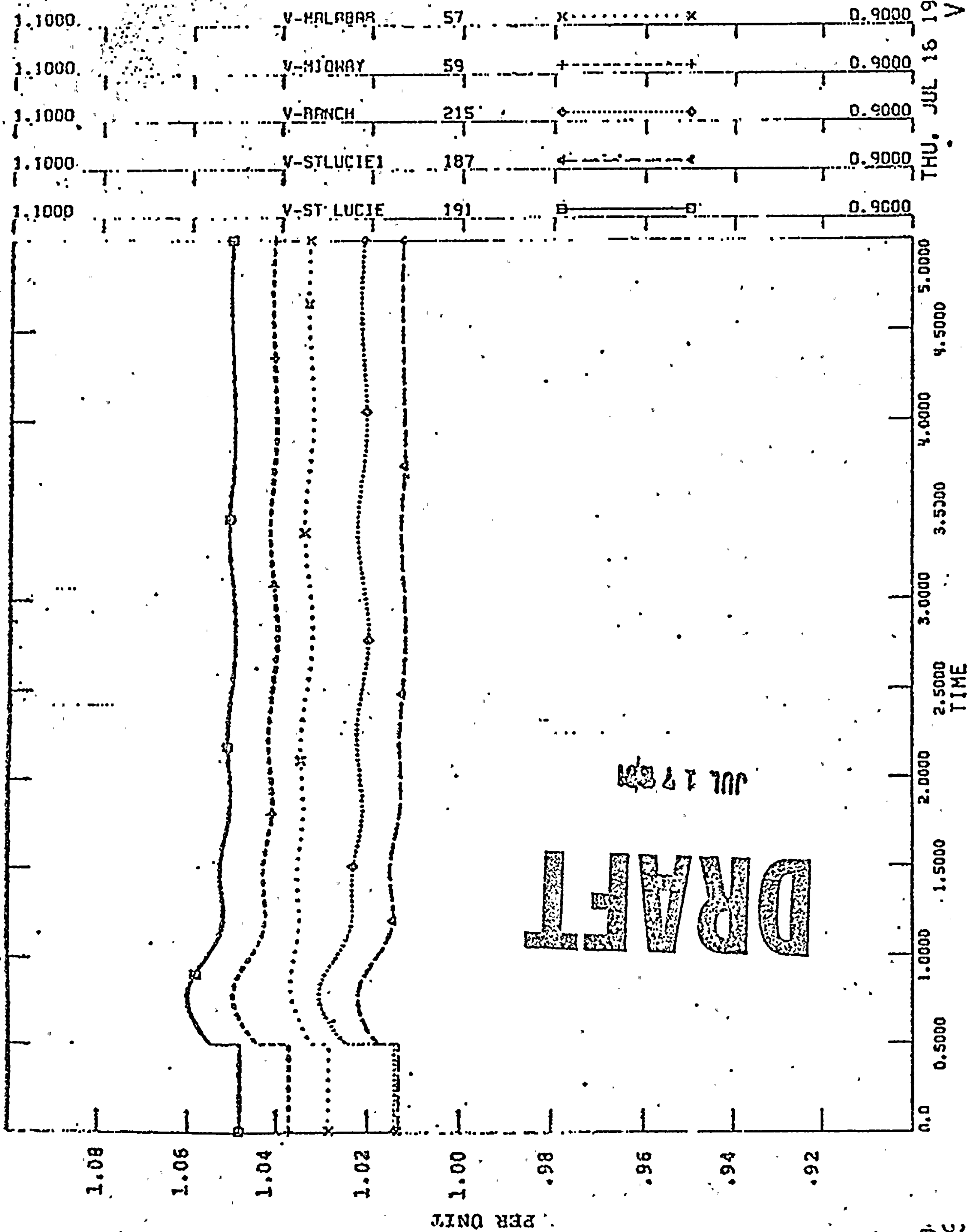


FIGURE 8-1-2.4

ST. LUCIE #2 ... LOAD FLOW
1983 SUMMER PEAK BASE CASE
FSAR ST. LUCIE UNIT = 2
L/O LAUD-PLANTATION-BROWARD 138KV (L/O LOAD)

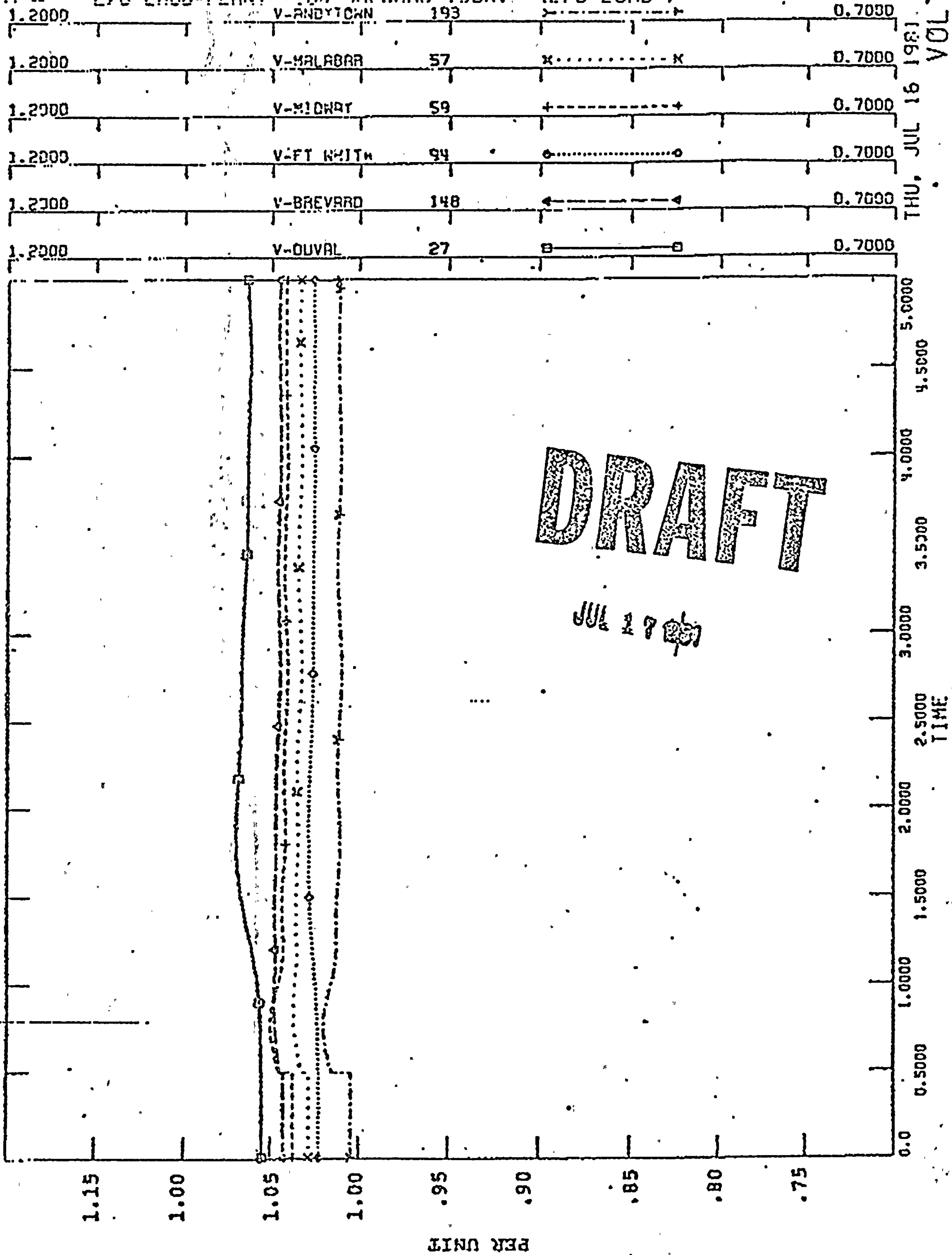


FIGURE 8-1-2.5

430.70 (8.2) It is not apparent from the information presented in Section 8.2.2 of the FSAR that the design of the switchyard components meet the requirements of GDC-18, "Inspection and Testing of Electric Power Systems." Describe in more detail this aspect of the design. In particular, describe the capability for testing transfer of power from the unit auxiliary transformers to the startup transformers (and vice versa) during operation.

Response: The power transfer from the unit auxiliary transformer to the start up transformer and vice versa is provided by inplant equipment rather than at the switchyard.

Power transfer from the unit auxiliary transformer to the startup transformers (and vice versa) is demonstrated and exercised periodically when the plant is started up and shutdown. This serves as an adequate basis to verify the proper operation of the transfer breakers and associated equipment. However, a testing switch is also provided to facilitate the testing of the transfer of power from the unit auxiliary transformers to the startup transformers (and vice versa) without disturbing the normal plant operation. Testing is done in the following manner.

1) Turn the applicable testing switches to "isolate" position except for the one which is associated with the feeder breaker that requires testing (e.g. 4160V switchgear bus 2A2 feeder breaker, 6900 V Start-up transformer 2A1 breaker etc). By turning the test switches to isolate position, a simulated generator lockout relay signal will be isolated from the rest of the power system, except that feeder breaker that is undergoing testing.

2) Manually actuate generator lockout relay (86/GP). This will close the feeder breaker that is under testing, but result in no disturbance on the rest of the power system. During the test period, the generator is still fully protected by the backup lockout relay (86/GB).

3) By systematically going through steps (1) and (2) above, all circuit breakers that are required for transfer of power can be tested one by one, without distrubing normal plant operation or compromising equipment protection.

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430.71 (8.2) It has been established by the Atomic Safety and Licensing Appeal Board that the total loss of alternating current (AC) power shall be considered a design basis event for St Lucie Unit 2 design. Provide an analysis demonstrating the ability of the plant to operate through such an event. In addition, provide your training programs and procedures for station operation during a blackout transient and for the restoration of AC power.

Response:

The decision reached by the Atomic Safety and Licensing Appeal Board that the total loss of alternating current (AC) power shall be considered a design basis event for St Lucie 2 has been reviewed by the commission and a subsequent memorandum and order (CLI-81-12) was issued concluding that:

"For the reasons discussed above, the Commission finds that ALAB-603 does not establish any generic guidelines for determining the design basis events to be used for plant design and operation and does not establish station blackout as a design basis event as that term is used by the staff".

However, in consideration of the Commissions concern that there is a "need for protective measures against loss of all AC power for some reasonable time" (Memorandum and Order CLI-81-12 Paragraph B item (2)). FPL is presently analyzing the affect of a total loss of ac power on the St Lucie Plant.

In the unlikely event of a complete loss of ac power (onsite and offsite) for St Lucie 2 and, for the benefit of a conservative anlysis, the simulataneous loss of offsite power and one (1) diesel generator at St Lucie 1, the remaining diesel generator in St Lucie 1 will be able to operate the minimum ESP loads such that both units are maintained in a safe hot standby condition. The present St Lucie design does have the capability of electrically connecting the two (2) units offsite 4.16 KV buses 1A2 and 2A2 (1B2 and 2B2) through 4.16 KV bus 2A4(2B4). This tie can only be done manually by racking and reracking a 4.16 KV breaker at 4.16 KV switchgear 2A4(2B4) under strict administrative controls. This transfer takes approximately ½ hour. During this time, operator action in both Unit 1 and Unit 2, in accordance with procedure, load shed all loads on the Unit 1 operating diesel generator not required for this event; verifies that all non safety loads on the 4.16 KV 1A2 (1B2) and 4.16 KV 2A2 (2B2) are in operative; and prepares for the manual initiation of the required Unit 2 loads on the onsite safety related 4.16 KV 2A2 (2B3) bus. Upon completion of the manual loading, both plants remain in the safe hot standby condition until the conclusion of the event or approximately four (4) hours.

The analysis for the above event will be found in Chapter 15.0

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430.72 a) Describe the procedures and/or design provisions which protect Class IE DC loads from over voltage conditions during equalizing charges.

Response:

a) The battery charger maintains a regulated float voltage of 2.17 to 2.20 Volts per cell so that no recharging/equalizing charge at 2.33 volts per cell is required under normal plant operation.

An investigation of the voltage range of class IE equipment is presently being conducted and results will be available by July 31, 1981.

b. Provide the results of an analysis which demonstrates the adequacy of the Class 1E battery systems to sustain the tabulated safety related loads for the time needed. Discuss the design margin provided in the Class 1E battery systems.

RESPONSE:

b) Two redundant safety related batteries each rated 1800 Ampere hours are provided.

The worst case loading is that of DC bus 2B and DC bus 2AB together. This load tabulation is denoted in table 8.3-3.

The batteries are required to supply power during the interval from loss of offsite power till loading its respective battery charger onto the diesel generator. The one minute rating in amperes that the battery must supply is 924 amperes. The actual duration prior to loading is less than one minute.

Design margin is provided as the guaranteed one minute rating of the battery is 1980 amperes. This provides a margin greater than 2.0 as the required loading is less than 50% of the guaranteed rating.

c) Identify all non-Class 1E circuits that are connected to the emergency batteries and describe how these loads meet the requirements of Regulatory Guide 1.75. Are these loads shed on safety injection signal?

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Response:

c) Non Class IE loads are provided with qualified isolation devices prior to connection to safety related dc panels. This design approach utilizes fault current interrupting devices (circuit breakers, fuses) which have previously been accepted by the NRC in the Safety Evaluation Report.

125V DC buses 2A, 2B, and 2AB and 125V DC power panels 238, 239, 240 are shown in figures attached. These figures list the non class IE loads connection via isolation devices to the appropriate DC bus/panel.

These loads connected to DC buses 2A, 2B and 2AB have the ability to be manually disconnected should it be so required. No loads are shed on receipt of a safety injection signal.

All non IE loads on all buses, panels are separated by a steel barrier to provide separation.

d. Provide the time period required for the battery charger to charge the battery from the design minimum charge condition to its fully charged condition, while supplying its steady state loads under any plant conditions.

Response

d) The battery charger is capable of recharging a fully discharged battery in a period of 12 hours while maintaining minimum design load. The minimum charge condition is that of a discharged battery having a voltage per cell of 1.75 Volts.

The battery charger is automatically loaded onto its respective diesel generator less than a minute after a loss of offsite power. At this time the DC system is returned to normal operation, whereby the charger provides power to the necessary loads while recharging the battery to a fully charged condition. As the battery has provided the necessary stored energy to its connected loads it has discharged or lost some of its capacity during the duration prior to reconnection of the battery charger. This process of discharging ampere hours will stop and will be reversed in order to replace the lost ampere hours by operation of the battery charger. The safety related battery charger will recharge the battery in a time duration of less than hour.

e) Describe the charger overcurrent protection provided in your design.

Response:

e) The battery charger is current limited to a value of 115% of its rated output. It is equipped with an automatic load limiting feature which prevents the output from exceeding 115% of rated output amperes regardless of the total dc battery load or the state of charge of the battery.

The current sensing circuit (located internal to the charger) receives a signal from six current transformers. When the output current increases beyond the current limit setting, the signal from the current sensing circuit overrides a voltage sensing circuit and causes the phase control boards to turn on the SCR's at the time necessary to limit the output current to the set level of 115.0%.

In the event of failure of the load limiting feature, backup protection is provided by means of output circuit breakers which will trip the unit off the line.

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430.73 In addition to the alarms and indication provided for the DC system,
(8.3.2) provide the following alarms:
RSP

1) Battery high discharge rate alarm in the control room.
2) Battery charger output current meter in the control room.
3) Battery breaker(s) open alarm in the control room.

430.73 Response

Additional alarms and indication will be provided in the control room for the dc system as follows:

a) Battery high discharge rate alarm
b) Battery charger output current meter
c) Battery breaker in open alarm

The circuits will be routed as Class IE circuits in accordance with the provisions of chapters 7 & 8 of the FSAR.

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430.74 Provide a detailed discussion in the FSAR as to how the St Lucie Unit 2 DC systems design meets the recommendations of IEEE-Standard 450 1972.

Response:

IEEE Standard 450 entitled Recommended Practice for Maintenance, Testing, and Replacement of Large Load Storage Batteries for Generating Stations and substations provides recommendations for maintenance, test schedules and testing procedures.

An acceptance test was performed at the Vendor's factory during which a continuous load of 225 amperes was applied for 8 hours and 16 minutes.

Circuits breakers are provided in dc buses 2A and 2B to facilitate connections to load banks for test purposes. For further information with respect to testing of batteries refer to FSAR Section 8.3.2.1.6.

Therefore, the testability features included in IEEE 450 have been provided in the design.

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XC: 12

Question 410.32
(3.6.1)

Provide the information and verification requested for the following Appendix 3.6.C items:

a. Provide an isometric drawing of the turbine driven auxiliar, feedwater pump steam lines.

b. Show the steam lines from the main steam lines shown on drawings 1.7 and 1.8 and include this connection in your analysis.

c. Verify the following information on drawing 1.5.

(1) Nodes 275 and 276 should be valves I-HCV-09-2B and -2A instead of I-V-09-258 and I-MV-09-8, respectively.

(2) Nodes 2761 and 277 are the connections for the auxiliary feedwater pumps 2B (motor) and 2C (Turbine), respectively.

d. Verify the following information on drawing 1.6.

(1) Nodes 22 and 21 should be valves I-HCV-09-1B and 1A instead of I-V-09-258 and I-MV-09-7, respectively.

(2) Nodes 1201 and 20 are the connections for the auxiliary feedwater pumps 2A (motor) and 2C (turbine), respectively.

(3) Line 14-BF-29 should be I-4-BF-28 (see drawing 6.3).

e. On drawing 6.1, where does the line containing valve I-V-14-625 (Nodes 760→504→505) go to? This connection is not shown anywhere else. Does this line tie into node 503 (I-V-14-625) on drawing 6.3? If so, the elevations and directions do not match, i.e., drawing 6.1 has the line going down below elevation 20.75' and drawing 6.3 has the line going up from elevation 42.75'.

f. Verify that valve I-V-09-310A on drawing 6.2 should be I-SE-09-3.

g. Verify the following information on drawing 6.3.

(1) Node 9 should be I-SE-09-2 instead of I-V-09-310A.

(2) This line is I-4-BF-28 not -29 as indicated on drawing 6.1.

h. Verify the following information on drawing 6.4.

(1) Node 107 should be I-SE-09-4 instead of I-V-09-310A.

(2) Line 4 "-BF-35 continues on Figure 3.6.C-6.5 instead of 3.6.C-8.5.

i. Verify that Node 171 should be I-SE-09-5 instead of I-V-09-310A.

Response 410.32

a. The isometric drawing of the turbine driven Auxiliary Feedwater Pump steam lines are provided on FSAR Figures 3.6 C-1.9, .10, .11.

b. The connections for the steam lines (I-4-MS-10 and -11) from the main steam lines to the Auxiliary Feedwater Pump are shown on Figures 3.6 C-1.7 and 3.6 C-1.8, respectively. These lines are contained wholly within the trestle area. These lines were considered in the jet impingement analysis of the trestle area.

c. (1) FSAR figure 3.6 C-1.5 provides the piping arrangement for the original Main Feedwater Isolation Valves (I-V-09-258 and I-MV-09-8). Figures 3.6 C-1.5 (nodes 275 and 276) have been revised to incorporate the final design which utilizes fast closing MFIV's (I-HCV-09-2A, 2B).

(2) Figure 3.6 C-1.5 has been revised to reflect the Auxiliary Feedwater Pump 2B tie (node 2761) and the Auxiliary Feedwater Pump 2C tie (node 277).

d. (1) Figure 3.6 C-1.6 (nodes 21 and 22) have been revised to incorporate the final feedwater design which utilizes two fast closing MFIV's (I-HCV-09-1A, 1B).

(2) Figure 3.6 C-1.6 has been revised to reflect the AFW Pump 2A tie (node 1201) and the AFW Pump 2C tie (node 20).

(3) Figure 3.6 C-1.6 shows the correct tie for the Auxiliary Feedwater Pump 2A (line 14-BF-29). The line I-4-BF-28 shown on figure 3.6 C-6.3 is upstream of line I-4-BF-29.

e. The line on Figure 3.6 C-6.1 which contains valve I-V-14-625 is a local drain line and is not routed to any other line in the Auxiliary Feedwater System.

f. Figures 3.6C-6.1, 3, 4, 5 present the Manual Auxiliary Feedwater System and have been revised to incorporate the Automatic AFWS. These figures have been revised to incorporate the addition of the four solenoid valves which were required for the Automatic AFW System.

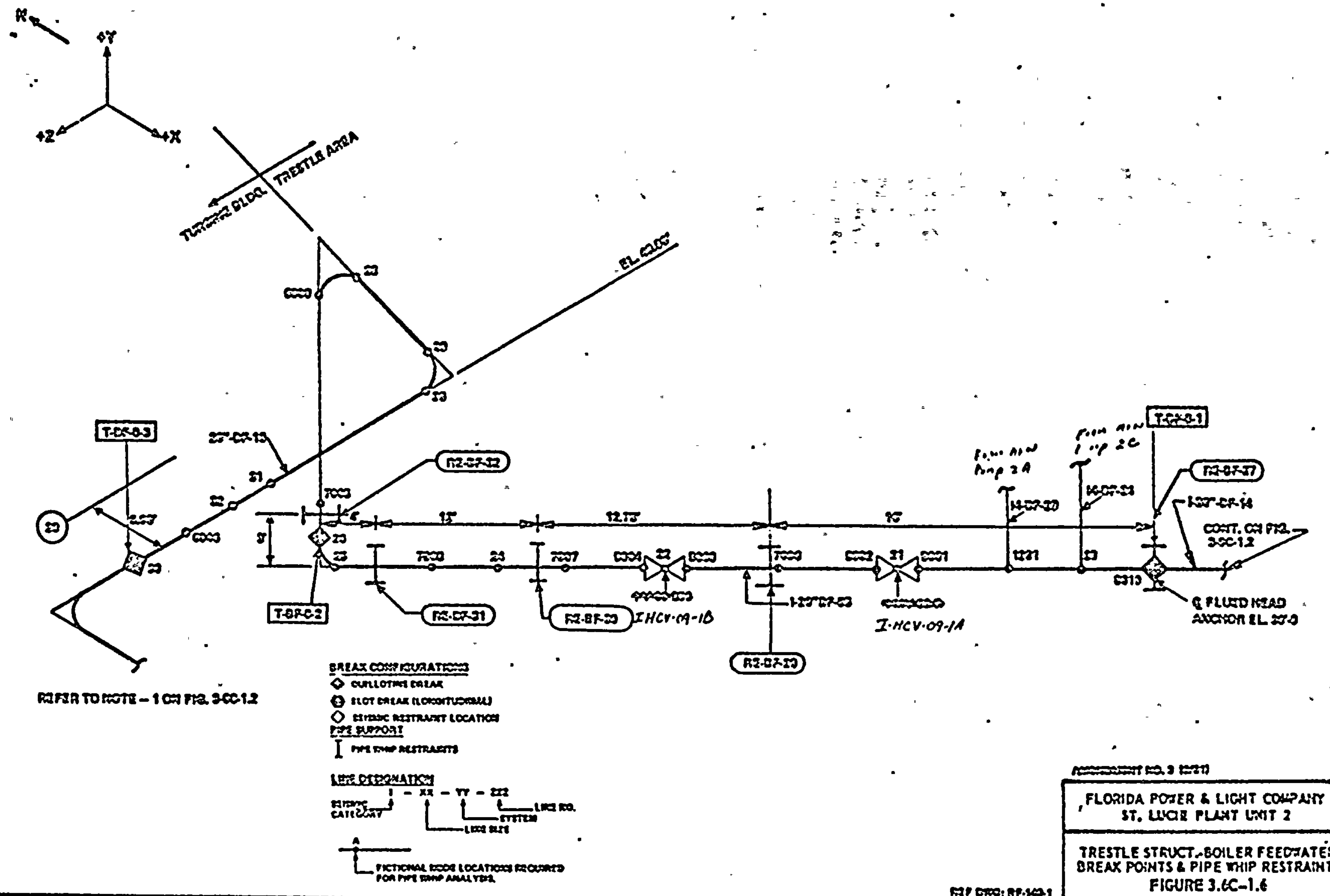
g. (1) Refer to Response to Question 410.32 (f).

(2) Refer to Response to Question 410.32 (d) (3).

h. (1) Refer to Response to Question 410.32 (f).

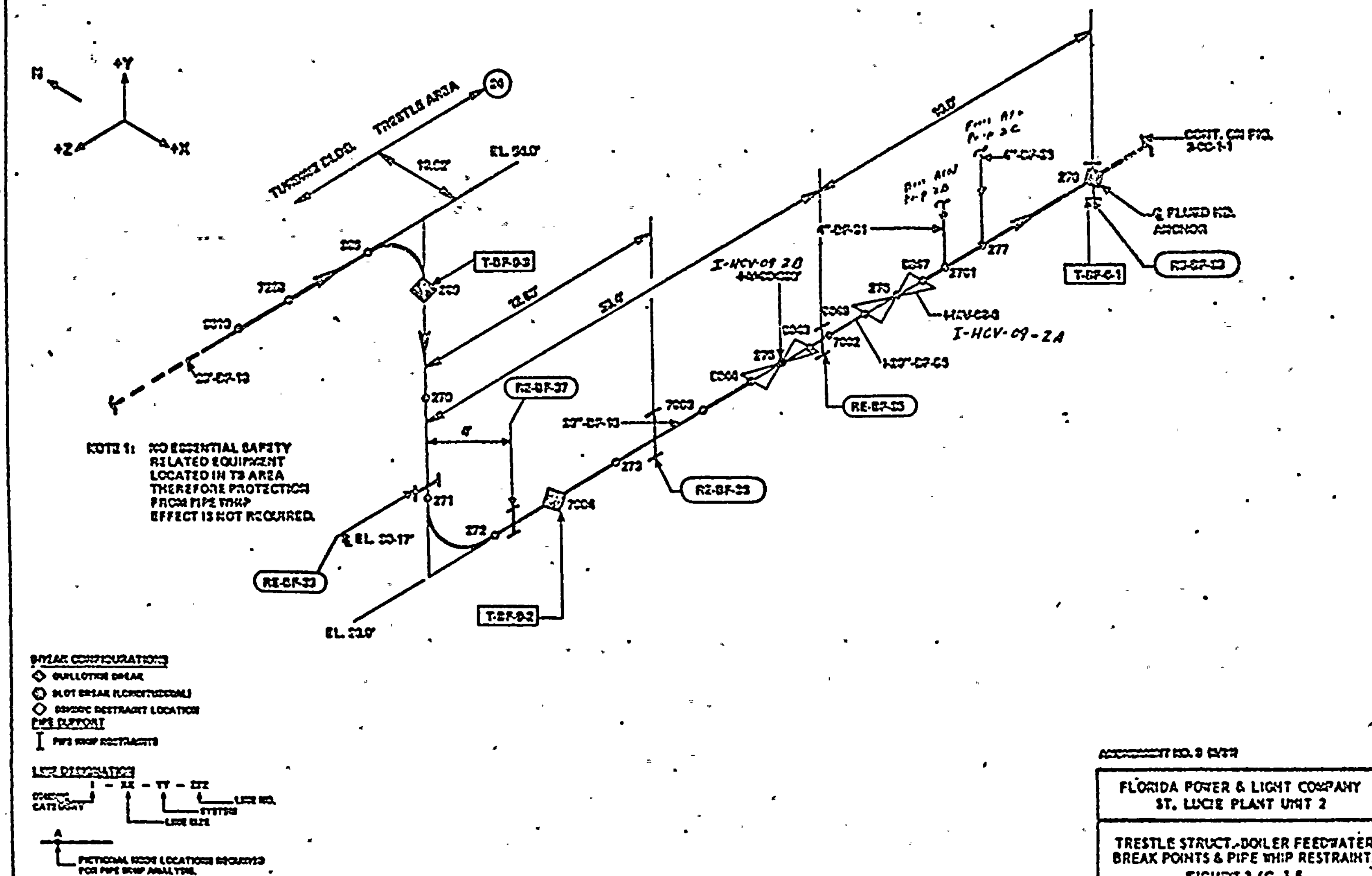
(2) Figure 3.6 C-6.4 has been revised to indicate tha line 4-BF-35 continues on Figure 3.6 C-6.5.

i. Refer to Response to Question 410.32 (f).



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

TRESTLE STRUCT.-BOILER FEEDWATER BREAK POINTS & PIPE WHIP RESTRAINTS
FIGURE 3.6C-1.6

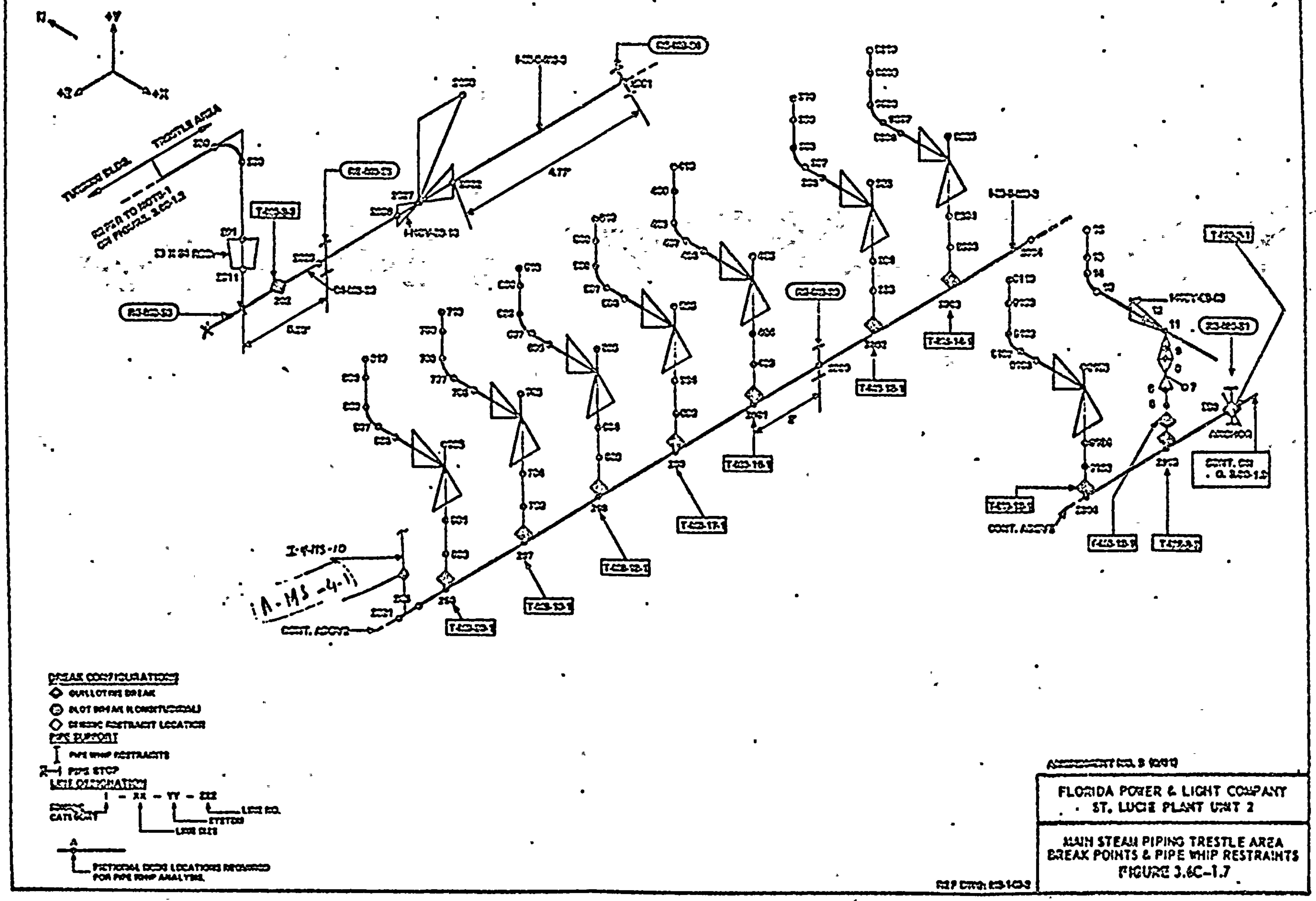


AMENDMENT NO. 3 (5/81)

REF DWG: BF-140-2

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

TRESTLE STRUCT.-BOILER FEEDWATER
BREAK POINTS & PIPE WHIP RESTRAINTS
FIGURE 3.6C-1.5



FLORIDA POWER & LIGHT COMPANY
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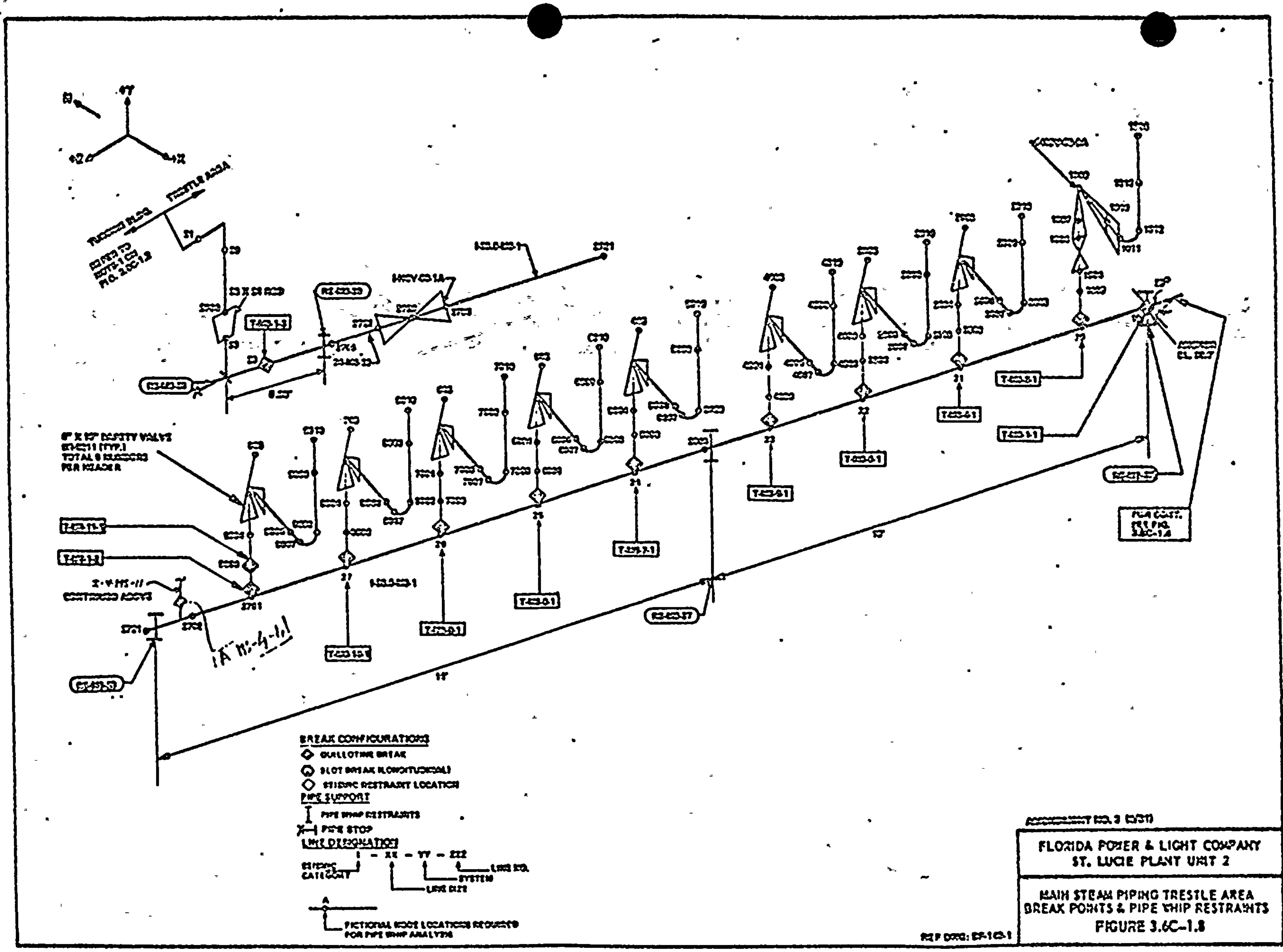
MAIN STEAM PIPING TRESTLE AREA
BREAK POINTS & PIPE WHIP RESTRAINTS
FIGURE 3.6C-1.7



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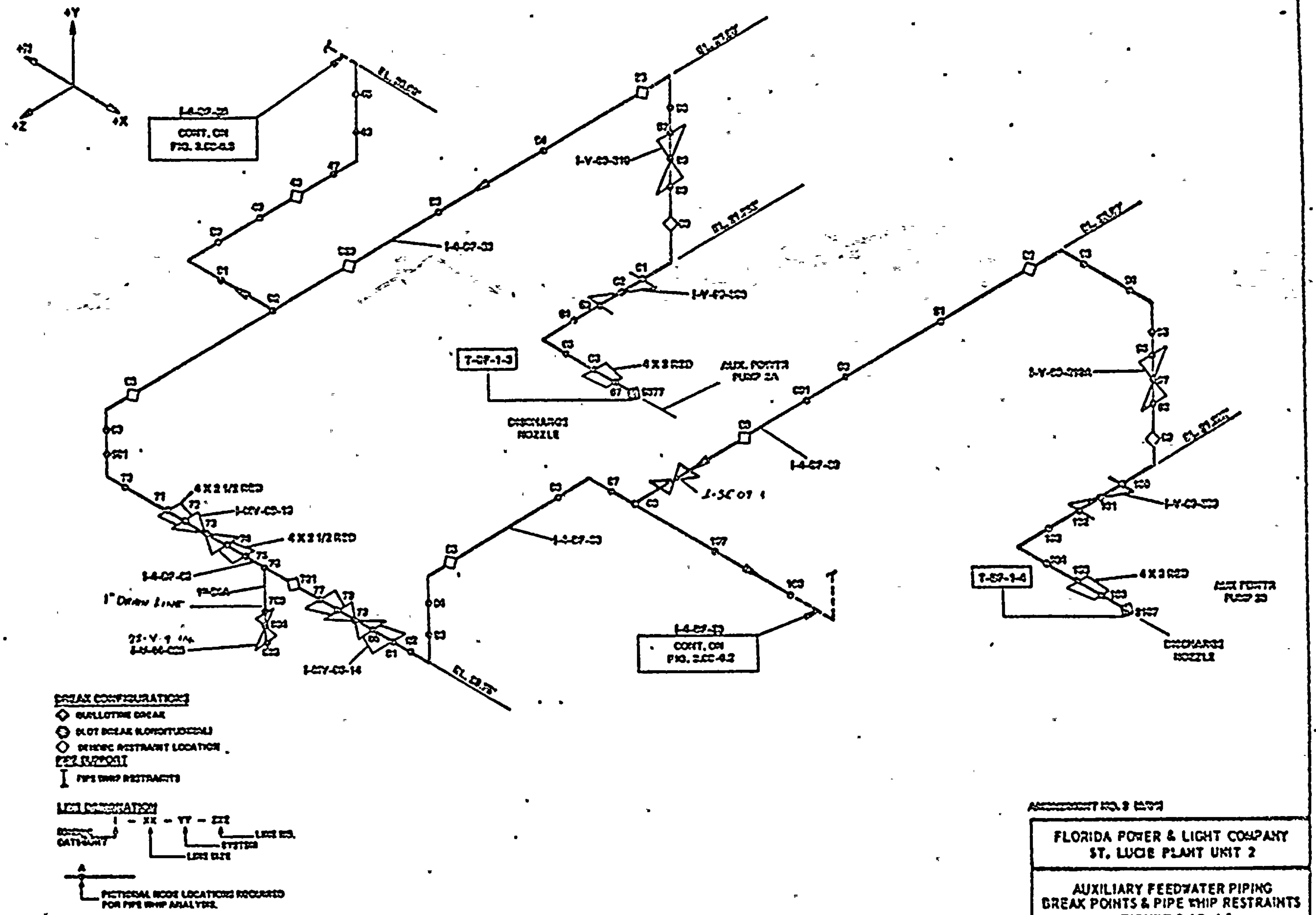
MAIN STEAM PIPING TRESTLE AREA
BREAK POINTS & PIPE WHIP RESTRAINTS
FIGURE 3.6C-1.8



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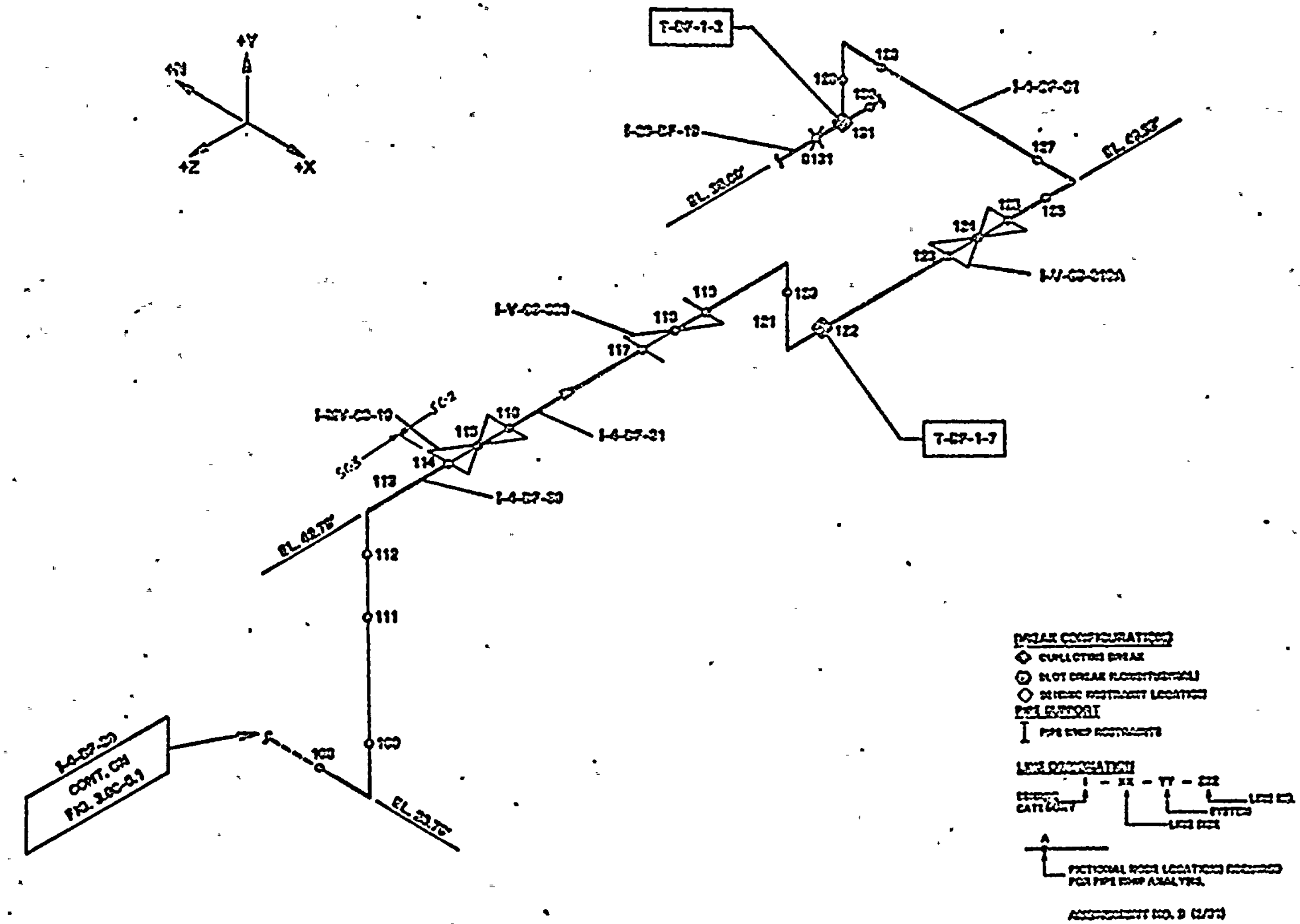
AUXILIARY FEEDWATER PIPING
BREAK POINTS & PIPE WHIP RESTRAINTS
FIGURE 3.6C-6.1



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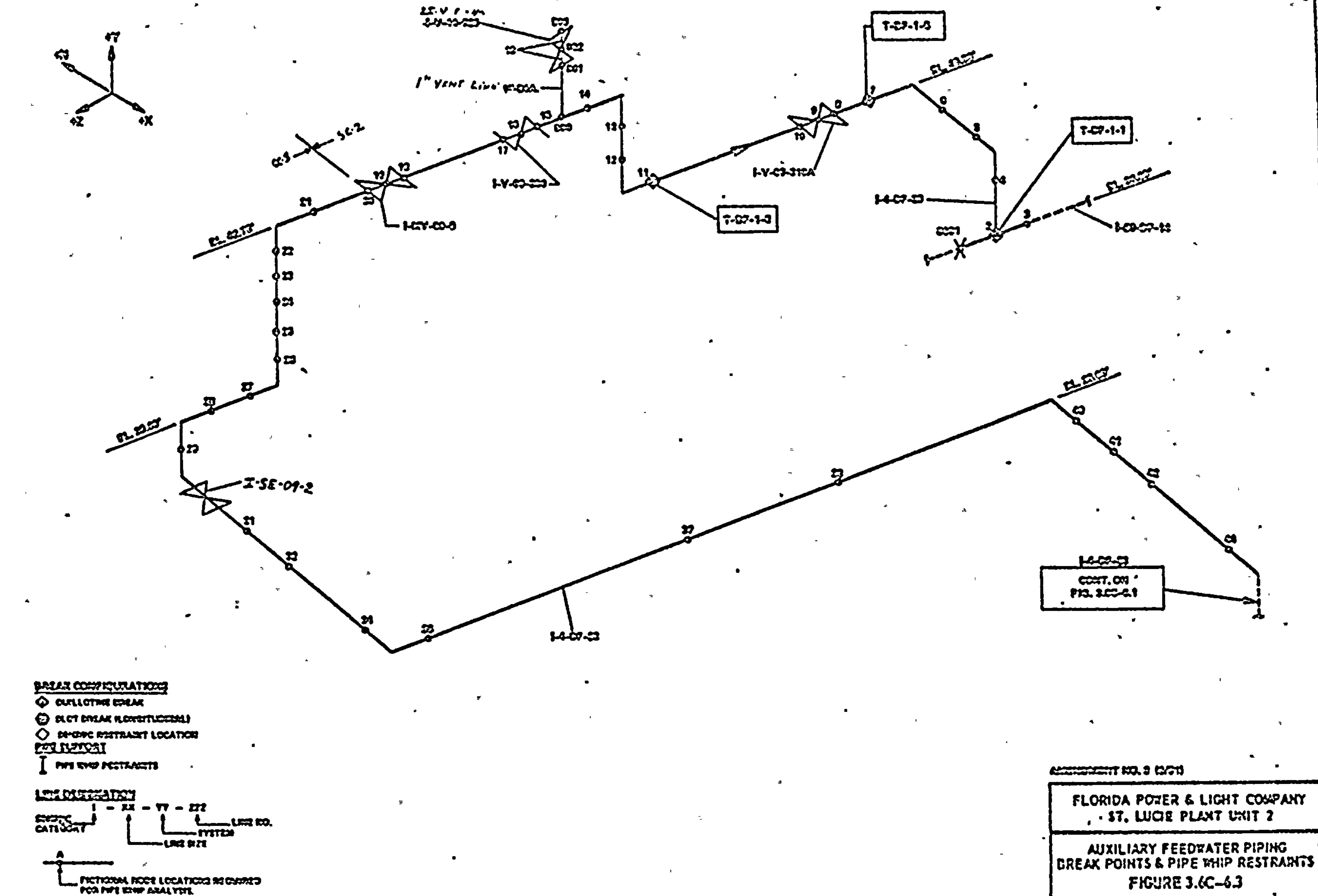
AUXILIARY FEEDWATER PIPING
BREAK POINTS & PIPE WHIP RESTRAINTS
FIGURE 3.6C-6.2



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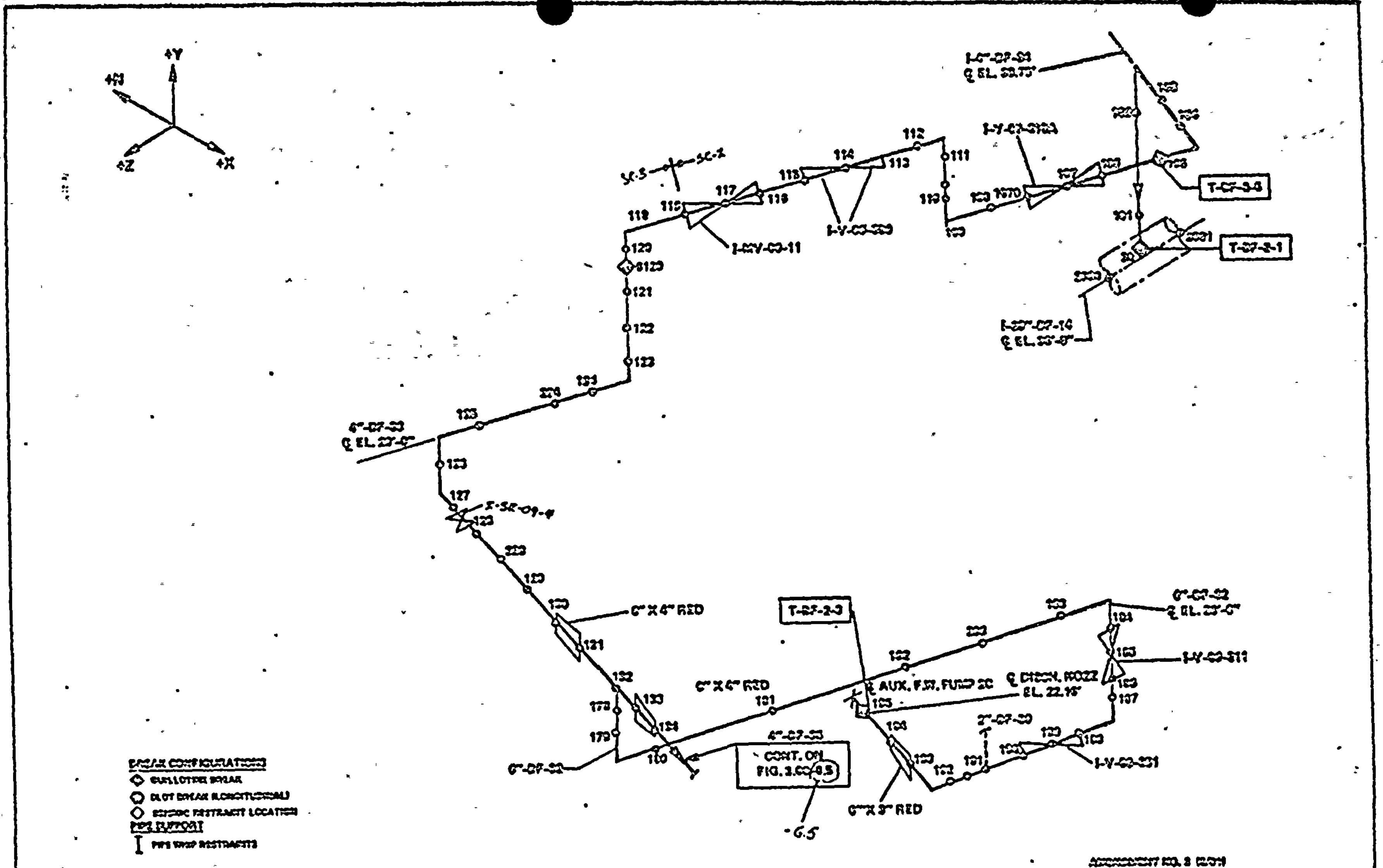
AUXILIARY FEEDWATER PIPING
BREAK POINTS & PIPE WHIP RESTRAINTS
FIGURE 3.6C-6.3



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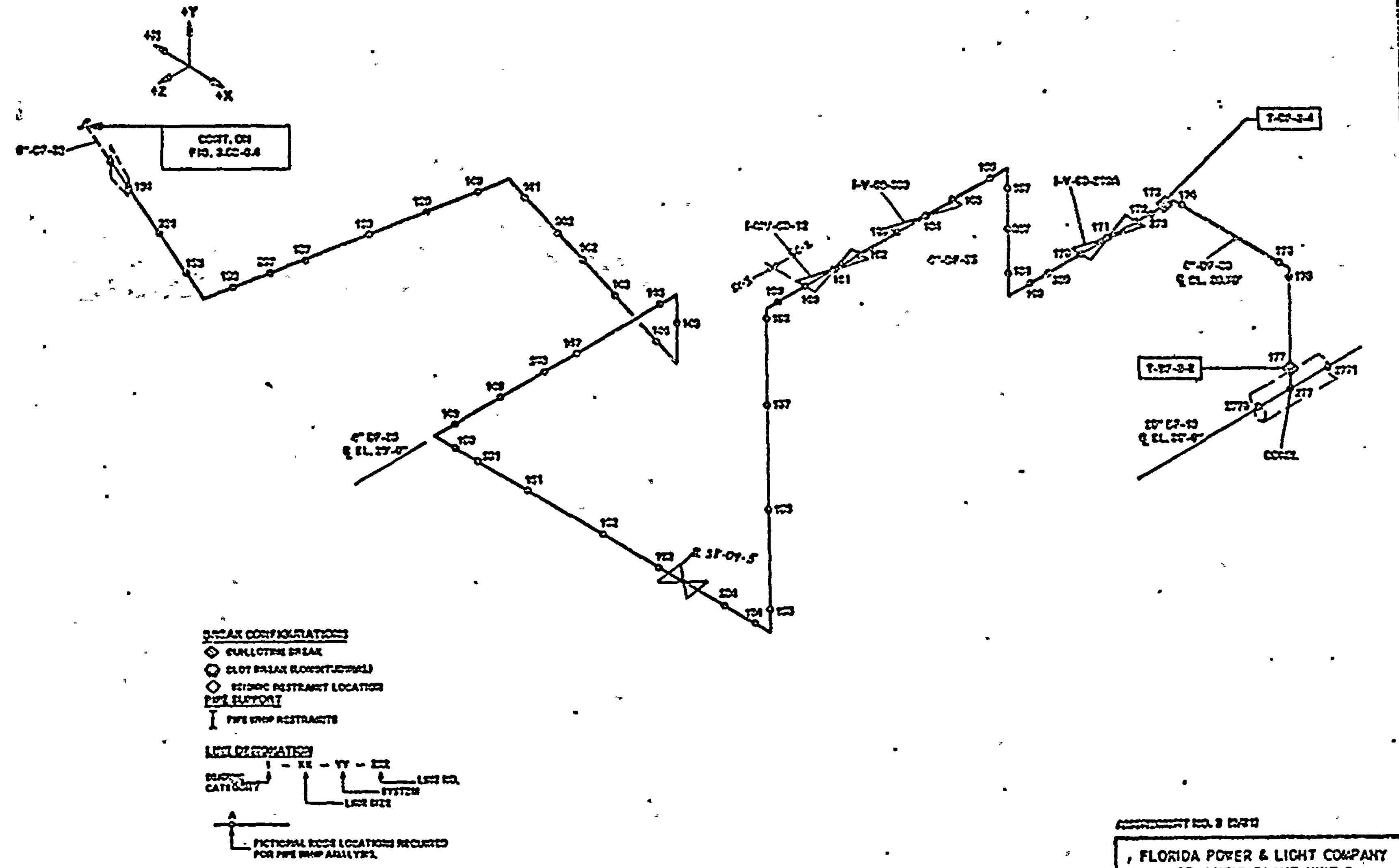
AUXILIARY FEEDWATER
BREAK POINTS & PIPE WHIP RESTRAINTS
FIGURE 3.6C-6.4



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

AUXILIARY FEEDWATER
BREAK POINTS & PIPE WHIP RESTRAINTS
FIGURE 3.6C-6.5

Question 410.33
(3.6.1)

Are the hold-up tank compartments in the reactor auxiliary building steel lined? If there is no seismic Category I steel liner, then provide the results of an analysis of the seismic failure of all four 40,000 gallon tanks concurrent with the failure of all other non-seismic Category I components, including all sump pumps, volume control tank, associated piping, and with the worst single active failure, and the resulting flooding of safety related equipment.

Response 410.33

The hold-up tank compartments in the Reactor Auxiliary Building are not steel lined. However, persuant to the staff's requirement in section 9.4.1 of the SER dated November 8, 1974 the adequacy of the ECCS pump room flood protection against a 1250 gpm fire main rupture has been evaluated and presented in the St Lucie 1 FSAR and SL 2 PSAR section 9.5.

The storage capability of all non seismic tanks in the RAB has been considered. If it were assumed that every non seismic tank ruptured during a seismic event, water from such a rupture could eventually drain toward the ECCS pump room sumps located at elevation -10 ft. Each sump is 4 ft x 4 ft x 10 ft deep with a capacity of 1,100 gallons. The pump room is divided into two subcompartments by a flood wall which extends a minimum of 9.5 ft high. Each ECCS compartment houses the minimum complement of the required engineered safety feature pumps.

The fluid from the ruptured tanks would drain into the "A" ECCS pump room via a single 4 inch and a single 3 inch line with a total capacity of about 130 gpm, whereas drainage into the "B" ECCS pump room is via two 4 inch lines and a single 3 inch line with a total capacity of about 210 gpm. Any substantial release of water inventory to EL -0.5 ft will drain into both ECCS pump rooms (EL -10.0 ft) and into the Reactor Drain Pump Room (EL -3.5 ft) and flood the 0.5 ft level of the RAB.

The analysis of the ECCS Flooding Protection and the associated sequence of events are presented in table 410.33-1. The most limiting component within the ECCS pump room has been found to be the HPSI Pump conduit boxes which is located 18 3/4 inches above the floor elevation. The analysis reveals that the fluid level will not reach HPSI Pump B conduit box within 102 minutes and HPSI Pump A within 145 minutes after the accident which is ample time for the operator to isolate the ECCS pump room areas. Upon isolating the ECCS pump room cubicle, the water will accumulate in the 0.5 ft level. However, no safety-related equipment on this level will be affected. The following design modifications were incorporated into the ECCS cubicle design and are available to the operator:

Response 410.33 (Cont'd)

(1) Each ECCS pump room contains a seismic Category I, class 1E level switch which provides both high and hi-hi sump level alarms in the control room.

The level switches are physically separated and electrically independent from each other. A backup seismic Category I level switch with control room alarms is also provided in each sump in order to provide greater reliability. The analysis shows that within eight minutes the operator receives four signals from four independent sources notifying him of the accident.

(2) All floor drain lines entering the ECCS pump room compartments are provided with redundant seismic Category I isolation valves. These isolation valves have the capability of remote-manual operation from the control room. The analysis shows that the flood level will not reach the Isolation Valves (EL -7.5 ft) in ECCS cubicle B until 142 minutes after the accident.

(3) Each entrance to the ECCS cubicle is provided with watertight doors thereby assuring that gross water volumes will not flood the ECCS pump room.

From the above analysis it is concluded that a potential flooding incident in the Reactor Auxiliary Building cannot impair the ability of redundant equipment to achieve a safe shutdown condition.

Table 410.33-1

RAB Flooding Analysis

Time (Min)	Event
0	Flood is initiated by rupture of all tanks in the RAB
4.1	High level alarm in ECCS Room "B" sump actuated in Control Room
5.0	High-high level alarm in ECCS Room "B" sump actuated in Control Room
7.1	High level alarm in ECCS Room "A" sump actuated in Control Room
8.0	High-high alarm in ECCS Room "A" sump actuated in Control Room
102	Flood level reaches bottom HPSI Pump 2B Conduit Box
142	Flood level reaches lowest of ECCS Room B redundant Isolation Valves
145	Flood level reaches bottom of HPSI Pump 2A Conduit Box
197	Flood level reaches bottom of ECCS Room A redundant Isolation Valves

Question 410.34
(3.6.1)

Specify the elevation of the lowest penetration between ECCS compartment A and compartment B. If the elevation is less than -7.0 feet MSL, verify that the seals are environmentally qualified for 212°F water and are seismic Category I.

Response 410.34

Each ECCS compartment houses a LPSI Pump; a HPSI Pump and a Containment Spray Pump. ECCS compartment A is physically separated from ECCS compartment B by a reinforced concrete wall which extends a minimum of nine feet above the base floor level (EL -10.0 ft). Piping penetrations between ECCS compartments A and B are minimized whenever possible. However, where penetrations between compartments were deemed necessary, the piping was provided with a water tight seal.

The ECCS cubicle design presently incorporates six piping penetrations between ECCS cubicles A and B. The lowest ECCS compartment penetration is presently located at EL -6.33 ft, which is 3.67 ft above the base floor level. Although these penetrations are provided with water tight boot seals which have a design temperature of 400°F.

Question 410.35
(3.6.1)

Discuss what alarms and signals are available to the operator in the control room to uniquely define each pipe break or crack specified in the appendices to Section 3.6 of the FSAR.

Response 410.35

The alarms, signals or control indications that are available to the operator in the control room to uniquely identify each pipe break or crack is provided in the revised FSAR Appendix 3.6F.

APPENDIX 3.6F

MODERATE ENERGY PIPING FAILURE ANALYSIS 3

3.6F MODERATE ENERGY PIPING FAILURE ANALYSIS

3.6F.1 MODERATE ENERGY PIPING FAILURE - INSIDE CONTAINMENT

Systems considered for moderate energy analysis inside containment are identified in Subsection 3.6.1.2.2. Design basis environmental conditions inside containment are established by high energy pipe breaks. Therefore, the effects of moderate energy piping failures inside containment are not evaluated.

3.6F.2 MODERATE ENERGY PIPING FAILURES - OUTSIDE CONTAINMENT

This section presents results of the analysis performed for moderate energy piping failures outside containment. The flooding resulting from moderate energy piping failures are considered in evaluating the availability of essential systems and components to mitigate the consequences of the piping failure.

3.6F.2.1 Criteria and Assumptions

In addition to the criteria given in Subsection 3.6.1.3 the following assumptions are used for moderate energy analysis: 3

a) Floor drainage system, sump pumps, etc, are considered available to mitigate the flooding consequences of the piping failure.

b) Rate of flow from cracks is assumed to be constant until operator isolates the crack or source volume is depleted.

c) The locations of postulated cracks in the moderate energy piping systems are not based on stress criteria. The crack is assumed to be located anywhere along the run of pipe for the flooding analysis.

d) Moderate energy fluid system pipe failures are considered separately as a single postulated independent event occurring during normal plant operation.

e) No operator action such as closing or opening a valve, stopping or starting a pump is assumed for 30 minutes following the first alarm indication in the control room.

3.6F2.2 Flooding Analysis

3.6F.2.2.1 Evaluation Technique

The Reactor Auxiliary Building (RAB), Fuel Handling Building (FHB), Diesel Generator Building (DGB), Component Cooling Water Building (CCWB), Trestle area and Yard were reviewed to identify all compartments and areas containing safety-related equipment which may be affected by flooding.

Based on this review, the following are considered for the flooding analysis:

a) ECCS compartments A & B in RAB

b) Shutdown Cooling Heat Exchanger Rooms A & B in RAB

c) Boric Acid Make-up Tank Room in RAB

d) Charging Pump Room in RAB

e) Diesel Generator Building

f) Diesel Oil Tank Enclosure

g) Intake Cooling Water Pump Area

h) Component Cooling Water Building

i) Letdown Heat Exchanger Room in RAB

j) Boric Acid Concentrator Room in RAB

k) Pipe Tunnel in RAB

l) Fuel Pool Heat Exchanger Room in Fuel Handling Building (FHB) 3

m) Fuel Pool Pumps Room in FHB

n) Fuel Pool Purification Pump Room in FHB

Some of these compartments and areas contain safety related equipment required for safe plant shutdown while others communicate through the floor drain system and corridors with the rooms containing safety related equipment.

The volume of the compartments and areas are taken from the general arrangement drawings, Figures 1.2-12 through 1.2-22.

a) ECCS Room in RAB

The ECCS room is located in the RAB at elevation - 10.0 feet. This room is divided into two compartments, A & B, by a partial height wall. Each compartment contains a high pressure safety injection pump, a low pressure safety injection pump and a containment spray pump. Two reactor drain pumps are located in ECCS Compartment A. There are three watertight doors, with bottom El 0.00 ft, between ECCS compartment B and the main corridor which is at El. -0.5 ft. There is one watertight door, with bottom El. -0.5 ft, between ECCS compartment A and the main corridor. The main corridor is located between the shutdown cooling heat exchanger room and ECCS rooms.

Each ECCS compartment has a sump, bottom El -19.0 ft, and each sump is provided with duplex full capacity sump pumps, 50 gpm each. Level switches and level operated mechanical alternators are provided in each sump for controlling the pump operation. The level control is delineated in the following steps.

1) When water reaches the "high water level", at El -11.25 ft the alternator starts the selected pump and actuates an alarm in the main control room.

2) If the level continues to rise and reaches "high-high water level", at El -10.25 ft, the second pump will start and actuate a second alarm in the main control room. Pumps discharge is routed to the equipment drain tank.

For flooding analysis, the largest flow crack is assumed to occur, during normal cold shutdown mode, in suction line of the LPSI pump I-14-SI-424 located in ECCS compartment A. The pipe is 14 in. nominal diameter and the operating fluid conditions are 300 psig and 300°F. The shutdown cooling system is categorized as a dual purpose moderate energy system since it is operating in the high energy pressure/temperature region less than two percent of the system normal operating time. INSERT A HERE The resulting flow from the crack is 330 gpm. As a conservative assumption, 2 sump pumps in ~~compartment A are considered to be out of operation.~~ The P&ID for the ECCS room sump pumps is provided in Figure 6.2-41 The analysis assumes that the operator is alerted by the alarm in control room which indicates a "high water level" in the sump and the operator takes corrective actions 30 minutes after the alarm. The flood level in the room at 30 minutes following the first alarm will be 1.6 ft above ECCS room floor level and will reach bottom of HPSI pump conduit box. 3

If the leakage crack had occurred in the portion of line between the LPSI pump and valve V-3444 in ECCS compartment A, operator action is to isolate the affected shutdown cooling train by closing valve V-3664 (valve V3444 is in the closed position prior to initiation of the shutdown mode) See Figure 6.3-1a.

INSERT B

A flooding analysis was also performed for ECCS compartment B, assuming a piping failure in LPSI pump 2B suction line during normal plant shutdown mode. The area for ECCS compartment B is larger than compartment A, therefore the flood level will be lower.

As shown above, the flood level in the compartment does not affect any safety related equipment. In addition, since the flooding is contained within the compartment, the redundant train is not affected. The unaffected train is used to bring the plant to cold shutdown conditions.

"This is INSERT A"

Moderate energy cracks are postulated to occur only when the fluid conditions are equal to or less than 275 psig and 200°F. However, for the flooding analysis, the crack was conservatively postulated to occur at 300 psig since this pressure resulted in the largest flow through the piping failure and thereby maximized the flooding of the ECCS cubicles.

"This is INSERT B"

The leakage crack in the suction line of LPSI pump reduces Reactor Coolant loop inventory and causes the pressurizer level to drop. Pressurizer low level indicator LI-1103 in the control room along with the ECCS sump high level alarm will alert the operator that the crack has occured in the LPSI pump suction line. The operator will isolate the affected shutdown cooling loop and continue plant shutdown by means of the redundant shutdown cooling loop.

b) Shutdown Cooling Heat Exchanger (SDCHX) Room

The two Shutdown Cooling Heat Exchangers are located in the RAB at El -0.5 ft. A seven ft high wall divides the room into two separate compartments. Both compartments communicate with ECCS compartment A through the floor drainage system. A door, with bottom El 2.0 ft, separates each SDCHX compartment from the main corridor.

For flooding analysis of SDCHX compartment B, the largest flow crack would be in a 12 inch nominal diameter shutdown cooling line (12-SI-164), Figure 9.2-2. The operating conditions of this line is 450 psig and 300F. INSERT C The flow rate from the crack is 620 gpm of which 38.4 gpm of this fluid drains through a 3 inch diameter floor drain line to the sump in ECCS compartment A. The remaining portion of fluid accumulates in the SDCHX compartment B.

When the fluid level in ECCS Compartment A sump reaches "high level", the level switch starts a sump pump and actuates an alarm in the control room. The worst flooding condition for ECCS compartment A is postulated to occur when the sump pumps fail to operate. The water level continues to rise and reaches "high water level" in the sump. A second alarm is actuated in the control room by the level switch.

INSERT D

The time required to reach "high water-level" in the sump, assuming the sump is initially 10 percent full, is 21.2 minutes. It is assumed that 30 minutes after the first alarm in the control room operator isolates the crack. During this period water level in the ECCS compartment A will reach 0.1 ft. above floor level. This flood level will not affect any safety related equipment in ECCS Compartment A. The flood level in the shutdown cooling heat exchanger compartment B will reach 7.2 ft. above floor level if no fluid leaks through the door. INSERT E ~~[illegible]~~ 3

c) Boric Acid Make-up Tank Room

The Boric Acid Make-up Tank room is located in the RAB at El. -0.5 ft. This room contains two Boric Acid Make-up Pumps. The room is open to a corridor which in turn is connected to an area containing the condensate recovery pumps. The floor drain in these areas are connected to ECCS compartment B sump.

For flooding analysis, a crack is postulated in a 4 inch discharge line of Boric Acid Make-up Tank 2B. Tank 2B is considered to be 92.5 percent full. This represents normal operating conditions. The capacity of each tank is 9755 gal. The operating fluid conditions for the four inch line are 8.0 psig and 170F. The flow from the crack is 17.0 gpm.

"This is Insert C"

Moderate energy cracks are to be postulated to occur only when the fluid conditions are equal to or less than 275 psig and 200°F. However, for the flooding analysis, the crack was conservatively postulated to occur at 450 psig since this pressure resulted in the largest flow through the piping failure.

"This Insert E"

The operator isolates the crack by closing the valves in the suction line of LPSI pump and stopping the pump. If the accumulated fluid in the SDC heat exchanger is allowed to drain to the ECCS room, the water level in the room will reach 3.1 ft.

The operator may close the valves I-HCV-25-5 and I-HCV-25-5A to permit draining of the water from the shutdown cooling heat exchanger room. These isolation valves can be closed from the control room. The unaffected SDC train can be used to shutdown the plant.

"This is Insert D"

The leakage crack in the discharge line of LPSI pump reduces flow rate in the system. Flow element FI-3306 or FI-3301 in the LPSI pump discharge line will show a reduction in the flow rate. The temperature elements in the LPSI pump discharge lines downstream of shutdown cooling heat exchangers will read temperatures lower than normal. Based on this data, the operator can identify the location of piping failure.

LEVEL Indicator LI-220B in the Boric Acid Makeup Tank will allow the operator to identify the system piping failure

The worst flooding condition for ECCS compartment B will exist when the entire flow from the crack is drained to the ECCS sump. The sump is assumed to be initially 10 percent of full. The "high water level" in the sump is reached after 47.6 minutes from the beginning of pipe failure. The high level switch in the sump actuates an alarm in the control room. It is conservatively assumed that the sump pumps fail to operate and that operator will isolate the crack 30 minutes after the first alarm in the control room.

During the 30 minutes the flood level in ECCS compartment B will be 0.4 inch high. This water level will not affect the operation of any safety related equipment in ECCS compartment B.

If the piping failure is located in the upstream side of Valve-V2142, the operator cannot isolate the crack. The entire content of the tank is considered to be drained to ECCS compartment B. The resulting water level in the ECCS compartment is 1.0 ft. This flood level will not affect the operation of safety related equipment.

0.7 ft.

d) Charging Pump Room 3

The three charging pumps are located in RAB at El -0.5 ft. The charging pump room is divided into three separate compartments by 6.5 ft high walls. Each charging pump is located in a separate compartment. Doors are provided between the charging pump room and the pipe tunnel at El +0.5 ft and RAB main corridor. Each compartment has a 6 inch high curb at the entrance.

For flooding analysis, the largest flow crack would be in the four inch charging pump 2C suction line 4-CH-967 with operating conditions 27 psig and 120F (see Figure 9.3-5c). The flow rate from the crack is 31.7 gpm. The entire spillage will drain to ECCS compartment B sump. The operator is alerted by the sump B "high water level" alarm in the control room 25.6 minutes after the pipe failure. It is assumed that 30 minutes after the alarm, corrective action is taken. The flood level in ECCS compartment B after the 30 minutes will be 0.06 ft, if the sump pumps are assumed to be out of operation. This flood level in ECCS compartment B will not affect operation of any equipment in the room. The operator isolates the piping failure by closing valve V-2501 on the discharge line of the volume control tank.

The flooding analysis for charging pump compartments 2A and 2B produces exactly the same result as that of charging pump compartment 2C.

THE OPERATOR will also notice the volume Control Tank Level decreasing via LI-226.

e). Diesel Generator Building

There are two diesel generators installed in separate rooms at el 22.67 ft in the diesel generator building. For flooding analysis, the largest flow crack would be in the Service Water System line 2-SW-108 (See Figure 9.2-6). The pipe is 2 in. nominal diameter and operating conditions are 75 psig and 95F. The Service Water System serve no safety function since it is not required to achieve safe plant shutdown nor to mitigate the consequences of a design basis accident. The flow rate from the crack is 18 gpm. The entire flow from the crack drains through the drainage system to the existing 36 in. diameter pipe which is directed to the existing grade.

Since there is no accumulation of fluid in the diesel generator room, the operation of the diesel generator is not affected by this accident. For flooding analysis, there is no critical time for the operator to isolate the pipe failure.

f) Diesel Oil Tank Enclosure

There are two diesel oil storage tanks with their pumps located in two separate compartments in the diesel oil tank enclosure. Tanks and pumps are installed at El 19.0 feet. For flooding analysis the highest flow crack would be in the 3 in. nominal diameter diesel oil pump suction line 3-DO-07 (See Figure 9.5-6). The operating fluid conditions are 25 psig and 100F. The drain line in each compartment is normally closed. Each of the compartments is designed to hold the entire capacity of its respective tank should a leak occur. 3

g) Intake Cooling Water Pump Area

There are three Intake Cooling Water Pumps located in the ICWP area at El 16.5 feet. For flooding analysis the largest flow crack would be in a 30 in. diameter ICWP discharge line I-30-CW-11 (See Figure 9.2-1). The operating conditions are 90 psig and 95F. The resulting flow from the crack is 604 gpm. The entire flow from the crack is drained through the annular area between the discharge pipe and the 42 inch diameter pipe sleeve to the suction well in the intake structure. No safety-related equipment is affected by this flooding.

