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UHRIG,R.E. Florida Power & Light Co.
RECIP.NAME RECIPIENT AFFILIATION
EISENHUT,D.G. Division of Licensing

SUBJECT: Forwards addl info & responses to NRC questions for SER. Responses will be incorporated into future FSAR amend. All Repts

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FPL

FLORIDA POWER & LIGHT COMPANY

August 11, 1981
L-81-348

RECEIVED AUG 21 1981 U.S. NUCLEAR REGULATORY COMMISSION

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

Dear Mr. Eisenhut:

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

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

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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<u>Attachment to L-81-348</u>

A. Responses to Auxiliary Systems Branch draft SER open items.

B. Revised response to question 451.08

C. Draft FSAR writeup and supporting documentation for underground cable qualification.

D. Control Wiring Diagram supplied in support of the response to Chapter 8.3 open SER item on power lock out to MOV's.

E. Response to Chapter 8.3 open SER item on isolation devices.

F. Response to Chapter 8.3 open SER item on GDC 18

G. Response to Chapter 8.3 open SER item on MOV Thermal Overload Bypass.

H. Responses to open items from 8/11/81 meeting on Post Accident Sampling System.

I. Revised response to question 410.19

J. Draft Environmental Report sections on the use of TBTO.

K. Tables 1.9B-3 and 1.9B-4, Evaluation of ICC Detection Instrumentation.

L. Responses to Containment Systems Branch questions.

M. Response to question 492.10

N. Revised responses to question 440.25, 440.28. 440.38, 440.39, 440.41, 440.44, 440.51, 440.54, 440.58, 440.59, 440.61, 440.62

O. Confirmation on MSIV bonnet and seat thickness conservations from Rockwell International.

P. Response to open item No. 1 from the Structural Engineering Branch design audit.

8108240256

RESPONSES TO AUXILIARY SYSTEMS BRANCH
REQUESTS FOR INFORMATION TO COMPLETE
THE ASB DRAFT SER..

1. <u>Section 3.5.2 Structures, Systems, and Components to be Protected from Externally Generated Missiles</u>

The applicant has verbally committed to providing missile protection for the auxiliary feedwater cross-over piping between the steam trestles and outside of the missile barriers; however, documentation has not been provided. We will report resolution of this item in a supplement to this SER. This item also impacts Sections 10.3.1 and 10.4.9 of this SER.

<u>Response</u>

See attached amended response to Question 410.25.

Question No.

410.25 (10.3, 10.4.9) With regard to the main steam trestle, provide the following:

a) Verify that the main steam trestle is designed to seismic Category I and maximum tornado load requirements.

b) Provide a complete description, including arrangement drawings, of the main steam trestle area which illustrates how the following items are protected from turbine and tornado missiles.

(1) Main Steam Isolation Valve (MSIVs)
(2) Main Steam Safety Valves
(3) Atmospheric Dump Valves
(4) Main Steam Piping up to the MSIVs
(5) Safety-related portions of the main feedwater piping.

c) Provide detailed layouts of the auxiliary feedwater pump and piping areas to demonstrate how the main steam trestle provides support "for missile protection enclosing the Auxiliary Feedwater Pump rooms" (FSAR Subsection 3.8.4.1.9) and its protection from high energy line breaks (eg. main steam or main feedwater pipe breaks) and moderate energy pipe cracks.

Response

a) The main steam trestle is provided to house the safety-related components of the Main Steam, Feedwater, and Auxiliary Feedwater System. The trestle is designed to seismic Category I requirements and is capable of withstanding the maximum tornado loadings outlined in FSAR Section 3.5. The loading combinations for the main steam trestle are provided in FSAR Subsection 3.8.4.3.

b) The main steam trestle is comprised of two compartments CONNECTED by the AFW system cro... piping. which is located at the west end of the Reactor Building, The two trestle compartments are two totally enclosed structures which are physically separated from each other. Each trestle compartment houses the following equipment:

(1) One main steam Line
(2) One main steam isolation valve (MSIV)
(3) Eight main steam safety valves
(4) One main feedwater line
(5) Two main feedwater isolation valves (MFIV's)
(6) Two atmospheric dump valves (ADV's)
(7) Two motor driven aux. feedwater pumps or one steam driven aux. feedwater pump (with associated piping and valves).

THE crossover piping is ENclosED by A one wch STEEL plate which provides protection against all postulated missles

Each of the two compartments of the testle is approximately 31 feet wide, 45 feet long and extends vertically from grade level to Elevation 62'-0". Three sides of the main steam trestle are completely enclosed with a one inch steel plate along the entire vertical run with a nine inch opening left on the base perimeter to provide for natural ventilation. The fourth side utilizes the containment structure as a missile barrier and is recessed several feet from the containment in order to provide adequate ventilation. The roof of the trestle structure utilizes a steel grating (several inches thick) for missile protection purposes. The openings in this grating have been designed to inhibit the smallest missile provided in FSAR Section 3.5 and to provide sufficient main steam Mass and Energy blowdown area to accommodate a main steam line break outside the containment.

c) Detailed layouts of the Auxiliary Feedwater Pump and piping arrangements are provided in FSAR Figures 10.4-14, 15 and 16. The motor driven auxiliary feedwater pumps are physically separated from the turbine driven pump by two one (1) inch steel plates. These plates provide adequate protection against the dynamic effects of a high energy line break. The dynamic effects associated with pipe rupture and jet impingement is provided in FSAR Section 3.6.

2. <u>Section 3.6.1 Plant Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment</u>

The applicant has not provided sufficient information necessary to demonstrate that a postulated high energy pipe break or moderate energy pipe crack will not cause a loss of function of any safety related system. The applicant has not provided sufficient information to adequately demonstrate that flooding due to failure of non-seismic Category I tanks will not adversely affect safety related equipment. We will report resolution of this item in a supplement to this SER. This item also impacts Sections 9.3.3, 10.3.1, 10.4.5, 10.4.7, and 10.4.9 of this SER.

<u>Response</u>

FP&L has formally submitted the above input via letter dated L-81-334 dated August 4, 1981.

3. <u>Section 9.1.3 Spent Fuel Pool Cooling and Cleanup System</u>

The applicant has verbally committed to the installation of a second spent fuel pool cooling system heat exchanger by the first refueling of Unit 2. Documentation to confirm the verbal commitment is required. We will report resolution of this item in a supplement to this SER.

<u>Response</u>

See attached amended FSAR page 9.1-10 adding the commitment for the applicant to add a second fuel pool heat exchanger.

lated by the fuel pool pumps through the fuel pool heat exchanger where heat is rejected to the Component Cooling Water System. From the outlet of the fuel pool heat exchanger, the cooled fuel pool water is returned to the bottom of the fuel pool via a distribution header. The cooling system is controlled manually from a local control panel. Control room alarms for high fuel pool temperature, high and low water level in the fuel pool, low fuel pool pump discharge pressure and, as discussed in Subsection 9.1.2, a high radiation in the fuel pool area, are provided to alert the operator to abnormal circumstances. Radiation monitoring for spent fuel pool area and Fuel Handling Building stack is discussed in Section 11.5. The components and piping are Quality Group C, seismic Category I.

9.1.3.2.2 Fuel Pool Purification

The clarity and purity of the water in the fuel pool, refueling cavity and refueling water tank are maintained by the purification portion of the fuel pool system. The purification loop consists of a fuel pool purification pump, fuel pool filter, fuel pool purification pump suction strainer, fuel pool ion exchanger, fuel pool skimmer, fuel pool ion exchanger strainer, associated valves, and piping. Most of the purification flow is drawn directly from the fuel pool. A small fraction of the purification flow is drawn through the fuel pool skimmer. A strainer is provided in the purification line to the fuel pool purification pump suction to remove particulate matter before the fuel pool water is pumped through the fuel pool filter and the fuel pool ion exchanger. The fuel pool water is circulated by the fuel pool purification pump through the fuel pool filter, which removes particulates larger than five micron size, then through the fuel pool ion exchanger to remove ionic material, and finally through a "Y" type fuel pool strainer.

Connections to the refueling water tank provide makeup to the fuel pool through the purification loop. In addition to purifying the fuel pool water, the refueling water tank and the refueling transfer canal are cleaned through connections to the purification loop. Fuel pool water chemistry is given in Table 9.1-4. The purification loop components and main process piping are Quality Group C, non-seismic.

9.1.3.2.3 Component Description

The major compnents of the Fuel Pool System are described in this section. The principal component data summary is given in Table 9.1-6.

a) Fuel Pool Heat Exchanger

The fuel pool heat exchanger is a horizontal shell and tube design with a two-pass tube side. A slight pitch, three degrees above the horizontal, is provided for complete draining of the fuel pool heat exchanger. The component cooling water circulates through the shell side, and fuel pool water circulates through the tube side. The internal wetted surface (tube side) is stainless steel. The applicant has committed to adding a second fuel pool heat exchanger by the first refueling.

4. <u>Section 9.1.4 Fuel Handling System</u>

We require that the applicant implement the interim actions identified in Enclosure 2 of the generic NRC letter dated December 22, 1980, con-concerning NUREG-0612 "Control of Heavy Loads at Nuclear Power Plants" prior to receipt of an operating license and prior to full implementation of NUREG-0612. The applicant indicated that the bulkhead gates (one between the cask pool and the spent fuel pool and the other between the spent fuel pool and the fuel transfer canal) are seismic Category I. Documentation to confirm the verbal commitment is required. We will report resolution of these items in a supplement to this SER.

<u>Response</u>

The six month response to the NRC December 22, 1980 letter was issued to the NRC via FP&L letter L-81-338 dated August 6, 1981 (Uhrig to Eisenhut).

See attached amended FSAR page 9.1-6 adding the fact that the removable bulkheads in the spent fuel storage pool are designed to seismic Category I requirements.

kinetic energy associated with the dropped fuel assembly is 29,000 in-lb.
This energy is conservatively assumed to be totally absorbed by one rack
module. Structural deformations of the racks are limited to preclude any 0
possibility of criticality.

The structural design also precludes the possibility of a fuel assembly being placed in the spaces between the fuel cavities.

Adequate clearance is provided between the top of the stored fuel assembly 0
and the top of the rack to preclude criticality in the event a fuel as-
sembly is dropped and lands in the horizontal position on the top. Rack
design also ensures adequate convection cooling of a fuel assembly lying
horizontally across the top of the racks.

The spent fuel storage racks are designed in accordance with the AISC
Specifications and the load combinations and allowable stresses specified 0
in Subsection 3.8.4.3 for seismic Category I steel structures.

The direct dose rate at the pool surface when not refueling is less than 0
2.5 mrem/hr. This dose rate is based on the most active fuel assembly two days after shutdown. During refueling the limit switches prevent the spent fuel handling machine from raising the spent fuel assembly above a height where less than nine ft. of water provides minimum radiation shielding. If the interlock should fail and if there were no operator action, the fuel handling machine cannot raise the assembly above a nine ft. water-to-active-fuel-length height because of the design geometry. Under the conditions described above, the dose rate at the surface of the water above the assembly would be still less than 2.5 mrem/hr. The grappling tool on the spent fuel handling machine is designed so that a fuel assembly cannot be released accidentally. The shielding provided in the Fuel Handling Building is discussed in Subsection 12.1.2.4.

A concrete wall to elevation 62 ft. separates the cask storage area from the spent fuel storage area. The wall prevents the water level from uncovering the spent fuel assemblies even if a dropped fuel cask causes damage to the pool or pool liner in the cask storage area. Removable Bulk heads ~~doors~~ are provided in the separating walls between the spent fuel storage pool and the cask storage area and the refueling canal. These ~~doors~~ bulkheads are designed to seismic Category I requirements.

The fuel enrichment selected for determination of the safe geometry is 3.7
percent. This is substantially higher than the enrichment for the initial
and future cores. In the analysis to determine allowable edge-to-edge
spacing, infinite arrays of fuel assemblies are assumed. The analysis of the
spent fuel storage rack design uses the CHEETAH-P[1]/PDQ-7[2] model as
the basic engineering tool. CHEETAH-P is the PWR lattice version of 0
Nuclear Associates International (NAI) CHEETAH code which is a modified
version of the original LEOPARD code[3] and uses a modified ENDF/
B-II[4] cross section library. The PDQ-7 program is the well-known few-
group spatial diffusion theory code widely used by the industry. The
CHEETAH-P/PDQ-7 model has been extensively tested by NAI by means of bench-
marking calculations for several existing operating power reactors.

CHEETAH-P determines a multigroup neutron spectrum for a given homogeneous mixture of materials and uses this spectrum to weigh the cross sections and provide average few group cross sections. PDQ-7 uses as input the cross

5. Section 10.4.7 Condensate and Feedwater Systems

The applicant has not committed to performing a water hammer test in accordance with Branch Technical Position ASB 10-2. We require the water hammer test. We will report resolution of this item in a supplement to this SER. This item also applies to Section 10.4.9 of this SER.

Response

A number of paragraphs were inadvertently omitted from the response to FSAR question 410.27. See attached page for amended response. In addition, FP&L letter L-81-318 dated July 27, 1981 (Uhrig to Eisenhut) provided justification for the applicant's position that steam generator water hammer testing need not be performed on St. Lucie Unit 2 (letter attached).

Question No.

410.27
(10.4.7)

State how Branch Technical Position ASB 10-2, "Design Guidelines for Water Hammers in Steam Generators with Top Feeding Designs" is met. Discuss the design features to minimize water hammer and the confirmatory tests to be performed.

Response

The feedwater piping and feedring have been designed to eliminate or minimize the cause and effects of possible water hammer in the feedwater system.

Feedwater enters the steam generator through the feedwater nozzle where it is distributed via a feedwater distribution ring. The feedwater ring has been constructed to include discharge nozzles called "J" tubes which are welded to the top of the ring (see Figures 5.4-6, 16, and 17 of the FSAR). This construction reduces the rate at which the feedwater ring drains, helping to provide assurance that the ring remains full of water. Thus, the probability of significant amounts of steam entering the feedring is greatly reduced, thereby minimizing the condition which can lead to water hammer.

In addition, the length of horizontal feedwater piping immediately external to the steam generator which could pocket steam is minimized (2 1/2 feet). This short length of horizontal piping has a downward sloping 90° elbow followed by approximately 32 feet of vertical feedwater piping. This piping arrangement minimizes the drainable volume of feedpipe. Hence, when the feedring and piping are drained and steam enters this region, the exposed surface of subcooled water to saturated steam is minimized.

The minimization of the exposed surface of subcooled water to the saturated steam reduces the depressurization of the steam space by slowing the rate of steam condensation on the subcooled water. The pressure pulses generated by a water slug in the piping are initiated by steam-water interaction which causes ripple formation at the steam-water interface. This results in the formation of a water slug which isolates the steam in the feedpipe. As the isolated steam condenses, pressures in the region falls and the water slug accelerates towards it. The kinetic energy in the slug keeps increasing until the steam bubble is collapsed. At this moment, the water slug impacts with the water filling the upstream side of the pipe and pressure pulses are generated.

Insert A

Insert "A"

Also note, that since only a small amount of steam can be trapped in a 90 degree elbow, a steam bubble will collapse before the water slug gains significant kinetic energy during a steam-water interaction.

Consequently, by introducing the combination of a short length of horizontal piping and the "J" tube design on the top of the feed-ring, the intensity of the pressure pulses generated (water hammer) is reduced to negligible levels.

St Lucie Unit 1 has conducted extensive feedwater hammer testing. A review of the Feedwater Piping drawing and Steam Generator internal indicates that St Lucie Unit 1 and St Lucie Unit 2 are virtually assembly. Based on this review and the testing performed on St Lucie Unit 1, the applicant concludes that additional feed-water hammer testing is not required for St Lucie Unit 2.

Section 10.4.9 of the FSAR has been revised to include the above response along with revisions for automatic initiation of the Auxiliary Feedwater System.

P.O. BOX 529100 MIAMI, FL 33152

FLORIDA POWER & LIGHT COMPANY

1981

E. Z. [illegible]

July 27, 1981
L-81-318

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

Dear Mr. Eisenhut:

Re: St. Lucie Unit 2
Docket No. 50-389
Steam Generator Water Hammer Testing

At a June 17, 1981 meeting with Olan Parr et al, Florida Power & Light Company (FPL) agreed to provide justification for our position that steam generator water hammer testing need not be performed on St. Lucie Unit 2.