The Intake Cooling Water Pump is designed for 14500 gpm at 130 ft head. Loss of 604 gpm through the crack will not affect the system operation. Normal plant operation and safe plant shutdown is not compromised.

h) Component Cooling Intake Area

The Component Cooling Water Area contains three CCW pumps and two heat exchangers. The floor elevation of the compartment is 12.0 ft. The pumps and heat exchangers are mounted on pedestals at about El 24.0 ft. There are two sumps in this area. One sump is located inside the compartment with its bottom El at 9.67 ft. The other sump is located at the pipe tunnel area with bottom elevation at 1.0 ft. The pipe tunnel sump is provided with a sump pump with capacity of 25 gpm. This pump transfers the fluid from the pipe tunnel sump to the sump in the CCW compartment. The fluid from the CCW compartment sump drains to the existing 36 inch drain pipe via a 3 inch drain line. The 36 inch line discharges to existing grade at El 0.0 ft.

he PoTO for the YARD sump
ump is provided
Figure 3.6F-8

For flooding analysis, the largest flow crack would be in the 30 in. CCW heat exchanger circulation water inlet line I-30-CW-78 operating at 60 psig and 95F (See Figure 9.2-1).

The flow rate from the crack is 490 gpm. The entire flow spills on the floor and fills up the pipe tunnel sump to "high-high water level" in seven minutes. The level switch in the sump starts the sump pump and actuates an alarm in the control room. The sump pump delivers 25 gpm to the CCW compartment sump. All the water will be drained from the CCW compartment because drain capacity is more than 25 gpm. 3

INSERT F

It is assumed that 30 minutes after pipe failure, corrective action is taken by the operator. During this 30 minutes the fluid level in the pipe tunnel area will reach El 8.0 ft. No safety related equipment is affected by this flooding. The operator may close valves ~~[illegible] and [illegible]~~ to isolate the crack. The intake cooling water pump is designed for 14500 gpm at 130 ft head. Loss of 490 gpm through the crack will not affect the operation of the system. Therefore plant shutdown is not compromised by this piping failure. Even if the piping failure is isolated, the unaffected component cooling water loop B is available and capable of supplying the minimum safety feature requirements for safe plant shutdown.

I-[illegible]-21185,
1186 and 21192

i) Letdown Heat Exchanger Room

The letdown heat exchanger room is located in the RAB at El 19.5 feet and contains the letdown heat exchanger and associated piping and valves. A door connects this room with the corridor. This room contains no equipment needed for safe plant shutdown but the room is connected with ECCS compartment A, through the floor drainage system.

For flooding analysis, the largest crack is in the letdown heat exchanger component cooling water outlet line 8-CC-134 (See Figure 9.2-2). The pipe is eight inch nominal diameter and the operating

fluid conditions are 100 psig and 150F. The resulting flow from the crack is 160 gpm of which 38.4 gpm drains through a three inch diameter floor drain to the equipment drain tank. The remaining 121.6 gpm accumulates in the letdown heat exchanger room.

ERT

Within 7.6 minutes after the pipe failure, the water level in the letdown heat exchanger room reaches the curb level and starts spilling into the corridor. Within 11.4 minutes after the pipe failure, the fluid level in the equipment drain tank reaches "high water level." The "high water level" switch in the equipment drain tank actuates an alarm in the control room. It is assumed that 30 minutes after the alarm the operator isolates the line by closing valve 2-SB-14241. During this 30 minutes, the equipment drain tank and the chemical drain SUMP ~~tank~~ are filled. The operator also closes valves I-HCV-25-5 and I-HCV-25-5A FROM THE CONTROL ROOM in ECCS compartment A sump drain line, so that the fluid will not reach ECCS compartment A. The fluid will spill into the corridor at El 19.5 ft. Part of the fluid will drain to the equipment drain tank, and part of the fluid spills to the corridor at El -0.5 ft through the stair well. No safety related equipment is affected by this flooding condition.

j) Boric Acid Concentrator Room

Two boric acid concentrator rooms and one waste concentrator room are located in RAB at El. 19.5 ft. Each room is connected with the corridor at El 19.5 ft via a door. The boric acid concentrator and waste concentrator are not safety related. However, these rooms are connected through the drainage system with ECCS compartment A. 3

The flooding analysis was performed for a postulated crack in the boric acid concentrator component cooling water line. Typical line is six inches in diameter with operating conditions of 100 psig and 120F. The flow from the crack is 106 gpm. The result of the analysis indicates that the operator has sufficient time (ie 30 minutes from the first alarm in the control room) to isolate the crack before the fluid reaches ECCS compartment A. However, if the operator fails to close the ECCS sump A isolation valves I-HCV-25-5 and I-HCV-25-5A, the accumulated fluid in concentrator room eventually will drain to ECCS compartment A and the water will reach 0.07 ft high. The flood level is insufficient to affect the operation of safety related equipment.

k) Pipe Tunnels in RAB

The upper tunnel is located at El 19.5 ft and the lower tunnel has bilevel floors at El -0.5 ft and at el 0.5 ft. An opening in the floor of the upper tunnel connects the lower tunnel. Two air tight doors separate upper tunnel from the switchgear room and the H_2 recombiner supply panel 1A ILRT panel, room. A door is provided between the lower

"This is INSERT F"

The alarm in the Control Room due to "high-high water level" in the pipe tunnel sump alerts the operator that there may be piping failure in the pipe tunnel area. The Circulating Water System and Component Cooling Water System piping are located in this area. If the crack occurs in the CCW System, the low level in the surge tank will initiate an alarm in the Control Room. If the alarm is not due to the surge tank low level then the operator could identify the piping failure to be in the CCW System.

"This is INSERT G"

The temperature indicator TI-04-5 and flow transmitter FT-14-6 in the Component Cooling Water line will allow the operator to identify the piping failure in the system. In addition there will be an alarm in the Control Room due to low level in CCW Surge tank after 5.3 minutes after the piping failure.

tunnel and the charging pump room. Another door is provided between the lower tunnel and the corridor which is between the ECCS room and shutdown cooling heat exchanger room. The lower tunnel communicates through the drainage system with ECCS compartment A&B.

The leakage with the greatest crack in the lower pipe tunnel is a postulated crack in containment spray line I-24-CS-41 (see Figure 6.2-41). The pipe line in 24 inch nominal diameter with operating fluid conditions at 30 psig and 120F.

E RWT LEVEL dicators LIS- -2A, 2B, 2C, 2D ll also alert e operator f the piping ailure accident

The flow from the crack is 180 gpm. There are two 3 inch diameter drain lines in the lower tunnel. One drain line delivers fluid to ECCS compartment A sump and the other drain line drains the fluid to ECCS compartment B sump. Flow rate through each drain line is 38.4 gpm. It is conservatively assumed that all 4 sump pumps are not available.

The operator is alerted by the sump "high water level" alarm in the control room 21 minutes after pipe failure. It is assumed that the operator takes corrective action 30 minutes after pipe failure. During this 30 minute period, the fluid level in ECCS compartment A will reach 0.1 ft. This fluid level will not affect the operation of safety related equipment in the compartment. The operator can isolate the break by closing valve I-MV-07-1A. The operator could also close valves I-HCV-25-5, I-HCV-25-5A, I-HCV-25-3 and I-HCV-25-3A in the drain lines to prevent further flooding due to draining of fluid accumulated in the pipe tunnel. However, the worst condition is to let all fluid in the pipe tunnel to drain to the ECCS sumps. In this case, the water level in both the ECCS compartments will reach 0.374 ft. This fluid level will not affect operations of any safety related equipment. 3

From the Control Room

The largest flow crack in the tunnel at El. 19.5 ft would be in Component Cooling Water line 20-CC-27 (See Figure 9.2-2). The pipe is 20 inch nominal diameter and the operating conditions are 100 psig and 180F. The flow from the crack is 433 gpm of which 82 gpm of this flow is directly drained to the equipment drain tank. The remainder drains to the lower pipe tunnel. From the lower pipe tunnel, the fluid is drained to the sumps in ECCS compartments A & B.

INSERT H

The operator is alerted by CCW Surge tank "low level" alarm one minute after beginning of leakage from the crack. The CCW makeup system which delivers 100 gpm to surge tank is taken into account to determine the time for level alarm. It is assumed that the operator requires 30 minutes after the alarm in the control room prior to initiating the corrective action. The operator may isolates the crack by closing valves 2I-HVC-14-10, I-MV-14,4, 2I-SB-14487, 2I-SB-14133, 2I-SB-14127, 2I-SB-14531, 2I-MV-14-19 and 2I-V-14301. The flood level in the ECCS compartments at this time (i.e., 31 minutes) will be 0.1 ft and safety related equipments is not affected. If the fluid accumulated in the

HCV

"This Is Insert H"

The CCW System surge tank low level alarms LS-14-1A & 1B, flow element FE-1410A and 1410B indicating higher flow and temperature indicator TI-09-5 registering lower temperature than normal will assist the operator to identify the piping failure location.

pipe tunnel El-0.5 ft is allowed to drain to the ECCS compartments without operator isolating them, the fluid level will reach 0.49 ft. The flood level does not affect any safety related equipment. The height from the floor to nearest safety related item, conduit box for HPSI pump, is 1.6 ft.

l) Fuel Pool Heat Exchanger Room

The Fuel Pool Heat Exchanger room is located in the Fuel Handling Building at El.19.5 ft and contains the fuel pool heat exchanger and associated piping and valves. A door connects this room with the Fuel Pool Purification Filter room. A six inch high curb separates Fuel Pool Heat Exchanger room from Fuel Pool Pump room.

For flooding analysis, the largest flow crack would be in CCW line 12-CC-130 from fuel pool heat exchanger to return header B (See Figure 9.2-2). The pipe is 12 in. nominal diameter and its operating conditions are 100 psig and 150F. The resulting flow from the crack is 275 gpm. A 4 in. diameter drain line delivers 82 gpm of the fluid from this room to the equipment drain tank. The equipment drain tank room is connected through the drainage system with the ECCS compartment A.

flow ... ment sys- ... will also ... the ... erator ... ing the ... line

The operator is alerted by CCW surge tank "low level" alarm two minutes after beginning of leakage. The CCW make-up system which delivers 100 gpm to surge tank is taken into account to determine the time for alarm level in the surge tank. Operator isolates the crack by closing valves 2-I-MV-14-17 and 2-I-MV-14-19. 3

The flooding analysis indicates that during this 30 minute period, the equipment drain tank, chemical drain sump, chemical drain tank are filled and overflow to the room containing the equipment drain tank and chemical drain tank. From this room the overflow drains to the ECCS compartment A sump. As the accumulated fluid continues to drain from the fuel pool heat exchanger room, the sump will overflow into ECCS compartment A to a depth of 1.29 ft which does not affect safety related equipment.

THE fluid drainage to ECCS Compartment Sump A could also be stopped from the Control Room by closing valves 2-HCV-25-5, 5A.

m) Fuel Pool Pump Room

The fuel pool pump room is located in Fuel Handling Building at El. 19.5 ft and contains two fuel pool pumps. One door with a six inch curb connects this room with fuel pool purification filter room. There is a six inch high curb between this room and the corridor. This corridor also has a six inch high curb to separate the fuel pool heat exchanger room.

For flooding analysis, the largest flow crack would be in fuel pool pump suction line 12-FS-501 between fuel pool and valves V-4203 or V-4202 (see Figure 9.1-6). The pipe is 12 in. nominal diameter and its operating conditions are 11 psig and 120F. The resulting flow is 43.6 gpm. This break cannot be isolated by shutting off the valves in the broken line. Flooding will stop when level of fluid in fuel pool drops below the fuel pool pump suction line at El. 56 feet. This will occur 925 minutes after leak initiation. Although normal surveillance would detect the leakage before the fluid level drops below suction level, this analysis assumes the fluid level drops below suction level. Fluid from leak fills fuel pool pumps room, overflows to the corridor and fuel pool heat exchanger room. Thereafter, all flow runs through a four in. diameter drain line to the equipment drain tank. The operator is alerted by equipment drain tank "high level" alarm 12 minutes after the failure and it is assumed operator closes valves 1-MVC-25-5 or HCV 1-MVC-25-5A after 30 minutes. These valves isolate the drain line from equipment drain tank room which runs to ECCS sump A. With these valves closed, the chemical drain sump overflows on to El-0.5 ft, flooding the floor to a depth of 0.2 ft before the water level in the fuel pool falls below fuel pool pump suction line. Therefore, flooding will not affect any safety related equipment.

When the water level falls below the fuel pool pump suction line, the accident is similar to loss of all external cooling. The analysis for this accident has been performed and the results are presented in FSAR Subsection 9.1.3. 3

n) Fuel Pool Purification Pump Room

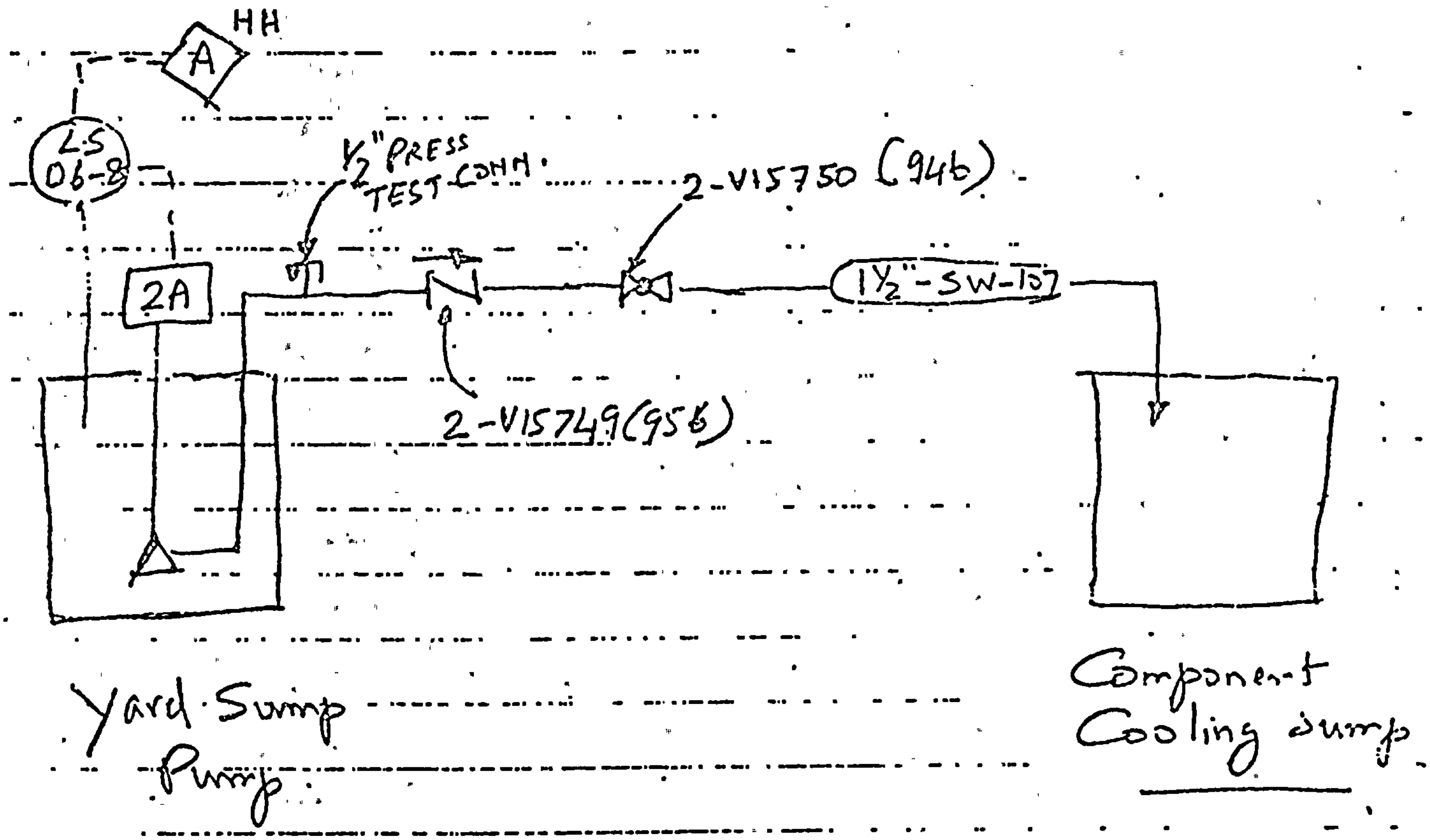
Fuel pool purification pump room is located in the Fuel Handling Building at El 19.5 ft and contains fuel pool purification pump. One door connects this room with fuel pool purification filter room. A wall, top El 26.27 ft, provides separation from the fuel pool pumps room. For flooding analysis, the largest flow crack is the fuel pool ion exchanger outlet line 3-FS-524 (See Figure 9.1-6). The pipe is three in. nominal diameter and operating conditions are 75 psig and 120F. The resulting flow is 21 gpm. All flow from the crack runs through a three in. diameter drain line to the equipment drain tank. The operator is alerted by equipment drain tank "high level" alarm 23 minutes after beginning of leakage and has 30 minutes to isolate the leakage by closing valve V-4220 if failure has occurred downstream of this valve. The operator cannot isolate leakage if crack is located inside of fuel pool purification pump room upstream of valve V-4220. The crack will be isolated 595 minutes after beginning of leakage when level of fluid in fuel pool will drop below fuel pool purification pump suction at El 59.0 ft. Although normal surveillance would detect the leakage before the fluid level drops below suction level, this analysis assumes the fluid level drops below suction level. At this time fluid has filled equipment drain tank and chemical drain sump. The fluid will not reach chemical drain tank or ECCS compartment sump A. Therefore, flooding will not affect safety related equipment.

3.6F.2.3 Environmental Effects

This is addressed in FSAR Section 3.11.

3.6F.2.4 Summary and Conclusion

The consequences of flooding due from the pipe crack were evaluated. The effects of flooding on systems and components required to shutdown the reactor and mitigate the consequences of a postulated piping failure were analyzed. As indicated in the analysis, moderate energy pipe failure does not affect essential equipment and components required for safe plant shutdown. 3



P&I Diagram for Yard Sump Pump

Figure : 2.6F-1

Question 410.36
(3.6.1)

Verify that the volume and area of the compartments for moderate energy pipe crack analysis does not include the volume and area of equipment, foundations, six inch and larger pipes, and water tight cabinets. If the analysis in the FSAR Appendix 3.6.F does not account for the volume and area of these items, provide the results of a revised analysis which does take these items into consideration.

Response 410.36

The net free volume of the compartments for the moderate energy crack analysis do not include the volume and area occupied by the equipment or equipment foundations.

The moderate energy analysis has shown that in all cases, the flooding is contained within one ECCS compartment and therefore, the redundant train is not affected. The volumes of the piping system were not considered since the analysis has shown that in all cases analyzed the flood level was well below the barrier walls between the cubicles. The unaffected train is available and is utilized to bring the plant to a safe shutdown condition.

Question 410.37
(3.6.1)

Assuming a high energy pipe break or critical crack of the main feedwater (MFW) pipe located above the motor driven auxiliary feedwater (AFW) pumps in combination with failure of the turbine driven AFW pump, demonstrate that safe shutdown and cooldown can be achieved by operation of at least one motor driven AFW pump. Show that the operability of the motor driven AFW pumps will not be affected by the potential jet impingement, flooding and environmental effects caused by the MFW pipe failure.

Response 410.37

The feedwater lines upstream of the Valves I-HCV-09-1A and I-HCV-09-1B are classified as non-seismic category piping. However these lines are seismically analyzed as part of the same stress calculation that includes the ASME III Class 2 Seismic Category I piping from valves I-HCV-09-1B and -2B to the flued head anchors on the trestle structure. Based on the stress analysis and as outlined in SRP 3.6.2 high energy line breaks were assumed at high stress points and terminal ends of feedwater lines in the vicinity of the Auxiliary Feedwater Pumps (AFP). In no case can the AFPs be directly impacted by the resultant jets (see SK 2998-M-764). The weatherproof enclosure of the motors protects them from indirect effects such as spraying. The open nature of the trestle and the storm drainage system precludes flooding.

The environmental effects of a high energy line break in this area will be addressed as part of the Environmental Qualification program to be submitted in November of this year.

Question 410.38
(10.4.9)

In accordance with Position C.2 of Regulatory Guide 1.29, verify that any failure of the turbine building, including complete collapse of the building or damage to its foundation, basemat, piping, and condenser, due to an earthquake will not result in flooding of safety-related equipment or damage the two lines from the condensate storage tank to the auxiliary feedwater pumps.

Response 410.38

The basemat and steel superstructure of the turbine building has been designed to withstand the effects of a Safe Shutdown Earthquake (SSE). This insures the safety of all essential components in the vicinity of the turbine building by eliminating the possibility of catastrophic failure. The local failure of non-seismic components located in the turbine building cannot adversely affect plant safety since no essential equipment is located there.

The open nature of the turbine building precludes the possibility of flooding. Leakages resulting from the failure of non-seismic piping would be prevented from affecting essential equipment by the storm drainage system and site grading.

The suction lines for the Auxiliary Feedwater Pumps are protected over their entire length from the Condensate Storage Tank (CST) to the trestle. From the CST to the turbine building and from the turbine building to the trestle the lines are totally enclosed in a pipe trench. The pipe trench is designed to withstand the effects of seismic events and tornados. Within the turbine building the suction lines are buried in class 1 fill.

Question No. ____

420.1

Loss of Non-Class 1E Instrumentation and Control Power System Bus During Power Operation (IE Bulletin 79-27)

If reactor controls and vital instruments derive power from common electrical distribution systems, the failure of such electrical distribution systems may result in an event requiring operator action concurrent with failure of important instrumentation upon which these operator actions should be based. This concern was addressed in IE Bulletin 79-27. On November 30, 1979, IE Bulletin 79-27 was sent to operating license (OL) holders, the near term OL applicants (North Anna 2, Diablo Canyon, McGuire, Salem 2, Sequoyah, and Zimmer), and other holders of construction permits (CP), including St. Lucie No. 2. Of these recipients, the CP holders were not given explicit direction for making a submittal as part of the licensing review. However, they were informed that the issue would be addressed later.

You are requested to address these issues by taking IE Bulletin 79-27 Actions 1 thru 3 under "Actions to be Taken by Licensees" (a copy of 79-27 is provided in the attachment to this enclosure). By July 6, 1981, complete the review and evaluation required by Actions 1 through 3 and provide a written response describing your reviews and actions. This report should be in the form of an amendment to your FSAR and submitted to the NRC Office of Nuclear Reactor Regulation as a licensing submittal.

Response

1) For Action Item 1 of IE Bulletin No. 79-27, refer to attached Table 420.1-1a and 1b and response 420.01 (Action Item 1b)

2) For response to Action Item 2 Refer to response 420.01 (Action Item #2).

3) For response to Action Item 3 refer to response 420.01 (Action Item 3)

PRELIMINARY INFO ONLY JUL 1 1981

ALARM INDICATION FOR LOSS of POWER to SAFETY and NON-SAFETY POWER BUS

TABLE 420.1-1a

ITEM	BUS OR DISTR. PANEL	CLASS	DEDICATED ALARM	BUS FAILURE DETECTION	REDUNDANT BUS
1	120/208V PP 201	IE/SA	NO	FAILURE OF IND & CONTROLS	PP-202
2	120/208V PP 202	IE/SB	NO	" " "	PP-201
3	120/208V PP 203	IE/SAB	NO	" " "	PP-201 & PP-202
4	120/208V PP 204	NS/NA	NO	" " "	PP-207
5	120/208V PP 205A	NS/NA	NO	" " "	PP 205B
6	120/208V PP 205B	NS/NB	NO	" " "	PP 205A
7	120/208V PP 207	NS/NB	NO	" " "	PP-204
8	120/208V PP 208	NS/NA	NO	" " "	PP-209
9	120/208V PP 209	NS/NB	NO	" " "	PP-208
10	120/208V PP 210	NS/NB	NO	" " "	PP-214
11	120/208V PP 211	IE/SA	NO	" " "	PP-212
12	120/208V PP 212	IE/SB	NO	" " "	PP-211
13	120/208V PP 213	NS/NB	NO	" " "	NONE
14	120/208V PP 214	NS/NA	NO	" " "	PP-210
15	120/208V PP 215	NS/NA	NO	" " "	PP-216
16	120/208V PP 216	NS/NB	NO	" " "	PP-215
17	120/208V PP 217A	NS/–	NO	" " "	NONE
18	120/208V PP 220	NS/NA	NO	" " "	PP-201
19	120/208V PP 221	NS/NB	NO	" " "	PP-220
20	120/208V PP 222	NS/NA	NO	" " "	NONE
21	120/208V PP 234	NS/NAB	NO	" " "	NONE
22	120/208V PP 235	NS/NA	NO	" " "	PP-236
23	120/208V PP 236	NS/NB	NO	" " "	PP-235
24	120/208V PP 241	NS/NA	NO	" " "	PP-242
25	120/208V PP 242	NS/NB	NO	" " "	PP-241
26	120/208V PP 250	IE/SA	NO	" " "	PP-251
27	120/208V PP 251	IE/SB	NO	" " "	PP-250

TABLE 420.1-1a (cont'd)

ITEM	BUS OR DISTR. PANEL	CLASS	DEDICATED ALARM	BUS FAILURE DETECTION	REDUNDANT BUS OR PP
28A	125V DC BUS 2A	1E/SA	YES	ANN & FAIL OF INDIC	125V DC BUS 2B
28B	" " " "	NS/NA	NO	FAILURE OF INDIC.	" " "
29A	" " " 2B	1E/SB	YES	ANN & FAIL OF INDIC	125V DC BUS 2A
29B	" " " "	NS/NB	NO	FAILURE OF INDIC.	" " " "
30A	" " " 2AB	1E/SAB	YES	ANN & " " "	125V DC BUS 2A/2B
30B	" " "	NS/NAB	—NO	" " "	" " " "
31	" " " 2C	NS/NB	YES	ANN & " " "	NONE
32	125V DC PP 218	NS/NA	NO	FAIL OF INDIC. & CONT	PP-219
33	" " PP219	NS/NB	NO	" " " "	PP-218
34	" " PP 238	1E/SA	NO	" " " "	PP-239
35	" " PP 239	1E/SB	NO	" " " "	PP-238
36	" " PP 240	1E/SAB	NO	" " " "	PP-238/PP239
37	125V DC BUS MA	1E/MA	NO	" " " "	REDUNDANT TO EACH OTHER
38	" " " MB	1E/MB	NO	" " " "	
39	" " " MC	1E/MC	NO	" " " "	
40	" " " MD	1E/MD	NO	" " " "	
41	120V AC VITAL PANEL 2A	NS/NA	NO	" " " "	VITAL PP 2B
42	120V AC VITAL PANEL 2B	NS/NB	NO	" " " "	" " 2A
43	120V AC INSTR. BUS 2MA	1E/MA	YES	ANN & FAIL OF IND	REDUNDANT TO EACH OTHER
44	" " " 2MB	1E/MB	YES	" " " "	
45	" " " 2MC	1E/MC	YES	" " " "	
46	" " " 2MD	1E/MD	YES	" " " "	
47	120V/208V PP 206	1E/SA	NO	PERIODIC SPACE HTR INSPECTION	NONE
48	" PP 223	1E/SB	NO		
49	" PP 232	1E/SB	NO		
50	" PP 233	1E/SAB	NO		
51	" PP 243	1E/SA	NO		
52	" PP 244	NS/NB	NO		
53	" PP 245	NS/NA	NO		
54	" PP 246	1E/SA	NO		
55	" PP 247	1E/SB	NO		
56	" PP 248	NS/—	NO		
57	" PP 249	NS/—	NO		

TABLE 420.1-1a (cont'd)

ITEM	BUS OR DISTR PNL	CLASS	ALARM	BUS FAILURE DETECTION	REDUNDANT BUS
58	480/120V MCC-2A2	NS/NA	No	Failure of Indication	2A2
59	480/120V MCC-2B2	NS/NB	No	Failure of Indication	2A2
60	480/120V MCC-2B6	~~NS/NB~~ 1E/SB	No	Failure of Indication	2B2

LOSS of NON-CLASS IE BUS and AFFECT on INSTRUMENTATION

TABLE 420.1-1b

ITEM	INSTR. BUS	BUS CLASS/CH.	TABLE I BUS FAIL ALARM/INDIC.	SERVICE SYSTEM	INSTR. TAG/LOOP	INSTR. CLASS/CHANNEL	DESCRIPTION	OTHER SYSTEMS FED BY DEVICE	IMPACT ON PLANT SAFETY	REQD FOR COLD SHUTDOWN	COMMON SENSE LINE/HDR REMARKS
1	120V AC PP 220 125V DC BUS 2AB	NS/NA	IT-18 IT-30B	RRS	PT-1100X (CWD-97)	NS/NA	PRESS PRESSURE	PZR HTR'S & SPRAY CONTROL (PZR PRESS CONTROL)	Refer to writeup response 420.01 (Action Item 1b)		SAME AS SAFETY CHANNELS A REF. LEG (PT1102A)
2	120V AC PP 221 125V DC BUS 2AB	NS/NB	IT-19 IT-30B	RRS	PT-1100Y (CWD-98)	NS/NB	PRESS PRESSURE	" " "			SAME AS SAFETY CHANNEL B REF. LEG (PT1102B)
3	120V AC PP 220	NS/NA	IT-18	RRS	TE-1111X (CWD 138)	NS/NA	REACTOR COOLANT LOOP TEMPERATURE	RECORDER (IND ONLY)			LOOP 2A HOT LEG (RCS)
4	120V AC PP-221	NS/NB	IT-19	RRS	TE-1121X (CWD-137)	NS/NB	SAME AS ABOVE	"			LOOP 2B HOT LEG (RCS)
5	120V AC PP-220	NS/NA	IT-18	RRS	TE-1111Y (CWD-138)	NS/NA	"	CEDS & AWP			LOOP 2A2 COLD LEG (RCS)
6	120V AC PP-221	NS/NB	IT-19	RRS	TE-1121Y (CWD-137)	NS/NB	"	CEDS & AWP			LOOP 2B2 COLD LEG (RCS)
7	120V AC PP-220	NS/NA		RRS	PT-22-37A.F. T. LINE F. I. S.	NS/NA	FIRST STAGE TURB PRESS				
7A	120V AC PP-734	NS/NAB		RRS	PT-22-37B	NS/NAB	" " " "				
8	120V AC PP-220 125V DC PP-201	NS/NA 1E/SA	IT-18 IT-1	PZR LEVEL CONTROL	LT-1110X (CWD-90)	NS/NA	PRESSURIZER LEVEL	PZR PRESS CONTROL (HTR INTERLOCKS)			SAME AS SAFETY CHANNEL A (PT-1102A)
9	120V AC PP-221 120V AC PP-202	NS/NB 1E/SB	IT-19 IT-2	"	LLT 1110Y (CWD-90)	NS/NB	" "	"			SAME AS SAFETY CHANNEL B (PT-1102B)

TABLE 420.1-1b (cont'd)

ITEM	INSTR. BUS	BUS CLASS	TABLE 3 BUS FAIL ALARM/INDIC.	SERVES SYSTEM	INSTR. TAG	INSTR. CLASS	DESCRIPTION	OTHER SYSTEMS FED BY DEVICE	IMPACT ON PLANT SAFETY	REQ'D FOR COLD SHUTDOWN	COMMON SENSE REMARKS	LINE/NDK.
10	120V AC PP220 PP221	NS/NA NS/NB	IT-18 IT-19	RRS	RRS: LEVEL SETPOINT 01-RRS/405	NS/NA	PRESSURIZER LEVEL CNTL (RRS 1 OR 2 MAYBE SELECTED AS INPUTS TO X/Y VIA 01-RRS/405)		Refer to write up response 420.B1 (Action Item 1b)			
11	125V DC BUS 2A	NS/NA	IT-28B	REACTOR COOLANT PUMP	TPS-1157 (CWD-101)	NS/NA	REACTOR COOLANT PUMP START PERMISSIVE	—			RCP-2A1	
12	125V DC BUS 2B	NS/NB	IT-29B	"	PS-1167 (CWD-109)	NS/NB	"	—			RCP-2A2	
13	125V DC BUS 2B	NS/NB	IT-29B	"	PS-1177 (CWD-105)	NS/NB	"	—			RCP-2B1	
14	125V DC BUS 2A	NS/NA	IT-28B	"	PS-1187 (CWD-113	NS/NA	"	—			RCP-2B2	
15	120V AC PP-214	NS/NA	IT-14	"	SS-1152 (CWD-101)	NS/NA	OIL LIFT PUMPS START/STOP CONTROL (SPEED SWITCH)	—			RCP-2A1	
16	120V AC PP-210	NS/NB	IT-10	"	SS-1162 (CWD-109)	NS/NB	"	—			RCP-2A2	
17	120V AC PP-210	NS/NB	IT-10	"	SS-1172 (CWD-105)	NS/NB	"	—			RCP-2B1	
18	120V AC PP-214	NS/NA	IT-14	"	SS-1182 (CWD-113	NS/NA	"	—			RCP-2B2	

TABLE 420.1-1b (cont'd)

ITEM	INSTR. BUS	BUS CLASS	TABLE I BUS FAIL ALARM/INDIC.	SERVES SYSTEM	INSTR. TAG	INSTR. CLASS CHANNEL	DESCRIPTION	OTHER SYSTEMS FED BY DEVICE	IMPACT ON PLANT SAFETY	REQ'D FOR COLD SHUTDOWN	COMMON SENSE LINE/HDR REMARKS
19	120V AC PP-208	NS/NA	IT-8	BORON CONTROL SYSTEM (CVCS)	PT-2261 (CWD-151)	NS/NA	REQ'D FOR COLD SHDN		Refer to writeup		LETDOWN LINE
20	125V DC BUS 2A	1E/SA	IT-28A	"	PDS-2216 (CWD 157)	1E/SA	" FLOW CONTROL	—	response 420.1		REGEN HX ΔP
21	120V AC MCC 2A2	NS/NA	IT-58	"	TE 2206 (CWD 168)	NS/NA	"BOAT" HTR CONTROLS FOR 2A & 2B, VIA HS	—	(Action Item 1b)		BA MAKE-UP TANK 2A
22	120V AC MCC 2B2	NS/NB	IT-59	"	TE 2207 (CWD 169)	NS/NB	" " " "	—			" " " "
23	120V AC MCC 2A2	NS/NA	IT-58	"	TE 2208 (CWD 170)	NS/NA	" " 2B "	—			" " " 2B
24	120V AC MCC 2B2	NS/NB	IT-59	"	TE 2209 (CWD 171)	NS/NB	" " " 2B	—			" " " "
25	120V AC MCC 2B6	NS/NB	IT-60	"	TE 2213 (CWD 172)	NS/NB	" " HTR CONTROL	—			" BATCHING TANK
26	120V AC PP-220	NS/NA	IT-18	"	TE-2221 (CWD 152)	NS/NA	REQ'D FOR COLD SHDN	—			REGEN HX OUTLET (LETDOWN)
27	120V AC PP-221	NS/NB	IT-19	"	TE-2223 (CWD 151)	NS-NB	"	(CCW VALVE)			LETDOWN HX OUTLET PIPING

TABLE 420.1-1b (cont'd)

ITEM	INSTR. BUS	BUS CLASS	TABLE I BUS FAIL ALARM/INDIC.	SERVES SYSTEM	INSTR. TAG	INSTR. CLASS CHANNEL	DESCRIPTION	OTHER SYSTEMS FED BY DEVICE	IMPACT ON PLANT SAFETY	REQ'D FOR COLD SHUTDOWN	COMMON SENSE LINE/HDR. REMARKS
28	120V AC PP-220	HS/NA	IT-18	BORON CONTROL SYSTEM (CVCS)	TE-2220 (CWD 152)	HS/NA	HIGH TEMP DIVERSION FOR IX, RT BORONMETER	—	Refer to writeup response	420.1 (Action Item 1b)	LETDOWN HX OUTLET PIPING
29	120V AC PP-221	HS/NB	IT-19	"	LT-2226 (CWD 154)	HS/NB	REQ'D FOR COLD SHDN (MAKEUP CONTROLS) WMS/VCT FLOW DIVERSION	—			VCT
30	120V AC PP-221	HS/NB	IT-19	"	LT-2227 (CWD 154)	HS/NB	"	—			VCT
31	125V DC BUS 2A	1E/SA	IT-28A	"	LS-2234X (CWD 187)	"	SUPPLIED W/RCP BY RCP VENDOR STUFFING BOX WATER LEVEL CONTROL (CHARGING PUMP)	—			CHARGING PUMP 2A
32	125V DC BUS 2B	1E/SA	IT-29A	"	LS-2234Y (CWD 187)			—			" " 2B
33	125V DC BUS 2AB	1E/SAB	IT-30A	"	LS-2234Z (CWD 187)		"	—			" " 2C
34	120V AC PP-220	HS/NA	IT-18	"	FT-2210X (CWD 198)		MAKE-UP FLOW TO VCT	—			REACTOR MAKE-UP LINE
35	120V AC PP-221	HS/NB	IT-19	"	FT-2210Y (CWD 193)		BA MAKE-UP FLOW TO VCT	—			BORIC ACID MAKE-UP
36	120V AC VITAL PNL 2B	HS/NB	IT-42	STM BYPASS CONTROL (RRS-2)	HIC-8801 (CWD 748)		TURBINE BYPASS TO COND VALVE				"

TABLE 420.1-1b (cont'd)

ITEM	INSTR. BUS	BUS CLASS	TABLE I BUS FAIL ALARM/INDIC.	SERVES SYSTEM	INSTR. TAG	INSTR. CLASS CHANNEL	DESCRIPTION	OTHER SYSTEMS FED BY DEVICE	IMPACT ON PLANT SAFETY	REQ'D FOR COLD SHUTDOWN	COMMON SENSE LINE/HDR REMARKS
37	120V AC VITAL PNL 2B	NS/NB	IT-42	STM. BY/PASS CONTROL (RRS-2)	HIC-8802 (CWD 749)	NS/NB	STM DUMP TO COND/ATM		Refer to Writeup response 42001 (Action Item 1b)		
38	"	"	"	"	HIC-8803 (CWD 749)	NS/NB	" " " " " "				
39	"	"	"	"	HIC-8804 (CWD 750)	NS/NB	" " " " "				
40	"	"	"	"	PIC-8010 (CWD 750)	NS/NB	" " " " "				
41	120V AC VITAL 2A	NS/NA	IT-41	"	FWCS STM FLOW	NS	FT-8011, FT-8021 INPUTS VIA FW: CONT SYS CAD'S 2A & 2B RESPECTIVELY				
41A	120V AC VITAL 2B	NS/NB	IT-42		" " "						
42	120V AC VITAL PNL 2B	NS/NB	IT-42	"	PT-8010 (CWD 748)	NS/NB					
43	"	"	"	"	PT-8020 (CWD 748)	NS/NB					
44	120V AC VITAL 2B	NS/NB	IT-42	"	FREQUENCY/LOAD CHANGE DESIRED	NS/NB	DEH-TURB CONTROL				
45	120V AC PP220 PP221	NS/NA NS/NB	IT-18 IT-19	RRS	THE INPUT		TAVE SIGNAL GENERATED BY RRS 1 OR 2 SWITCH SELECTABLE	RRS			RRS 1 OR 2

TABLE 420.1-1b (cont'd)

ITEM	INSTR. BUS	BUS CLASS.	TABLE 1 BUS FAIL ALARM/INDIC.	SERVES SYSTEM	INSTR. TAG	INSTR. CLASS CHANNEL	DESCRIPTION	OTHER SYSTEMS FED BY DEVICE	IMPACT ON PLANT SAFETY	REQ'D FOR COLD SHUTDOWN	COMMON SENSE LINE/HDR. REMARKS
46	CEDM HOLDING POWER	NS/–	—		CONTACT CLOSURE RTSG UV	NS/–	TRIP TURBINE GENERATOR ANNUNCIATOR		Refer to writeup response 420.01 (Action Item 1b)		
47	120V AC VITAL PNL 2A	NS/NA	IT-41	FEEDWATER CONTROL SYSTEM	LT-9005 (CWD 619)	NS/NA	S/G LEVEL INSTRUMENTS POWERED FROM RESPECTIVE FWCS CABS 2A & 2B	—			
48	120V AC VITAL PNL 2B	NS/NB	IT-42	"	LT-9006 (CWD 624)	NS/NB	"	—			
49	120V AC VITAL PNL 2A	NS/NA	IT-41	"	LT-9011 (CWD 619)	NS/NA	"	—			
50	120V AC VITAL PNL 2B	NS/NB	IT-42	"	LT-9021 (CWD 624)	NS/NB	"	—			
51	120V AC VITAL PNL 2A	NS/NA	IT-41	"	FT-8011 (CWD 619)	NS/NA	MAIN STM FLOW FROM EACH FWCS CH TO SDCS (RRS #2)	SPEC [illegible]			
52	120V AC VITAL PNL 2B	NS/NB	IT-42	"	FT-8021 (CWD 624)	NS/NB	"				
53	120V AC VITAL PNL 2A	NS/NA	IT-41		FT-9011 (CWD 619)	NS/NA	MAIN FEEDWATER FLOW				
54	120V AC VITAL PNL 2B	NS/NB	IT-42		FT-9021 (CWD 624)	NS/NB	"				

TABLE 420.1-1b (cont'd)

ITEM	INSTR. BUS	BUS CLASS	TARGET BUS FAIL ALARM/INDIC.	SERVES SYSTEM	INSTR. TAG	INSTR. CLASS CHANNEL	DESCRIPTION	OTHER SYSTEMS PERDY. DEVICES	IMPACT ON PLANT SAFETY	REQ'D FOR COLD SHUTDOWN	COMMON SENSE LINE/HDR. REMARKS
55	120V AC INSTR BUS 2A	1E/MA	IT-43	FEEDWATER CONTROL SYSTEM	LK-500/2013A (CND 376,377)	1E/MA	FW OVERRIDE ON HIGH SIGNAL LEVEL	N/A	Refer to writeup response 42001 (Action Item 1b)		SAFETY CHANNEL A
56	120V AC INSTR BUS 2B	1E/MB	IT-44	"	" " B	1E/MB	"	"			" " B
57	120V AC INSTR BUS 2C	1E/MC	IT-45	"	" " C	1E/MB	"	"			" " C
58	120V AC INTR BUS 2D	1E/MD	IT-46	"	" " D	1E/MD	"	"			" " D
59	125VDC BUS 1AB	NS/NA	IT-28B	TURB CONT	20/AST	NS/NB	TURB. TRIP SOLENOID				
60	125VDC BUS 2AB	NS/NB	IT-29B	" "	20/	NS/	" " "				
61	120V VITAL 2A	NS/NA	IT-41	" "	RX1/DEH	NS/NA	TURBINE RUNBACK				
62	120V VITAL 2B	NS/NB	IT-42	" "	DEH	NS/NB	TURB. CONTROL - DEH				
63	125V DC BUS 2B	NS/NB	IT-42	GEN CONTR	ANN-AA1	NS/NB	GEN: H_2 ANNUNCIATOR				
64	120V VITAL BUS 2C	NS/NB	IT-42	" "	EXCIT. SWGR	NS/NB	GEN EXCITATION CONTR				
65	120V DC BUS 2B	NS/NB	IT-42	" "	" "	NS/NB	GEN VOLT REGULATOR				

TABLE 420.1-1b (cont'd)

ITEM	INSTR. BUS	BUS CLASS	TABLE 1 BUS FAIL ALARM/INDIC.	SERVICE SYSTEM	INSTR. TAG	INSTR. CLASS	DESCRIPTION	OTHER SYSTEMS FOR RDDY. DEVICES	IMPACT ON PLANT SAFETY	REQD FOR COLD SHUTDOWN	COMMON SENSE LINE/HDR. REMARKS
66	VITAL 2A	NS/NA	IT-41	FW/I	FI-09-1A	NS/NA	FW FLOW PUMP 2A INDIC.				
67	120V VITAL 2B	NS/NB	IT-42	FW	FI-09-1B	NS/NA	FW FLOW PUMP 2B INDIC.		Refer to	Writeup	
68	120V VITAL 2A	NS/NA	IT-41	CONDENSATE	—	NS/NA	COND PUMP 2A RECIRC CONTROL		response	420.1	
69	120V VITAL 2B	NS/NB	IT-42	CONDENSATE	—	NS/NB	COND PUMP 2B RECIRC CONTROL		(Action	Item 1b)	
70	120V VITAL 2A	NS/NA	IT-41	CONDENSATE	—	NS/NA	COND. PUMP 2C RECIRC CONTROL				
71	120V VITAL 2A	NS/NA	IT-41	″	O_2R-05-1	NS/NA	DISSOLVED O_2 ANALYZER REC.				
72	120V VITAL 2B	NS/NB	IT-42	″	CR-05-1	NS/NB	CONDUCTIVITY RECORDER				
73	120V VITAL 2A	NS/NA	IT-41	″	PHR-05-1	NS/NA	PH RECORDER				
74	120V VITAL 2A	NS/NA	IT-41	FW	—	NS/NA	FW PUMP 2A RECIRC CONTR.				
75	120V VITAL 2B	NS/NB	IT-42	FW	—	NS/NB	FW PUMP 2B RECIR CONTR.				
76	120V VITAL 2A	NS/NA	IT-41	FW	VARIOUS	NS/NA	FW PUMP 2A BEARING TEMP INDIC.				
77	120V VITAL 2B	NS/NB	IT-42	FW	″	NS/NB	″ ″ 2B ″ INDIC.				
78	PP-23B 125V DC	NS		FW/COND AUX, HTR DRAIN	VARIOUS	NS	TEMPORARY STRAINER ALARMS				

TABLE 420.1-1b (cont'd)

ITEM	INSTR. BUS	BUS CLASS	TABLE 1 BUS FAIL ALARM/INDIC.	SERIES SYSTEM	INSTR. TAG	INSTR. CLASS	DESCRIPTION	OTHER SYSTEMS PERIOD DEVICE	EFFECT ON PLANT SAFETY	REQ'D FOR COLD SHUTDOWN	COMMON SENSE LINE/HDR REMARKS
79	125V DC BUS 2AB	NS/B		GEN. [illegible]	86 UP (CWD 882)	NS/HB	GENERATOR UNDERFREQ. LOCKOUT REL.		Refer to Writeup response 420.01 (Action Item 1b)		
80	125V DC BUS 2AB	NS/NA	IT	" "	86 GP (CWD 883)	NS/NA	GENERATOR PRIMARY LOCKOUT RELAY				
81	125V DC BUS 2AB	NS/HB		" "	86GB CWD 885	NS/HB	GENERATOR BACKUP LOCKOUT RELAY				
82	125V DC BUS 2A	NS/NA	IT-41	AUX. FEED	AXY SWGR-2A2, -2A1, 480V SWGR-2A1	NS/NA	FEEDER PROTECTION & CONTROL				
83	125V DC BUS 2B	NS/HB	IT-42	"	AKV SWGR 2B2, -2B1 & 480V SWGR 2B1	NS/NA	FEEDER PROTECTION & CONTROL				
84	125V DC PP 219 OR 120V AC PP-221	NS/ NS/HB	IT-19	ANNUNCIATORS	ALC-1, 2, 3	NS	STATION ALARMS				

Response 420.1 (Action Item 1b)

1b) The buses identified in Table 1b were reviewed and the buses presented in the second half of this response were determined to be the limiting items in their impact on achieving cold shutdown. Safety related instrumentation and controls are designed, as described in the first half of the response so that the impact of losing a bus or safety related instrumentation will not impact the ability to achieve cold shutdown.

Safety related instrumentation and systems conform to the critieria of IEEE-279-1971, "Criteria for Protection Systems for Nuclear Generating Stations". This means that the safety systems and instrumentation are designed for high functional reliability such that no single failure results in loss of the safety function and does not result in loss of the required minimum redundancy unless acceptable operation can be demonstrated. The safety systems are designed to assure that the affects of natural phenomena, normal operating maintenance, testing and postulated accident conditions on redundant channels do not result in loss of the safety function. The safety systems are separated from control systems to the extent that failure of any single control system component, power supply, or channel which is common to the control and safety system leaves intact a system satisfying the reliability redundancy, and independence requirements of a safety system.

The following identifies the non-safety related instrumentation and control systems and corresponding power supplies whose loss could affect the ability to achieve a cold shutdown condition. An evaluation of the effect of the loss of power supply on the ability to achieve a cold shutdown condition is also provided:

Power Panel 220 (120VAC)
Systems affected are: pressurizer pressure control system (PPCS)
reactor regulating system (RRS)
boron control system (BCS)
steam bypass control system (SBCS)
pressurizer level control system (PLCS)

Evaluation for achieving cold shutdown:
Due to the loss of power the RRS cannot move the CEAs, unless the operator switches the selector to the other channel which is still powered. Manual control of the rods is also available. Once the reactor is tripped the RRS will not impact achievement of cold shutdown. One channel of the PLCS will lose power, however the operator can switch to the other channel for level control. The charging pumps do not lose power (manual control available) and letdown is isolated (control valves close) should the operator not switch channels. The operator can conduct a plant cooldown and achieve the shutdown boron concentration in the RCS without letdown by balancing charging flow with volume shrinkage of the reactor coolant. The PPCS will also lose power but can be re-energized by switching the channel. Should the operator not switch channels, the pressurizer heaters can be manually operated and auxiliary sprays can be operated in place of the pressurizer sprays. Those systems can be used to achieve a cold shutdown condition. The impact to the BCS and SBCS will not impact

achievement of cold shutdown. Reactor makeup water flow control will not be available, but boric acid flow control is available for achieving a cold shutdown boron concentration. Additionally, emergency boration can be implemented. Manual operation of the SBCS is available, or the operator could choose to use the atmospheric dump valves to relieve secondary system pressure to shutdown cooling conditions.

Power Panel 221 (120VAC)
Systems affected are the same as those of power panel 220 (120VAC)

Evaluation for achieving cold shutdown:
The evaluation for power panel 220 (120VAC) applies with the following exceptions:

> The boric acid flow controller and volume control tank level (VCT) indication will not be available therefore the operator, by procedure, will emergency borate by going directly to the charging pumps with the boric acid flow to achieve the cold shutdown boron concentration.

480V MCC 2A6 (non-essential portion)

Systems affected are the same as those of power pannel 220 (120VAC).

Evaluation for achieving cold shutdown:

The evaluation for power panel 220 (120VAC) applies.

480V MCC 2B6 (non-essential portion)
Systems affected are the same as those of power panel 221 (120VAC).

Evaluation for achieving cold shutdown:

The evaluation for power panel 221 (120VAC) applies.

Vital Panel 2A (120VAC)

The systems affected are: feedwater regulating system (FWRS)
steam bypass control system (SBCS)
turbine generator control system (TGCS)

Evaluationfor achieving cold shutdown:

Due to the loss of power, control power to one-half of the FWRS will be lost (one feedwater regulating valve and one bypass valve), the SBCS will not

operate, but the turbine will runback in response to the reduced feedwater flow. A backup mechanism on vital panel 2B (120VAC) controls the runback. Should it not runback a reactor trip on low steam generator pressure would result. Manual operation of the main or auxiliary feedwater and turbine bypass or atmospheric dump valves is available to control RCS heat removal during cooldown to cold shutdown conditions.

Vital Panel 2B (120VAC)

The systems affected are the same as those of vital panel 2A (120VAC).

Evaluation for achieving cold shutdown:

As in the evaluation of vital panel 2A (120VAC) one half of the FWRS will be disabled (control power lost to one regulating and bypass valve). Control power to the SBCS will be lost and the turbine runback backup mechanism will be without power. Manual operation of the main or auxiliary feedwater and atmospheric dump valves (SBCS control power completely lost) to control RCS heat removal during cooldown to cold shutdown conditions.

Vital Panel 2A and Vital Panel 2B (120VAC)

The systems affected are: feedwater regulating systems (FWRS)
steam bypass control system (SBCS)
turbine generator control system (TGCS)

Evaluation for achieving cold shutdown:

Control power will be lost to the FWRS and SBCS. The TGCS will lose power to the turbine runback mechanism. A reactor trip on low steam generator level will result. Automatic actuation of auxiliary feedwater and opening of the main steam safety valves will relieve secondary system pressure. The atmospheric dump valves and auxiliary feedwater will be used to control RCS heat removal to cold shutdown.

Bus 2AB (125VDC)

The systems affected are: reactor regulating system (RRS)
pressurizer pressure control system (PPCS)
turbine generator control system (TGCS)

Evaluation on achieving cold shutdown:
The RRS would not control the CEAs. They would remain in the position they were in before the power loss and could be controlled through the CEDMCS by the operator or automatically tripped by the RPS if a trip signal occurs to shutdown reactor. The loss of power to the TGCS would not permit tripping of the turbine electronically. However the turbine could trip on a mechanical trip (e.g. overspeed) or could be isolated on a main steam isolation signal to close the main steam isolation valves. RCS pressure control would be maintained by the manual control of charging and letdown auxiliary spray. RCS heat removal to shutdown cooling could be controlled by auxiliary or main feedwater and SBCS or atmospheric dump valves.

Based on the evaluations discussed above no design modifications are required due to the effect of losing power to the buses identified in table 1b.

Response 420.01 (Action Item #2)

FPL will prepare emergency procedures that will be used by control room operators, including procedures required to achieve a cold shutdown condition, upon loss of power to each class 1-E and non-class 1-E bus supplying power to safety and non-safety related instrument and control systems. The emergency procedures will include the diagnostics/alarms/indicators/symptoms resulting from the review and evaluation conducted per IE Bulletin No 79-27 action item No. 1. The emergency procedures will describe the use of alternate indication and/or control circuits which may be powered from other non-class 1-E or class 1-E instrumentation and control busses. These procedures will also describe methods for restoring power to the bus. The emergency procedures that are developed for actions required during situations involving plant fires will also incorporate the above guidelines. These procedures will be ~~submitted to the NRC~~ available prior to startup.

Response 420.01 (Action Item 3)

The non-safety Vital A-C Power Supplies are fed from two Static Uninterruptible power supplies (SUPS). These are used to power non-safety instrumentation and control circuits, communication, security, fire detection and radiation monitoring systems. They are both rated 120V ± two percent ac, 60HZ, single phase, 20 KVA and 30 KVA.

125V dc

The 20 KVA SUPS is powered from MCC 2AB for the main feed & MCC 2AB for the by pass source. The dc is supplied from bus 2AB. The 30 KVA SUPS is powered from MCC 2AB for the main feed and MCC 2C for the bypass supply. The dc is supplied from bus 2C. The bypasses for these SUPS are provided through a step-down/regulating transformer.

The SUPS are so designed to provide power to its loads normally from the main feed through the rectifier/inverter. Failure of this main AC power feed will cause the SUPS to be powered from the battery.

The safety related instruments for the Reactor Protective System and the Engineered Safety Features Actuation System is powered from four safety related inverters. The inverters are powered directly from the DC bus. Inverters 2A & 2C are powered from battery 2A and Inverters 2B & 2D are powered from battery 2B. Each inverter is provided with a maintenance bypass transformer. This must be manually switched usually during maintenance.

Circuitry is provided in the non-safety SUPS to shutdown and the inverter portion and transfer to the alternate source, on one of the following conditions 1) Low inverter voltage output, 2) High inverter voltage output, 3) Inverter output off frequency. The inverter will also transfer to the alternate source on an over current condition. Two timing relays are provided in this protective circuitry to prevent tripping the unit on spurious transients of the kind listed above. One timing relay delays the tripping of the unit and is set at approximately a 60 second delay. The other controls the transferring of the unit to the bypass source and is set at 10 seconds. If one of the above trouble conditions is sensed the timing relays start to time out and at 10 seconds the unit will transfer to the alternate source. The other relay continues running for 60 seconds and then will shut the inverter down. This scheme is employed to allow transferring to the alternate source before the unit shutsdown. All these malfunctions are alarmed.

(105 to 140 dc)

The safety related inverters are fed directly from the DC Bus. The inverters will automatically shutdown on the following conditions 1) Low DC voltage input 2) High DC input voltage, Low AC voltage inverter output. The inverter is designed to operate within the DC system voltage swing. A timing relay is provided to prevent shutdown of the inverter on spurious transients of the dind listed above. This timing relay is set at 10 seconds. There is no automatic transfer to a bypass source on the safety inverters.

The AC SUPS input is fed through a regulated rectifier. This allows the AC input voltage to vary and not affect the DC output. The regulator will allow the input AC voltage to vary -15% + 10% and not effect SUPS operation.

The same type units are employed on Unit 1 with succcessful operation.

PRELIMINARY
INFO ONLY

JUL 1

Question No.

420.2 Engineered Safety Features (ESF) Reset Controls (IE Bulletin 80-06)

If safety equipment does not remain in its emergency mode upon reset of an engineered safeguards actuation signal, system modification, design change or other corrective action should be planned to assure that protective action of the affected equipment is not compromised once the associated actuation signal is reset. This issue was addressed in IE Bulletin 80-06.

For facilities with a construction permit including OL applicants, Bulletin 80-06 was issued for information only. The NRC staff has determined that all CP holders, as a part of the OL review process are to be requested to address this issue. Accordingly, you are requested to take actions called for in Bulletin 80-06 Actions 1 through 4 under "Actions to be Taken by Licensees" (a copy of 80-06 is provided in the attachment to this enclosure). By July 6, 1981, complete the review verifications and descriptions of corrective actions taken or planned as stated in Action 1 through 3 and submit the report called for in Action Item 4. The report should be submitted to the NRC Office of Nuclear Reactor Regulation as a licensing submittal in the form of an FSAR amendment.

Response

We have reviewed the drawings (i.e., CWD's) as required in the Bulletin 80-06 and have identified the following systems that return to their normal position after an ESFAS reset.

a. SI Tank Check Valve Leakoff Valves HCV-3618, HCV-3628, HCV-3638 and HCV-3648 (CWD's 280, 281, 282, and 283)
b. D.G. Lockout Relay trip block by ESFAS (CWD's 956 and 966)
c. VCT Discharge Valve V-2501 (CWD 161)
d. Start inhibit RCP Oil Lift Pumps (CWD's 103, 107, 111, 115)

Control Wiring Diagrams (CWD's) are provided in FSAR Section 1.7.

CORRECTIVE ACTIONS & RESOLUTIONS

1. The control circuits for the items a, c and d currently are undergoing modification for the conformance with the Bulletin 80-06. Completion of this modification is anticipated August 31, 1981.

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2. Item b - During an emergency mode of operations all Diesel Generators (DG) trips, except differential current and overspeed, are bypassed by an ESFAS. ESFAS reset will restore the DG trip circuits provided the emergency bus tie breakers are closed manually upon restoration of offsite power. Since the ESFAS reset restores all DG trips only if the emergency bus tie breakers are closed (offsite power available), no changes are planned for these circuits.

3. All circuitry for reset will be tested and verified per IE Bulletin 80-06 Item 2 prior to power operation during plant start-up.

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420.3 Qualification of Control Systems (IE Information Notice 79-22)

Operating reactor licensees were informed by IE Information Notice 79-22, issued September 19, 1979, that certain non-safety grade or control equipment, if subjected to the adverse environment of a high energy line break, could impact the safety analyses and the adequacy of the protection functions performed by the safety grade equipment. In the attachment to this Enclosure there is a copy of IE Information Notice 79-22, and reprinted copies of an August 30, 1979 Westinghouse letter and a September 10, 1979 Public Service Electric and Gas Company letter which addresses this matter. Operating Reactor licensees conducted reviews to determine whether such problems could exist at operating facilities.

We are concerned that a similar potential may exist at light water facilities now under construction. You are, therefore, requested to perform a review to determine what, if any, design changes or operator actions would be necessary to assure that high energy line breaks will not cause control system failures to complicate the event beyond your FSAR analysis. Provide the results of your reviews including all identified problems and the manner in which you have resolved them to NRR, by July 6, 1981.

The specific "scenarios" discussed in the above referenced Westinghouse letter are to be considered as examples of the kinds of interactions which might occur. Your review should include those scenarios, where applicable, but should not necessarily be limited to them. Applicants with other LWR designs should consider analogous interactions as relevant to their designs.

Response:

A review of potential control system interactions during high energy pipe breaks has been conducted for St. Lucie Unit 2. The review is based on the Combustion Engineering (C-E) generic review effort. The review considered both the specific systems listed in IE Information Notice 79-22 and other non-safety systems which could possibly interact with safety grade systems.

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St. Lucie Unit 2
(Instrumentation and Control Systems Branch Questions)

Despite the low probability of a high energy line break a generic review has been performed of thirteen control systems involving four accidents scenarios which encompass the spectrum of postulated high energy line breaks. A matrix was established of the high energy line breaks and control functions (Attachment 1). In the time available, the matrix was reduced to include only those systems and events which require further evaluation. A general description of the procedure used to reduce this matrix is listed below:

I. An initial review of each postulated Control Function failure for each pipe break was completed and served as the basis for consideration. Where a postulated failure could potentially increase the severity of a high energy pipe break, the following criteria were employed to resolve the concern:

1. Is the postulated Control Function failure mode credible?

2. Is the Control Function Equipment (Sensor, Cable, etc.) qualified to operate properly in the postulated environment?

3. Where the postulated Control Function failure is credible, could its impact potentially affect the conclusions presented in the SAR? Considerations such as Maximum Control Function capabilities, and delayed, but proper operator action were employed in this effort.

In several cases, most notibly the PORV failure in the open position, no specific failure mechanism has been identified. The only manner for such a failure to occur would be for power to be inadvertently applied to the valve solenoid and not be removed. Partof the short term recommendations is to evaluate whether or not a failure mechanism of this type is credible.

The potential adverse impact of high energy pipe breaks on reactor coolant pumps was considered. Both the seized shaft and the simultanteous three or four pump loss of flow were eliminated from consideration based on judgement that these failures are not considered credible within the time frame limited by operator action (30 minutes) due to environmental impact alone. The impact of other potential loss of flow events (e.g., one or two pump loss of flow) during high energy pipe breaks was reviewed and it was judged that the resulting rapid reactor trip was sufficient to ensure that the conclusions of the SAR would not change.

JUL 2 4 1981

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St. Lucie Unit 2
(Instrumentation and Control Systems Branch Questions)

Attachment 2 details specific event/interactions scenarios and defines specific short term recommendations which have been established, on a generic basis, to minimize the probability and impact of the postulated events. This attachment also discusses potential long term alternatives which have been identified on a generic basis.

The results of a review of the C-E generic evaluation applied to the St. Lucie Unit 2 design are also provided in Attachment 2. These results are discussed after the generic short and long term recommendations for each postulated event addressed. Based on these results the items shown on the generic matrix (Attachment 1) have been eliminated. Therefore no design changes are necessary to assure that high energy line breaks do not cause control system failures to complicate events beyond the FSAR analysis for St. Lucie Unit 2.

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CONTROL FUNCTIONS AND EVENTS

Control Functions Considered

Pressurizer Level
Pressurizer Pressure
Power Operated Relief Valves & Block Valves; Relief and Closure
Reactor Coolant Flow (RCPs)
Rod Position (RRS, CEDMCS)
Boron Concentration (Boron Control System)
Feedwater Flow (FWRS)
Steam Flow to Turbine (TGCS)
Steam By-Pass to Condenser (SBCS)
Steam Dumps to Atmosphere Upstream of MSIVs
Steam Dumps to Atmosphere Downstream of MSIVs
Steam Generator Blowdown (SGBS)
Safety Injection Tank Depressurization/Isolation

The listed functions were evaluated in conjunction with the following events:

Small Steamline Rupture Inside Containment
Small Steamline Rupture Outside Containment
Large Steamline Rupture Inside Containment
Large Steamline Rupture Outside Containment
Small Feedline Rupture Inside Containment
Small Feedline Rupture Outside Containment
Large Feedline Rupture Inside Containment
Large Feedline Rupture Outside Containment
Small LOCA Inside Containment
Small LOCA Outside Containment
Large LOCA
Rod Ejection

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JUL 24 1981

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Washington, D.C. 20008

EXPERIENCE

Communications

- Creating and producing public affairs programming in discussion and audience participation formats.
- Initiating and implementing programming ideas in the areas of public affairs, the arts, and community involvement.
- Producing an Emmy award-winning public affairs special program.
- Securing and interviewing participants for on-air discussions.
- Creating film and still montage openings and wrap-arounds for programs.

Public Relations

- Developing contact and maintaining liaison with print and broadcasting media concerning station and programming publicity.
- Ascertaining programming needs and funding allocations of member stations.
- Initiating and implementing ideas for publicity campaigns.
- Researching and securing promotional materials.
- Coordinating and writing press releases and newsletters.
- Responding to inquiries received by telephone and by mail.

Administrative/Management

- Directing production office staff of three assistants and four student interns and volunteers.
- Analyzing office procedures and communication materials during reorganization.
- Creating new methods and restructuring existing procedures to facilitate communication during reorganization.
- Evaluating and updating previous corporation literature to facilitate communication with membership.
- Supervising the acquisition and preparation of films for broadcast.

EMPLOYMENT

Public Broadcasting Service, National Public Radio, and other production companies	Consultant in Programming, Public Relations May 1977 - October 1979
National Public Radio Washington, D.C.	Assistant to the Vice President for Corporate Relations October 1976 - May 1977
Public Broadcasting Service Washington, D.C.	Consultant in Programming, Public Relations January 1976 - October 1976
WTTG, Metromedia Washington, D.C.	Producer of Panorama and other production staff positions February 1973 - October 1975
	Promotion Assistant January 1971 - February 1973

EDUCATION - B.A., Catholic University of America, Washington, D.C.

ATTACHMENT 1

MATRIX OF EVENTS/CONTROL FUNCTIONS

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JUL 24 1981

Pipe Break / Control Function	SLB	FWLB	CEA Ejection	SBLOCA	LBLOCA
Pressurizer Level		X			
Pressurizer Pressure					
Pilot Operated Relief Valves	X	X			
CEA Position	X	X	X	X	
Feedwater Flow	X	X			
Boron Concentration					
Turbine Control	X				
Steam Bypass	X				
Steam Dump Upstream of MSIV	X	X			
Steam Dump Downstream of MSIV	X				
Steam Gen. Blowdown					
Safety Injection Tank Isolation				X	
Reactor Coolant Flow					

ATTACHMENT 2

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DESCRIPTIONS OF REMAINING EVENTS AND CONTROL FUNCTIONS

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I. Assessment of Control System Failures on Steam Line Break Event

A. Sequence of Events for Generic SAR Steam Line Break at Full Power, Inside or Outside Containment

1. Double-ended steam line break occurs
2. Reactor trip on low steam generator pressure
3. MSIS initiates to isolate the steam generators
4. RCS temperature decreases due to excessive steam removal
5. Total reactivity increases due to moderator cooldown effect
6. MSIVs close
7. Pressurizer empties
8. Low pressurizer pressure initiates SIAS
9. MFIVs close
10. Safety injection boron reaches core
11. Affected steam generator empties, terminating cooldown effect, the transient reactivity reaches peak and decreases gradually due to boron injection
12. Limited or no post-trip return-to-power
13. No fuel in DNB

B. Steam Line Break With PORV Control System Failure

1. Significant Interaction Effects:
   a. Increased Containment Pressure
   b. A stuck open PORV in combination with a steam line break has not been analyzed.

2. Assumptions
   a. Steam line break (large break inside containment for Item 1.A above, any size or location for Item 1.B above).
   b. Inadvertently PORVs open and remain open
   c. PORV Block valve also fails to close when required
   d. Initial condition: full power

3. It must be emphasized that no mechanism has been identified for the PORV to inadvertently open and remain open since its signal to open comes from safety grade equipment and the Garrett valves and solenoids are qualified for an environment in excess of 400°F.

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4. Sequence of Events

   a. Large steam line break occurs inside containment.

   b. Reactor trip occurs on steam generator low pressure within 5 seconds.

   c. Should the adverse environment cause the PORV to inadvertently open and then remain open, the following steps may also occur. It should be noted that no meachnism has been identified which would cause this to occur.

   d. Steam from PORV fills quench tank and bursts rupture disk releasing steam to the containment and cuasing additional containment pressurization.

   e. Mass removal via PORV causes additional void formation within the reactor coolant system.

5. Actions

   a. Short term:

      1. Utilities continue to investigate qualification levels and location of power cables to PORVs and PORV block valves to assess credibility of this failure mode.

      2. Ensure operators take action to shut PORV and PORV block valve if PORV fails open.

   b. Long term:

      1. Complete assessment of PORVs and block valves. Dependent on the results of that assessment

         a. upgrade environmental qualification level of PORVs and block valves; or

         b. perform detailed analysis of event if required.

6. Evaluation for St. Lucie Unit 2

   C-E has not identified a failure mechanism relative to this concern. Furthermore, this system provides input to the Reactor Protective System and, as such, is safety-grade and post-LOCA qualified. We do not believe this item is applicable to St. Lucie Unit 2.

C. <u>Steam Line Break With Feedwater Flow Control System Failure</u>

1. Significant Interaction Effects

   a. Steam generator filling - causing potential piping structural problems

2. Assumptions

   a. Small steam line break inside containment that does not cause an immediate reactor trip

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4. Sequence of Events

   a. Large steam line break occurs inside containment.

   b. Reactor trip occurs on steam generator low pressure within 5 seconds.

   c. Should the adverse environment cause the PORV to inadvertently open and then remain open, the following steps may also occur. It should be noted that no meachnism has been identified which would cause this to occur.

   d. Steam from PORV fills quench tank and bursts rupture disk releasing steam to the containment and cuasing additional containment pressurization.

   e. Mass removal via PORV causes additional void formation within the reactor coolant system.

5. Actions

   a. Short term:

      1. Utilities continue to investigate qualification levels and location of power cables to PORVs and PORV block valves to assess credibility of this failure mode.

      2. Ensure operators take action to shut PORV and PORV block valve if PORV fails open.

   b. Long term:

      1. Complete assessment of PORVs and block valves. Dependent on the results of that assessment

         a. upgrade environmental qualification level of PORVs and block valves; or

         b. perform detailed analysis of event if required.

6. Evaluation for St. Lucie Unit 2

C-E has not identified a failure mechanism relative to this concern. Furthermore, this system provides input to the Reactor Protective System and, as such, is safety-grade and post-LOCA qualified. We do not believe this item is applicable to St. Lucie Unit 2.

C. Steam Line Break With Feedwater Flow Control System Failure

1. Significant Interaction Effects

   a. Steam generator filling -, causing potential piping structural problems

2. Assumptions

   a. Small steam line break inside containment that does not cause an immediate reactor trip

b. Feedwater flow exceeds steam flow due to failure of steam generator level instrument, indicating flow

c. SAR conservatism

i. no operator action within 30 minutes

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3. Sequence of Events

a. Small steam line break occurs which does not cause an immediate reactor trip

b. Steam generator level instrument fails, causing an increase of feedwater flow in excess of steam flow

c. Steam generator begins to fill causing increased moisture content of steam

d. If no operator action occurs undefined piping structural problems could result

e. It should be emphasized that this event can be prevented by prompt operator action. Safety grade steam generator level instrumentation exists, enabling comparison with control grade level instruments of the feed system.

4. Action

a. Short term

i. Ensure the operator is aware of this potential interaction so that he may take promptcorrective action shoud it occur

b. Long term

i. Assess the need of upgrading steam generator level indication to the feedwater control system

ii. Assess the need to install a safety grade high steam generator level alarm

5. Evaluation for St. Lucie Unit 2

The concern in this area assumes a failure in a steam generator level instrumentcausing the FWRS to supply feedwater in excess of steam demand, thereby filling the affected steam generator potentially leading to excessive moisture carryover. The St. Lucie Unit 2 design incorporates a design feature that automatically closes the feedwater regulating valves at the high steam generator level and trips the turbine and main feedwater pumps at the high-high level. The instrumentation transmitting the signal is a four channel system with portions qualified to withstand the adverse environment. Those portions not qualified will not be exposed to the adverse environment. We therefore conclude that this concern is not applicable to St. Lucie Unit 2.

D. Steam Line Break With Failure of Main Steam Paths Downstream of MSIV's

1. Significant Interaction Effects

   a. Increase post-trip return-to-power

2. Assumptions

   a. Large steam line break inside containment

   b. MSIV on unaffected steam generator fails to close. This sequence of events is pertinent only if this assumption is made.

   c. Downstream of MSIV's main steam paths fail open

   d. Initial condition: full power

   e. SAR conservatisms

      i. end of cycle core

      ii. the most reactive CEA stuck out

      iii. steam blowdown through steam line break

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3. The number of failures which must occur during this event are significant. First there must be the large break. Then the MSIV on the opposite steam generator must fail to close. There is a stuck rod on reactor trip. Then steam paths downstream of the MSIV's must be affected. These include turbine control valves and steam dump and bypass valves. The probability of this event occurring is much less than 10^{-6} per reactor year.

4. Sequence of Events

   a. Large steam line break inside containment

   b. Reactor trip on low steam generator pressure trip signal

   c. MSIV on unaffected steam generator fails to close on MSIS

   d. Main steam paths downstream of MSIV open or fail to close due to control system malfunction caused by adverse environemnt following large steam line break.

   e. Open main steam paths increase the steam blowdown and increase moderator cooldown effect which adds positive reactivity to core. A post-trip return-to-power is more severe under these conditions.

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5. Actions

   a. Short term

      i. should a steam line break occur, ensure operator takes action to isolate all alternate steam flow paths

      ii. determine whether this event warrants further consideration, in light of low probability of all consequential failures which must occur for the event to be significant

   b. Long term

      i. utilities investigate environmental qualification level of the systems involved

      ii. upgrade qualification level of affected equipment if this is determined to be necessary

6. Evaluation for St. Lucie Unit 2

The systems which must fail in order to open the main steam path downstream of the MSIV are the turbine generator control system (TGCS) and steam bypass control system (SBCS). Review of the St. Lucie Unit 2 design shows that the TGCS and SBCS would not be exposed to the adverse environment. However, the T_{ave} input to the SBCS generated by the RRS could be exposed to the accident environment. The T_{ave} input though, is used only to block initiation of a quick opening signal and cannot cause the SBCS valves to open. A quick opening signal would not be generated due to the low steam flow and pressure inputs to the SBCS so the valves would remain closed. We therefore conclude that this is not applicable to St. Lucie Unit 2.

E. Steam Line Break with Atmospheric Dump Valve Control System Failure

1. Significant Interaction

   a. Post-accident controlled cooldown

2. Assumptions

   a. Steam line break outside containment and upstream of MSIV

   b. Atmospheric dump valves on opposite steam line open and remain open*

   c. SAR conservatism

      i. no operator action within 30 minutes

3. Sequence of Events

   a. A steam line break outside of containment but upstream of the MSIV occurs

*The failure mechanism identified is a failure of the input signals that would cause the valve to open if operating in the automatic mode. Although no operator action is assumed for 30 minutes prompt operator action to shut the open valve would mitigate any effects of this event.

b. Reactor trip on low steam generator pressure

c. Atmospheric dump valves upstream of MSIV's open and remain open due to control system failure

d. If no operator action takes place there would be the potential for dry-out and depressurization of both steam generators

e. Failure to shut atmospheric dump valves could inhibit a controlled plant cooldown by limiting the ability of the auxiliary feed pumps to deliver to the steam generator(s)

4. Actions

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a. Short term

i. operate atmospheric dump valves in manual mode, or

ii. ensure operator shuts atmospheric dump valves on steam line until control is assured

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b. Long term

i. Continue investigation to determine if this failure mechanism is plausible

ii. upgrade atmospheric dump valve control system to withstand the adverse environment, if required

5. Evaluation for St. Lucie Unit 2

The atmospheric dump valves are located upstream of the main steam isolation valves at St. Lucie Unit 2, and the postulated failure in this area would be a valid concern were the system to be in the automatic mode during power operations. However, consistent with the anlayses in the FSAR, this system is maintained in the manual mode during normal operations. We believe this method of operation adequately addresses any concern in this area.

II. <u>Assessment of Impact of Control System Failures on Feed Line Break Event and CEA Ejection</u>

A. SAR Feed Line Break

1. Sequence of Events

a. Main feed line break occurs downstream of reverse flow check valve, discharging main feed and steam generator fluid

b. RCS heatup due to loss of subcooled feed flow

c. Reactor trip occurs on steam generator low water level or high pressurizer pressure. Turbine trip occurs on reactor trip.

d. Rapid RCS heatup and pressurization due to loss of heat transfer as the ruptured steam generator empties

e. Depressurization of the ruptured steam generator initiates MSIS and isolates the intact generator

f. RCS pressurization terminates with opening of primary relief/ safety valves and decreasing core heat flux

g. RCS cooldown begins, controlled by the main steam safety valves

h. Auxiliary feed is initiated automatically or by operator action

B. <u>Feed Line Break With RCS Inventory Control Failure</u>

1. Significant Interaction Effect

a. Increased RCS pressurization due to liquid filled pressurizer

2. Assumptions

a. Small feed line break inside containment

b. Adverse environment impacts pressurizer level instrument causing indication to fail low which causes the control system to increase inventory (and pressurizer level)

c. Initial conditions

i. 102% power

ii. steam bypass control system in manual mode

iii. beginning-of-cycle core parameters

d. Analysis conservatisms

i. no operator action for at least 30 minutes

ii. no credit for steam generator low water level trip in ruptured unit until empty

iii. heat transfer in ruptured steam generator instantaneously terminated on emptying

iv. failure of the feed line reverse flow check valve, if the break occurs upstream of the valve

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3. Sequence of Events

   a. Feed line break in containment

   b. Main feed spills from break

   c. Adverse containment environment causes pressurizer level indication to fail low causing RCS inventory to increase

   d. Reactor trip occurs on steam generator low water level on high pressurizer pressure. Turbine trips on reactor trip

   e. RCS heatup results from rapid decrease in SG heat transfer due to loss of fluid from the ruptured steam generator

   f. Pressurizer relief and/or safety valves open

   g. Potential for pressurizer to fill with liquid exists due to high level in pressurizer prior to heatup. Relief/safety valve relief capacity reduced by liquid discharge

   h. Extent of increased RCS pressurization is dependent on time of pressurizer filling relative to the rapid heatup

4. Actions

   a. Short term

      i. alert operator to this potential failure mode, so that prompt corrective action can be taken

   b. Long term

      i. Perform plant specific analyses to determine upper limit allowable for pressurizer level which is consistent with the maximum rate of level increase and the maximum RCS expansion during the potentially rapid heatup associated with feed line breaks

      ii. upgrade pressurizer level instrumentation

5. Evaluation for St. Lucie Unit 2

The C-E concern postulates the failure of a pressurizer level instrument in the control system, which, in the absence of operator action, causes the pressurizer to fill, thereby allowing the reactor coolant system to go solid. As discussed in our response to IE Bulletin 79-01, the level instruments are post-LOCA qualified. We therefore do not believe there is a concern in this area.

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C. Feed Line Break With PORV Control Failure

1. Significant Interaction Effects

   a. A failed open PORV in combination with a feed line break has not been analyzed

2. Assumptions

   a. Feed line break inside containment

   b. PORV's inadvertently open and remain open

   c. PORV block valve also fails to close when required

   d. No operator action until 20 minutes

3. PORV would not be expected to remain open due to actuation malfunction since Garrett valves and solenoids are qualified for temperatures in excess of 400°F

4. Sequence of Events

   a. Feed line break occurs inside containment

   b. Steam generator fluid and/or main feed spill from break

   c. RCS heatup and pressurization results from loss of feed flow

   d. PORV opens on high pressure and fails to reclose due to adverse environment

   e. Reactor trip occurs on high pressurizer pressure. Turbine trips on reactor trip

   f. RCS depressurization occurs if PORV's fail to reclose

   g. Mass removal via PORV causes void formation within RCS

   h. Feed line break in combination with a failed open PORV has not been analyzed

5. Actions

   a. Short term

      i. utilities investigate qualification level and location of power cables to PORV's and PORV block valves to assess credibility of this failure mode

      ii. ensure operators take actions to shut PORV's and PORV block valves, should this failure occur

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b. Long term

i. Complete assessment of PORV's and block valves. Dependent on results of that assessment

A. upgrade environmental qualification level of PORV's and block valves, or

B. perform detailed analysis of event, if required

6. Evaluation for St. Lucie Unit 2

C-E has not identified a failure mechanism relative to this concern. Furthermore, this system provides input to the Reactor Protective System and, as such, is safety-grade and post-LOCA qualified. We do not believe this item is applicable to St. Lucie Unit 2.

D. Feed Line Break With Feedwater Control Failure

1. Significant Interaction Effects

a. Overfilling of the steam generator(s) causing potential structural problems

2. Assumptions

a. Small feed line break inside containment

b. Feed control in automatic mode

c. Adverse environment causes steam generator level indication to fail low which causes the feed control system to increase feed flow above the steam flow

d. No operator action for 30 minutes

3. Sequence of Events

a. A small feed line break occurs inside containment

b. Main feed spills from break

c. Steam generator level instrument fails indicating low and causes increased feed flow in excess of steam flow

d. Steam generator begins to fill causing increased moisture content of steam

e. If no operator action occurs undefined structural problems could result

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f. It should be emphasized that this event can be prevented by prompt operator action. Safety grade level instrumentation exists to compare to control grade instruments. The feed system can then be controlled manually

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4. Actions

a. Short term

i. ensure the operator is aware of the potential failure mode so the he may take prompt corrective action, should it occur

ii. assess the need to install safety grade high steam generator level alarm

5. Evaluation for St. Lucie Unit 2

The concern in this area assumes a failure in a steam generator level instrument causing the FWRS to supply feedwater in excess of steam demand, thereby filling the affected steam generator potentially leading to excessive moisture carryover. The St. Lucie Unit 2 design incorporates a safety grade design feature that automatically closes the feedwater regulating valves at the high steam generator level and trips the turbine and main feedwater pumps at the high-high level. The instrumentation transmitting the signal is a four channel system with portions qualified to withstand the adverse evnironment. Those portions not qualified will not be exposed to the adverse environment. We therefore conclude that this concern is not applicable to St. Lucie Unit 2.

E. Feed line Break With Atmospheric Steam Dump Control Failure

1. Significant Interaction Effects

a. Controlled plant cooldown

2. Assumptions

a. Feed line break outside containment and downstream of reverse flow check valve

b. Adverse environment impacts the atmospheric steam dump control on unaffected steam generator causing an uncontrolled steam release upstream of the MSIV's

c. No operator action until 30 minutes*

*The failure mechanism identified is a failure of the input signals that would cause the valve to open if operating in the automatic mode. Although no operator action is assumed for 30 minutes, prompt operator action to shut the open valve would mitigate any effects of this event.

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3. Sequence of Events

   a. Feed line break occurs outside containment downstream of check valve.

   b. Steam generator fluid and/or main feed spill from break

   c. Reactor trip occurs on steam generator low water level or high pressurizer pressure. Turbine trip occurs on reactor trip

   d. Steam generator pressure increases following turbine trip

   e. Environment could cause atmospheric dump valves upstream of MSIV in unaffected steam generator to open and remain open

   f. If no operator action takes place there would be a potential for dry out and depressruization of both steam generators

   g. Depressurization of both steam generators may limit the ability of the auxilairy feed pumps to deliver to the steam generator(s)

4. Actions

   a. Short term

      i. operate atmospheric steam dump valves in the manual mode, or

      ii. ensure that the operator is aware of this potential interaction so that prompt corrective action can be taken

   b. Long term

      i. continue investigation to determine if this failure mechanism is plausible

      ii. upgrade atmospheric dump valve control system environmental qualification if required

5. Evaluation for St. Lucie Unit 2

The atmospheric dump valves are located upstream of the main steam isolation valves at St. Lucie Unit 2, and the postulated failure in this area would be a valid concern were the system to be in the automatic mode during power operations. However, consistent with the analyses in the FSAR, this system is maintained in the manual mode during normal operations. We believe this method of operation adequately addresses any concern in this area.

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III. <u>Potential Effect of Reactor Regulating System During High Energy Pipes Break Events</u>

A. CEA position malfunctions due to steam and feedline breaks and CEA ejection

1. Significant interaction effect:

   a. Potentially higher reactor power levels prior to reactor trip than presently analyzed

2. Assumptions

   a. Small high energy pipe break inside containment

   b. Reactor regulating system in automatic mode

   c. Adverse environment results in a low indicated power level from the ex-core sensor input to the Reactor Regulating System causing CEAs to be withdrawn

3. Sequence of events

   a. High energy pipe break inside containment of a small enough size where immediate reactor trip does not occur

   b. Control grade ex-core sensor indication fails low due to adverse environmental impact

   c. Reactor regulating system causes CEAs to be withdrawn

   d. Reactor power exceeds the power previously assumed during the transient

   e. Reactor trip occurs due to high energy pipe break at conditions not considered in present analyses

4. Actions

   a. Short term

      i. place the control element drive system in manual

      ii. Modify emergency procedures to state that the operator should not take any control action based upon reactor power as measured by the control grade ex-core detectors during high energy pipe breaks

   b. Long term

      i. evaluate the consequences of small high energy pipe breaks in containment with CEA withdrawl, if required

      ii. if required, upgrade the environmental qualification level of the control grade excore detector system

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5. Evaluation for St. Lucie Unit 2

The C-E concern regarding control rod withdrawal with the Reactor Regulating System (RRS) in automatic control is considered valid. However, consistent with the analyses in the FSAR, this system is maintained in the manual mode during normal operations. We believe this method of operation adequately addresses any concern in this area.

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B. Small Break LOCA With CEA Control System Malfunction

1. Significant interaction effects

   a. Potential exists for increasing power. This would cause pressure to remain above low pressurizer pressure trip for a longer period than previously assumed

2. Assumptions

   a. Small break LOCA inside containment

   b. CEA control system in automatic mode

   c. Adverse environment impacts CEA control system or related sensors resulting in consequential failure

   d. Control system causes CEA to withdraw

   e. Standard LOCA licensing assumptions

3. Sequence of events

   a. Small break LOCA occurs inside containment

   b. CEA control system in automatic mode

   c. Adverse environment caused by rupture potentially causes excore power indication to indicate low power level

   d. Should CEAs begin to withdraw, the magnitude of the overpower excursion prior to scram would be increased. This could produce a higher primary system pressure which could then delay reactor trip and SIAS and result in higher peak clad temperature

4. Action

   a. Short term

      i. Place the control element drive system in manual

      ii. Modify emergency procedures to state that the operator should not take any control action based upon reactor power as measured by the control grade excore detectors during a LOCA.

   b. Long term

      i. Evaluate the consequences of a small break LOCA with CEA withdrawal, and

      ii. if required upgrade the environmental qualification level of the control grade excore instrumentation

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5. Evaluation for St. Lucie Unit 2

The C-E concern regarding control rod withdrawal with the Reactor Regulating System (RRS) in automatic control is considered valid. However, consistent with the analyses in the FSAR, this system is maintained in the manual mode during normal operations. We believe this method of operation adequately addresses any concern in this area.

C. Small Break LOCA with SIT Isolation Malfunction

1. Significant interaction effects

   a. Potential exists for injection of non-condensible gas into the RCS. This could cause problems with natural circulation and heat transfer in the steam generators should the gas collect there.

2. Assumptions

   a. Small break LOCA inside containment

   b. Adverse environment impacts safety injection tank(s) isolation resulting in consequential failure.

   c. Operator cannot isolate the safety injection tank(s)

   d. Standard LOCA licensing assumptions

3. Sequence of events

   a. Small break LOCA occurs inside containment

   b. Adverse environment caused by rupture disables SIT isolation mechanism

   c. Operator is unable to isolate the SIT(s) and non-condensible gas (nitrogen cover gas) enters the RCS.

   d. Possibility exists for degraded natural circulation flow and/or buildup of gases in the steam generators causing heatup of RCS.

4. Action

   a. Short term

      i. Instruct operator that the possibility of gas formation existsif SITs are not isolated.

      ii. Identify drain lines that could be used to drain the SITs and their qualification levels

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b. Long term

i. Evaluate options for providing another means of isolating the SITs and revise the design as necessary.

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5. Evaluation for St. Lucie 2

The valves and instrumentation and control systems are environmentally qualified to withstand the adverse environment. Backup means are also available to depressurize the SITs and thereby prevent non-condensible gases from entering the RCS.

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420.4 Control System Failures

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The analyses reported in Chapter 15 of the FSAR are intended to demonstrate the adequacy of safety systems in mitigating anticipated operational occurrences and accidents. Both Congress and ACRS have raised an issue in this area. Commissioner Ahearne has responded to Congress regarding this issue (refer to attachment to this enclosure) and part of his response referred to control system reviews to be performed in connections with OL licensing.

Based on the conservative assumptions made in defining these Chapter 15 design-basis events and the detailed review of the analyses by the staff, it is likely that they adequately bound the consequences of single control system failures.

To provide assurance that the design basis event analyses adequately bound other more fundamental credible failures you are requested to provide the following information:

(1) Identify those control systems whose failure or malfunction could seriously impact plant safety.

(2) Indicate which, if any, of the control systems identified in (1) receive power from common power sources. The power sources considered should include all power sources whose failure or malfunction could lead to failure or malfunction of more than one control system and should extend to the effects of cascading power losses due to the failure of higher level distribution panels and load centers.

(3) Indicate which, if any, of the control systems identified in (1) receive input signals from common sensors. The sensors considered should include, but should not necessarily be limited to, common hydraulic headers or impulse lines feeding pressure, temperature, level or other signals to two or more control systems.

(4) Provide justification that any simultaneous malfunctions of the control systems unidentified in (2) and (3) resulting from failures or malfunctions of the applicable common power source or sensor are bounded by the analyses in Chapter 15 and would not require action or response beyond the capability of operators or safety systems.

Response:

(1) The control systems whose failures or malfunctions may impact plant safety are shown below:

Feedwater Regulating System

Turbine-Generator Control System

Steam Bypass Control System

ADV Control System

Boron Control System

Reactor Regulating System

Control Element Drive Mechanism Control

Pressurizer Pressure Control System

Pressurizer Level Control System

Reactor Control Pumps.

Power Operated Relief Valves

Steam Generator Blowdown System

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(2)&(4) The control systems identified in (1) that receive power from common power sources are identified below. The effect of losing the power sources and an evaluation of plant response are also provided. The results of this evaluation provide justification that any simultaneous malfunctions of control systems identified herein, resulting from common power supply malfunctions are bounded by the analysis of Chapter 15 and would not require action or response beyond the capability of operators or safety systems.

Impact of Loss of Common Power Sources

Loss of 120V AC from Power Panel 220

This power loss will impact the Pressurizer Level Control System (PLCS), the Pressurizer Pressure Control System (PPCS), tne Reactor Regulating System (RRS), the Boron Control System (BCS), and the Steam Bypass Control System (SBCS). Specifically, the PLCS will lose control power, assuming the selector switch is on that channel (it will be unaffected if on the other channel). The letdown control valve will go to its fail closed position and the charging pumps will remain powered, and available for manual control. The PPCS will lose control power, assuming the selector switch is on that channel. The pressurizer spray valve will go to its fail closed position and the pressurizer heaters will remain powered and available for manual control. Additionally the low-low level automatic cut-off of the pressurizer heaters will lose control power. The RRS will lose power assuming the selector switch is on that channel (it will be unaffected if on the other channel). The control element assemblies will remain in their position prior to the power loss. The BCS will not completely be lost. The reactor makeup water flow controller will lose power with the boric acid flow controller unaffected. The letdown line will be affected with the temperature elements for the regenerative and letdown heat exchangers losing power, however, the letdown line will be isolated by the letdown control valves mentioned previously. The SBCS will not receive a T_{ave} input from the RRS which may cause the turbine bypass valves to remain closed. Secondary pressure relief and RCS heat removal control can be accomplished through the main steam safety valves and atmospheric dump valves.

Evaluation of Plant Response:

The loss of the PLCS, PPCS, RRS, BCS, and SBCS due to loss of 120V AC from power panel 220 will not seriously impact plant safety. The reactor could function for a time without operator action before a reactor trip would result (most likely on high pressurizer pressure). The operator can choose to select the other channel for correct operation of the PLCS, PPCS, and RRS. However, manual control of the charging pumps, pressurizer heaters, auxiliary sprays, and turbine bypass valves is available. The operator will still have control of the boric acid flow to the charging pumps and he can choose to align the refueling water tank to charging if necessary.

<u>Loss of 120V AC from Power Panel 221</u>

This power loss will impact the Pressurizer Level Control System (PLCS), the Pressurizer Pressure Control System (PPCS) and the Reactor Regulating System (RRS), the Boron Control System (BCS), and the Steam Bypass Control System (SBCS). Specifically, the same impact as with the loss of 120V AC from power panel 220 will occur with the following exceptions:

> The reactor makeup water flow control will remain powered, however, the boric acid flow controller will lose power.

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Additionally the temperature element on the letdown heat exchanger controlling the component cooling water control valve will lose power. The volume control tank level inputs to the BCS will lose power. Also the station alarms (annunciators) will transfer to 125V DC power.

Evaluation of Plant Response

There will be no serious impact to plant safety for the event presented above. In the absence of operator action the reactor would eventually trip (on high pressurizer pressure). However, the operator would be alerted to such an event due to incorrect pressurizer pressure level indications in the control room. He may choose to switch the redundant channel for correct operation of the PLCS, PPCS, and RRS. However, manual control of the charging pumps, pressurizer heaters, and auxiliary sprays is available. The operator can also bypass the boric acid flow controller and provide borated water directly to the charging pumps or align the refueling water tank.

<u>Loss of 480V ACC 2A6 (non-essential portion)</u>

The impact of losing this motor control center (MCC) is similar to the loss of 120V AC from power panel 220, since power panel 220 receives power from this MCC.

Evaluation of Plant Response:

The plant response for loss of power panel 220 (120V AC) applies.

<u>Loss of 480V MCC 2B6 (non-essential portion)</u>

The impact of losing this MCC is similar to the loss of 120V AC from power panel 221, since power panel 221 receives its power from this MCC.

Evaluation of Plant Response:

The plant response for loss of power panel 221 (120V AC) applies.

<u>Loss of 120V AC VITAL PANEL 2A</u>

This loss of power will impact the Feedwater Regulating System (FWRS), Steam Bypass Control System (SBCS) and the Turbine Generator Control System (TGCS). Specifically, in the FWRS control power to one regulating valve and bypass valve will be lost. Additionally, main steam flow input to the SBCS from the FWRS is not transmitted from one channel. The turbine runback mechanism will be without power.

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Evaluation of Plant Response:

The feedwater regulating system will still control one regulating and bypass valve. The loss of the turbine runback function is backed up by instrumentation on 120V AC vital Panel 2B which will runback the turbine in response to the decreased feedwater flow. Should the runback not operate properly, a reactor trip may result on low steam generator pressure. Manual operation of the atmospheric dump valves and auxiliary feedwater is available. Should the SBCS operate properly or reactor trip not occur the plant would stabilize at a decreased power condition.

<u>120V AC Vital Panel 2B</u>

This loss of power will impact the Feedwater Regulating System (FWRS), Steam Bypass Control System (SBCS), and the Turbine Generator Control System (TGCS). Specifically, in the FWRS control power to one regulating valve and one bypass valve will be lost. Additionally, control of the SBCS would be lost. The TGCS would remain functional, but would suffer a loss of the backup to the turbine runback function.

Evaluation of Plant Response:

The FWRS will still control one regulating and one bypass valve. The SBCS will be without control power and the turbine would runback in response to decreased feedwater flow. Should it not runback a reactor trip may result on low steam generator pressure. The auxiliary feedwater and atmospheric dump valves are available for RCS heat removal. Should a reactor trip not be generated a new steady state at a decreased power level would occur.

<u>Loss of 120V AC Vital Panels 2A and 2B</u>

This power loss will impact the FWRS, SBCS, and TGCS. Specifically, feedwater and steam bypass control would be lost and the turbine runback mechanism would lose power.

Evaluation of Plant Response:

A reactor trip on low steam generator level will result. Automatic actuation of auxiliary feedwater and opening of the main steam safety valves will relieve secondary system pressure. The atmospheric dump valves and auxiliary feedwater will be used to control RCS heat removal.

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Loss of 125V DC Bus 2AB

This power loss will impact the RRS, the PPCS and the TGCS. Specifically, control of the RRS and PPCS, both channels would be disabled. The turbine trip solenoids and generator under frequency lockout relays would be disabled. The turbine trip solenoids and generator under frequency lockout relays would be without power.

Evaluation of Plant Response:

The CEAs would remain in the position they were in before the power loss and could be controlled through the CEDMCS by the operator. Without the PPCS, pressure control would be maintained by manual control of the charging pumps and letdown and auxiliary spray. Should a reactor trip result, the turbine would not trip electrically but would be tripped automatically on a mechanical overspeed trip. If required the main steam isolation valves would close isolating the turbine and maintaining RCS heat removal functions.

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Impact of Failure in Common Sensors

The control systems identified in (1) that receive input signals from common sensors are identified below. Descriptions of the effect of the malfunctions on the control systems and an evaluation of plant response and backup system availability are also provided. Prudent engineering judgement based on knowledge of system design and transient analysis was used to develop these descriptions. The results of this evaluation provide justification that any simultaneous malfunctions of control systems identified herein, resulting from common sensor malfunctions are bounded by the analyses of Chapter 15 and would not require action or response beyond the capability of operators or safety systems.

Malfunction of Pressurizer Pressure Signal (falls low) to the RRS and PPCS

If malfunction causes a low pressurizer pressure signal to be transmitted, the pressurizer sprays would shutoff and the RRS would adjust the CEAs to accommodate a low pressure input, thereby increasing power.

Evaluation of Plant Response:
The reactor would trip on high pressurizer pressure or high power due to control system actions. The operator could de-energize the heaters manually and control pressure with the charging and letdown systems and auxiliary sprays. Should the reactor not trip, because the appropriate trip setpoints were not reached by the affected parameters (pressure and power), a new steady state would be reached. Operator action could maintain power operation until the sensor could be repaired.

Evaluation of Plant Response:
The increased heat output from the RCS due to raising the regulating CEAs increases the steam flow to the turbine. The SBCS receives a high T_{ave} signal from the RRS. A mismatch between T_{ave} and pressure in the steam header as measured by the SBCS opens the turbine bypass valves. The opening of these valves sends an automatic withdrawal prohibit to the control element drive mechanism control system stopping CEA withdrawal. The operator can manually lower the rods or switch to the other RRS channel to resume a stable condition.

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Malfunction of Main Steam Flow Signal (falls low) to the FWRS and SBCS

If the malfunction causes a low steam flow signal to be transmitted, the FWRS will reduce feedwater flow and the SBCS will not open the turbine bypass valves.

Evaluation of Plant Response:
The mismatch between feedwater flow and turbine demand would produce a reactor trip on low steam generator level. The auxiliary feedwater system and manual control of the SBCS or atmospheric dump valves is available to achieve a stabilized plant condition.

Malfunction of Main Steam Flow Signal (falls high) to the FWRS and SBCS

If the malfunction causes a high steam flow signal to be transmitted, the FWRS will increase feedwater flow and the SBCS may open the turbine bypass valves to relieve steam flow based on the T_{ave} input from the RRS.

Evaluation of Plant Response:
The steam generator level will increase and there may be a steam generator pressure decrease if the turbine bypass valves open. The operator could manually control the FWRS and SBCS based on steam generator level and pressure indications in the control room. Should the operator not take action a high steam generator level signal would close the feedwater regulating valves and trip the turbine. A reactor trip or turbine trip would follow with actuation of auxiliary feedwater on steam generator low level signal. Auxiliary feedwater and manual operation of the SBCS or atmospheric dump valves provide a mechanism for RCS heat removal to stabilize the plant.

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Common Lines/Sensors

13172-310-110 Rev. 10

Common Tap	Ins. P,T,L,F	(P) Process/Safety (S)
3/4-RC-127	PDT-1121 C	S
	PDT-1124 Z	Indication Only
	PDT-1124 Y	Indication Only
1-RC-104	PT-1104	S
	PT-1102 (C)	S
1-RC-105	PT-1103	S
	PT-1108	Indication Only
	PT-1102 (A)	S
	PT-1100 (X)	P
	LT-1105	Indication Only
	LT-1110 X	P&S
1-RC-130	LT-1110 Y	P&S
	PT-1100 Y	P
	PT-1102 (B)	S
	PT-1107	Indication Only
	PT-1105	S
1-RC-107	PT-1106	S
	PT-1102 (D)	S
2998-G-074 Sh. 1 SG2B1		
I-1"-MS1-108	LT-9023 A	S
	LT-9021	P indicates
2998-G-079 Sh. 1 SG2A1		
I-1" MS1-100	LT-9013 A	S
	LT-9011	P
I-1" MS1-101	PT-8013 A	S
	LT-9013 A	S
	LT-9011	P
I-1" MS1-102	PT-8013 B	S
	LT-9013 B	S
I-1" MS1-103	LT-9013 B	S

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Common Tap	Ins. P,T,L,F	(P) Process/Safety (S)
I-1" MS1-104	PT-8013 C	S
	PT-8113	S indication
	LT-9013 C	S
I-1" MS1-104	LT-9013 L	S
I-1" MS1-106	PT-8013 D	S
	LT-9005	P
	LT-9013 D	S
	LT-9113	S indicate
	LT-9012	P
I-1" MS1-116	LT-9012	P
	LT-9013	S
I-1" MS1-107	LT-9005	P
	LT-9013 D	S
I-1" MS1-109	LT-9021	P indicates
	LT-9023 A	S
	PT-8023 A	S
I-1" MS1-110	PT-8023 B	S
	LT-9023 B	S
I-1" MS1-111	LT-9023 B	S
I-1" MS1-112	PT-8023 L	S
	PT-8123	S indication
	LT-9023 C	S
I-1" MS1-113	LT-9023 C	S
I-1" MS1-114	PT-8023 D	S
	LT-9006	P indicates
	LT-9023	S
	LT-9022	P
	LT-9123	P indicates
I-1" MS1-117	LT-9123	P indicates
	LT-9022	P indicates
I-1" MS1-115	LT-9023	S
	LT-9006	P indicates

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Malfunction of Pressurizer Pressure Signal (falls high) to the RRS and PPCS

If the malfunction causes a high pressurizer signal to be transmitted, the pressurizer sprays would come on and the pressurizer heaters would be de-energized. The RRS would adjust the rods in response to the high pressure signal thereby decreasing reactor power.

Evaluation of Plant Response:
The reactor would trip on low pressurizer pressure, and a SIAS may result. The operator could close the spray valves and use the charging and letdown systems and auxiliary spray to control pressure. Should the reactor not trip due to affected parameters not reaching the trip setpoints, a new steady state would be reached. Operator action could maintain power operation until the sensor could be repaired.

Malfunction of Pressurizer Level Signal (falls low) to the PLCS and PPCS

If malfunction causes a low pressurizer level signal to be transmitted, the charging flow would increase and letdown flow would decrease. The pressurizer heaters would be de-energized if a low enough signal was transmitted.

Evaluation of Plant Response:
Increasing pressurizer level would be identified by the operator on level indication and alarm in the control room. Manual control of the charging and letdown systems could prevent the overfilling of the pressurizer and preclude a reactor trip on high pressurizer pressure.

Malfunction of Pressurizer Level Signal (falls high) to the PLCS and PPCS

If malfunction causes a high pressurizer level signal to be transmitted, the charging flow would decrease and letdown increase.

Evaluation of Plant Response:
A decreasing pressurizer level may lead to a possible reactor trip on low pressure and SIAS if the operator does not intervene. The SIAS would isolate letdown and charging would be available to restore pressurizer level. Operator could avert a reactor trip and SIAS through manual control of charging and letdown based on level indication in control room.

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Malfunction of First Stage Turbine Pressure Signal (falls low) to the RRS

If the malfunction causes a low pressure signal to be transmitted the RRS will lower the CEAs to produce a T_{ave} commensurate with the low pressure signal. This T_{ave} output signal is transmitted to the SBCS affecting its operation.

Evaluation of Plant Response:
The reduced heat output from the RCS due to the lowering of the regulating CEAs reduces the steam flow to the turbine. The SBCS receives a low T_{ave} signal from the RRS so the valves will not open. A reactor trip would occur on low steam generator pressure with a possible MSIS. The main steam safety valves and atmospheric dump valves are available for controlling RCS heat removal.

Malfunction of First Stage Turbine Pressure Signal (falls high) to the RRS

If the malfunction causes a high pressure signal to be transmitted the RRS will raise regulating CEAs to produce a T_{ave} commensurate with the high pressure signal. This T_{ave} output signal is transmitted to the SBCS causing its valves to open.

Impact of Failure of Common Instrument Line or Tap

The attached Table identifies the Common Line/Tap for protection channel and control channels (or multiple control channels) that are serving multiple channels. This table has been reviewed and those lines or taps which were determined to be limiting in their effect on plant response are identified below. The effect of losing protection channels due to a single failure on a common instrument line or tap, as identified in the response to Question 420.06 does not defeat required protection system redundancy. Therefore the effect of losing protection channels is not addressed here. Descriptions of the effect of the malfunctions on the control systems and an evaluation of plant response and backup system availability are also provided. Prudent engineering judgement based on knowledge of system design and transient analysis was used to develop these descriptions. The results of this evaluation provide justification that any simultaneous malfunctions of control systems identified herein, resulting from common instrument line or tap malfunctions are bounded by the analysis of Chapter 15 and would not require action or response beyond the capability of operators or safety systems.

Pressurizer Pressure Signal (PT-1100X) and Pressurizer Level Signal (LT-1110X) Tap 1-RC-105

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Systems affected are RRS, PPCS, PLCS, and SBCS

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Evaluation of Pressure Signal and Level Signal Failing Low due to Instrument Tap Damage on Plant Response:

If malfunction causes a low pressure and level signal to be transmitted, the pressurizer heaters would turn on, the pressurizer sprays would decrease flow. The RRS would adjust the CEAs to accommodate a low pressure input, thereby increasing power. This increase in power causes T_{ave} to increase. The SBCS receives the T_{ave} input from the RRS and may open the turbine bypass valves (TBVs) when it senses a mismatch between T_{ave} and turbine pressure. The opening of the TBVs sends an automatic withdrawal prohibit to CEDMCS stopping CEA withdrawal. However should this not occur the reactor would trip on high power due to rod withdrawal or achieve a new steady state at higher power. If the TBVs did not open the MSSVs would relieve steam generator pressure should it go that high. The PLCS, meanwhile, would decrease letdown and increase charging. Due to the increase in charging, and pressurizer heating and increase in power the reactor may trip on high pressurizer pressure (if not on high power as mentioned earlier). The operator has safety grade instrumentation from which to evaluate event progress. Manual control of charging, atmospheric dump valves and auxiliary sprays, without the use of PLCS, PPCS, and SBCS will bring the plant to a stable condition.

Evaluation of Pressure Signal and Level Signal Failing High due to Instrument Tap Damage on Plant Response:

If malfunction caused a high pressure and level signal to be transmitted, the pressurizer heaters would de-energize, the sprays would increase flow. The RRS would adjust rods in response to the high pressure signal thereby decreasing reactor power. The SBCS would receive a lower T_{ave} input due to the decrease in reactor power and not open the TBVs. The PLCS would increase letdown and decrease charging. A low pressurizer pressure situation would occur leading to a possible reactor trip and SIAS on low pressure or a new steady state at lower power and pressure. The operator has safety grade instrumentations from which to evaluate event progress. Isolation of letdown on SIAS or by the operator and manual control of charging with pressurizer spray insolation will bring the plant to a stable condition without using the PLCS, PPCS, and SBCS.

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Evaluation of Pressure Signal Failing High and Level Signal Failing Low due to Instrument Tap Damage on Plant Response:

The plant response is similar for the PPCS, RRS, and SBCS as discussed above for the pressure signal failing high. The PLCS, however would increase charging and decrease letdown. The increase in charging and pressurizer spray flow with no pressurizer heaters may lead to a low pressure condition or a

steadily increasing pressurizer level. The operator has safety grade instrumentation from which to evaluate event progress. Manual control of charging and turning off pressurizer sprays will bring the plant to a stable condition.

<u>Evaluation of Pressure Signal Failing Low and Level Signal Failing High due to Instrument Tap Damage on Plant Response:</u>

As discussed in the evaluation for both signals failing low the PPCS, RRS, and SBCS response is similar. The PLCS, however would increase letdown and decrease charging. An increasing reactor power, due to a rod withdrawal and decrease in RCS inventory would lead to a reactor trip on high power or thermal margin/low pressure. The operator can manually control charging to increase pressurizer level and isolate letdown flow. The plant can be brought to a stable condition through operator action and non-reliance on automatic control of the PPCS, PLCS, RRS, and SBCS.

<u>Pressurizer Pressure Signal (PT-1100Y) and Pressurizer Level Signal (LT-1110Y) Tap 1-RC-130</u>

The systems affected and the evaluation of plant response are the same as those described above for pressurizer pressure signal (PT-1100X) and pressure level signal (LT-1110X).

<u>Steam Generator Level Signal (LT-9021 and LT-9011) Tap I-1" MS1-108</u>

System affected is the FWRS

<u>Evaluation of Level Signals Failing Low due to Instrument Tap Damage on Plant Response:</u>

If the malfunction causes a low steam generator level signal to be sent from both transmitters then the flow control valve would open to increase level for both steam generators. As feedwater flow increased the FWRS would note a mismatch between main steam and feedwater flow. This would close the flow control valve to match feedwater and steam flow. An oscillation of the flow control valve with increasing steam generator level results leading to a high steam generator level signal being sent from the reactor protection system to close the control valves and trip the turbine. Should the control valves not close and turbine not trip the operator could take manual action to close the valves or stop the feedwater pumps. Finally a high-high steam generator level signal would close the feedwater pump discharge valves should the above actions not occur.

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Evaluation of Level Signals Failing High due to Instrument Tap Damage on Plant Response:

If the malfunction caused a high steam generator level signal to be sent from both transmitters then the flow control valve would close to decrease level for both steam generators. As feedwater flow decreased the FWRS would note a mismatch between the main steam and feedwater flow. This would open the flow control valve to match feedwater and steam flow. As oscillation of the flow control valve with decreasing steam generator level. Auxiliary feedwater would be automatically actuated to account for the insufficient feedwater flow.

Evaluation of One Level Signal Failing High and One Level Signal Failing Low due to Instrument Tap Damage on Plant Response:

One steam generator would experience a decreasing level due to closing of the control valve on receipt of the failed high level signal. The other steam generator would experience an increasing level due to opening of the control valve on receipt of the failed low level signal. The result would be either a reactor trip on low steam generator level or a closure of the control valve on high steam generator level with a turbine trip. Additionally, the operator can take appropriate action (manual reactor trip with auxiliary feedwater actuation) based on safety grade steam generator level instrumentation.

Steam Generator Level Signals (LT-9005 and LT-9012) Tap 1-1"-MSI-106

System affected is the FWRS

Evaluation of Level Signals Failing Low due to Instrument Tap Damage on Plant Response:

Wide range steam generator level will indicate a low level condition on one steam generator. The operator will still have safety grade steam generator level indications to rely on (one safety channel of the four safety channels will also be lost for that steam generator). Additionally, on the same steam generator the instrumentation and control of the feedwater bypass valve sends a signal to open the valve and actuates a low level alarm in the control room. However since a turbine trip signal is not present it will not open the valve. For conservatism it is assumed to open increasing flow to the steam generator. The intact portion of the FWRS on that steam generator will see the increased level and close the regulating valve enough to maintain level. Should this regulating valve control work improperly a

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high steam generator level will cause closure of the feedwater regulating valves and turbine trip. The operator can use the auxiliary feedwater system to maintain adequate inventory in the affected steam generator and may choose to manually trip the plant based on safety grade instrumentation readings conflicting with process instrumentation and control actions.

Evaluation of Level Signals Failing High due to Instrumentation Tap Damage on Plant Response:

Wide range steam generator level will indicate a high level condition on one steam generator. The operator will still have safety grade steam generator level indications to rely on (one safety channel of the four safety channels will also be lost for that steam generator). The control and instrumentation for the bypass valve will see the high level signal and actuate a high level alarm in the control room. The operator based on safety grade instrumentation will see normal level because the FWRS valves are not acting improperly. However, due to erroneous level signals he may take manual control of the FWRS and eventually trip the reactor using auxiliary feedwater to control the steam generator inventory.

Evaluation of One Level Signal Failing High and One Level Signal Failing Low due to Instrument Tap Damage on Plant Response:

Wide range steam generator level indication does not control a system and the operator will compare it to safety related instrumentation to ascertain the true reading. Failure of the instrumentation and control of the feedwater bypass valve is adequately discussed previously.

Steam Generator Level Signals (LT-9006 and LT-9022) Tap 1-1" MS1-114

The systems affected and evaluation of plant response are the same as for steam generator level signals LT-9005 and LT-9012 for instrument tap 1-1" MS1-106.

Condenser Storage Tank Level Signals (LT-12-11A and LT-12-11B)

The other control channel transmitters sharing a common tap not identified in the table are the Condensate Storage Tank level transmitter LT-12-11A and 11B. Individual root valves and excess flow check valves are added to ensure that instrument line rupture in one channel does not affect the other channel. The only failure affecting both channels is the break of the tap. For diversity, two safety related level switches provide low level alarms on the safety annunciators. Since the function of LT-12-11A and 11B is only indication and alarm and since alarm backup is provided a tap failure would not cause system actions required to be analyzed by Chapter 15 of the FSAR.

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420.05 (7.1) The instrumentation and control system comparison information of FSAR Table 1.3-1 and FSAR Subsection 7.1.1.6 is insufficient. The information supplied does not completely show that each instrumentation, control and supporting system is:

1. Identical to that of a nuclear power plant of similar design which has recently received an operating license, or

2. Different from previous/recent designs with a discussion of the differences and their effects on safety related systems.

The above information is required by Regulatory Guide 1.70, Revision 3, "Standard format and content of safety reports for nuclear power plants", Section 7.1.1. Therefore, in conformance with Regulatory Guide 1.70, Section 7.1.1, provide a comparative discussion for each St. Lucie 2 instrumentation and control system.

Response

Chapter 7 will be revised to include the following information:

St Lucie 2 instrumentation and control systems are designed and built identical to those systems provided for St Lucie 1 (Docket No. 50-335).

RPS

St Lucie 2 does not incorporate Asymmetric Steam Generator Tilt (ASGT) as part of the TM/LP PVAR calculation as St Lucie 1 does.

St Lucie 2 has a loss of CCW trip for RCP (Equipment) protection.

This trip is neither presently nor previously licensed, and is not credited in the Safety Analysis.

Overall the Nuclear Instrumentation portion of the RPS is functionally identical to that of St. Lucie 1. However the sub-function, zero power Mode Bypass, enables the low power section of the Linear Power Range Safety Channel rather than the Wide Range Log Channels, as in St. Lucie 1.(1)

The St. Lucie 2 Logic functions identical to St. Lucie 1, but also includes fuses in all matrix inter bay connections as part of improved fault protection. In addition, a test circuit is provided for checking the fuses associated with this matrix fault protection periodically.(2) Matrix fuse integrity will be checked periodically in accordance with technical specifications.

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St. Lucie 2 matrix relays are dry reed types, for improved reliability over the original St. Lucie 1 mercury wetted reed type relay design.

St. Lucie 2 incorporates a new RPS bistable design which, while functionally identical, is characterized by: greater accuracy, input buffering for improved circuit isolation, improved noise immunity via an adjustable response time, less cycling due to a variable hysterisis feature, and a pull up (down) circuit design which forces a bistable trip on a loss of input signal. Consequently, contrary to the St. Lucie 1 FSAR Subsection 7.2.2.2, the St. Lucie 2 auctioneered Input Bistables utilizing negative inputs will trip in an open circuit configuration.(3)

St Lucie has incorporated Reg. Guides 1.53, 1.22, 1.75, IEEE 323, 344, 384 in RPS design, as these standards were not in effect when St. Lucie was licensed.

Systems Required for Safe Shutdown

CE equipment supplied for St Lucie 2 conforms to R.G. 1.75, which identifies a 6 inch spatial separation requirement, vice the 12 inch criteria of St Lucie 1.

Safety Related Display Instrumentation

The upper and lower CEA limits are indicated on the CEDMCS panel for St Lucie 2, while St Lucie 1 displays this information on the core MIMIC display. The St Lucie 2 design is identical to the SONGS design. (docket no. 50-362).

Many aspects of the St. Lucie 2 design for Post Accident Monitoring are different from St. Lucie 1. St. Lucie 2 is identical to SONGS with the exception of invoking BTP EICSB No. 23, Qualification of Safety Related Display Instrumentation for Post Accident and Safe Shutdown. However, the associated changes in this area for invoking R.G. 1.97 are forthcoming.

St. Lucie 2 utilizes the Analog Display System (ADS), which while functionally identical to the St. Lucie 1 Metroscope, exhibits improved reliability design features and incorporates improved human factors characteristics.

This indication is not 1E indication and is further described in Subsection 7.7.1.1.6.

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NOTES

1. This design reflects that of the CE System 80* design, which is qualified to IEEE 323/74 and 344/75.

2. The fuses of this section are utilized in the System 80 Plant Protection System Design. The test circuit however is not included in prior plant or system designs.

3. The bistable design is a modified System 80 design, since the System 80 design does not utilize auctioneering.

*System 80 (CESSAR) Licensing Docket #STN-50-470F.

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Question No.

420.06 (7.1) The Safety Evaluation Report (and supplements) for the St. Lucie 2 construction permit describes instrumentation and control system items which require resolution at the operating license stage. Also, several commitments were made by the applicant to modify the St Lucie 2 design. Please give the status for each item where such resolution/commitments were made.

Response

Refer to attached Table 420.06-1.

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TABLE 420.6-1

ITEM	DOCUMENT SECTION	RESOLUTION/COMMITMENT	STATUS
1	SER Section 7.2.4	During our operating license review we will require that the applicant demonstrate that response times assumed in the plant accident analysis are valid on the basis of experience with like plants, or we will require that he provide a test program to periodically verify the response times of the protective systems and their associated sensors.	Identification of response times will be provided in the tech. spec.
2	SER Section 7.2.5	The applicant will document the information required by WASH-1270 by December 1, 1974.	Information was provided in letter dated March 31, 1975. Refer to SER Supplement Section 7.2.5 for status.
3	SER Section 7.3.2	For the motor operated isolation valves between the safety injection tanks and primary coolant system we will require, as on recently-licensed plants, that the design include provisions to automatically open the isolation valves on the occurrence of a safety injection signal and on the occurrence of a reactor coolant pressure signal in excess of a preselected value, and that redundant and independent indicating systems for each safety injection tank isolation valve be provided.	Refer to Control Wiring Diagram (CWD) 269S-272S in FSAR Section 1.7.
4	SER Section 7.3.3	Use of a single, electrically operated valve, at the discharge of redundant low pressure safety injection pumps does not meet the single failure criterion of IEEE Std 279-1971 for safety systems nor the redundancy requirements of General Design Criterion 35. We will require that the applicant provide a redundant valve at the discharge of the pumps.	In Amendment No. 27 to the PSAR, the applicant committed to provide a manually operated valve in parallel with the flow control valve at the discharge end of the LPSI pumps. Subsequent to Amendment No. 27 the system design was modified to include redundant flow paths for each of the LPSI pumps. Refer to FSAR Figure 6.3-1 A&B.
5	SER Section 7.3.3	The proposed design and mode of operation of the high pressure safety injection pumps "B" and "C" located in the same water tight room, do not provide the independence required between redundant safety-related systems and was found unacceptable. The applicant has committed to modify the design and mode of operation of pump C such that pump cannot be aligned to the redundant system A at any time.	In Amendment No. 27, the applicant presented a modified design, in which pump C cannot be aligned to the redundant system A at any time. Subsequent to Amendment No. 27 the design was modified in which pump C was eliminated. Refer to FSAR Figure 6.3-1 A&B.
6	SER Section 7.3.3	The proposed design of the component cooling loop, including the alignment of component cooling water pump "C", does not provide the independence required between redundant safety-related systems. The applicant has committed to modify the design to provide annunciation for improper alignment of the pump C motor power in relation to any of its motor operated discharge valves positions.	Refer to CWD 361 attached and to CWD 204 and 208 in FSAR Section 1.7. The technical specification will include a minimum period of time within which any improper alignment of these valves must be rectified following annunciation of misalignment.

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TABLE 420.06-1 (Cont'd)

ITEM	DOCUMENT SECTION	RESOLUTION/COMMITMENT	STATUS
7	SER Section 7.4	In the proposed auxiliary feedwater system the required delivery of feedwater to the second steam generator could be precluded by a single failure in the plant 125 V dc system following a feedwater line break near a steam generator. The applicant has agreed to modify the 125 d-c system control to enable a control room operator to isolate the faulted steam generator and establish auxiliary feedwater to the intact steam generator within the time limit specified in the accident analysis.	The Auxiliary Feedwater System design modification has been presented in the FSAR Amendment No. 4. This amendment includes a description of the AFW actuation system required to meet NUREG 0737 Item II.E.1.2 and alleviates the concern presented.
8	SER Section 7.5	We will require that redundant sensors be included in the design. We will also require that the sensors and associated cables for the steam generator pressure and level and pressurizer pressure and level be qualified for the long-term containment environment following a LOCA or a steam line break accident in addition to being qualified for the short-term environment as proposed by the applicant. We will require that a monitoring system be provided to monitor all the parameters monitored in plants of a similar design that have been reviewed and accepted. In the proposed design, the containment temperature is inferred from the containment sump liquid temperature. We will require the applicant to establish the reliability of the relationship between the containment and its sump liquid temperatures, for various conditions of operation. If the relationship cannot be established, we will require direct measurement of the containment temperature.	Amendments No. 27 and No. 39 provided response to these resolution/commitments. Refer to SER Supplement Section 7.5 for acceptance of the above amendments. In Amendment No. 27 the limiting case was LOCA. The applicant will also evaluate main steam line break for Environment Qualification. Containment atmosphere and containment sump direct temperature measurement will be provided. Equipment has been purchased and is presently planned for installation. The measurement equipment is described in FSAR Table 7.5-1.
9	SER Section 7.5	The applicant has documented in his PSAR that bypassed and inoperable status indication for protection systems will be provided in the control room to meet the recommendations contained in Regulatory Guide 1.47.	Refer to FSAR Subsection 7.5.2.7.
10	SER Section 7.5	The applicant has documented in the PSAR the criteria that will be used in the design of the control circuits for the valves provided to ensure the isolation of the low pressure residual heat removal system from the high pressure reactor coolant system. These criteria are consistent with those required in other recent construction permit reviews. The redundant interlocks provided to prevent opening and automatic closure of these valves are designed to IEEE Std 279-1971.	Refer to FSAR Subsections 7.4.1.3 and 7.4.2.2.
11	SER Section 7.7	To terminate spurious withdrawal of control rods and maintain fuel design limits as required by AEC General Design Criterion 25, the applicant relies on the intelligence from the above systems. The above control systems in turn derive their input signals from the two CEA position indication systems. Since the CEA position indication systems are not totally independent, technical specifications will specify limiting conditions for operation on the loss of either of the CEA position indications systems.	The technical specification will specify limiting conditions for operation on the loss of either of the CEA position indication systems.

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Question No.

420.07 (7.1) Various instrumentation and control system circuits in the plant (including the reactor protection system, engineered safety features actuation system, instrument power supply distribution system) rely on certain devices to provide electrical isolation capability in order to maintain the independence between redundant safety circuits and between safety circuits and non-safety circuits. Therefore, please provide the following information:

1. List all parameters and systems that interface/interconnect between redundant safety circuits and between the safety circuits and non-safety circuits (control systems, associated circuits, etc.).

2. Identify the type of transmission (i.e., analog, digital, electric, optic, etc.) which is involved with each interface that is identified in response to Part 1 above.

3. Identify the type of isolation device which defines the Class 1E boundary for each interface which was identified in response to Part 1 above.

4. Provide the acceptance criteria for each isolation device which is identified in response to Part 3 above.

5. Describe the test program for the isolation devices to insure adequate protection against EMI.

Response

Reactor Protection System

The isolation and independence of the Reactor Protective System is discussed below within two classifications: 1) Isolation of external non-ie interface signals and 1) Internal isolation to maintain independence of redundant channels.

1. Below is a listing of the signals which interface with systems external to the RPS.

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Signal	Transmission Type	Isolation Device
Reactor Coolant Pump Breaker Status Contacts	Digital	Relay
Reactor Trip Switchgear Trip Circuit Breaker Current Detectors	Digital	Relay
Bistable Trip To Sequence of Events	Digital	Relay
Bistable Trip & Pre Trip to Plant Annunciator	Digital	Relay
Operating Bypass and Misc. Ann to Plant Annunciator	Digital	Relay
CEA Withdrawal Prohibit	Digital	Relay
10^{-4}% Power to Analog Display System	Digital	Relay
Power Operated Relief Valve Closure Signal	Digital	Relay

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When reviewing the above list it should be noted that signals which are listed as not requiring an isolation device are maintained separate from signals classified as IE or associated in accordance with the requirements set forth in Reg. Guide 1.75. Also the isolation device identified as Relay is physically a relay in conjunction with a fuse. The relay provides contact to coil isolation (dialectric strength) while the fuse maintains the integrity of the wire. The two devices together are considered to be the isolation device.

Each type isolation device is qualified for a fault of 480V ac and 325V dc. The actual test voltages are 60V ac and 400V dc.

The general acceptance criteria for RPS isolation devices is as follows:

a. Application of the fault to the appropriate side of the isolation device shall not propagate to the other side of the isolation device or adversely affect the operation of circuitry connected to the other side of this isolation device.

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b. The integrity of the wire insulation must be maintained. The above acceptance criteria meets Reg. Guide 1.75 and IEEE 384.

2. The following is a discussion of the means by which independence of the four RPS channels is maintained.

Process input signals are sent to bistable trip units within the RPS where the signal is first buffered and then compared to a setpoint to create an on/off type signal. This signal deenergizes five separate relays within the trip unit. At this point all signals, cablings, modules, dedicated power supplies and any associated test circuitry are maintained totally independent across the four channels.

One contact from each trip unit is wired in series together within each channel. This series string is produced three times within each channel. The strings are then combined with another channel such that each contact is in parallel with a contact from another channel. This forms the six possible combinations of logic matrices AB, AC, AD, BC, BD, C. All connections of relay contacts between channels are fuse protected in the channel of origin and the channel of destination. This fuse in conjunction with its related contact and coil provide the required isolation between bistable and matrix.

Each matrix is powered from two diode isolated power supplies located in two different channels of the RPS. Each power supply has with it an isolation circuit which limits the fault to acceptable values and prevents the fault from disturbing the independent vital buses.

Each logic matrix drives four matrix relays. One matrix relay contact from each of the six matrices are connected in series to drive an initiation relay. This circuit is labled the trip path. All connections of relay contacts between channels are fuse protected in the channel of origin and the channel of destination. This fuse in conjunction with its related contact and coil provide the required isolation between the trip path and each matrix.

Testing within each channel is maintained independent through the use of a test interlock circuit which provides the intelligence to allow testing in only one channel at a time. The test is performed in three levels: 1. bistable or calculator test, 2. Matrix test and 3. Trip path test. The bistable/calculator test is performed using an independent test source within each channel such that a fault would effect only one channel. The matrix and trip path test is performed through the matrix test module by energizing bistable and/or matrix secondary relay coils. A combination of contact to

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contact, contact to coil, coil to contact and coil to coil isolation (all in conjunction with a fuse) are used to ensure a fault within the test circuit will not compromise the four channel redundancy.

All isolation devices discussed above are qualified to 480V ac and 325V dc and tested to 600V ac and 400V dc. The entire system is also subjected to an EMI test in accordance with MIL-STD-4 CIA "Electromagnetic Interference Characteristics Requirements for equipment for both conducted and radiated signals using tests CS01, CS02, CS06, RS07 and RS03.

In addition to the above, the safety portion of the pressurizer.level channels; (L1110X, L1110Y) are isolated from the non-safety portion by an analog voltage to analog voltage isolation. This isolation utilizes transformer coupling as its isolating/signal coupling mediums.

Short circuits, open circuits, and high voltages (4800 ac) are applied to the output circuitry as credible faults. The failure of these faults to perturb or propagate to the input circuitry form the basis of the acceptance criteria for this isolation.

There are no additional safety to non-safety interfaces nor process instrumentation interconnections between redundant safety circuits.

Engineered Safety Features Actuation System

Refer to attached Table 420.07-1 for a list of systems, type transmission, isolation device and interfacing/interconnect channels.

The general acceptance criteria for ESFAS isolation devices is as follows:

a. Application of the fault to the appropriate side of the isolation device shall not propagate to the other side of the isolation device or adversely affect the operation of circuitry connected to the other side of this isolation device.

b. The integrity of the wire insulation must be maintained. The above acceptance criteria meets Reg. Guide 1.75 and IEEE-384.

In addition to the above general acceptance criteria the vendors' compliance to the following IEEE Standards and Guides provides the basis for the acceptance criteria.

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Reg. Guide 1.75

- IEEE-323-1974
- IEEE-344-1975
- IEEE-384-1977
- IEEE-381-1977
- IEEE-383-1974
- IEEE-279-1971
- IEEE-308-1974
- IEEE-379-1972
- IEEE-338-1975

10CFR50 Appendix A criterion 22 and 25

Various fabrication and installation techniques have been employed to the isolation devices to alleviate any problems caused by electromagnetic interference. The following is a list of a few such items which account for this:

a. All external cables to and from the isolation devices are routed in control cable trays or conduits and are separated from power cables.

b. All isolation devices are encased in metal enclosures and separated from any major sources of EMI such as motors.

c. Isolation cabinet and isolation relay enclosures are designed Class 1E and seismic Category 1.

d. Metal fire barriers are provided to separate safety and non-safety channels.

Onsite Power Distribution System

For a discussion of the power distribution system refer to FSAR Subsection 8.3.1.

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TABLE 420.03-1

ITEM NO.	ISOLATION SYSTEM/PARAMETER	TYPE TRANSMISSION	TYPE ISOLATION DEVICE	INTERFACE/INTER-CONNECTION CHANNELS	REQUIRED FOR	LOCATION
1	ESFAS - SIAS CIAS MSIS CSAS RAS	Optical	Isolation Module Electro-optically led coupled devices.	MA/SA MA/SB MB/SA MB/SB MC/SA MC/SB MD/SA MD/SB	Initiation of 2/4 logic for - -SIAS -CIAS -MSIS -CSAS -RAS	ESFAS Logic cabinets - MA MB MC MD
2	ESFAS - SIAS CIAS MSIS CSAS	Optical	Isolation Module: Optical Couplers	MA/NS MB/NS MC/NS MD/NS ASA/NS ASB/NS ASAB/NS SA/NS SB/NS SAB/NS	Annunciation & Sequence of events recorder, interlocks	Isolation Cabinet - RAB Elevation 43'
3	ESFAS - MSIS A	Electro-Magentic	Isolation Relay	SA/SB	Closure of main steam and feedwater isolation valves by Channel A HCV-08-1A HCV-08-1B HVC-09-1B HVC-09-2B MV-08-1B	Isolation Relay Enclosure Box - B2G66 RAB Elevation 43'
4	CEDM Cooling Fan 2HVE-21A	Electro-Magnetic	Isolation Relay	ASA/ASB	Interlocking with CEDM Cooling Fan 2HVE-21B	Isolation Relay Enclosure Box - B2G66 RAB Elevation 43'
3	CEDM Cooling Fan 2HVE-21B	Electro-Magnetic	Isolation Relay	ASB/ASA	Interlocking with CEDM Cooling Fan 2HVE-21A	Isolation Relay Enclosure Box - B2G43 RAB Elevation 43'
6	RAB Emergency Exhaust Fan 2HVE-9A	Electro-Magnetic	Isolation Relay	SA/SB	Close RAB ECCS Channel "B" dampers.	Isolation Relay Enclosure Box - B2G66 RAB Elevation 43'

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TABLE 420.00-1 (Cont'd)

ITEM NO.	ISOLATION SYSTEM/PARAMETER	TYPE TRANSMISSION	TYPE ISOLATION DEVICE	INTERFACE/INTER-CONNECTION CHANNELS	REQUIRED FOR	LOCATION
7	RAB Emergency Exhaust Fan 2HVE-9B	Electro-Magnetic	Isolation Relay	SB/SA	Close RAB ECCS Channel "A" dampers	Isolation Relay Enclosure Box - B2G43 RAB Elevation 43'
8	ESFAS - MSIS B	Electro-Magnetic	Isolation Relay	SB/SA	Closure of Main Steam and Feed-water isolation valves by Channel B HCV-08-1B HCV-08-1A HCV-09-1A HCV-09-2A MV-08-1A	Isolation Relay Enclosure Box - B2G43 RAB Elevation 43'
9	Boric Acid Flow Control Valve FCV-2210X	Electro-Magnetic	Isolation Relay	SA/NA	Interlock with valve FCV-2210X	Isolation Relay Enclosure Box - B2G24 RAB Elevation 43'
10	Reactor Sump Iso-lation Valve LCV-07-11A	Electro-Magnetic	Isolation Relay	SA/NS	Prohibits starting of Reactor Cavity Sump Pump 2A when-ever SIAS or CIAS signal closes Reactor Sump Iso-lation Valves LCV-07-11B and 11A	Isolation Relay Enclosure Box - B2G64 RAB Elevation 43'
11	Reactor Sump Iso-lation Valve LCV-07-11B	Electro-Magnetic	Isolation Relay	SB/NS	Prohibits starting of Reactor Cavity Sump Pump 2B when-ever SIAS of CIAS signal closes Reactor Sump Iso. Valves LCV-07-11A and LCV-07-11B	Isolation Relay Enclosure Box - B2G75 RAB Elevation 43'
12	4160V SWGR 2A3 incoming FRR from Bus 2A2	Electro-Magnetic			Trips 2A2 Bus tie breaker when 2A3 Bus tie breaker is tripped	Isolation Relay Enclosure Box - B2G64 RAB Elevation 43'
13	4160V SWGR 2A3 incoming FDR from Bus 2A2	Electro-Magneitc	Isolation Relay	SA/NS	Permissive to close 2A2 Bus tie breaker to bus 2A3	Isolation Relay Enclosure Box - B2G64 RAB Ele-vation 43'

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TABLE 430.03-1 (Cont'd)

ITEM NO.	ISOLATION SYSTEM/PARAMETER	TYPE TRANSMISSION	TYPE ISOLATION DEVICE	INTERFACE/INTER CONNECTION CHANNELS	REQUIRED FOR	LOCATION
14	4160V SWGR 2B3 incoming FDR from Bus 2B2	Electro-Magnetic	Isolation Relay	SB/NS	Trips 2B2 Bus tie breaker when 2B3 bus tie breaker is tripped	Isolation Relay Enclosure Box-B2G75 RAB Elevation 43'
15	4160V SWGR 2B3 incoming FDR from Bus 2B2	Electro-Magnetic	Isolation Relay	SB/NS	Permissive to close 2B2 Bue tie breaker to Bus 2B3	Isolation Relay Enclosure Box-B2G64 RAB Elevation 43'
16	Component Cooling Water Pump 2A	Electro-Magnetic	Isolation Relay	SA/SAB	Interlock with component cooling water Pump 2C	Isolation Relay Enclosure Box-B2G73
17	4160V SWGR 2AB incoming FRD from Bus 2A3	Electro-Magnetic	Isolation Relay	SA/SAB	Interlocking Bus 2A3 to 2AB SWGR	Isolation Relay Enclosure Box-B2G73 RAB Elevation 43'
18	4160V SWGR 2AB incoming FDR from Bus 2B3	Electro-Magnetic	Isolation Relay	SB/SAB	Interlocking Bus 2B3 to 2AB SWGR	Isolation Relay Enclosure Box-B2G73 RAB Elevation 43'
19	Intake Cooling Water Pump 2A	Electro-Magnetic	Isolation Relay	SA/SAB	Interlock with intake cooling water pump 2C	Isolation Relay Enclosure Box-B2G99 RAB Elevation 43'
20	Intake Cooling Water Pump 2B	Electro-Magnetic	Isolation Relay	SB/SAB	Interlock with intake cooling water Pump 2C	Isolation Relay Enclosure Box-B2E98 RAB Elevation 43'
21	4160V SWGR 2A-3	Electro-Magnetic	Isolation Relay	SA/SAB	Interlocking 4160V SWGR 2A-3 to 4160V SWGR 2AB	Isolation Relay Enclosure Box-B2G99 RAB Elevation 43'
22	Diesel Generator 2A Loading	Electro-Magnetic	Isolation Relay	SA/SAB	Interlocks with Emergency Diesel Generator's 2A Loading Lights	Isolation Relay Enclosure Box- B2G99 RAB Elevation 43'
23	Diesel Generator 2B Loading	Electro-Magnetic	Isolation Relay	SB/SAB	Interlocks with Emergency Diesel Generator's 2B Loading Lights	Isolation Relay Enclosure Box-B2E99 RAB Elevation 43'

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TABLE 420.0~~3~~7-1 (Cont'd)

ITEM NO.	ISOLATION SYSTEM/PARAMETER	TYPE TRANSMISSION	TYPE ISOLATION DEVICE	INTERFACE/INTER-CONNECTION CHANNELS	REQUIRED FOR	LOCATION
24	4160V SWGR 2B-3	Electro-Magnetic	Isolation Relay	SA/SAB	Interlocking 4160V SWGR 2B-3 to 4160V SWGR 2AB.	Isolation Relay Enclosure Box- B2G99 RAB Elevation 43'
25	Reactor Trip by Turbine	Electro-Magnetic	Isolation Relay	NS/MA NS/MB NS/MC NS/MD	Interlocking Measure-ment Channels MS,MB, MC, and MD to RPS Cabinet	Isolation Relay Enclosure RAB Elevation 0.5 MA-Box B2G44 MB-Box B2G45 MC-Box B2G46 MD-Box B2G47
26	Charging Pump 2C Actuation from Pressurizer	Electo-Magnetic	Isolation Relay	NS/SAB	Interlocking with start and stop circuits of Charging Pump 2C	Isolation Relay Enclosure Box-B2G65 RAB Elevation 43'
27	Component Cooling Water Pump 2B	Electro-Magnetic	Isolation Relay	SA/SAB	Interlock with Com-ponent Cooling Water Pump 2C	Isolation Relay Enclosure Box-B2E98 RAB Elevation 43'
28	Radiation Monitor-ing	Optical	Optical Isolator	NS/SA NS/SB SA/SB NS/MA NS/MB NS/MC NS/MD	Computer Commun-ication LOOP Isolation	RAB, Fuel Handling ling Building
29	Pressurizer HTR Transf. 2A3 4160V FDR Breaker - Watt Transducer	Electrical	Fuses 1/8 AMP	NS/SA	Isolating/Inter-facing the data processor terminal cabinet 1 and the watt transducer signal (1 ma) pressurizer HTR transf. 2A3 4160V FDR breaker	4160 V SWGR BUS 2A3 CUB 4

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Question No.

420.08 (7.1) FSAR Subsection 7.1.1.6 states that there have ~~has~~ been minor changes in the core protection calculator (CPC) software. Describe the changes in "software" used for the "analog" CPC.

Response

The software of a calculator is its program or sets of instructions. The software for the analog core protection calculator is the coefficient setting for the function modules which makeup the calculator. These coefficient settings are treated as setpoints and may vary from one fuel cycle to another.

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Question No.

420.09
(7.1)

Identify all instrumentation, control circuits, and components (both safety and non-safety) that may become submerged as a result of a LOCA. For all such components and circuits that are not qualified for service in such an environment, provide the results of an analysis to determine the following: (1) the safety significance of the failure of the components and circuits (e.g., spurious operation, loss of function, loss of accident/post accident monitoring, etc.) as a result of flooding and (2) the proposed design changes, if any, resulting from your analysis.

Response

St Lucie Unit No. 2 will address submergence as a result of a LOCA event and its impact on instrumentation, control circuits, and components (both safety and non-safety) in compliance with Section 3.11. A LOCA event, and its resultant flood, is a harsh environment. Specific information for harsh environments in general accord with NUREG 0588 Appendix E will be submitted to the USNRC by November 30, 1981 as stated in Section 3.11, Appendix 3.11 B, "Equipment Environmental Qualification Program for St Lucie Unit No. 2" paragraph 3.11 B2 (c), Amendment No. 4 (7-2-81). This submittal to the EQB will specifically verify that submergence will not degrade safety function by identifying equipment locations, equipment functions, maximum flood levels, and impact of submergence.

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					[illegible] watt transducer signal (1 ma) for pressurizer HTR Transf. 2B3 4160V FDR Breaker	
31	480V SWGR 2A2 metering/relaying	Electrical	Fuses 3 AMP	NS/SA	480V SWGR 2A2 non-safety load shedding	Isolating Fuse Box-B2E64
32	480V SWGR 2B2 metering/relaying	Electrical	Fuses 3 AMP	NS/SB	480V SWGR 2B2 non-safety load shedding	Isolating Fuse Box-B2E60

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TABLE 420.10-1

COMMON LINES/SENSORS

13172-310-109 Rev. 3

Common Tap	Ins. P,T,L,F	(P) Process/Safety (S)
1-RC-104	PT-1104	S
	PT-1102 (C)	S
1-RC-105	PT-1103	S
	PT-1108	Indication Only
	PT-1102 (A)	S
	LT-1110 X	P&S
1-RC-130	LT-1110 Y	P&S
	PT-1102 (B)	S
	PT-1105	S
1-RC-107	PT-1106	S
	PT-1102 (D)	S
3/4-RC-127	PDT-1121 C	S
	PDT-1124 Z	Indication Only
	PDT-1124 Y	Indication Only
2998-G-079 Sh. 1 SG2A1		
I-1" MS1-100	LT-9013 A	S
	LT-9011	P
I-1" MS1-101	PT-8013 A	S
	LT-9013 A	S
I-1" MS1-102	PT-8013 B	S
	LT-9013 B	S
I-1" MS1-103	LT-9013 B	S
I-1" MS1-104	PT-8013 C	S
	LT-9013 C	S
I-1" MS1-105	LT-9013 C	S
I-1" MS1-106	PT-8013 D	S
	LT-9005	P
	LT-9013 D	S
	LT-9113	S indicate
	LT-9012	P
I-1" MS1-107	LT-9013 D	S

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TABLE 420.10-1 (Cont'd)

Common Tap	Ins. P,T,L,F	(P) Process/Safety (S)
2998-G-074 Sh. 1		
SG2B1		
I-1" MS1-108	LT-9023 A	S
	LT-9021	P indicates
I-1" MS1-109	LT-9021	P indicates
	LT-9023 A	S
	PT-8023 A	S
I-1" MS1-110	PT-8023 B	S
	LT-9023 B	S
I-1" MS1-111	LT-9023B	S
I-1" MS1-112	PT-9023 C	S
	PT-8123	I indication
	LT-9023 C	S
I-1" MS1-113	LT-9023 C	S
I-1" MS1-114	PT-8023 D	S
I-1" MS1-117	LT-9123	P indicates
	LT-9022	P indicates
I-1" MS1-115	LT-9023	S

Question No.

420.10 (7.2) (7.3)

Identify where instrument sensors or transmitters supplying information to more than one protection channel are located in a common instrument line or connected to a common instrument tap. The intent of this item is to verify that a single failure in a common instrument line or tap (such as break or blockage) cannot defeat required protection system redundancy.

Response

Table 420.10-1 lists the Common Line/Tap for protection system channels (S) that are serving multiple protection channels.

Listed are P&ID number, Line Number, Channel Number and Category.

Single failure in a common instrument line or tap does not defeat required protection system redundancy.

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Question No.

420.11 (7.2) (7.3) Identify where instrument sensors or transmitters supplying information to both a protection channel and control channel or to more than one control channel are located in a common instrument line or connected to a common instrument tap. The intent of this item is to verify that a single failure in a common instrument line or tap can neither defeat required separation between control and protection nor cause multiple control system actions not bounded by analyses contained in Chapter 15 of the FSAR.

Response

Identification of instrument sensors having common instrument lines or taps supplying information to more than one system is provided in the response to Question 420.4(3).

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Question No.

420.12 (7.2) Recent review of a plant (Waterford) revealed a situation where heaters are to be used to control temperature and humidity within insulated cabinets housing electrical transmitters that provide input signals to the reactor protection systems. These cabinet heaters were found to be unqualified and a concern was raised since possible failure of the heaters could potentially degrade the transmitters, etc..

Please address the above design as it pertains to St Lucie 2. If cabinet heaters are used then describe as a minimum the design criteria used for the heaters.

Response

All electrical transmitters on the St Lucie Unit 2 plant are mounted on open instrument racks. Insulated cabinets with heaters are not utilized on this project.

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Question No.

420.13 (7.2) (7.3) In the FSAR it is stated that four measurement channels are provided for each parameter monitored in the protection systems. The applicant proposes to operate various protection systems with one of the four channels in bypass. The system involved would then function as a 2 of 3 channel protective system. (With one channel tripped, the system would function as a 1 of 3 channel protective system). The proposal is based on asserted four channel independence. To demonstrate independence the applicant must demonstrate separation of power supplies, logic and sensors. St Lucie 2 has been designed as a two battery system, that is, the four protective channels obtain power from four separate vital ac instrument buses, which in turn obtain power from two ac/dc power divisions. Hence, the demonstration of 4 channel independence is, a priori, incomplete.

On previously reviewed plants (Waterford) we have required (by plant Technical Specification) that the protective system be used as a four channel system with bypass of a known defective channel for no more than 48 hours and require trip of a known defective channel after 48 hours. Please be prepared to discuss this design concept.

Response

Response to this question is in two parts: part (a) demonstrates acceptability and standard "ac/dc power division" design; part (b) describes independence and operability of the four channel design.

Part "A" -

A response to this question on the adequacy of a four (4) channel based ac UPS system deriving its stored energy power source from two divisions of dc power requires a brief review of the philosophy of ac UPS power for RPS and ESFAS power supply. The ac UPS power supply four channel concept is selected for plant availability and not plant safety as the loss of power to the RPS and ESFAS will result in channel trip. Furthermore, the number of or channels, whether three of four, provides a design basis in excess of that required for safety by providing for spurious channel trips or testing during plant operation without plant trip for the specific purpose to enchance plant availability or provide testing during operation.

In fact, the requirement for the ac UPS system is actually the ability to "ride-through" a momentary power loss without plant trip. Boiling Water Reactors including those presently in construction (e.g. WPPSS No. 2) utilize non-Class IE "ride-through flywheel motor-generator power systems" to power the reactor protection systems.

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Table 7.3-7, "Engineered Safety Features Actuation System-Failure Modes and Effects Analysis" clearly indicates that the loss of a battery will not preclude completion of safety function. Furthermore, the two redundant Class IE divisions of onsite AC power deriving its onsite power generation from Class IE diesel-generators forms the basis for compliance with 10CFR50 Appendix A GDC 17. These two divisions provide the source of power to the AC UPS RPS & ESFAS power supplies through the DC power distribution system battery charges in Light Water Reactors. Provision of four batteries for utility convenience or symmetry, each in support of a RPS and ESFAS channel, would typically only support RPS and ESFAS loads for the short time necessary to resequence the battery charges on the Class 1E ac system subsequent to a Loss of Offsite Power. A review of recently licensed nuclear plants demonstrates the acceptability of the two safety-related battery design as follows:

1) Arkansas Power & Light, Arkansas Nuclear One Unit 2, FSAR Subsection 8.3.2.1 describes the two battery design

2) Alabama Power Company, James M Farley Nuclear Plant FSAR Section 8.3 describes the two battery design.

On the basis of the information described above the St Lucie 2 design is considered acceptable.

Part "B" -

The four channel independence begins at the output of the 4 ac UPS inverters, designated Inverter 2A, 2B, 2C and 2D or the Maintenance Bypass Transformer 2A, 2B, 2C and 2D and their associated Instrument Buses 2MA, 2MB, 2MC and 2MD as shown on FSAR Figure 8.3.3. Independence of the four channels of RPS or ESFAS is maintained in accordance with FSAR Subsections 8.3.1.3, 8.3.1.4, 7.2.1.1.7, and 7.3.1.1.1h.

Independence of four measurement channels can and will be demonstrated during the drawing review described in Enclosure 2 to the ICSB questions. This drawing review is expected to duplicate the successful drawing review and actual site inspections by the NRC staff performed on St Lucie 1 which verified the four channel independence. The position of the NRC on previously reviewed plants that a channel bypass must be placed in a tripped mode within 48 hours is not considered applicable to St Lucie Unit 2 for RPS, SIAS, MSIS, or CIAS due to the full independence of the four measurement channels.