A steam generator water hammer test program was conducted on St. Lucie Unit 1 with no water hammer observed. The NRC, in a Safety Evaluation Report issued February 7, 1980, concluded that steam generator water hammer was not likely to occur at that facility.

The St. Lucie Unit 1 and 2 piping arrangements are essentially identical. Isometric drawings of both units were compared, and dimensional differences were measurable in fractions (e.g., the horizontal sections of piping entering the steam generator, which are the sections of piping most likely to experience water hammer, are all equal in length (two feet long), with one section on Unit 1 3/8 inch shorter than on Unit 2).

The preoperational test program will verify the adequacy of the design. Preoperational test procedures 2-0700091, "Auxiliary Feedwater Pumps 2A, 2B, and 2C Initial Run", and 2-0700081, "Auxiliary Feedwater System Functional and Endurance Test", will verify that the pumps meet or exceed the manufacturers head/flow curves and associated manual controls and alarms function as required, and also verify automatic operation of the system following an actuation signal. The functional test will be performed prior to hot functional testing of the unit. FPL intends to station an operator inside containment during the initial injection phase to monitor for water hammer. Also, FPL will have a vibration monitoring program during the St. Lucie Unit 2 startup, and piping vibration will be measured.

FPL is reviewing the San Onofre steam generator feed ring collapse incident and will inform you if any change in our position on steam generator water hammer testing for St. Lucie Unit 2 is required.

Very truly yours,

Robert E. Uhrig
Vice President
Advanced Systems & Technology

REU/TCG/ah

cc: J.P. O'Reilly, Director, Region II
Harold F. Reis, Esquire

ST. LUCIE UNITS 1 & 2
NRC CORRESPONDENCE
SL-

LT		
RM		
CJB		
EZZ		✓
RJH		✓
PES		
JBH		
GK		
DC		✓
[illegible]		✓
[illegible]		✓
[illegible]		✓

Note! NRC requested justification as to why feedwater hammer testing was not required on SL-2.

6. Section 10.4.9 Auxiliary Feedwater System & Post TMI Task II.E.1.1

The following items pertain to Section 10.4.9 of the SER, "Auxiliary Feedwater System," for which documentation is required as indicated for items a, b, and c.

a. The Unit 2 condensate storage tank includes a dedicated water volume for Unit 2 auxiliary feedwater system in the event of tornado missile damage to the Unit 1 condensate storage tank. There are locked closed valves in the parallel connecting lines. The applicant has not provided the procedures delineating when these locked valves will be opened.

b. The applicant has not provided the results of an analysis of the effects of a potential failure of the Unit 1 condensate storage tank and the most severe failure or operator error on Unit 1 or 2 resulting in draining the Unit 2 condensate storage tank below the Unit 2 dedicated volume.

c. Additional Short Term Recommendation 2 - The applicant has not committed to providing a copy of the pump endurance test results specified in this recommendation. We require that these results be provided.

d. Our review is not complete with respect to the minimum dedicated water supply for the auxiliary feedwater system, the minimum flow requirements, and the reliability analysis.

e. Additional Short Term Recommendation 3 - The design for emergency feedwater flow indication is under review by the Instrumentation and Control Systems Branch as part of item II.E.1.2 of NUREG-0737 and will be reported in a separate evaluation.

f. Long Term Recommendation GL-5 - The design for emergency feedwater automatic initiation is under review by the Instrumentation and Control Systems Branch as part of Item II.E.1.2 of NUREG-0737 and will be reported in a separate evaluation.

Response

a, b and c: See attached revised FSAR pages.
d, e and f: NRC Action.

A) FPL intends to perform the Auxiliary Feedwater Endurance Test as part of Preoperational Test No. 2-0700081, "Auxiliary Feedwater System Functional and Endurance Test."

B) FPL will modify the St. Lucie Unit 2 FSAR, Section 10.4.9.4 to reflect Endurance Testing and Section 14.2.12.1.4E to address the specifics of Ref. (a). Attached please find copies of the proposed FSAR modifications.

C) FPL will provide the NRC (after completion of Preoperational Test No. 2-0700081 results review), a summary of the Endurance Test consisting of the following:

1) Description of the test.

2) Plots of bearing temperature -vs- time.

3) Plots of Pump Room Temperature (Environment) -vs- Time.

4) A statement confirming that pump vibration did not exceed allowable limits.

5) Plot of observed pump performance (pump flow, head, speed, and stem temperature) on the vendor supplied specific equipment performance curves.

Equipment is "Qualified" for 100% humidity therefore humidity will not be monitored.

TABLE 10.4.9A-4 (Cont'd)

ACCEPTANCE CRITERIA	COMPLIANCE
Recommendation - The licensee should perform a 72 hour endurance test on all AFW system pumps, if such a test or continuous period of operation has not been accomplished to date. Following the 72 hour pump run, the pumps should be shut down and cooled down and then restarted and run for one hour. Test acceptance criteria should include demonstrating that the pumps remain within design limits with respect to bearing/bearing oil temperatures and vibration and that pump room ambient conditions (temperature, humidity) do not exceed environmental qualification limits for safety related equipment in the room.	A 48 hour endurance test will be performed on the Auxiliary Feedwater pumps. Test results will be submitted to the NRC.
11) 5.3.3 Indication of AFW Flow to the Steam Generators	
Concern - Indication of AFW flow to the steam generators is considered important to the manual regulation of AFW flow to maintain the required steam generator water level. This concern is identical to Item 2.1.7.b of NUREG-0578.	
Recommendation - The licensee should implement the following requirements as specified by Item 2.1.7.b on page A-32 of NUREG-0578: (1) Safety-grade indication of AFW flow to each steam generator should be provided in the control room. (2) The AFW flow instrument channels should be powered from the emergency buses consistent with satisfying the emergency power diversity requirements for the AFW system set forth in Auxiliary Systems Branch Technical Position 10-1 of the Standard Review Plan, Section 10.4.9.	Safety grade Auxiliary Feedwater flow indication and safety grade, redundant steam generator level indication is available to the operator in the control room. These instrument loops are powered by the 120V ac Class IE power source.
12) 5.3.4 AFW System Availability During Periodic Surveillance Testing	
Concern - Some plants require local manual realignment of valves to conduct periodic pump surveillance tests on one AFW system train. When such plants are in this test mode and there is only one remaining AFW system train available to respond to a demand for initiation of AFW system operation, the AFW system redundancy and ability to withstand a single failure are lost.	
Recommendation - Licensees with plants which require local manual realignment of valves to conduct periodic tests on one AFW system train and which have only one remaining AFW train available for operation should propose Technical	Not applicable. Local manual realignment of valves to conduct periodic pump surveillance tests on AFS trains is not required.

4

i) The AFWS is designed to withstand pipe rupture effects (see Section 3.6).

10.4.9.2 System Description

During normal operation, feedwater is supplied to the steam generators by the Feedwater System. The Auxiliary Feedwater System (AFWS) is utilized during normal plant startup, hot standby, and cooldown. During plant startup and hot standby, the system provides a source of water inventory for the steam generators. During cooldown, the AFWS provides a means of heat removal to bring the Reactor Coolant System to the shutdown cooling system activation temperature. With offsite power and the main condenser available, the condenser will be used as a heat sink. The AFWS system is not utilized during full power operation.

The major active components of the system consist of one steam driven pump with greater than full flow capacity and two full flow capacity motor driven 4
auxiliary feedwater pumps. Both electrical and steam driven AFWS pumps are centrifugal units with horizontal split casings and are designed in accordance with ASME Code, Section III and Quality Group C requirements. The larger pump is driven by a noncondensing steam turbine. The turbine receives steam from the main steam isolation valves, and exhausts to the atmosphere. The pumps take suction from the condensate storage tank and discharge to the steam generators. The turbine-driven pump is capable of supplying auxiliary feedwater flow to the steam generators for the total expected range of steam generator pressure by means of a turbine driver controlled by a variable 4
speed mechanical governor.

Each motor-driven pump supplies feedwater to one steam generator. A cross connection is provided to enable the routing of the flow of the two motor-driven pumps to one steam generator. The turbine-driven pump supplies feedwater to both steam generators by means of two with its own control valve and each sized to pass the full flow. The control of auxiliary feedwater flow and steam generator level is accomplished by means of control room operated control valves. Local control stations are also provided. Each of the motor driven auxiliary feedwater pumps utilize a Class IE ac power supply (4.16 kV safety related bus). The turbine driven pump train relies strictly on a dc power supply.

10.4.9.3 Safety Evaluation

The AFWS removes sensible and decay heat from the Reactor Coolant System during hot standby and cooldown for initiation of shutdown cooling. For events in which main feedwater flow is unavailable, (e.g., loss of main feedwater pump, loss of offsite power, and main steam line break), the AFWS is automatically initiated to provide hot standby and/or cooldown heat removal.

The condensate storage tank (CST) discussed in Subsection 9.2.6, provides 4
the water supply for the Auxiliary Feedwater System. The CST is sized to provide ~~150,400~~ gallons of demineralized water for St Lucie Unit 2 for hot standby and cooldown operations; an additional ~~150,400~~ gallons is reserved in the St Lucie Unit 2 CST only for the unlikely event that a

149,600 125,000

tornado missile somehow ruptures the St Lucie Unit 1 CST and the water contained therein (116,000 gallons per St Lucie Unit 1 Technical Specifications) is unavailable to St Lucie Unit 1. When no tornado warnings are in effect, the St Lucie Unit 2 total capacity of 300,800 gallons is available if needed. This minimum capacity accounts for the following volume:

Insert A →

The quantity of water required for St Lucie Unit 2 cooldown has been determined assuming a worst case condition wherein the unit is brought to hot standby conditions and held there for approximately two hours then cooled down at the maximum rate until the shutdown cooling window is reached. Under this scenario, each Auxiliary Feedwater Pump has the capability of achieving an orderly shutdown consisting of two hours of hot standby followed by a regulated cooldown to the shutdown cooling entry point within the next five hours. The quantity of condensate required for this scenario is approximately 129,000 gallons as shown on Table 10.4-2 (Case 2). 4

The condensate storage requirements for the Auxiliary Feedwater System were compared with the requirements of Regulatory Guide 1.139 "Guidance for Residual Heat Removal System". Under this scenario, the unit is brought to hot standby conditions and held there for four hours then cooled down at the maximum rate of 75F/hour until the shutdown cooling window of 350F is reached. The condensate storage requirement for this scenario is 149,600 gallons as shown on Table 10.4-2 (Case 1)and Figure 10.4-9.

During emergency blackout conditions (except the hypothetical tornado missile which drains the St Lucie Unit 1 CST) there is sufficient water in the CST to allow hot standby operation for 16 hours and a subsequent cooldown to 350 F over four hours (see Figure 10.4-10). The condensate requirements and the auxiliary feedwater flow rate basis is discussed in FSAR Appendix 10.4.9A.

The steam generated during decay heat removal and cooldown after a loss of offsite power will be discharged through the atmospheric dump valves, except for the steam used by the turbine driven auxiliary feed pump. There are two ac/dc motor operated atmospheric dump valves (ADVs) located on each main steam line. The ADV's are capable of automatic modulating service using ac power and are capable of open/close service from the control room 0 using dc power only. Each ADV is sized to pass 50 percent of the flow required to bring the Reactor Coolant System to the shutdown cooling system entry temperature, assuming that only ~~125,000~~ 129,000 gallons of condensate is available from the condensate storage tank.

The auxiliary feedwater pumps are located underneath [illegible] steam trestle. The AFWS is designed to withstand natural phenomena as described in Sections 3.3 and 3.5. The condensate storage tank is a s[illegible] Category I structure. It is surrounded by a structural barrier whic[illegible] ovides missile and tornado protection for the tank. Components in the AFWS are protected from flooding as components are located above the probable maximum flood level (refer to Section 3.4). The design provisions utilized to protect the AFWS against the dynamic effects of pipe rupture and jet impingement effects are provided in Section 3.6. The Auxiliary Feedwater System piping layout and the steam trestle configuration is provided in Figures 10.4-14, 4
10.4-15 and 10.4-16.

EBASCO SERVICES INCORPOR ED

NEW YORK

BY______ DATE______ SHEET____ OF____

CHKD. BY______ DATE______ OFS NO.______ DEPT. NO.______

CLIENT______

PROJECT______

SUBJECT______

Insert A

Unusable Volume

All water stored below a line 8 inches above the suction point is considered unusable. This quantity of 9,400 gallons is considered in the determination of the minimum required stored volume. No credit is taken for the height of water in the tank in the evaluation of the Net Positive Suction Head available to the Auxiliary Feedwater Pumps.

Unit 1 Shutdown Volume

A volume of 125,000 gallons is maintained for use by Unit 1 in the event the SL-1 CST is ruptured by a tornado missile. This amount is more than sufficient for shutdown purposes. Unit 1 Tech Spec level is 116,000 gallons.

Unit 2 Shutdown Volume

A volume of 149,600 gallons is maintained to shutdown Unit 2 as outlined below.

Instrument Error

Although instrumentation error is expected to be no greater than 1%, a conservative margin of 5% of the instrument range (21,400 gallons) has been added to the total of the above volumes.

Working Volume

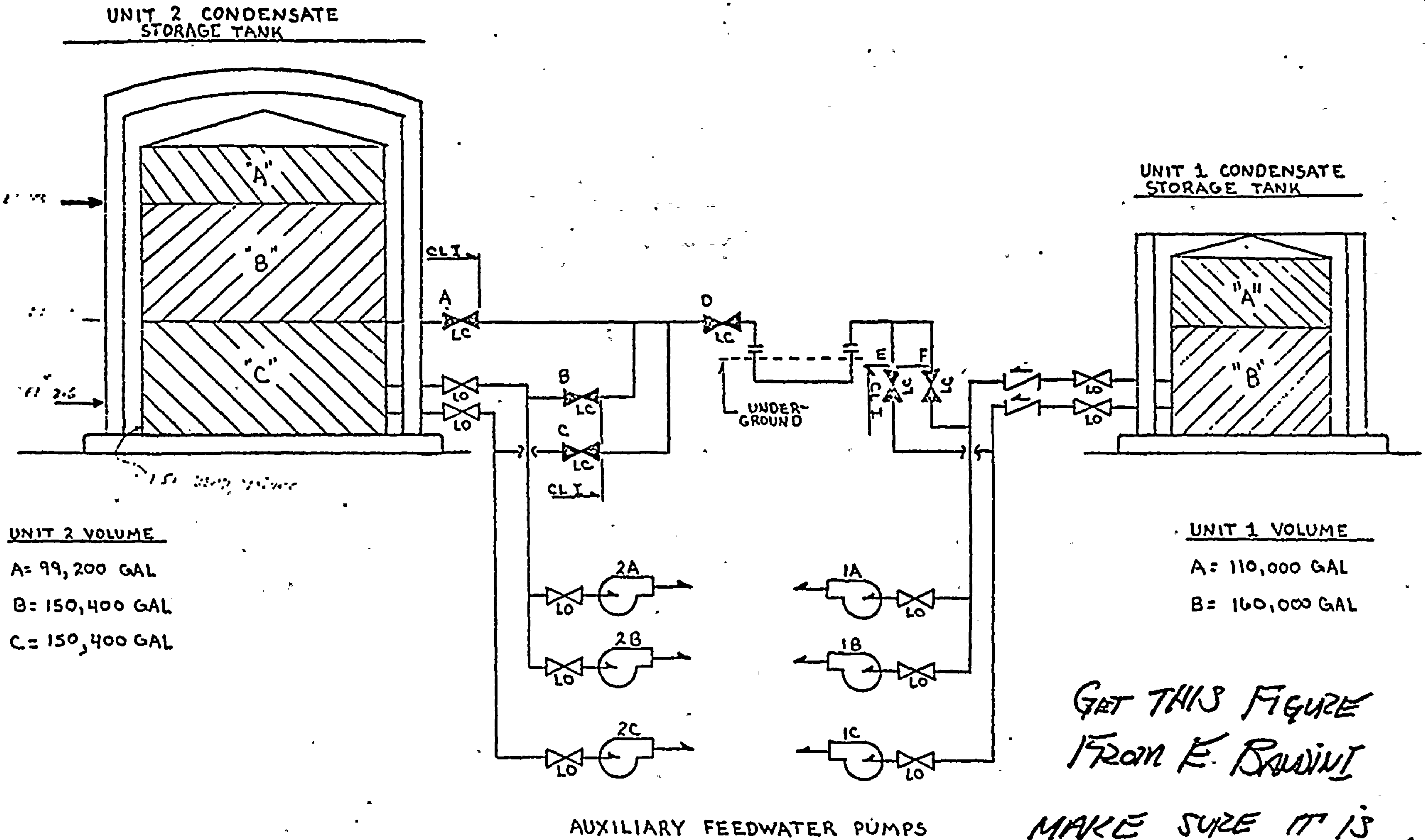
The total of the above volumes, including allowance for instrumentation error, amounts to 305,400 gallons. The minimum stored volume is 307,000 gallons. Approximately 10 feet of usable tank volume remains for operating purposes.