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In fact, the plant basis (Figure 7.3-1) is a three channel ESFAS with an "installed spare" for the RPS, SIAS, MSIS, and CIAS. However the design basis for RAS and CSAS is the energization of actuation relays (Figure 7.3-3) to make it incredible for spurious actuation of Containment Spray or Recirculation which can be detrimental to equipment in a non-accident condition. Therefore, the NRC position of trip instead of continuous bypass for one of the four channels used for RAS or CSAS is acceptable to the applicant.

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Question No.

420.14 (7.2) The reactor protection system (RPS) includes two trip inputs (turbine trip and loss of component cooling water trip) which are classified as not being required for reactor protection. It is the staff's position (BTP ICSB 26) that all reactor trip inputs to the RPS are required to meet the design requirements of IEEE 279 without exception. This includes the entire trip function from the sensor to the final actuated devices.

FSAR Chapter 15 shows that the accident analysis takes credit for reactor trip on turbine trip. FSAR Subsection 7.2.2.2.11 states that the turbine trip is taken from non-Class IE hydraulic oil pressure switches. The use of non-Class IE switches is not acceptable. Also, it is not clear that the component cooling water trip meets the requirements of IEEE-279.

Therefore, provide a description of these and other such RPS inputs with respect to their conformance to BTP ICSB 26. This design description should be supported with electrical schematics, logic diagrams, piping and instrument drawings, test procedures and technical specifications.

Response

The Chapter 15 accident analysis does not take credit for reactor trip on turbine trip to mitigate the results of any event. This is so stated in note 7 to Table 15.0-7. The sequence of events analyses presented in Chapter 15 recognize that such a trip exists and may occur. For the Increased Feedwater Flow (with failure to achieve a fast transfer at a 4.16 kV bus) event presented in Subsection 15.1.2.1, it was more adverse to trip the reactor on turbine trip. This was done to increase the cooldown for this increased heat removal event. This event is discussed in the response to Question 420.11.

Although, the two trips are not required for safety, the CCW trip is Class IE in accordance with IEEE-279. Isolation devices are provided for the turbine trip inputs to the RPS in accordance with Regulatory Guide 1.75.

→ INSERT "A" ←

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420.14

INSERT "A"
(for Q420.14)

Isolation device are provided for the turbine trip inputs to the RPS in accordance with Regulatory Guide 1.75. The electric cables that are routed from the isolation devices to the turbine trip input sensors are routed in their own dedicated raceway systems. These systems are classified as non safety measurement channel A (NMA), non safety measurement channel B (NMB), non safety measurement channel C (NMC) and non safety measurement channel D (NMD) respectively, these dedicated raceway systems contain only the respective cable per non safety measurement channel that provides the trip input signal to the Reactor Protection System (RPS). They are separated and enclosed through out the entire routing of the respective cable by the use of both regid galvanized steel and liquid tight flexible conduit such that each cable is isolated from all other cables throughout its routing.

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Question No.

420.15 (7.2) (15.0) FSAR Subsection 15.2.1.1.2 states that the operator manually trips the reactor after receiving the turbine trip alarm. This is not consistent with the other accident analysis events which trip the reactor automatically on turbine trip. Please clarify this inconsistency.

Response

Subsection 7.2.1.1.1.10 discusses the turbine trip input to the reactor protective system. A bypass of this trip during low power operation is one of its features. This bypass is designed for startup and low power operation when the operator is likely to take manual control of important plant functions. For the purposes of a limiting analysis, Subsection 15.2.1.1.2 assumed this bypass was operational up to the 20% power level. Thus, for the analysis presented in Subsection 15.2.1.1.2 there is no automatic trip which will occur.

For this moderate frequency transient, it is assumed that the operator has manual control of the plant and is alerted by the turbine trip alarm. Ten minutes for operator action is considered appropriate for such an event. This is especially true where the event is one which he is anticipating, such as a turbine trip. See Subsection 15.0.4.2.

As discussed in the second paragraph of Subsection 15.1.2.1.3.b, a reactor trip on turbine trip is simulated to increase the excess heat removal aspect of this event by reducing the heat input from the reactor. This maximizes the reactor coolant system cooldown as shown on Figures 15.1.2.1-5, -6 and -7. Reactor trip is assumed to occur on low electrohydraulic pressure following turbine trip. If the reactor trip does not occur on turbine trip, a reactor trip would occur on high pressurizer pressure. The consequences of this event will be similar to but less severe than the loss of condenser vacuum, which is described in Subsection 15.2.2.

DRAFT

JUL 2 4 1981

Question No.

420.16 (7.2)

The reactor protection system brings the four Class IE independent and redundant instrument power supply circuits into common logic matrices. This results in the potential for compromising the physical and electrical independence of these circuits. Therefore, describe the degree of physical separation and electrical isolation provided for the redundant instrument power supplies at these logic matrices and also at any other points of confluence.

Response

Each channel of the RPS receives 120V ac from separate Class IE instrument busses MA, MB, MC and MD. This IE power remains within its related channel and does not cross the channel barriers. The 120V ac within each channel powers dc power supplies. The dc side of the power supplies is auctioneered between channels to power the matrices. Independence of these busses is maintained through the use of qualified isolators. These isolators are connected to the output of each matrix power supply such that a fault appearing within the matrix would not effect the 120V ac Class IE instrument bus.

FP&L will commit to testing the power supply isolaters and submit the test report to the NRC for review.

DRAFT

JUL 24 1981

Question No.

420.17 (7.2) (7.3) Please describe how your test procedures for the protection systems conform to Regulatory Guide 1.118 (Revision 0) Position C.13 guidelines which states that test procedures for periodic tests shall not require jury rig test setups, the use of temporary jumper wires, or the removal of fuses. Identify and justify any exceptions.

Response

The periodic tests of the RPS and ESFAS utilize the built in test circuitry. No additional test equipment or fuse removal procedures are required. The installed test equipment contains its own power supply and checks all logic and trip relays. Unit 2 also incorporates a matrix fuse test circuit.

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JUL 24 1981

Question No.

420.18 (7.2) State whether open-column reference legs are used in the level measurement systems for the steam generators and the pressurizer. If so, discuss the effect on the measurement accuracy caused by the heatup of the reference leg due to a high energy line break inside the containment.

Response

Both steam generators and pressurizer at St Lucie 2 have open-column reference legs susceptible to containment temperature changes. The effect of a High Energy Pipe Break inside the containment would be to heatup the reference legs and cause a decrease in the density of the water columns. The resultant affect on the level measurement system would be an indicated level that is reading significantly higher than the actual level. The main concern for an accurate level reading during an accident such as a main steam line break would be to maintain an inventory level in the intact steam generator(s) using the auxiliary feedwater system to allow a controlled cooldown and. also to record an accurate pressurizer level as a means of reacting to changing RCS conditions.

The level error is accounted for in the determination of safety setpoints.

Curves similar to Figure 420.18-1 are provided to the operators for level corrections. Additionally, both the pressurizer and steam generators employ external condensate pots to maintain reference leg full of subcooled liquid. As such, "flashing" within the reference leg upon vessel pressure reduction has a negligible effect on indicated level.

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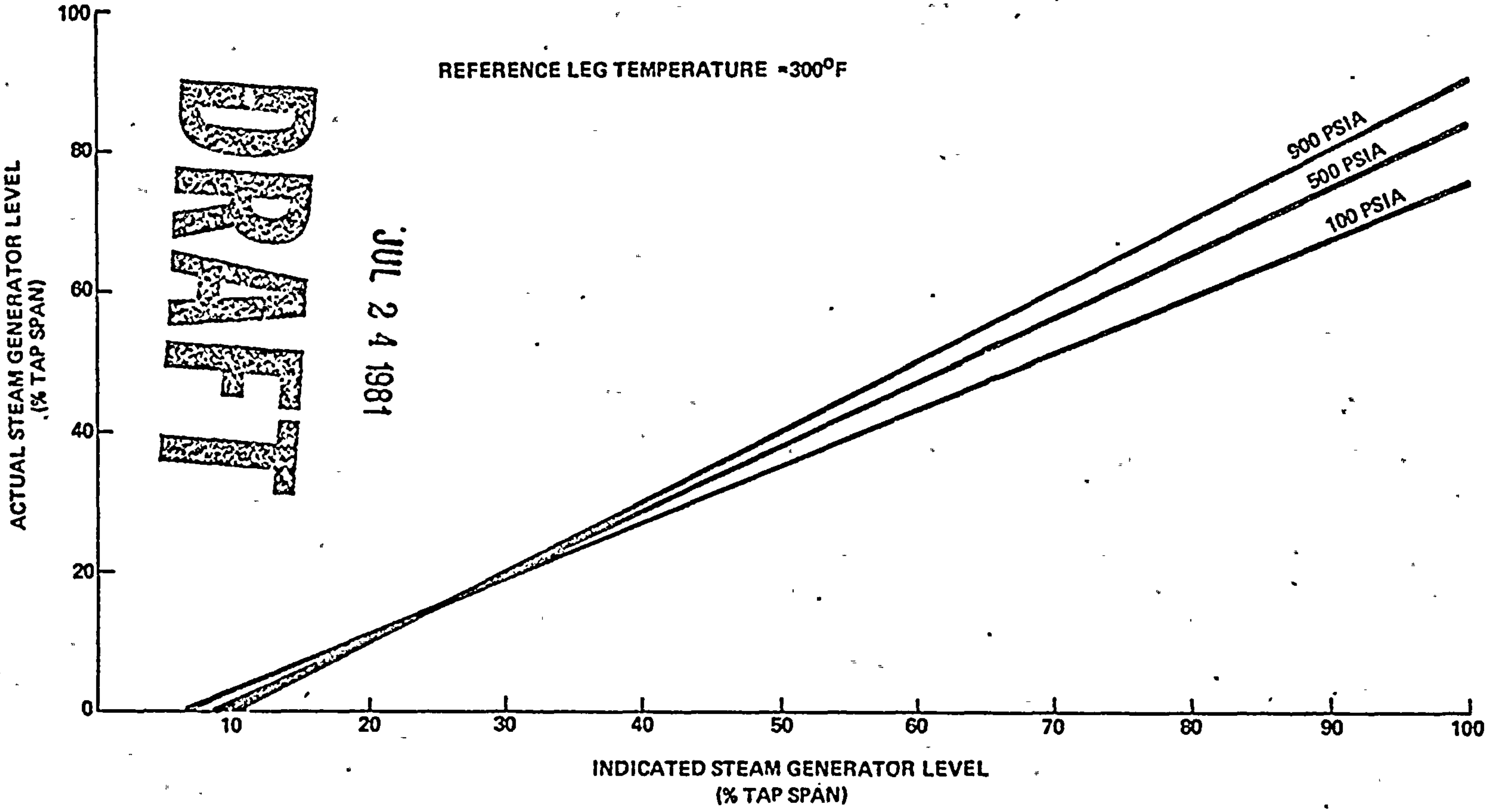

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FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

STEAM GENERATOR
LEVEL CORRECTION
(TYPICAL)
FIGURE 420.18-1

Question No.

420.19 (7.3) The St Lucie 2 design consists of interconnections for AB shared system equipment. For example, FSAR Table 7.3-2 shows that the intake cooling water pump 2C and component cooling water pump 2c each receive both SA and SB actuation signals from the redundant trains. This results in the potential for compromising the physical and electrical independence of the redundant ESFAS circuits. Therefore, describe all situations where interconnections (third channel (SAB) equipment actuated by redundant actuation trains SA and SB) for SAB shared system equipment exist. Discuss how this design concept meets the requirements of IEEE Standard 279-1971 and IEEE Standard 384. We are particularly concerned with physical and electrical independence of redundant safety circuits. Also, describe the physical location of the third channel actuated equipment in relation to Channel A and B actuated equipment.

Response

a) Interconnections (third channel (SAB) equipment actuated by redundant actuation trains SA and SB) for SAB shared system equipment are as follows:

1) Intake Cooling Water Pump 2C
2) Charging Pumps 2C
3) Component Cooling Water Pump 2C

b) The design concepts which meet the requirements of IEEE Standard 279-1971 and IEEE Standard 384 are as follows:

Channel independence is achieved by electrical and physical separation between channels as described below.

Engineered safety features A and B actuating circuits are maintained independent with respect to signal interconnections for the AB shared system equipment control by both physical separation and electrical isolation. FSAR Figure 7.3-11 shows this arrangement. A welded sheet metal box is located in each ESFAS logic cabinet and contains AB equipment actuation relays. These relays with 24 volt dc coils are hermetically sealed. The AB cables are routed from an AB tray through steel conduit to the AB1 and AB2 boxes and connected to the terminal boards. Tefzel insulated wires connect the terminal board and relay contacts. The two relay coils are connected to a 2 out-of 4 actuation module which is used for the AB relay only. A failure mode and effects for ESFAS AB system is given in FSAR Table 7.3-8. All other design concepts which meet the requirements of IEEE Standard 279-1971 and IEEE Standard 384-1977 are discussed in FSAR Subsection 7.3.2.1.2.

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The isolation box is located in both the 9N38-5 and 9N38-6 cabinets and a single normally closed contact is used to provide a start signal to the C pump. The isolation characteristic is provided by a relay (coil to contacts) in each of the isolation boxes. The approximate isolation barrier is 500 volts ac or dc between the coil and contacts of this relay. The response time is approximately 12 milliseconds and the relay coil and contact wiring within the isolation box is routed so that the input (coil) and output (contacts) wires do not come in proximity.

c) Additional safety-related equipment (e.g., third intake cooling water pump motor) are arranged to function as a "third service" (swing) load group AB. This load group consists of equipment which can be used for backup or replacement purposes to the equipment in either of the main redundant load groups A or B.

All the AB buses (4.16 kV, 480 Volts 125V dc) are connected to either the corresponding A division or B division at any one time.

In the control room, alarms are provided to alert the operator if the AB buses on all voltage levels are not aligned properly. Electrical interlocking schemes are provided on the incoming breakers (two in series) to prevent the AB bus from being simultaneously connected to A and B divisions.

Once any third service bus is assigned to a safety division, either A or B, the loads served by that bus are committed to that safety division. The third buses are manually switched to the appropriate division A or B bus.

Physical separation is provided between load group A and load group B and between load group AB and both load groups A and B since load group AB may at various times function as part of either load group A or B. Separate cable tray and conduit systems are provided for each of the redundant load groups.

All SAB cables are permitted to be routed only with its own safety class cables and not safety A or safety B. This is a design requirement to which cables are routed in their respective raceways. Separate tray and conduit systems are furnished for the following classes of cable 5 kV, 600 Volt power, 600 Volt control and 300 Volt shield instrument cable. Physical separation is further discussed in Subection 8.3.1.2, "Regulatory Guide 1.75 Rev. 1."

There are no AB instrumentation protective systems.

The physical location of the third channel actuated equipment is shown on FSAR Figures 1.2-12 (Charging pumps), 1.2-20 (CCW pumps) and 1.2-22 (Intake Cooling Water Pumps).

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Question No.

420.20 (7.3) Discuss design features which insure that the blocking of the operation of selected protection function actuator circuits is returned to normal operation after testing. Is reliance placed upon the operator doing this and then observing test lights in the safeguards test racks, or are there more positive means to insure that systems are returned to normal operation?

Response

The design features of the ESFAS testing is described in the FSAR Subsection 7.3.1.1.1.

The bistable test circuit uses a momentary, spring return "Auto" calibration switch. After calibration test, the bistable is returned to its normal automatic position. The bistable trip test uses a momentary spring return pushbutton located on the bistable. After observing trip test lights and releasing the button, the bistable returns to its normal position.

The logic matrices are tested by depressing a trip test momentary pushbutton located on the individual modules. This, in concert with function and test group selector switches, provides one trip input to the matrix and a second input is provided by the trip tested bistable. This causes the logic matrix to trip and actuate the output relays connected to the matrix. The matrix does not reset after the test and requires operators action on the main control board to actuate the system reset switch.

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Question No.

420.21 (7.3) With regard to the recirculation system (RAS), provide a response to the following items:

(1) For all modes of plant operation, evaluate the consequences of an inadvertent switchover signal which could cause the RAS to operate and realign the pumps and valves when not required. If any of the consequences are found to be unacceptable, describe the design features which are provided to help insure against such an occurrence.

(2) Discuss the safety-related display instrumentation associated with this actuation which is available to the operator.

(3) Can the reset of safety injection actuation prior to automatic switchover from injection to recirculation defeat the automatic switchover?

Response

(1) The RAS measurement channels and logics are designed to "energize to actuate". By designing the RAS as "energize to actuate," a loss of power on one 125V dc bus will not cause spurious RAS initiation which could possibly interrupt cooling water supply to the core and containment before adequate water is available in the sump for recirculation. Consequences due to spurious RAS initiation are summarized below:

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(a) NORMAL PLANT OPERATION: The LPSI, HPSI and containment spray are not operating. On a spurious RAS initiation, (LPSI, HPSI and Containment Spray Pumps remain not operating) one outlet valve opens and one refueling water tank outlet valve closes. This should not affect normal plant operation because the other ESFAS channel will remain operational. Adequate valve position, sump/tank levels instrumentation, and alarms in the control room are provided. The operators are alerted to correct the abnormal condition promptly.

(b) EMERGENCY REACTOR SHUTDOWN CONDITION (i.e. SIAS AND/OR CIAS): The HPSI, LPSI and Containment Spray Pumps are running with their suction headers lined up with the Refueling Water Tank (RWT). If RAS signal of one (1) safety channel actuated, the corresponding LPSI pump will be stopped. The HPSI and Containment Spray Pumps of that channel will be connected to the dry sump. However, the remaining redundant safety pump trains will remain intact and perform the required safety functions. The control room operator has adequate alarms and instrumentations to recognize the abnormal pump-valve line up and correct it manually from the control room prior to pump damage.

(c) NORMAL SHUTDOWN COOLING: The LPSI pumps are isolated from RWT and containment sump by V3444 and V3432. Pump suctions are obtained from RCS. Spurious RAS switchover signal should not affect the Decay Heat Removal System or damage the pumps.

(2) Redundant safety class instrumentations are provided for RWT level and containment sump level. Annunciations are available to the control room operator to alert him of abnormal valve positions, and pump operating conditions. Furthermore, RAS annunciation is provided in the control room.

(3) The reset of SIAS prior to automatic switchover from injection to recirculation will not affect RAS. The RAS actuation strictly depends on RWT levels (2 out of 4 channels) and is independent of SIAS.

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Question No.

420.22
(7.3)

FSAR Subsection 7.3.1.1.3 states that, "The SIAS and high-high containment pressure signals are combined in four AND circuits within the ESFAS initiating logic." However, FSAR Figure 7.3-3 shows two AND curcuits. Please correct this discrepancy.

Response

Refer to revised FSAR Subsection 7.3.1.1.3.

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7.3.1.1.3 Containment Spray Actuation Signal

This description deals with the instrumentation and controls for the containment spray actuation signal (CSAS). Refer to Subsection 6.2.2 for a description of the Containment Spray System (CSS). The containment heat removal function is also performed by the Containment Cooling System which is actuated by SIAS.

The CSAS automatically actuates the CSS. The CSAS is initiated by a coincidence of two-out-of-four high-high containment pressure signals (rather than two-out-of-three, because it is designed to energize to actuate rather than de-energize to actuate) and a simultaneous SIAS signal as shown on Figure 7.3-3. The four measurement channels for high-high containment pressure are physically and electrically separated and all four channels are active during plant operation. A manual bypass for maintenance of one of the four channels places this channel in a trip condition and the trip of one-out-of-three remaining channels in conjunction with a SIAS actuates the CSAS.

The system is composed of four redundant channels, MA, MB, MC, and MD. The instrumentation and controls in a channel are physically and electrically separate and independent of the instrumentation and controls in other channels. This independence maintains the redundancy required to ensure equipment functionality following any design basis event.

The two redundant CSAS actuation channels (SA and SB) initiate the operation of the containment spray pumps (A and B) and their associated valves (see Figure 6.2-41). Each spray system isolation valve (FCV-07-1A and 1B) is opened by its associated CSAS actuation channel (SA or SB).

The CSAS containment pressure measurement channels and CSAS actuation logics are designed as "energize to actuate" to prevent spurious spray system operation on loss of power to one of the two 125V dc buses.

The 125V dc system is designed such that no single failure results in loss of power to either of the 125V dc buses (see Subsection 8.3.2). In the event of loss of power to one bus, CSAS is initiated when required by the measurement channels associated with the unaffected bus. Each CSAS actuation channel can also be initiated manually from the control room. Thus, no single failure prevents proper CSAS actuation.

a) Initiating Circuits

Initiating circuits are similar to the initiating circuits described in Subsection 7.3.1.1.1a for SIAS except that the parameter monitored is containment pressure only.

The SIAS and high-high containment pressure signals are combined in two AND circuits within the ESFAS initiating logic. The AND circuits prevent inadvertent operation of the Containment Spray System upon generation of an SIAS only. 5
420.22

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Question No.

420.23
(7.3.2.1.1)

The information supplied in FSAR Subsection 7.3.2.1.1 for GDC 24 is insufficient. Therefore, provide additional information on separation of protection and control systems and clarify the statement that, "The ESFAS is not a protection system."

Response

The ESFAS is separated from the control systems. No single failure of any control system component can impair the safety functions of ESFAS. FSAR Subsection 7.3.2.1.1 has been revised.

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Where protective action is required under adverse environmental conditions during certain incidents of moderate frequency, infrequent events and limiting faults, the ESFAS components are designed to function under such conditions.

Criterion 24: Separation of Protection and Control Systems

The ESFAS systems is separated from the control systems. No single failure of any control system component can impair the safety functions of ESFAS. 5 420.23

Criteria 34, 35, 37, 38, 40, 41, 43, 44 and 46

The ESF systems and the ESF support system are designed to comply with the above criteria. The instrumentation and control for these systems are discussed in Subsection 7.3.1.1.

Criteria 54, 55, 56, 57:

The instrument sensing lines for monitoring containment pressure are discussed in Subsection 7.1.2.2.

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Question No.

420.24
(7.3.2.1.3)
(7.2.2.3.3)

Subsection 7.3.2.1.3 refers to certain actuated devices which are not tested during reactor operation but are to be tested during reactor shutdown. Such devices are not sufficiently discussed in the appropriate portions of Subsections 7.2.2.3.3 and 7.3.2.1.3. Therefore, identify the specific equipment and provide the justification for not including this equipment in the tests during reactor operation in line with the recommendations contained in Regulatory Guide 1.22 and BTP ICSB #22 in Appendix 7A of Standard Review Plan.

Response

With regard to ESFAS testing, refer to revised FSAR Subsection 7.3.2.1.3. Also refer to the FSAR Table 7.3-9 for listing of actuated devices which are not tested directly from the ESFAS during normal reactor operation. The table also indicates degree of testing during operation and an effect of failure of component to assume accident position.

All RPS Functions can be tested one channel at a time while the plant is operating by using the built in test circuits, with the following exceptions:

1) PORV Actuation - This logic circuit requires two out of four trip actuations and therefore can only be tested during plant shutdown when the PORV control circuit external of the RPS can be defeated. Testing the PORV will also initiate a reactor trip.

2) CEA Withdrawal Prohibit (CWP) - This logic circuit requires two out of four one-trip actuations and should be tested only during plant shutdown.

3) Response Time Testing - This test requires two out of four actuations of the RPS and can only be performed during plant shutdown.

NI detectors and preamplifiers where utilized are not capable of being tested during operation. Proper operation of these channels is verified by periodic channel comparisons.

Process transmitters and sensors feeding the RPS not accessable during operation are also checked for proper operation by periodic channel comparisons.

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4.20 "Information Readout"

Instruments are provided in the control room to allow the operator to monitor ESFAS measurement channel inputs. The specific displays that are provided for continuous monitoring are described in Subsection 7.5.1.

4.21 "System Repair"

Identification of a defective channel is accomplished by observation of system status lights or by testing as described in Subsection 7.3.1.1.1d. Replacement or repair of components is accomplished with the affected channel bypassed.

4.22 "Identification"

The ESFAS equipment, including panels, modulus, and cables associated with the actuation system, are uniquely identified. Interconnecting cables are color coded on a channel basis (see Subsection 8.3.1.3).

7.3.2.1.3 Testing Criteria

IEEE 338-1971, "Criteria for the Periodic Testing of Nuclear Generating Station Protection Systems," and Regulatory Guide 1.22, (RO) provides guidance for development of procedures, equipment, and documentation of periodic testing. The basis for the scope and means of testing are described in this section. Test intervals and their bases are included in the Technical Specifications. Since operation of the ESF system is not expected, the systems are periodically tested to verify operability. The system is tested from the sensor signal through the actuation devices. Complete channels can be individually tested without initiating protective action, without violating the single failure criterion, and without inhibiting the operation of the systems. The organization for testing and for documentation is described in Chapter 13.

Minimum frequencies for checks, calibration and testing of the ESFAS instrumentation are given in the Technical Specifications. Overlap in the checking and testing is provided to assure that the entire channel is functional.

The operability of the measurement channel sensors is verified during reactor operation by cross-checking between sensor output signals. Each of the ESFAS sensors has a control room readout and the operator can detect sensor malfunction through anomalous indication of the failed sensor.

Those actuated devices, which are not tested during reactor operation as described in Subsection 7.3.1.1.1 (e.g., main feedwater isolation valves), are tested during scheduled reactor shutdown to assure that they are capable of performing the necessary functions. Table 7.3-9 lists all actuated devices not tested from ESFAS during normal operation and indicates degree of testing during reactor operation. 5 420.24

During refueling the ESFAS sensors are checked and calibrated against known standards. The test equipment which is used to verify the sensor ac-

curacies is checked periodically against shop reference standards traceable to nationally recognized standards. The pressure and electronic calibration standards are as accurate or better than the devices to be checked in accordance with ANSI N45.2.1b.

Testing of ESFAS sensor response times is in accordance with the requirements of the Technical Specifications.

7.3.2.1.4 Failure Modes and Effects Analysis

Failure modes and effects analyses for the ESFAS are provided in Table 7.3-7. Figures 7.3-6, 7 and 8 are used as a typical ESFAS showing bistables and isolation modules. Figure 7.3-9 shows the typical logic.

7.3.2.1.5 Consideration of Selected Plant Contingencies

a) Loss of Instrument Air System

None of the essential control or monitoring instrumentation is pneumatic. Electrical instrumentation is powered from the emergency power system. Therefore, the loss of instrument air does not degrade instrumentation and control systems required for shutdown of the plant.

b) Loss of Cooling Water to Vital Equipment

None of the instrumentation and controls required for safe shutdown rely on cooling water for operation. Air conditioning systems required to maintain the environment within the instrument design parameters are redundant and described in Sections 6.4 and 9.4.

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Question No.

420.25
(7.3)

In the discussion of the Main Steam Isolation Signal (MSIS), in Subsection 7.3.1.1.5 of the FSAR, it is stated that a MSIS on either channel (steam generator A or steam generator B) closes the main steam isolation valve, the main feedwater isolation valve and the backup feedwater isolation valve in that channel, and sends a signal through an isolation device to close the same components of the other channel. Upon review of the associated logic, schematic, and wiring diagrams, the following discrepancies were noted:

a) The MSIS logic diagram, Figure 7.3-5, does not include the logic in which the signal from one channel actuates the components in the other channel. Modify this figure accordingly.

b) On the schematic diagrams for the main steam isolation valves (2998-B-326 sheets 312 and 315, Revision 1) the two MSIS contacts are both shown in the normally closed position. However, in the control wiring diagrams (2998-B-327 sheets 312 and 315, Revision 6) the two MSIS contacts are shown as one normally open and one normally closed. Resolve this inconsistency.

c) Also, in the schematics and wiring diagrams identified in b), it was noted that the 4YA coil is connected directly to the positive bus through the SA/SB contact while the 4YB coil is connected to the positive bus through several contacts. Please clarify this difference.

Response

a) Refer to revised FSAR Figure 7.3-5.

b,c) Refer to revised Schematic diagrams 2998-B-326 sheets 312 and 315.

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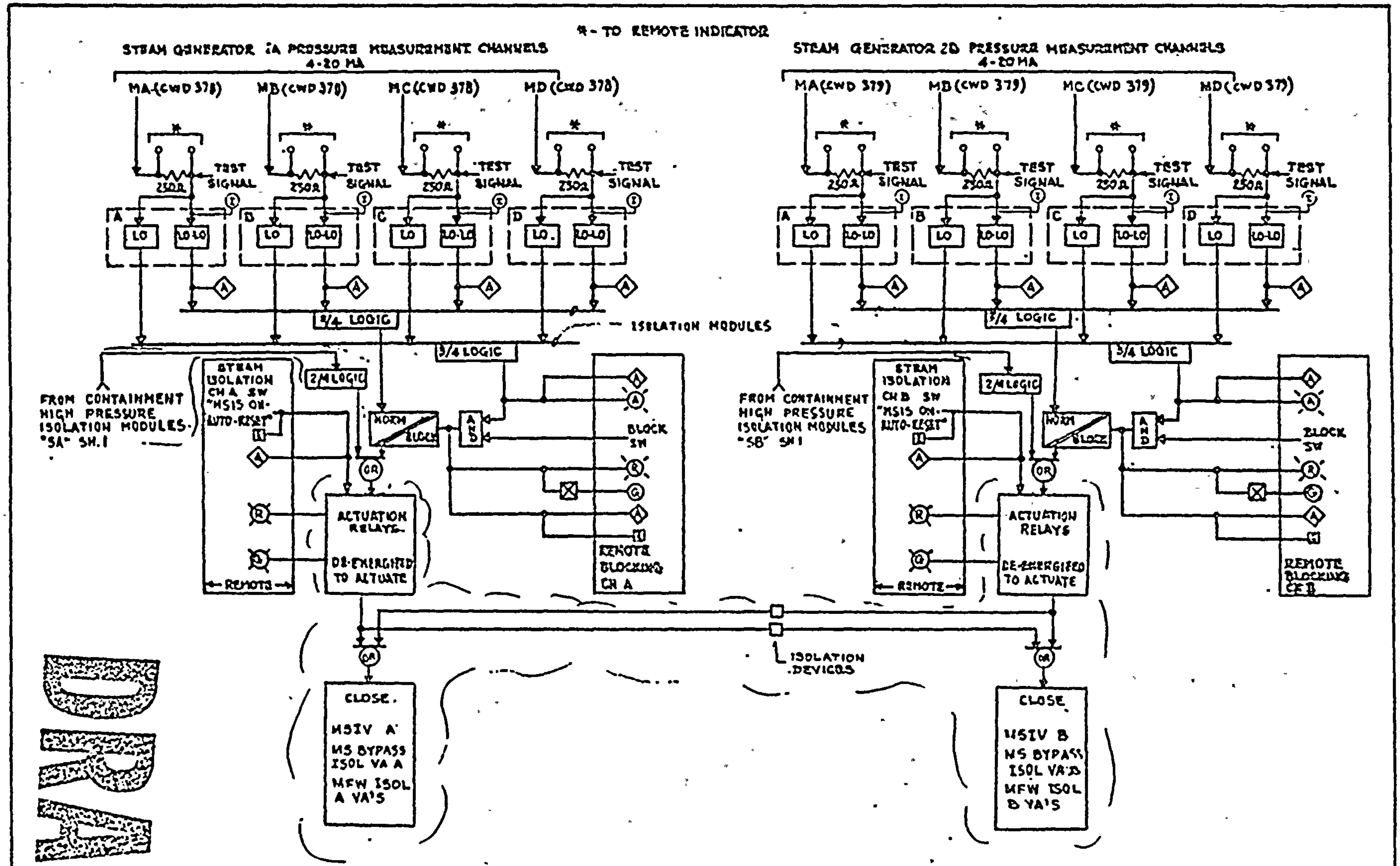

NOTE:
1. FOR SYMBOLS SEE FIGURE 7.3-1.
2. MSIAS BLOCK IS AUTOMATICALLY REMOVED ABOVE LO STEAM GEN. PRESSURE.

REF DWG: 8X-2998-145 SH 4 (REV 1)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

MSIS LOGIC DIAGRAM

FIGURE 7.3-5

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Question No.

420.26
(7.3)

The second and third paragraphs of Subsection 7.3.1.1.5 state that the MSIS signal is initiated by low steam generator pressure or high containment pressure. However, in parts a) and h) of this section, it is stated that only one parameter, steam generator pressure, initiates that signal. Resolve this inconsistency.

Response

Refer to revised FSAR Subsection 7.3.1.1.5.

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of-three logic for automatic actuation. The two-out-of-three logic meets full safety requirements including the requirement of the single failure criterion.

The measurement channels logic and actuation channels associated with steam generator A are separated from those associated with steam generator B. An MSIS signal on either channel closes the MSIV, the main feedwater isolation valve, and the backup feedwater isolation valve on that channel, and sends a signal through an isolation device to close the MSIV, the main feedwater isolation valve, and the backup feedwater isolation valve of the other channel. This ensures that in the unlikely event of a steam line break accident upstream of the MSIVs; the MSIVs close and limit the blowdown to the faulted steam generator. The consequences of such an occurrence are evaluated in Chapter 15.

A manual block on the MSIS is provided to permit shutdown depressurization of the Main Steam System without initiating MSIS. This process is under strict administrative control with block and block permissive annunciated and indicated in the control room. It is not possible to block above a preset pressure: if the system is blocked and pressure rises above this point, the block is automatically removed. The block circuit is designed to comply with the single failure criterion specified in IEEE 279-1971. Each MSIS actuation channel can be initiated manually from the control room. A list of components activated on a MSIS is given in Table 7.3-6. 0

a) Initiating Circuits

The initiating circuits for the MSIS is similar to that described in Subsection 7.3.1.1.1a for SIAS except that the parameters monitored are the steam generator pressure for each steam generator and containment pressure. 5 420.26

b) Logic

The MSIS logic is shown on Figure 7.3-5.

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c) Output Relays

The output relays for MSIS are similar to those described in Subsection 7.3.1.1.1c for SIAS.

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d) Manual and Automatic Test Circuitry

Manual and automatic testing for MSIS is similar to that described in Subsection 7.3.1.1.1d for SIAS.

e) Bypasses

Bypasses for MSIS are similar to those described in Subsection 7.3.1.1.1e for SIAS.

f) Interlocks

Interlock provisions for MSIS are similar to those described in

Subsection 7.3.1.1.1f for SIAS.

g) Redundancy

Redundancy features for MSIS are similar to those described in Subsection 7.3.1.1.1h for SIAS.

h) Diversity

The only parameters being measured are steam generator pressure and containment pressure; therefore functional diversity is applicable. 5 420.26

i) Sequencing

Sequencing equipment and functions for MSIS are similar to those described in Subsection 7.3.1.1.1g for SIAS.

j) Auxiliary Supporting Systems Required

The auxiliary supporting systems required are identified and described in Subsection 7.3.1.1.6.

7.3.1.1.6 ESF Supporting Systems

The ESF supporting systems listed below are described in the referenced sections:

a) Component Cooling Water System (Subsection 9.2.2)

b) Intake Cooling Water System (Subsection 9.2.1)

c) Onsite Power System, including the diesel generator system (Section 8.3)

d) Diesel Fuel Oil Storage and Transfer System (Subsection 9.5.4)

e) Heating, Ventilating and Air Conditioning (HVAC) Systems as required for areas containing systems and equipment required for safe shutdown (Section 9.4).

7.3.1.1.7 Systems Not Actuated by ESFAS

a) Combustible Gas Control System

The Combustible Gas Control System is provided to control the concentration of hydrogen that may be released into containment following a LOCA; see Subsection 6.2.5.

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Question No.

420.27 The discussion concerning the loss of the instrument air system in Subsection 7.3.2.1.5 states that none of the essential control or monitoring instrumentation is pneumatic. However, Table 6.2-53, which lists the containment isolation valves, shows that many of the ESF actuated valves are pneumatically operated. Revise your discussion of the consequences of loss of instrument air accordingly. This discussion should include the following:

(1) A list of all pneumatically operated valves and controls which are safety related.

(2) The normal operating position for each pneumatically operated valve and control and the safety function position.

(3) Identification of all pneumatically operated valves and controls that do not move to the safety function position upon loss of air.

Response

FSAR Subsection 7.3.2.1 "Engineered Safety Features Actuation System" provides the criteria for the ESFAS and states that the essential control and monitoring instrumentation for the ESFAS system is electrically powered from the emergency power system and, thus, does not require the use of the Instrument Air System.

The Instrument Air System, which is described in FSAR Subsection 9.3.1 serves no safety function and, therefore, is designed to non-safety, non-seismic requirements. Safety related air operated valves are designed to fail in the position required to perform their safety function in the event a loss of instrument air supply occurs. The pneumatic safety related valves which require air to perform safety functions are provided with seismic Category I air accumulators for valve operation (refer Subsection 9.3.1). Therefore, the complete loss of the instrument air system during full-power operation or under accident conditions in now way reduces the ability of the Reactor Protection System or the Engineered Safety Features and their supporting system to safely shut down the reactor or mitigate the consequences of an accident.

All valves go to their safe position as a result of loss of instrument air, loss of power or safety actuation. Those valves required to change state after an actuation signal are provided with seismic Category I air accumulators.

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Question No.

4 20. 28 (7.4) (5.4.7) SHUTDOWN COOLING SYSTEM (SDCS): FSAR Subsection 5.4.7.2.6 states that manual actions for alignment of the SDCS require that the LPSI pump suction valves from the refueling water tank and the containment sump be closed with a handwheel located in the safeguards pump room (outside the control room).

This design is not suitably justified as required by Position A.3 of BTP RSB 5-1. Therefore, describe all areas where system operation is required outside the control room to align the SDCS and provide sufficient information to justify such a design as required by the above position.

Response

A) The LPSI pump suction valves from the refueling water tank and the containment sump, V3432, V3444, respectively, are in the process of being changed to motor operated valves with remote manual actuation from the control room.

B) Manual action outside the control room is required to restore power to the safety injection isolation valves motor operators. Once the pressurizer pressure is above 500 psig the SIT valves are opened and the power to the operators is removed. In order to isolate the SITs from the SDCS these isolation valves (V3614, 24, 34, 44) must have their power restored and closed. The power is restored in the motor control center which is located outside the control room.

C) There are no other areas where normal actions are required in order to align the SDCS.

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Question No.

420.29 (7.4) FSAR Subsection 7.4.2.3 states that the safe shutdown systems are periodically tested to verify proper functioning during normal plant operation. Describe how the safe shutdown systems coform to the requirements of IEEE 338 and the recommendations of Regulatory Guide 1.22 since the existing FSAR information is insufficient. conform

Response

Pumps and valves for safety and shutdown systems are tested monthly. Pumps are run for a minimum of 15 minutes. Valves are actuated for full travel verification. The safeguards actuation system has an automatic test circuit to monitor trip set points. At 18 month intervals an integrated test of the ESF is performed. This test assured operation and response of all safety equipment and circuits.

Testing will be done in accordance with technical specifications.

DRAFT

JUL 24 1981

Question No.

420.30 (7.4) Control wiring diagrams for the atmospheric dump valves show control switches on the hot shutdown control panel which are not listed in FSAR Table 7.4-2. Please clarify and amend the FSAR where necessary.

Response

Refer to revised FSAR Table 7.4-2.

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TABLE 7.4-2(1)

INSTRUMENTATION AND CONTROL - HOT SHUTDOWN PANEL
OUTSIDE THE CONTROL ROOM

Instruments Tag No.	Service	Safety Section	Scale Range	
LI-9113	Steam Generator 2A Water Level	SA	0-100%	
PI-8113	Steam Generator 2A Press	SA	0-1000 psia	
PIC-08-1A1,3A1	S.G 2A Atmospheric Steam Dump	SA	0-1200 psig	
PI-1108	Pressurizer Pressure	SA	0-3000 Psi psia	
LI-1105	Pressurizer Water Level	SA	0-100%	
TI-1115-1	Reactor Cold Leg Temp	SA	0-600 F	
TI-3351Y	Shutdown Cooling Temp	SA	0-350 F	0
FI-3306	Shutdown Cooling Flow	SA	0-5000 gpm	
VM-1606-1	Diesel-Gen 2A Volts	SA	0-5250V	
WM-1606-1	Diesel-Gen 2A Watts	SA	0-5000kW	
JI-001A1	Neutron Power Level	MA	2×10^{-8}%-200%	
JI-001B1	Neutron Power Level	MB	2×10^{-8}%-200%	
LI-9123	Steam Generator 2B Water Level	SB	0-100%	
PI-8123	Steam Generator 2B Press	SB	0-1000 psia	
PIC-08-1B1,3B1	S.G. 2B Atmospheric Steam Dump	SB	0-1200 psig	
PI-1107	Pressurizer Pressure	SB	0-3000 Psi psia	0
LI-1104	Pressurizer Water Level	SB	0-100%	
TI-1125-1	Reactor Cold Leg Temp	SB	0-600 F	
TI-3352Y	Shutdown Cooling Temp	SB	0-350 F	
FI-3301	Shutdown Cooling Flow	SB	0-5000 gpm	
VM-1616-1	Diesel-Gen 2B Volts	SB	0-5250V	
WM-1616-1	Diesel-Gen 2B Watts	SB	0-5000kW	
HIC-09-1C1	Aux. F. W. Pump 2C Turbine	SAB	0-6000 gpm	

Switches and Indicating Lamps

Tag. No	Service	Safety Section	
CS-610-2	Aux FW 2A Disch Tie MV-09-13	SA	
CS-608-2	Aux FW 2A Disch MV-09-9	SA	
CS-629-2	Aux FW Pump 2A	SA	
CS-189-1	Aux Spray Valve SE-02-3	SA	
CS-157-1	Letdown Contain Isol V-2516	SA	
CS-194-2	Charging Line Isol V-2523	SA	
CS-177	Charging Pump 2A	SA	
CS-176-1	Charging Line Valve ISE-02-02	SA	
CS-246-3	SIAS "A" Block	SA	
CS-1625-2	Stm Gen 2A Atm Stm Dump Valve MV-08-19A	SB	
CS-1626-2	Stm Gen 2A Atm Stm Dump Valve MV-08-18A	SA	5
CS-1628-2	Stm Gen 2B Atm Stm Dump Valve MV-08-18B	SA	420:30
CS-1627-2	Stm Gen 2B Atm Stm Dump Valve MV-08-19B	SB	
CS-609-2	Aux FW 2B Disch MV-09-10	SB	
CS-611-2	Aux FW 2B Disch Tie MV-09-14	SB	

SL2-FSAR

TABLE 7.4-2 (Cont'd)

Switches and Indicating Lamps

Tag No.	Service	Safety Section	
CS-630-2	Aux FW Pump 2B	SB	
CS-189-2	Aux Spray Valve SE-02-4	SB	
CS-157-2	Letdown Stop Valve V-2515	SB	
CS-194-1	Letdown Contain Isol V-2522	SB	
CS-178	Charging Pump 2B		
CS-176-2	Charging Line Valve ISE-02-01	SB	
CS-248-3	SIAS "B" Block	SB	
CS-612-2	Aux FW 2C to SG 2A MV-09-11	SB	
-	Aux FW 2B Disch Valve SE-09-3	SB	
-	Aux FW 2C Disch Valve SE-09-4	SB	
CS-179	Charging Pump 2C	SAB	4
CS-652-2	Steam from SG 2A to Aux FW 2C Turbine MV-08-13	SB	
CS-653-2	Steam from SG 2B to Aux FW 2C Turbine MV-08-12	SB	
CS-632-2	Aux FW Pump 2C Turbine	SAB	
CS-124	Pressurizer Back-up Htr Bank B-1	None	
CS-125	Pressurizer Back-up Htr Bank B-2	None	
CS-126	Pressurizer Back-up Htr Bank B-3	None	
CS-127	Pressurizer Back-up Htr Bank B-4	None	
CS-128	Pressurizer Back-up Htr Bank B-5	None	
CS-129	Pressurizer Back-up Htr Bank B-6	None	

(1) Information identified as Later will be provided in a future amendment.

Question No.

420.31 (7.4.1) According to Subsection 7.4.1, monitoring of the reactor coolant boron concentration is required for shutdown. Please describe the instrumentation/systems to be used to measure the boron concentration. Be sure to include a description of the power sources(s) and design criteria. Electrical schematics and one-line wiring diagrams should be included as support documentation. Also, explain why this instrumentation is not included in Tables 7.4-1 and 7.5-1.

Response

The boronometer is provided to permit data to be available as a backup and to assist in trending. Principal boron monitoring is attained by local and remote wet chemistry samples. The boronometer is non safety-related, non-IE and is isolated (on letdown line) for post-accident conditions; it is therefore not included in the Table 7.4-1. This table includes minimum requirements for monitoring safe shutdown. Table 7.5-1 provides for IE equipment, the boronometer is not so qualified. The boronometer receives power from 120V PP220.

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Question No.

420.32 (7.4.1.3) Section B.1.(a) of BTP RSB 501, "Design requirements of the residual heat removal system," requires that valve positions be indicated in the control room. Please provide a description of how (limit switches, indicators, etc.) the shutdown cooling system meets this requirement. Also, provide the acceptance design criteria used for valve position indication.

Response

Branch Technical Position RSB 5-1, B.1.(a) reads as:

B. RHR System Isolation Requirements

The RHR system shall satisfy the isolation requirements listed below.

1. The following shall be provided in the suction side of the RHR system to isolate it from the RCS.

(a) Isolation shall be provided by at least two power-operated valves in series. The valve positions shall be indicated in the control room.

The design satisfies the branch position with the following feature. For train A the power operated isolation valves in series inside the containment boundary on the shutdown cooling suction line are V3480 and V3481. For train B they are V3651 and V3652. Each valve has an "open" light, A "closed" light.

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Question No.

420.33 (7.4.1.3) (7.6.1.1) With regard to the Shutdown Cooling System Interlocks (Section 7.6.1.1), the description of the measurement channels does not establish that there is any diversity among the channels. The staffs' position in this area (see Standard Review Plan Appendix 7A-ICSB BTP 3 Item 2) requires diversity in the interlocks.

Provide a discussion of your conformance to this portion of the position. In addition, identify all other points of interface between the Reactor Coolant System (RCS) and other systems whose design pressure is less than the design pressure of the RCS. For each such interface, discuss the degree of conformance to the above cited Branch Technical ~~p~~osition 3.

Response

Overpressure protection is provided by interlocks and high capacity relief valves. Diversity of the interlock channels has not been provided. There is sufficient redundancy and adequate controls on operator action that overpressure protection is provided.

The operator is not solely dependent on pressure channels controlling the interlocks to make the decision to open the shutdown cooling valves.

Two other reactor coolant system pressure indications exist for comparison, PI 1107 and PI 1108.

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Question No.

420.34 (7.3) (7.4) (7.6) Branch Technical Position (BTP) ICSB 18, "Application of the single failure criterion to manually-controlled, electrically operated valves," gives the staff's position on disconnection of power to electrical components of fluid systems. Please identify such areas of design and state your conformance to the BTP ICSB 18.

Response

6

Disconnecting power to electrical components as required by the BTP ICSB-18 is provided for the safety injections tank isolation valves V-3614, V-3624, V-3634 and V-3644 (Reference drawings B-327 Sheets 269, 270, 271, and 272). The removal of electrical power (by rackout and lockout of the breakers) is to assure the open position of these valves and to prevent, by single failure, isolation of the safety injection tanks. Isolation of the tanks is not required until the RCS is depressurized below 600 psi. Ample time in excess of the 10 minute criterion is available to restore power for this action.

In addition, the motor operated valves in the safety injection system which have the power removed are the SIT isolation valves and the hot leg injection isolation valves. (Valves: 3614, 3624, 3634, 3644, 3551, and 3550, respectively).

The hot leg injection valves V3551 and V3550 meet the Branch Technical Position for their ability to have power restored. Because hot leg injection is not manually initiated until two hours (per FSAR Subsection 6.3.2.8) after the event of safety injection actuation the valves meet the 10 minute criterion for having power restored. The position indication redundancy requirement is met by having position indication displayed in the control room for the isolation valves and the throttling valves (V3540 and V3523) which are in series.

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Question No.

420.35 (7.4.2.4) In the description of systems required for safe shutdown in Subsection 7.4.1, no discussion of the pressurizer heaters and spray system is presented. However, controls for these systems are included on the hot shutdown panel. Please provide a description of the pressurizer controls as required for shutdown.

Response

A description of the pressurizer system with a discussion of the pressurizer heaters and the pressurizer main spray system is supplied in FSAR Subsection 5.4.10. The manual operation of certain pressurizer heaters from the hot shutdown panel is provided for operator convenience. The pressurizer heater system is not required for safe shutdown as sufficient stored energy is available in the pressurizer. Safety-related, Class IE pressurizer auxiliary spray is available for required RCS depressurization following plant cooldown. The pressurizer auxiliary spray system is part of the Chemical and Volume Control Systems. FSAR Subsection 7.4.1 d) 5) will be revised to designate the auxiliary spray subsystem.

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d) Reactor Coolant System cooldown to cold shutdown which requires:

1) Actuation and control of Shutdown Cooling System

2) Control of Component Cooling Water System

3) Control of Intake Cooling Water System

4) Operation and control of boron addition and charging subsystem of CVCS

5) Monitoring of Reactor Coolant System pressurizer temperature, pressure and water level

6) Availability of auxiliary spray flow, as further described in Subsection 5.4.7.5 (item A.2). However, RCS depressurization during cooldown can be accomplished without auxiliary spray flow (see Subsection 5.4.7.5 (item A.2). 5 420.35

For off-normal shutdowns (e.g., loss of offsite power, loss of condenser cooling), the atmospheric dump valves are utilized for heat removal until shutdown cooling is initiated. The Onsite Power System (Section 8.3) provides power upon a loss of offsite power. For all shutdown conditions the capability exists for emergency actions (see Subsection 7.4.1.5) outside of the control room.

Based on the above, the following is the minimum equipment required to be operable for safe shutdown:

a) Auxiliary Feedwater System

b) Chemical and Volume Control System (Boron addition and charging portions only)

c) Shutdown Cooling System

d) Atmospheric Dump Valves (or Steam Dump and Bypass System)

e) Control Room

f) Instrumentation listed in Table 7.4-1. 0

The following support systems are also required to be operable for safe shutdown, including shutdown with a concurrent loss of offsite power:

a) Onsite Power System

b) Diesel Fuel Oil Storage and Transfer System

c) Intake Cooling Water System

d) Component Cooling Water System

e) Heating, Ventilating, and Air Conditioning (HVAC) Systems for areas containing systems and equipment required for safe shutdown

The instrumentation and control systems required for safe shutdown of the reactor are in the subsections which follow.

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PRELIMINARY INFO ONLY JUL 1 198

Question No.
420.36
(7.4)

The FSAR states that manual transfer switches are provided at appropriate locations outside the control room so that the required circuits for hot shutdown are isolated from circuits in the control room. Please provide the following information:

a) Design basis for selection of instrumentation and control equipment on the hot shutdown panel.
b) Location of transfer switches and remote control station (include layout drawings, etc.).
c) Design criteria for the remote control station equipment including transfer switches.
d) Description of control of access to the displays and controls located outside the control room.
e) Discuss the testing to be performed during plant operation to verify the capability of maintaining the plant in a safe shutdown condition from outside the control room.
f) Description of isolation, separation and transfer/override provisions. This should include the design basis for preventing electrical interaction between the control room and remote shutdown equipment.
g) Description of any communication systems required to coordinate operator actions, including redundancy, separation, and environmental qualification.
h) Description of control room annunciation of remote control or override of devices under local control.

Response

a) The instrumentation and control equipment located on the hot shutdown panel has been selected to allow the operator to shutdown and maintain the unit at hot standby or cooldown conditions from outside the control room. Section 7.4.1.5 provides the basis for selection of equipment for the hot shutdown panel as follows:
1) Achieve prompt hot shutdown of the reactor.
2) Maintain the unit in a safe condition during hot shutdown.
3) Monitor cooldown
4) Control room evacuation is not accompanied by any DBA.
5) Any single failure does not prevent safe plant shutdown.
6) Channel independence is maintained by electrical and physical separation between redundant channels.
7) Equipment, including electric cables, related with redundant systems are uniquely identified with colored markers or nameplates.
8) The systems are designed to withstand safe shutdown earthquake loads without loss of their safety functions.
9) The systems can be tested with the plant shutdown.
10) Equipment is provided in appropriate locations outside the control room to bring the plant to a hot standby condition with capability for subsequent cold shutdown.

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b) Transfer switches and isolation switches are located on transfer panel 2A, 2B, 2AB and various MCC, Switchgear, respectively. These panels, MCCs and switchgears are concentrated in the middle section of RAB at Elevation 43 and RAB at Elevation 19.5 to facilitate transfer from control room to Hot Shutdown Control Panel (HSCP). HSCP is located in a room at the southwest corner of the RAB at Elevation 43. For specific locations, see attached Table 430.36-1 and drawings in FSAR Table 1.7-1 page 1.7-5.

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c & d) To meet the intent of Regulatory Guide 1.68.2 for Reactor remote shutdown capability, the following are remote shutdown procedures under three different plant conditons.

The three plant conditions are:

I) Remote Hot Shutdown (No LOOP)
II) Remote Hot Shutdown (LOOP)
III) Remote Cooldown and Shutdown (with or without (LOOP)

The shutdown procedures are developed, based on the availability of three to four operational personnels.

I) Condition I: Remote Hot Shutdown (No LOOP)

Before leaving the control room, the operators assure the Reactor and Turbine has been tripped. On the way down to the hot shutdown panel station, one person will be sent to the turbine building ground floor (7 KV and 4 KV Switchgear room) to trip the reactor coolant pumps, feed pumps, etc. Meanwhile, two persons will have the responsibility to activate all the transfer (isolate) devices mounted on transfer panel 2A, 2B, 2AB; 480 volt switchgear 2A2, 2B2; MCC 2A5, 2B5, 2A-6, 2B-6, 2AB; 4 KV switchgears 2A3, 2B3; Pressurizer Heater MCC 2A3, 2B3; 480-volt switchgear 2AB, and 4 KV switchgear 2AB. Most of the above MCCs, switchgears, transfer panels are located in the Reactor Auxiliary Building, floor elevation 43 ft, scattered on the west half of the floor. The 480 volt switchgear 2AB and 4KV switchgear 2AB are located on the 19.6 ft floor elevation. Approximately 56 transfer switches have to be activiated. It takes two persons approximately 10 minutes to complete the above transfer functions. From the time the operators leave the control room to the moment the hot shutdown panel is fully operational, it requires approximately 15 to 20 minutes. Once the hot shutdown station is operational, the senior licensed operator is stationed there to monitor and control the hot shutdown process, whereas the other two operators are strategically stationed at the MCC area 43 ft floor elevation (Reactor Auxiliary Building) and in the turbine building Communication is maintained by way of sound power phones (head sets) at required stations.

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c&d (cont'd) II) Condition II: Remote Hot Shutdown(LOOP)

If off-site power is not available (or lost), the Reactor Coolant Pumps and main FW pump, will be de-energized (ie., no further switchgear tripping is necessary in the turbine building). Under Loop conditions, one operator proceeds directly to the diesel building to assure proper initial loading of the diesels, whereas the other two operators will perform all the necessary transfer functions as mentioned in the above No Loop condition (Condition I).

Some additional manual switchgear loading might be required in order to connect certain plant investment load onto the emergency buses. Upon completion of all the necessary transfer functions, the hot shutdown panel is manned continuously by the senior operator, whereas the other two operators are stationed in Diesel Building and the Reactor Auxiliary Building, respectively, awaiting for further instructions.

III) Condition III: Remote Cooldown and Shutdown (with or without(LOOP)

For further plant cooldown and shutdown from HSP, several systems are required to be operated.

They are identified as follows:

A) Chemical & Volume Control System (CVCS). (SEE 9.3.4)

B) Shutdown Cooling System (SEE 5.4.7)

C) Reactor Coolant Sampling System (SEE 9.3.2)

D) Other supporting Systems such as CCW, ICW System etc; that are needed for A), B), and C) above.

From the Hot Shutdown Panel, the senior licensed operator directs the line-ups of the above systems which requires manual valve operation, "locked closed" and "locked open" valves, coolant sampling to check proper reactivity. Two operators are assigned to accomplish these tasks.

Access and regress to the displays and controls located outside of the control room is monitored and controlled by the security systems, card-keyed in and out of these areas. Control Board annunciation of switch positions are also provided and locked access to isolate switches are maintained.

For a list of ESF support systems and their associated subsections see Response to Question 420.38

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e) ~~Monthly testing is performed for control room inaccessibility Operating Procedure 0030151 remote shutdown monitoring.~~ By positioning the transfer/isolation switch to "ISOLATE", ~~each of~~ the instrument and control on the HSCP can be tested to assure their operability. This kind of test will be performed on a "not to disturb the normal operation" basis. There are a few other instruments on HSCP (such as pressurizer pressure) which have their own dedicated detectors and do not require transfer action because they are continuously functioning.

f) All instruments and controls of redundant channels are physically and electrically separated in accordance with Regulatory Guide 1.75 requirements. The isolation/transfer switches transfers the controls and instrumentation from the control room to the HSCP. During normal plant operation, constant supervision of the transfer/isolation switch positions (as discussed in paragraph (d) above) assures that no remote shutdown stations action will affect the control room operation. After the transferring, the remote shutdown controls and instrumentations are independent of the control room to the maximum practical extent.

g) Refer to response to NRC Question 430.5, which was reviewed & accepted by the PSB and incorporated into FSAR via Am#4 (7/2/81).

h) Each local transfer switch which renders control room inoperable in the isolation position is alarmed in the control room.

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Monthly testing is performed as per Operating Procedure #0030141 for remote shutdown monitoring assuming control room inaccessibility. These procedure will be available prior to startup.

Table 430.36-1

Transfer (isolate) devices are on transfer panel 2A, 2B, 2AB; 480V SWGR 2A2, 2B2, 2AB; MCC 2A5, 2B5, 2A6, 2B6, 2AB; 4KV SWGR 2A3, 2B3, 2AB; Pressurizer Heater MCC 2A3, 2B3.

The following are the locations of the above equipment:

EQUIPMENT	BUILDING/ELEVATION	EBASCO DRAWING NO.
Control Trasf. Panel 2A	RAB/43	G 394 Sh1
Control Trasf. Panel 2B	RAB/43	G 394 Sh1
Control Trasf. Panel 2AB	RAB/43	G 394 Sh1
480V SWGR 2A2	RAB/43	G 394 Sh1
480V SWGR 2B2	RAB/43	G 394 Sh1
480V SWGR 2AB	RAB/19.5	G 393
MCC 2A5	RAB/43	G 394 Sh1
MCC 2B5	RAB/43	G 394 Sh1
MCC 2A6	RAB/43	G 394 Sh1
MCC 2B6	RAB/43	G 394 Sh1
MCC 2AB	RAB/43	G 394 Sh1
4KV SWGR 2A3	RAB/43	G 394 Sh1
4KV SWGR 2B3	RAB/43	G 394 Sh1
4KV SWGR 2AB	RAB/19.5	G 393
Press Heater MCC 2A3	RAB/43	G 394 Sh1
Press Heater MCC 2B3	RAB/43	G 394 Sh1

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atmospheric dump valve.

7.4.1.5 CONTROL ROOM (or Hot and Cold Shutdown Capability from Outside the Control Room)

As discussed in the above subsections, the required instrumentation and controls utilized for safe shutdown are initiated from the control room. However emergency instrumentation and controls are provided to enable the operator to shutdown and maintain the unit at hot standby or cooldown conditions from outside the control room.

The control room and all Class 1E equipment therein are designed for design basis accident (DBA) scenarios discussed throughout the FSAR; thus the postulated control room conditions and/or event which would make it inaccessible and result in its evacuation, remain undefined. No mechanism is postulated which requires control room evacuation; therefore a control room evacuation is not accompanied by any DBA. Instrumentation and controls for equipment required for the hot or cold shutdown operations are provided outside the control room.

Controls and instrumentation for redundant equipment are mounted in separate sections of the hot shutdown panel (HSDP) such that no single failure can prevent the safe shutdown of the reactor. A list of indicators, controllers, control switches and indicating lamps located on the HSDP is given in Table 7.4-2.

INSERT "A"

In the event of a non-mechanistic evacuation of the control room, the operator trips the reactor before leaving the control room. Manual transfer switches are provided at appropriate locations outside the control room so that the required circuits for hot shutdown are isolated from the circuits in the control room. After completion of the required circuit transfers, the HSDP becomes fully operational. An alarm is initiated in the control room whenever any one of the transfer switches are operated into the transfer position. Operability of controls for equipment required for shutdown are based on the assumption that they are not affected by the destruction of circuitry within the control room. Sufficient instrumentation and controls are provided outside the control room to:

a) Achieve prompt hot shutdown of the reactor

b) Maintain the unit in a safe condition during descent to hot shutdown 0

f) If required, monitor cooldown and achieve cold shutdown through the use of suitable procedures. 0

7.4.1.6 Supporting Systems for Safe Shutdown

The supporting systems required for safe shutdown of the reactor listed below are described in the referenced sections:

a) Component Cooling Water System (Subsection 9.2.2)

b) Intake Cooling Water System (Subsection 9.2.1)

THIS IS INSERT "A"

All safety class (class IE) components on HSDP are qualified to IEEE 323-1974. The panel design meets the separation requirement of RG 1.75 and the overall design criteria of IEEE 279-1971 for protection system.

To activate HSDP, transfer switches and isolation switches have to be turned to "isolate" position. Transfer switches and isolation switches are located on transfer panel 2A, 2B, 2AB and various MCCs and switchgears are concentrated in the middle section of RAB at Elevation 43 and RAB at Elevation 19.5 to facilitate transfer from control room to Hot Shutdown Panel (HSDP). HSDP is located in a room at the southwest corner of the RAB at Elevation 43.

Question No.

420.37 (7.5) FSAR Table 7.5-1, "Safety-related display instrumentation," does not describe the display instrumentation on the plant auxiliary control board. Therefore, please describe the function, design criteria and location of this control board and amend Table 7.5-1 appropriately.

Response

Plant Auxiliary Control Board is one panel section of Heating-Ventilating and Plant Auxiliaries Control Board. This board is physically located in the southeast corner of the control room, to the right hand side of the Reactor Turbine Generator (RTG) control board 201. The board can be observed by the RTG Board operators from their control stations. Plant auxiliaries such as outdoor aviation lighting switches, instrument air compressor control switches, etc; are located on the non-safety section of the plant auxiliary board. On the safety sections of the board (SA and SB section), two safety-related redundant annunciator LA and LB and atmospheric steam dump controls are located. The atmospheric steam dump controls are duplicated here as a backup to the controls located on RTG board 202 and Hot Shutdown panel. The safety section is separated from the non-safety section of the plant auxiliary control board in accordance with Regulatory Guide 1.75. Refer to FSAR Table 7.5-1 which was revised in Amendment No. 4, July 2, 1981 to include the steam dump controls.

DRAFT

JUL 24 1981

Question No 420, 38 (7.4.1.5)

The FSAR states that sufficient instrumentation and controls are provided outside the control room to achieve cold shutdown through the use of suitable procedures. Please provide a summary of the procedures used to achieve cold shutdown from outside the control room. These procedures and associated equipment should ensure that cold shutdown can be accomplished before Technical Specification limits on hot shutdown are exceeded. Be sure to include a list of the systems required for cold shutdown from outside the control room and the location of the panels where these system controls are housed. Discuss the design criteria applied to these systems and controls. Also, if coordination of control at the hot shutdown panel and the local panels is needed to achieve and maintain cold shutdown, discuss what communication facilities are available.

Response. The systems listed below are required to achieve ~~cold~~ shutdown conditions from outside of the control room. These systems are discussed in section 7.4.1.

a) Auxiliary Feedwater System.

b) Chemical and Volume Control System
   Boric Acid System
   RCS Charging
   Auxilary Pressurizer Spray

c) Shutdown Cooling System.

d) Atmospheric Dump Valves.

e) ESF Support Systems

Controls for the above systems are located outside the control room at the hot shutdown panel or locally. The design criteria for the above systems are provided in the FSAR sections as listed below:

System	FSAR Section
Auxiliary Feedwater System	7.4.1.1
Chemical and Volume Control System	7.4.1.2
Shutdown Cooling System	7.4.1.3
Atmospheric Dump Valves	7.4.1.4

INSERT A

Additionally, the actions needed to ~~achieve cold~~ shutdown with only safety grade systems are discussed in FSAR Section 5.4.7 as revised in Amendment 4.

Recognizing the complexity of ~~acheiving~~ cold shutdown from outside the control room, FP&L will ~~has~~ generated a single ~~single~~ off-normal/emergency procedure to accomplish this. Procedure for cold shutdown from outside the control room ~~is~~ will be provided in the Off-normal/Emergency Procedure #0030141 when the control room is inaccessible. These procedures will be available prior to startup.

INSERT A

ESF Support Systems are the following:

a) Onsite Power System 8.3.1

b) Diesel Fuel Oil Storage and Transfer System 9.5.4

c) Intake Cooling Water System 9.2.~~I~~1

d) Component Cooling Water System 9.2.2

e) Heating, Ventilating, and Air Conditioning Systems for areas containing systems and equipment required for safe shutdown 9.4

Question No.

420.39 (7.5) (7.5.1.1) Please provide the following information on bypass and inoperable status indication (Regulatory Guide 1.47):

a) Regulatory Guide 1.47 recommends automatic indication at the system level of bypassed or deliberately induced inoperability of the protection system and systems actuated or controlled by the protection system. The second paragraph of Subsection 7.5.1.6 implies that some protection systems do not have automatic initiation of bypassed or inoperable status, but require manual initiation. Identify all protection systems not provided with automatic initiation of bypass and inoperable status at the system level and provide justification for this manual initiation.

b) State how the bypass and inoperable status indication system conforms to Regulatory Position C.2 of Regulatory Guide 1.47. Discuss the design criteria (bases) used in the selection of equipment/systems to be monitored, and provide the criteria to be employed in the display of inter-relationships and dependencies on equipment/systems. This is to insure that bypassing or deliberately induced inoperability of any auxiliary or support system will automatically indicate all safety systems affected.

c) The title of Table 7.3-10 suggests that the table includes the RPS/ESF bypasses or inoperable status indication. However, no RPS equipment is included in the table. Also, the combustible gas control system and the diesel fuel oil storage and transfer system are not included. Revise the table to include all RPS/ESF systems for which bypass or inoperable status indication is provided.

d) Information supplied is insufficient to determine complete conformance to the design criteria of branch technical position (BTP) ICSB 21. Therefore, please provide additional information on how the bypass and inoperable status indication system complies to Positions B.3, B.4, and B.5 of BTP ICSB 21.

Response

a) St. Lucie Bypass Indication System is basically actuated automatically. The effectiveness of this automatic indicating system is further enchanced by including a manual actuation capability. The manual capability of the bypass indication system is endorsed by the Regulatory Guide 1.47 position C4.

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The FSAR Table 7.3-10 identifies all systems for which bypass indications are automatic. However, some parts of those systems require manual actuation, e.g. closure of the manual HPSI pump suction valve (bypass indication window A2) for the maintenance of HPSI pump 2A.

b) <u>Conformance with the R.G. 1.47 Position C2.</u>

The Bypass Indicating System is automatically activated by the bypassing or deliberately induced inoperability on the supporting systems. FSAR Table 7.3-10 reflects ~~this~~ these requirements (e.g., LP Safety injection "A1" automatically activated by the diesel generator and/or the component cooling water unavailability).

c) RPS trip channel bypasses are not automatically annunciated on the control board but are indicated on the RPS which is in the control room in view of the operator. Table 7.3-10 lists only the ESFAS systems and it will be amended to indicate this.

The combustible gas systems are assigned to the bypass indication windows A-13 and B-13 as "H_2 systems". The Diesel Fuel Oil Storage and fuel oil transfer to the day tanks systems are not indicated automatically on the bypass indication module, but they are annunciated in the control room by redundant Class IE annunciators. Refer to drawing 2998-B-327 sheets 1142 & 1143 in FSAR Section 1.7.

d) Compliance to ICSB 21 Position B.3, B.4, and B.5 can be summarized as follows:

B.3) St Lucie 2 ESF bypass indicating system provides availability (or bypass) indications of all ESF systems. These indications are at a system level. M ~~m~~eans are not provided to cancel erroneous bypass indication. However, the operator can always assure the system status by cross checking the associated component operating status through their corresponding annunciation windows.

B.4) The ESF bypass indicating system is strictly status indication available to the control room operator. Based on the bypass informations and other related instrumentations, the operator can intelligently coordinate all maintenance/test activities throughout the plant, without compromising the plant safety.

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B.5) Proper isolation devices are provided between the bypass indicating system and all safety related systems to assure adverse effects cannot propagate from the indicating systems to the plant safety systems. Isolation devices are in accordance with Regulatory Guide 1.75.

The bypass indication system is not essential to safety and is primarily used as augmented indication to other safety-related indicators (i.e., motor indicating lights, valve position, Class IE indicators, etc.). Administrative procedures do not rely on bypass indication for immediate operator actions.

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Question No.

420.40 (7.5.1.1) The FSAR states that available information for the engineered safety features systems consist of valve position indication. Please describe the design features used to provide direct indication of ESF system valves.

Response

All ESF valves have red and green indicating lights in the control room. The red light indicates open valve position and the green light indicates closed valve position. The lights are powered from the same power source as the valve actuating circuit and are located above the control switch, except for valves supplied with the valve position indicators. In this case, the valve position indicator is located above the control switch with lights located on the vertical section of the board.

The following valves have position indicators and indicating lights in the control room: (refer to Table 420.~~38~~-1, attached).

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TABLE 420.40-1

VALVE TAG #	VALVE DESCRIPTION	POSITION INDICATOR TYPE	POSITION INDICATOR POWER	CWD
V 3614	SIT 2A2 Isolation Valve	Analog	Separate from control power	270, 255
V 3624	SIT 2A1 Isolation Valve	Analog	Separate from control power	269, 255
V 3634	SIT 2B1 Isolation Valve	Analog	Separate from control power	271, 255
V 3644	SIT 2B2 Isolation Valve	Analog	Separate from control power	272, 255
HCV-3615	LPSI Flow Control Valve	Analog	Same as control	257
HCV-3625	LPSI Flow Control Valve	Analog	Same as control	260
HCV-3635	LPSI Flow Control Valve	Analog	Same as control	263
HCV-3645	LPSI Flow Control Valve	Analog	Same as control	266
HCV-3616	HPSI Flow Control Valve	Analog	Same as control	261
HCV-3626	HPSI Flow Control Valve	Analog	Same as control	258
HCV-3636	HPSI Flow Control Valve	Analog	Same as control	264
HCV-3646	HPSI Flow Control Valve	Analog	Same as control	267
HCV-3617	HPSI Flow Control Valve	Analog	Same as control	262
HCV-3627	HPSI Flow Control Valve	Analog	Same as control	259
HCV-3637	HPSI Flow Control Valve	Analog	Same as control	265
HCV-3647	HPSI Flow Control Valve	Analog	Same as control	268
V 3540	HPSI to Hot Leg 2A Valve	Analog	Same as control	233
V 3523	HPSI to Hot Leg 2B Valve	Analog	Same as control	235
FCV-3306	Shutdown Cooling Bypass Valve	Analog	Same as control	1516
FCV-3301	Shutdown Cooling Bypass Valve	Analog	Same as control	1517
HCV-3657	Shutdown Cooling Control Valve	Analog	Same as control	1514
HCV-3512	Shutdown Cooling Control Valve	Analog	Same as control	1515

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TABLE 420.40-1 (Cont'd)

VALVE TAG #	VALVE DESCRIPTION	POSITION INDICATOR TYPE	POSITION INDICATOR POWER	CWD
V 3536	Shutdown Clg Line 2A Warm-up Valve	Analog	Same as control	1510
V 3539	Shutdown Clg Line 2B Warm-up Valve	Analog	Same as control	1511
V 1474	Pressurizer Power Oper. Relief (PORV)	Acoustical - Lights	Separate	Note (1)
V 1475	Pressurizer Power Oper. Relief (PORV)	Acoustical - Lights	Separate	Note (1)
V 1200	Pressurizer Relief Valve	Acoustical - Lights	Separate	Note (1)
V 1201	Pressurizer Relief Valve	Acoustical - Lights	Separate	Note (1)
V 1202	Pressurizer Relief Valve	Acoustical - Lights	Separate	Note (1)

Note (1) - Will be Implemented by 10-15-81

Went out to NRC ~ 8/4/81

Question No: 420.41 (7.5)

"Instrumentation for light-water-cooled nuclear power plants, to assess plant and environs conditions during and following an accident, "Regulatory Guide 1.97 (Rev. 2), Section D, Implementation, states that "Plants scheduled to be licensed to operate before June 1, 1983, should meet the requirements of NUREG-0737 and the Commission Memorandum and Order (CLI-80-21) and the schedules of these documents or prior to the issuance of a license to operate, whichover date is later. The balance of the provisions of this guide should be completed by June 1983." Provide a commitment to comply with this schedule.

Response: 420.41

The requirements of RG 1.97 Rev.2 are implemented as described in Attachment C for type B,C,D and E variables. Type A variables will be identified and described in accordance with the statement provided in Attachment B. Definitions of types A,B,C,D and E as well as Category 1,2 and 3 variables are provided in Attachment A.

Environmental qualification of RG 1.97 Rev. 2 equipment in accordance with NUREG 0588 will be handled in the same manner as all the other equipment in the plant. The results of the environmental review will be submitted or available for review in accordance with Section 3.11 of the FSAR. The submittal for equipment in harsh environment is scheduled for November 30, 1981.

ATTACHMENT A

Type A - Those variables that provide primary information so that operators can take the specified manual actions for which there are no automatic actions so that safety systems can accomplish their safety function for DBE. This does not include those variables required for contingency actions.

Type B - Those variables that indicate that safety functions are being accomplished.

Type C - Those variables that indicate a breachor potential to breach of barriers to fission product release. (fuel cladding, RCS pressure boundary, containment)

Type D - Those variables that indicate the operation of individual safety systems and other systems important to safety.

Type E - Those variables that indicate the magnitude of radioactive releases and for assessing such releases.