FORM 581 REV 7-71

INSERT AFTER SECOND PARA. OF 10.4.9.3

INSERT (A) (con't)

The Consdensate Storage Tanks (CST) are intertied between Units 1 and 2. Each CST is a seismic Category 1, Safety Class 3 structure designed to store sufficient water to bring each plant from power operation to the inititation of shutdown cooling conditions. The Unit 2 tank is located within a concrete structure designed to withstand the DBE and the impact of tornado missiles. The Unit 1 tank, which has been designed to withstand the DBE and horizontal missiles, is not provided with protection from the vertical missiles. In the unlikely event that a tornado missile ruptures the Unit 1 CST, an intertie with the Unit 2 tank is provided. The Unit 2 CST, which stores sufficient condensate to cool down both plants, can be connected directly with the suctions of the Unit 1 Auxiliary Feedwater Pumps. Should Unit 1 require condensate before Unit 2, valves A, D, E & F could be opened. The location of the nozzle on the Unit 2 tank insures that the Unit 2 supply of condensate is not compromised while at the same time providing sufficient coolant for Unit 1. Alternately, if Unit 2's condensate had been previously consumed, valves B, C, D, E & F are opened to supply Unit 1. Check valves are placed in the Unit 1 suction lines between the tank and the interties to prevent the backflow of condensate to a ruptured tank. The provision of redundant locked closed manual valves precludes the accidental loss of condensate. The entire intertie line that runs between the Units is buried, thereby providing protection from the effects of tornado missiles.



UNIT 2 VOLUME

A= 99,200 GAL

B= 150,400 GAL

C= 150,400 GAL

UNIT 1 VOLUME

A= 110,000 GAL

B= 160,000 GAL

GET THIS FIGURE FROM E. BAUINI

MAKE SURE IT IS REFERENCED SOMEWHERE

UNIT 1 - UNIT 2 CONDENSATE STORAGE TANK INTERTIE

Additional request for information regarding the trestle grating missile protection.

Response - See amended FSAR page 3.5-40

TABLE 3.5-3 (Cont'd)

Equipment	Location Bldg/Elevation (ft)	FSAR System Description	FSAR Figure	Enclosure
Atmospheric Dump Valves Main Steam Isolation Values FW Isolation valves Main Steam Safety Values	Steam Trestle Area/ +36.0	10.4.9 10.3 10.4.7	10.1-1	~~Under design~~ North - 1" steel plate A36 South - 1" steel plate A36 East - 36" reinforced concrete wall West - 1" steel plate A Top - A36 Grating Bearing Bar thickness 3/8" Cross Bar - thickness 1/4" Bearing Bar Depth 7" Cross Bar Depth 1 1/4" Opening Size 1" x 1 3/4"

Revision #1
8/3/81

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 meteorological 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 the 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.

The magnitude of the terrain/recirculation factors presented in Table 2.3-102 for large distance from the source are expected and appropriate due to the physical processes involved and the nature of the two models. Because of the lack of major terrain considerations and the general persistence of the sea breeze circulations at coastal sites in Florida, 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, but not unreasonable, than the values calculated closer to the source of the meteorological data.

d) Emergency Core Cooling System piping

e) control rod drive mechanisms

f) fuel assemblies and spacer-grids

g) reactor internals

h) reactor cavity shield walls

i) secondary shield walls

1.9.4 LOW TEMPERATURE OVERPRESSURE PROTECTION (LTOP)

Low temperature overpressure protection will be provided via the installation of power-operated relief valves (PORVs) qualified for both saturated steam and liquid relief service. The PORVs will be sized to accommodate the pressure transient associated with a Controlled Rod Withdrawal 1
and also (at the low pressure setpoint) to mitigate the pressure transient resulting from either a spurious initiation of safety injection, or a reactor coolant pump start with an excessive temperature difference between the RCS and the steam generator. The final design is described 1
in Subsection 5.2.6. Corresponding transients analyses will be provided in Section 15.8 early in 1981.

1.9.5 HYDROLOGICAL DATA

As discussed in Section 2.4, additional information for Hutchinson Island is being evaluated, on the separate subjects of further tide data and 0
possible potable well locations. An amendment to Section 2.4 will be filed on or about March 1981 incorporating the relevant information.

1.9.6 UNDERGROUND CABLE REVIEW

Kerite insulated power and control cables have been reviewed and approved 0
by the NRC for underground wet/dry environmental qualification[9]. ~~Information on the~~ Underground ~~instrumentation~~ cables ~~will be submitted in an~~ 0
~~amendment to Section 8.3 on or about February 1981.~~ is discussed in Subsection 3.11.6.

1.9.7 ENVIRONMENTAL AND SEISMIC QUALIFICATION OF CLASS 1E EQUIPMENT 0

In mid-1978 the NRC issued a letter[10] requesting additional information on Class 1E equipment qualification. Sections 3.10 and 3.11 have been organized to provide the requested information on seismic and environmental qualification test results. However, at the date of tendering the FSAR several vendors' qualification test summaries and reports of results are still being generated and have not yet been received. Therefore, amendments to Sections 3.10 and 3.11 will be filed periodically in order to provide the necessary information and also to provide results of relevant analyses when available.

Per a memorandum and order issued on May 23, 1980[11], the NRC has 0
ordered applicants for operating licenses to meet the requirements of

integrated radiation exposure combining 40 years normal operation and the required term of functionality during the post design basis accident (DBA) period (up to 1 year). Tables 3.11-1 present the design parameters for radiation for each specified environmental condition.

The normal operations exposure dose for equipment is either derived more explicity from the design source terms presented in Chapter 11 taking account of equipment arrangement and shielding configuration, or based on the maximum dose rate anticipated for the radiation zone in which the equipment is generally located. See Section 12.3 and the zonal dose maps on Figures 12.3-4 through 12.3-12. For equipment in lower radiation zones (I & II) the cumulative 40 year exposure is conservatively taken as 10^3 Rads. For Zone V equipment with a few exceptions, (the CVCS ion exchanger, spent resin tank, spent fuel transfer tube and volume control tank) the dose rate is 100 R/hr. For the aforementioned exceptions, the design dose rate is higher than 100 R/hr.

The DBA exposure dose affecting ESF systems and associated safety related components is dependent on equipment location. The DBA considered for the containment, Reactor Auxiliary, Turbine, and Diesel Generator buildings is the postulation of a LOCA in accordance with the recommendations of TID-14844[3] and Regulatory Guide 1.4, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors", June 1974 (R2). The DBA affecting equipment in the Fuel Handling Building is based on the postulation of a fuel handling accident.

The few organic materials that exist within the containment are discussed in Subsection 6.1.2.

The radiation exposure dose rates given in Table 3.11-1 is based on gamma radiation exposure. It is recognized that the beta energy release from noble gases is as much as 2.5 times greater than the gamma energy release within 30 days post accident.[4] However a representative cable geometry inside containment has protective cover sheathing the insulation layer and an overall cover of fire protective Flamemastic or equivalent. Therefore the integrated beta radiation dose for a one year post accident period is less than 10 percent of the integrated gamma radiation dose over the same period. This comparison includes the conservative assumption of comparing effective 2.2 Mev betas with effective 2.2 Mev gammas and assumes a spherical cloud, radius 40 ft, of airborne nuclides. Other components inside containment are considered sufficiently shielded from beta radiation since it is effectively attenuated by only a few mills thickness of metal. Therefore based on the aforementioned discussion beta radiation is not considered an environmental qualification problem.

3.11.6 SUBMERGED CABLES

Safety related cables located outdoors that could be submerged in water are qualified for operability under submerged conditions. Data on environmental qualification of Okonite Company and Kerite Company cable used ~~for~~ underground and exposed to wet/dry environment has been submitted under separate cover to the NRC.[5]

SECTION 3.11: REFERENCES

(1) D B Vassalo (NRC) letter to Dr. R E Uhrig (FPL), "Environmental and Seismic Qualification of Class IE Equipment" dated July 28, 1978.

(2) Dr. R E Uhrig (FPL) letter L-78-334 to D B Vassalo (NRC) dated October 16, 1978.

(3) J J Di Nunno, F D Anderson, R E Baker and R L Waterfield, "Calculation of Distance Factors for Power and Test Reactor Sites," TID-14844, USAEC, March 23, 1962.

(4) 1976 ANS Paper: "In-containment Radiation Environments following the Hypothetical LOCA (LWR)."

(5)

To be filled in once FPL sends letter to NRC

FLORIDA POWER & LIGHT COMPANY
ST LUCIE UNIT 2
DOCKET 50-389

ENVIRONMENTAL DATA FOR UNDERGROUND CABLE EXPOSED TO WET/DRY ENVIRONMENTS

I. Types of Cables Used In Underground Ducts

Two cable vendors supply cables for use in underground ducts. They are the Okonite Company and the Kerite Company. Okonite supplies 5KV & 15KV power cable. Kerite supplies 600V power, control and instrumentation cable.

The 5KV and 15KV power cables are insulated with unfilled cross linked polyethylene, wrapped with an extruded layer of semiconducting insulation shield material compatible with the insulation, and covered with a lead sheath and a heavy duty overall neoprene jacket.

The 600V power cables are insulated with a high temperature Kerite insulation (HTK) and covered with black heavy duty flame resistant (FR) jacket.

The 600V control cables are insulated with Kerite flame resistant (FRII) insulation and covered with heavy flame resistant (FR) jackets.

The 600V instrumentation cables consists of twisted paired shielded and unshielded cables. Unshielded cables consist of twisted pairs with Kerite flame resistant (FRII) insulation covered with an extruded polymer layer and having an overall flame resistant (FR) jacket. Shielded cables in addition to the above have a drain wire with each pair in direct contact with alumimum mylar tape. Each shielded pair is separated by glass mylar tape.

II. Test Data

Vendor data (Kerite and Okonite) regarding the environmental qualification of their cables exposed to a wet/dry environment are attached for your use.

In addition to the above, a procedure was developed on St Lucie Unit 1 to test certain underground cables to confirm their functionability.

The following is a brief synopsis of this Unit 1 procedure. At least once per 18 months, during shutdown, by selecting on a rotating basis at least three (3) cables, one from switchgear to intake cooling water motor, one from switchgear to component cooling water motor and one from switchgear to diesel generator are tested with a 2500VDC megger. Control cables that are associated with each of the above motors and diesel generators are tested with 1000VDC megger. The three spare cables are DC proof tested at 25,000 volts and measured for leakage current at 30 seconds intervals for 10 minutes.

All readings must meet technical specification 4.8.1.1.3. If any installed spare cable fails the Hit Pot test, the NRC will be notified and corrective action take per technical specification 4.8.1.1.3.

Attached are copies of actual test data taken at St Lucie Unit 1.

Intake

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT
MAINTENANCE PROCEDURE NO. 0920061

PAGE 2 of 26
Revision 0
Cycle 1
Date 4/4/75

DATA SHEET
CLASS IE INSTALLED SPARE CABLE 10866 Intake Cooling Water Pump

Megger 2500 V Serial No. E-101 Temp. 77°F
Hi-Pot Tester Serial No. 39007-E-96 Humidity 59.4 DP

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
BEFORE	2500 V	100 M	2000 M	[illegible] 4/16/79

DIELECTRIC/HI-POTENTIAL READING IN MICROAMPS

00 MIN - 30 SEC	1.0	05 MIN - 30 SEC	0.5	
01 MIN - 00 SEC	1.0	06 MIN - 00 SEC	0.5	
01 MIN - 30 SEC	1.5	06 MIN - 30 SEC	0.5	
02 MIN - 00 SEC	1.2	07 MIN - 00 SEC	0.4	
02 MIN - 30 SEC	1.0	07 MIN - 30 SEC	0.5	
03 MIN - 00 SEC	0.8	08 MIN - 00 SEC	0.4	
03 MIN - 30 SEC	0.7	08 MIN - 30 SEC	0.4	
04 MIN - 00 SEC	0.5	09 MIN - 00 SEC	0.5	
04 MIN - 30 SEC	0.6	09 MIN - 30 SEC	0.4	
05 MIN - 00 SEC	0.7	10 MIN - 00 SEC	0.4	

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
AFTER	2500 V	100 M	20,000 M	[illegible]

Completed By [illegible] Date [illegible]

Reviewed By [illegible] Date 5-8-78
Asst. Supt. Electrical

NOTE: All readings must meet technical specifications 4.8.1.1.3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT
MAINTENANCE PROCEDURE NO. 0920061

PAGE 1 of 24
Revision 0
Cycle 1
Date

DATA SHEET
CLASS 1E INSTALLED SPARE CABLE 10887

Megger 2500 V Serial No. E-101
Hi-Pot Tester Serial No. E-98

Temp. 74°F
Humidity 59.4%

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
BEFORE	2500 V	100 M	[illegible]	[illegible] 4/6/78

DIELECTRIC/HI-POTENTIAL READING IN MICROAMPS

00 MIN - 30 SEC	[illegible]	05 MIN - 30 SEC		0.6
01 MIN - 00 SEC	.6	06 MIN - 00 SEC		0.4
01 MIN - 30 SEC	.5	06 MIN - 30 SEC		0.5
02 MIN - 00 SEC	0.7	07 MIN - 00 SEC		0.4
02 MIN - 30 SEC	[illegible]	07 MIN - 30 SEC		0.4
03 MIN - 00 SEC	.6	08 MIN - 00 SEC		.4
03 MIN - 30 SEC	0.5	08 MIN - 30 SEC		0.3
04 MIN - 00 SEC	0.5	09 MIN - 00 SEC		0.4
04 MIN - 30 SEC	0.6	09 MIN - 30 SEC		0.4
05 MIN - 00 SEC	0.5	10 MIN - 00 SEC		0.4

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
AFTER	2500 V	100 M	[illegible]	[illegible]

Completed By [illegible] Date [illegible]

Reviewed By [signature] Date 5-8-78
Asst. Supt. Electrical

NOTE: All readings must meet technical specifications 4.8.1.1.3

D/G

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT
MAINTENANCE PROCEDURE NO. 0920061

Revision 0
Cycle 1
Date 4/16/78

DATA SHEET
CLASS 1E INSTALLED SPARE CABLE 10993 Diesel Generator

Megger 2500 V Serial No. E-101 Temp. 74°F
Hi-Pot Tester Serial No. E-96 Humidity 59.4 DP

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
BEFORE	2500 V	100 M	[illegible]	[illegible] 4/16/78

DIELECTRIC/HI-POTENTIAL READING IN MICROAMPS

00 MIN - 30 SEC	0.2	05 MIN - 30 SEC		0.1
01 MIN - 00 SEC	0.2	06 MIN - 00 SEC		0.2
01 MIN - 30 SEC	0.2	06 MIN - 30 SEC		[illegible]
02 MIN - 00 SEC	0.3	07 MIN - 00 SEC		[illegible]
02 MIN - 30 SEC	[illegible]	07 MIN - 30 SEC		[illegible]
03 MIN - 00 SEC	[illegible]	08 MIN - 00 SEC		[illegible]
03 MIN - 30 SEC	[illegible]	08 MIN - 30 SEC		[illegible]
04 MIN - 00 SEC	0.1	09 MIN - 00 SEC		[illegible]
04 MIN - 30 SEC	[illegible]	09 MIN - 30 SEC		[illegible]
05 MIN - 00 SEC	[illegible]	10 MIN - 00 SEC		[illegible]

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
AFTER	2500 V	100 M	[illegible]	[illegible]

Completed By [illegible] Date [illegible]

Reviewed By [signature] Date 5-8-78
Asst. Supt. Electrical

NOTE: All readings must meet technical specifications 4.8.1.1.3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT
MAINTENANCE PROCEDURE NO. 0920061

DATA SHEET
CLASS 1E INSTALLED SPARE CABLE 10336

Megger 2500 V Serial No. E-1   Temp. 80

Hi-Pot Tester Serial No. E-96   Humidity 69.1

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
BEFORE	2500 V	100 M	5000	RJH

DIELECTRIC/HI-POTENTIAL READING IN MICROAMPS

00 MIN - 30 SEC	.3	05 MIN - 30 SEC	.9	RJH
01 MIN - 00 SEC	.5	06 MIN - 00 SEC	.5	
01 MIN - 30 SEC	.5	06 MIN - 30 SEC	.5	
02 MIN - 00 SEC	.5	07 MIN - 00 SEC	.5	
02 MIN - 30 SEC	.5	07 MIN - 30 SEC	.3	
03 MIN - 00 SEC	.3	08 MIN - 00 SEC	.3	
03 MIN - 30 SEC	.3	08 MIN - 30 SEC	.2	
04 MIN - 00 SEC	.2	09 MIN - 00 SEC	.3	
04 MIN - 30 SEC	.4	09 MIN - 30 SEC	.1	
05 MIN - 00 SEC	.3	10 MIN - 00 SEC	.1	

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
AFTER	2500 V	100 M	5000	RJH

Completed By R. J. Hawkins   Date 5-9-79

Reviewed By M. B. Vincent   Date 5/14/79
Asst. Supt. Electrical

NOTE: All readings must meet technical specifications 4.8.1.1.3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT
MAINTENANCE PROCEDURE NO. 0920061

DATA SHEET
CLASS 1E INSTALLED SPARE CABLE 10837

Megger 2500 V Serial No. E-1 Temp. 80
Hi-Pot Tester Serial No. E-96 Humidity 69.1

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
BEFORE	2500 V	100 M	5K Megs	RJH

DIELECTRIC/HI-POTENTIAL READING IN MICROAMPS

00 MIN - 30 SEC	4.0	05 MIN - 30 SEC	3.2	RJH
01 MIN - 00 SEC	3.7	06 MIN - 00 SEC	3.2	
01 MIN - 30 SEC	3.5	06 MIN - 30 SEC	3.1	
02 MIN - 00 SEC	3.4	07 MIN - 00 SEC	3.1	
02 MIN - 30 SEC	3.3	07 MIN - 30 SEC	3.1	
03 MIN - 00 SEC	3.3	08 MIN - 00 SEC	3.0	
03 MIN - 30 SEC	3.3	08 MIN - 30 SEC	3.0	
04 MIN - 00 SEC	3.2	09 MIN - 00 SEC	2.9	
04 MIN - 30 SEC	3.2	09 MIN - 30 SEC	2.9	
05 MIN - 00 SEC	3.2	10 MIN - 00 SEC	2.9	

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
AFTER	2500 V	100 M	5K Megs	RJH

Completed By R. J. [illegible] Date 5-10-78

Reviewed By A. J. B. Vincent Date 5/11/78
Asst. Supt. Electrical

NOTE: All readings must meet technical specifications 4.8.1.1.3

D/G

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT
MAINTENANCE PROCEDURE NO. 0920061

DATA SHEET
CLASS 1E INSTALLED SPARE CABLE 10663 Diesel Generator

Megger 2500 V Serial No. E-101 Temp. 74°F
Hi-Pot Tester Serial No. E-96 Humidity 59.4 DP

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
BEFORE	2500 V	100 M	[illegible]	[illegible] 4/16/78

DIELECTRIC/HI-POTENTIAL READING IN MICROAMPS

00 MIN - 30 SEC	0.2	05 MIN - 30 SEC		0.1
01 MIN - 00 SEC	0.2	06 MIN - 00 SEC		0.2
01 MIN - 30 SEC	0.2	06 MIN - 30 SEC		0.2
02 MIN - 00 SEC	0.2	07 MIN - 00 SEC		[illegible]
02 MIN - 30 SEC	[illegible]	07 MIN - 30 SEC		[illegible]
03 MIN - 00 SEC	[illegible]	08 MIN - 00 SEC		[illegible]
03 MIN - 30 SEC	[illegible]	08 MIN - 30 SEC		[illegible]
04 MIN - 00 SEC	0.1	09 MIN - 00 SEC		0.2
04 MIN - 30 SEC	0.2	09 MIN - 30 SEC		[illegible]
05 MIN - 00 SEC	0.1	10 MIN - 00 SEC		0.2

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
AFTER	2500 V	100 M	[illegible]	[illegible]

Completed By [illegible] Date [illegible]
Reviewed By [illegible] Date 5-8-78
Asst. Supt. Electrical

NOTE: All readings must meet technical specifications 4.8.1.1.3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT
MAINTENANCE PROCEDURE NO. 0920061

DATA SHEET
CLASS 1E INSTALLED SPARE CABLE 10883

Megger 2500 V Serial No. E-1 Temp. 80

Hi-Pot Tester Serial No. E-96 Humidity 69.1

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
BEFORE	2500 V	100 M	8000 M	[illegible]

DIELECTRIC/HI-POTENTIAL READING IN MICROAMPS

00 MIN - 30 SEC	.8	05 MIN - 30 SEC	.4	[illegible]
01 MIN - 00 SEC	.6	06 MIN - 00 SEC	.35	
01 MIN - 30 SEC	.5	06 MIN - 30 SEC	.35	
02 MIN - 00 SEC	.5	07 MIN - 00 SEC	.35	
02 MIN - 30 SEC	.5	07 MIN - 30 SEC	.3	
03 MIN - 00 SEC	.4	08 MIN - 00 SEC	.3	
03 MIN - 30 SEC	.4	08 MIN - 30 SEC	.3	
04 MIN - 00 SEC	.4	09 MIN - 00 SEC	.3	
04 MIN - 30 SEC	.4	09 MIN - 30 SEC	.3	
05 MIN - 00 SEC	.4	10 MIN - 00 SEC	.3	

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
AFTER	2500 V	100 M	8000 M.	[illegible]

Completed By [illegible] Date 5-10-79

Reviewed By [illegible] Date 5/11/79
Asst. Supt. Electrical

NOTE: All readings must meet technical specifications 4.8.1.1.3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT
MAINTENANCE PROCEDURE NO. 0920061

DATA SHEET
CLASS 1E INSTALLED SPARE CABLE 10086

Megger 2500 V Serial No. E-303 Temp. 79
Hi-Pot Tester Serial No. E 296 Humidity 70%

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
BEFORE	2500 V	100 M	50K MΩ	Young

DIELECTRIC/HI-POTENTIAL READING IN MICROAMPS

00 MIN - 30 SEC	1.2	05 MIN - 30 SEC	.3	
01 MIN - 00 SEC	1	06 MIN - 00 SEC	.4	
01 MIN - 30 SEC	.9	06 MIN - 30 SEC	.5	
02 MIN - 00 SEC	.8	07 MIN - 00 SEC	.3	
02 MIN - 30 SEC	.6	07 MIN - 30 SEC	.3	
03 MIN - 00 SEC	.7	08 MIN - 00 SEC	.3	
03 MIN - 30 SEC	.6	08 MIN - 30 SEC	.4	
04 MIN - 00 SEC	.5	09 MIN - 00 SEC	.3	
04 MIN - 30 SEC	.4	09 MIN - 30 SEC	.3	
05 MIN - 00 SEC	.6	10 MIN - 00 SEC	.3	

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
AFTER	2500 V	100 M	50K MΩ	Young

Completed By Young Meredith Date 3/17/83
Reviewed By [signature] Date 3/23/83
Asst. Supt. Electrical

NOTE: All readings must meet technical specifications 4.8.1.1.3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT
MAINTENANCE PROCEDURE NO. 0920061

DATA SHEET
CLASS 1E INSTALLED SPARE CABLE 10837
B-176A

Megger 2500 V Serial No. E201 Temp. 84°

Hi-Pot Tester Serial No. E296 Humidity 70%

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
BEFORE	2500 V	100 M	10K MΩ	Young

DIELECTRIC/HI-POTENTIAL READING IN MICROAMPS

00 MIN - 30 SEC	.2	05 MIN - 30 SEC	.15	
01 MIN - 00 SEC	.2	06 MIN - 00 SEC	.1	
01 MIN - 30 SEC	.2	06 MIN - 30 SEC	.15	
02 MIN - 00 SEC	.2	07 MIN - 00 SEC	.1	
02 MIN - 30 SEC	.2	07 MIN - 30 SEC	.1	
03 MIN - 00 SEC	.2	08 MIN - 00 SEC	0	
03 MIN - 30 SEC	.2	08 MIN - 30 SEC	0	
04 MIN - 00 SEC	.15	09 MIN - 00 SEC	0	
04 MIN - 30 SEC	.1	09 MIN - 30 SEC	.1	
05 MIN - 00 SEC	.2	10 MIN - 00 SEC	0	

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
AFTER	2500 V	100 M	10K MΩ	Young

Completed By Young Date 3/25/80

Reviewed By [illegible] Date 4/3/80
Asst. Supt. Electrical

NOTE: All readings must meet technical specifications 4.8.1.1.3

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT
MAINTENANCE PROCEDURE NO. 0920051

DATA SHEET
CLASS 1E INSTALLED SPARE CABLE 10888

Megger 2500 V Serial No. E201 Temp: 82°
Hi-Pot Tester Serial No. E296 Humidity 70%

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
BEFORE	2500 V	100 M	10K MΩ	Young

DIELECTRIC/HI-POTENTIAL READING IN MICROAMPS

00 MIN - 30 SEC	.2	05 MIN - 30 SEC	.1	
01 MIN - 00 SEC	.2	06 MIN - 00 SEC	.15	
01 MIN - 30 SEC	.15	06 MIN - 30 SEC	.15	
02 MIN - 00 SEC	.15	07 MIN - 00 SEC	.15	
02 MIN - 30 SEC	.15	07 MIN - 30 SEC	.1	
03 MIN - 00 SEC	.15	08 MIN - 00 SEC	.15	
03 MIN - 30 SEC	.15	08 MIN - 30 SEC	.1	
04 MIN - 00 SEC	.15	09 MIN - 00 SEC	.15	
04 MIN - 30 SEC	.15	09 MIN - 30 SEC	.15	
05 MIN - 00 SEC	.15	10 MIN - 00 SEC	.15	

MEGGER READING	TEST VOLTS	MIN. READ	ACTUAL READ	COMPLETED BY
AFTER	2500 V	100 M	10K MΩ	Young

Completed By Young Date 3/25/80
Reviewed By [illegible] Date 4/2/80
Asst. Supt. Electrical

NOTE: All readings must meet technical specifications 4.8.1.1.2

THE OKONITE COMPANY

Post Office Box 340
Ramsey, New Jersey 07446
201-825-0300/Cable: Okonite

VS 1/C sent one copy to Licensing

ENGRG. DEPT.
JUL 23 1981

July 21, 1981

Ebasco Services, Inc.
Two World Trade Center
New York, N.Y.

Att: Mr. George Attarian

Subject: St. Lucie Unit II
P.O. NY-422574
5 & 15kV Power Cable

Dear Mr. Attarian,

This is to confirm our conversation of today relative to our previously submitted qualification documentation on wet and dry cable installations. We have no objection of your submitting any part or all of our qualification reports to the NRC nor do we have any objection to the information becoming public information.

Very truly yours,

R. A. Guba

RAG/mg

THE OKONITE COMPANY
Ramsey, New Jersey 07448

FLORIDA POWER & LIGHT COMPANY

ST. LUCIE PLANT

MEDIUM VOLTAGE POWER CABLE

EBASCO SPECIFICATION NO. 211-73, REV. 3
PROJ. ID # FLO-2998-291

NUCLEAR QUALIFICATION REPORT
for
X-OLENE INSULATED CABLES

This document is The Okonite Company's nuclear qualification report for X-Olene insulated cables. It complies literally with IEEE Standard 383-1974, Section 1.4 "Documentation". Section 1.4 documents the parameters specified in Section 1.3.

Included in this report are seven Appendices which serve to further clarify Okonite's test procedures and results. These Appendices are as follows:

Appendix	
1	Comparison of Okonite's LOCA Qualification Test to the Suggested Test Procedures and NESCR Sheets as given in the Ebasco 211-73 Specification.
2	Comparison of Okonite's LOCA Test Profile to Ebasco's Postulated Event
3	40-Year Life Detail Document.
4	Radiation Certification
5	LOCA Autoclave Drawing
6	List of Equipment
7	Elevated Temperature Moisture Absorption

The necessary data to document satisfactory compliance as specified in Section 2.6 of IEEE 383, Documentation of Type Testing, is provided in this report. The following cross-reference table illustrates where this information can be found.

APPENDIX 7

MOISTURE RESISTANCE

Long term moisture stability is one of the essential factors in selection of an insulation for many applications. It is not unusual for a power cable to be required to operate in an environment alternately wet and dry. To determine the long term water stability of a cable, a sample insulated with a thin wall dielectric is immersed in water at an elevated temperature to accelerate the deteriorating effects of moisture. Monitoring the electrical properties provides an indication of long term behavior. Based upon actual experience capability of withstanding total water immersion at 90°C should be capable of a life in excess of a generating station's designed life in an environment of 100% humidity.

Figure I shows long term 90°C water immersion on a 1/C #14 AWG X-Olene insulated cable. Testing has been performed in accordance with ICEA S-66-524, paragraph 6.6 "Accelerated Water Absorption Tests " except that (1) the water temperature was 90°C, (2) three 25 ft. samples were tested, (3) the test period was extended for 12 months and (4) a 600 volt ac potential was applied continuously. Even with the more strenuous test parameters, the samples met the requirements of ICEA S-66-524, Section 3.7.3.3. The extended 12 month data demonstrates a large margin of assurance.

Alternate wet/dry cyclic testing on this insulation has never been performed. For the purchased 5 and 15 kV cables this question (as well as the entire question concerning moisture) is academic since the lead sheath would prevent all moisture from becoming in contact with the insulation.

THE OKONITE COMPANY
Ramsey New Jersey 07446

LONG TERM 90°C WATER IMMERSION TEST

Construction: 1/C, #14 Solid CC, .047" X-Olene (Ref. 2-18, pg. 240).
Continuous Stress, 600 Volts, Ac

Average of 2 Samples

Time	Measuring Stress Volts/mil	% PF	SIC	SIR M ohms-1000 ft. at - 500 V
Initial	40	0.11	2.31	>250,000
	80	0.10	2.31	
1 Day	40	0.10	2.09	>289,000
	80	0.13	2.09	
1 Week	40	0.06	2.13	> 276,000
	80	0.08	2.13	
2 Weeks	40	0.07	2.15	> 263,000
	80	0.07	2.15	
4 Weeks	40	0.07	2.15	>237,000
	80	0.08	2.15	
2 Months	40	0.05	2.15	>141,000
	80	0.06	2.15	
3 Months	40	0.06	2.15	>257,000
	80	0.06	2.15	
4 Months	40	0.03	2.18	> 257,000
	80	0.04	2.18	
5 Months	40	0.03	2.18	>250,000
	80	0.03	2.18	
6 Months	40	0.05	2.18	>250,000
	80	0.05	2.18	
12 Months	40	0.02	2.19	>257,000
	80	0.03	2.19	

49 Day Street
Seymour, Connecticut 06483
(203) 888-2591

the kerite company

July 1, 1981

ELEC. ENGRG. DEPT.
RECEIVED
JUL 09 1981

Ebasco Services Inc.
2 World Trade Center
New York, NY 10048

ATTENTION: MR. W. LUNDGREN
SENIOR ENGINEER, ST. LUCIE #2 PROJECT

Gentlemen:

SUBJECT: FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT #2
PURCHASE CONTRACT NY-422573

Confirming our conversation of June 29, this is to advise that our Engineering Department has released the following documents so that you may copy and submit them to the Nuclear Regulatory Commission:

Kerite Qualification Documents For:	Document Reference
Reference 6 Kerite FRII/FR Signal and Instrumentation Cable	Engineering Memorandum 240 June 6, 1979
Reference 6 Kerite HTK/FR Power Cable	Engineering Memorandum 223 May 4, 1977
Reference 5 Kerite FR/FR Control Cable	Engineering Memorandum 205 November 6, 1975

We trust that this will satisfy your requirements.

Yours truly,

THE KERITE COMPANY

From the office of: E.N. Sleight
Assistant Vice President
National Generation

Norma H. Dube

Signee: Norma H. Dube
Administrator-
Power Plant Generation

NHD:ss

ST. LUCIE NUCLEAR PLANT
EBASCO SERVICES INCORPORATED
FLORIDA POWER AND LIGHT COMPANY

QUALIFICATION DOCUMENTATION
FOR
KERITE FR/FR CONTROL CABLES

ASSIGNED TO EBASCO SERVICES, INC.