Category 1

a) Provides the most stringent requirements for key variables.

b) Qualified to RG 1.89

c) Seismically qualified to RG 1.100

d) The instrumentation systems will be single failure proof.

c) A minimum of two channels will be provided with additional backup instruments (same or diverse) to verify correct channel in the event of a "mid-scale" instrument failure.

d) Redundant or diverse channels will be independent and physically separated in accordance with RG 1.75.

e) The instrumentation will be powered from Standby Power per RG 1.32 and backed up by battery. (UPS)

f) The instrumentation will be available prior to an accident.

g) The proper QA requirements apply.

h) Continuous indication will be provided (may be a recorder).

i) Where variable trending is required for operator information, dedicated recorders or continuously updated and stored in computer memory and displayed on demand information will be provided.

j) These variables are considered PAM instrumentation or part of effluent monitoring instrumentation.

k) Types A,B, and C will be identified on the control boards for easy recognition by the operator.

Category 2

a) Less stringent requirements than Category 1 and applies to variables which indicate system operating status.

b) Qualified to RG 1.89.

c) Seismic qualification to RG 1.100, <u>if</u> the device is part of a safety related system.

d) Instrumentation will be powered from a high reliablility power source.

e) Technical Specification out of service requirements for the system the process variable covers, apply also to the process variable components.

f) The proper QA requirements apply.

g) The signal may be displayed on an individual instrument or CRT (demand display).

h) The display may be dial, digital, CRT or stripchart recorder.

i) Where variable trending is required for operator information, a dedicated recorder or continuously updated, stored in computer memory and displayed on demand information will be provided.

j) These variables are considered PAM instrumentation or part of effluent monitoring instrumentation.

k) Types A,B, and C will be identified on the control boards for easy recognition by the operator.

Category 3

a) provides requirements for high quality off-the-shelf instrumentation and applies to backup and diagnostic variables.

b) provides the requirements for equipment where state-of-the art cannot meet Category 1 & 2 levels.

c) Will be high quality commercial grade and capable of the specified service environment.

d) Display may be dial, digital, CRT or stripchart recorder.

e) Where variable trending is required for operator information, a dedicated recorder or continuously updated, stored in computer memory and displayed on demand information is provided.

ATTACHMENT B

F P&L is conducting a program to identify R.G.1.97, Rev 2 Category "A" variables by the end of the first quarter of 1982. Any necessary changes to instrumentation will be installed by June of 1983, but in all cases efforts will be made to complete installation at the earliest possible date. C-E Owners Group generic emergency guidelines will be reviewed to identify all preplanned manual actions. The guidelines to be reviewed are contained in CEN-152: Combustion Engineering Emergency Procedures Guildelines which was submitted to the NRC by the C-E Owners Group on June 30, 1981. Instruments needed to perform actions will be identified by tag number. The range, and qualification states of each instrument will also be identified. The necessary range will be determined from existing St Lucie 2 FSAR and C-E Owners Group calculation.

In summary, by the end of the first quarter of 1982 F P&L will provide the following

A. Category A variables list
   - Instrumentation identified by tag number.
   - Required and actual ranges, and qualification
B. What changes will be made by October 1982
C. What changes will be made by June 1983

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
JI-001A B C D	Neutron Flux	B1	10^{-6}% to 100% full power	1	2×10^{-8} to 200%	Safety grade indication is provid in the control room. Recording i also provided.
91 Reed Switch Position Indicators-1 per CEA	Control Rod Position	B2	Full in or not full in	3	Full in or not full in	
Boronometer AR-2203	RCS Soluble Boron Concentration	B3	0 to 6000 ppm	3	0-1250/ 5000 ppm	There are two additional boron concentration measurement possibilities. 1 - Manual grab sample - primary means. See E18 2 - Post Accident Sampling
See B6	RCS Cold Leg Water Temperature	B4	50°F to 400°F	3	See B6	Same indicators and recorders as for Item B6.
TI-Later TI-Later TR-Later TR-Later	RCS Hot Leg Water Temperature	B5	50°F to 750°F	1	-	Wide range indicators will be installed measuring 50° - 750°F range to meet the regulatory requirements. Safety grade indication and recording will be provided in the control room.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
TI-1115 TI-1125 TR-1115 TR-1125 TI-Later TI-Later	RCS Cold Leg Water Temperature	B6	$50^{O}F$ to $750^{O}F$	1	$0-600^{O}F$	Wide range measurement will be provided with a range $50^{O}-750^{O}F$. TI-1115 and 1125 are safety grade Indication and recording is provided in the control room. Two additional safety temperature monitoring loops will be provided for the other two cold legs.
PI-1107 PI-1108 PR-1107	RCS Pressure	B7	0 to 4000 psig	1	0-3000 psia	Safety grade redundant indication is provided in the control room. One channel is recorded. Existing range is acceptable. The 0-4000 psig range required is based on ATWS which is not a resolved issue.
	Core Exit Temperature	B8	$200^{O}F$ to $2300^{O}F$	3		Core Cooling is currently being addressed as part of TMI. This measurement consists of heater junction thermocouples for Reacto Vessel level, core exit thermocouples and Subcooled Margin Monitor. Details will be submitte as part of the NUREG 0737 submitted.
	Coolant level in Reactor	B9	Bottom of core to top of vessel	1		
	Degrees of Subcoolant	B10	$200^{O}F$ subcooling to $35^{O}F$ superheat	2		
Same as B7	RCS Pressure	B11	0-4000 psig		See B7	See B7
LI-07-14A LR-07-13A/14A	Cont Sump Wtr Level	B12	Narrow range (Sump)	2	(-7 elev) - (0 ft elev)	No redundancy required. Indicato and recorder will be in control room. For details see response to NUREG 0737 Item II.F.1.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
LI-07-13A LI-07-13B LR-13A/14A	Cont Wtr Level	B12	Wide range, bottom of cont to 600,000 gal level equivalent	1	(-1 ft elev) -(26 ft elev	Range will be provided per NRC requirements. Safety grade redundant measurement and indicator in CR will be provided. One channel is recorded. For more details see resonse to NUREG 0737 Item II.F.1.
PI-07-4A/5A	Containment Pressure	B13	0 to design pressure	1	0-60 psig Existing PAM Instrumentation	Design pressure is 44 psig. Range provided covers the required 0-44 psig range. Safety grade redundant measurement is provided. One channel is indicated and one channel is recorded in the control room.
Various	Containment Isolation Valve Position	B14	Closed - Not Closed	1	Closed - Not Closed	Safety grade position indication is provided as required.
(Same as B13)	Containment Pressure	B15	10 psia to design pressure	1	0-60 psig Existing PAM Instrumentation	Range provided does not cover the lower end of the required range (-5 psig -44 psig) however additional containment pressure transmitters PT-07-4A1 and 4B1 cover -5 psig to 175 psig. In addition four transmitters are provided (PT-07-2A,B,C & D) with ranges 0-15 psig for Safety Injection Actuation. The combination of these ranges provide adequate coverage.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
Same as B8	Core Exit Temperature	C1	200°F to 2300°F	1	See B8	See comments on B8
	Radioactivity Concentration or Radiation Level in Circulating Primary Coolant	C2	1/2 Tech Spec limit to 100 times Tech Spec limit, R/hr.	1		A Category 2 radiation monitor that is connected to the primary system letdown line will be provided. The range of those monitors will extend from 1% tech spec limit to at least 10 times the tec spec limit. Extending the range tc 100 times is being investigated.
	Analysis of Primary Coolant (Gamma Spectrum)	C3	10 μCi/gm to 10 Ci/gm or TID-14844 source term in coolant volume	3	Grab Samples	Same method with lab analysis capability for 10 μCi/ml to 10 Ci/ml
Same as B7	RCS Pressure	C4	0-4000 psig	1	See B7	See comments on B7.
Same as B13 and B15	Containment Pressure	C5	10 psia to design pressure	1	0-60 psig Existing PAM Instrumentation	See comments on B13 and B15.
Same as B12	Containment Sump Water Level	C6	Narrow Range (Sump) Wide Range (Bottom of Cont to 600,000 gal equivalent)	2 1	(-7 ft elev) 0 ft elev) (-1 ft elev) -(26 ft elev)	See comments on B12

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
RE-26-40 RE-26-41	Containment Area Radiation	C7	1 R/hr to 10^4 R/hr	3	1R/hr to 10^8 R/hr	The equipment to be provided will be category 1 and will cover the range requirements. Redundancy will be provided. Both channels will be indicated and recorded in the CR. For details see response to NUREG 0737 requirement - Item II.F.1.C
RS-26-11	Effluent Radioactivity-Noble Gas Effluent From Condenser Air Removal System Exhaust	C8	10^{-6} μCi/cc to 10^{-2} μCi/cc	3	10^{-7} μCi/cc to 10^{-2} μCi/cc	The equipment provided covers the range requirements. Indication is provided in the control room
Same as B7	RCS Pressure	C9	0-4000 psig		See B7	See comments on B7.
H_2 Analyzer Panel	Containment Hydrogen Concentration	C10	0-10% (Capable of operating from 10 psia to maximum design pressure)	1	0 - 10%	The range being provided is compatible with NRC requirement. The equipment was specified to operate between -2 psig to 44 psig (design pressure). Since the St Lucie 2 containment is atmospheric, the pressure is not anticipated to drop below -2 psig. Two safety related indicators and one recorder are located in the CR.
PI-07-4A1 PI-07-4B1 PR-07-4A1	Containment Pressure	C11	10 psia to 4 times design press for steel containment	1	-5 psig to 175 psig	Range provided per NRC requirement Safety grade redundant measurement and indication in CR will be provided. One channel will be recorded. For details see response to NUREG 0737 Requirement - Item II.F.1.a

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
RS-26-13 RS-26-14	Containment Effluent Radioactivity Noble Gases from identified release points	C12	10^{-6} μCi/cc to 10^{-2} μCi/cc	2	10^{-7} μCi/cc to 10^{-2} μCi/cc	The range provided covers the requirements. Redundant safety related monitors are provided with indication and recording in the CR. This is an off-line monitor on the plant stack that conforms to ANSI N13.1-1969.
Same as E2	Radiation Exposure Rate	C13	10^{-1} R/hr to 10^{4} R/hr	2	Same as E2	See E2 methods.
RS-26-90 RS-26-Later RS-26-Later	Effluent Radioactivity Noble Gases	C14	10^{-6} μCi/cc to 10^{3} μCi/cc	2	10^{-6} μCi/cc to 10^{5} μCi/cc	Equipment is being added to satis fy TMI requirements. The ranges provided cover the requirements. Plant vent indication and recording is provided in the CR. Redundant indication and recording will be provided for the ECCS vents. For more details see response NUREG 0737 Item II.F.1.
FIC-3301 FIC-3306 FR-3301 FR-3306	RHR System Flow	D1	0 - 110% design flow	2	0-5000 gpm	Safety grade indication and recording is provided in the contrc room. Design flow is 3300 ppm therefore the range provided is acceptable.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
TR-3303W TI-3303X TI-3303Y TR-3303Z	RHR Heat Exchanger Outlet Temperature	D2	$32^{o}F$ to $350^{o}F$	2	$0\text{-}350^{o}F$	Safety grade indication and recording is provided in the control room.
LIA-3311 LIA-3321 LIA-3331 LIA-3341	Accumulator Tank Level and Pressure	D3	10% to 90%	2	6.5% to 93.5%	Measurements are non safety. The environmental qualification of the sensors will be evaluated against the requirements of the guide.
PIA-3311 PIA-3321 PIA-3331 PIA-3341			0 - 750 psig	2	0-700 psig	The range provided for tank pressure should be acceptable. 700 psig exceeds tank design pressure and tank safety valve setpoint.
	Accumulator Isolation Valve Position	D4	Closed or Open	2	Closed or Open	Safety grade open/closed position is provided in the Control Room.
FIA-2212	Boric Acid Charging Flow	D5	0 - 110% design flow	2	0-150 gpm	The measurement provided measures flow from the charging pumps; it does not measure directly Boric Acid flow to the charging pumps. Design flow is 132 gpm so range provided is adequate.
FI-3311 FI-3321 FI-3331 FI-3341	Flow in HPI System	D6	0 - 110% 0 - 352 gpm	2	0 - 400 gpm	Safety grade redundant indication is provided in the control room. 0-110% design flow coresponds to 0-352 gpm, therefore range provided is acceptable.

TAG NO.	VARIABLE DESCRIPTION	TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
FI-3312 FI-3322 FI-3332 FI-3342	Flow in LPI System	D7	0 - 110% design flow	2	0 - 2500 gpm	Safety grade redundant indication is provided in the control room. 0 - 110% design flow corresponds to 0 - 650 gpm therefore the range provided is acceptable.
LIS-07-2A LIS-07-2B LIS-07-2C LIS-07-2D	Refueling Water Storage Tank Level	D8	Top to Bottom	2	0 - 50 ft	The range provided covers the useful volume of the tank. Safety grade redundant indication is provided in the CR. Useful volume includes 2.6% to 100% of total tan height.
AM-101, 105 109, 113	Reactor Coolant Position Indication	D9	Motor Current	3	0-800 amps	One Motor Current indicator per pump is provided in the CR. Indicators are non-safety.
FI-01-1 FI-01-2 FI-01-3 FI-01-4 FI-01-5	PORV and SRV Position Indication	D10	Closed - Not Closed	2	Acoustic Flow Monitors - Closed-0 Flow Open -100% Flow Intermediate positions will also be indicated	One measurement channel will be provided for each valve with indication in the CR. The equipment is environmentally qualified for the accident in which is required to operate. For more details see response to NUREG 0737 Requirement - Item II.D.3.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
LI-1110X LI-1110Y	Pressurizer Level	D11	Bottom to Top	1	0 - 100%	Safety grade redundant indication is provided in the control room. The range is equivalent to 1.6% to 93% of bottom to top of vessel height. Range is adequate to assure continued safe operation of the pressurizer heaters and for the purposes of determining RCS leak and void
AM-Later	Pressurizer Heater Status	D12	Electric Current	2	0-150 amps	Two indicators will be provided (one per bus) to meet the regulatory requirements.
LIA-1116	Quench Tank Level	D13	Top to Bottom	3	0 - 100%	One non-safety level indication is provided in the control room. The range corresponds to 9.5 to 90.5% of top to bottom tank height. This range is adequate for monitoring tank operation.
TIA-1116	Quench Tank Temperature	D14	$50^{o}F$ to $750^{o}F$	3	0 to $300^{o}F$	One non-safety temperature indication is provided in the control room. The St Lucie 2 quench tank design pressure is 100 psig. Prior to attaining this pressure the 18" rupture disc will provide a relief path to the containment atmosphere. Therefore any relief from the pressurizer safety valves will be maintained below 100 psig and a corresponding saturation temperature less than the proposed $350^{o}F$ temperature range of the tank. The existing range will be changed to $0-350^{o}F$.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
PIA-1116	Quench Tank Pressure	D15	0 to design pressure	3	0 - 100 psig	One non-safety pressure indication is provided in the control room. Design pressure is 100 psig therefore the range provided is acceptable.
LIC-9013A LIC-9013B LIC-9013C LIC-9013D LR-9013D LIC-9023A LIC-9023B LIC-9023C LIC-9023D LR-9023D	Steam Generator Level	D16	From tube sheet to separators	1	0 - 100%	Redundant safety grade indicators are provided in the control room. One channel per steam generator is also recorded in the control room. The lower tap is just above the tube sheet and the upper tap is just below the separators therefore the range provided is adequate.
PI-8013A PI-8013B PI-8013C PI-8013D PR-8013D PI-8023A PI-8023B PI-8023C PI-8023D PR-8023D	Steam Generator Pressure	D17	From atmospheric pressure to 20% above the lowest safety valve setting.	2	0 - 1000 psia	Redundant safety grade indication is provided in the control room. One channel per steam generator is recorded. The range provided is not adequate and will be changed to meet the requirements to 0-1200 psia.
FI-08-1A FI-08-1B	Safety/Relief Valve Positions of Main Steam Flow	D18	Closed - Not Closed	2		Main Steam flow is indicated in the CR. This measurement is accepted for Safety Relief valve position indication. Qualified sensors are being utilized.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
FR-9011 FR-9021	Main Feedwater Flow	D19	0 to 110% design flow	3	0 to 6.0 x 10^6	Non-safety flow recording is provided in the control room. Since the existing range of 0 to 6 x 10^6 lb/hr is close to the required range of 0-6.2 x 10^6 lb/hr range is considered adequate.
FI-09-2A FR-09-2A FI-09-2B FR-09-2B/2C FI-09-2C	Auxiliary or Emergency Feedwater Flow	D20	0 - 110% design flow	2	0 - 300 gpm 0 - 300 gpm 0 - 600 gpm	Safety grade indication and recording is provided in the control room. The ranges provided for the motor driven pump flow are inadequate based on the recalculated pump capacities and SG cooling requirements. For the motor driven pumps the maximum flow is 350 gpm. The turbine driven pump is 500 gpm. FI-09-2A, 2B will be changed to 0-400 gpm range. For FI-09-2C, 0-600 gpm is adequate.
LIS-12-11 LIS-12-11B LR-Later	Condensate Storage Tank Level	D21	Plant Specific	1	0 - 50 ft	The range provided covers 1.1% to 100% of bottom to top of vessel height. Since this is a category 1 measurement redundancy is required. Redundancy is also required due to NRC's generic review of the AFWS. A redundant measurement is added, LIS-12-11B. Both safety related channels will be indicated and one channel will be recorded in the CR.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
FI-07-1A FR-07-1A FI-07-1B FR-07-1B	Containment Spray Flow	D22	0 - 110% design flow	2	0-5000 gpm	Maximum flow is 3600 gpm. The range provided covers the require ments. Safety related indication and recording is provided in the control room for each spray pump flow.
TI-07-3A/5A TR-07-3B/5B	Containment Atmospheric Temperature	D24	40^{o}F to 400^{o}F	2	50^{o}-350^{o}F	The range provided does not cover the requirements. Considering that during a MSLB the containment can reach 420^{o}F the scale range will be changed to 50° - 450^{o}F.
TR-25-1A TR-25-1B	Heat Removal by the Containment Fan Heat Re- moval System	D23	Plant Specific	2	0 - 300^{o}F	Containment cooling Fans 2HVS-1A, 1B, 1C and LP Cooling Coil inlet and outlet temperatures are re- corded in the CR. The measuremen is safety related. The scale ranc provided covers the requirements.
TI-07-3A/5A TR-07-3B/5B	Containment Sump Water Temperature	D25	50^{o}F to 250^{o}F	2	50^{o}-350^{o}F	The range provided covers the requirement. One channel is indicated and the other is recorded in the CR.
Same as D5	Makeup Flow - In	D26	0 - 110% design flow	2	See D5	See D5

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
FIA-2202	Letdown Flow-Out	D27	0 - 110% design flow	2	0-150 gpm	Non-safety indication is provided in the control room. Existing range covers the requirements. The instrumentation will meet Category 2 requirements.
LIC-2226 LIC-2227	Volume Control Tank Level	D28	Top to Bottom	2	0 - 100%	Non-safety indication is provided in the control room. The range covers 14.1% to 85.9% of top to bottom of tank heights. Existing range is acceptable for monitoring CVCS operation. Instrumentation will meet Category 2 requirements.
TE-14-3A TR-25-2A TE-14-3B TR-25-2B	Component Cooling Water Temperature to ESF System	D29	$32^{o}F$ to $200^{o}F$	2	$0-300^{o}F$	CCw HX outlet temperature is recorded in the control room by a multipoint recorder. The range requirements is covered by the safety grade instrument provided.
FI-14-1A FI-14-1B	Component Cooling Water flow to ESF System	D30	0 to 110% design flow	2	0-15,000 gal/min.	Component Cooling Water HX outlet design flow 8500 gpm. The range provided is well within the requirements safety grade indication is provided in the CR.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
LIA-6607 LIA-6608 LIA-6609 LIA-6610	High Level Radioactive Liquid Tank Level	D31	Top to Bottom	3	0 - 100%	Level indication is provided in the control room. The range provided covers 5.2% to 93% of tank volume. This range is suitable for monitoring tank operation.
PI-6650 PI-6651 PI-6652	Radioactive Gas Holdup Tank Pressure	D32	0 to 150% design (0-300 psig) pressure	3	0-200 psig	The pressure range is not adequate and the indicator is not in the control room. Measurement will be upgraded to satisfy the required range. Control room indication is not necessary. Details for this system are provided in Chapter II.
All emergency ventilation dampers	Emergency Ventilation Damper Position	D33	Open - Closed Status	2	Open-Closed Status	Open-closed position is provided in CR for the all emergency ventilation dampers.
Various	Power Supplies Status of Standby Power and Other Energy Sources Important to Safety	D34	Voltages, currents, pressures	2	Various Indicators	See Page 14A, 14B.
See C7	Containment Area Radiation-High Range	E1	1 R/hr to 10^7 R/hr	1	See C7	See comments on C7.

The following status of Standby Power and Other Energy Sources Important to Safety are monitored in the control room:

1 - Startup/Standby Transformers -

a - Transformer primary winding voltage (230KV East-West Bus) - 240KV Recorder/888**, DVM/888**

b - Primary and Secondary breakers - status lights (closed-open)**

c - Transformer secondary winding (4160V Bus 2A2 & 2B2) voltage (VS-916, VS-917)**, Bus energized lights (IL-916, IL-916)**, current (AS-916, AS-917)**, Watthours (WHM-916, WHM-917)**

2 - Emergency on site 4160V 2A3, 2B3 & 2AB Buses -

a - Bus Tie Breakers Status lights*

b - 4160V Bus 2AB voltage, current & status (VM-942, AM-942, IL-942)*

c - 4160V Bus 2A3 & 2B3 voltage (VM-954, VM-564, IL-954, IL-964)*

3 - Emergency on site 480V Bus 2A2, 2B2 and 2AB

a - Incoming feeder breaker status lights (open-close)*

4 - Emergency on site Diesel-Generators 2A & 2B

a - current (AM-955, AM-965)*

b - voltage (VM-1606D, VM-1616D)*

c - frequency (FM-1606, FM-1616)*

d - vars (VARM-1606, VARM-1616)*

e - watts (W-REC-1606, W-REC-1616)*

f - Watthours (WHM-955D, WHM-965D)*

4 - (Cont'd)

g - diesel generator loading lights - 4160V feeders (IL-996 A,-B,-C,-D,-E, -F,-G,-H,-I, IL-997A,-B,-C,-D,-E,-H,-P, IL-998B,-C)*
480V feeders (IL-996K,-L,-M,-P,-Q,-R,-T, IL-997S,-T,-U,-V,-Q,-R, -M,-N, IL-998D,-E)*

5 - 125V DC Batteries

a - voltage (VM-1001, VM-1002, IL-1001, IL-1002)*
b - battery charges current (AM-1001, AM-1002)*
c - battery high discharge rate alarms(1)
d - battery breakers in open positions alarms (1)
e - ground alarms(1)

6 - 120V AC non-interruptable instrument buses MA, MB, MC & MD control room annunciation via local annunciator (1)

a - low DC voltage
b - high DC voltage
c - low AC voltage
d - out of frequency
e - ground
f - DC breaker trip

* - Category 1
** - Category 3
(1) - Non-Safety annunciators - the isolation devices are provided between annunciators and an associated Class 1E actuating devices.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
Various	Radiation Exposure Rate	E2	10^{-1} R/hr to 10^{4} R/hr	2	Area Radiation Monitors with range up to 10R/hr provided portable detectors are also available.	FSAR Subsection 12.3.4 describes the radiation monitors that will meet the intent of RG 1.97 items E2 and C13. Also, refer to the Plant Shielding and Radiation Source Control documents required by NUREG 0737.
See C14	Containment or Purge Effluent Noble Gas	E3	10^{-6} μCi/cc to 10^{5} μCi/cc 0 to 110% vent design flow	2	See C14	For radiation monitors see comments on C14. Radiation release rate available at the plant stack monitor.
See C14	Reactor Shield Building Noble Gas	E4	10^{-6} μCi/cc to 10^{4} μCi/cc 0 to 110% vent design flow	2	See C14 Flow not needed	See comments on C14 Reactor Shield Bldg annulus is vented through the plant vent stack.
See C14	Auxiliary Building Noble Gas	E5	10^{-6} μCi/cc to 10^{3} μCi/cc 0 to 110% vent design flow	2	See C14 Flow not needed	See comments on C14 Auxiliary bldg is vented through the plant vent stack (See E3)
Not Required	Condenser Air Removal System Exhaust (Noble Gas)	E6	10^{-6} μCi/cc to 10^{5} μCi/cc 0 to 110% vent design flow	2	Not Required Flow not needed	Upon high radiation effluent flow is directed to the main plant stack (See E3) Procedures are existing that insure that realignment of valves to send CAE to Plant stack will be done within 30 minutes of high radiation signal. The flow through this vent is 50 cfm.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	RANGE REQUIRED	CATEGORY	EXISTING RANGE	COMMENTS
See C14	Common Plant Vent (with Cont Purge) (Noble Gas)	E7	10^{-6} μCi/cc to 10^{3} μCi/cc 0 to 110% vent design flow	2	See C14	For radiation monitors see comments on C14. Flow measurement is available indirectly through the plant stack radiation monitor.
RE-26-Later RE-26-Later	Vent from Steam Generator Safety Relief Valves or Atmospheric Dump Valves (Noble Gas)	E8	10^{-1} μCi/cc to 10^{3} μCi/cc	2	1 mR/hr to 10^{5} mR/hr	Monitors detect more easily total radiation. Isotopic analysis to provide μCi/cc result is provided by FPL. Indication is provided in the CR.
	All other identified release points (Noble Gas)	E9	10^{-6} μCi/cc to 10^{2} μCi/cc 0 to 110% vent design flow	2	10^{-7} - 10^{5} Ci/cc	For details on the ECCS Vent Monitors see NUREG 0737 item II.F.1 submittal. ECCS Vent Flow is 30,0 CFM. The flow indication provide is 50,000 CFM. This more than satisfies the 110% design flow requirements. The only other identified release point is the Fuel Handling Building. Upon high radiation effluent is diverted to the plant stack.
Various	All identified Plant release points (Particulates and Iodines)	E10	10^{-3} μCi/cc to 10^{2} μCi/cc 0 to 110% vent design flow	3	10^{-3} μCi/cc to 10 μCi/cc flow not needed	For details see NUREG 0737 Item II.F.1 submittals.
DELETED	~~Radiation Exposure Meters (continuous indication at fixed locations)~~	~~E11~~	Range location and qualification criteria to be developed to satisfy NUREG 0654, Section II.H.5b and 6b requirements for emergency radiological monitors	--	--	~~Can presently handle the range of 10 R/hr maximum in RAB. Investigating a factor of 1000 R/hr increase.~~ DELETED

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2			EXISTING RANGE	COMMENTS
		TYPE	RANGE REQUIRED	CATEGORY		
	Airborne Radiohalogens and Particulates (portable sampling with onsite analysis capability)	E12	10^{-9} μCi/cc to 10^{-3} μCi/cc	3		Sample on site and provide on site analysis. St Lucie 1 provides capability for backup for St Lucie 2.
	Plant and Environs Radiation (portable instrumentation)	E13	10^{-3} R/hr to 10^{4} R/hr, photons 10^{-3} rads/hr to 10^{4} rads/hr, beta radiations and low energy photons	3 3	10^{-3} R/hr to 10^{4} R/hr	Gross activity monitor available for the required range. There is no known available equipment for beta with a 10^{4} Rad/hr range.
	Plant and Environs Radioactivity (portable instrumentation)	E14	Multichannel gamma-ray spectrometer	3		Portable analyzers are available to meet the requirement.
	Wind Direction	E15	0 to 360° (±5° accuracy with a deflection of 15°). Starting speed 0.45 mps (1.0 mph). Damping ratio between 0.4 and 0.6, distance constant meters	3		Existing equipment meets the requirements.
	Wind Speed	E16	0 to 30 mps (67 mph) ±0.22 mps (0.5 mph) accuracy for wind speeds less than 11 mps (25 mph) with a starting threshold of less than 0.45 mps (1.0 mph)	3		Existing equipment meets the requirements.

TAG NO.	VARIABLE DESCRIPTION	R.G. 1.97 Rev 2 TYPE	 RANGE REQUIRED	 CATEGORY	EXISTING RANGE	COMMENTS
	Estimation of Atmospheric Stability	E17	Based on vertical temperature difference from primary system, -5° C to 10°C (-9° F to 18°F) and $\pm 0.15^{\circ}$ C accuracy per 164 foot intervals) or analogous range for alternative stability estimates	3		Existing equipment meets the requirements.
	Primary Coolant and Sump	E18	Grab sample			1 - Grab and delution capability - liquid scimtillation - proportional counting - spectroscopy-gamma spectrum.
	Cross Activity		10μCi/mi to 10 Ci/mi	3		
	Gamma Spectrum		(Isotopic Analysis)			
	Boron Content		0 to 6000 ppm			2 - Auto dilution capability to 10^6 ppm.
	Chloride Content		0 to 20 ppm			**Boron Content** 0 - 6000 ppm range capability
	Dissolved Hydrogen or Total Gas[19]		0 to 2000 cc(STP)/kg			**Chloride Cont** 0 - 20 ppm range capability
	Dissolved Oxygen[19]		0 to 20 ppm			
	pH		1 to 13			**Oxygen** See response to NUREG 0737 - Item II.B.3.
	Containment Air		Grab sample			
	Hydrogen Content		0 to 10% 0 to 30% for ice condensers	3		**Hydrogen** Delpihine portable activity analysis available.
	Oxygen Content		0 to 30%			
	Gamma Spectrum		(Isotopic analysis)			**Gamma Spectrum** Isotopic analysis is done with grab samples from H_2 analyzer

Question No.

420.42 (7.5) Both Tables 7.4-1 and 7.5-1 list instrumentation required for shutdown. However, the lists are not consistent. Audit both tables and modify them so that the shutdown instrumentation is consistent.

Response

Refer to FSAR Tables 7.4-1 and 7.5-1 which were revised in Amendment No. 4 July 2, 1981.

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Question No.

420.43 SAFETY INJECTION TANK (SIT) ISOLATION VALVE INTERLOCKS:

(7.6.2.2.2) 1) Describe how valve position indication (i.e., limit switches, visual indicators, etc.), is accomplished for the safety injection tank isolation valves as required by Position 2 of branch technical position (BTP) ICSB 4.

2) Describe the design criteria applied to this position indication system.

3) Discuss how the SIT isolation valve system conforms to Position 3 of BTP ICSB 4. As a minimum, describe the independence of power supplies for the visual indication system and alarms and provide electrical schematics, one line wiring diagrams, etc., as support information.

4) The FSAR information supplied for Item 4.22 of IEEE 279-1971 states that, "The instrumentation and cables associated with SIT isolation valve interlocks is not uniquely identified." It is the staffs position that a method be used for identifying safety related instrumentation and control circuits and equipment which is in conformance with the recommendation of Regulatory Guide 1.75 and the requirements of IEEE 384. Therefore, please describe how the instrumentation and cables associated with the SIT isolation valve interlocks conform to the above recommendations and requirements.

Response

1) Each SIT isolation valve has two means of position indication displayed in the control room. There is an open light and a closed light display for each. Also there is a 0-100% position indicator.

2) The design criteria applied for this system is ICSB 18 which required redundant position indication in the control room for valves which have their power racked out.

3) Audible and visual alarms are ~~provied~~ provided which meet the requirements of ICSB 4, technical position items 2 and 3.

4) The SIT isolation valve interlocks are uniquely identified as Class 1E circuits and are in conformance with the recommendations of Regulatory Guide 1.75 and the requirements of IEEE 384. The FSAR Subsection 7.6.2.2.2 paragraph 4.22 will be amended to clarify this.

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The SIT level and pressure instrumentation is not uniquely identified as Class 1E instrumentation. These SIT level and pressure instrumentation are not utilized for SIT isolation valve interlocks. Therefore, these instruments are located on the control board in a non-safety section. However, the redundant instrument cables are routed in the physically separate non-safety cable trays and the instrument power is supplied from a separate non-safety power source.

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TABLE 420.43-1

SIT INSTRUMENT

SIT	TAG #	DESCRIPTION	NON-SAFETY POWER SOURCE	CABLE TRAY SYSTEMS	INSTRUMENT FUNCTION	CWD
2A2	LIA-3311	Level Narrow Range	PP 220 (NA)	NA	Indication & Hi-Low Alarm	280, 647
	LIA-3312	Level Wide Range	PP 221 (NB)	NB	Indication & HH-LL Alarm	1521, 647
	PIA-3311	Pressure	PP 220 (NA)	NA	Indication & H-L Alarm	280, 647
	PS-3312	Pressure	PP 209 (NB)	NB	LL Alarm	1522
	PS-3313	Pressure	PP 209 (NB)	NB	HH Alarm	1522
2A2	LIA-3321	Level Narrow Range	PP 220 (NA)	NA	Indication & H-L Alarm	281, 647
	LIA-3322	Level Wide Range	PP 221 (NB)	NB	Indication & HH-LL Alarm	1521, 647
	PIA-3321	Pressure	PP 220 (NA)	NA	Indication & H-L Alarm	281, 647
	PS-3322	Pressure	PP 209 (NB)	NB	LL Alarm	1522
	PS-3323	Pressure	PP 209 (NB)	NB	HH Alarm	1522
2B1	LIA-3331	Level Narrow Range	PP 221 (NB)	NB	Indication & H-L Alarm	282, 647
	LIA-3332	Level Wide Range	PP 220 (NA)	NA	Indication & HH-LL Alarm	1521, 647
	PIA-3331	Pressure	PP 221 (NB)	NB	Indication H-L Alarm	282, 647
	PS-3332	Pressure	PP 220 (NA)	NA	LL Alarm	1522
	PS-3333	Pressure	PP 220 (NA)	NA	HH Alarm	1522
2B2	LIA-3341	Level Narrow Range	PP 221 (NB)	NB	Indication & H-L Alarm	283, 647
	LIA-3343	Level Wide Range	PP 220 (NA)	NA	Indication & HH-LL Alarm	1521, 647
	PIA-3341	Pressure	PP 221 (NB)	NB	Indication H-L Alarm	283, 647
	PS-3342	Pressure	PP 220 (NA)	NA	LL Alarm	1522
	PS-3343	Pressure	PP 220 (NA)	NA	HH Alarm	1522

NA-Non-Nuclear Safety-Division A
NB-Non-Nuclear Safety-Division B
CWD-Ebasco Drawing 2998-B-327

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4.15 "Multiple Setpoints"

This requirement is not applicable.

4.16 "Completion of Protective Action Once Initiated"

This requirement is not applicable.

4.17 "Manual Initiation"

The valves are locked open during normal operation. The controllers are permissive controls which permit the operator to close the valves below a certain pressure. The controllers also open the valves above a certain pressure. The keylock required to close the valves does not override the controllers.

4.18 "Access to Setpoint Adjustments, Calibration and Test Points"

Access is controlled by administrative procedures.

4.19 "Identification of the Protective Action"

This requirement is not applicable.

4.20 "Information Readout"

The readout consists of pressure indicators and position indication for each valve. This provides the operator with clear and concise information.

4.21 "System Repair"

The components are accessible for repair. One channel can be placed out of service without jeopardizing the availability of the SITs.

4.22 "Identification"

The cables associated with SIT isolation valve interlocks are uniquely identified. The instrumentation cables associated with SIT level and pressure indication are not uniquely identified. The channels are identified to distinguish between channels of safety related equipment (see Subscription 7.1.2). 5 420.43

7.6.3 ADDITIONAL SYSTEMS REQUIRED FOR SAFETY

7.6.3.1 Refueling Interlocks

Refueling interlocks are described in Subsection 9.1.4.

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7.6.3.2 Fuel Pool Cooling and Purification System

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The Spent Fuel Pool Cooling and Purification System is described in Subsection 9.1.3.

Question No.

420.44
(7.7)

a. The FSAR Subsection 7.7.1.1.1 discusses the automatic withdrawal prohibit signal. Describe the logic used to implement this signal. Include logic diagrams and electrical schematics.

b. FSAR Subsection 7.7.1.2.1 states that the withdrawal prohibit signal can be bypassed at the operator's module. Discuss the operational procedures to be used to actuate this bypass and discuss the possible implications resulting from actuation of this bypass. Be sure to include as a minimum, such items as administrative control, control room indication, effects upon the reactor protective system, effects upon fuel design limits, etc.

Response

The design of the AWP and CWP are functionally identical to St Lucie Unit 1. Receipt of an AWP (Automatic Withdrawal Prohibit) signal, which is a contact closure interface, energizes the AWP relay. The energized AWP relay opens the contact interfacing the AWP signal to the control AWP raise/lower logic. When the logic power is removed from the AWP input, the circuitry cannot generate a CGR (control group raise) signal which is necessary for CEA motion.

Indications of AWP initiation are as follows:

1. At the CEDMCS supervisory panel
2. Plant Annunciator

The following is a functional description of the AWP:

a. The AWP Prohibits the withdrawal of all Regulating CEAs in the Automatic Sequential mode of control.

    1. The AWP interlock does not prohibit CEA motion in any other mode of control except Automatic Sequential.
    2. The AWP interlock does not prohibit CEA insertion.

b. An AWP interlock is generated by the CEDMCS whenever any of the conditions of Sections 1 through 4 occur.

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1. Reactor Coolant Loop Cold Leg Temperature (T_{cold}) exceeding a setpoint as indicated by a contact closing from either one or both of two channels of (T_{cold}) instrumentation.

2. Mismatch between average reactor coolant temperature (T_{AVG}) and the programmed temperature (T_{REF}) exceeding a setpoint as indicated by a contact closure from the Reactor Regulating System.

3. Turbine Bypass Demand as indicated by a contact closing from the Steam Bypass Control System.

4. A dropped rod condition, as indicated by a contact closure from a Reed Switch Position Transmitter Dropped Rod Contact (Reference Subsection 3.4.1).

The CWP signal from the RPS is interfaced to the CEDMCS via a normally closed contact. A CWP condition opens the contact de-energizing the CWP relay in the CEDMCS Common Logic Relay Interface. This removes a logic "1" input to the individual CEA enable logic which prevents a "withdraw CEA (WCE) signal from being generated to the CEDM coil timing logic. The WCE signal is necessary for CEA motion.

To bypass the CWP signal, at the CEDMCS control panel the operator must:

a. Depress and maintain the Bypass Enable switch.
b. Depress and maintain the CWP Bypass switch.

Control room annunciation is provided to indicate a CWP condition. Feedback signals from the CEDMCS illuminate the bypass pushbutton on the CEDMCS control panel to indicate operation of the override.

The following is a functional description of the CWP signal:

a. The CWP interlock prohibits the withdrawal of all CEAs in all modes of control regardless of any demand for motion.

b. A CWP interlock is generated by the CEDMCS upon a contact opening signal from the Reactor Protection System (RPS). This signal is initiated by a 2 of 4 pre-trip actuation in any one of the following:

   1. Local Power Density
   2. High Start-up Rate
   3. Thermal Margin Low Pressure
   4. High Power

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c. Local indication and a contact opening output for remote annunciation of the CWP interlock are provided.

d. The CWP interlock may be overridden from the CEDMCS Control Panel by depressing both the Bypass Enable and CWP Bypass Pushbuttons. The CWP bypass Pushbutton must be held depressed while demanding CEA motion. The override will allow all CEA motion in all modes of control.

The CWP function is not required by the Safety Analysis to prevent exceeding core safety limits. The CWP Bypass is maintained under strict administrative control via plant operating procedures.

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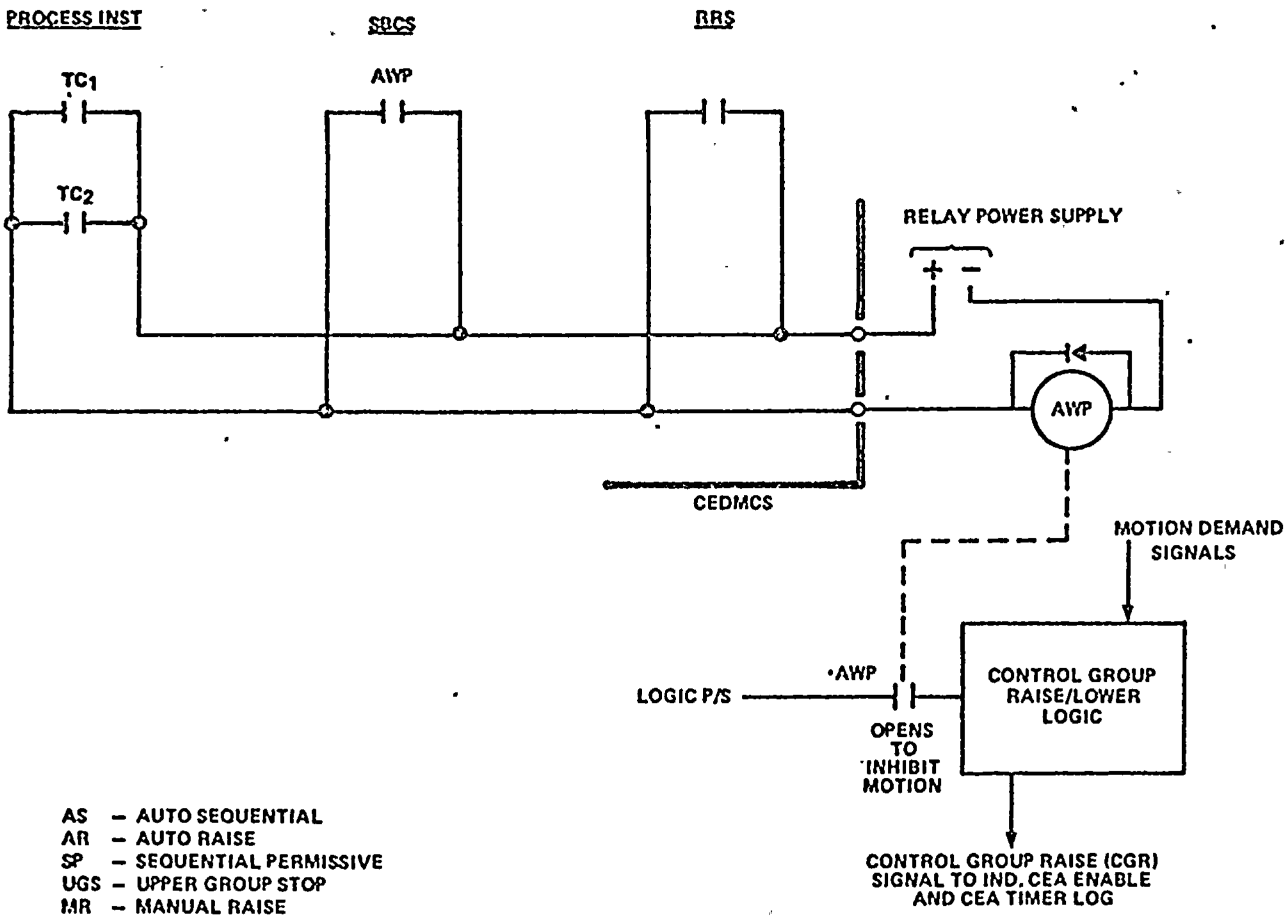

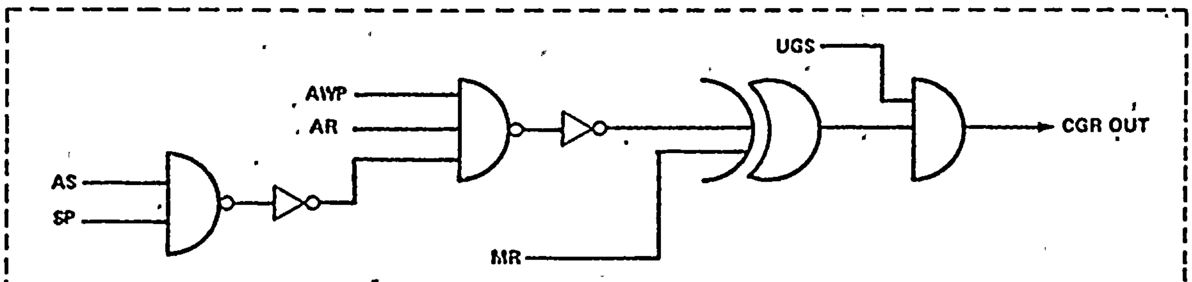

BASIC CONTROL GROUP RAISE/LOWER LOGIC

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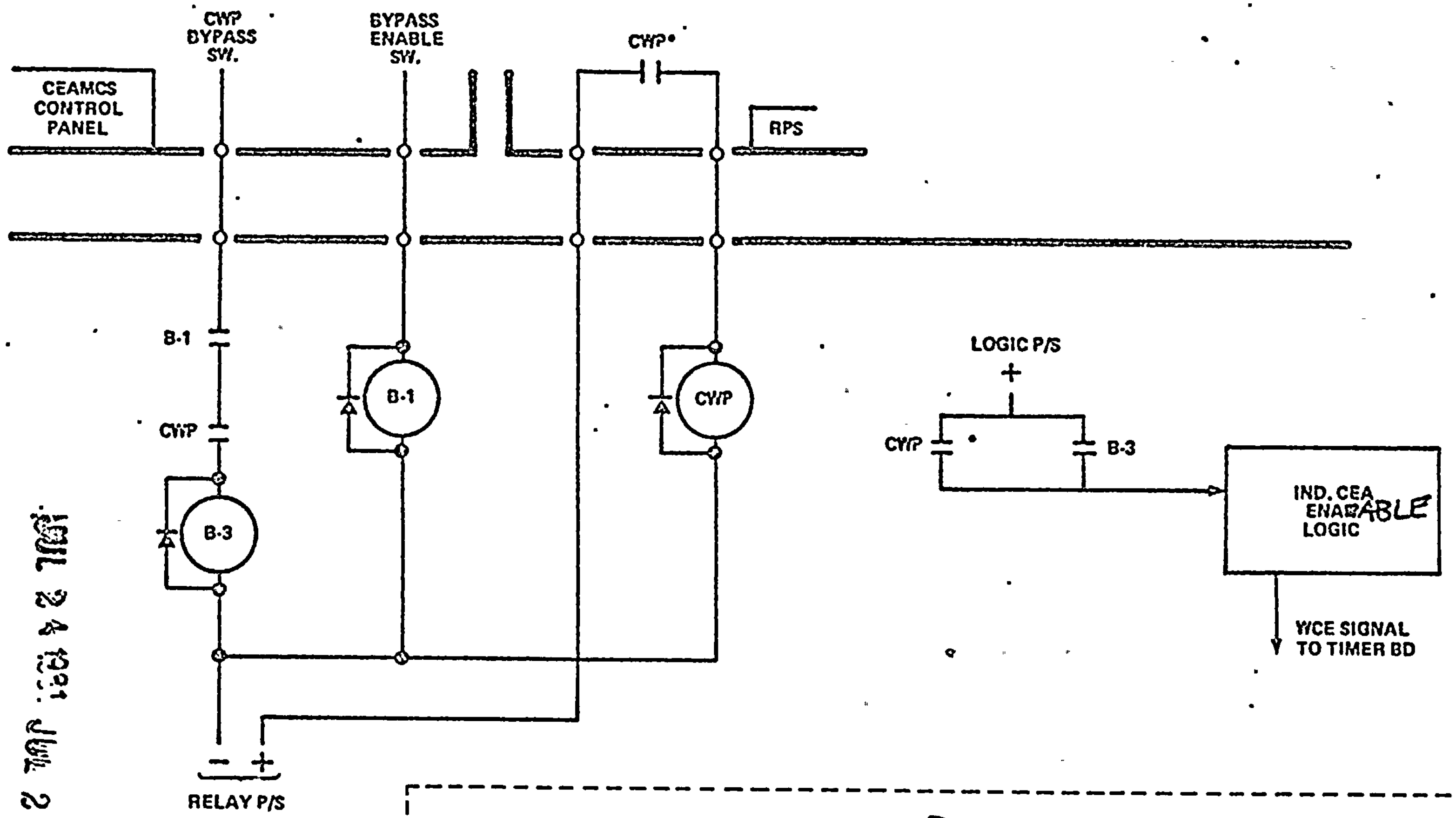

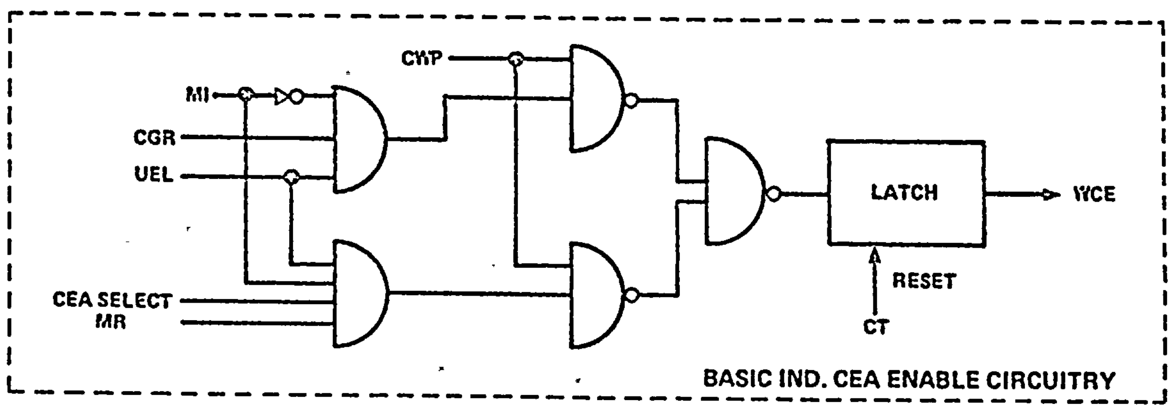

* OPENS ON INTERLOCK CONDITIONS

CGR – CONTROL GROUP RAISE
CWP – CEA WITHDRAWAL PROHIBIT
CT – CYCLE TIME
WCE – WITHDRAW CEA ENABLE
UEL – UPPER ELECTRICAL LIMIT
MI – MANUAL INDIVIDUAL
MR – MANUAL RAISE
RPS – REACTOR PROTECTION SYSTEM

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

420.44-2

Question No.

420.45 (7.7) The last statement in Subsection 7.7.2 states that the safety analyses of Chapter 15 do not require the systems discussed in Section 7.7 to remain functional. However, the first paragraph of Subsection 15.0.2.3 states that several normally operating control systems (including some discussed in Section 7.7) are assumed to function during certain accidents. Resolve this inconsistency.

Response:

Operation of the control systems described in Section 7.7 is not required in order to mitigate the consequences of the transients analyzed in Chapter 15. The analyses in Chapter 15 include the assumption that these control systems respond normally to each transient and that their operational mode is that which would be most adverse for the transient under consideration. The consequences produced by a malfunction of these control systems would be less severe than the additional failures considered in the transients analyzed in Chapter 15. The sequence of events diagrams accompanying the Chapter 15 analyses clearly demonstrate that there is a safety grade backup for every control system action, or that the control system action is not required.

Although the control systems are not required, credit is taken for their not failing in their most adverse mode during each event. Specific control system failures are evaluated as low-probability independent occurrences and are listed in Table 15.0-3. Our treatment of these low-probability independent occurrences is discussed in Subsections 15.0.1.5.2 and 15.0.2.3.

The Chapter 15 analysis demonstrates "that the protection systems are capable of coping with all (including gross) failure modes of the control systems" as required by Subsection 7.7.2 of Regulatory Guide 1.70, Rev. 3.

Standard Review Plan 7.7 requires the reviewer "b. To verify that no credit is taken for the operability of these control systems in the plant accident analyses of Chapter 15 of the SAR". The Chapter 15 analyses does not take credit for these control systems being in a particularly favorable mode to mitigate the consequences of an event. For the base event without any coincident occurrences (except possibly a stuck CEA or steam generator tube leak, as applicable) these control systems are assumed to operate, as discussed in Subsection 15.0.2.3. The event with an accompanying loss of offsite power following turbine trip presents the plant's response without these control systems functioning (except for the turbine trip).

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Question No.

420.46 (7.7) In the discussion of the Digital Data Processing System in Subsection 7.7.1.2.10, the statement is made that the system is functionally identical to the system supplied for St. Lucie Unit 1. State whether the system provided for Unit 1 provided group sequencing for the control element assemblies.

List all other functions provided by the Digital Data Processing System for Unit 2 that were not provided for Unit 1, and vice versa.

Repsonse:

The basic functional requirements established for both Unit 1 and 2 Digital Data Processing Systems are the same, and are summarized as follows:

1. Provide current records of flux and temperature seen by eacn in-core detector, and of CEA positions.

2. Display information periodically or by operator demand.

3. Provide alarm messages if undesirable flux and temperatures, or CEA position combinations are detected.

4. Provide logic signals in the form of Contact closure outputs (CCO) to the CEDMCS when certain combinations of CEA positions are detected.

5. Compute secondary plant calorimetric data on a periodic and demand basis.

6. Control and process information for the Movable In-Core Detector System.

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Question No.

420.47 Our Letter (R.L. Tedesco to Dr. R.E. Uhrig) dated May 5, 1981 requests additional information pertaining to four instrumentation and control system concerns. These concerns are entitled:

1. Loss of non-Class IE instrumentation and control power system bus during power operation (IE Bulletin 79-27);

2. Engineered safety features (ESF) reset controls (IE Bulletin 80-06).

3. Qualification of control systems (IE Information Notice 79-22), and

4. Control system failures.

Please provide the requested information.

Response:

The subject concerns are addressed in the response to the questions in the letter of May 5, 1981 to Dr. R.E. Uhrig from R.L. Tedesco, "St. Lucie Plant Unit 2 FSAR - Request for Additional Information."

1. Loss of non-Class 1E instrumentation and control power system bus during power operation concern is addressed in the response to Question 420.1.

2. Engineered safety features (ESF) reset controls concern is addressed in the response to Question 420.2.

3. Qualification of control systems (IE Information Notice 79-22) concern is addressed in the response to Question 420.3.

4. The control system failures control is addressed in the response to Question 420.4.

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Question No.
420.48

FSAR Subsection 1.9.1 states that the FSAR will be amended as appropriate to address the TMI Action Plan Items as described in NUREG-0737. To date no responses to NUREG-0737 TMI Items II.B.1, II.D.3, II.E.1.2, II.F.2 or II.K.3.1 have been received. Therefore, please provide information on the above TMI items as required by NUREG-0737.

Response

Preliminary responses to the above items were provided in FSAR Appendix 1.9A in Amendment 0 (December 1980) and Amendment 1 (April 1981). A draft revision to Appendix 1.9A, which provides additional information on the TMI Items, was submitted informally to the NRC on July 21, 1981. The draft revision will be incorporated into the FSAR by August 1981.

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ENCLOSURE 2

PRELIMINARY INFO. ONLY JUL 2 4 198

DRAWING REVIEW ITEMS FOR ST. LUCIE UNIT NO. 2

Electrical schematics and physical layout drawings should be used by the applicant to "walk through" all equipment from initiating signals to actuated devices. The applicant should be prepared to follow energy sources for this equipment back to electrical buses discussed in Chapter 8 of the FSAR and instrument air supplies discussed in Chapter 9 of the FSAR. Conformance with IEEE Standard 279, Regulatory Guide 1.53, Regulatory Guide 1.75, Regulatory Guide 1.47, and Regulatory Guide 1.32 should be demonstrated.

Question No.

420.49 Discuss the routing of the instrumentation wiring for the four pressurizer pressure transmitters (PT1102A, PT1102B, PT1102C, and PT1102D) used in the reactor protection system. The discussion should (a) identify the physical location of the transmitters, (b) trace the wiring from the transmitters through conduit to the penetrations, (c) describe the penetrations, (d) trace the wiring from the penetrations through conduit and/or cable trays to the reactor protection system cabinets, and (e) continue tracing the wiring through the trip logic within the RPS cabinets to and including the RPS trip breakers.

420.50 Identify the physical location of the equipment that actuates the reactor trip on turbine trip. Trace the wiring from this equipment to the reactor protection system cabinets.

420.51 Discuss the routing of the control wiring for the three component cooling water pumps. The discussion should (a) identify the physical location of the controls (on main control panel as well as local panels), (b) trace the wiring from the manual controls and from the automatic actuation (SIAS) logic cabinets to the final actuated equipment, and (c) trace the wiring which annunciates improper alignment of pump 2c motor power in relation to any of its motor operated discharge valve positions.

420.52 Discuss the routing of instrumentation and control circuitries between the hot shutdown panel and the main control room control boards. Identify the location of the manual transfer switches.

420.53. Table 7.3-10 of the FSAR lists several components in the Charging and Boron System that automatically provide annunciation when they are bypassed or become inoperable. These components include the charging pumps, boric acid make-up pumps, boric acid make-up tanks, and return valves. Describe the bypass or inoperable circuitry for each of these components. The description should include (a) how the bypass or inoperable signal is generated, (b) the location of the circuitry generating the signal, (c) the routing of the signal wiring to the annunciator panels, and (d) the location and layout of the various annunciator panels. If the plant computer system is used to monitor the status of these signals, the routing of the signal wiring to the computer system should be traced.

Response

Question 420.49 through 420.53 have been discussed and found acceptable at an NRC meeting on July 7, 1981

PRELIMINARY
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Question No.

420.54

FSAR Subsection 7.6.3 describes additional systems required for safety. Overall, the FSAR information supplied to date does not sufficiently describe the instrumentation and controls associated with most of these systems. Therefore, please provide the following information:

a. Identify and describe the instrumentation and controls associated with each system listed below:

- Fuel pool cooling and purification system
- Process and effluent radiological monitoring and sampling system
- Containment vacuum relief system
- Shield building ventilation system

b. For each instrument and control identified in (a) above, designate whether the equipment is Class 1E or non-Class 1E.

c. For each system listed in (a) above, discuss the qualification criteria applied to its associated instrumentation and controls. As a minimum, you are requested to include for each system, a discussion of how the instrumentation and controls for that system conforms to the requirements of IEEE 279-1971, IEEE 308-1974, IEEE 323-1974, and IEEE 344-1975.

Response

a.) I) FUEL POOL COOLING AND PURIFICATION SYSTEM

The fuel pool instrumentation system is described in Section 9.1.3.2.4. A tabulation of the instrument channels is included in Table 9.1-7.

II) PROCESS AND EFFLUENT RADIOLOGICAL MONITORING AND SAMPLING SYSTEM

The radiation monitoring system is composed of three process, seven effluent, forty one area, and four inplant airborne monitors. Tabulations of these monitors are given in Tables 11.5-1, 12.3-2, and 12.3-3.

III) CONTAINMENT VACUUM RELIEF SYSTEM

The instrumentation provided for this system is in accordance with the revised Figure 3.8-8 and contains the following equipment:
- PDT-25-1A (1B) with its electronic PDIS-25-1A (1B) is interlocked with FCV-25-7(8) by energizing SE-25-10(11) to open FCV-25-7(8) when the differential pressure between the containment and annulus reaches -9.75" H_2O ± 0.25" H_2O PDIS-25-1A(1B) also pro-

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vides indication on the HVCB for ΔP range of $-25" H_2O$ to $+ 25 H_2O$.

- PDT-25-13A(13B) with its electronic PDS-25-13A(13B) is interlocked with FCV-25-7(8) by deenergizing SE-25-10(11) to close FCV-25-7(8) when the differential pressure reaches $-7.75" H_2O$.
- PDIS-25-11A(11B) provides local full range indication and a high alarm on the HVCB at $11.5" H_2O$.
- PDT-25-15A(15B) with its PDI-25-15A(15B) provides full range ($-25" H_2O$ to _ $25" H_2O$) indication on the HVCB.

IV) SHIELD BUILDING VENTILATION SYSTEM

The Shield Building Ventilation System is an ESF System and is listed in Section 7.3 of the FSAR. The SBVS switchover from Fuel Handling Building is the only portion of this system listed in Section 7.6. The SBVS is described in Section 6.2.3.2 of the FSAR.

The instrumentation requirements are provided in Section 6.2.3.5 and Table 6.2-51 of the FSAR.

b) I- CE to provide input

II - The Class 1E effluent monitors are the plant stack, as described in subsection 11.5.2.2.8, and the ECCS exhaust monitors, as described in subsection 11.5.2.2.10. The Class 1E area monitors include the four CIAS and 6 spent fuel pool monitors, as well as two post-accident monitors. All these monitors are described in subsection 12.3.4.1.4. The Class 1E in-plant monitors include the containment atmosphere monitors, as described in subsection 12.3.4.2.3.1, the control room air intake monitors, described in subsection 12.3.4.2.3.2, and the ECCS exhaust monitors, as described in subsection 12.3.4.2.3.3.

III -All PDT's; PDIS's; PDS's and PDI's discussed in item a) above are Class 1E.

IV - Instrumentation and controls discussed above for SBVS system are Class 1E. Alarms are announciated on non-safety annunciation windows through proper isolation devices.

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c) IEEE 323-1974 AND IEEE 344-1975

I - CE to provide input

II - All Class 1E monitors are qualified to IEEE 323-1974 and IEEE 344-1975.

III- All pressure transmitters listed in item a) above are qualified to IEEE 344-1975 and IEEE 323-1974 in the environment in which they operate. The remote mounted indicators and bistables are mounted on the seismically qualified HVCB in the control room.

IV - All controls and instrumentations for SBVS is qualified to IEEE 323-1974 and IEEE 344-1975. The remote mounted indicators and bistables are mounted on the seismically qualified HVCB in the control room.

IEEE 279-1971

The four containment areas radiation monitors which input into the CIAS and the SBVS ~~IEEE 279-1971 similarly with the ESFAS as described~~ in Section 7.3.1.2 of the FSAR. conforms to

The requirements of IEEE 279-1971 for the other systems required for safety are not completely applicable because

this instrumentation is not part of a protection system. However, the intent of the design criteria contained therein has been applied in the design of these systems to the following extent:

4.1 - General Functional Requirements

The safety related instrumentation for the above systems is designed to provide monitoring and actuation as applicable during normal or accident conditions. The instrument performance characteristics, response times and accuracy are selected for compatibility for the particular function.

4.2 - Single Failure Criterion

This is functionally identified to that described in Subsection 7.4.2.2.

4.3 - Quality Control of Components and Modules

See Chapter 17

4.4 Equipment Qualification

The instrumentation and controls for these systems meet the equipment qualification requirements discussed in Sections 3.10 and 3.11.

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4.5 - Channel Integrity

The "Channel Integrity" is functionally identical to that discribed in Subsection 7.3.2.1.2.

4.6 - Channel Independence

The channel independence is functionally identified to that described in Subsection 7.3.2.1.2.

4.7 - "Control and Protection System Interaction"

No portion of these systems is used for both control and protection.

4.8 - "Derivation of System Inputs"

The monitoring signals for the above systems are a direct measurement of the desired variables.

4.9 - "Capability for Sensor Checks"

The monitoring sensors are checked by comparing the monitored variables of redundant channels or by observing the effects of introducing and varying a substitute input to the sensor similar to the measured variable.

4.10 - "Capability for Test and Calibration"

IEEE 338-1971 and Regulatory Guide 1.22, "Periodic Testing of Protection System Actuation Functions" 2/72 (R0) provides guidance for the development of procedures, equipment and documentation of periodic testing. The measurement signals required for the above systems have the capability of being tested and calibrated under the design requirements of the system.

4.11 - "Channel Bypass or Removal from Operation"

Any one of the channels may be tested, calibrated, or repaired without detrimental effects on the other channels.

4.12 - "Operating Bypasses"

There are no "Operating Bypasses" for these systems.

4.13 - "Indication of Bypasses"

A discussion of bypass and inoperable status indication is provided in Subsection 7.5.1 and a listing of inoperable or bypassed components is contained in Table 7.3-10.

4.14 - "Access to Means for Bypassing"

This section is not applicable.

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4.15 - "Multiple Setpoints"

This section is not applicable.

4.16 - "Completion of Protective Action Once it is Initiated"

This section is not applicable.

4.17 - "Manual Initiation"

Manual initiation of the components in these systems is available.

4.18 - "Access to Setpoint Adjustments, Calibration, and Test Points"

This section is not applicable.

4.19 - "Identification of Protective Actions"

This section is not applicable.

4.20 - "Information Readouts"

The monitoring and control channels for these systems are indicated in the control room.

4.21 - "System Repair"

Replacement or repair of components can be accomplished in reasonable time when the systems are not actuated. Outage of system components for replacement or repair are limited by the Technical Specifications.

4.22 - "Identification"

Safety equipment and cables associated with these systems are uniquely identified.

<u>IEEE 308-1971</u>

The St Lucie Unit 2 FSAR is committed to Regulatory Guide 1.32 Rev. 0 which addresses IEEE 308-1971. For a further discussion of IEEE 308-1971 refer to FSAR Section 8.3.1.2. All class 1E electrical components are electrically and physically separated in accordance with Regulatory Guide 1.75 as discussed in FSAR Section 8.3.1.2. Electrically redundant and physically independent power supplies to the above systems, electrical components, and to the safety related power panèls that provide power to control and instrumentation devices are provided.

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All Class 1E electrical system components are uniquely identified in accordance with FSAR Section 8.3.1.3.

The fuel pool purification pump is a non-safety pump and as such is physically independent and electrically separated from Class 1E components.

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h) Piping and Valves

All the piping in the Fuel Pool System is stainless steel with mostly welded connections throughout. All the valves in the Fuel Pool System are stainless steeel, at least 150 pound class.

9.1.3.2.4 Instrumentation Requirements

A tabulation of instrument channels is included in Table 9.1-7

9.1.3.2.4.1 Temperature Instrumentation

a) Fuel pool temperature indications are provided locally and high temperature alarms are actuated in the control room to warn the operator of a system malfunction. Two separate instrument channels are used due to the importance of preventing the fuel pool water from boiling resulting in a loss of fuel pool water.

b) Fuel Pool Heat Exchanger Inlet Temperature: Local indication of the fuel pool heat exchanger inlet temperature (tube side) is provided. This indication, in conjunction with the heat exchanger outlet temperature and component cooling water temperature, serves as a measure of fuel pool heat exchanger performance.

c) Fuel Pool Heat Exchanger Outlet Temperature: Local indication of the fuel pool heat exchanger outlet temperature (tube side) is provided.

9.1.3.2.4.2 Pressure Instrumentation

a) Fuel Pool Pump Discharge Pressure: The discharge pressure of each fuel pool pump is indicated locally.

b) Fuel Pool Pumps Discharge Header Pressure

A discharge header pressure switch for the fuel pool pumps serves to activate a low pressure alarm in the control room to warn the operator of system malfunction.

c) Fuel Pool Purification Pump Suction Pressure

Suction pressure to the fuel pool purification pump is indicated locally. This indication, in conjunction with the fuel pool purification pump discharge pressure gage serves as a measure of fuel pool purification pump performance.

d) Fuel Pool Purification Pump Discharge Pressure

Discharge pressure of the fuel pool purification pump is indicated locally.

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e) Fuel Pool Purification Filter and Fuel Pool Ion Exchanger Differential Pressure

Differential pressure of the fuel pool purification filter and the fuel pool ion exchanger are indicated locally.

Periodic readings of these instruments indicate any progressive loading of the units.

9.1.3.2.4.3 Level Instruments

a) Fuel Pool Water Level

The fuel pool water level is monitored by two redundant level switches. These switches actuate high or low alarms in the control room to warn the operator of system malfunction. Two separate level instrument channels are used due to the importance of maintaining fuel pool water level.

9.1.3.3 Safety Evaluation

With one-third of a core batch, which is assumed to have undergone finite irradiation of three years, placed in the spent fuel pool seven days after reactor shutdown and six previous annual refueling batches, the heat load is 12.48×10^6 BTU/hr. Under these conditions, with one fuel pool pump operating and the fuel pool heat exchanger in service, the spent fuel pool temperature does not exceed 125 F.

During a full core unloading, it is assumed that one full core is placed in the fuel pool seven days after reactor shutdown. One-third of a core from a previous refueling is assumed to have been stored in the spent fuel pool for 90 days with six previous annual batches. The resultant heat load from one full core and seven annual refueling batches is 2.99×10^7 BTU/hr, the maximum heat load in the fuel pool. Under these conditions, both the fuel pool pumps are in service to limit the maximum fuel pool water temperature to 150 F. With one fuel pool pump inoperable, the fuel pool equilibrium temperature is 160 F.

All connections to the fuel pool are made so as to preclude the possibility of siphon draining of the fuel pool. Any leakage from the fuel pool cooling system is detected by reduction in the fuel pool inventory. Makeup to the fuel pool is from the refueling water tank. Makeup inventory to the fuel pool is provided in Subsection 9.1.3.3.1.

During accident conditions, the Fuel Pool Cooling System is isolated from the Component Cooling Water System. However, multiple sources (seismic and non-seismic) of makeup water exist as discussed in Subsection 9.1.3.3.1.

The purification loop normally runs continuously during fuel pool operation to maintain the fuel pool water purity and clarity. It is possible to operate the purification system with either the fuel pool ion exchanger or fuel pool filter bypassed. Local sample points are provided to permit analysis of fuel pool ion exchanger and fuel pool filter efficiencies.

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TABLE 9.1-7

FUEL POOL SYSTEM INSTRUMENTATION

Instrument Identification Number	System Parameter & Location	Indication		Alarm		Instrument	Normal Operating	Instrument
		Local	Control Room	Local	Control Room	Range	Range	Accuracy
TI-4420	Fuel Pool Temperature	*			Hi	0-200 F	120-150 F	± 4 F
TI-4421	Fuel Pool Temperature	*			Hi	0-200 F	120-150 F	± 4 F
TI-4404	Fuel Pool Heat Exchanger Inlet Temp.	*				0-200 F	120-150 F	± 4 F
TI-4405	Fuel Pool Heat Exchanger Outlet Temp.	*				0-200 F	108-128 F	± 4 F
LS-4420	Fuel Pool Water Level				Hi & Lo	-	-	± 1"
LS-4421	Fuel Pool Water Level				Hi & Lo	-	-	± 1"
PI-4402	Fuel Pool Pump 2B Discharge	*				0-60 psig	40-50 psig	± 1.2 psig
PI-4401	Fuel Pool Pump 2A Discharge Pressure	*				0-60 psig	40-50 psig	± 1.2 psig
PI-4411	Fuel Pool Purification Pump Suction Pressure	*				0-25 psig	5-10 psig	± .5 psig
PS-4403	Fuel Pool Pump Discharge Header Pressure				Lo	-	40-50 psig	± 1 psig
PI-4412	Fuel Pool Purification Pump Discharge Pressure	*				0-100 psig	75-90 psig	± 2 psig
PDI-4415	Fuel Pool Purification Filter Differential Pressure	*				0-30 psid	5-30 psid	± .6 psid
PDI-4416	Fuel Pool Ion Exchanger Differential Pressure	*				0-30 psid	7-10 psid	± .6 psid

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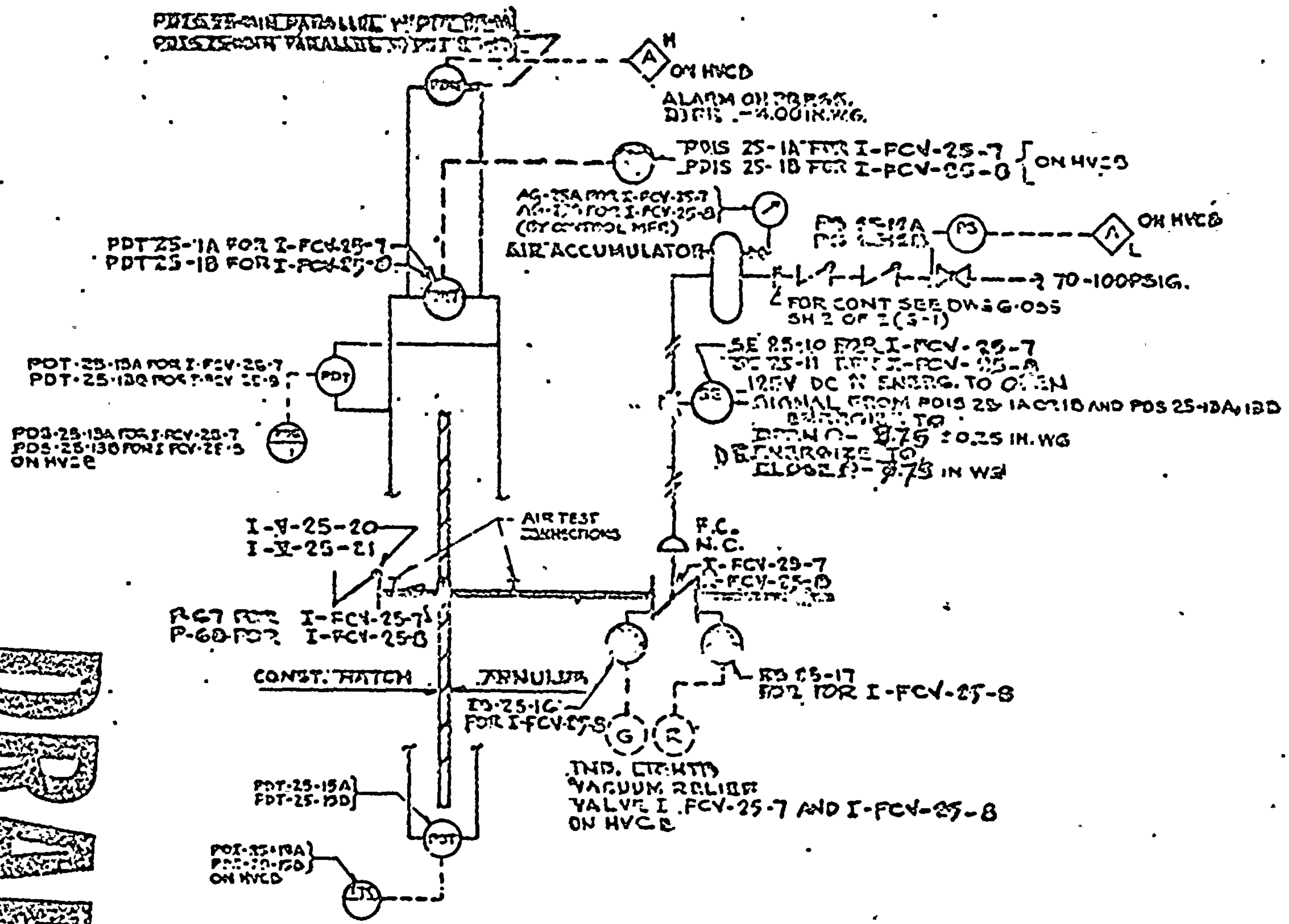

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT VACUUM RELIEF

FIGURE 3.8-8

valve is opened automatically when the annulus differential pressure reaches one in. wg negative. The check valve in the cooling line is designed to have a pressure drop of not more than 2.5 in. wg and to open at 1.4 in. wg negative to provide vacuum control in the system and to allow outside air to cool the filters.