REF/dm
4/20/77

APR 22 1977

St. Lucie Nuclear Plant
Kerite FR/FR Control Cable

Other supportive aging data (not referenced in EM 178-A) and not included because of their proprietary nature but available for audit at our plant or upon visitation to other offices are:

Four Hour Overload Cycles - Kerite - October 9, 1956

Overload Cycling Test - Kerite - January 23, 1957

Product Evaluation Test 49 - Kerite - April 18, 1962 - Oven Aging

High Voltage Lab Test Sheet No. 2233 - Oven Aging Dielectric Strength - FR Insulation - December 14, 1970

Physical Test Sheet - Kerite - Oven Aged - 4 Years at 52°C - April 19, 1962

Miscellaneous Tests - Kerite - February 13, 1973

CONFIDENTIAL

APR 22 1977

III. Water Immersion

The subject of water immersion is covered in Kerite Engineering Memorandum No. 205 (Ref. 5), with the supporting data available for audit at The Kerite Company.

As with the thermal aging, an evaluation technique has been developed by Kerite to compare our later materials to Kerite with its time proven service record. The data developed shows FR insulation capable of operating at a temperature level 22°C higher than Kerite. Again, this corresponds with the 90°C conductor rating assigned to the FR insulation. Summary sheets (attached to EM 205) cover the points used to develop the plots.

In summary, the monitoring of the effect of water on electrical properties showed the IR was the most useful parameter in terms of comparing the later compounds with Kerite insulation. The rate of change of insulation resistance rather than the absolute value of insulation resistance is used. The data plotted on the charts, unless noted in the summary sheet, is for immersed conductors continuously energized at 600 volt AC.

A multiconductor FR/FR control cable of the type recommended for St. Lucie has been immersed in 90°C water with 600 volt DC excitation between conductors and ground (water) for over 39 weeks. Comparison of performance of multiconductor constructions to individual conductors immersed in water

St. Lucie Nuclear Plant
Kerite FR/FR Control Cable

shows the benefit of coverings over the insulation (see summary sheet).

Continuous water immersion would only normally apply to cables that are used for submarine applications although some underground ducts are almost always flooded. Both of these installations also give the alternate wet and dry exposures (i.e., tides, seasonal ground water levels). According to our information, there are several locations in the southeastern U.S. area where Kerite submarine signal cables have been installed and operating since 1926. The Altamaha River near Everett, Georgia, installed in 1926 and still in existence in 1970. Also Satilla River at Woodbine, Georgia; St. Mary's River, Georgia; and Trout River, Jacksonville. This service record can be verified by the railroads if needed.

IV. Alternate Wet and Dry

Kerite Engineering Memo No. [illegible]05 also states that from our experience, alternate wet and dry is no more severe than continuously wet and usually much less severe, depending on the drying temperatures and drying times. Actual supporting test data as reported March 16, 1976, is referenced and attached (Ref. 6). Additional data is being developed and will be available for audit.

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APR

V. Radiation

The FR insulation has been subjected to a number of radiation tests. The Report of April 20, 1970 was submitted originally. This report, in itself, contains all the supportive data necessary to qualify FR/FR control cables for the required total 40 years plus one year emergency integrated radiation dose of 8.5×10^7 rad, for inside the containment of the St. Lucie Plant.

However, the specific test program based upon Par. 2.3.3 of IEEE 383-1974 including pre-aging by The Kerite Company for 101 hours at 150°C, gamma irradiation of 50 megarads, and then the electrical integrity verified by IR measurements and high potential withstand tests is covered in Report F-C4020-3 prepared by the Franklin Institute Research Laboratories, entitled "Test of Electrical Cables Under Exposure to Gamma Radiation". The Franklin test was done on single conductor No. 12 AWG, 50 mils FR insulation without the benefit of any outer jackets or coverings (a more severe test). The cable successfully met the requirements.

ENGINEERING MEMORANDUM NO. 205 November 6, 1975
(Supersedes August 8, 1975 Issue)
Chart redrawn Oct. 22, 1976

DETERMINING TEMPERATURE 'RATING' OF CABLES FOR OPERATION IN ALTERNATE WET AND DRY LOCATIONS

Temperature 'rating' of cables for alternate wet and dry locations is established utilizing the Arrhenius techniques but incorporating a reference material to relate actual field performance of cables to the higher temperature continuous water soak data on small wire. This relationship is then used to predict the 'water aging' of materials in field service that do not have an extended operating history. Continuous immersion is more severe than alternate wet and dry conditions, and a relationship between these 'aging' rates is necessary. Supporting data showing periodic immersion to be no more severe than continuous immersion on Kerite and FR insulation is found in the following test reports or programs:

A. Hvizd, Jr.'s Project No. 21[illegible] (November, 1967) - Kerite
15-3 Lab Test Sheet No. 25[illegible] - FR insulation (July 27, 1970)
Engineering Project No. 75-4[illegible] - FR Insulation (in progress)

The reference material used is regular Kerite which has had an extended service history encompassing in excess of 100 millions of feet of many construction types in all environments and at conductor operating temperatures of 70 to 75^{o}C. and cable surface temperatures of 60 to 65^{o}C.

The method by which this analysis is performed is described as follows:

The basis for comparison between insulations is the "insulation resistance". Tests have shown that this electrical parameter is representative of aging in wet environments. Change in capacitance or dissipation factor, however, is also measured. Engineering Project No. 75-40 covering the electro-endosmosis program with samples energized with 600 volts AC, 600 volts DC, or not energized showed no significant effect on time to 1/2 IR or approximate doubling of tan delta due to electrification.

One further question was whether current loading retarded or accelerated any electrical degradation. A laboratory test to answer this question (15-3 Lab Test Sheet No. 227 dated March 29, 1970) gave no indication that current loading affected 'electricals'.

Having identified the relevant aging factors to be time and water temperatures, the relationship between materials was selected to be based on the time to reach one-half of the original IR level. Other levels could have been selected; however, the 1/2 IR point was something achievable in reasonable time periods.

One other requirement in this analysis is that the 'slopes' of the aging curves be essentially parallel. This is the case with these materials; i.e., the slopes of FR insulation and Kerite are parallel.

Test points in water for Kerite were at 90, 75, and 52°C. and for FR insulation 90 and 75°C.

15-3 Lab Book-B, Pages [illegible].
15-3 Lab Book-B, Sample [illegible]
Chemical Lab Records, Samples 75-118 (1971), 75-119 (1971), 75-87 ([illegible]), [illegible]-24 (1960), 75-123 (1971)

CONFIDENTIAL APR 22 1977

On this basis, compounds having identical 'aging' slopes are expected to age similarly under similar environmental service conditions and their operating temperatures for equivalent aging would therefore be relatable. Thus, from the attached chart, the performance of Kerite having a proven service record of more than forty years at insulation surface temperatures of 60°C. and higher, it is seen that the equivalent continuous water immersion time at 60°C. to reach 1/2 IR is eighty days. Also from the chart, for FR insulation, the water temperature required to reduce the IR to 1/2 the original level in eighty days is 82°C. This analysis indicates that FR insulated cables may be rated 22°C. higher than Kerite. (FR insulation is conservatively rated at 90°C. conductor temperature.)

In actual service, cables fully immersed in water will tend to have their surface temperatures approach the temperature of the water. Therefore, attempting to establish a temperature rating for cable (assumed to be dry) may not be as significant as determining what the environmental water temperature will be; however, this analysis provides at least a comparison between newer materials and service proven materials for general use conditions.

The addition of a jacket over the cabled insulated conductors or an increase in insulation thickness shows significant improvement of IR performance. See 15-3 Lab Book-B, Sample 1 MCB.

It should be noted that salt water immersion is less severe than tap water. Refer to Product Evaluation No. 177, report dated March 8, 1974.

The introduction of FR insulation in 1966 has given no evidence of field problems in Tower and Case wire applications. It has been and is being used as the insulating jacket on 1/c, 5 KV, 90°C. rated non-shielded cables in wet and dry applications, also without any reported service problems.

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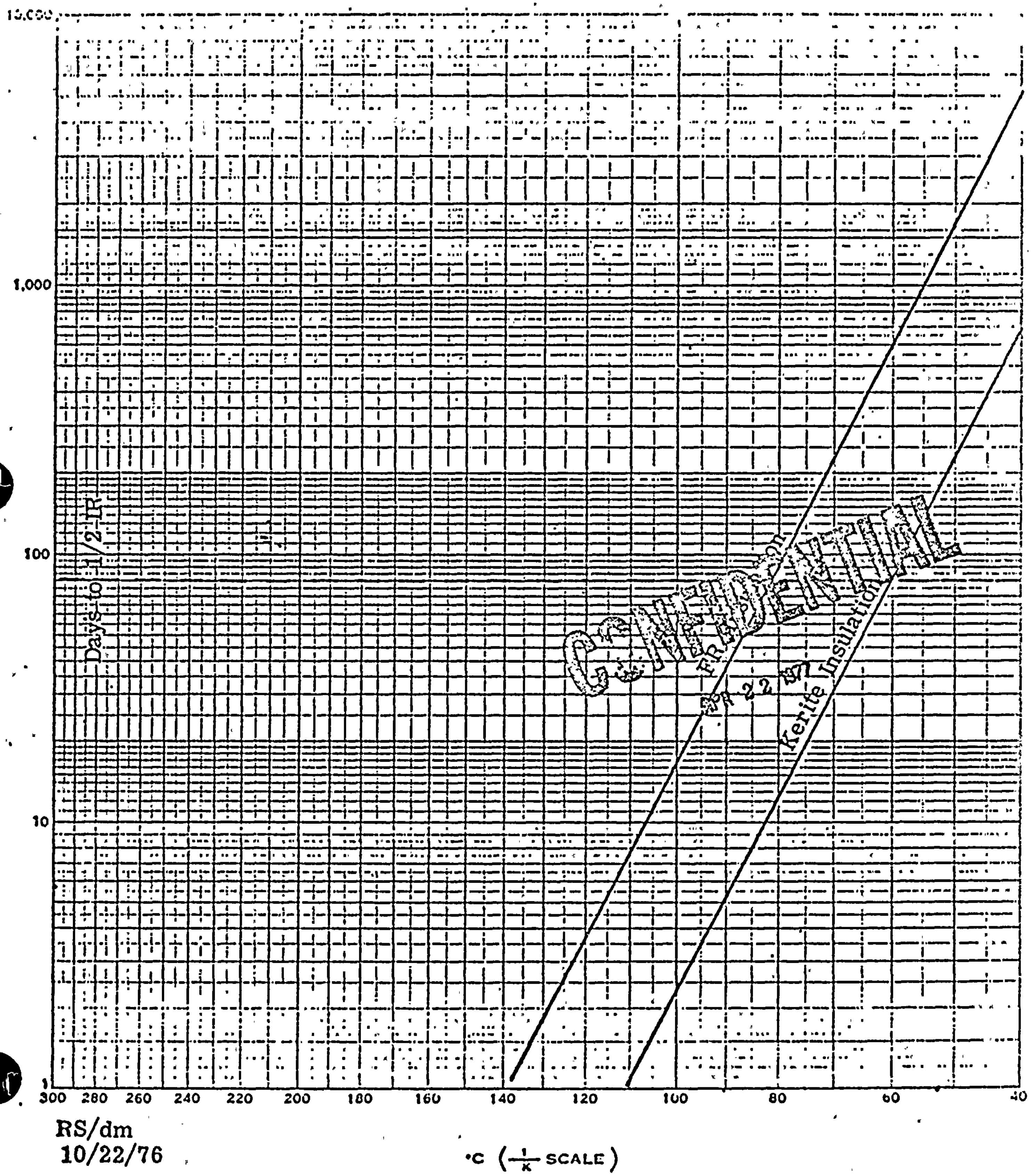
APR 22 1977

A. Hvizd, Jr.
V. P. of Engineering

AH, Jr. /dm
copies:
Engineering Managers
Sales Offices

Determining Temperature Ratings of Fire Resistant (FR) Cable for Operation in Wet Locations



RS/dm
10/22/76

March 16, 1976

CONFIDENTIAL.

To: W. F. Parsons

From: A. Hvizd, Jr.

Subject: St. Lucie Nuclear
Alternate Wet/Dry Cycle Test - HI-70 Insulation

Reference: Electrical Lab Report No. 599

Purpose

Evaluate and compare the electrical characteristics of HI-70 insulation cycled alternately between 90°C. water and room temperature air to a control sample continuously immersed in 90°C. water.

Procedure

Prior to the periodic removal of the cycled test samples from the water bath, measure insulation resistance, dissipation factor and capacitance of all test samples. Cycle period consists of 3 1/2 days in 90°C. water and 3 1/2 days in room temperature air (approximately 22°C.).

Sample Description

ZB-1 (control) - No. 14 (solid) conductor, .030" HI-70 insulation.
ZB-1 (cycled) - No. 14 (solid) conductor, .030" HI-70 insulation.
ZB-3 (control) - No. 14 (solid) conductor, .050" HI-70 insulation.
ZB-3 (cycled) - No. 14 (solid) conductor, .050" HI-70 insulation.

Data

	Elapsed Time - days to:		
Sample Reference	50% of Initial IR	200% of Initial DF	200% of Initial Capac.
ZB-1 (control)	30	25.5	29
ZB-1 (cycled)	58	51	56
ZB-3 (control)	71	82	149
ZB-3 (cycled)	97	110	>155*

*Test terminated before reaching 200% of initial capacitance

WFP
St. Lucie Nuclear

Mar. 16, 1976

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Results

1) Tests on samples subjected to sustained water immersion are more severe than those consisting of alternate wet/dry cycles.

2) The relationship between samples undergoing sustained water immersion and those which were cycled is influenced by sample wall thickness.

A. Hvizd, Jr.
V. P. of Engineering

RS/dm

the kerite company

ST. LUCIE NUCLEAR PLANT - UNIT 2
EBASCO SERVICES INCORPORATED
FLORIDA POWER AND LIGHT COMPANY
QUALIFICATION DOCUMENTATION
FOR
KERITE FR2/FR SIGNAL
AND INSTRUMENTATION CABLES

Assigned to: Ebasco Services - copy 1

ISSUED

MAR 20 1980

St. Lucie Nuclear Plant - Unit 2
Kerite FR2/FR Signal and Instrumentation Cables

SECTION V. WATER IMMERSION

The subject of water immersion is covered in Kerite Engineering Memorandum No. 240 entitled "Determining Temperature Rating of FR2 Insulated Cables for Operation in Wet and Alternate Wet and Dry Locations, dated June 6, 1979 (Ref. 6), with the supporting data available for audit at The Kerite Company.

As with the thermal aging, an evaluation technique has been developed by The Kerite Company to compare our later materials to Kerite with its time proven service record. The data developed shows FR2 insulation capable of operating at a temperature level 30°C higher than Kerite. Again, this corresponds with the 90°C conductor rating assigned to the FR2 insulation.

In summary, the monitoring of the effect of water on electrical properties showed the IR was the most useful parameter in terms of comparing the later compounds with Kerite insulation. The rate of change of insulation resistance rather than the absolute value of insulation is for immersed conductors continuously energized at 600 Volt AC.

Continuous water immersion would only normally apply to cables that are used for submarine applications although some underground ducts are almost always flooded. Both of these installations also give the alternate wet and dry exposures (i.e., tides, seasonal ground water levels). According to our information, there are several locations in the southeastern U.S. area where Kerite submarine signal cables have been installed and operating since 1926. The Altamaha River near Everett, Georgia, installed in 1926 and still in existence in 1970. Also Satilla River at Woodbine, Georgia; St. Mary's River, Georgia; and Trout River, Jacksonville. This service record can be verified by the railroads if needed.

SECTION VI. ALTERNATE WET AND DRY

Kerite Engineering Memorandum No. 240 also states that from our experience, alternate wet and dry is no more severe than continuously wet and usually much less severe, depending on the drying temperatures and drying times.

SECTION VII. RADIATION, LOCA AND POST LOCA

To cover the requirements of LOCA and Post LOCA exposure for the St. Lucie Plant, Unit 2, the report "St. Lucie Nuclear Plant, Unit 2, LOCA Qualification of Kerite 600 volt FR 2 Insulated, FR Jacketed Signal and Instrumentation Cables, dated 3/20/80, (Ref. 7) was prepared.