The SBVS is also interconnected to the spent fuel pool area exhaust duct. Upon receipt of a high-high radiation signal in the fuel pool area, the exhaust air is directed to the SBVS filtration units. The motor operated butterfly valves I-FCV-25-30 and 31 open and the exhaust fans start automatically. The motor operated valves I-FCV-25-32 and 33 close to isolate the annulus. Although a fuel handling accident inside the FHB concurrent with a LOCA is not considered a design basis event, a CIAS overrides the Fuel Handling Building high-high radiation signal and initiates the depressurization of the Shield Building annulus. The Fuel Handling Building Ventilation System is further discussed in Subsection 9.4.2.

Each of the SBVS intake trains is also connected to the Continuous Containment/Hydrogen Purge System. This connection, manually initiated from the control room, provides hydrogen purge capability while minimizing offsite radiological consequences. The Continuous Containment/Hydrogen Purge System description is provided in Subsection 9.4.8.3.

Both SBVS subsystems are automatically started by a CIAS or high-high radiation signal from the Fuel Handling Building. One can be manually shut down and placed in the standby mode. The standby subsystem automatically restarts if the operating subsystem should fail. The cross connection valve is opened from the control room to assure air flow through the failed system. Detectors in the charcoal beds annunciate temperatures exceeding 200 F.

6.2.3.3 Design Evaluation

6.2.3.3.1 Performance Requirements and Capabilities

Each of the two full capacity fan-filter trains of the Shield Building Ventilation System, along with the Shield Building, are designed to fulfill the performance requirements stated in the design bases in Subsection 6.2.3.1.

The analysis of the functional capability of the SBVS to depressurize and maintain a uniform negative pressure within the Shield Building annulus is performed for the 9.82 ft^2 double ended suction leg slot break LOCA using the WATEMPT computer code described in Appendix [illegible]. The description of the development of the pipe break mass and energy release rate and the containment initial conditions are contained in Subsection 6.2.1. Any additional initial conditions or changes from those listed in Subsection 6.2.1 are contained in Table 6.2-49. The [illegible] heat transfer coefficients are applied whether the surface temperature exceeds the annulus atmosphere or the annulus atmosphere temperature exceeds the surface temperature.

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6.2.4 CONTAINMENT ISOLATION SYSTEM

The containment isolation system provides the means of isolating fluid systems that pass through containment penetrations such that any radioactivity that may be released into the containment atmosphere following a postulated design basis accident (DBA) is confined. There is no one particular system for complete containment isolation, but isolation design is provided applying acceptance criteria common to penetrations in many different fluid systems.

6.2.4.1 Design Bases

The design bases governing the containment isolation system are discussed below.

The containment isolation valves are designated seismic Category I and designed to ASME Code, Section III and Quality Group B requirements. Containment isolation valves are designed to ensure leak-tightness and reliability of operation. Containment isolation globe, check and gate valves meet the requirements of manufacturers standards MSS-SP-61, "Hydrostatic Testing of Steel Valves" and containment isolation butterfly valves meet the requirements of manufacturers standards MSS-SP-67, "Butterfly Valves".

6.2.4.1.1 Conditions Requiring Containment Isolation

a) Automatic initiation of a containment isolation actuation signal (CIAS) occurs when a high containment pressure of 5 psig or a high containment radiation level of 10R/hr is detected. This provides diversity of parameters sensed for the initiation of containment isolation.

b) The CIAS closes fluid line penetration isolation valves not required for operation of the Engineered Safety Features.

c) The containment isolation system is designed such that no single active failure (in conjunction with loss of offsite power) could result in offsite doses or doses to operators in the control room in excess of 10CFR100 and GDC 19, respectively.

d) The main steam and feedwater valves close on MSIS and the valves for the component cooling water for the reactor coolant pump motors close on SIAS (see Section 7.3 and Subsection 6.2.4.3.2).

6.2.4.1.2 Criteria for Isolation of Fluid System Penetrating the Containment

a) The containment isolation provisions for the fluid system penetrations (excluding the ESF systems) are designed in accordance with General Design Criteria 54, 55, 56 and 57 (refer to Table 6.2-52). Exceptions to GDC provisions are discussed in Subsection 6.2.4.3.

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TABLE 6.2-51

SHIELD BUILDING VENTILATION SYSTEM INSTRUMENTATION APPLICATION

	System Parameter & Location	Indication Local	Indication Control Room	Alarm Control Room	Control Room Recording	Automatic Control Function	Instrument Range	Normal Operating Range	Instrument Accuracy
1.	Annulus/atmosphere pressure differential		*	Hi-Lo		Energizes fan discharge damper motor and regulates flow to preset value and energize outside cooling air valve	-10 to +30 in. H_2O	-1 to -3 in. H_2O	+1.0%
2.	Fuel pool area/atmosphere pressure differential		*	Hi-Lo		Energizes fan discharge damper motor and regulates flow to preset value and energize outside cooling air valve	-10 to +30 in. H_2O	-1 to -3 in. H_2O	±1.0%
3.	Air flow temperature downstream of demister	*					0-250 F	40-177 F	+2.0%
4.	Inlet temperature upstream of filter train	*					0-250 F	40-177 F	+2.0%
5.	Demister & Electric Heaters differential pressure	*							
6.	Air flow temperature downstream of 30 Kw heating coil				*		0-250 F	40-177 F	+2.0%
7.	Pre-HEPA filter differential pressure	*	*	Hi	*		0-10 in. H_2O	1 to 3 in. H_2O	±1.0%
8.	After-HEPA filter differential pressure	*			*		0-10 in. H_2O	1 to 3 in. H_2O	±1.0%
9.	Air flow moisture downstream of HEPA filter	*		Hi			0-100%	50-70%	+2.0%
10.	Charcoal adsorber differential pressure indicator	*			*		0-10 in. H_2O	1 to 1.15 in. H_2O	+1.0%
11.	Charcoal adsorber temperature			Hi	*		0-250 F	40-177 F	+2.0%
12.	Air flow temperature downstream of charcoal adsorbers	*			*		0-250 F	40-177 F	+2.0%

TABLE 6.2-51 (Cont'd)

	System Parameter & Location	Indication Local	Indication Control Room	Alarm Control Room	Control Room Recording	Automatic Control Function	Instrument Range	Normal Operating Range	Instrument Accuracy
13.	Air flow downstream of fan or Air flow of filter train	*	*		*	Energizes idle fan to start at low flow and alarms	0-10,000 cfm	6000 cfm	-
14.	Filter train differential pressure				*		0-15 in. H_2O	4 to 8 in. H_2O	±1.0%
15.	Cross-connect flow control valve position		*				-	-	-
16.	Outside cooling air flow control valve position		*				-	-	-
17.	Shield building suction valve position		*				-	-	-
18.	Fuel handling building suction valve position		*				-	-	-
19.	Purge discharge valve position		*				-	-	-

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Question No.

420.55 Subsection 6.2.3.2.2 of the FSAR states that a high-high radiation signal from the spent fuel pool area is used to actuate the SVBS subsystems. However, Figure 6.2.5-1 and control wiring diagrams 2998-B-327, Sheets 513 and 516 indicate a high radiation signal is used. Clarify this discrepancy. Also, according to Table 12.3-2, six radiation monitors are provided in the spent fuel pool area. Describe the logic used to generate the two redundant high radiation signals (RA and RB) from the six monitors.

Response

The Shield Building Ventilation System (SBVS) is interconnected to the spent fuel pool area exhaust duct. Upon receipt of a high radiation signal in the fuel pool area, the exhaust air is directed to the SBVS filtration units. FSAR Subsection 6.2.3.2.2 will be revised to be consistent with Control Wiring Diagrams 513, 516 and Figure 6.2.5-1.

Six radiation monitors, strategically located around the spent fuel pool area, are used to generate the high radiation signals for RA, RB relays (located in the HVCB in the control room) as shown on the attached sketch, "2 out of 3 logic" is used to generate these high radiation signals.

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valve is opened automatically when the annulus differential pressure reaches one in. wg negative. The check valve in the cooling line is designed to have a pressure drop of not more than 2.5 in. wg and to open at 1.4 in. wg negative to provide vacuum control in the system and to allow outside air to cool the filters.

The SBVS is also interconnected to the spent fuel pool area exhaust duct. Upon receipt of a high radiation signal in the fuel pool area, the exhaust air is directed to the SBVS filtration units. The motor operated butterfly valves I-FCV-25-30 and 31 open and the exhaust fans start automatically. 5 420.55 The motor operated valves I-FCV-25-32 and 33 close to isolate the annulus. Although a fuel handling accident inside the FHB concurrent with a LOCA is not considered a design basis event, a CIAS overrides the Fuel Handling Building high radiation signal and initiates the depressurization of the Shield Building annulus. 5 420.55 The Fuel Handling Building Ventilation System is further discussed in Subsection 9.4.2.

Each of the SBVS intake trains is also connected to the Continuous Containment/Hydrogen Purge System. This connection, manually initiated from the control room, provides hydrogen purge capability while minimizing offsite radiological consequences. The Continuous Containment/Hydrogen Purge System description is provided in Subsection 9.4.8.8.

Both SBVS subsystems are automatically started by a CIAS or high radiation signal from the Fuel Handling Building. 5 420.55 One can be manually shut down and placed in the standby mode. The standby subsystem automatically restarts if the operating subsystem should fail. The cross connection valve is opened from the control room to assure air flow through the failed system. Detectors in the charcoal beds annunciate temperatures exceeding 200 F.

6.2.3.3 Design Evaluation

6.2.3.3.1 Performance Requirements and Capabilities

Each of the two full capacity fan-filter trains of the Shield Building Ventilation System, along with the Shield Building, are designed to fulfill the performance requirements stated in the design bases in Subsection 6.2.3.1.

The analysis of the functional capability of the SBVS to depressurize and maintain a uniform negative pressure within the Shield Building annulus is performed for the 9.82 ft^2 double ended suction leg slot break LOCA using the WATEMPT computer code described in Appendix 6.2B. The description of the development of the pipe break mass and energy release rate and the containment initial conditions are contained in Subsection 6.2.1. Any additional initial conditions or changes from those listed in Subsection 6.2.1 are contained in Table 6.2-49. The same heat transfer coefficients are applied whether the surface temperature exceeds the annulus atmosphere or the annulus atmosphere temperature exceeds the surface temperature.

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Question No.

420.56

Position C.8 of Regulatory Guide 1.45 states that "leakage detection systems should be equipped with provisions to readily permit testing for operability and calibration during plant operation". Discuss how each of the systems described in Subsections 5.2.5.1.1 thru 5.2.5.11 comply witn the above position.

Response

As recommended by Position C.3 of Regulatory Guide 1.45, the three separate unidentified leakage detection methods utilized on St. Lucie - Unit 2 are (1) sump level and flow monitoring, (2) airborne particulate radioactivity monitoring, (3) airborne gaseous radioactivity monitoring.

The Containment Atmosphere Radiation Monitoring System wnich includes the airborne particulate and gaseous radioactivity measurements have radioactive check sources for the determination of the operability of each of the radiation channels during full power operation. Calibration can also be performed during power operation in the Reactor Auxiliary Building at 19.5 ft elevation.

The instrumentation for the third method of leak detection, sump level and flow monitoring, cannot be tested and calibrated during plant operation due to the location of the equipment (inside Containment Building). However, a comparison with the readings of the other two methods described above provides the operator with sufficient information to determine channel inoperability or malfunction.

JUL 24 1981

DRAFT

XC: ~~DE~~13

Question #1

Figure 6.2-9 and Figure 6.2-10, with respect to containment pressure and temperature responses follow a MSLB accident, should be revised to show the containment pressure/temperature pressure/temperature response profiles (from time = 0 second to 10^5 seconds following the accident) for use in equipment qualification.

Response

Figures 6.2-9 and 6.2-10 has been revised to reflect the containment pressure versus time and temperature versus time profiles (from time = 0 to 10^5 seconds) following a MSLB accident. See revised attached figures 6.2-9 and 6.2-10.

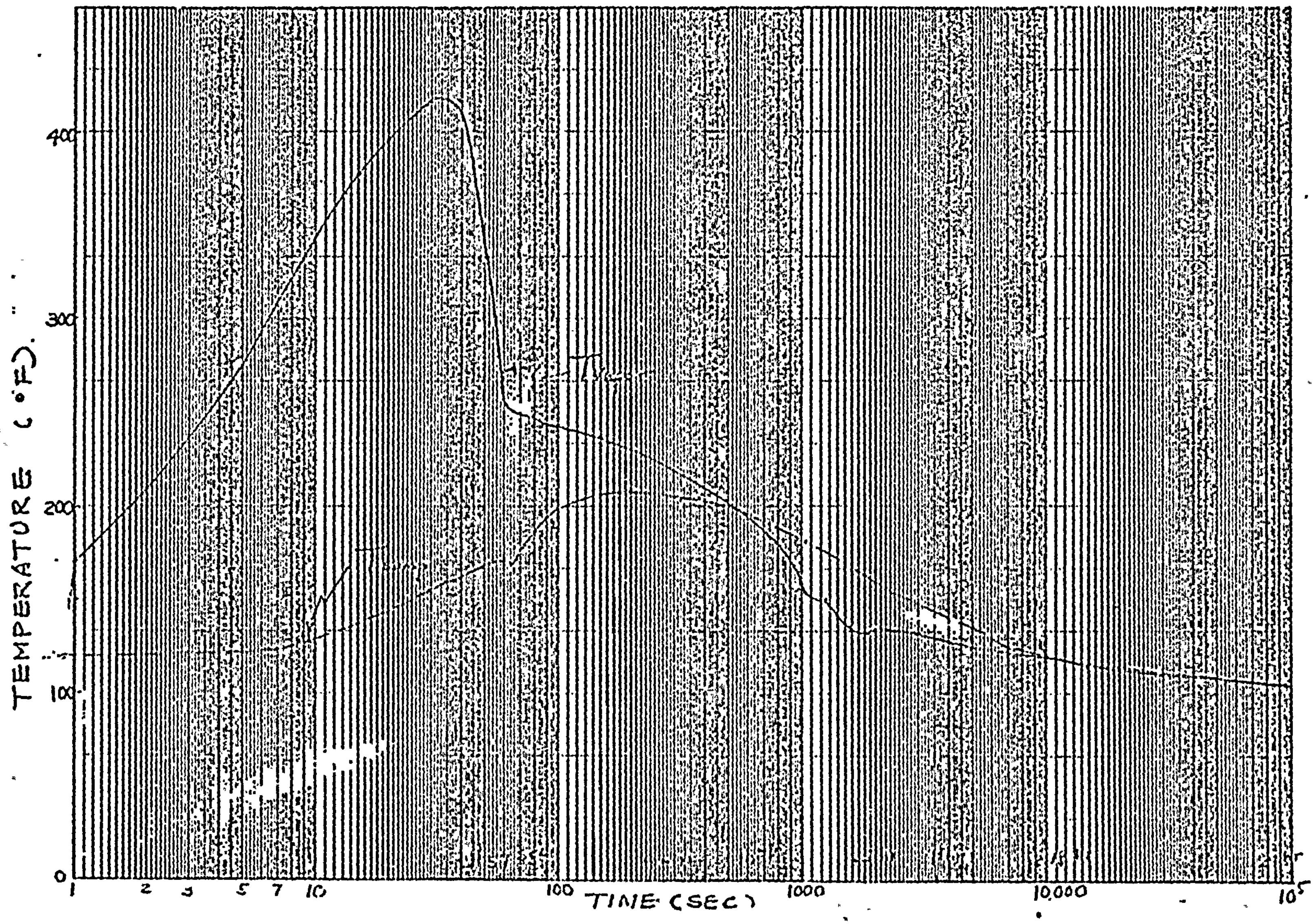


FIG. 6.2-10a CONTAINMENT TEMP. - MSLB - MSIV FAILURE AT 102 % POWER

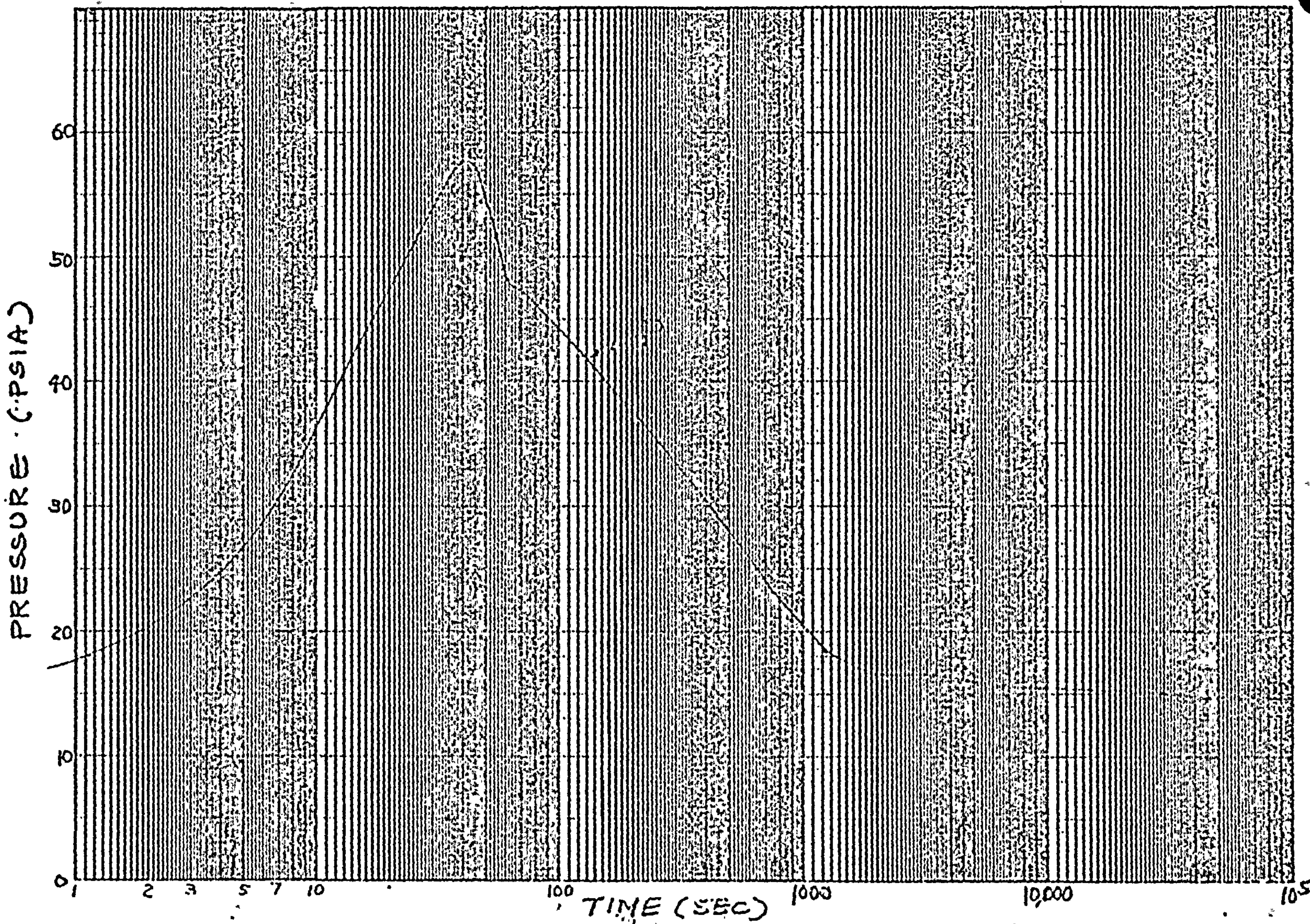


FIG. 6.2-9a CONTAINMENT PRESSURE — MSLB-MSIV FAILURE AT 102% POWER

Question #2

For the compartment (i.e. reactor cavity; secondary shield wall area; and pressurizer area) structural design pressure evaluation, provide the design differential pressure and discuss whether the design differential pressure is uniformly applied to the compartment structure or whether it is spatially varied.

Response

Design differential pressures are 24 PSI and 14 PSI for secondary shield wall, and pressurizer compartment above elevation 62'-00", respectively. The pressures are uniformly applied to the compartment structures. Pressures in the primary shield wall design shall be provided by July 16, 1981.

EBASCO Interoffice Correspondence

DATE June 29, 1981 FILE REF.

TO P. E. Grossman OFFICE LOCATION 80/2WTC

FROM C. H. Shelton CHS OFFICE LOCATION 88/2WTC

SUBJECT FLORIDA POWER AND LIGHT CO.
ST. LUCIE UNIT NO. 2
TECHNICAL BASIS: GDC51 COMPLIANCE

During the meeting with the NRC on June 17, 1981, Joe Halaptz designated certain Certified Material Test Reports to be submitted to him for use as supporting documents in demonstrating compliance with GDC51. Those CMTR's are listed below, and copies are attached hereto for transmittal to Joe Halaptz through John Sheetz.

1. Containment Shell. Lukens Steel Co. SA516 Gr70, 5¼" thick.

2. Penetrations.

   a. Sleeves (1) Lukens Steel Co. SA516 Gr70, 3" thick.
   (2) Armco Steel Corp. SA333, Gr6, 1.3" thick.

   b. Process Pipes (1) Main Steam. Tube Turns, SA155 KCF70, (SA516 Gr70) 2" wall.

   (2) Feedwater. U.S. Steel, SA106 GrB, 1.031" wall.

   c. Flued head. Main Steam, Tube Turns, SA105, 10.4" thick.

3. Main Steam and Main Feedwater Piping Subassemblies

   a. Main Steam Piping (Piece Mark MS1-1)

      (1) Piping. Tube Turns, SA155 KC65, Cl. 1, 2.125" thick.

      (2) Fittings Weldolet, Bonney Forge, SA105, 2" thick.

   b. Main Feedwater Piping Subassembly (1-20-BF-14-1)

      (1) Piping. U.S. Steel, SA106 GrB, 1.031" thick.

4. Main Steam Isolation Valve

   a. Body. Rockwell International, SA216WCC, 1.98" thick.

   b. Bonnet. Gulf Forge Co. SA105 GrII,

   c. Disc. Gulf Forge Co. SA182, GrF-11,

   d. Bolting

      (1) Studs, Victor Products Corp., (Copperweld) SA540, Gr23.

      (2) Nuts, Victor Products Corp., (Timken) SA194, Gr7

5. Main Feedwater Isolation Valve

   a. Body. Quaker Alloy Casting Co. SA216 GrWCB 1.9" thick. (Drawing attached)

   b. Bonnet. Lenape Forge SA105, 2" thick. (Drawing attached).

   c. Disc. Bethlehem Steel Co. SA516, Gr70, 2.5" thick. (Drawing attached).

   d. Bolting. No pressure bolting used.

CHS:jl
Attachments

cc: E. Zuchman - W/O Attachments
L. M. Petrick - " "
R. Keilbach - " "

SHELL

PURCHASER:

6 Chicago Bridge & Iron Co.
Pur. Dept.
Greenville, Pa. 16125

LUKENS STEEL COMPANY
COATESVILLE, PA. 19320
TEST CERTIFICATE

MILL ORDER NO.	CUSTOMER P.O.	
13833-1	73-7302U-III 20	MP 4175 DC

DATE: 4/4/75

FILE NO. 40-03-99 Submit

CONSIGNEE:

Chicago Bridge & Iron Co.
Birmingham, Ala. 35201

THIS MATERIAL HAS BEEN MANUFACTURED AND TESTED IN ACCORDANCE WITH PURCHASE ORDER REQUIREMENTS AND SPECIFICATION(S):

CB&I MS-6042 Rev. 0 1974 QAS-347 Rev. 0 SA-516 GR. 70 ASME Code Sect. 2 & 3 CL. MC 1971 Edition Thru Summer 1973 Addenda

BEND TEST O.K. HOMOGENEITY TEST

Sheet #1 of 2

CHEMICAL ANALYSIS

MELT NO.	C	MN	P	S	CU	SI	NI	CR	MO	V	TI	AL	B		Grain Size
B9071	26	1.02	010	025		23									7-8
D1157	25	94	009	023		20									7-8

RECEIVED APR 9 1975 GREENVILLE

PHYSICAL PROPERTIES

MELT NO.	SLAB NO.	YIELD PSI X100	TENSILE PSI X100	% ELONG. IN 2"	% R.A.	BHN	Long. V-Notch IMPACTS 40°F.			Fracture Appearance % Shear	DESCRIPTION
B9071 31-4 R/L	1	561 550	828 812	26 27			62	62	51	50-50-50	1- 5-1/4" x 76-1/2 x 354
					Lateral Expansion in Inches		.046	.048	.039		
" 31-5 R/L	2	575 581	848 838	27 26			82	48	57	40-40-40	1- " EQH1
					Lateral Expansion in Inches		.046	.040	.060		
D1157 32-4-L	4*	612 542	846 816	26 26			70	68	62	50-50-50	1- 5-1/4" x 70 x 368 EQH3
					Lateral Expansion in Inches		.052	.050	.056		

J. Thomas 8/5/76

We hereby certify the above information is correct.

SUPERVISOR-TESTING H. W. Kline

PURCHASER:

6 Chicago Bridge & Iron Co.
Greenville, Pa. 16125

LUKENS STEEL COMPANY

COATESVILLE, PA. 19320

TEST CERTIFICATE

MILL ORDER NO.	CUSTOMER P.O.	
13833-1	73-7302U-20	

DATE: 4-4-75 FILE NO. 40-03-99

CONSIGNEE:

Chicago Bridge & Iron Co. Submit
Birmingham, Ala. 35201

THIS MATERIAL HAS BEEN MANUFACTURED AND TESTED IN ACCORDANCE WITH PURCHASE ORDER REQUIREMENTS AND SPECIFICATION(S):

SAME

BEND TEST HOMOGENEITY TEST

Sheet #2 of 2

CHEMICAL ANALYSIS

MELT NO.	C	MN	P	S	CU	SI	NI	CR	MO	V	TI	AL	B		

PHYSICAL PROPERTIES

MELT NO.	SLAB NO.	YIELD PSI X100	TENSILE PSI X100	% ELONG. IN "	% R.A.	BHN	IMPACTS		DESCRIPTION

Plates and tests heated 1625-1675°F., held 1/2 hr. per inch min. and water quenched, then tempered 1210-1240°F., held 1/2 hr. per inch min. and water quenched.

*Plate and tests heated 1625-1675°F., held 1/2 hr. per inch min. and water quenched, then tempered 1200-1220°F., held 1/2 hr. per inch min. and water quenched.

Tests stress relieved by heating within a rate of 100°F. per hr. to 1150°F., held 15 hrs. and furnace cooled within a rate of 100°F. per hr. to 600°F.

RECEIVED APR 1975 GREENVILLE

Affirmed and subscribed before me this ____ day of APR 4 1975

[signature]

Notary Public

My Commission Expires April 1, 1976

We hereby certify the above information is correct.

[signature]

SUPERVISOR-TESTING

SLEEVES

PURCHASER:

Chicago Bridge & Iron Co.
6 Greenville, Pa. 16125

C/F
EW

LUKENS ST COMPANY
COATES PA. 19320
TEST CERTIFICATE

DATE: 5-30-75

FILE NO. 10-03-99

CONSIGNEE:
Chicago Bridge & Iron Co.
Birmingham, Ala.

submit

MILL ORDER NO.	CUSTOMER P.O.	
79625-2	73-7302U-8	MP 51775 DM

IS MATERIAL HAS BEEN MANUFACTURED AND TESTED IN ACCORDANCE WITH PURCHASE ORDER REQUIREMENTS AND SPECIFICATION(S):

CB&I MS-6042 Rev. 0 1974 QAS 347 Rev. 0 SA-516 GR. 70 ASME Code Sect. 2 & 3 CL. MC 1971 Edition Thru Summer 1973 Addenda

BEND TEST O.K. HOMOGENEITY TEST

CHEMICAL ANALYSIS

MELT NO.	C	MN	P	S	CU	SI	NI	CR	MO	V	TI	AL	B		Grain Size
A3655	23	1.06	011	018		25									7-8

21-2
21-3

RECEIVED
JUN -4

PHYSICAL PROPERTIES

MELT NO.	SLAB NO.	YIELD PSI X100	TENSILE PSI X100	% ELONG. IN 2"	% R.A.	BHN	IMPACTS Long. V-Notch -10°F.			Fracture Appearance % Shear	DESCRIPTION
A3655	5	525 595	823 830	25 29			82	116	88	60-60-60	1- 3" x 60 x 192
					Lateral Expansion in Inches		.052	.058	.068		

Plate and tests heated 1625-1675°F., held 1/2 hr. per inch min. and water quenched; then tempered 1260°F., held 1/2 hr. per inch min. and water quenched.

Tests stress relieved by heating within a rate of 133°F. per hr. to 1150°F., held 15 hrs. and furnace cooled within a rate of 167°F. per hr. to 600°F.

Affirmed and subscribed before me this ____ day of MAY 30 1975

Phillip A. Romano Jr.

Notary Public
My Commission Expires April 1, 1976

11

We hereby certify the above information is correct.

SUPERVISOR-TESTING H. H. Kline

Submit

ARMCO STEEL CORPORATION
AMBRIDGE WORKS, AMBRIDGE, PA

Form No. 0021-5 (3/1/74)

REPORT OF TESTS

Customer: CAPITOL PIPE & STEEL PRODUCTS INC.   Date: 3-16-74
Specification: ASTM A-333-72A / ASME SA-333   Armco Order No. 00244890-0170
Material: SML'S. GR 1 AND GR 6 STEEL PIPE   Customer Order No. 64209

PHYSICAL TESTS (MATERIAL NORMALIZED AT 1650° F) STILL-AIR COOLED 80 MIN

Item	Heat Number	Identification	Yield Strength	Ultimate PSI	% Elongation In 2 Inch	Transverse / Longitudinal Strip	Round	Hydro Test PSI
1	234099	12 3/4 x 1.312	48750	74000	36.0	X		7800
"	"	" "	42500	73500	38.0	"		"

CHEMICAL ANALYSIS

Item	Heat Number	C	Mn	P	S	Si	Ni	Cr	Mo	V	Other
1	234099	26	94	011	017	23					CHEM
"	"	27	95	010	018	24					CHECK
"	"	25	93	011	017	24					LADLE

Chicago Bridge & Iron
Capitol S.O.# RN-1024-A
P.O.# G80184-73024

Ch# P-18893

Item# 15+16

AND STEEL

IMPACT TESTS – Longitudinal X Transverse Size 10x 10 MM.

Condition 1: Impact Test Normalizing Temperature 1650 °F at 80 Minutes Soak, Still Air Cooled.
Condition 2: Impact Test Normalizing Temperature 1650 °F at 80 Minutes Soak, Still Air Cooled and Stress Relieved at 1100 °F at 80 Minutes Soak, Furnace Cooled.
Condition 3: Impact Test Water Quenched & Tempered at Minimum Soak of one Hour Per Inch of Wall.

V-Notch Charpy Test

Item	Heat Number	FT/LB Impact Value of Set &			Avg.	% Ductile Fracture			Lateral Expansion			Condition	Temperature °F
1	234099	16	16	17 =	16	5%	5%	5%	.014	.010	.013	STR REL	-50°
"	"	23	16	15 =	18	5%	5%	5%	.018	.006	.006	NORM	-50°

Flattening Test OK

Bending Test

The chemical analyses and physical or mechanical tests reported above are correct as contained in the records of the corporation.

S. Mitelsky
Metallurgical Laboratory

Sworn and subscribed before me this 18th day of MARCH 1974

Rita Fones
RITA FUNIS
Notary Public, Harmony Twp., Beaver Co.
My Commission Expires December 8, 1975

PROCESS PIPES

AO:5 9/76

SOLD TO	Tube Turns [redacted]O. Box 987 Louisville, Ky. 40201
SHIP TO	Tube Turns 718 South 28th St. Gate #1 Louisville, Ky. 40211

DETAILED ANALYSIS REPORT

TU[redacted]URNS

DIVISION OF CHEM[redacted]RON CORPORATION

Main Steam Line Penetrations

'C'

Page 1 of 3

HOUSTON, TEXAS 11/9[redacted] bh

TUBE TURNS ORDER NO. HPM 4 93161

CUSTOMERS' ORDER NO. 93161

DESCRIPTION	PHYSICALS OF MATERIALS FROM WHICH MADE					CHEMICAL ANALYSIS									HEAT OR LOT NO.	SPECIFICATION OF MATERIAL FROM WHICH MADE
	** HEAT TREATMENT	YIELD POINT PER SQUARE INCH	TENSILE STRENGTH PER SQUARE INCH	PERCENT ELONGATION IN 2"	PERCENT REDUCTION IN AREA	C	MN	P	S	SI	CR	NI	MO	CB		
Item 001 1 Pieces	1	57,400	82,300	29.0		.21	Ladle Analysis .99	.010	.016	.18					J2254	SA-516 Gr.70
35.500 Process Pipe (Outer		Transverse weld tensile 76,000				.21	Check Analysis .99	.006	.017	.19					78335	
Nipple) 35.500 O.D. +0 -1/4 x		SERIAL NO: J2254-1-HA														
2.000 Wall x 46-5/8" +1/4		Charpy "V" Notch @ +50°F. (10mm x 10mm)														
-0 Long. Machine one end per		BASE	50-48-60 Ft. Lbs./47-44-48 Mils L.E./50-50-50% Shear													
Detail X on Dwg. 77273-D1.1		WELD	54-51-57 Ft. Lbs./45-46-53 Mils L.E./30-30-30% Shear													
Rev. 4 other end square																
TAG: P.O. 71189 Item 1 Code C																
Item 002 1 Piece	1	57,400	82,300	29.0		.21	Ladle Analysis .99	.010	.016	.18					J2254	SA-516 Gr.70
35.500 Process Pipe (Outer		Transverse weld tensile 76,000				.21	Check Analysis .99	.006	.017	.19					78335	
Nipple) 35.500 O.D. +0 -1/4 x		SERIAL NO: J2254-1-HB														
2.000 Wall x 46-5/8" +1/4		Charpy "V" Notch @ +50°F. (10mm x 10mm)														
-0 Long. Machine one end per		BASE	50-48-60 Ft. Lbs./47-44-48 Mils L.E./50-50-50% Shear													
Detail X on Dwg. 77273-D2.1 Rev. 4		WELD	54-51-57 Ft. Lbs./45-46-53 Mils L.E./30-30-30% Shear													

* STANDARD ROUND TEST SPECIMEN ** 1=NORMALIZED 2=ANNEALED 3=HEAT TREATED PER ORDER SPECIFICATION.

SUBSCRIBED AND SWORN TO BEFORE ME THIS

9th DAY OF November 19 77.

NOTARY PUBLIC

COPY

I HEREBY CERTIFY THIS REPORT TO BE TRUE AND CORRECT ACCORDING TO RECORDS IN THE POSSESSION OF THIS CORPORATION

R. Avera, Quality Control Engr.

45-197

Submit

(USS) United States Steel Corporation.

STANDARD CERTIFIED TEST REPORT

TUBULAR PRODUCTS

LORAIN

8-14-75 DATE

MATERIAL: Smls.

GRADE: B ASTM A106 & ASME SA106

TREATMENT

CUSTOMER'S ORDER NO. A-09009

U.S. STEEL ORDER NO. EB 36295

INVOICE NO.

CUSTOMER NAME: GUYON ALLOYS -COPY

ADDRESS

CITY AND STATE: Turbo Turns PO# 19386

CODE OR LOT NO.	SIZE O.D.	WT/FT OR WALL THICKNESS		HEAT NUMBER	MIN. HYDRO. TEST PRESSURE P.S.I.	YIELD STRENGTH P.S.I./POINT	TENSILE STRENGTH P.S.I.	ELONG. IN 2" %	C	Mn	P	S	Si	Mo	
	20	1.031		N12576	2710	40100	74300	42.5	.26	.94	.010	.032	.19		CK.
									.26	.95	.009	.028	.18		L.
	120	5180													
				L02461	"	40000	69900	45.0	.23	.89	.009	.016	.20		CK.
				LU6253					.22	.89	.007	.014	.18		

FLATTENING TEST OK

Q. A. APPROVED
BY: [signature] DATE: 8-19-75
GUYON ALLOYS, INC.

EBASCO VQA REP.

REVIEWED BY
We hereby certify that the above figures are correct as contained in the records of the company.
R. L. Bush 5/17/78
EBASCO VQA REP.

[signature]

FLUED HEAD

DETAILED ANALYSIS REPORT

TUBE TURNS
DIVISION OF CHEMETRON CORPORATION

40-5 9/70

SOLD TO: Tube Turns
P. O. Box 987
Louisville, Ky.

SHIP TO: Tube Turns
718 South 28th St.
Louisville, Ky.

Main Steam Line Penetration
Flued Head

HOUSTON, TEXAS 6/28/ 'bh

TUBE TURNS ORDER NO. HMF 4 93092

CUSTOMERS' ORDER NO. 93092

DESCRIPTION	PHYSICALS OF MATERIALS FROM WHICH MADE					CHEMICAL ANALYSIS									HEAT OR LOT NO.	SPECIFICATION OF MATERIAL FROM WHICH MADE
	** HEAT TREAT-MENT	YIELD POINT PER SQUARE INCH	TENSILE STRENGTH PER SQUARE INCH	PERCENT ELONGA-TION IN 2"	PERCENT REDUCT-TION IN AREA	C	MN	P	S	SI	CR	NI	MO	CB		
Item C01 2 Pieces	3	49,000	79,000	30.0	62.6	.29	.84	.011	.025	.17					215003	SA-105
70 x 60 x 47 x 35.5 x 34						.30	.88	.012	.024	.24						
Multi-Flued Heads 70.0 x 31.5																
x 17.75 SA-105 Component Spec		Charpy "V" Notch @ +50°F				(10mm x 10mm)				45-46-44 Ft. Lbs.						
CS-7-119 DWG. 77.273-E1.7		Lat. Exp.								43-44-42 Mils						
Rev. 0		% Shear								50-50-50						
TAG: CODE U P.O. 77273 &																
1 Pc. P 1 Item 1		Ultrasonic and Magnetic Particle tested per Ebasco 873-73 - Satisfactory														
1 Pc. P 2 Item 2																

COPY

REVIEWED BY
[signature] 7-1-77
EBASCO VQA REP.

* STANDARD ROUND TEST SPECIMEN ** 1-NORMALIZED 2-ANNEALED 3-HEAT TREATED PER ORDER SPECIFICATION.

SUBSCRIBED AND SWORN TO BEFORE ME THIS 28th DAY OF June 19 77

[signature: Vicki Divin]
NOTARY PUBLIC

VICKI DIVIN
Notary Public in and for Harris County Texas
My Commission Expires November 8, 1978

I HEREBY CERTIFY THIS REPORT TO BE TRUE AND CORRECT ACCORDING TO RECORDS IN THE POSSESSION OF THIS CORPORATION

[signature]
R. C. Campbell, Q. C. Manager

MAIN STEAM PIPING

June 30, 1981

To: C Shelton

From: J Flaherty/T S Sahansra

Subject: FLORIDA POWER & LIGHT COMPANY
ST LUCIE PLANT
1983 - 890 MW(e) EXTENSION - UNIT 2
NRC-GDC-51
MAIN STEAM PIPING
FRACTURE PREVENTION OF CONTAINMENT BOUNDARY

Ref: Your memo dated June 18, 1981, item #3

The Detailed Analysis Report for main steam piping piece mark #I-35½-MS-1-1 issued by Tube-Turns on August 16, 1977 was in error and did not indicate the normalizing of these pieces. Revised DAR issued by Tube-Turns dated June 30, 1981 attached herewith indicates that the pieces were normalized at 1650°F and stress relieved at 1150°F.

This completes the information requested.

TSS/lf
Attachments

cc: E Zuchman w/o attach
D Chin w/o attach
C F M Trapp w/o attach
K N Chow w/o attach
J Flaherty w/o attach
P Grossman w/attach
R Walpole w/o attach
T S Sahansra w/o attach
DB-15 w/o attach
R-23 w/attach
M-2 w/attach

SOLD TO: B. F. SHAW COMPANY
P. O. BOX 228
Wilmington, Delaware 19899

SHIP TO: B. F. SHAW COMPANY
Old Laurens Airport
Laurens, S. C. 29360

DETAILED ANALYSIS REPORT

1-35½-MS-1-1 (*)

Tube Turns Division
Chemetron Corporation

(*) Replaces DAR Dated 8-16-77

TT-1A REV. (4-76)

LOUISVILLE, KY. 6-30-81 bb (*)

TUBE TURNS ORDER NO. HRM 4 27525

CUSTOMERS' ORDER NO. L 6757

DESCRIPTION	HEAT TREAT-MENT	YIELD STRENGTH P.S.I.	TENSILE STRENGTH P.S.I.	ELONG.	REDUCT.	C	MN	P	S	SI	NI	CR.	MO	CU	HEAT OR LOT NO.	SPEC. OF MATERIAL
							Ladle Analysis									
Item 001 2 PCS	3	45400	73800	31.5		.20	.68	.010	.023	.15					J2078	SA-515GR.
		Transverse weld tensile					Check Analysis									
35.500" O.D. X 2.125" M.W.			74000			.22	.70	.009	.027	.17					82044	
E. F. W. Pipe per SA155 KC 65		Serial No'S: J2078-1-HA, 2-HB														
Cl. 1 Sect. III Cl. 2. Furnished with square ends in the following quantities and lengths:																
1 Pc. 3' 5-1/2" TAG: MS-1-1																
1 Pc. 3' 5-1/2" TAG: MS-3-1																

(*) This DAR replaces Tube Turns Houston DAR Dated 8-16-77 - Page 1, 8-23-77 - Page 2, and 8-23-77 Page 3. A review of the early DAR revealed the Heat treatment for the two pieces of Item #001 was reported incorrectly. According to the records in possession of this corporation the heat treatment should read Normalize and Stress Relieve.

* CONDITION FOUND TEST SPECIMEN
1 AS ROLLED
2 NORMALIZED
3 NORMALIZED AND STRESS RELIEVED
4 [illegible]
5 QUENCHED AND TEMPERED
6 [illegible]
7 HEAT TREAT PER ORDER SPECIFICATION

SUBSCRIBED AND SWORN TO BEFORE ME THIS 30th DAY OF January 1981

NOTARY PUBLIC

My Commission Expires March 3, 1983

I HEREBY CERTIFY THIS REPORT TO BE TRUE AND CORRECT ACCORDING TO RECORDS IN THE POSSESSION OF THIS CORPORATION.

Ray A. Metcalf - Product Control

SOLD TO B. F. SHAW COMPANY
P. O. BOX 228
Wilmington, Delaware 19899

SHIP TO B. F. SHAW COMPANY
Old Laurens Airport
Laurens, S. C. 29360

DETAILED ANALYSIS REPORT

1-35½-105-1-1A

Chemetron Corporation

Replaces DAR dated 8-23-77

T115A REV. (4-70)

LOUISVILLE, KY. June 20, 1981 bh

TUBE TURNS ORDER NO. HPM 4 27535

CUSTOMERS' ORDER NO. L 6761

DESCRIPTION	HEAT TREATMENT	YIELD STRENGTH PSI	TENSILE STRENGTH PSI	ELONG. %	REDUCT. AREA %	C	MN	P	S	SI	NI	CR.	MO	CU	HEAT OR LOT NO.

NOTES:

1) Sub Arc welded per TTWO 14-0109 Rev. 14 using Linde 81 (Ht. 031113) and Linde 231 Flux (Lot 1101) per NC 2400 (SFA 5.17)

Weld Repair per TT 11-0106 Rev. 11 using Atom Arc E7018 (Ht. 20400/Lot H011N1AD).

2) Pipe Manufactured per Applicable portions of Ebasco 810-74, 884-74.

3) Bend test performed per SA155 - Satisfactory

4) Welds Radiographed per Ebasco 850-73, 873-75 Section 1 and TT 03-081 Rev. 0 - Satisfactory

5) Pipe hydro tested at 2750 PSI per SA155 - Satisfactory

6) Pipe Normalized at 1650°F for 1 hour per inch and cooled in still air.

7) Pipe Stress Relieved at 1150°F for 1 hour per inch and cooled in still air.

8) Welds 100% Magnetic Particle tested per Ebasco 850-73, 873-75 - Satisfactory

9) Plate 100% Ultrasonic tested per Ebasco 850-73, 873-75 and Section III.

SUBSCRIBED AND SWORN TO BEFORE ME THIS 20th DAY OF June 1981

NOTARY PUBLIC

I HEREBY CERTIFY THIS REPORT TO BE TRUE AND CORRECT ACCORDING TO RECORDS IN THE POSSESSION OF THIS CORPORATION.

Ray A. Metcalf Product Control

1-35 1/2-M-1-13

T115A REV: (4-7

SOLD TO B. F. SHAW COMPANY
P. O. Box 228
Wilmington, Delaware 19899

SHIP TO B. F. SHAW COMPANY
Old Laurens Airport
Laurens, S. C. 29360

DETAILED ANALYSIS REPORT

Tube Turns Division

Replaces DAR dated 8-23-77

LOUISVILLE, KY. June 30, 1981 bh

TUBE TURNS ORDER NO. BPM 4 27535

CUSTOMERS' ORDER NO. L 6761

DESCRIPTION	HEAT TREAT-MENT	YIELD STRENGTH PSI	TENSILE STRENGTH PSI	% ELONGATION	% REDUCTION	C	MN	P	S	SI	NI	CR.	MO	CU	HEAT OR LOT NO.	DIRECTION OF ... TENSILE PROPERTIES OF SPECIMENS

NOTES CONTINUED:

10) The pipe described herein are identified as follows with low stress interrupted dot stampings:

R R

NPT CL. 3 TT Tube Turns 35.500" O.D. X 2.125" MW ASME SA155 Cl. II

"Serial No." YR. BLT. 1977 2750 PSI

11) This certifies that the above material meets the purchasing requirements, material (c) specifications and all special requirements of ASME Sect. III, to be fulfilled by the manufacturers of parts, articles NC 2000 and NC 4000 applicable.

(1971 Ed./Sum. '73 Ad.)

* STANDARD ROUND TEST SPECIMEN
1 ANNEALED
2 NORMALIZED
3 NORMALIZED AND STRESS RELIEVED
4 STRESS RELIEVED
5 QUENCHED AND TEMPERED
6 HOT FORMED
7 HEAT TREAT PER ORDER SPECIFICATION

SUBSCRIBED AND SWORN TO BEFORE ME THIS

30th DAY OF June 1981

D. Yochum Taylor

NOTARY PUBLIC

I HEREBY CERTIFY THIS REPORT TO BE TRUE AND CORRECT ACCORDING TO RECORDS IN THE POSSESSION OF THIS CORPORATION.

Ray M. Metcalf

Ray M. Metcalf - Product Control

MAIN STEAM WELDOLET

C-E-W Bonney Forge Division
Energy Products Group
CARLINVILLE, ILLINOIS

(3)

1-35½ - MS-1-1 AD

Log No. R 79592 Page 1 of 1

PHONE 217/854-9511

CUSTOMER: B.F.Shaw
Date January 25, 1979
CUSTOMER'S Order No.: L-8938
Bonney Order No. 0512
SHIPPED TO:
Mark

COPY

Item No.	Quantity No.	Bonney Lot No.	Grade or Specification No. Chemical Analysis, Physical Properties, Remarks:
			ASME SA105N
1	2	270BB	35.5 (2.00MW) x 10 (1.125) Weldolet UT-PT-1-22-79-1 and 2 Ladle Analysis: C.28 Mn.82 P.010 S.013 Si.28 T/S 75,134 Y/S 53,303 El 34.5 Ra 67.2 Mill Heat No: 115202 Lab Chemical: C.25 Si.21 S.014 Mn.77 P.011
	----	----	This certifies that the fittings supplied were normalized by heating to within 1625°F and 1675°F for 3/4 hr. per inch of thickness (1 hr.min.) followed by cooling in still air.
			This certifies that the fittings supplied are capable of withstanding without bulging, cracking or leaking, a hydrostatic pressure test of 1 1/2 times the fittings maximum permissible working pressure.
			The above fittings are in accordance with purchase order L-8938 and Ebasco 872-75 and 873-75.
			Liquid Penetrant Test per BF-DP-2 Rev. BS-1 dtd. 12-8-71, and Ebasco 873-75.
			Ultrasonic Test per BF-UT-1 Rev. 1 dtd. 11-29-72 and Ebasco 873-75.
			This certifies that the fittings supplied are in complete accordance with the ASME Boiler and Pressure Vessel Code, Section III, Class 2, 1971 edition thru summer 1973 addenda and SA105N.

REVIEWED FOR CORRECTNESS AND COMPLETENESS BY [initials]
EBASCO ENGINEERING REVIEW VERIFIED BY
[signature] 7-16-79
EBASCO VQA REP.

BENJAMIN F. SHAW CO.
CHECKED L-8938-1 1322
ITEM 1 OF 2
...
APPROVED B.J.K.
DATE 2/9/79

APPROVED
QUALITY DEPT.
PRODUCT ENGINEERING
BY
DATE 1-26-79

Bonney Forge Division
Energy Products Group
Carlinville, Illinois
by [signature]
QUALITY ASSURANCE MANAGER
PHIL SIMPSON

MAIN FEEDWATER PIPING

1-20-CF-1[illegible]-1 Feedwater inlet elbow
Between Isolation valve & Pen #2

PRODUCTION DEPARTMENT – METALLURGICAL

United States Steel Corporation

REPORT OF TUBULAR PRODUCTS

S LORAIN-CUYAHOGA U.S.S. ORDER NO. AN14576 LOAD TALLY OR INVOICE NO

MFR ORDER NO. A-04602-H

SHIPPER NO. & DATE 11/13/75

(6)

Submitted

REVIEWED BY [illegible] 5/6 BF SCO VQA

GUYON ALLOYS INC
3400 ROGERDALE RD
P O BOX 42345
HOUSTON TEX 77042

MAIL TO

GUYON ALLOYS INC
3400 ROGERDALE RD
P O BOX 42345
HOUSTON TEX 77042

3

WE HEREBY CERTIFY THAT THE FIGURES SET FORTH BELOW ARE CORRECT, AS CONTAINED IN THE RECORDS OF THE COMPANY.

MILL CERTIFIED

F = FULL SECTION GAUGE WIDTH
* = 3/4 INCH GAUGE WIDTH
** = 1 1/2 INCH GAUGE WIDTH

MATERIAL SMLS

SIGNATURE E. L. BARTOLOTTA CHIEF METALLURGIST

DATE 11/19/75

ITEM NUMBER	SIZE INCHES	WALL INCHES	GRADE	SPECIFICATION	HEAT NUMBER	MIN. HYDRO TEST PRESSURE P.S.I.	YIELD STRENGTH P.S.I.	TENSILE STRENGTH P.S.I.	ELONGATION INCHES	ELONGATION %
7	20	1031	B	ASTM A106	N12577	2710	39000	68700	2	460
	ALSO CERTIFIED TO ASME SA106							FLATTENING TESTS OK		
7	20	1031	B	ASTM A106	N14096	2710	42700	79000	2	375
	ALSO CERTIFIED TO ASME SA106							FLATTENING TESTS OK		
7	20	1031	B	ASTM A106	N14097	2710	44500	77200	2	400
	ALSO CERTIFIED TO ASME SA106							FLATTENING TESTS OK		

20" 5/80

Job No: 9320
This document was transmitted with check list.
Dated 3-21-77

B.F. Shaw
PO # L-68
Item # 1

COPY

Q. A. APPROVED
BY [illegible] DATE 11-24-75
GUYON ALLOYS, INC.

MATERIAL TESTED ACCORDING TO COMPANY RECORDS CONFORMS TO THE REQUIREMENTS OF THE SPECIFICATION LISTED ABOVE.

ITEM	TYPE	HEAT NO.	C	Mn	P	S	Si	Cu	Ni	Cr	Mo	Sn	Al	N	V	B	Ti	Cb	Ce
7	LADL	N12577	22	95	025	019	170												
7	CHK	N12577	21	92	009	037	170												
7	LADL	N14096	25	93	013	015	160												
7	CHK	N14096	23	102	009	020	150												
7	LADL	N14097	25	103	010	012	169												
7	CHK	N14097	26	103	008	015	160												

BENJAMIN F. SHAW CO.
CNTR NO. 4-6872-2
PAGE 1 OF 3
P.O. ITEM NO. 1
APPROVED DKS
DATE 1-12-77

MAIN STEAM ISOLATION VALVE

Body

Submit

SEI 4.74
36-61871.
Stone & Webster
(VEPCO)

RALEIGH

Customer

Transportation Equipment Division
Rockwell International
P O Box 188
Fourth and Park
Atchison, Kansas 66002
(913) 367 2121

Larry S. Shirley

Chemist

Witness

ATCHISON, KANSAS 7-17-74

Heat No	Patt No	No. Pcs	SRL No	Order No	Spec	YS PSI	TS PSI	Elong In 2" %	Red Area %	BHN	Charpy Impact °F / Ft. Lb.	C	MN	P	S	SI	CR	NI	MO	CU	AL	B	TI	V	ZR	CO	Other
3740519	183 242	1	103	36-3595	RMC 01024 SA-216 WCC	46000	83000	29.0	55.5			.21	1.09	.012	.014	.41	.07	.16	.07		.031						N

HEAT TREAT INFORMATION:

1700°F for 12 hours; normalize
1225°F for 11 hours; temper

The following operations not performed at TED:

(A) Final Stress Relieve
(B) Final MT Inspection

REVIEWED BY
AI C. D. C.
DATE 8-31-75
CUST.
INSP.
DATE

Rockwell
RALEIGH PLANT
RALEIGH, N. C.
APPROVED
7-26-74
C.E. Chi
MET. PROC. CONT.

JJH 12-31-74

CERTIFIED TEST REPORT

SEI 474
36-61821
VCP Co.

GULF FORGE COMPANY

8881 HEMPSTEAD HWY. P. O. BOX 2926 713-869-3643
HOUSTON, TEXAS 77001

CUSTOMER'S ORDER No.	DATE	JOB ORDER No.
36-7243 #1	10-14-74	73490

Bonnet

SOLD TO: Rockwell Manufacturing Company
1900 South Saunders Street
Raliegh, North Carolina 27603

SHIPPED TO: Same

Submit

N

CORRECTED MILL TEST REPORT

QUANTITY	DESCRIPTION
2	Rough Machined 32" .1612-Y bonnet Dwg. A-185150 43.25"OD x 12.12 Lg. ASME SA 105-II, Also Complys with RMC 01112. Part # A-185150

Rockwell
RALEIGH PLANT
RALEIGH, N. C.
APPROVED
10-18-74
C.E.Oli
MET. PROC. CONT.

REVIEWED BY
AI C.B.C.
DATE 10/30/74
CUST. INSP.

OCT 18 1974

H.H. 10-21-74

CHEMICAL ANALYSIS

249194	Finkl	.28	.79	.010	.019	.25					

PHYSICAL PROPERTIES

43,700	75,650	31.0	59.0					

HEAT TREATMENT

Normalize	1600	14 hrs.			
Temper	1250	14 hrs.			

SCRIBED AND SWORN TO BEFORE ME
SS NO. 462-92-3210

THIS 14th DAY OF October 1974

NOTARY PUBLIC

I CERTIFY THAT THIS IS A TRUE COPY OF ORIGINAL TEST SHEET NOW ON FILE AT THE OFFICE OF GULF FORGE CO. AND THAT THIS STEEL WAS MANUFACTURED AND FORGED IN THE UNITED STATES OF AMERICA.

BY

A Finkl & Sons Co

A Subsidiary of Republicsteel

Barnet

METALLURGICAL REPORT

USTOMER Kiefer-Prowell & Assoc. Inc.

DATE August 16, 1974

O. 74-2119-H

QUANTITY 5 Pcs. S.O. 48402

M 34 X 34 X 25,000 lbs. Approx.

RADE EF-1026 Modified, As Cast Ingots

Submit

FORGED SURFACE

ECIFICATION

Heat No.	Mill	Class	C	Mn	P	S	Si	Ni	Cr	Mo	V	Cu	W		Grain Size
249194	X	BE	.28	.79	.010	.019	.25	-							

Jominy	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	18	20	22	24	26	28	30	32	

Test No.	Test Dia.	Test Direction or Location	Yield Strength PSI	Tensile Strength PSI	Elongation % in 2"	Reduction of Area %	Fracture Rating	Hardness BHN	Impact Ft.-Lbs.	Serial No.
Required:										

eat Treatment

Rockwell
RALEIGH PLANT
RALEIGH, N. C.
APPROVED
10-18-74
C.E. Olive
MET. PROC. CONT.

Remarks

OCT 18 1974

RECEIVED
AUG 22 1974
STEEL CORPORATION OF TEXAS

WITNESSED

PHYSICAL ______ FOR ______ DATE ______

SURFACE ______ FOR ______ DATE ______

above agrees with the official company records.

J. Valentine

F-57—Rev. 11-73

SEL 4/4
50 6177
VETCO

GULF FORGE COMPANY

8881 HEMPSTEAD HWY. P. O. BOX 2926 713-869-3643
HOUSTC 'I, TEXAS 77001

CUSTOMER'S ORDER No.		DATE	JOB ORDER No.
36-7262 #1	N	Jan. 31, 1975	73633

Disc

SOLD TO
Rockwell Manufacturing
1900 South Saunders Street
Raleigh, North Carolina 27603

SHIPPED TO
Rockwell Manufacturing
1900 South Saunders Street
Releigh, North Carolina 27603

QUANTITY	DESCRIPTION
4	Rough Machine Disc. Dwg. A-183876 29.62 "OD x 15.0 Lg. ASME SA 182 F-11 Weight 2930# These forgings Comply with RMC 02271 Rev. 2

REVIEWED BY
AI CBB
DATE 3-4-75
CUST. INSP.
DATE

Rockwell
RALEIGH PLANT
RALEIGH, N. C.
APPROVED
2/10/75
MET. PROC. CONT.

FEB 10 1975

CHEMICAL ANALYSIS

3310	Sharon	.14	.50	.011	.013	.64		1.23	.48			

PHYSICAL PROPERTIES

46,000	83,342	29.5	63.0	174				
48,156	77,220	26.5	63.0	179				
49,350	85,540	28.0	52.5					
46,700	81,000	29.0	56.0					

HEAT TREATMENT

Normalize	1600	16 hrs.			
Temper	1250	16 hrs.			

SUBSCRIBED AND SWORN TO BEFORE ME
SS NO. 462-92-3210

31st DAY OF January 19 75

Mary Beth [illegible]
NOTARY PUBLIC

I CERTIFY THAT THIS IS A TRUE COPY OF ORIGINAL TEST SHEET NOW ON FILE AT THE OFFICE OF GULF FORGE CO. AND THAT THIS STEEL WAS MANUFACTURED AND FORGED IN THE UNITED STATES OF AMERICA.

BY Sam [illegible]

ORDER DATE: /15/74 20 : OUR ORDER NO. R-3043 PAGE 2 of PAGE 3

ORDER NO. 36-7531 CUST. REQ. NO.

Utility Products Group 7-4605-3
Rockwell International
1900 S. Saunders St.
Raleigh, NC 27603

The Above

Studs

Submit

VICTOR PRODUCTS CORPORATION

2635 BELMONT AVENUE
CHICAGO, ILLINOIS 60618
TELEPHONE (312) 539-5940
D-U-N-S 00-500-3539

TEST REPORTS

FOR

SIZE
2.00-8 UN x 14.82
B/P A183785 (A)

DESCRIPTION
Special Stud

SA-540 Gr 23 Cl. 4
RMC 02861 (5)
ASME Sect. III/71 & Winter '72
Add. Nucl. Cl. 2

ITEM P
Refer to page 1

MATERIAL
4340 HR Annld A.Q
2.250 Rd

MILL HEAT No.
Castle
Copperweld 76898

VPC HEAT No.
7674

DOCUMENT No. 1 1A

CHEMICAL ANALYSIS (1 1A)

C	Mn	P	S	Si	Ni	Cr	Mo	Va	Cu
.40	.78	.015	.023	.28	1.75	.86	.22		.14

PHYSICAL PROPERTIES (2 2A)

Tensile Str.	Yield Str.	Elongation in 2" %	Reduction of area %	Hardness Rc
150,800	133,800	18.0	59.1	31
148,751	133,300	18.5	59.6	31/32

HEAT TREATMENT (3)

Hardened at	hrs.	Quench Media	at	Tempered at	hrs.
1550 °F	2½	Salt	400 °F	1100 °F	4

ULTRASONIC INSPECTION Not Req'd
All bars tested
a) No reportable indication detected
b) Defective portions of bars cut off and scrapped

CHARPY V-NOTCH IMPACT TEST (4 4A)
Testing Temperature + 33 °F

Sample	Impact Energy ft-lbs	Duct. Fracture Area %	Lateral Expansion inches
94-1	62.0	55.0	.036
4-2	63.0	55.0	.035
94-3	63.0	55.0	.035

DOCUMENTATION REVIEWED
Date 6/10/75
BECHTEL CORPORATION
By [illegible]

MAGNETIC PARTICLE INSPECTION 59-MT-012 of 11/14/73 (5)
100% Inspected
100% Accepted (Any non-conforming items scrapped)

MARKING (for identification and traceability) 4/17/75 [illegible signature]
VB23 R3043P

ORDER DATE		OUR ORDER NO.	PAGE	PAGE
15/74	20	R-3044	2	of 3

ORDER NO. 36-7532 | CUST. REQ. NO.

Utility Products Group
Rockwell International
1900 S. Saunders St.
Raleigh, NC 27603

7-4605-3

The Above

Submit

Nute

VICTOR PRODUCTS CORPORATION

2635 BELMONT AVENUE
CHICAGO, ILLINOIS 60618
TELEPHONE (312) 539-5940
D-U-N-S 00-509-3539

TEST REPORTS

FOR

SIZE	DESCRIPTION		ITEM
2.00-8 UN-2B B/P A185197	Hvy SF Hex Nut	SA-194 Gr 7 RMC 01291 (3) ASME Sect. III/71 incl. Winter 72 Add. Nucl. Cl 2	Refer to page 1

MATERIAL	MILL HEAT NO.	VPC HEAT No.	DOCUMENT No.
A-4140 HR/HT 3.750 Rd	Hy-Alloy, Timken 41583	7667	1

CHEMICAL ANALYSIS

C	Mn	P	S	Si	Ni	Cr	Mo	Va	Cu	DOCUMENT No.
.41	.81	.012	.014	.30	.11	.94	.18		.09	1 2

CONE STRIPPING TEST Not Req'd
Using 120 degrees hardened steel cone, nuts exceeded the proof load of ______ lbs. without stripping.

HARDNESS TEST
Final condition | after 24 hrs at 1100 °F
Rc 26-27 | RB-103 | Document No. 5

HEAT TREATMENT Re-tempered @ 1100°F -4 hrs

Hardened at °F	hrs.	Quench Media	at °F	Tempered at °F	hrs.	DOCUMENT No.
1550	2½	Oil		1050	6	2 6

PHYSICAL PROPERTIES

Tensile Str.	Yield Str.	Elongation in 2" %	Reduction of area %	Hardness Rc/BHN

CHARPY V-NOTCH IMPACT TEST
Testing Temperature + 33 °F — Document No. 3

Sample	Impact Energy ft-lbs	Duct. Fracture Area %	Lateral Expansion inches
7A-1	60	40.0	.035
-2	67	50.0	.040
-3	65	50.0	.038

MAGNETIC PARTICLE INSPECTION 59-MT-012 of 11/14/73 — Document No. 7
100% Inspected
100% Accepted (Any non-conforming items scrapped)

12/4/74

MARKING (for identification and traceability)

MAIN FEEDWATER ISOLATION VALVE

Body

QUAKER ALLOY CASTING CO.
a division of HARSCO corp.
MYERSTOWN, PA. 17067

MATERIAL TEST REPORT

CUSTOMER

Anchor/Darling Valve Co.

CUSTOMER ORDER NO.	PATTERN NO.	DATE
S1314	1-20F-14A	10/29/80

SPECIFICATION	QUAKER DESIG.
ASME SA216 Gr. WCB	Q70

CONTROL NO.	52214		
HEAT SERIAL	F9340-1		
RT. NO.	U2121		
CHEMICAL COMPOSITION			
C	.24		
Mn	.75		
Si	.45		
P	.004		
S	.004		
Cr	.34		
Ni	.02		
Mo	.02		
Cu	.10		
V	.002		
MECHANICAL PROPERTIES			
TENSILE: TENSILE, Ksi	78.5		
TENSILE: YIELD, Ksi	43.5		
TENSILE: ELONG. %	29.0		
TENSILE: RED. of AREA %	57.0		
CHARPY: ENERGY, ft-lbf	64-66-53		
CHARPY: LAT. EXP. mils	53-53-48		
CHARPY: SHEAR, %	60-60-60		
CHARPY: TEST TEMP., 40°F			
OTHER			
PIECES SHIPPED	1		

ADDITIONAL INFORMATION:

Bend test satisfactory per material specification.

Physical properties determined after simulated PWHT of test coupons at 1150°F ± 50°F for 15 hours.

11/10/80

8 81 260

REVIEWED BY
EBASCO ENGINEERING
REVIEW VERIFIED BY
EBASCO QA SUP.

"I HEREBY CERTIFY THAT THE ABOVE INFORMATION IS CORRECT."

J. Spangler 10-29-80
AUTHORIZED SIGNATURE

STATE OF PENNSYLVANIA, COUNTY OF LEBANON, S.S.
SWORN TO AND SUBSCRIBED BEFORE ME

THIS ______ DAY OF ______ 19

E9328-1-1

TAG # 1-HCV-09-1A

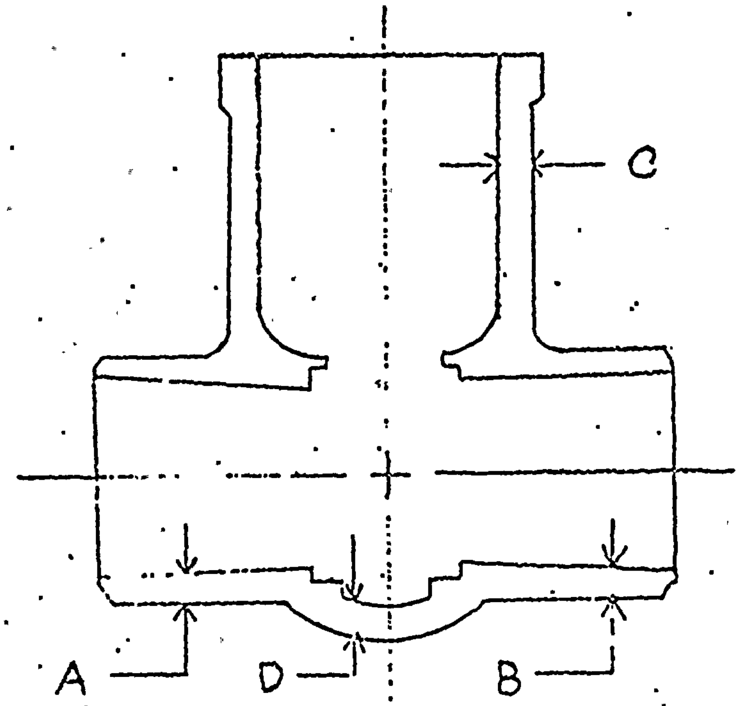
ANCHOR/DARLING VALVE COMPANY

WILLIAMSPORT, PA.

ATTACHMENT 4

Gate Valve Body (Pressure Seal)

SO E9328 ITEM 1 VALVE 20"X18"X20" HEAT F9340 SERIAL U2121



Submit

	12 o'clock	3 o'clock	6 o'clock	9 o'clock
A	2.250	2.500	2.500	2.350
B	2.200	2.350	2.450	2.450
C	2.370	2.300	2.300	2.330
D	N/A	3.100	2.500	3.100

AB&D
QA 14
LEVEL II
11-5-80

Min. Actual Measurement 2.200 Min. Required Measurement 1.894

Remarks:

Customer Inspector ______ Date ______

Inspected By QA 23 LEVEL II Date DEC 12 1980

Bonnet

R 81160

ENERGY PRODUCTS GROUP
GULF+WESTERN MANUFACTURING COMPANY
Plant 35
P. O. Box 536, West Chester, Pennsylvania 19380

Phone: (215) 793-1500
TWX: 510-663-0372
Telex: 83-5453
Telecopier: (215) 793-1500 Ext. 264

E9328-1
BONNET
CA 6 12/9/80

manufacturers of LENAPE FORGE products

MATERIAL TEST REPORT S. O. NO. 0278-0 WEST CHESTER, PA 12/8/80 19

PURCHASER Anchor/Darling Valve Company DISTRIBUTOR

PURCHASER'S ORDER NO. S-2569 DISTRIBUTOR'S ORDER NO.

ITEM NO.	QTY.	PRODUCT	SPEC.	HEAT OR CODE NO.	REMARKS
1	4	18" X 900# Bonnet Forging,RMAO per dwg.#F0218F14A dated 3/10/80 Part # 2-18F-14A TAG: P.O.# S-2569 Part # 2-18F-14A	SA105 Normalized & Tempered per A/D Spec PUR-11,Rev C and ASME Section III Cl.2 '77 Ed thru W '78 Add	AB17NT	M/O 576S

CHEMICAL ANALYSIS AND MECHANICAL PROPERTIES

HEAT NO.	C	MN	P	S	SI	CR	NI	MO			REMARKS
AB17NT	.21	1.23	.011	.013	.20					LADLE	Heat Treatment: 1650°F ± 25°F 5½ hrs. A.C. 1150°F ± 25°F 10½ hrs. A.C. HT-1 Attachment: U.T.Report L/F guarantees Magnetic Part.

HEAT NO.	TENSILE	YIELD	ELONG % IN 2"	R.A. %	B. H. N.	IMPACT	REMARKS
AB17NT	74,500	46,500	30	65		105-105-90	.079-.083-.073 60-60-50

MATERIAL INCLUDED ON THIS TEST REPORT WAS MANUFACTURED UNDER ASME QUALITY SYSTEM'S CERTIFICATE (MATERIALS) NO. N-1950. EXPIRES DECEMBER 9, 1980.

REVIEWED BY SSC
... ENGINEERING
SSC 1/6/8

We hereby certify the above results to be correct as contained in the records of the Company.

Tanya Pollock

ANCHOR/DARLING VALVE COMPANY

E9328-1-1

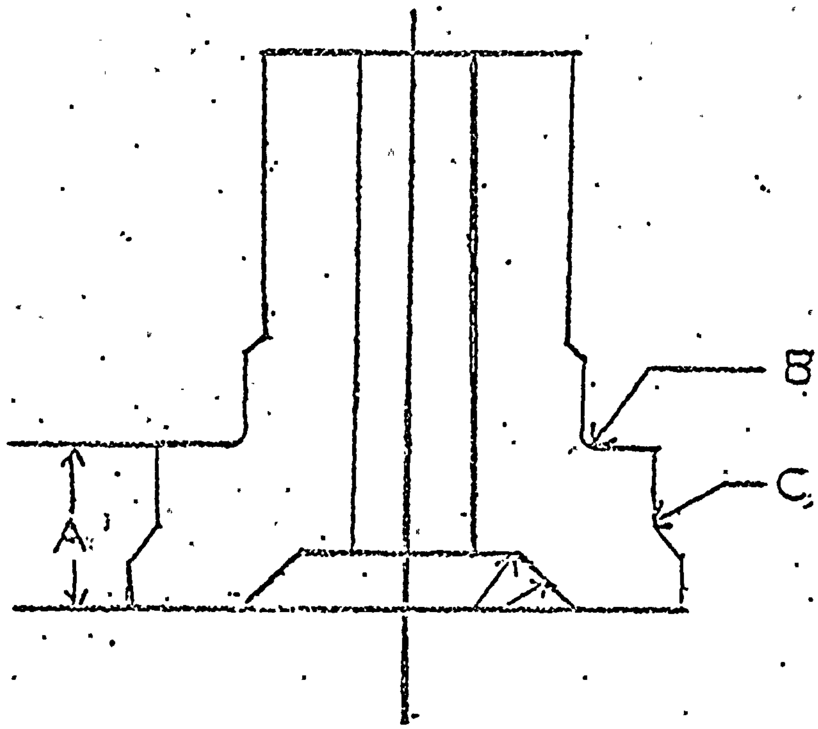
WILLIAMSPORT, PA.

Submit

ATTACHMENT 10

Gate or Globe Valve Bonnet (Pressure Seal)

SO E9328 ITEM 1 VALVE 20"-900 HEAT AB17NT SERIAL 2



	12 o'clock	3 o'clock	6 o'clock	9 o'clock
A	3.650	3.650	3.650	3.670
B	2.870	2.870	2.870	2.870
C	3.330	3.330	3.330	3.330

Min. Actual Measurement 2.870 Min. Required Measurement 2.000

Remarks:

Customer Inspector ______ Date ______

Inspected By QA 57 LEVEL II BEC 15 1980 Date DEC 15 1980

MQCS-93-10

Xisc Submit

53123N

BETHLEHEM STEEL CORPORATION
METALLURGICAL DEPARTMENT
REPORT OF TEST AND ANALYSIS

T 1781

PLANT	SHIPMENT NO.	DATE SHIPPED	CAR OR VEHICLE NO.	
SPARROWS PT.	409- 15216	08/10/79	GTRC GEORGE TFR	PG 1 LAST

SOLD TO
MILLS-ALLOY STEEL CO
1 W INTERSTATE RD
BEDFORD OH 44146

SHIP TO
MILLS-ALLOY STEEL CO
1 W INTERSTATE RD
BEDFORD OH 44146

ITEM	SERIAL NUMBER	PAT NO.	HEAT NUMBER	NO. PCS.	THICKNESS	WIDTH OR DIA.	LENGTH	WEIGHT	YIELD KSI	TENSILE STRENGTH KSI	ELONG. IN.	ELONG. %	RED. %	BEND
	CO# 256HSI					16080770	GD# 015-58558			6861/157		20		

3664 ASME SA516 GR 70 PVQ SUMMER 78 ADD
PLTS & TEST PCS NORM AT 1650 DEG & HELD 1/2 HR PER INCH OF THICKNESS
IN ACCORD W/NCA 3800 ASME SECT 3 NUCLEAR -
VESSELS

ITEM	SERIAL NUMBER	PAT NO.	HEAT NUMBER	NO. PCS.	THICKNESS	WIDTH OR DIA.	LENGTH	WEIGHT	YIELD KSI	TENSILE STRENGTH KSI	ELONG. IN.	ELONG. %	RED. %	BEND
01	H 96061		421H8271 DISC	1	4	95	240	25864	44.5	74.0	2	30	46.2	OK

QA REVIEWED M.A.S. CO. 8/17/79

CH-V SA20S5 L 15FTLB AT MTSF INFO L MILS&SAR AT MTSF BEND TEST SA20S1-REPORT
REDUCTION OF AREA FOR INFO ONLY

SERIAL NUMBER	PAT NO	HEAT NUMBER	THICKNESS	HARD-NESS	TYPE	SIZE	DIR	TEST TEMP.	ENERGY 1	ENERGY 2	ENERGY 3	AVG.	DUCTILITY 1	DUCTILITY 2	DUCTILITY 3	LAT. EXP. 1	LAT. EXP. 2	LAT. EXP. 3
H096061		421H8271				010X10	L-015		42	35	35		30	25	25	38	41	37

HEAT NUMBER	C	Mn	P	S	Si	Cu	Ni	Cr	Mo	V	CB	N	Al		MCQUAID GRAIN SIZE
421H8271	.23	1.07	.009	.013	.210										78

E. B. Shelly

SUBSCRIBED AND SWORN TO BEFORE ME THIS 10 DAY OF Aug 1979
[signature] NOTARY PUBLIC MY COMMISSION EXPIRES 7/1/82

I certify that the above results are a true and correct copy of records prepared and maintained by Bethlehem in compliance with the requirements of the specification cited above.

E. B. SHELLY
CHIEF METALLURGIST

810530

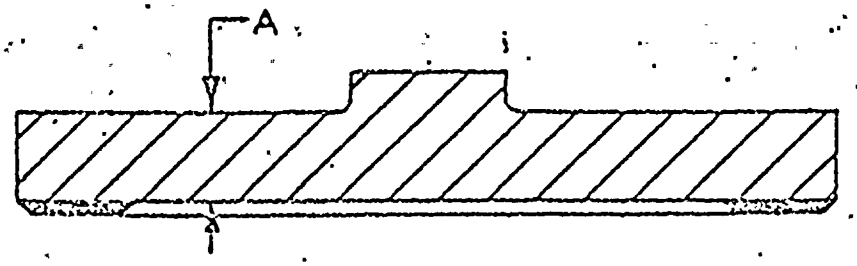
BY [signature]
ERASCO ENGINEERING
REVIEWED BY [signature] 7/21/81
ERASCO VQA REP.

E9328-1-1

ATTACHMENT 16

GATE VALVE DISC

S.O. E9328
ITEM 1
HEAT 42LH8271
SERIAL 8



	12 o'clock	3 o'clock	6 o'clock	9 o'clock
A	2.625	2.625	2.625	2.625

Min. Actual Measurement 2.625 Min. Required Measurement 2.500

Remarks: ______________________

Inspected by QA 8

Date 11/13/80

Interoffice Correspondence

DATE July 2, 1981 FILE REF.

TO P Grossman

OFFICE LOCATION

FROM A P Letizia
P G Hummer

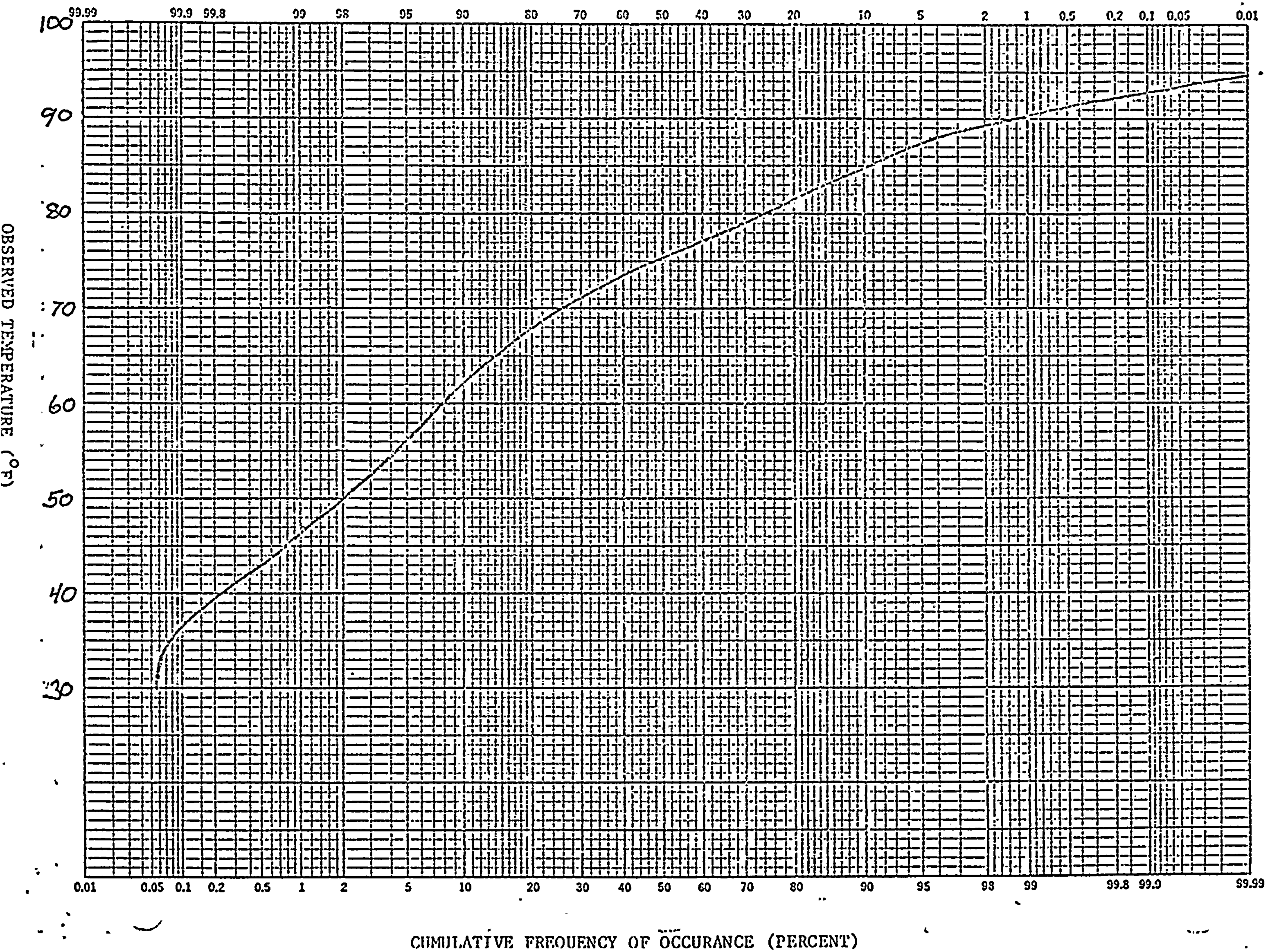
OFFICE LOCATION ENVIROSPHERE

SUBJECT ST LUCIE UNIT 2
CUMULATIVE TEMPERATURES AT WEST PALM BEACH

A cumulative frequency analysis of dry-bulb temperatures was performed on available West Plam Beach surface data. These data covered the period January 1, 1948 through March 21, 1960 and represented over 107,000 hourly observations. The data were taken at the National Weather Service Office at West Palm International Airport (26° 41' North, 80° 06' East). The temperature sensor was located 18 feet above the ground. The analysis consisted of counting the number of temperature observations (temperatures were recorded in whole degrees), summing the number of observations from the lowest to the highest observed temperature and determining the cumulative frequency of each temperature based on the total number of observations. Attached is a plot of the cumulative frequency distribution derived from the above analysis. As the diagram shows, 90% of the observed temperaturesfor the period at West Palm Beach are above 62°F.

APL/PGH:das

cc: J Ferris
N Wilding



OBSERVED TEMPERATURE (°F)
100
90
80
70
60
50
40
30
99.99 99.9 99.8 99 98 95 90 80 70 60 50 40 30 20 10 5 2 1 0.5 0.2 0.1 0.05 0.01
0.01 0.05 0.1 0.2 0.5 1 2 5 10 20 30 40 50 60 70 80 90 95 98 99 99.8 99.9 99.99
CUMULATIVE FREQUENCY OF OCCURANCE (PERCENT)

Question 2

Provide sufficient shielding to meet the requirements of GDC-19 assuming Reg. Guide 1.4 source terms.

Response:

Sufficient shielding will be provided around the post accident sampling system components to limit personnel exposure to the GDC-19 limits. Regulatory Guide 1.4 source terms will be used.

Question 4

Verify that all electrically powered components associated with post accident sampling are capable of being supplied with power and operated within thirty minutes of an accident in which there is core degradation, assuming loss of offsite power.

Response:

The post accident sampling panel will be powered from power panel 2AB which is capable of being powered from the diesel generator in the event of a loss of offsite power. The electrical cables associated with the post accident sampling panel and associated instruments will be routed in accordance with Reg. Guide 1.75, physical Independence of Electrical Systems (Rev 1), as associated circuits.

Heat tracing circuits will be electrically connected to the respective Boric Acid Heat Tracing Panels which are electrically independent, physically separated and are connected to the diesel generator in the event of a loss of offsite power.

Question 5

Verify that valves which are not accessible for repair after an accident are environmentally qualified for the conditions in which they must operate.

Response:

Post accident sampling system valves which are required to operate after an accident and are not accessible for repair, will be qualified to the accident environment in which they operate. Environmental qualification is addressed in FSAR Section 3.11.

460.1 (11.2) Figure 11.2-9 of the FSAR shows a "volume tank" which receives evaporator concentrates from the waste concentrator. In an informal communication, you indicated that you are in process of engineering the addition of this volume tank to the liquid radwaste system. Describe the tank in appropriate sections of the FSAR.

Response

Section 11.2.2 and Table 11.2-5 of the FSAR have been modified to describe the Liquid Waste Concentrator Bottoms Storage Tank.

11.2.2.1.2 Waste Surges

The holdup tanks are sized with sufficient capacity to handle the waste surges which would occur during the normal operation of the plant, and be received in the BMS. There is also sufficient redundancy and interconnections to allow the contents of one holdup tank to be processed through the boric acid concentrators while another is being recirculated prior to processing, and the remaining two are receiving incoming wastes. This flexibility allows the BMS to create additional holdup capacity by simultaneously eliminating stored waste while accepting new waste

The holdup tank capacity is adequately sized to handle the relief valve discharge (see interfaces on Figure 11.2-1) in the unlikely event that they should lift.

11.2.2.1.3 Boric Acid Concentrator Operation

The holdup tank contents are transferred to either of the boric acid concentrators (Figures 11.2-3 or 11.2-4) by the holdup drain pumps (Figure 11.2-2), which first pass the fluid through a pre-concentrator filter and the pre-concentrator ion exchanger (Figure 11.2-2).

Once the waste stream enters the boric acid concentrator, it is separated into two effluent streams by a simple evaporation process. The boric acid concentrator is designed to concentrate a dilute boric acid solution with a boron concentration of 30 to 1720 ppm, into a bottoms stream with a concentration of 10,900 to 21,000 ppm boron and a distillate stream with a concentration of 10 ppm boron maximum.

11.2.2.1.3.1 Distillate

The distillate is condensed before it leaves the boric acid concentrator and is then pumped to the boric acid condensate ion exchanger (Figure 11.2-5) where any trace impurities remaining in the distillate are removed. The water continues on to the boric acid condensate tanks (Figure 11.2-5), where it is stored prior to sampling and reuse or discharge. Should high levels of impurities still be present in the condensate there are provisions to recycle it back through the boric acid concentrator.

11.2.2.1.3.2 Bottoms

INSERT A

~~The concentrated boric acid solution leaving the boric acid concentrator is pumped through the boric acid strainer and then to the boric acid holding tank (Figure 11.2-5). All piping, components, and tanks which handle the concentrated boric acid solution are heat traced to keep the boric acid in solution.~~

~~Once in the boric acid holding tank the concentrate (bottoms) is recirculated using the boric acid holding pumps (Figure 11.2-5), to insure a uniform chemistry. A sample is taken and analyzed to determine the purity and concentration of the boric acid solution. Depending on the analysis and plant requirements, the boric acid can be either reused in the plant (transferred to the boric acid makeup tanks in the CVCS), sent to the Solid Waste Management System for offsite disposal (Figure 11.2-9), or recycled~~ | 1

~~to the boric acid concentrators for further concentration if the solution is too dilute.~~

11.2.2.2 Liquid Waste Subsystem

Liquid waste from sources outside of containment, usually of low activity and low purity are collected in either the equipment drain tank, chemical drain tank, or laundry drain tanks.

Prior to processing, the contents of these tanks are thoroughly mixed via recirculation, and representative samples are taken. The samples are analyzed to determine what, if any, processing is required for that liquid. In the case of waste going to the waste concentrator, chemical adjustments (primarily ph) may have to be made.

11.2.2.2.1 Normal Mode

The equipment drain tank, as shown on Figure 11.2-6, receives wastes from the various equipment drains outside containment. When the tank reaches a preset level it is emptied via the equipment drain pumps (Figure 11.2-6). The waste liquid is first filtered via the waste filter (Figure 11.2-6), to remove suspended solids, then processed through the waste concentrator (Figure 11.2-7).

The chemical drain tank seen on Figure 11.2-6, receives liquid waste inputs from the lab drains and decontamination area drains, which are normally high in impurities. The chemical drain tank is emptied upon reaching a preset level, by the chemical drain pump. The waste liquid is first filtered via the waste filter (Figure 11.2-6), then processed through the waste concentrator (Figure 11.2-7).

The laundry drain tanks, on Figure 11.2-6, store the influents from the plant showers, contaminated sinks, laundry operations, and potential inputs from the Steam Generator Blowdown System. When a laundry drain tank reaches a preset level, it is emptied by a laundry drain tank pump (Figure 11.2-6) and filtered via the laundry filter (Figure 11.2-6). From there it goes on to the circulating water discharge (Figure 11.2-5) and is released from the plant.

Should the need arise, it is possible to route the contents of the laundry drain tank to the waste concentrator for processing.

11.2.2.2.2 Waste Surges

When waste surges occur in the influent volumes to the LWMS tanks, there is sufficient capacity, redundancy and system interconnections to provide adequate handling of these wastes.

Smaller quantity surges would only cause the waste tanks to fill quicker, hence more frequent processing of each tank's contents. Larger quantity surges which would exceed the capacity of those tanks could be routed to the aerated waste storage tank (Figure 11.2-8), for holdup until operations permit its processing. 4

The aerated waste storage tank specifically acts as a surge tank for the Waste Management System equipment drain tank. The waste in the equipment drain tank is pumped to the aerated waste storage tank if:

(1) the chemical drain tank is being processed and the equipment drain tank is filled

(2) the influents to the equipment drain tank exceed the processing capabilities of the waste concentrator such that overflow of the tank could result.

The equipment tank may become filled at any time and require emptying to handle further inputs. The equipment drain pump will be automatically started on high equipment drain tank level and the contents will be 4
pumped to the aerated waste storage tank.

The aerated waste storage tank's contents would be mixed using the equipment drain pumps (Figure 11.2-8). A representative sample would be obtained and analyzed to determine what processing, if any, is required for the waste liquid. The liquid would be pumped from the aerated waste storage tank via the equipment drain pumps to either the circulating water discharge, or through the waste filter to the waste concentrator (see Figure 11.2-6 for process routes), depending on the water quality.

11.2.2.2.3 Waste Concentrator Operation

Liquid wastes enter the waste concentrator (Figure 11.2-7), and the waste stream is separated into two effluent streams by a simple evaporation process. One stream, the distillate, is a very pure water stream. The other, the bottoms, is a highly concentrated solution of impurities.

11.2.2.2.3.1 Distillate

The distillate may still contain some trace impurities. It is then condensed and pumped from the waste concentrator to the condensate ion exchanger (Figure 11.2-6), where those trace impurities are removed. The condensate is stored in the waste condensate tanks, mixed via the waste condensate pumps (Figure 11.2-6), and sampled to analyze for purity.

The condensate may then be either sent to the circulating water discharge for release from the plant, or routed back through the waste system for further treatment if needed. Reuse within the plant is also possible (see Figures 11.2-1, 2 and 6 for process routes).

11.2.2.2.3.2 Bottoms

INSERT B

~~Most of the impurities which are present in the influent stream to the con-~~ centrator leave in the bottoms stream. Because of the high concentration of boron the piping, components, and tanks are heat traced to keep them in solution (see Figures 11.2-6 and 7 for heat traced process routes). The bottoms are pumped from the concentrator (Figure 11.2-7) directly to the drumming station (Figure 11.2-6), where it is prepared for offsite ~~disposal (see Section 11.4).~~

INSERT A

11.2.2.1.3.2 Bottoms

The concentrated boric acid solution leaving the boric acid concentrator is pumped through the boric acid strainer and then to the boric acid holding tank (Figure 11.2-5). All piping, components, and tanks which handle the concentrated boric acid solution are heat-traced to keep the boric acid in solution.

Once in the boric acid holding tank the concentrate (bottoms) is recirculated using the boric acid holding pumps (Figure 11.2-5), to insure a uniform chemistry. A sample is taken and analyzed to determine the purity and concentration of the boric acid solution. Depending on the analysis and plant requirements, the boric acid can be either reused in the plant (transferred to the boric acid makeup tanks in the CVCS), sent to the liquid waste concentrator bottoms storage tanks of the Liquid Waste Subsystem prior to solidification in the Solid Waste Management System (Figure 11.2-9), or recycled to the boric acid concentrators for futher concentration if the solution is too dilute.

INSERT B

11.2.2.2.3.2 Bottoms

Most of the impurities which are present in the influent stream to the concentrator leave in the bottoms stream. Because of the high concentration of boron the piping, components, and tanks are heat-traced to keep them in solution (see Figures 11.2-6 and 7 for heat-traced process routes). The bottoms are pumped from the concentrator (Figure 11.2-7) via the concentrate pumps into one of the two liquid waste concentrator bottoms storage tanks (Figure 11.2-9).

Once in the liquid waste concentrator bottoms storage tank the concentrate (bottoms) is recirculated using a liquid waste concentrator bottoms pump (Figure 11.2-9) to insure a uniform chemistry. Both tanks together will provide up to 120 days of holdup under expected processing conditions. During liquid waste processing the concentrate is pumped via a liquid waste concentrator bottoms pump directly to the drumming station (Figure 11.2-9) where it is prepared for offsite disposal (see Section 11.4).

TABLE 11.2-5 (Cont'd)

Waste Condensate Pumps (Cont'd)

Motor Horsepower	7.5
Operating Temperature, °F	120
Code	Manufacturers Standard

Resin Dewatering Pump

Type	Centrifugal
Quantity	1
Design Pressure, psig	150
Design Temperature, °F	200
Normal Operating Temperature, °F	120
Capacity, GPM	100
Rated Head, Ft.	95
NPSH Available, Ft.	2
Motor Horsepower	10
Wetted Materials	SS
Code	Manufacturers standard

Boric Acid Concentrators

Quantity	2
Design DF (Bottoms/Distillate)	10^4 (Minimum)
Design Pressure, psig	80
Design Temperature, °F	250
Normal Operating Pressure (process), psig	27
Normal Operating Temperature (process), °F	120
Design Flow (process), gpm	20
Normal Operating Flow (process), gpm	20
Code	ASME VIII
Material	SS

Waste Concentrator

Quantity	1
Design DF (Bottoms/Distillate)	10^4
Design Pressure, psig (Process)	80
Normal Operating Pressure (Process), psig	27
Design Temperature, °F (Process)	250
Normal Operating Temperature, °F	120
Design Flow, gpm	20
Normal Operating Flow, gpm	20
Material	SS
Code	ASME VIII

INSERT C

Preconcentrator Ion Exchangers

Quantity	2
Type	Flushable
Design Pressure, psig	150
Design Temperature, °F	250
Normal Operating Pressure, psig	60
Normal Operating Temperature, °F	120
Resin Volume (Useful) Required, ft^3	32
Design Flow, gpm	40
Normal Flow, gpm	20

INSERT C

Liquid Waste Concentrator Bottoms Storage Tank

Quantity	2
Type	Vertical, Cylindrical
Internal Volume, gallons	2,300
Design Pressure, psig	Atmospheric
Design Temperature, ^{o}F	250
Normal Operating Pressure, psig	Atmospheric
Normal Operating Temperature, ^{o}F	160
Code	Class 4, ASME VIII, 1974 Edition
Material	SS

Liquid Waste Concentrator Bottoms Pump

Quantity	2
Type	Centrifugal
Design Pressure, psig	50
Design Temperature, ^{o}F	250
Normal Operating Temperature, ^{o}F	160
Capacity Rate, gpm	60
Rated Head, feet	50
NPSH Available, feet	30
Motor Horsepower	5
Wetted Materials	SS
Code	Manufacturers Standard

Question No.

460.2
(11.2)

List outdoor storage tanks that may contain potentially radioactive liquid and describe provisions designed to prevent, collect, and process spills from outdoor storage tanks. It is our position that outdoor tanks should be designed in accordance with Regulatory Position 1.2 in Regulatory Guide 1.143, Rev. 1.

Response:

The Refueling Water Tank (RWT) Condensate Storage Tank (CST), Primary Water Storage Tank (PWST) and the Steam Generator Blowdown Monitor Tank (SGBMT) are outdoor storage tanks which could contain potentially radioactive liquid.

The RWT, CST and PWST are provided with control room level indication and high level alarm. The CST and PWST are also provided with local high alarm and the SGBMT is provided local level indication and high level alarm.

The SGBMT overflow and drains are routed to the equipment drain tank in the Liquid Waste Management System. The CST is surrounded by the CST building so that overflow and leakage are collected in the building. The RWT and PWST overflow is collected in catch basins. The catch basin overflows to the plant storm drainage system.

For the tanks where drain and overflow are not routed back to the Liquid Waste Management System, Standard Technical Specification which will be prepared and submitted to the NRC at least 6 months prior to the fuel loading will require periodic analysis to verify that radioactive content (in curies, excluding tritium and dissolved or entrained noble gases) will be below a specified value. The curie limit of the tanks will be determined based on the methodology presented in Appendices A and B of NUREG 0133.

460.3 In Section 11.2.1 (g) of the FSAR, you state that seismic and quality group classification of the LWMS components and piping meet or exceed the guidelines of Regulatory Guide 1.143. It is our position that the LWMS design also should be in accordance with Regulatory Position 4.0 "the additional design, construction, and testing criteria" and Regulatory Position 6.0 "quality assurance" in Regulatory Guide 1.143.

Response

Section 11.2.1 (g) has been modified to describe compliance with Regulatory Guide 1.143, including Positions 4 and 6.

Question No.

460.4
(11.2)

In Section 11.2.2.3 of the FSAR you state that you collect the Turbine Building floor drains and monitor for radioactivity prior to discharge. Describe the provisions to collect, monitor, and discharge of the building drains.

Response:

During normal operation, the Turbine Building floor drains are discharged to the settling pond without processing or monitoring. If the condenser air ejector or steam generator blowdown radiation monitors detect excessive levels of radioactivity in the main steam line, a procedure of grab sampling the settling pond for traces of radioactivity will be instituted.

Subsection 11.2.2.3 will be revised in Amendment 5 to reflect this information.

460.5 In Section 11.3.1 (g) of the FSAR, you state that seismic and quality group classification of the LWMS components and piping meet or exceed the guidelines of Regulatory Guide 1.143. It is our position that the LWMS design also should be in accordance with Regulatory Position 4.0 "the additional design, construction, and testing criteria" and Regulatory Position 6.0 "quality assurance" in Regulatory Guide 1.143.

Response

Section 11.3.1 (g) of the FSAR has been modified to describe compliance with Regulatory Guide 1.143, including Positions 4 and 6.

11.2 LIQUID WASTE SYSTEM

11.2.1 DESIGN BASES

Radioactive liquid wastes which are discharged from the plant are first processed by the Liquid Waste Management System (LWMS). The LWMS design bases are as follows:

a) The discharge activity level is in accordance with 10CFR20 criteria. An evaluation is provided in Subsection 11.2.3. The analysis takes into consideration normal and design basis operations.*

b) The principal design criteria for the LWMS is that it provides for handling of liquid wastes in such a manner as to meet the requirements of 10CFR20 and 10CFR50, Appendix I.

c) The St Lucie Unit 2 Environmental Report (CP) in Amendment 7, dated October 1975 and Amendment 8, dated June 1976 provides a detailed evaluation to show that the LWMS is capable of controlling releases of radioactive materials within the numerical design objectives of Appendix I to 10CFR50. A review of the plant design and site usage characteristics reveal that no change has occurred which would require a re-evaluation (see Subsection 11.2.3). Amendment 8 of the ER (CP) also provides a cost benefit analysis in Subsection 10.7.8 which is still applicable.

d) The estimated total LWMS releases are summarized in Table 11.2-1. Assumed equipment decontamination factors are shown in Table 11.2-2. The concentration of radiological releases at the site boundary and a comparison with 10CFR20 limits for normal and design basis conditions are shown in Tables 11.2-3 and 4. The RCS activities are given in Section 11.1.

e) The individual component design parameters are given in Table 11.2-5.

f) The expected liquid borated waste inputs are described in Table 11.2-6 which gives the yearly inputs. Non-borated liquid waste inputs are shown in Table 11.2-7. The LWMS is designed to handle both sets of influents on a batch mode basis for flexibility of operation. "Batching" allows the LWMS system to handle "surges" in the influent rate, which may exceed the annual average flow rate.

g) ~~Seismic and quality group classification of liquid radwaste components and piping meet or exceed the guidelines of Regulatory Guide 1.143 and are provided in Table 11.2-5 and Section 3.2. All the liquid radwaste system components are located in either the Reactor Building or the Reactor Auxiliary Building which are designed as seismic Category I.~~ 4

INSERT P

*Note: "Design" means 2700 MWt and 1 percent failed fuel for source terms. "Normal" means 2560 MWt and NUREG 0017, April 1976, (R1) source terms.

11.3 GASEOUS WASTE SYSTEM

11.3.1 DESIGN BASES

Radioactive gaseous wastes which are to be discharged from the plant are first collected by the Gaseous Waste Management System (GWMS). The GWMS design bases are as follows:

a) The principal design objective of the GWMS is to protect plant personnel, the general public, and the environment by ensuring that all releases of radioactive gases both in the plant and to the environment are as low as is reasonably achievable (ALARA).

b) The principal design criteria for the GWMS is that it provides for the handling of the plant's gaseous wastes in such a manner as to meet the requirements of 10CFR20 and 10CFR50, Appendix I.

c) The St Lucie Unit 2 Environmental Report (CP) in Amendment 7, dated October 1975 and Amendment 8 dated June 1976 provides a detailed evaluation to show that the GWMS is capable of controlling releases of radioactive materials within the numerical design objective of Appendix I to 10CFR50. A review of the plant design and site usage characteristics reveals that no significant change has occurred which would require a re-evaluation (see Subsection 11.3.3). Amendment 8 of the ER (CP) also provides a cost benefit analysis in Subsection 10.7.8 which is still applicable.

d) The estimated annual GWMS releases are summarized in Tables 11.3-1 and 2. These are based on the process points activities for the GWMS, (see item (j)) specifically the inventories for the gas decay tanks adjusted to account for decay due to holdup. (The basis for these activities are the Reactor Coolant System activities given in Section 11.1 and releases from liquid tanks to the gas collection header.)

e) The individual component design parameters are given in Table 11.3-3.

f) The expected inputs to the GWMS are listed on Table 11.3-4. Surges to the GWMS are handled by more rapid filling of the gas decay tanks.

INSERT Q

g) ~~The seismic design and quality group classification of the GWMS and the seismic design classification of the structure housing the GWMS are done to meet or exceed the guidelines of Regulatory Guide 1.143 and are described in Section 3.2, and in Table 11.3-3.~~ 4

h) General design criteria 60 and 64 are met.

i) Redundant compressors insure that at least one compressor is available to keep the GWMS functioning properly. Multiple gas decay tanks allow for sufficient flexibility so that one tank can be filled while another is discharged and a third holds up gas for decay.

INSERT P

g) The design, quality assurance, construction and testing criteria for the LWMS meet or exceed the guidelines of Regulatory Guide 1.143 particularly Position 1 (Systems Handling Radioactive Materials in Liquids) Position 4 (Additional Design, Construction and Testing Criteria) and Position 6 (Quality Assurance for Radwaste Management Systems). Furthermore, the seismic design and quality group classification of LWMS and the seismic design classification of the structures housing the LWMS are done to meet or exceed the guidelines of Regulatory Guide 1.143 and are described in Section 3.2 and in Table 11.3-3.

INSERT Q

g) The design, quality assurance, construction and testing criteria for the GWMS meet or exceed the guidelines of Regulatory Guide 1.143 particularly Position 2 (Gaseous Radwaste Systems) Position 4 (Additional Design, Construction and Testing Criteria) and Position 6 (Quality Assurance for Radwaste Management Systems). Furthermore, the seismic design and quality group classification of the GWMS and the seismic design classification of the structures housing the GWMS are done to meet or exceed the guidelines of Regulatory Guide 1.143 and are described in Section 3.2 and in Table 11.3-3.

Question No.

460.6
(11.3)

In Table 9.4-16 of the FSAR you have taken an exception to Regulatory Position 2.b in Regulatory Guide 1.140 exceeding 30,000 CFM air flow limit for the RAB Main Exhaust and Containment Purge. State if you can generate enough DOP to test 84,000 and 43,000 CFM air flows in such quantity that the concentration downstream of the HEPA filter is sufficient to test in accordance with Regulatory Guide 1.140. It is also our position that a shroud will be required in order to test the HEPA filters and that the shroud be used such that the entire face of the HEPA filter is ultimately tested.

Response:

The RAB Main Exhaust and Containment Purge are designed to be "In place tested" as per ANSI-N510-1975 and ERDA-76-21. Provisions have been made for injection and sampling connections. In order to be sure that enough DOP will be generated a multiple discharge distributor will be provided to introduce the agent through a shroud to each filter element individually as per ERDA 76-21 paragraph 8.3.3.

Question No.

460.7
(11.3)

In Table 9.4-16 of the FSAR, you have taken an exception to Regulatory Position 3.1 of Regulatory Guide 1.140 stating that the dampers and balancing dampers are designed and constructed in accordance with the industry and manufacturers standards rather than ANSI N-509 Section 5.9. Compare the differences in design and construction of dampers between these two standards.

Response:

Table 9.4-16 of the FSAR states that:

"Dampers and balancing dampers are designed and constructed in accordance with the industry and manufacturer's standards" as required by ANSI-N509-1976 paragraph 5.9.3.2 for construction class B dampers. We consider that we comply with Regulatory Guide 1.140 R1 position 31.

The valves utilized as shut off devices are designed in accordance with ASME Section III and ANSI B31.1; therefore we comply with the requirements of ANSI-N509-1976 paragraph 5.9.3 for construction class A devices.

FSAR Table 9.4-16 has been revised to indicate compliance.

Question 460.8 In Section 11.4.1(c) of the FSAR you state that the handling of the solid radwaste will be done while maintaining the exposure level to plant personnel with the permissible limits of 10 CFR 20. It is our position that the SWMS design and operation shall be in accordance with the guidelines of Regulatory Guide 8.8 Rev 3.

Response: The solid waste management system design and operation will be in accordance with the guidelines of Regulatory Guide 8.8 Rev 3. The FSAR will be amended to reflect compliance to the guidelines of Regulatory Guide 8.8 Rev 3.

Question 460.9

In Section 11.4.1, (a), of the FSAR, you state that the SWMS storage area is capable of providing sufficient space to allow liners and drums to be temporarily stored to allow decay prior to shipment offsite.

It is our position that the SWMS storage area for temporary storage prior to shipment offsite should be in accordance with Section III in Branch Technical Position ETSB 11-3, Rev 1.

Response:

The drumming storage area will have sufficient storage area to meet the storage area requirements of ESTB 11-3 Rev 1. The FSAR will be amended to indicate compliance with the storage area requirements of ESTB 11-3 Rev 1.

Question 460.10 In Section 11.4.1,(e) of the FSAR you state that all radioactive waste is packaged (including the shipping container) in a manner which will allow shipment and disposal in accordance with 49 CFR 170-179, 10 CFR 20 and 10 CFR 71. Shipment and disposal of packaged solid radwaste should also be in accordance with applicable DOT and state regulations.

Response: 49 CFR 170-179 are the DOT regulations covering the shipment and disposal of radioactive wastes. The FSAR will be amended to the following: "All radioactive waste is package (including the shipping container) in a manner which will allow shipment and disposal in accordance with 49 CFR 170-179, 10 CFR 20, 10 CFR 71 and applicable state regulations.

Question 460.11

In Section 11.4.1, (g) you state that the SWMS is located in the Reactor Auxiliary Building, which is a seismic Category I building.

State where the contractor's mobile unit equipment will be located while processing and packaging wet radioactive wastes.

Response:

The contractor's mobile solidification unit will be located in or adjacent to the drumming storage area when processing and packaging wet radioactive wastes.

Question 460.12 In Section 11.4.2 of the FSAR, you describe radioactive wet waste solidification process. It is our position that the solidification process should be in accordance with Process Control Program in Branch Technical Postion ETSB 11-3, Rev 1.

Response: The purchase order for the portable solidification system will require that the Process Control Program be in accordance with ETSB 11-3 Rev 1 and any exceptions must be identified to and approved by FP&L. The FSAR will be amended to reflect this.

Question 460.13

In Section 11.4.1 of the FSAR, you stated that Seismic and quality group classification of the SWMS components and piping meet or exceed the guidelines of Regulatory Guide 1.143.

It is our position that the SWMS design also should be in accordance with Regulatory Position 4.0 "the additional design, construction, and testing criteria" and Regulatory Position 6.0 "quality assurance" in Regulatory Guide 1.143.

Response:

Section 11.4 of the FSAR does not; at this time, make any reference to Regulatory Guide 1.143. The permanently installed equipment and piping is in accordance with Regulatory Position 4.0 of Regulatory Guide 1.143 with the following exception: nonconsumable backing rings are used in the 3 inch line which transfers resin to the portable solidification system. Quality assurance requirements for the permanently installed equipment and piping are in accordance with Regulatory Position 6 .0 with the exception of the dry waste compactor which is a commerically procured item. The purchase order for the portable solidification system will require that the system comply with Regulatory Guide 1.143 and any exceptions must be identified to and approved by FP&L. The FSAR will be amended to reflect compliance with Regulatory Guide 1.143 with exceptions as noted above.

Question 460.14

In Section 11.4.2.4 of the FSAR, you describe the quality assurance program for the SWMS design. It is our position that the quality assurance program should be in accordance with Regulatory Position c. (6) of Regulatory Guide 1.143 (Rev. 1).

Response:

Quality assurance requirements for the permanently installed equipment and piping are in accordance with Regulatory Position c (6) of Regulatory Guide 1.143 Rev 1 with the exception of the dry waste compactor which is a commerically procured item. The purchase order for the portable solidification system will require that the system comply with the quality assurance requirements of Regulatory Guide 1.143 Rev 1 and any exceptions must be identified to and approved by FP&L. The FSAR will be amended to reflect compliance with the quality assurance requirements of Regulatory Guide 1.143 Rev 1 with exceptions as noted above.

Questions 460.15 In Tables 11.4-1 and 11.4-3 of the FSAR, you indicated the expected amounts of waste inputs and offsite shipment of solidified waste. Review of the semi-annual reports from operating nuclear power plants through 1979 indicates that approximately 13,000 ft^3/yr of solidified wet waste would be expected from the primary system wet waste (concentrator bottoms and spent resin) and approximately 10,000 ft^3/yr, of dry waste would be expected from a 3400 MWt PWR. Discuss the process capability of your SWRS to handle these quantities of waste at St. Lucie 2.

Response: The inputs to the solidification system, Table 11.4-1, is in the process of being revised and based on this input data the solid waste outputs, Table 11.4-3 will also be revised. The inputs will be shown to comprise a small fraction of the solidification system capacity discussed in Section 11.4 (Table 11.4-2 and Figure 11.4-1). This will be demonstrated in a table similar to the one attached. This table will also demonstrate that the solid waste management system will be capable of processing more than 13000ft^3/yr of solidified wet waste and 10,000 ft^3/yr of dry wastes.

SOLID WASTE MANAGEMENT PROCESS DATA

Type of Waste	Output of Solidified Waste Ft^3/YR	Solidification System Capabilities			
		Process Flow Rate GPM	System Output Ft^3/YR	Fraction of Process Capacity Used	
St Lucie No. 2 Design Basis					
Spent Resins Concentrator Bottoms					
Filters					
Total					
Compressible Solids					
Values Given by NRC					
Solidified conc.					
Dry Waste					

* Per Table 11.4-3 of FSAR

Question 460.16 In Table 11.4-3 of the FSAR, you estimated the quantities of output from the SWMS are based on two volumes of wet waste per volume of solidification agent. State the solidification agent to be used at St. Lucie 2 and provide operating solidification experience utilizing the same agent and mixing ratio at any operating nuclear power plants.

Response: Since the portable solidification vendor has not been determined at this time, the solidification agent has not been established. However, the solidification agent will most probably be cement, cement plus sodium silicate or Dow binder. The ratio of wet waste to solidification agent will depend on the type of wastes being solidified and the type of solidification agent being used. This ratio is included as part of the process parameters which are included in the portable solidification vendor's Process Control Program.

460.17 In Table 11.5-4 of the FSAR you indicate the capability of analyzing radioactivity in gas decay tanks, gas surge tank, containment vent header, volume control tank and flash tank vent. Describe the provisions for monitoring radioactivity in these components. Include a process flow diagram and/or P&ID.

Response

Table 11.5-4 (items 24 through 30) has been modified to further describe the provisions for monitoring radioactivity in the subject components. The gas analyzer is shown in the P&ID of Figure 11.2-8. A more detailed drawing of the gas analyzer is shown in the attached P&ID, which will replace Figure 11.2-8.

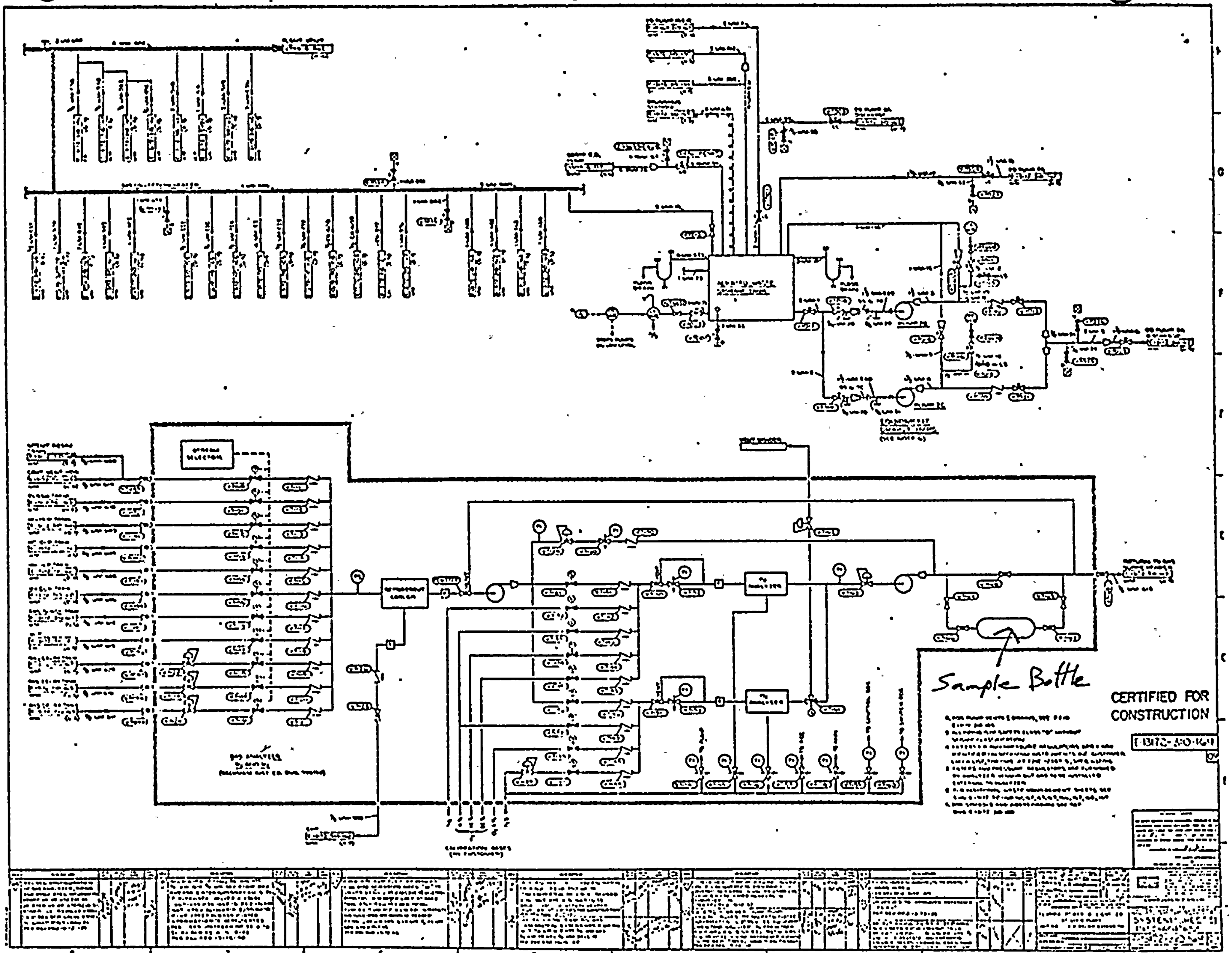
footnote added

TABLE 11.5-4 (Cont'd)

Location	Basis for Selection	Expected Concentration	Sampling Frequency	Sample Analysis
22) Fuel Pool Ion Exchanger 1/2-FS-543,531	Determine DF performance of the ion exchanger	Table 12.2-34	As required	Gross activity or Isotopic analysis
23) Fuel Pool Purification Filter 1/2-FS-531,525	Determine performance of Filter efficiency	Table 12.2-34	Monthly for radiation levels; as required by water quality measurements of spent fuel pool	Radiation surveys
24) Volume Control Tank - Gas Sample[a)] Gas Analyzer	Analyze for potential explosive mixture and radioactivity concentration	95% H_2 when operating 95% N_2 when shutdown	Weekly	H_2, O_2, N_2 isotopic or Gross Activity
25) WHS Flash Tank - gas sample[a)] Gas analyzer	Analyze for potential explosive mixture and radioactivity concentration		As required	H_2, O_2 and isotopic
26) Holdup Tanks - gas sample[a)] Gas Analyzer	Analyze for potential explosive mixture	95% H_2	Weekly	H_2, O_2
27) Spent Resin Tank - gas sample[a)] Gas Analyzer	Analyze for potential explosive mixture and radioactivity concentration	4% O_2	As required by operation	H_2, O_2 and isotopic
28) Containment Vent Header - gas Sample[a)] Gas Analyzer	Analyze for potential explosive mixture and radioactivity concentration	4% O_2	Weekly	H_2, O_2 and isotopic
29) Gas Surge Tank - gas sample[a)] Gas Analyzer	Analyze for potential explosive mixture and radioactivity concentration	4% O_2	Weekly	H_2, O_2 and isotopic
30) Gas Decay Tank - gas sample[a)] Gas Analyzer	Analyze for potential explosive mixture and radioactivity concentration	4% O_2	Weekly	H_2, O_2 and isotopic

added

[a)] The monitoring of radioactivity is accomplished by obtaining a grab sample of the gas to be analyzed at the gas analyzer. Provisions are provided on the gas analyzer to manually mount and dismount a grab sample bottle so that it can be filled and then removed for laboratory analysis of its contents.



Sample Bottle
CERTIFIED FOR
CONSTRUCTION

Question No.

460.18
(11.5)

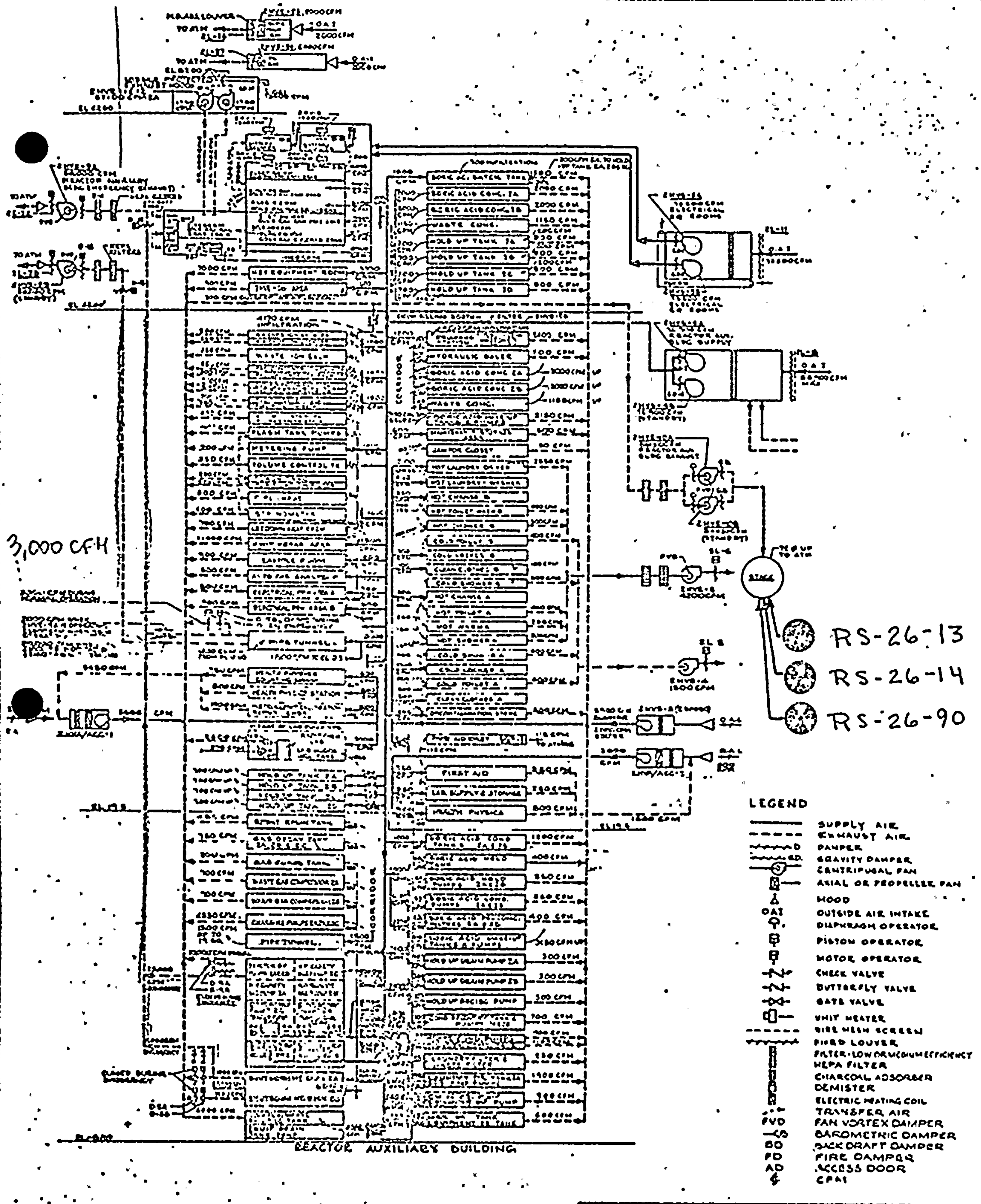
In Table 11.5-5 of the FSAR, you list radiation monitoring system provisions. Show the plant stack monitor, the containment purge monitor, and the containment hydrogen purge monitor on appropriate P&IDs.

Response:

The various monitors will be described or located on the appropriate attached P&IDs. Figures 9.4-5 and 9.4-8 show the plant stack radiation monitors.

Figure 12.3-13a shows the location of the CIAS radiation monitors that are used for the containment purge and hydrogen purge process monitors.

FSAR will be revised to include these changes.

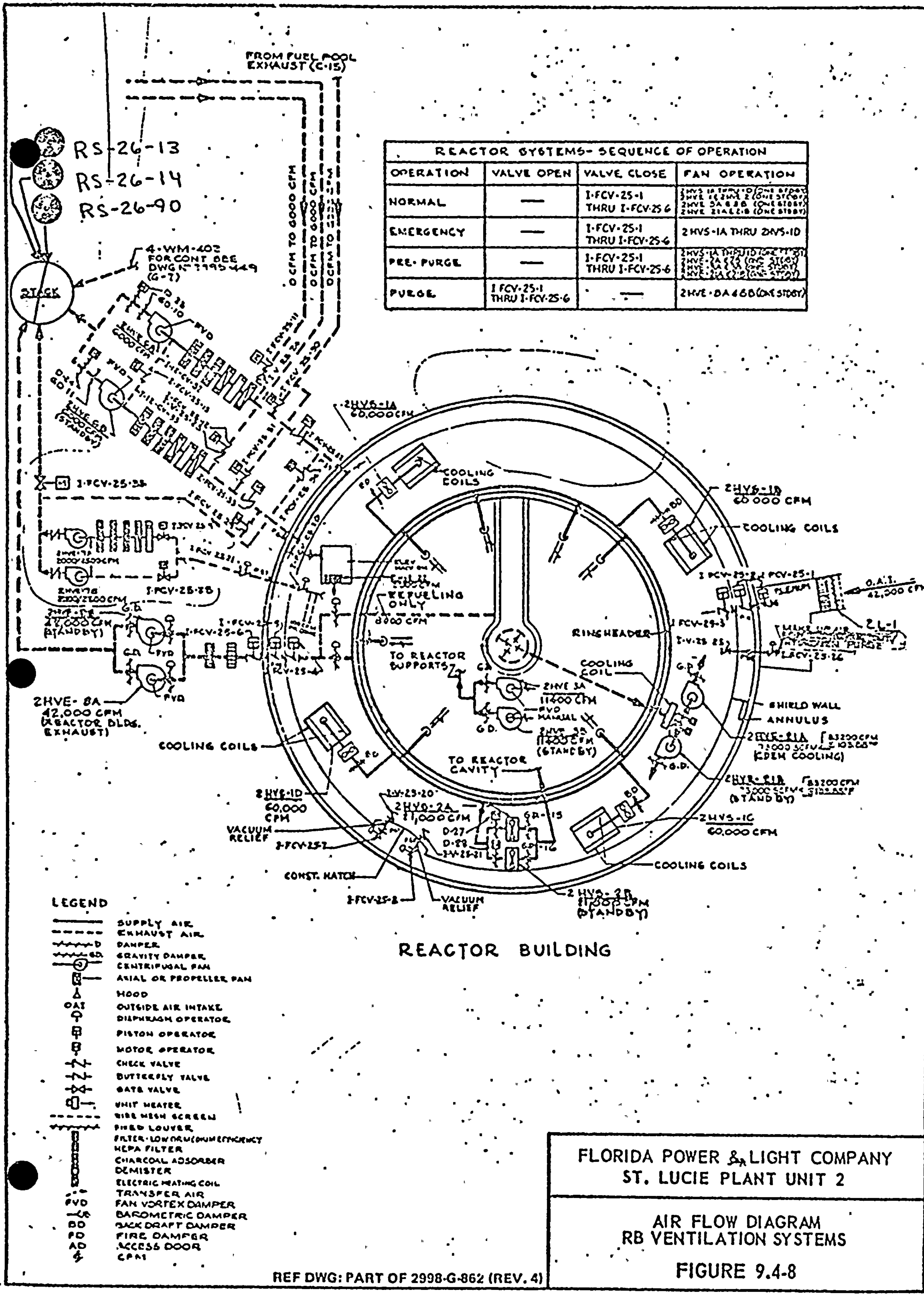


FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

AIR FLOW DIAGRAM
RAB VENTILATION SYSTEM

FIGURE 9.4-5

REF DWG: PART OF 2998-G-862 (REV. 4)



REACTOR SYSTEMS- SEQUENCE OF OPERATION			
OPERATION	VALVE OPEN	VALVE CLOSE	FAN OPERATION
NORMAL	—	I-FCV-25-1 THRU I-FCV-25-6	[illegible]
EMERGENCY	—	I-FCV-25-1 THRU I-FCV-25-6	2HVS-1A THRU 2HVS-1D
PRE-PURGE	—	I-FCV-25-1 THRU I-FCV-25-6	[illegible]
PURGE	I FCV-25-1 THRU I-FCV-25-6	—	2HVE-8A & 8B (ONE STDBY)

REF DWG: PART OF 2998-G-862 (REV. 4)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

AIR FLOW DIAGRAM
RB VENTILATION SYSTEMS

FIGURE 9.4-8

TABLE 11.5-5

RADIATION MONITORING SYSTEM PROVISIONS

No.	Process System	Monitor Provisions: In Process Continuous	Monitor Provisions: In Effluent ACF	Monitor Provisions: In Effluent Continuous	Sample Provisions: In Process Grab	Sample Provisions: In Effluent Grab	Sample Provisions: In Effluent Continuous
1.	Waste Gas Holdup System		N			NT	
2.	Condenser Evacuation System			N	I	NT	
3.	Vent & Stack Release Pt. System			N		NIT	I
4.	Containment Purge Systems[a]	G	G^x			NT	(I)
5.	Aux. Bldg. Ventilation System			(N)	I	(NI)	(I)
6.	Fuel Storage Area Vent. System[a]	G	G^x	N	I	NT	I
7.	Radwaste Area Vent. Systems			(N)	(I)	(NT)	(I)
8.	Turb. Gland Seal Cond. Vent System			(N)	(I)	(NT)	
9.	Mechanical Vacuum Pump Exhaust Hogging System			(N)	(I)	(NT)	
10.	Evaporator Vent Systems			(N)	(I)	(NIT)	(I)

3

TABLE 11.5-5 (Cont'd)

No.	Process System	Monitor Provisions In Process Continuous	Monitor Provisions In Effluent ACF	Monitor Provisions In Effluent Continuous	Sample Provisions In Process Grab	Sample Provisions In Effluent Grab	Sample Provisions In Effluent Continuous
11.	Pre-Treatment Liquid Radwaste Tank Vent Gas Systems			(N)	(I)	(NIT)	(I)
12.	Flash Tank and Steam Generator Blowdown Vent Systems	*	*	*	*	*	*
13.	Turbine Bldg. Vent. Systems	N/A	N/A	N/A	N/A	N/A	N/A 3
14.	Pressurized Boron Recovery Vent Systems		(N)	(N)		(NT)	(I)

ACF - Automatic Control Feature

N - Noble gas radioactivity

T - Tritium radioactivity (carbon-14 analysis in gaseous effluents may be considered)

I - Radioiodine radioactivites and radioactivity of materials in particulate form and alpha emitters

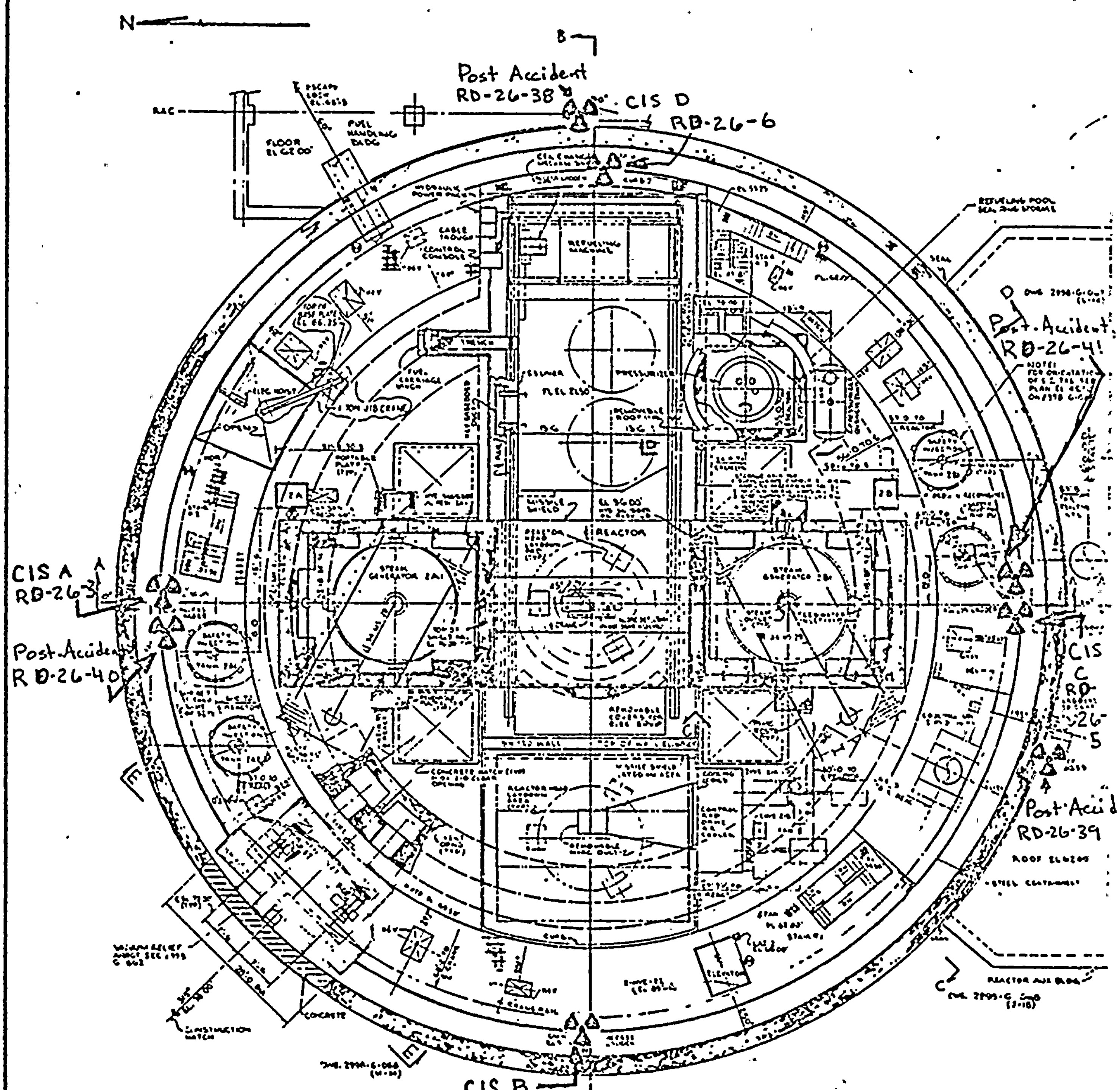
G - Gross radioactivity

x - The automatic control feature is provided by the process continuous radiation monitor.

* - Monitored and Sampled by Unit 1 equipment

( ) - These provisions are required only for systems not monitored, sampled or analyzed (as indicated) prior to release by downstream provisions

a - Process monitoring by area monitors



NOTE
1. FOR NOTES & REFERENCE DWGS. SEE DWG. 2998-G-060

OPERATING FLOOR PLAN EL. 62.00'

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

LOCATION OF CIS AND POST ACCIDENT RADIATION MONITORS

FIGURE 12.3-13A

Question No.

460.19
(11.5)

In Section 11.5.1 of the FSAR, you describe process and effluent monitoring system design bases. It is our position that the system design should also be in accordance with the guidelines of Regulatory Guide 4.15, "Quality Assurance for Radiological Monitoring Programs".

Response:

The design of the effluent monitoring system will follow the recommendations of Regulatory Guide 4.15. FSAR Subsection 11.5.1.2 will be revised to include this.

Question No.

460.21
(11.5)

In Table 11.5-1 of the FSAR, you indicated effluent radiation monitor ranges for the condenser evacuation, the vent stack, and the fuel handling building releases. It is our position that these monitor ranges should be in accordance with the requirements of NUREG 0737.

Response:

FSAR Sections 11.5 and 12.3 will be revised in Amendment 5 to incorporate the NUREG 0737 wide range effluent monitors. A draft writeup was informally transmitted to the NRC on July 21, 1981.

Question No.

460.22
(10.4.8)

In Section 10.4.8.5 of the FSAR, you describe the SGBS instrumentation and controls for radiation monitoring. Describe the provisions for monitoring radioactive gases in the SGBS monitor tank vents should primary to secondary system leakage occur. It is our position that all potential pathways for release of radioactive materials to the environment should be monitored in accordance with General Design Criteria 64.

Response:

The Steam Generator Blowdown Monitor Tank has a vent that exhausts directly to the atmosphere. The operation of this tank will be within the guidelines of 10CFR50, Appendix I, regarding the release from the vent. The tank radioactivity will be monitored per the applicable tech specs. In addition, upon high radiation in the blowdown line, the tank can be isolated to prevent contamination to accumulate.

Question No.

460.23
(6.5)

In Table 6.5-1 of the FSAR, you have taken an exception to Regulatory Position 2.b in Regulatory Guide 1.52 designing the ECCS Area Ventilation System without demister, prefilter or HEPA filter after charcoal adsorbers. Without prefilter, how much more do you anticipate replacement of HEPA filter. Provide an isometric sketch showing any potential sources of moisture in the area, distances from the filter, overhead location, and expected air velocities. State how you intent to monitor a decrease in charcoal adsorbers pressure differential and expected relative amounts of radioactivity in carbon particles.

Response:

a. The only source of dust inside the ECCS Area is the atmospheric dust brought into the building with ventilation air. The supply air system has provision for a prefilter.

Therefore there is no need to provide a prefilter in the exhaust system because it is already installed on the supply system as allowed per ERDA 76-21 paragraphs 2.3.3 and 2.3.4.

b. The velocity of the air coming into the filtration unit is 2500 FPM. Due to the increase in duct cross sectional area, the velocity into the unit is reduced from 2500 FPM to 700 FPM. The duct is coming from elev -0.50' to 43.00' via 19.5'. Considering the changes in air direction and the reduction in the air velocity, whatever moisture is carried over is separated before the air stream reaches the HEPA filter. A maximum relative humidity expected in the area in case of postulated pipe break will not exceed 73.5%.

For each postulated pipe break case in this area of the RAB, we do not require the service of the ESF filtration unit to mitigate the consequences of this particular accident.

c. A combination of differential pressure transmitter-recorder across the charcoal adsorber (loop accuracy is given in Table 7.5-1) and radiation monitor with a high alarm in the Control Room installed downstream of the filtration unit (set point and accuracy given in Table 11.5-1) will monitor the differential pressure across the charcoal adsorber and the amounts of radioactivity.

Question No.

Additional NRC Question verbally transmitted in June 19, 1981 Meeting: What is the charcoal efficiency criterion? WSES 3 has identified compliance with 99% criterion. Who is the supplier of charcoal tested (see FSAR page 6.5-17) for SL-2?

Response:

CVI Corp., the supplier of the charcoal adsorber indicates that the new charcoal adsorber which they are going to supply will meet the requirements of Reg. Guide 1.52 Rev. 2 (Charcoal adsorber efficiency will be minimum 99%). Table 6.5-1 will be revised to reflect this change.

Question No.

220.1 Table 3.3-1 lists the Auxiliary Building as being designed for a tornado velocity of 300 mph while the other buildings are designed for 360 mph. The Containment Shield Building is omitted from this table. Subsection 3.3.2.2 states the Shield Building is designed for 300 mph. Correct Table 3.3-1 to reflect your actual design velocities. Justify in detail why the velocity of 300 mph is used instead of 360 mph. Submit your supporting calculations.

Response

FSAR Table 3.3-1 has been revised to include the hurricane and tornado wind speeds used in the design of the Shield Building and Condensate Storage Tank Building. The external pressure coefficients for these dome-cylinder structures are given on Figures 3.3-1 and 3.3-2, respectively.

The 300 mph average combined tangential velocity and translational velocity tornado design and wind speed specified for the Shield Building and Reactor Auxiliary Building was based upon consideration of the horizontal dimensions of those structures and wind speed ban widths and conclusions presented in FSAR Section 3.3 References 3 and 4.

The tornado design wind speeds specified for the structures are considered conservative since the tangential velocity versus height above ground is held constant at the maximum average values. Based upon data presented in References 3 and 4, the tangential velocity reduces substantially close to the ground and, in particular, in the height range of St Lucie Unit 2 structures.

Question No.

220.2 Provide your basis and method of calculations to support the pressure differential in the Diesel Generator Building of 2.25 psi. If venting is considered in any other building provide method of computing differential pressures.

Response

The pressure differential value of 2.25 psi, used in the design of the Diesel Generator Building for St Lucie Unit 2, was established during St Lucie Unit 1 design and accepted by the NRC during Unit 1 operating license review. Based upon the large ventilation and cooling openings in the exterior walls, the reduced differential pressure was considered a conservative assumed design value; no calculations were performed to determine that value. Each of the two equipment housing compartments within the Diesel Generator Building contains approximately 49,200 cu ft of air volume (before deducting equipment volume) and each compartment has approximately 618 sq ft of available ventilation area after deducting wire screen area. Venting is not considered in any other structure.

Question No.

220.3 You stated in Subsection 3.5.3.1.1 that the modified Petry Formula was used to evaluate the concrete for missile protection. The current requirement for computing required concrete wall thickneses is the NDRC Formula. Submit a table showing the required wall thicknesses compared with the actual wall and roof thicknesses for all Category I structures, based on the NDRC Formula.

Response

FSAR Table 3.5-11 lists roof and exterior wall thicknesses for all Category I concrete structures. The attached table summarizes design values obtained by use of the NDRC Formula for missile penetration (x), thickness required to prevent scabbing (s) and the maximum thickness of concrete which a missile will completely penetrate (e). Please note that the NDRC Formula is only applicable to hard missiles and not the soft missiles; i.e., the automobile and wood missiles.

827W

TABLE 220.3-1

TORNADO MISSILE IMPACTIVE ANALYSIS

Penetration of Concrete for Design Base Spectrum of Tornado Missiles
Using Modified National Defense Research Committee Formula (NRDC)

Missile No.	Missile	W (lb)	A ($in.^2$)	d (in.)	V_o (ft/sec)	x (in.)	$\frac{x}{d}$	$\frac{e}{d}$	$\frac{s}{d}$	e (in.)	s (in.)	Required Concrete Thickness 1.25 S (in.)	Actual Minimum Concrete Thickness for	Remarks
1	4" x 12" Plank 12' Long	200	48.0	-	322	-	-	-	-	-	-	-	Wall or Roof Slab of All Class I Structures (in.)	Soft** Missile
2	1" dia x 3' Steel Rod	8.0	0.785	1.0	163	1.58	1.58	3.28	4.27	3.28	4.27	5.34		
3	6" dia Sch 40 x 15' Pipe	284.5	5.58	2.67	116	4.69	1.76	3.50	4.51	9.35	12.05	15.06		
4	12" dia Sch 40 x 15' Pipe	743.4	14.6	4.31	116	6.27	1.45	3.12	4.09	13.44	17.63	22.04	≥ 24"	Critical Case
5	13.5" dia x 35' long Wooden Utility Pole	1,497	143.0	-	153	-	-	-	-	-	-	-		Soft** Missile
6	Automobile	4,000	2,880	-	84	-	-	-	-	-	-	-		Soft* Missile
7	2" x 4" Plank 10' Long	27.8	8.0	-	403	-	-	-	-	-	-	-		Soft** Missile

22.04"< 24" minimum wall or roof slab concrete thickness

* Missile does not penetrate based on ASCE Reference Page 6-28

** NRDC Formula is not applicable based on ASCE Reference Page 6-41

References - Design Based Spectrum of Tornado Missiles Table 3.5-10 SL2-FSAR
Tornado Missile Concrete Barrier Minimum Thickness Table 3.5-11 SL2-FSAR
ASCE "Manual of Standard Practices for Design of Nuclear Power Plant Facilities" Chapter 6

Question No.

220.4 In Subsection 3.4.1 you stated that polyvinyl chloride (PVC) water stops were used in the construction joints. When PVC is exposed to radiation it converts into hydrochloric acid which will attack the concrete. Show that the water stops will not be degraded by radiation.

Response

FSAR Subsection 3.4.1 addresses flood penetration provided for design flood water level. The flood penetration provided on and within exterior walls of seismic Category I structures with basements (Reactor Building and Reactor Auxiliary Building), consists of waterproofing membranes and polyvinyl chloride (PVC) water stops, respectively. Radiation levels at exterior walls of those buildings are well below the levels which PVC can tolerate without appreciable damage (5×10^5 rads) and the level at which corrosive gases could be liberated (approximately $10^6 - 10^7$ rads based upon the behavior of similar compounds).

The only area on St Lucie No. 2 where radiation levels could be high enough to cause damage to PVC water stops was within the Shield Building Steel Containment Structure. Rubber water stops were specified for use in construction joints below EL 23 within the Steel Containment Structure. Rubber has a threshold to damage above 2×10^6 rads and does not liberate gases until very high radiation levels are reached (above 10^8 rads) which is considerably above the maximum radiation levels predictable for the plant.

Question No.

220.5 On Page 3.5-24 you stated the maximum thickness of concrete barriers is two feet. What is the maximum thickness provided and show that this is enough to stop the potential missile using the NDRC Formula.

Response

Page 3.5-24 incorrectly stated the maximum thickenss of concrete barriers is two feet. The page has been corrected to read "the minimum thickness.....etc." Refer to response to Question 220.3 for discussion of required concrete wall thicknesses based upon the NDRC Formula.

Question No.

220.6 Describe your procedure used to predict thicknesses which prevent spalling or scabbing of concrete barriers and generation of secondary missiles.

Response

The procedure used to prevent the generation of secondary missiles by spalling was to provide a minimum concrete thickness of two feet, and to check that the calculated missile penetration depths calculated with the Petal formula, were less than half the wall thickness. Deepest penetration for steel missile (1" dia x 3' steel rod) was calculated to be 3.13 in. and the deepest penetration for a wood missile (2" x 4" plant 10" long) was 5.10 inches. The FSAR references tests which show that wood missile splinter into pieces without causing any local damage for concrete barrier thicknesses of 12 inches or more. Therefore, the steel rod should penetrate the deepest of all the missiles. The ratio of 2 ft. wall thickness to maximum depth of penetration would be 7.6.7.

NOTE: The calculation results, presented on the table in response to Question 220.3, indicate that the 24 inch minimum thickenss of concrete walls and roof slabs is more than the 1.25s minimum requirement to prevent spalling as calculated with the NDRC Formula.

Question No.

220.7 -Provide label on ordinate of Figure 3.7-5.

Response

Figure 3.7-5 has been revised by adding references to obtain ordinate values.

Question No.

220.8 (3.7.1) State where the design time history is applied to the mathematical model relative to the finished grade. If deconvolution procedures are used, describe these procedures and furnish the response spectra computed for the input to the math models shown on Figures 3.7-30 thru 3.7-51.

Response

The design time history is applied at the foundation level of Category I structures in the free field. Deconvolution procedures are not used.

Question No.

220.9 (3.7.1) Some of the response spectra points computed for the artificial time histories fall below the design response spectra. Show that no more than 5 points fall more than 10 percent below the design spectra for each damping value.

Response

Comparisons between the response spectra points computed from the artificial time histories and the design response spectra suggested in R.G. 1.60 has been done. Both horizontal and vertical time histories are considered. The spectra values are generated at 1/2 percent, 2 percent, 5 percent, 7 percent and 10 percent damping, as suggested in R.G. 1.60. The frequency intervals used are that suggested in SRP Table 3.7.1-1. Results show that only for the 1/2 percent damping curve more than 5 points (out of 75 points) fall more than 10 percent below the design spectra curve. However, for St Lucie Unit 2, the lowest damping valve specified is 1 percent (for steel piping) so the case of 1/2 percent damping has no effect on the seismic analysis. Moreover, the lowest frequency value for St Lucie Unit 2 is 1.22 cycles per second (SL2-FSAR-Table 3.7-18, Reactor Building), therefore, points falling below design spectra for frequencies less than 1.22 HZ do not affect the results of seismic analysis. For the other points, the design spectra for the time histories show substantial higher values than the R.G. 1.60 design spectra. Thus the positive values should compensate the effects, if any, of the negative values and insure a conservative design. | 5

In summary, the 1/2 percent damping curve is not used for any design purpose on St Lucie Unit 2 and the remaining response spectra curves meet the criteria of no more than 5 points falling more than 10 percent below the design spectra.

Question No.

220.10 (3.7.2) Your seismic models include provisions for structural torsion however, the soil springs do not include a torsional component. Describe how you account for the torsion at the foundation soil interface.

Response

Two dimensional seismic models are used for analyzing the Category I structures, since the Category I structures are supported independently and the geometrics of the structures are largely symmetrical. In the two dimensional models, torsional degrees of freedom of mass points are considered as fixed conditions. For the soil springs, the torsional component is also fixed but may be visualized to have a spring with very large torsional spring constant. Original analysis of Waterford No. 3 also utilized two dimensional models without torsional degrees of freedom. In response to NRC questions, a new three-dimensional model with torsional degrees of freedom and torsional sail spring was developed. The accelerations obtained from the new model (with torsional degrees of freedom) compared to those of the original two-dimensional model are smaller.