CONFIDENTIAL ISSUED 1980

DETERMINING TEMPERATURE RATING OF FR II INSULATED KERITE CABLES FOR OPERATION IN WET AND ALTERNATE WET AND DRY LOCATIONS

Temperature 'rating' of cables for wet and alternate wet and dry locations is established utilizing the Arrhenius technique, but incorporating a reference material to relate actual field performance of cables to the higher temperature continuous moisture absorption tests on small insulated wires. This relationship is then used to predict the 'water aging' of materials in field service that do not have an extended operating history.

The reference material used is regular Kerite, which has had an extended service history encompassing in excess of one hundred million feet of many construction types in all environments and at conductor operating temperatures of 70 to 75°C and cable surface temperatures of 60 to 65°C.

The method by which this analysis is performed is described as follows:

> The basis for comparison between insulations is the "Insulation Resistance". Tests have shown that this electrical parameter is representative of aging in wet environments. Change in capacitance and dissipation factor, however, is also measured. Samples energized with 600 volts AC, DC or not energized, showed no significant effect on the electrical Parameters measured. (Ref. 1).
>
> Having identified the relevant aging factors to be time and water temperature, the relationship between materials was selected to be based on the time to reach one-half of the original IR value. Other criteria could have been selected; however, the one-half IR point was something achievable in reasonable time periods.
>
> Test points in water for Kerite were at 90°C, 75°C and 52°C, and for FR II insulation (ED-72), 90°C and 75°C were used.
>
> On this basis, compounds having essentially identical 'aging' slopes are expected to age similarly under similar environmental service conditions and their operating temperatures for equivalent aging would therefore be relatable. Thus, from the attached chart, the performance of Kerite having a proven service record of more than forty years at insulation surface temperatures of 60°C and higher, it is seen that the equivalent continuous water immersion time at 60°C to reach one-half IR is 1950 hours. Also, from the chart, for FR II insulation, the water temperature in 1950 hours is 90°C. This analysis indicates that FR II insulation can be rated 30°C higher than Kerite. This material, however, is conservatively rated at 90°C. (References 1, 2, and 3.)

In actual service, cables fully immersed in water will tend to have their surface temperatures approach the temperature of the water. Therefore, attempting to establish a conductor temperature rating for cable (assumed to be dry) may not be as significant as determining what the environmental water temperature will be; however, this analysis provides a good comparison between newer materials and service-proven materials for general use conditions.

Laboratory tests to determine the effects of alternate wet and dry environments have also been conducted and indicate no significant difference between continuous water immersion and alternate wet and dry immersion. (Reference 4.)

Laboratory References

The information presented above and on the attached plot has been based on the references given below. The data has been collected as part of a continuing water absorption program and represents that which is presently available. These references are available for audit at the Kerite Company in the Engineering Department.

1. Engineering Project No. 75-40. Sample Nos. 97B, 98B, and 99B.
2. Engineering Project No. 75-40 Sample No. 94A..
3. Chemical Lab Records, Samples 75-118 (1971), 75-119 (1971) 75-87 (1965), 52-24 (1960); 75-123 (1971).
4. Engineering Project No. 75-40, Sample Nos. ZB-29, 30 and 31. Sample No. ZBA, 29, 30, and 31.

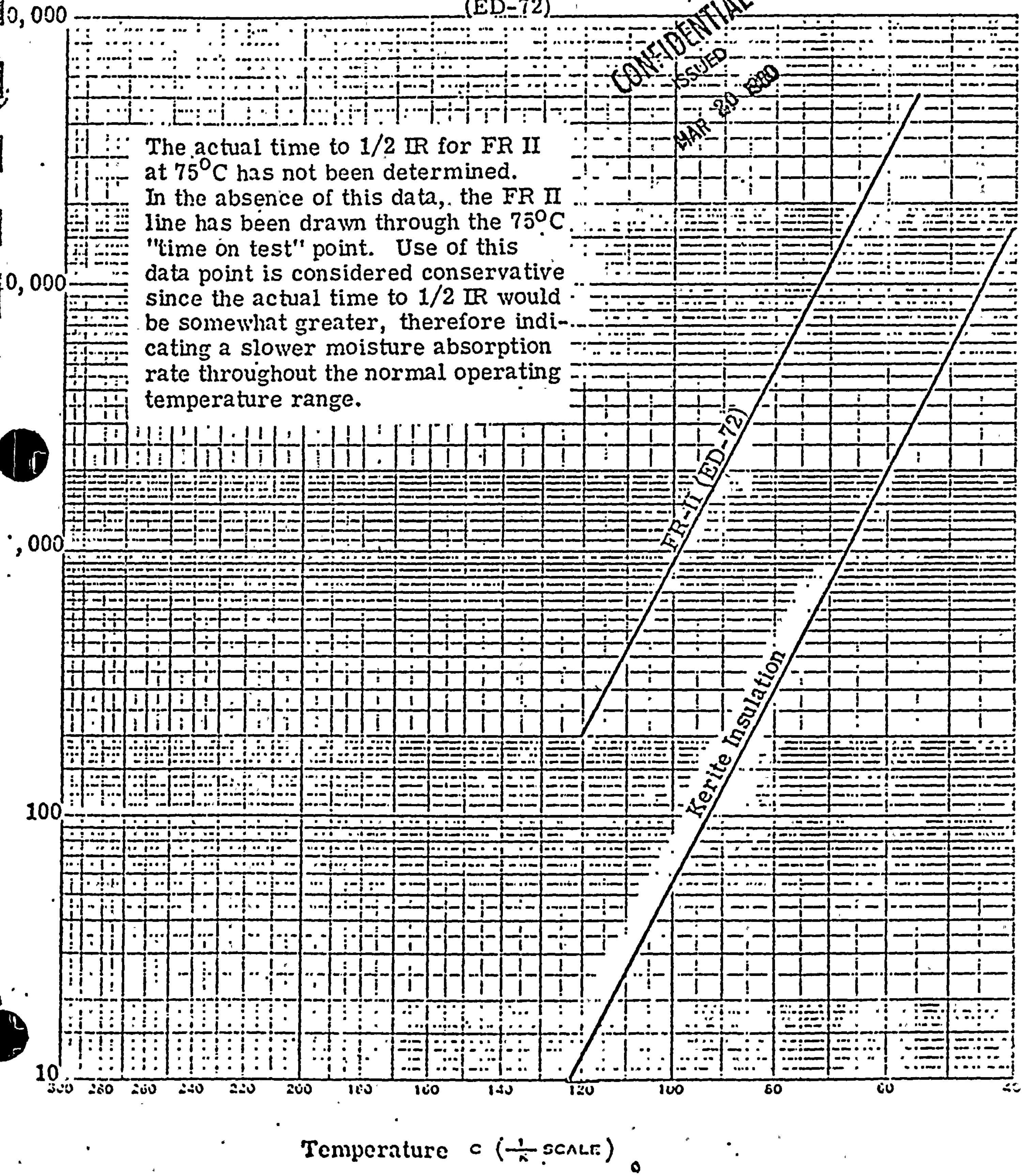
Robert F. Smith Jr.
R. F. Smith Jr.
Electrical Engineer

RFS/lc
Attach.

cc: Book Holders

APPROVED J B Gardner / J R Crouf
J. B. Gardner, V.P. of Engineering

Determining Temperature Ratings of FR-II Insulated Cables for Operation in Wet and Alternate Wet and Dry Locations
(ED-72)



the kerite company

ST. LUCIE NUCLEAR PLANT
EBASCO SERVICES INCORPORATED
FLORIDA POWER AND LIGHT COMPANY
QUALIFICATION DOCUMENTATION
FOR
KERITE HTK/FR POWER CABLES
ASSIGNED TO EBASCO SERVICES

REF:mc
5/5/77

Four-Hour Overload Cycles - Kerite - October 9, 1956

Overload Cycling Test - Kerite - January 23, 1957

Product Evaluation Test 49 - Kerite - April 18, 1962 - Oven Aging

Physical Test Sheet - Kerite - Oven Aged - 4 Years at 52° C - April 19, 1962

Miscellaneous Tests on Kerite - February 13, 1973

III. Water Immersion

The subject of water immersion is covered in Kerite Engineering Memorandum No. 223 (Ref. 6), with the supporting data available for audit at The Kerite Company.

CONFIDENTIAL

As with the thermal aging, an evaluation technique has been developed by The Kerite Company to compare our later materials to Kerite with its time-proven service record. The data developed shows HTK insulation capable of operating at a temperature level [illegible] C higher than Kerite. Again, this corresponds with the 90° C conductor rating assigned to the HTK insulation.

In summary, the monitoring of the effect of water on electrical properties showed the insulation resistance was the most useful parameter in terms of comparing the later compounds with Kerite insulation. The rate of change of insulation resistance, rather than the absolute value of insulation resistance, is used. The test results for energized samples (either at 600 volts AC or 600 volts DC) versus unenergized samples are, for practical purposes, the same. Also, the comparison of the performance of finish cables versus insulated conductors showed the benefit of the jacket.

Continuous water immersion would only normally apply to cables that are used for submarine applications, although some underground ducts are almost always flooded. Both of these installations also give the alternate wet and dry exposures (i.e., tides, seasonal ground water levels). According to our information, there are several locations in the southeastern U.S. area where Kerite submarine signal cables have been installed and operating since 1926. The Altamaha River near Everett, Georgia, installed in 1926 and still in existence in 1970. Also Satilla River at Woodbine, Georgia; St. Mary's River, Georgia; and Trout River, Jacksonville. This service record can be verified by the railroads if needed.

the kerite company

IV. Altnerate Wet and Dry

Kerite Engineering Memo No. 223 also states that from our experience, alternate wet and dry is no more severe than continuously wet, and usually much less severe, depending on the drying temperatures and drying times. Supporting data is available for review and audit at The Kerite Company.

V. Radiation

The HTK insulation has been subjected to a number of radiation tests and is qualified for radiation levels in excess of 200 megarads (more than twice the required level for St. Lucie Nuclear Plant, Unit 2). Supporting data is presented in the St. Lucie Nuclear Plant, Unit No. 2, Qualification Test of Kerite 600 Volt HTK/FR Power Cable Under Simulated Post Accident Conditions Report of 5/3/77 (Ref. 7).

VI. LOCA and Post LOCA

To cover the requirements of LOCA and Post LOCA for the St. Lucie Plant, Unit 2, the report "St. Lucie Nuclear Plant, Unit 2, Qualification Test of Kerite 600 Volt HTK/FR Power Cable Under Simulated Post Accident Conditions," (Ref. 7) was prepared.

CONFIDENTIAL 6 1977

The one-year Post LOCA duration required, from practical time considerations, an accelerated test cycle. This "accelerated relationship" is developed from the Arrhenius aging analysis in EM 178-A or EM 178-B, using "equivalent aging times." It should be noted that the "rate" of aging for HTK insulation is essentially identical, whether the environment is air or water. The test profile attached to the LOCA report shows the accelerated test cycle (also described in the report) used to encompass the entire one-year Nuclear Environment Service Cycle Requirement given in the St. Lucie, Nuclear Plant, Unit 2 Specification.

A requirement in IEEE 323 is that equipment--in this case, cable-- perform under LOCA and Post LOCA conditions for at least the required operating time. This information was not furnished, and the actual "margins" presented in these reports may be well beyond the applicable factors suggested in Paragraph 6.3.1.5 of IEEE 323.

VII. Flame Tests

The HTK/FR power cables meet the fire tests described in IEEE 383. Individual reports on 1/c, No. 6 (7), 600 volt, HTK insulated and FR jacketed power cables are as follows:

ENGINEERING MEMORANDUM NO. 223 May 4, 1977
(Supersedes EM 223 dated 8-12-76)

DETERMINING TEMPERATURE 'RATING' OF HIGH TEMPERATURE KERITE INSULATED CABLES FOR OPERATION IN WET AND ALTERNATE WET/DRY LOCATIONS

Temperature 'rating' of cables for wet locations is established utilizing the Arrhenius techniques but incorporating a reference material to relate actual field performance of cables to the higher temperature continuous moisture absorption on small wire. This relationship is then used to predict the 'water aging' of materials in field service that do not have an extended operating history.

The reference material used is regular Kerite, which has had an extended service history encompassing in excess of 100 millions of feet of many construction types in all environments and at conductor operating temperatures of 70 to 75° C and cable surface temperatures of 60 to 65° C.

The method by which this analysis is performed is described as follows:

> The basis for comparison between insulations is the "insulation resistance". Tests have shown that this electrical parameter is representative of aging in wet environments. Change in capacitance and dissipation factor, however, is also measured. Samples energized with 600 volts AC, 600 volts DC, or not energized, showed no significant effect on the electrical parameters measured.[1]
>
> MAY - 6 1977
>
> Having identified the relevant aging factors to be time and water temperatures, the relationship between materials was selected to be based on the time to reach one-half of the original IR level. Other levels could have been selected; however, the 1/2 IR point was something achievable in reasonable time periods.
>
> One other requirement in this analysis is that the 'slopes' of the aging curves be similar, which is the case with these materials.
>
> Test points in water for Kerite were at 75 and 52° C, and for HTK insulation, 90 and 75° C.

On this basis, compounds having essentially identical 'aging' slopes are expected to age similarly under similar environmental service conditions and their operating temperatures for equivalent aging would therefore be relatable. Thus, from the attached chart, the performance of Kerite having a proven service record of more than forty years at insulation surface temperatures of 60° C and higher, it is seen that the equivalent continuous water immersion time at 60° C to reach 1/2 IR is 1950 hours. Also, from the chart, for HTK insulation, the water temperature required to reduce the IR to 1/2 the original level in 1950 hours is 92° C. This analysis indicates that HTK insulated cables may be rated 32° C higher surface temperature than Kerite. HTK insulation, however, is conservatively rated at 90° C conductor temperature.[2]

In actual service, cables fully immersed in water will tend to have their surface temperatures approach the temperature of the water. Therefore, attempting to establish a conductor temperature rating for cable (assumed to be dry) may not be as significant as determining what the environmental water temperature will be. However, this analysis provides a good comparison between newer materials and service-proven materials for general use conditions.

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MAY - 6 1977

Laboratory tests to determine the effects of alternate wet and dry environments have also been conducted and indicate that continuous water immersion is more severe.[5]

The addition of a jacket over the individual or the cabled insulated conductors or an increase in insulation thickness shows significant improvement of IR performance.[3] It should also be noted that salt water immersion is less severe than tap water.[4]

Laboratory References

The information presented above and on the attached plot has been based on the references given below. The data has been collected as part of a continuing water absorption program and represents that which is presently available.

1. Engineering Project No. 75-40. Sample Nos. 22A, 23A, 24A, 22B, 23B, and 24B.

2. Engineering Project No. 75-40. Sample Nos. 22A, 22B, 23A, 23B, 24A, and 24B. Chemical Lab Records - 52-24, 75-27, 75-186, 75-202, 75-203, 75-204, and 75-205.

(Continued)

(Laboratory References - Continued)

3. Engineering Project No. 75-40. Sample Nos. 2MCB, 19A-24A, 19B-24B, 7A, 8A, 9A, 85A, 86A, 87A, 7B, 8B, 85B, 86B, 87B.

4. Product Evaluation No. 177.

5. Engineering Project No. 75-40, Sample Nos. ZB-12 - ZB-16.

CONFIDENTIAL

MAY 6 1977

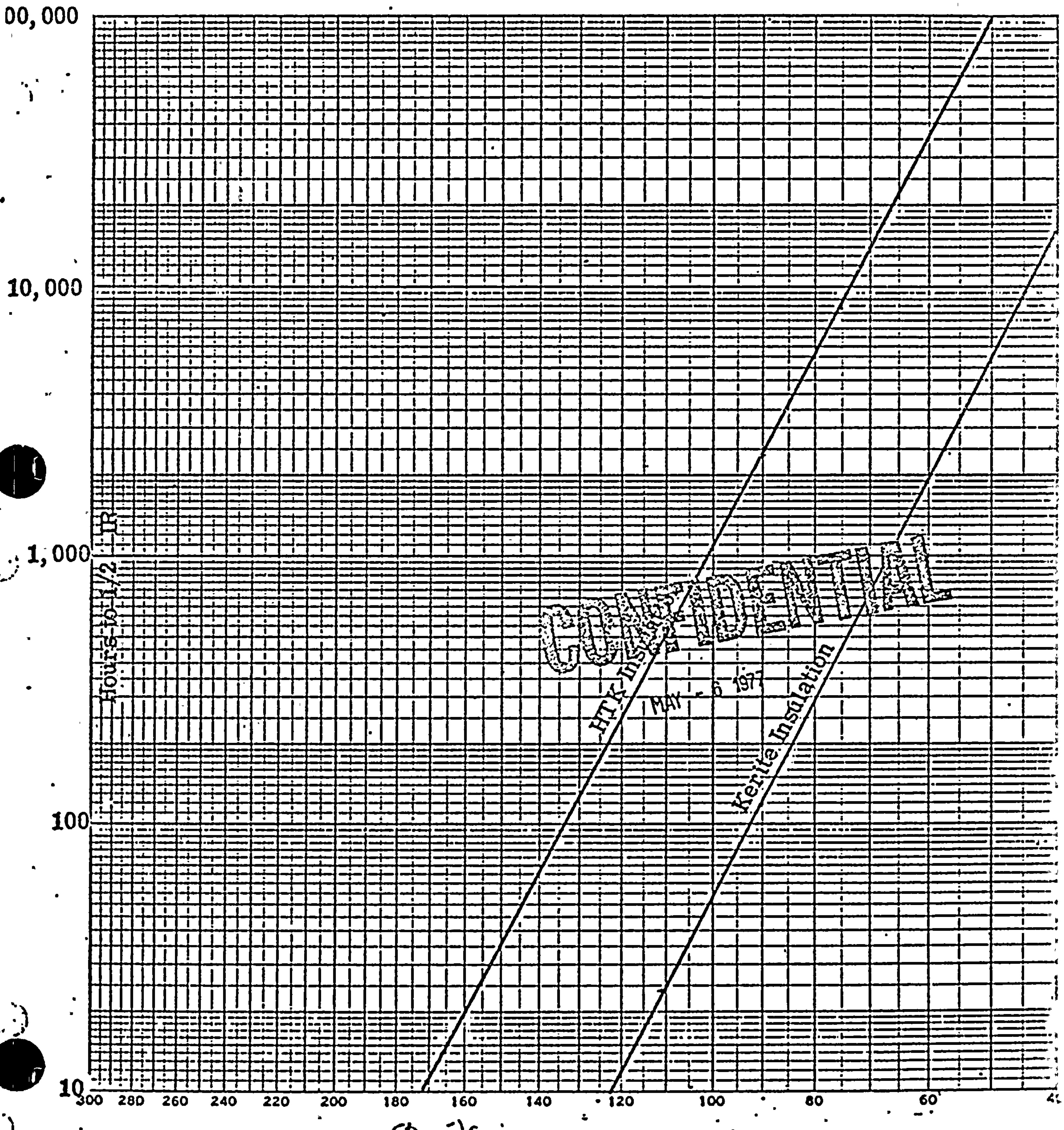
Robert F. Smith Jr.
R. F. Smith, Jr.
Assistant Electrical Engineer

RFSJr:mc

APPROVED: J R Carey
J. R. Carey
Chief Electrical Engineer

Copies: Book Holders

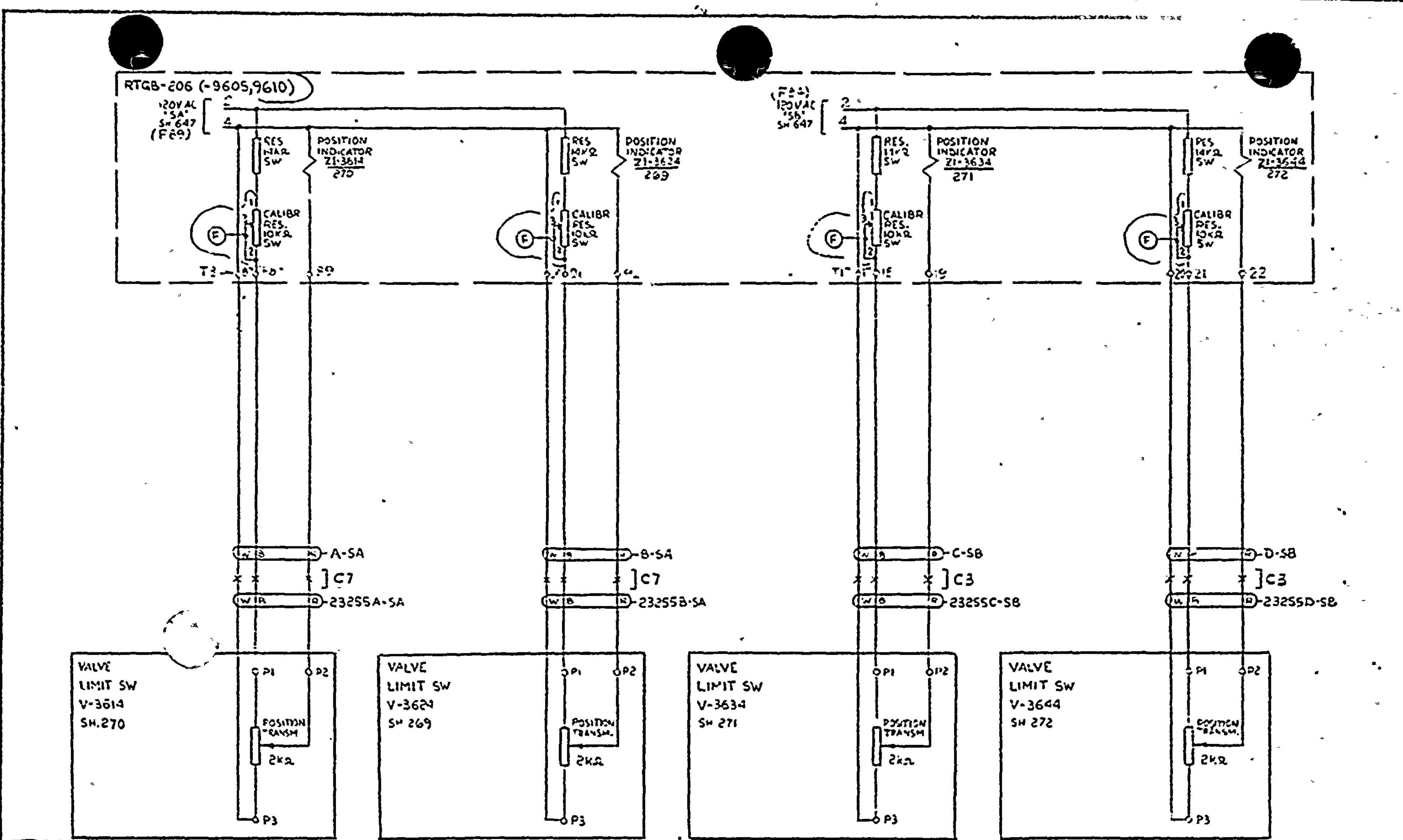
Determining Temperature Ratings of High Temperature Kerite Insulated Cables for Operation in Wet Locations



50 mils

RFSJr:mc

78 Mils



NOTE:-
Ⓕ - BY FIELD

NUCLEAR SAFETY RELATED

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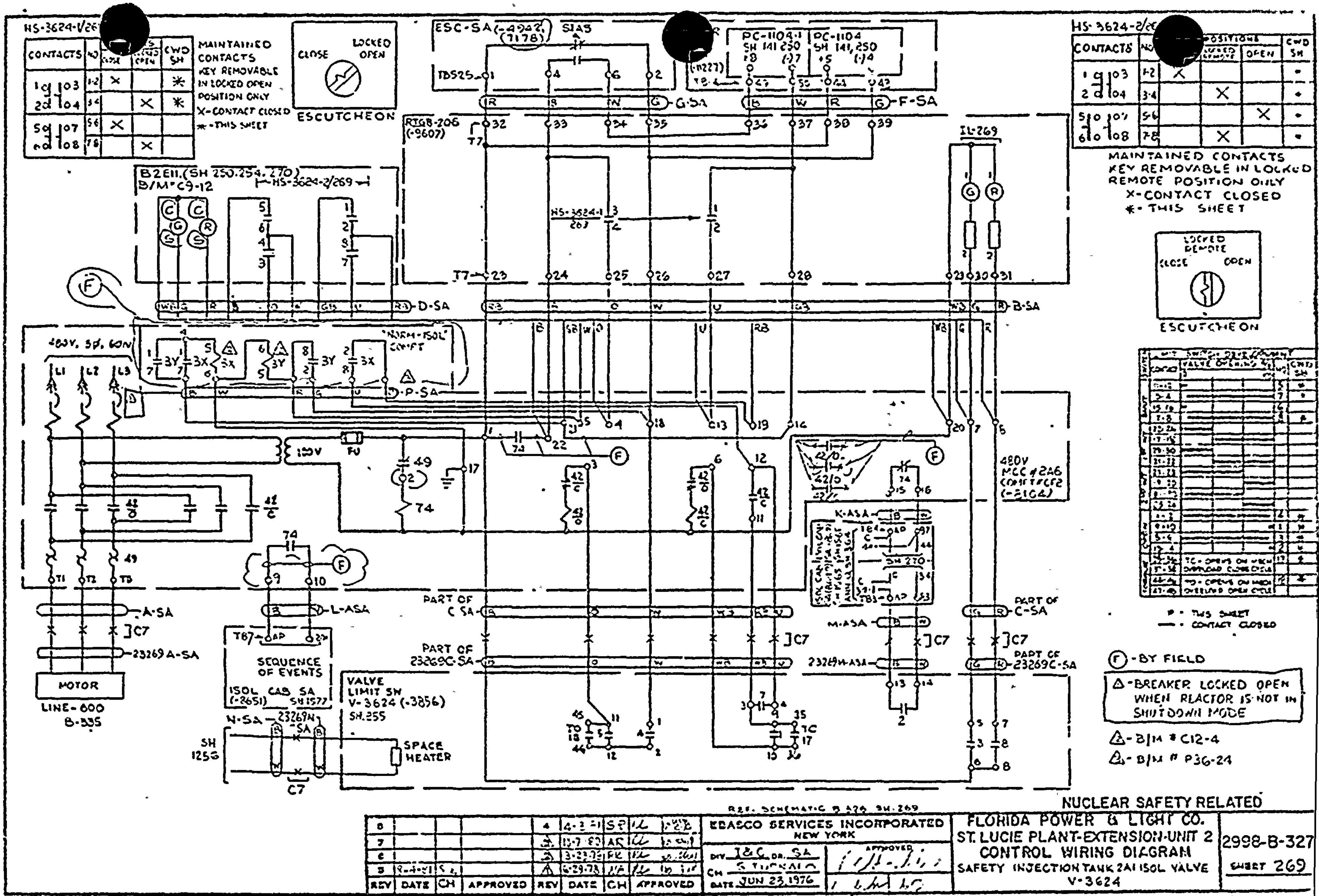
7				3	12-7-80	RH	
6				2	5-14-80	SL	
5				1	7-27-79	RM	

EBASCO SERVICES INCORPORATED

DIV I&C DR AR
CH W. ARNHEITER
DATE JAN 27, 1978
APPROVED

FLORIDA POWER & LIGHT CO.
ST. LUCIE PLANT-EXTENSION-UNIT 2
CONTROL WIRING DIAGRAM
ISOL VALVES V-3614, V-3624, V-3634 & V-3644
POSITION INDICATORS

2998-B-327
SHEET 255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ESC-SA (-4942) (7178)
SIAS
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G-SA
F-SA
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PC-1104 SH 141,250
RTGB-206 (-9607)
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B-SA
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480V, 3Ø, 60N
"NORM-ISOL" CONT
P-SA
120V
FU
480V MCC #2A6 CONT #CF2 (-2104)
K-ASA
SH 270
MOTOR
LINE-600 B-335
A-SA
23269A-SA
C7
L-ASA
TB7
SEQUENCE OF EVENTS
ISOL CAB SA (-2651) SH 1577
VALVE LIMIT SW V-3624 (-3856) SH.255
PART OF C SA
PART OF 23269C-SA
M-ASA
23269M-ASA
PART OF C-SA
PART OF 23269C-SA
N-SA
23269N-SA
SH 1256
SPACE HEATER
F - BY FIELD
Δ - BREAKER LOCKED OPEN WHEN REACTOR IS NOT IN SHUTDOWN MODE
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REF. SCHEMATIC 8-426 SH. 269
EBASCO SERVICES INCORPORATED NEW YORK
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APPROVED
FLORIDA POWER & LIGHT CO.
ST. LUCIE PLANT-EXTENSION-UNIT 2
CONTROL WIRING DIAGRAM
SAFETY INJECTION TANK 2A1 ISOL VALVE V-3624
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SHEET 269
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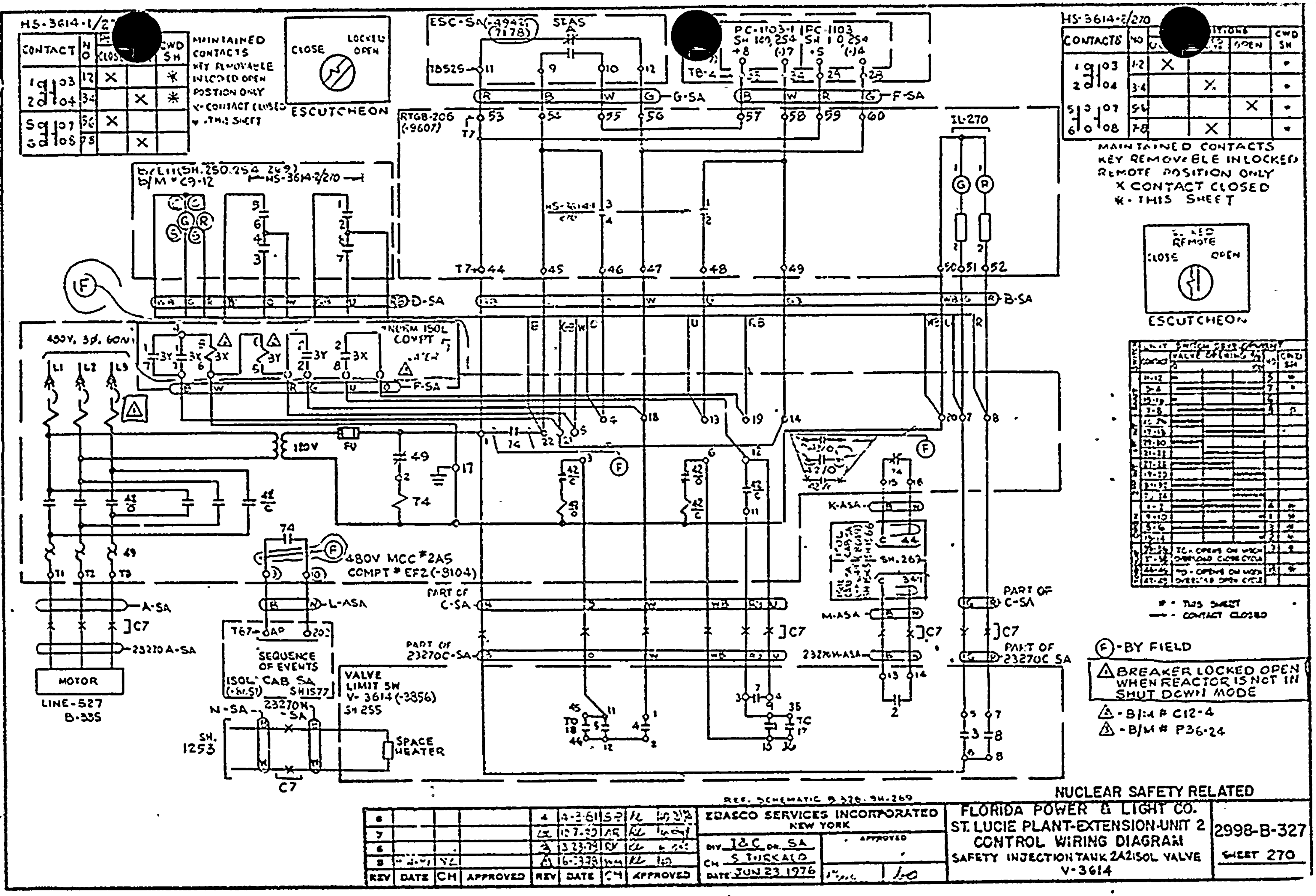