TABLE 220.10-1

NATURAL FREQUENCIES IN CYCLES PER SECOND (CPS)

Node No.	E-W EARTHQUAKE						N-S EARTHQUAKE					
	G = 6,400 PSI			G = 16,050 PSI			G = 6,400 PSI			G = 16,050 PSI		
	Without Torsion	With Torsion	Ebasco Dynamic	Without Torsion	With Torsion	Ebasco Dynamic	Without Torsion	With Torsion	Ebasco Dynamic	Without Torsion	With Torsion	Ebasco Dynamic
1	1.091	1.086	1.079	1.706	1.700	1.68	1.087	1.086	1.08	1.702	1.700	1.68
2	2.445	1.684	2.473	3.334	2.620	3.35	2.468	1.815	2.51	3.410	2.833	3.42
3	4.562	2.450	4.540	5.248	3.363	5.22	4.275	2.468	4.26	4.883	3.410	4.86
4	7.535	4.545	7.487	7.571	4.684	7.51	7.475	4.265	7.43	7.491	4.701	7.42
5	10.936	4.678	9.183	10.965	5.184	9.10	10.254	4.680	8.40	10.284	4.860	8.01
6	11.975	6.529	11.149	11.982	6.587	11.12	10.807	6.741	9.72	10.863	6.797	9.81
7	12.154	7.626	11.987	12.155	7.696	11.99	12.125	7.511	12.07	12.129	7.539	12.07
8	14.874	11.464	14.241	15.046	11.471	14.37	14.914	10.054	14.16	14.940	10.083	13.77
9	20.438	12.004	16.567	20.464	12.009	16.46	19.270	10.826	15.16	19.303	10.877	14.74
10	21.640	13.113	17.924	21.640	13.176	17.84	21.637	12.105	17.24	21.638	12.108	17.20

TABLE 220.10-2

COMPARISON OF ACCELERATION OF DYNAMIC ANALYSIS

WITH AND WITHOUT TORSIONAL DEGREE OF FREEDOM

SOIL SHEAR MODULUS G = 6400 PSI, SSE, SPECTRUM METHOD, 5% DAMPING

	E - W DIRECTION				N - S DIRECTION			
	STARDYNE - 3			EBASCO DYNAMIC 2037	STARDYNE - 3			EBASCO DYNAMIC 2037
MASS NO.	CASE -I*	CASE - II**	DIFF %	CASE I*	CASE I*	CASE II**	DIFF %	CASE 1*
1	0.278	0.272	-2.2	0.287	0.231	0.231	0	
2	0.257	0.251	-2.3	0.263	0.218	0.217	-0.5	
3	2.240	0.234	-2.5	0.246	0.208	0.207	-0.5	
4	0.226	0.220	-2.7	0.230	0.199	0.198	-0.5	
5	0.211	0.205	-2.8	0.214	0.190	0.189	-0.5	
6	0.194	0.188	-3.1	0.195	0.179	0.179	0	
7	0.178	0.172	-3.4	0.178	0.169	0.169	0	
8	0.167	0.161	-3.6	0.165	0.162	0.161	-0.6	
9	0.156	0.150	-3.9	0.153	0.154	0.154	0	
10	0.148	0.143	-3.4	0.145	0.149	0.148	-0.7	
11	0.141	0.137	-2.8	0.139	0.144	0.144	0	
12	0.234	0.228	-2.6	0.239	0.200	0.200	0	
13	0.223	0.217	-2.7	0.226	0.194	0.193	-0.5	
14	0.211	0.205	-2.8	0.214	0.187	0.186	-0.5	
15	0.200	0.195	-2.5	0.202	0.180	0.180	0	
16	0.190	0.184	-3.2	0.191	0.174	0.174	0	
17	0.180	0.174	-3.3	0.180	0.168	0.168	0	
18	0.170	0.165	-2.9	0.169	0.162	0.162	0	
19	0.161	0.156	-3.1	0.160	0.157	0.156	-0.6	
20	0.153	0.148	-3.3	0.151	0.152	0.151	-0.7	
21	0.146	0.141	-3.4	0.143	0.147	0.146	-0.7	

* Without torsional degree of freedom
** With torsional degree of freedom

TABLE 220.10-2 (Cont'd)

	E - W DIRECTION				N - S DIRECTION			
	STARDYNE - 3			EBASCO DYNAMIC 2037	STARDYNE - 3			EBASCO DYNAMIC 2037
MASS NO.	CASE -I*	CASE - II**	DIFF %	CASE I*	CASE I*	CASE II**	DIFF %	CASE 1*
22	0.167	0.161	-3.6	0.166	0.160	0.159	-0.6	
23	0.164	0.159	-3.1	0.163	0.158	0.158	0	
24	0.167	0.156	-3.7	0.160	0.156	0.156	0	
25	0.157	0.152	-3.2	0.156	0.154	0.154	0	
26	0.153	0.148	-3.3	0.151	0.152	0.151	-0.7	
27	0.148	0.143	-3.4	0.146	0.148	0.148	0	
28	0.145	0.140	-3.5	0.142	0.146	0.146	0	
29	0.179	0.164	-8.4	0.179	0.169	0.169	0	
30	0.161	0.147	-8.7	0.160	0.158	0.157	-0.6	
31	0.153	0.154	+0.7	0.151	0.152	0.151	-0.7	
32	0.145	0.149	+2.8	0.144	0.147	0.148	+0.7	
35	0.171	0.180	+5.3	0.172	0.164	0.164	0	
36	0.163	0.170	+4.3	0.162	0.158	0.159	+0.6	
39	0.137	0.135	-1.5	0.134	0.141	0.140	-0.7	

* Without torsional degree of freedom
** With torsional degree of freedom

TABLE 220.10-3

COMPARISON OF ACCELERATION OF DYNAMIC ANALYSIS

WITH AND WITHOUT TORSIONAL DEGREE OF FREEDOM

SOIL SHEAR MODULUS G = 6400 PSI, SSE, SPECTRUM METHOD, 5% DAMPING

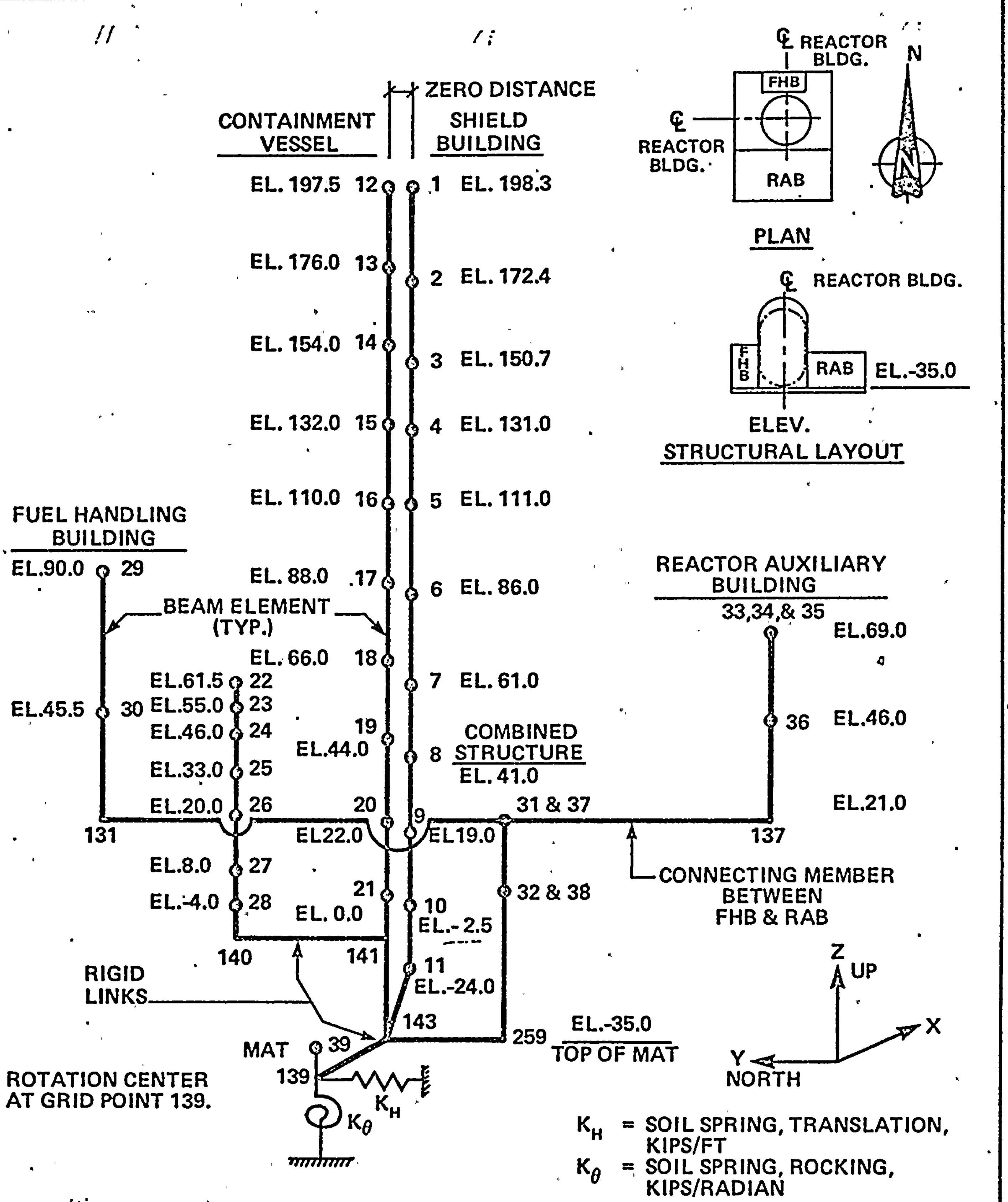
	E - W DIRECTION				N - S DIRECTION			
	STARDYNE - 3			EBASCO DYNAMIC 2037	STARDYNE - 3			EBASCO DYNAMIC 2037
MASS NO.	CASE -I*	CASE - II**	DIFF %	CASE I*	CASE I*	CASE II**	DIFF %	CASE 1*
1	0.492	0.479	-2.6		0.430	0.429	-0.2	
2	0.453	0.440	-2.9		0.401	0.399	-0.5	
3	0.423	0.411	-2.8		0.379	0.377	-0.5	
4	0.395	0.384	-2.8		0.358	0.357	-0.3	
5	0.367	0.356	-3.0		0.337	0.336	-0.3	
6	0.333	0.322	-3.3		0.311	0.310	-0.3	
7	0.299	0.290	-3.0		0.286	0.285	-0.3	
8	0.275	0.266	-3.3		0.268	0.266	-0.8	
9	0.250	0.242	-3.2		0.249	0.248	-0.4	
10	0.232	0.224	-3.5		0.234	0.233	-0.4	
11	0.216	0.209	-3.2		0.222	0.221	-0.5	
12	0.356	0.344	-3.4		0.312	0.311	-0.3	
13	0.341	0.330	-3.2		0.303	0.301	-0.7	
14	0.325	0.315	-3.1		0.293	0.292	-0.3	
15	0.310	0.300	-3.2		0.284	0.282	-0.7	
16	0.295	0.286	-3.1		0.274	0.273	-0.4	
17	0.280	0.271	-3.2		0.265	0.264	-0.4	
18	0.265	0.257	-3.0		0.255	0.254	-0.4	
19	0.251	0.243	-3.2		0.245	0.244	-0.4	
20	0.237	0.229	-3.4		0.236	0.235	-0.4	
21	0.223	0.217	-2.7		0.226	0.226	0	

* Without torsional degree of freedom
** With torsional degree of freedom

TABLE 220.10-3 (Cont'd)

	E - W DIRECTION				N - S DIRECTION			
	STARDYNE - 3			EBASCO DYNAMIC 2037	STARDYNE - 3			EBASCO DYNAMIC 2037
MASS NO.	CASE -I*	CASE - II**	DIFF %	CASE I*	CASE I*	CASE II**	DIFF %	CASE 1*
22	0.259	0.250	-3.5		0.248	0.247	-0.4	
23	0.255	0.246	-3.5		0.246	0.245	-0.4	
24	0.251	0.243	-3.2		0.243	0.242	-0.4	
25	0.244	0.236	-3.3		0.239	0.238	-0.4	
26	0.236	0.229	-3.0		0.235	0.234	-0.4	
27	0.228	0.220	-3.5		0.229	0.228	-0.4	
28	0.221	0.214	-3.2		0.225	0.224	-0.4	
29	0.277	0.254	-8.3		0.268	0.267	-0.4	
30	0.251	0.229	-8.8		0.248	0.247	-0.4	
31	0.238	0.239	+0.4		0.238	0.236	-0.8	
32	0.224	0.228	+1.8		0.228	0.229	+0.4	
35	0.268	0.282	+5.2		0.259	0.262	+1.2	
36	0.254	0.267	+5.1		0.250	0.252	+0.8	
39	0.206	0.203	-1.5		0.215	0.213	-0.9	

* Without torsional degree of freedom
** With torsional degree of freedom



AMENDMENT NO. 5 (8/81)

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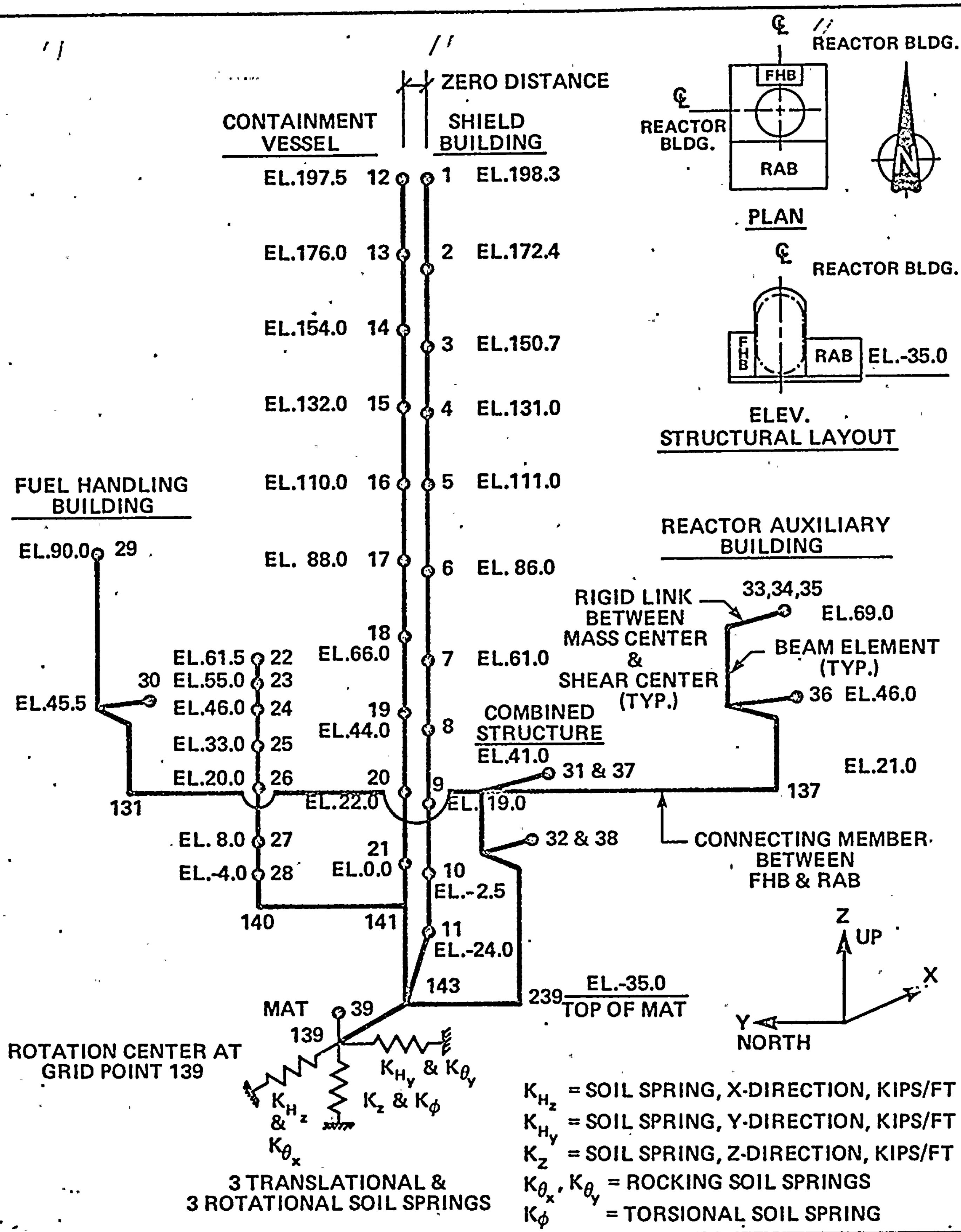
REACTOR BLDG. MATHEMATICAL MODEL (NO TORSIONAL EFFECT)
FIGURE 220.10-1



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

REACTOR BUILDING MATHEMATICAL TORSION MODEL
FIGURE 220.10-2

Question No.

220.11 In Table 3.7-24 the maximum moment at mass points 20, 22, 23 and 24 show smaller values for the time-history method than for the response spectra method. Explain these differences since the time-history method is expected to yield a larger response than the response spectra method. This situation exists for other structures shown in other tables.

Response

Table 3.7-24 has been revised to reflect correct values for maximum moments at mass points 20 and 22 for time-history method. These values are higher than response spectra method as anticipated. Maximum moments at mass points 23 and 24 are negligibly higher for response spectra method than time-history method and could be attributed to the conservatism used in reading acceleration values from ground response spectra and/or due to slightly different models used in two different methods.

Question No.

220.12 The natural frequency of 70.36 shown in Table 3.7-18 for ES = 40 ksi, E-W direction, Mode 1, is in error. What is the correct frequency?

Response

The correct frequency is 1.36. Table 3.7-18 has been corrected.

Question No.

220.13 Outline the method used to account for differential structural movement during an earthquake for piping that is supported by different seismic Category I structures.

Response

1. For piping that is supported by two buildings on a common mat or two structures within the same building, the relative seismic displacements between interface support/restraints are derived by taking the square root of the sum of the squares (SRSS) of each relative seismic displacement towards the common reference. The common reference can either be the common mat or the structure base which is considered as anchorage in the analytical model of the structure.

2. For piping that is supported by two buildings on separate mats, the relative seismic displacements between interface support/restraints, in general, are derived from the combination of co-directional maximum absolute seismic displacement of the two buildings at the supporting elevation by square root of the sum of the square (SRSS) method. If the interface support/restraints at both buildings are located near the ground level or the two adjacent buildings have similar base response, the larger of the two maximum absolute seismic displacements may be considered as the maximum relative seismic displacement between the interface support/restraints.

3. All the maximum relative seismic displacement are placed at the interface anchorage such as the penetration connections of the Reactor Steel Containment Vessel in the seismic displacement analysis. The seismic displacement analysis are at first performed for each of the three orthogonal directions independently. Then the result data are combined by SRSS method.

Question No.

220.14 Describe the method used to analyze the Turbine Building for seismic motion.

Response

Although the Turbine Building is a nonseismic building, we have taken into account the equivalent static "g" loads in the stress analysis of the Turbine Building Framing.

The seismic required design "g" values for the Turbine Building structure evaluation were obtained from the dynamic seismic response analysis using a simplified model to represent the dynamic behavior of the Turbine Building structure.

Question No.

220.15 Describe your criteria for system/subsystem decoupling. Standard Review Plan 3.7.2 contains an acceptable criteria.

Response

For the reactor building in particular, studies using seismic models with and without subsystem are made to ensure the coupling effect is minimal. Models with major equipment (such as steam generators and reactor vessel) and the supporting structure (i.e., the internal structure) modeled separately and modeled together are constructed and the Computer Code STARDYNE is employed. Dynamic responses such as frequencies, accelerations, and response spectra are compared. The differences are found negligible.

Question No.

220.16 (3.7.3) The comparison points in Table 3.7-38, sample problem 2 do not match. Show other point comparisons for each problems and show points where difference between methods is a maximum.

Response

Because of the difference in the consideration of load distribution between static and dynamic analyses, the maximum computer stress will not always appear at the same point. However, with the consideration in the procedure delineated in Subsection 3.7.3.1.1b, the maximum computed stress will be higher for the "Modified Equivalent Static Load" method which is a frequency based static analysis.

The original calculations for the three sample problems were performed on the basis of a flat response spectra of 1.0g acceleration. For an actual response spectra generated from ordinary structure, the response values beyond the resonant region usually decay rapidly. This is evidently demonstrated on the attached Figures 220.16-1 thru 220.16-3. The three sample problems have been recalculated for both flat response spectra and this more realistic response spectra using combination methods of NRC Regulatory Guide 1.92 Rev 1 and ASME Code Summer 1973 version for Code Class 2 & 3 piping.

The attached tables represent a comparison of pipe stresses computed by both "Modified Equivalent Static Load Method" and the mode response spectra analysis. Table 220.16-1 is the result based on a flat response spectra of 1.0g acceleration. Table 220.16-2 is the result based on the enveloped response on Figures 220.16-1 thru 220.16-3. In all cases, the maximum computed stress is higher for the frequency based static analysis. As it is shown in Table 220.16-2 this is even more evidential in the comparison based on a real response spectra.

It is worth to mention that while the sample problems 2 & 3 were arbitrarily picked from actual piping systems, the sample problem #1 does not reflect any normal restrained piping system. It was purposely modeled and restrained to exemplify the possible dynamic response of the piping. In general practice, the restraints are placed near the valves, corners and offsets as much as possible.

TABLE 220.16-1

HIGH STRESS COMPARISON
based on flat 1.0g response

Sample Problem 1
(Fig. 3.7-254)

Point No.	Seismic Stress (PSI) Static	Dynamic	Difference
16	13083	7304	5779*
14	8371	5559	2812
18	7355	4789	2566
1	6260	4921	1339
4	5525	4386	1139
15	4422	3743	679
30	1969	5572	-3603
29	1964	5566	-3602

Sample Problem 2
(Fig. 3.7-255)
(Fig. 3.7-256)

Point No.	Seismic Stress (PSI) Static	Dynamic	Difference
25	8755	7031	1724
31	8291	5112	3179*
19	8002	5026	2976
28	7733	6521	1212
21	6732	5293	1439
17	6708	4143	2565
5	6337	5385	952
13	6008	4699	1309
36	2663	3505	-842
32	1544	2389	-845

Sample Problem 3
(fig. 3.7-257)

Point No.	Seismic Stress (PSI) Static	Dynamic	Difference
2	8179	5717	2462*
27	6577	4708	1869
8	6553	4459	2094
4	6317	5180	1137
3	6174	4734	1440
1	5428	4008	1420
2501	5198	4091	1107
5	5169	3723	1446
100	1357	2054	-697

* greatest difference

TABLE 220.16-2

HIGH STRESS COMPARISON
based on floor response spectra

Sample Problem 1
(Fig. 3.7-254)

Point No.	Seismic Stress (PSI) Static	Dynamic	Difference
16	6853	1634	5219*
18	3645	1087	2558
1	3226	1936	1290
14	3152	1502	1650
15	2647	644	2003
4	2384	1524	860
30	711	1322	-611
29	709	1320	-611

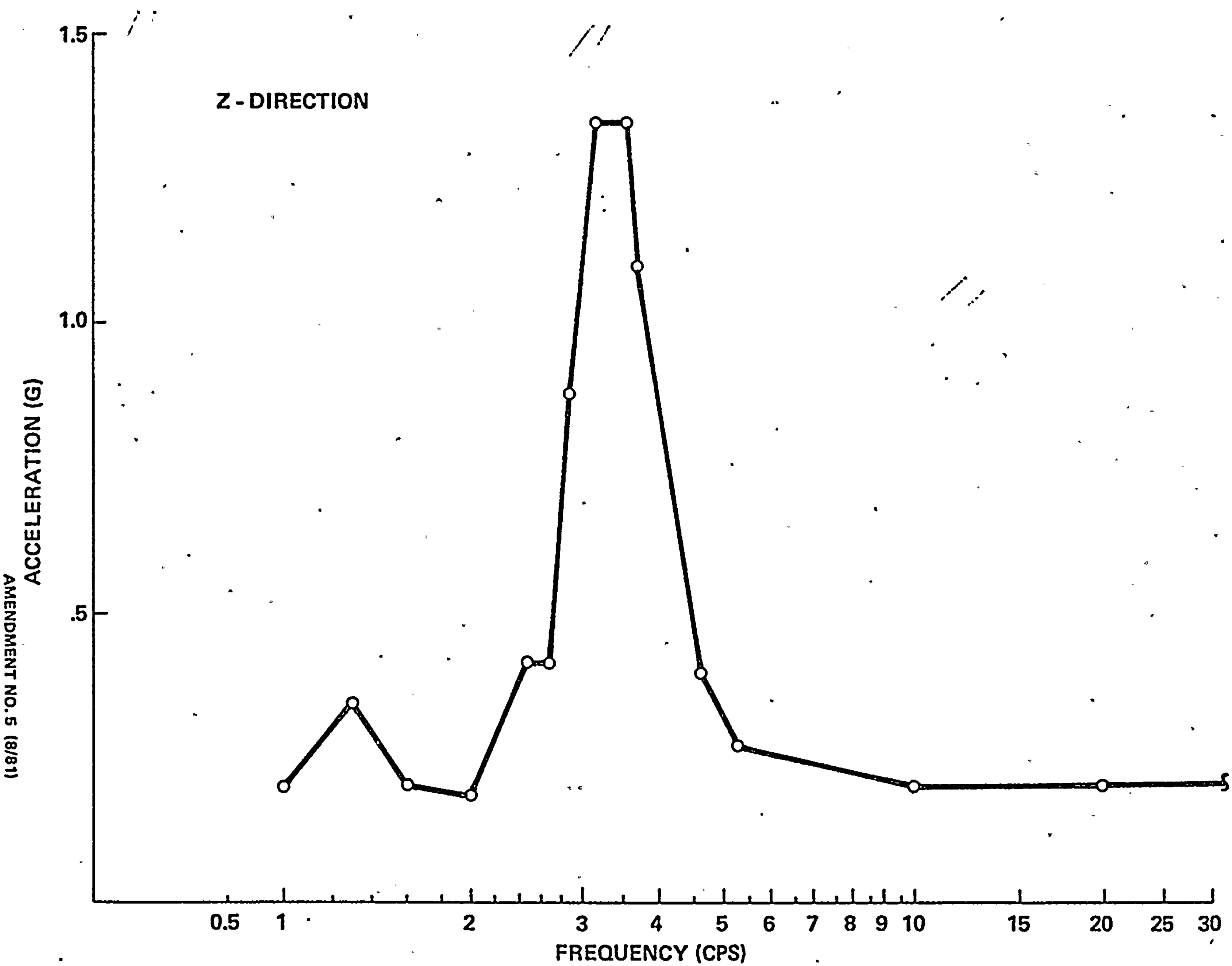
Sample Problem 2
(Fig. 3.7-255)
(Fig. 3.7-256

Point No.	Seismic Stress (PSI) Static	Dynamic	Difference
31	3894	1315	2597
19	3673	1315	2358
17	3649	1010	2639*
21	3165	1236	1929
5	3042	1330	1712
13	2983	1101	1882
12	2784	1055	1729
30	2745	1005	1740

Sample Problem 3
(Fig. 3.7-257)

Point No.	Seismic Stress (PSI) Static	Dynamic	Difference
27	3289	1134	2155*
1	3029	1324	1705
13	2804	1100	1704
2	4212	2518	1694
4	3162	1510	1652
20	2615	991	1624
8	3286	2055	1231
3	3139	2088	1051

* greatest difference

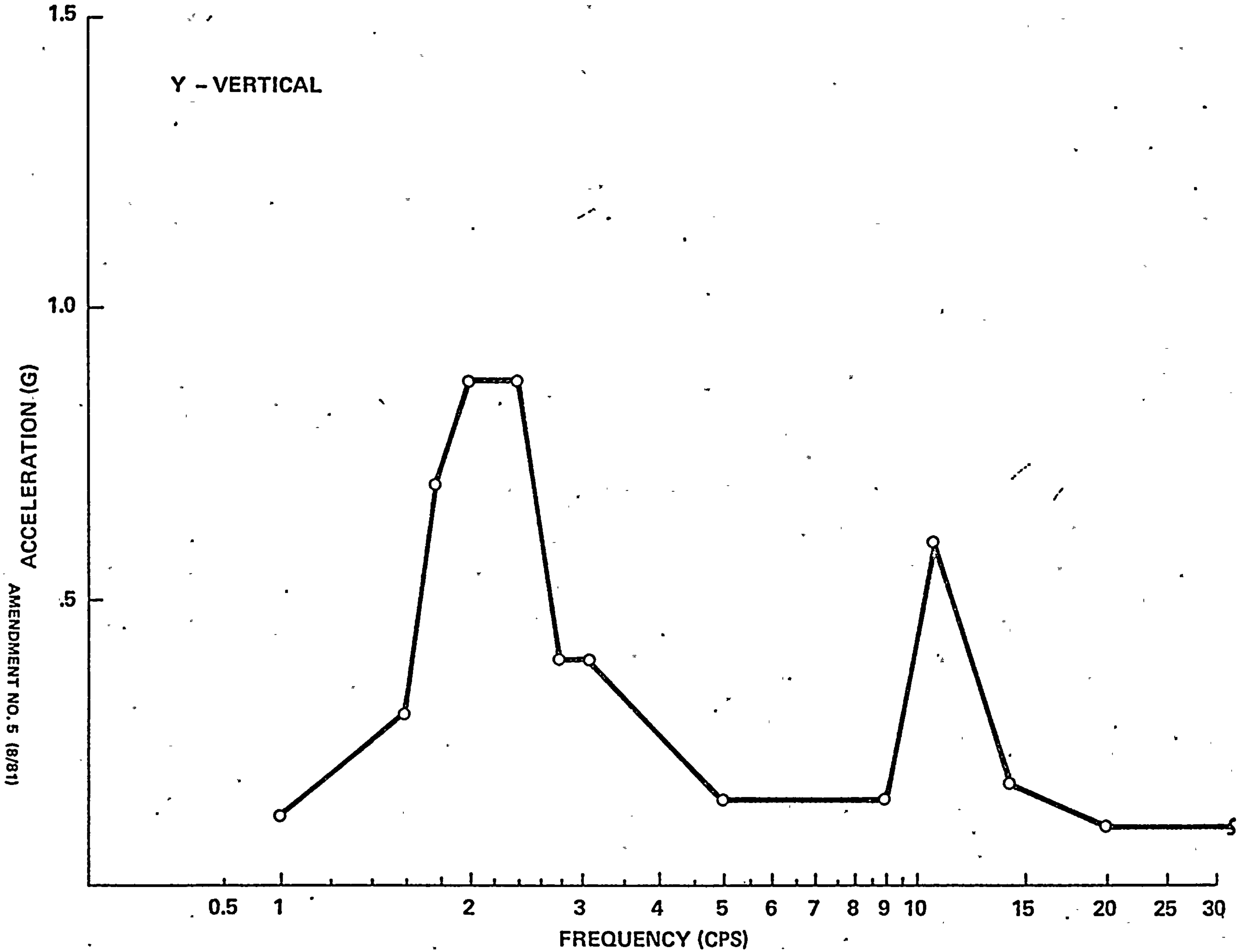


AMENDMENT NO.5 (8/81)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

RESPONSE SPECTRA USED FOR HIGH STRESS COMPARISON BETWEEN MODIFIED EQUIVALENT STATIC LOAD METHOD & MODE RESPONSE SPECTRA ANALYSIS

FIGURE 220.16-1

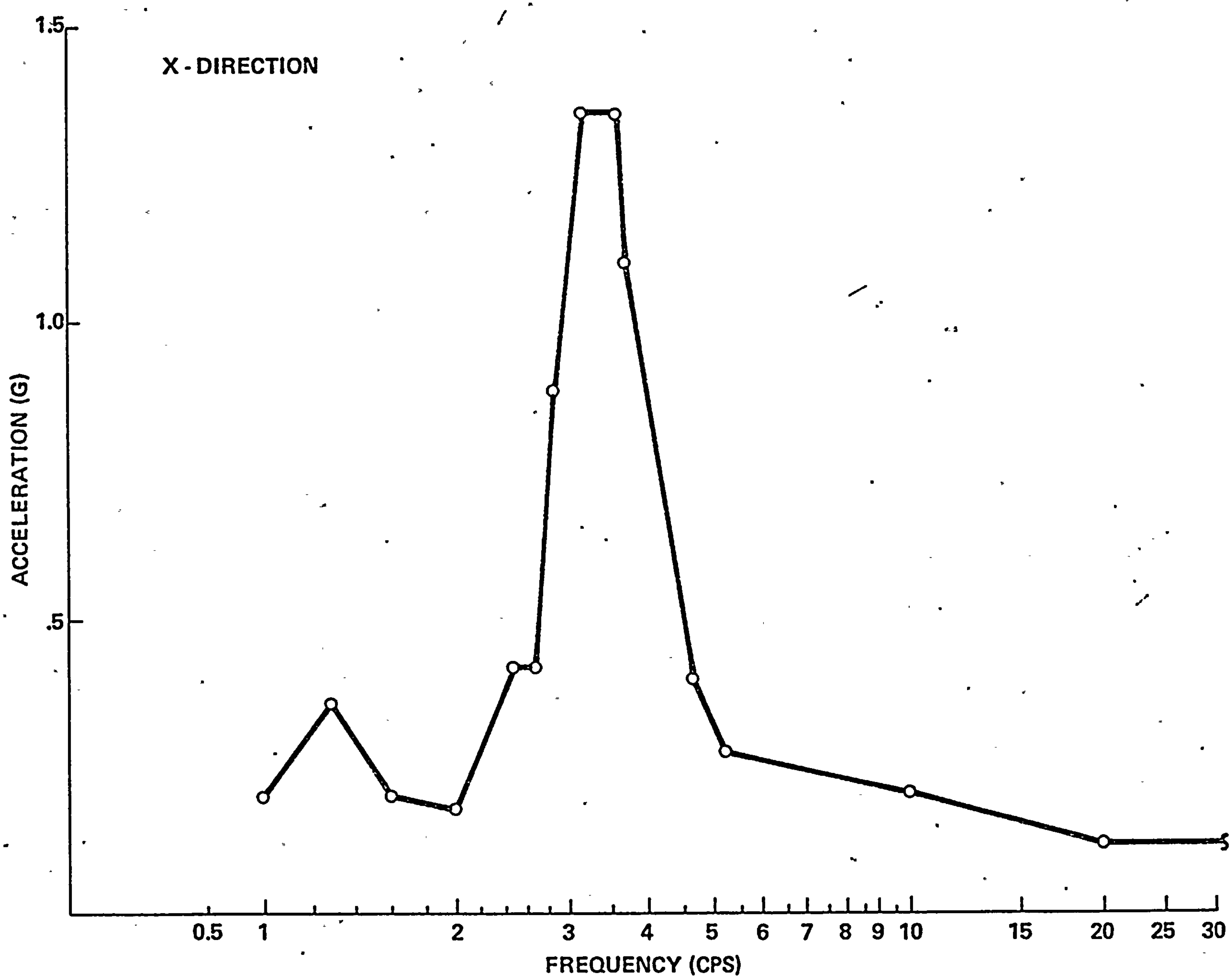


AMENDMENT NO. 5 (8/81)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

RESPONSE SPECTRA USED FOR HIGH STRESS COMPARISON BETWEEN MODIFIED EQUIVALENT STATIC LOAD METHOD & MODE RESPONSE SPECTRA ANALYSIS

FIGURE 220.16-2



AMENDMENT NO. 5 (8/81)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

RESPONSE SPECTRA USED FOR HIGH STRESS
COMPARISON BETWEEN MODIFIED EQUIVALENT
STATIC LOAD METHOD & MODE RESPONSE
SPECTRA ANALYSIS

FIGURE 220.16-3

Question No.

220.17 In Subsection 3.7.3.9, Item C, you used the words "significant support displacement." Define the threshold of significant and the basis for this lower bound if a lower bound is used.

Response

All the relative seismic displacement between restraint/support points which may contribute an estimated bending stress more than five percent of the code allowable stress limit are considered to be significant.

Question No.

220.18 In Subsection 3.7.3.3 you stated sufficient mass points will be included in the model and sufficient dynamic modes computed. Define "sufficient" for number of mass points and dynamic modes.

Response

If the mass points and corresponding dynamic degrees of freedom are distributed to provide for appropriate representation of the dynamic characteristics of the subsystem, then it is considered to be sufficient. As indicated in Subsection 3.7.3.1.1.a, the maximum spacing of the mass points may not exceed one half the distance for which the frequency of a simply supported beam would be 20 H_z. The criterion for sufficiency in number of dynamic modes is that the inclusion of additional modes does not result in more than a 10 percent increase in responses. In general, this can be satisfied by including all the dynamic modes below 33 H_z, if the highest mode calculated by 33 H_z has already fallen into the flat rigid response region of the corresponding response spectra, the effect of the remaining high modes are taken care of by adding the dynamic analysis result with an equivalent static solution in SRSS summation.

Question No.

220.19 In Subsection 3.7.3.4 what is your criteria for moving the frequency of the subsystems with respect to the supporting system?

Response

The subsystems in general, are designed or restrained to be in the rigid region to avoid resonance with the supporting system. If the first mode period of the piping is more than 70 percent of the first mode period of the structure, a multimode response analysis is performed. If the first mode period of the piping is 70 percent or less of the first mode period of the structures, the procedures as outlined in Subsection 3.7.3.1.1.b and c are followed as an alternative of analysis approach.

Question No.

220.20 Your modal response combination procedure (Subsection 3.7.3.7) uses only SRSS and omit consideration of closely spaced modes. Use Regulatory Guide 1.92 for combining modes that are closely spaced and correct the appropriate loads.

Response

The consideration of closely spaced modes for subsystems are stated in Subsections 3.7.3.7.1, 3.7.3.7.2, 3.7.3.1.1.a,4 and 3.7.3.1.2.3.d.b following Regulatory Guide 1.92 for combining modes that are closely spaced.

Question No.

220.21 Your procedure in Subsection 3.7.3.1.1.a,1(b) for determining piping support locations is unnecessarily complicated. State the frequency you intend to use for support spacing.

Response

Subsection 3.7.3.1.1.a.1.(b) addresses to mass spacing not restraint spacing. As it is stated in the response to Question 220.18, the mass points are distributed to provide for appropriate representation of the dynamic characteristic of the piping system. The maximum spacing between mass points are limited so as to provide fair mode shape for all the significant modes.

Question No.

220.22 (3.7.3.12) Your description of the method for analyzing the buried seismic Category I piping and tunnels is very sketchy. Provide a more detailed procedure and copies of calculations including any referenced material.

Response

Procedure and calculation will be provided to the NRC via Amendment 6 to the FSAR to be issued August 31, 1981.

Question No.

220.23 What method is used to determine the composite damping for the reactor vessel and the primary loop system.

Response

As illustrated in Subsection 3.7.3.1.2.1, uniform modal damping is used. We note that one percent damping is utilized for OBE and two percent damping is utilized for SSE.

Question No.

220.24 Provide a comparison of results of Unit 1 seismic analysis to the results of Unit 2 analysis to support your conclusion this site is a "Multi-unit site" addressed by Regulatory Guide 1.12.

Response

The St. Lucie Unit 2 structural designs are essentially the same as those of Unit 1, hence the seismic responses expected to be experienced in the St. Lucie Unit 2 plant are similiar to those of Unit 1 plant. Using identical seismic inputs, a seismic response analysis of the structures comprising St. Lucie Units 1 and 2 would demonstrate identical effects for both units.

Question No.

220.25 (3.5) The ductility relationships for reinforced concrete beams and slabs are larger than those acceptable to the staff. Re-evaluate your concrete beams and slabs for a ductility of $\frac{.05}{p-p'} \leq 10$. The ductility ratios for steel members are larger than those acceptable to the staff. Re-evaluate the beams for a ductility ratio of 10 and columns with a $kl/r \leq 20$ for a ductility ratio of 1.7. For columns with a $kl/r > 20$ use a ratio of 1.0.

Response

We have evaluated concrete slabs for ductility of $\frac{.05}{p-p'} \leq 10$ and have found them acceptable. The concrete beams had already been designed for that valve. See Table 3.5-12.

Question No.

220.26 Provide a comparison of your load combinations with the load combination equations in Standard Review Plan 3.8.2, II.3 and address the effects of not meeting the load combinations, including any loads that are missing from your combinations.

Response

Load Combination: SRP 3.8.2	Load Combination: St. Lucie 2 Table 3.8-1	Remarks
(1) $D + L + P_t + T_t$	(1) $D + L + W$	Construction load case (1) is equivalent to SRP load combination (1) with P_t and T_t not applicable. W = lateral wind load.
(1) $D + L + P_t + T_t$	(2) $D + W + P_t + T_t$ (3) $D + E + P_t + T_t + R_o + T_o$	Live load not included in SL2 load combination. The additional effect would be insignificant.
(2) $D + L + T_o + R_o$ (3) $D + L + T_o + R_o + E$	(4,5) $D + L + T_o + R_0 + E + P_e$	SL2 load combination (4) or (5) is equivalent to SRP load combination (3) (governs over SRP load combination (2)) except P_e was added to the load case.
(4) $D + L + T_a + R_a + P_a + E$	(6) $D + T_a + R_a + P_a + E$	Live load not included in SL2 load combination (6) - LOCA plus OBE loads. The additional effect would be insignificant.
(5) $D + L + T_e + R_e + P_e + E$	(4,5) $D + L + T_e + R_e + P_e + E$	Equivalent

Load Combination: SRP 3.8.2	Load Combination: St Lucie 2 Table 3.8-1	Remarks
(6) $D + L + T_a + R_a + P_a + E'$	(7) $D + T_a + R_a + P_a + E'$	Live load not included in SL2 load combination (7). The additional effect would be insignificant.
(3) $D + L + T_o + R_o + E$	(8) $D + L + T_o + R_o + E + Y_r$ (10) $D + L + T_o + R_o + E + Y_j$	SL2 load combinations equivalent to SRP load combination (3) except that Y_r or Y_j was added to the load case.
(7) $D + L + T_e + R_e + P_e + E'$	None	No corresponding load combination on SL2. Effect on containment cannot be assessed without detail analysis. Completion date of additional detail analysis is July 31, 1981.
(8) $D + L + T_a + R_a + P_a + Y_r + Y_j + Y_m + E'$	(9) $D + L + T_o + R_o + Y_r + E'$	St. Lucie 2 load combination is equivalent to SRP load combination with Y_m, P_a and Y_j either insignificant or not applicable. With $P_a = 0$, R_a and T_a reduces to R_o and T_o respectively.
(8) $D + L + T_a + R_a + P_a + Y_r + Y_j + Y_m + E'$	(11) $D + T_a + R_a + P_a + Y_j + E'$	St. Lucie 2 load combination is equivalent to SRP load combination with L, Y_r and Y_m either insignificant or not applicable.

SRP load combination (9) was not compared because F_L is not applicable. With the elimination of this term, this SRP load combination is enveloped by SRP load combination (3).

Question No.

220.27 Describe how the containment steel shell is anchored to the concrete foundation slab. Describe the procedures used to account for the shear stresses between the steel shell and the concrete on both sides of the ellipsoidal head for the loads which will produce these stresses.

Response

The steel containment ellipsoidal bottom head is completely embedded in concrete. The containment dead weight and any overturning moments due to seismic are assumed to be transferred to the concrete in bearing. Shear stresses are assumed to be zero. We believe that these are valid assumptions since the head is not hemispherical.

Question No.

220.28 The methodology used to analyze the containment shell to guard against buckling is not completely described. Provide the following:

(1) Details of the assumptions and boundary conditions used in the analyses of the dome and the cylinder and justify why the analysis for each section was done separately.

(2) All the load combinations which are considered critical (the limiting cases) for the buckling analysis. For each load combination state the most likely effected regions of the shell for this type of compressive loadings.

(3) Compare and justify the methodology used in your analysis with the acceptable methods stated in the current version of the ASME Code subsubarticle NE-3100. Provide a discussion of the factor of safety for each service level.

(4) Provide a copy of the referenced papers used in the buckling analysis of the containment shell.

Response

(1) The design of the containment is in accordance with ASME Code Section III, NE-3133 design rules with assumptions and boundary conditions inherent in the design rules.

(2) The loading combinations are considered critical for buckling.

a) Case 5 - Cold shutdown at ambient temperature. This case includes OBE seismic with external pressure.

b) Case 9 - Condition with safe shutdown earthquake.

This case includes SSE seismic with no internal pressure.

The design most likely affected regions of the shell are the top head near the cylinder junction and the bottom tangent line on the cylinder. Buckling in the ellipsoidal head is not considered since it is embedded in concrete.

(3) As stated above, the design of the containment is in accordance with ASME Code Section III, NE-3100 design rules. External pressure for cylinder and head are checked using design rules in NE-3133.3 and NE-3133.4. The cylinder is checked for axial compression using the design rules in NE-3133.6. Seismic and dead loads are considered to cause axial compression. For those areas with unequal biaxial compressive stresses, the ASME rules as modified by WRC 69 have been used. Basically, the allowable stress for compression determined by NE-3133 remains the same for all "design conditions" except for SSE earthquake where the ASME Sect III; Winter 1972 Addenda NE-3131 C(2) allows a 20 percent increase. The St Lucie 2 design did not use this 20 percent increase.

(4) Reference paper is WRC 69, June, 1961.

Question No.

220.29 State the code used in the design of the steel structural supports for the reactor coolant system and show a comparison of the code used to the current version of the ASME Code Section III, Division I, Subsection NF. Also show a comparison of the ACI 349 Code to the ACI 318-71 Code you used for design of the Concrete Internal Structure.

Response

Part I

The AISC code is used in the design of the structural steel supports for the Reactor Coolant Systems. Refer to Subsections 3.8.3.2.1 and 3.8.3.5.2.

Part II

The major difference between the ACI 318-71 and ACI 349 codes is in the area of design loading. The design loads specified in ACI 349 are supplemented by RG 1.142 which makes the design loads consistent with those presented in SRP 3.8.4. Refer to the attached partial lineup of SRP 3.8.4 for comparison of load combinations specified therein and those used in the design of seismic Category I structures. The attached lineup of RG 1.142 gives supplemented requirements on design procedures to the ACI 349 Code, with statements of compliance, alternate compliance and remarks on impact of deviations.

RG 1.142 also requires, that for concrete structures used to provide radiation shielding, the provisions of Sections 5.1 and 10 of ANSI Standard N101.6-1972 "Concrete Radiation Shields" be followed. The provisions of those sections are followed with the following clarifications:

DOCUMENT: SRP 3.8.4 TITLE: OTHER SEISMIC CATEGORY I STRUCTURES

ACCEPTANCE CRITERIA	COMPLIANCE	ALTERNATE COMPLIANCE	REMARKS
<u>Load Combinations for Concrete Structures</u>			
For concrete structures, the load combinations are acceptable if found in accordance with the following:			
a - For service load conditions, either the working stress design (WSD) method or the strength design method may be used.	a - The strength design method was used.		
i - If the WSD method is used, the following load combinations should be considered: (1) $D + L$ (2) $D + L + E$ (3) $D + L + W$ If thermal stresses due to T_o and R_o, are present, the following combinations should be considered: (1a) $D + L + T_o + R_o$ (2a) $D + L + T_o + R_o + E$ (3a) $D + L + T_o + R_o + W$ Both cases of L having its full value or being completely absent should be checked.	i - Not applicable		

DOCUMENT: SRP 3.8.4 (Cont'd)

ACCEPTANCE CRITERIA	COMPLIANCE	ALTERNATE COMPLIANCE	REMARKS
ii - If the strength design method is used, the following load combinations should be considered: (1) 1.4 D + 1.7 L (2) 1.4 D + 1.7 L + 1.9 E (3) 1.4 D + 1.7 L + 1.7 W If thermal stresses due to T_o and R_o are present, the following combinations should also be considered: (1b) (0.75) (1.4 D + 1.7 L 1.7 T_o + 1.7 R_o) (2b) (0.75) (1.4 D + 1.7 L + 1.9 E + 1.7 T_o + 1.7 R_o) (3b) (0.75) (1.4 D + 1.7 L +1.7 W + 1.7 T_o + 1.7 R_o Both cases of L having its full value or being completely absent should be checked. In addition the following combination should be considered: (2b') 1.2 D + 1.9 E (3b') 1.2 D + 1.7 W	ii - St. Lucie Unit 2 design complies with the load combinations listed, with the exception of load combinations (1b), (2b) and (3b).	ii - The alternate load combinations used are: (1b) 1.4 (B + D) + 1.3 (R_o + T_o) + 1.7 (L + H) (2b) 1.4 (B + D) + 1.3 (R_o + T_o) + 1.7 (L + H') + 1.9 E (3b) 1.4 (B' + D) + 1.3 (R_o + T_o) + 1.7 (L + H) + W) where B = Buoyancy at normal groundwater level B' = Buoyancy at maximum groundwater level re-resulting from a PMH. H = Lateral earth loads under normal conditions H' = Lateral earth loads under normal and earthquake conditions	Since the acceptance criteria load combinations have a multiplication factor of 0.75, the combined loads used as identified in alternate compliance for the St. Lucie Unit 2 design would be greater for all design cases. The load combinations used on St. Lucie Unit 2 were based upon guidance provided in AEC letter to FP&L Co., August 30, 1973, "Enclosure 2 - Structural Design Criteria for Category I Structures Outside the Containment," in addition to those given in the ACI 318-71 Code.
Where soil and hydrostatic pressures are present, in addition to all the above combinations where they have been included in L and D respectively, the requirements of Sections 9.3.4 and 9.3.5 of ACI-318-71 (Ref 1) should also be satisfied.	Soil and hydrostatic pressures are included in the design and the requirements of ACI-318-71 Sections 9.3.4 and 9.3.5 were considered.		

DOCUMENT: SRP 3.8.4 (Cont'd)

ACCEPTANCE CRITERIA	COMPLIANCE	ALTERNATE COMPLIANCE	REMARKS
b - For factored load conditions, which represent extreme environmental, abnormal, abnormal/severe environmental and abnormal/extreme environmental conditions, the strength design method should be used and the following load combinations should be considered. (4) $D + L + T_o + R_o + E'$ (5) $D + L + T_o + R_o + W_t$ (6) $D + L + T_a + R_a + 1.5\ P_a$ (7) $D + L + T_a + R_a + 1.25\ P_a + 1.0\ (Y_r + Y_j + Y_m) + 1.25\ E$ (8) $D + L + T_a + R_a + 1.0\ P_a - 1.0\ (Y_r + Y_j + Y_m) + 1.0\ E'$ In combinations (6), (7), and (8), the maximum values of P_a, T_a, R_a, Y_j, Y_r and Y_m, including an appropriate dynamic load factor, should be used unless a time-history analysis is performed to justify otherwise. Combinations (5), (7), and (8) and the corresponding structural acceptance criteria of Section II.5 of this plan should be satisfied first without the tornado missile load in (5) and without Y_r, Y_j, and Y_m in (7) and (8). When considering these concentrated loads, local section strength capacities may be exceeded provided there will be no loss of function of any safety-related system. Both cases of L having its full value or being completely absent should be checked.	b - St Lucie Unit 2 design complies with the load combinations listed.		

220.29-4

Amendment No. 5, (8/81)

DOCUMENT: SRP 3.8.4 (Cont'd)

ANSI N101.6-72 Section	Clarifications
5.1.2	No high density concrete is used.
5.1.3	No hydrous aggregate is used.
5.1.4	No boron containing aggregates are used.
5.1.6	Coatings of clay, silt, gypsum, calcite or caliche on coarse aggregate total no more than three and one half percent of the total weight of the aggregate. Radiation attenuation calculations take this into account.
10.1.2	Dimensional tolerances for hatches and openings as specified in ACI-347 are used rather than those given in Table 1 of ANSI N101.6-72. Minimum practicable joint clearances are specified.
10.1.3	Service trenches are not used.
10.2.2	The weight of each block is indicated on the design drawing, not marked on the block.
10.2.3	Blocks are cured according to good construction practice, e.g., use of wet burlap or curing compound, but not necessarily in the absence of direct sunlight or heat. This sunlight or heat, however, does not result in the loss of shielding efficiency.
10.3.1	There are no present plans for penetrations through shielding plugs. However, if they are required, streaming is prevented by proper design of the penetration.
10.4	No movable or removable poured walls are used.
10.6	Precast shielding components are fabricated at the site.

DOCUMENT: RG 1.142 (REV. 0) TITLE: SAFETY-RELATED CONCRETE STRUCTURES FOR NUCLEAR POWER PLANTS (OTHER THAN REACTOR VESSELS AND CONTAINMENT)

ACCEPTANCE CRITERIA	COMPLIANCE	ALTERNATE COMPLIANCE	REMARKS
The procedures and requirements described in ACI Standard 349-76, "Code Requirements for Nuclear Safety Related Concrete Structures," are generally acceptable to the NRC staff and provide an adequate basis for complying with the Commission's regulations with regard to the design of safety-related concrete structures other than reactor vessels and containments, subject to the following:		The design and analysis procedures utilized for safety-related concrete structures are in accordance with the ACI 318-71 Code.	Design and analysis of St. Lucie Unit 2 started before ACI 349-76 was issued.
1. The applicability of strength design methods to structures whose principal function is to provide a barrier to contain or retain pressure such as the divider barrier of the ice-condenser of the PWR containment is questionable. Therefore, for those structures, mere conformance with the requirements of ACI 349-76 is unacceptable to the staff, who will continue to review the design of these structures on a case-by-case basis.			1. Not applicable to St Lucie - Unit 2.
2. When concrete structures are used to provide radiation shielding, the provisions of Sections 5.1 and 10 of ANSI Standard N101.6-1972,[2] "Concrete Radiation Shields," and those of ANSI Standard N101.4-1972,[3] as endorsed by Regulatory Guide 1.54, "Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants," are acpplicable.			2. Refer to response to Question 220.29 for compliance to Sections 5.1 and 10 of ANSI Standard N101.6-1972.

DOCUMENT: RG 1.142 (REV. 0) (Cont'd)

ACCEPTANCE CRITERIA	COMPLIANCE	ALTERNATE COMPLIANCE	REMARKS
3. ACI Standard 349-76 lacks specific requirements to ensure ductility of framed structures. Adherence to the requirements of Appendix A to ACI Standard 318-71 is acceptable.			3. Appendix A of ACI 318 "Special Provisions for Seismic Design" is applicable when seismic loads are based on empirical formulae such as those of the Unified Building Code. For the Category I structures, seismic loads are obtained from dynamic analysis of the structures based on SSE and OBE design response spectra. Shear walls and bracing systems are designed to take the seismic forces calculated from such analysis. For these reasons Ebasco feels that the requirements of Appendix A of ACI 318 are not applicable to the nuclear plant structures whose design is based on conservative criteria and detailed seismic analysis.
4. Section 5.1.2 permits depositing concrete without the prior removal of water from the place of deposit at the discretion of the owner. Since the presence of water in the place of deposit may seriously affect the strength properties of concrete, it is important that water be removed before concrete is deposited unless a tremie is used.	4. Water is removed before concrete is deposited.		4. Refer to Concrete Specification FLO 2998.473.
5. Section 5.4.1 allows concrete that has partially hardened or has been contaminated with foreign materials or remixed after initial set to be reused at the discretion of the engineer. Such a material would be defective and therefore should not be used.	5. The placement of partially hardened, contaminated or retempered concrete is not permitted.		5. Refer to Concrete Specification FLO 2998.473.

DOCUMENT: RG 1.142 (REV. 0) (Cont'd)

ACCEPTANCE CRITERIA	COMPLIANCE	ALTERNATE COMPLIANCE	REMARKS
6. In addition to the requirements of Section 1.3.1 of ACI Standard 349-76, the inspectors should have sufficient experience in reinforced and prestressed concrete practice to interpret plans and specifications. The inspectors should be thoroughly familiar with the applicable ACI and ASTM Standards. ACI Standard 311-74,[1] "Recommended Practice for Concrete Inspection," should be followed except where the requirements of Section 1.5 of ACI Standard 349-76 control.			6. FP&L to indicate compliance based on site inspection practices.
7. The frequency of cylinder testing required by Section 4.3.1 of ACI Standard 349-76 is not consistent with generally accepted practice. A test frequency in conformance with ANSI Standard N45.2.5-1974,[4] as endorsed by Regulatory Guide 1.94, "Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants," is acceptable.	ANSI N45.2.5-1974 concrete cylinder testing frequency was followed on St. Lucie Unit 2.		
8. The minimum pressure-testing requirements for embedded piping of ACI Standard 318-71 have been deleted from ACI Standard 349-76. In order to ensure that minimum pressure-testing requirements are met, the pressure tests of embedded pipes in Section 6.3.2.4 of ACI 349-76 should also satisfy the requirements of Subsection 6.3.2.4 of ACI 318-71.			8. Not applicable. ACI Standard 318-71, Section 6.3.2.4, indicates that piping, with the exceptions of Section 6.3.2.5, is to be tested prior to concreting. Section 6.3.2.5 is as follows: "Drain pipes and other piping designed for pressures of not more than 1 psi above atmospheric pressure need not be tested as required in Section 6.3.2.4."

DOCUMENT: RG 1.142 (REV. 0) (Cont'd)

ACCEPTANCE CRITERIA	COMPLIANCE	ALTERNATE COMPLIANCE	REMARKS
9. More conservative load factors are appropriate in accounting for the effects of normal or shutdown thermal loads, postulated pipe break accidents, and an operating basis earthquake (OBE) in combination with a postulated pipe break. The load factors used in Section 9.3.1 of ACI Standard 349-76 are acceptable to the staff except for the following: a. In load combinations (9), (10), and (11), 1.7 T_o should be used in place of 1.4 T_o. b. In load combination (6), 1.5 P_a should be used in place of 1.25 P_a. c. In load combination (7), 1.25 P_a and 1.25 E_o should be used in place of 1.15 P_a and 1.15 E_o, respectively. d. In load combinations (2) and (10), 1.9 E_o should be used in place of 1.7 E_o			9. Load factors utilized are presented in SRP 3.8.4 line-up. The noted load factor changes make the load combination consistant with those presented in SRP 3.8.4.
10. Structures must be able to withstand the effects of differential settlement under environmental loads as well as under abnormal loads. Thus, in Section 9.3.2 of ACI 349-76, consideration of the effects of differential settlement should be included in load combinations (1) through (11).			10. Not applicable since each safety-related concrete structure is supported on an individual mat. Differential settlement within a building was not expected to occur and was not included as a design consideration.
11. The provisions of Section 9.3.3 of ACI Standard 349-76 to account for the effects of transitory loads are not sufficiently general. Thus, in Section 9.3.3 of ACI Standard 349-76, when any load reduces the effects of other loads, the corresponding coefficient for that load should be taken as 0.9 if it can be demonstrated that the load is always present or occurs simultaneously with the other loads. Otherwise, the coefficient for that load should be taken as zero.		11. Load combinations used in design either useful dead and line loads or full dead and zero line loads.	11. The load combinations used on St Lucie Unit 2 were based upon guidance provided in AEC letter to FP&L Co., 8-30-73, "Enclosure 2-Structural Design Criteria for Category I Structures Outside the Containment," in addition to those given in the ACI 318-71 Code.

DOCUMENT: RG 1.142 (REV. 0) (Cont'd)

ACCEPTANCE CRITERIA	COMPLIANCE	ALTERNATE COMPLIANCE	REMARKS
			11. (Continued) Exception is taken to the regulatory position which requires that a coefficient of 0.9 or zero be applied to any load which reduces the effects of other loads. Considering live load as having its full value or being completely absent satisfies the requirement for setting a transitory load to zero. However, applying the 0.9 coefficient to all other such mitigating loads, which are always present or occur simultaneously, would increase the number of load combinations to an impractical level with no demonstrated or meaningful increase in the overall conservatism of the governing load combinations. Our position is consistent with ACI 318-77 and ACI 349-76.
12. The provision in Section 9.3.6 of ACI Standard 349-76 permitting local exceedance of section strength under concentrated dynamic loads does not ensure that the section can withstand the associated distributed loadings. Thus, if the provision of Section 9.3.6 of ACI 349-76 permitting exceedance of local section strengths is invoked, it should be demonstrated that section strengths are adequate to accommodate load combinations (7) and (8) without the dynamic loads Y_j, Y_m, and Y_r.			12. Design criteria used on St Lucie Unit 2 does not permit local exceedance of section strength.

DOCUMENT: RG 1.142 (REV. 0) (Cont'd)

ACCEPTANCE CRITERIA	COMPLIANCE	ALTERNATE COMPLIANCE	REMARKS
13. The NRC staff would accept the local exceedance of section strength for concentrated tornado-generated-missile loading under load combination (5). However, an analysis should be performed to demonstrate that section strengths are adequate to accommodate load combination (5) without the dynamic load effect of tornado-generated missiles.			13. Same as 12 above.
14. ACI Standard 349-76 does not address the subject of openings in slabs and footings. Provisions of Section 11.12 of ACI 318-71 are acceptable for this purpose.	14. Provisions of Section 11-12 of ACI 318-71 are followed.		

Question No.

220.30 You stated that the allowable stress for the factored load combinations was increased. These load combinations contain the earthquake loading. The staff does not allow any increase in the allowable for earthquake loads. Re-evaluate the structures without the increase in the allowable stresses and provide the results of your re-evaluation.

Response

Our load combinations and allowable stresses comply with those in the Standard Review Plan 3.8.8. SRP 3.8. II 5 does allow an increase in the allowables for earthquake loads in the factored load combinations.

Question No.

220.31 (3.8.3) (3.8.4) In several analysis you have used static loads to represent a dynamic loading. Provide your procedures for transforming the dynamic loads into static loads, reference pipe reactions and pressurization of shield wall.

Response

The St. Lucie 2 structural design utilizes equivalent static load methodology. The loading combination for all structural loads is provided in FSAR Subsection 3.8.4. The method of transforming the dynamic loads with equivalent static loads is as follows:

(1) The dynamic piping loads (i.e., seismic, relief valve discharge) are transformed into static loads in the piping stress analysis by either utilizing the model response spectra method or by applying an amplification factor to the excitation load. These pipe loads on structures are considered in the design for both the positive and negative directions with the same magnitude.

(2) The dynamic effects of pipe whip and jet impingement are discussed in FSAR Section 3.6. The pipe whip loads on the structural components (i.e., pipe whip restraints) were calculated utilizing static methods while various confirmatory dynamic analysis were utilized to confirm these piping loads (refer to Appendix 3.6E). The jet impingement analysis utilized a Dynamic Load Factor (DLF) of two applied to the KPA load to determine the loads on structural components (refer to Subsection 3.6.2).

(3) The dynamic effects associated with the containment subcompartment pressure analysis were considered in the structural design of the subcompartment walls. The equivalent static loads were obtained by applying a Dynamic Load Factor to the peak of each dynamic loads. The calculated peak pressure for each subcompartment and the corresponding design valves (with calculated margin) will be provided in FSAR Subsection 6.2.3.

Question No.

220.32 You stated that the cable tray restraints were designed for a "minimum natural frequency within 16 hz". You further say the HVAC restraints are designed with a minimum natural frequency of 15 hz. What provisions were made to ensure the first natural frequency was 15 or 16 hz and how do you account for higher modes in the systems? Also state how the restraints are anchored to the structure. FSAR Subsection 3.8.3.1.5 contains several restraint designs.

Response

The first natural frequency of the cable tray (HVAC) restraint is determined after member selection to ensure that the minimum natural frequency of 16 hz (15 hz) is satisfied. Amplification factors are used to account for the participation of higher modes. The cable tray (HVAC) restraints are welded to steel embedments with a fillet weld all around.

Question No.

220.33 (3.8.5.5) You stated you used only the passive earth pressure on the portion of the structures to resist sliding. Discuss how you accounted for this load on the walls and provide a table showing the structure and the maximum earth pressure.

Response

FSAR Subsection 3.8.5.5 states that, if we discount the ability of the waterproofing membrane (beneath the Shield Building and Reactor Auxiliary Building) to resist shear forces, passive earth pressures would be sufficient to resist sliding.

A design impact review of this assumption has been completed and results are as follows:

Shield Building - A substantial portion of the Shield Building has structural concrete and fill concrete throughout the building cross-section below plant island grade elevation. Therefore, the soil passive pressure loads on the building are of no design significance. However, the design analysis of the building determined a seismic movement and resisting earth pressure less than the full passive earth pressure. This requires the waterproofing membrane to be able to transfer shear forces. Therefore, the design calculations for resistance to sliding are based upon the combination of resisting earth pressure and the membrane shear strength value documented by the manufacturer. See Figure 220.33-1 for the maximum passive pressure and design resisting pressure.

Reactor Auxiliary Building - The building general arrangement and resulting mat layout allows sliding to be resisted through internal shear resistance of the soil and resisting earth pressures, in the east, west and south directions. The ability of the waterproofing membrane to transfer shear forces is not required in those directions. In the north direction, the earth pressure required to resist sliding is greater than the design capacity of the building walls. Therefore, the design calculations for resistance to sliding in that direction are based upon the combination of resisting earth pressure and the membrane shear strength value. See Figure 220.33-2 for resisting pressures.

See FSAR Subsection 3.8.5.5 for revised statement on the design consideration of waterproofing membrane in structure sliding analysis.

Question No.

220.34 (3.8.5.2) State the codes used and list any deviations to the codes used for foundation design. Compare the codes used to the present version of the codes showing deviations and the effect of these deviations.

Response

Standard Review Plan 3.8.5 "Foundations" refers to Standard Review Plan 3.8.3 "Internal Structures of Containments" for foundation design codes and ACI 381-71 is the only applicable code listed. St. Lucie Unit 2 foundation design is in accordance with ACI 381-71 as supplemented by Standad Review Plan 3.8.4 "Other Seismic Category I Structures." See response to Question 220.29 for comparison of SRP 3.8.4 load combination requirements and those used in the St. Lucie Unit 2 design.

A review of the 1977 edition of ACI 318 Code has determined that the changes have insignificant effect on foundation design requirements.

Question No.

220.35 Provide a table showing the factor of safety against sliding, overturning and flotation for the load combinations shown in Standard Review Plan 3.8.5.

Response

The attached tables show the factors of safety against sliding; overturning and flotation for the load combinations shown in Standard Review Plan 3.8.5 for the major and typical seismic Category I buildings.

No change to the FSAR is required.

TABLE 220.35-1

REACTOR BUILDING

LOAD COMBINATION	FACTOR OF SAFETY AGAINST SLIDING	OVERTURNING	FLOATATION
D + H + E	>1.5	>2.69	-
D + H + E	>8.7	>21.7	-
$D + H + E^1$	1.23	2.69	-
$D + H + W_t$	8.7	21.7	-
$D + F^1$	-	-	3.12

D = Dead Loads

E = OBE

E^1 = DBE

W = Hurricance Wind @ 194 mph

W_t = Tornado Wind @ 300 mph

F^1 = Buoyancy, Max GWT EL + 21.00

H = Soil Pressure

TABLE 220.35-2

REACTOR AUXILIARY BUILDING

LOAD COMBINATION	FACTOR OF SAFETY AGAINST SLIDING	OVERTURNING	FLOATATION
D + H + E	1.35	2.64	-
D + H + E	3.88	4.14	-
D + H + E^1	1.16	2.15	-
D + H + W_t	2.84	3.15	-
D + F^1	-	-	2.35

D = Dead Loads

E = OBE

E^1 = DBE

W = Hurricance Wind @ 194 mph

W_t = Tornado Wind @ 300 mph

F^1 = Buoyancy, Max GWT EL + 17.00

H = Soil Pressure

TABLE 220.35-3

CONDENSATE STORAGE TANK

LOAD COMBINATION	FACTOR OF SAFETY AGAINST SLIDING	OVERTURNING	FLOATATION
D + H + E	>2.24	>2.54	-
D + H + E	>4.71	>3.93	-
$D + H + E^1$	2.24	2.54	-
$D + H + W_t$	4.71	3.93	-
$D + F^1$	-	-	5.90

D = Dead Loads

E = OBE

E^1 = DBE

W = Hurricance Wind @ 194 mph

W_t = Tornado Wind @ 360 mph

F^1 = Buoyancy, Max GWT EL + 17.00

H = Soil Pressure

Note:

Factors of safety for load combinations D+H+E and D+H+W will be higher than for $D+H+E^1$ and $D+H+W_t$ respectively.

TABLE 220.35-4

FUEL HANDLING BUILDING

LOAD COMBINATION	FACTOR OF SAFETY AGAINST SLIDING	OVERTURNING	FLOATATION
D + H + E	2.11	2.33	-
D + H + E	> 1.50	> 1.50	-
D + H + E^1	1.25	1.39	-
D + H + W_t	4.09	4.45	-
D + F^1	-	-	9.1

D = Dead Loads

E = OBE

E^1 = DBE

W = Hurricance Wind @ 194 mph

W_t = Tornado Wind @ 360 mph

F^1 = Buoyancy, Max GWT EL + 17.00

H = Soil Pressure

Note:

Dyn soil pressure > active soil pressure in calculations H is neglected and this is conservative.

TABLE 220.35-5

DIESEL GENERATOR BUILDING

LOAD COMBINATION	FACTOR OF SAFETY AGAINST SLIDING	OVERTURNING	FLOATATION
D + H + E	2.98	9.68	-
D + H + E	>7.45	>23.92	-
$D + H + E^1$	1.55	4.71	-
$D + H + W_t$	7.45	23.92	-
$D + F^1$	-	-	6.44

D = Dead Loads

E = OBE

E^1 = DBE

W = Hurricance Wind @ 194 mph

W_t = Tornado Wind @ 360 mph

F^1 = Buoyancy, Max GWT EL + 17.00

H = Soil Pressure

TABLE 220.35-6

COMPONENT COOLING

LOAD COMBINATION	FACTOR OF SAFETY AGAINST SLIDING	OVERTURNING	FLOATATION
D + H + E	>1.52	>4.16	-
D + H + E	>3.07	>12.68	-
$D + H + E^1$	1.52	4.16	-
$D + H + W_t$	3.07	12.68	-
$D + F^1$	-	-	3.11

D = Dead Loads

E = OBE

E^1 = DBE

W = Hurricance Wind @ 194 mph

W_t = Tornado Wind @ 360 mph

F^1 = Buoyancy, Max GWT EL + 17.00

H = Soil Pressure

TABLE 220.35-7

INTAKE STRUCTURE

LOAD COMBINATION	FACTOR OF SAFETY AGAINST SLIDING	OVERTURNING	FLOATATION
D + H + E	1.64	1.52	-
D + H + E	4.38	1.65	-
D + H + E^1	1.13	1.23	-
D + H + W_t	3.83	1.61	-
D + F^1	-	-	2.31

D = Dead Loads

E = OBE

E^1 = DBE

W = Hurricicance Wind @ 194 mph

W_t = Tornado Wind @ 360 mph

F^1 = Buoyancy, Max GWT EL + 16.00

H = Soil Pressure

Question No.

220.36 The load combinations listed in Subsection 3.8.4.3.2.1 are not in accordance with Standard Review Plan 3.8.4. Compare your load combinations and discuss the effects of your deviations.

Response

Refer to response to Question 220.29 for comparison of load combinations specified in SRP 3.8.4 and those used in the design of seismic Category I structures, statements of compliance, alternate compliance and remarks on impact of deviation.

Question No.

220.37 Identify all masonry walls in your facility which are in proximity to or have attachments from safety-related piping or equipment such that wall failure could affect a safety-related system. Describe the systems and equipment, both safety and non-safety-related, associated with these masonry walls. Include in your review, masonry walls that are intended to resist impact or pressurization loads, such as missiles, pipe whip, pipe break, jet impingement, or tornado, and fire or water barriers, or shield walls. Equipment to be considered as attachments or in proximity to be walls shall include, but is not limited to pumps, valves, motors, heat exchangers, cable trays, cable/conduit, HVAC ductwork, and electrical cabinets, instrumentation and controls.

Provide a re-evaluation of the design adequacy of the walls, identified above, to determine whether the masonry walls will perform their intended function under all postulated loads and load combinations.

Submit a written report upon completion of the re-evaluation program. The report shall include the following information:

1 - Describe, in detail, the function of the masonry walls, the configurations of these walls, the type and strengths of the material of which they are constructed (mortar, grout, concrete and steel), and the reinforcement details (horizontal steel, vertical steel, and masonry ties for multiple wythe construction). A wythe is considered to be (as defined by ACI Standard 531-1979) "each continuous vertical section of a wall, one masonry unit or grouted space in thickness and 2 in. minimum in thickness."

2 - Describe the construction practices employed in the construction of these walls and, in particular, their adequacy in preventing significant voids or other weaknesses in any mortar, grout, or concrete fill.

3 - The re-evaluation report should include detailed justification for the criteria used. References to existing codes or test data may be used if applicable for the plant conditions. The re-evaluation should specifically address the following:

a - All postulated loads and load combinations should be evaluated against the corresponding re-evaluation acceptance criteria. The re-evaluation should consider the loads from safety and non-safety-related attachments, differential floor displacement and thermal effects (or detailed justification that these can be considered self limiting and cannot induce brittle failures), and the effects of any potential cracking under dynamic loads. Describe in detail the methods used to account for these factors in the re-evaluation and the adequacy of the acceptance criteria for both in-plane and out-of-plane loads.

b - The mechanism for load transfer into the masonry walls and postulated failure modes should be reviewed. For multiple wythe walls in which composite behavior is relied upon, describe the methods and acceptance criteria used to assure that these walls, especially with regard to shear and tension transfer at the wythe interfaces. With regard to local loadings such as piping and equipment support reactions, the acceptance criteria should assure that the loads are adequately transferred into the wall, such that any assumptions regarding the behavior of the walls are appropriate. Include the potential for tensile stress transfer through bond at the wythe interfaces.

Existing test data or conservative assumptions may be used to justify the re-evaluation acceptance criteria if the criteria are shown to be conservative and applicable for the actual plant conditions. In the absence of appropriate acceptance criteria a confirmatory masonry wall test program is required by the NRC in order to quantify the safety margins inherent in the re-evaluation criteria. Describe in detail the actions planned and their schedule to justify the re-evaluation criteria. If a test program is necessary, provide your commitment for such a program and a schedule for submittal of a description of the test program and a schedule for completion of the program. This test program should address all appropriate loads (seismic, tornado, missile, etc). Submit the results of the test program upon its completion.

<u>Response</u>

This question is NRC Bulletin 80-11. A field inspection program and a design re-evaluation program were instituted and completed on St. Lucie 1 which addressed the requirements of IE Bulletin 80-11. A program, similar to St. Lucie 1, of field inspections and re-evaluation of design adequacy will be implemented on St. Lucie 2 as follows:

1. Perform field surveys of all masonry walls to identify all masonry walls which are in proximity to or have attachments from safety-related piping or equipment such that wall failure could affect a safety-related system..

2. Masonry walls identified by the field inspection program as safety-related will be re-evaluated to demonstrate their capacity to withstand the postulated design loads.

A re-evaluation report will be submitted upon the completion of the re-evaluation program. This report will include the information as requested by NRC. Justification for the re-evaluation criteria will be based on reference to effective codes and established standards of practice related to concrete and masonry design typically used throughout the industry. It is anticipated that such justification will be considered appropriate and a test program will not be necessary.

Masonry walls on St. Lucie 2 are reinforced and intended to resist seismic forces.

The duration of the re-evaluation program is six months. The erection of concrete block walls and installation of equipment adjacent to them should be sufficiently completed by November 1981. The re-evaluation program will then start. This will allow the field inspection portion of the re-evaluation program to be completed in one pass (survey).