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480V, 3Ø, 60Hz
120V
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MOTOR
LINE-527
B-335
480V MCC #2A5
COMPT # EF2 (-8104)
SEQUENCE OF EVENTS
VALVE LIMIT SW V-3614 (-3856)
SH 255
SPACE HEATER
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PART OF C-SA
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(F) - BY FIELD
BREAKER LOCKED OPEN WHEN REACTOR IS NOT IN SHUT DOWN MODE
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EBASCO SERVICES INCORPORATED
NEW YORK
APPROVED
DATE JUN 23 1976
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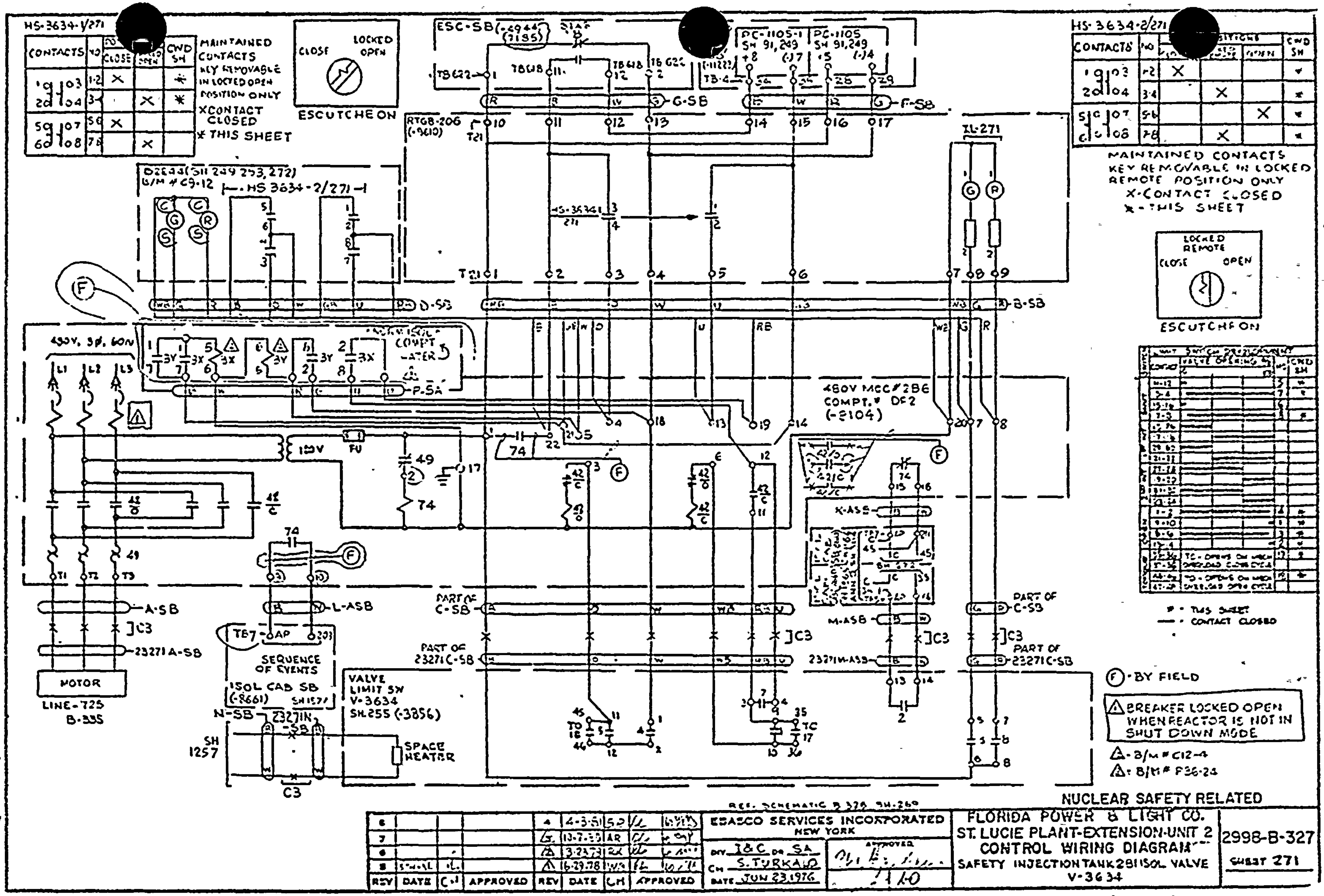
APPROVED
FLORIDA POWER & LIGHT CO.
ST. LUCIE PLANT-EXTENSION-UNIT 2
CONTROL WIRING DIAGRAM
SAFETY INJECTION TANK 2A2 ISOL VALVE
V-3614
2998-B-327
SHEET 270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F-SB
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PC-1105 SH 91,249
HS-3634-2/271
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ESCUTCHEON
IL-271
RTGB-206
D-SB
B-SB
P-SA
480V, 3Ø, 60N
480V MCC#2B6 COMPT.# DF2
SEQUENCE OF EVENTS
ISOL CAB SB
A-SB
L-ASB
C-SB
M-ASB
23271A-SB
23271C-SB
23271M-ASB
MOTOR
LINE-725
B-335
N-SB
SPACE HEATER
VALVE LIMIT SW V-3634 SH.255 (-3856)
F - BY FIELD
BREAKER LOCKED OPEN WHEN REACTOR IS NOT IN SHUT DOWN MODE
* - THIS SHEET
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NUCLEAR SAFETY RELATED
EBASCO SERVICES INCORPORATED NEW YORK
FLORIDA POWER & LIGHT CO.
ST. LUCIE PLANT-EXTENSION-UNIT 2
CONTROL WIRING DIAGRAM
SAFETY INJECTION TANK 2B1 ISOL VALVE V-3634
2998-B-327
SHEET 271
DR. I&C
CH. S. TURKALO
DATE JUN 23 1976
APPROVED
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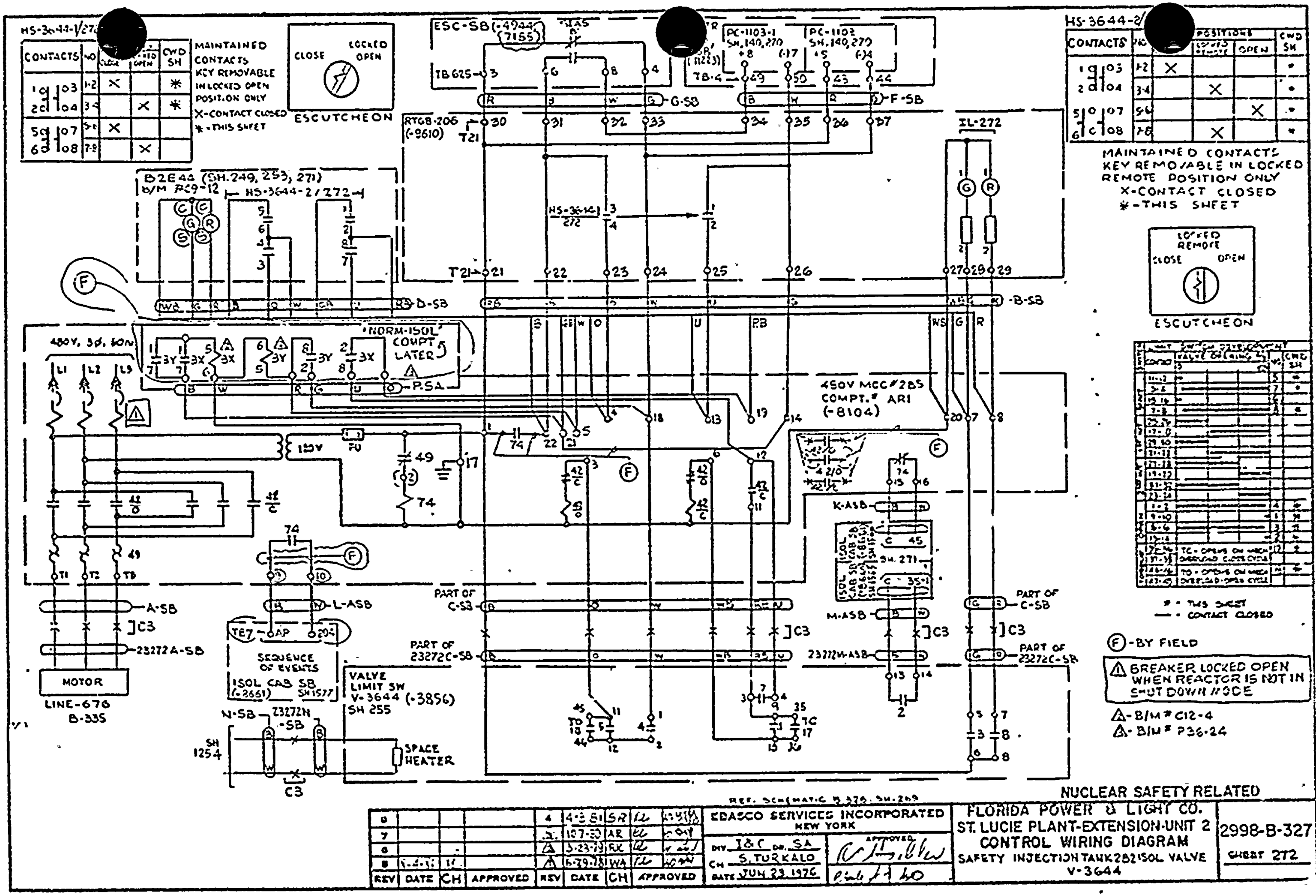

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LOCKED REMOTE
OPEN
480V, 3Ø, 60N
MOTOR
LINE-676
B-335
SEQUENCE OF EVENTS
ISOL CAB SB
VALVE LIMIT SW V-3644 (-3856) SH 255
SPACE HEATER
450V MCC #2B5 COMPT.# AR1 (-8104)
Ⓕ-BY FIELD
BREAKER LOCKED OPEN WHEN REACTOR IS NOT IN SHUT DOWN MODE
B/M # C12-4
B/M # P36-24
NUCLEAR SAFETY RELATED
EBASCO SERVICES INCORPORATED
NEW YORK
S. TURKALO
JUN 23 1976
FLORIDA POWER & LIGHT CO.
ST. LUCIE PLANT-EXTENSION-UNIT 2
CONTROL WIRING DIAGRAM
SAFETY INJECTION TANK 2B2 ISOL VALVE
V-3644
2998-B-327
SHEET 272
REV
DATE
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APPROVED

NOTE
1-FOR TYPICAL ANNUNCIATOR WINDOW DESCRIPTION SEE SH.802

ENG'D SAFEGUARDS MODULE REMOVED Q-1 NC | | 1580	ENG'D SAFEGUARDS AUTO TEST CHECK ABNORMAL Q-2 NO | | 1580	CONTAINMENT PRESSURE SIAS MEASUREMENT CHANNEL TRIP Q-3 NO | SIAS-MA, MB, MC, MD | [illegible]	Q-4	Q-5
Q-11	Q-12	Q-13	Q-14	Q-15
HPSI PUMP 2B MOTOR OVERLOAD ALARM TRIP Q-21 [illegible] | [illegible] | 255	Q-22	HPSI PUMP DISCHARGE V-[illegible] CLOSED Q-23 NC | 33 | [illegible]	Q-24	Q-25
HPSI PUMP 2B START FAIL [illegible] SIAS OVERRIDE Q-31 NO | [illegible], [illegible], CS | 255	Q-32	HPSI PUMP DISCHARGE V-[illegible] CLOSED Q-33 NC | 33 | [illegible]	SI TANK ISOLATION V-3614, V-3624 CLOSED Q-34 NC | 33 | [illegible]	SI TANK ISOLATION V-3634, V-3644 CLOSED Q-35 NC | 33 | [illegible]
Q-41	Q-42	Q-43	SI TANK ISOL V-3614, V-3624 MOTOR OVERLOAD ALARM TRIP Q-44 NO | 4 | [illegible]	SI TANK ISOL V-3634, V-3644 MOTOR OVERLOAD ALARM TRIP Q-45 NO | 34 | [illegible]
HPSI FLOW HCV-3616, HCV-3626 HCV-3636, HCV-3646 MOTOR OVERLOAD SIAS OVERRIDE Q-51 NO | ([illegible]) 253 261 264, 267 | 255	Q-52	Q-53	Q-54	Q-55

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EBASCO SERVICES INCORPORATED
DIV. I&C DR. SA
CH. R MURAT
DATE SEP 17, 1976
APPROVED [signature]

FLORIDA POWER & LIGHT CO.
ST. LUCIE PLANT-EXTENSION-UNIT 2
CONTROL WIRING DIAGRAM
ENGINEERED SAFEGUARDS
ANNUNCIATOR O'[illegible] 1 RTGB - 206

2998-B-327
SHEET 36[illegible]

Chapter 8.3 SER Item - Isolation Devices

The St Lucie 2 design utilizes circuit breakers, fuses, and CT's (4.16KV system only) as isolation devices for power and control (120,125VDC) circuits. This is in accordance with the PSAR, section 8.3 which states:

The design will comply with the intent of Regulatory Guide 1.75 (RG 1.75) and complies in toto with one exception, i.e., the design includes fault current interrupting devices which serve an isolation function. This is required to preserve to the extent practicable the duplicity of Units 1 & 2. Compliance with this regulatory guide will result in modification of the cable tray system or the RTGB, or some combination thereof. The exact modifications will be delineated during the detailed design. Circuit interrupting devices actuated by fault current (fuses, circuit breakers) are commonly used as isolating devices. Once actuated these devices prevent the faulted circuit from influencing the unfaulted circuit in an unacceptable manner. Thus, the design is both compatible with the duplication concept and is responsive to the intent of RG 1.75.

The definition of an Isolation device was clearly identified as well in PSAR Section 8.3.1.2.3 c)8 which states:

A device in a circuit which prevents malfunctions in one section of a circuit from causing unacceptable influences in other sections of the circuit or other circuits. Class IE circuit interrupting devices actuated by fault current are considered to be isolation devices.

Although this approach was accepted by the NRC as evidence by issue of a construction permit based on the PSAR, the St Lucie 2 electrical design was enhanced such that:

a. All cables downstream from isolation devices are fully qualified to IEEE 383.

b. All cables downstream from isolation devices are subject to the same cable derating, raceway fill flame retardance and splicing restrictions as that of class 1E cable.

c. The isolation devices are qualified to the same level of qualification as class 1E circuit breakers and fuses.

Other than unique identification and not routing these cables in class 1E or associated raceway, the requirements discussed in a and b above are in accordance with RG 1.75 R 0 paragraph 4.5a for associated circuits.

It must be considered that all non-class 1E cable that share the same raceway as those down stream of isolation devices are of the same quality i.e. environmentally qualified; quality assurance requirements etc as that of class 1E cables.

It must also be considered that for the 4.16KV and 480V systems, single line to ground faults as suggested in RG 1.75 Rev 2 Section C will not cause the tripping of any bus breaker or back up breaker since these systems feature high resistance grounding which limits the fault current to 10 to 15 amps, and is insufficient to trip a bus breaker. For 125V DC power circuits, fuses in each leg or two pole thermal magnetic breakers assure that in the unlikely event that both lines are faulted together two interrupting means are provided.

Furthermore, since these cables are routed only with cables that are qualified to IEEE 383 as are the safety related cables, the likely hood of a cable fire in a non safety cable tray where a cable downstream of an isolation device is routed is no greater than in a safety tray. Should this cable fire cause a three phase fault and the qualified isolation device fail to clear the fault, it would be considered as a single failure as would be the same event on a safety cable.

Based upon the previous acceptability by NRC and recognizing the enhancements to the St Lucie 2 design as discussed above, we consider the use of circuit breakers fuses, and CT's as acceptable isolation devices.

Chapter 8.3 Open SER - GDC 18

Tests are periodically perform on the onsite safety related electrical distribution system in accordance with the Technical Specifications. Since the two electrical onsite distribution systems (divisions) are physically and electrically redundant and independent, either of the divisions can be tested while the other load group provides power.

The diesel generators are tested at least once per 31 days and at 18 month intervals during shutdown. During these tests portions of the onsite distribution system is also exercised to assure that each safety division is in a ready state to perform its intended function. For further description of these tests, see the appropriate technical specification.

The 4.16KV undervoltage relays can also be tested through test circuitry provided at the 4.16KV safety related switchgear.

Various safety related equipment is also tested and/or monitored as per the recommendations of the equipment manufacturer.

The FSAR will be revised accordingly.

Chapter 8.3 SER - MOV Thermal Overload Bypass

Safety related 480V motor operated valves that are required to be manually operated during a design bases event will have their thermal overload protection bypassed. This is consistant with the RG 1.106 "Thermal Overload Protection for Electric Motors on Motor-Operated Valves.

For safety related 480V motor operated valves inside the containment, manual or automatic, starter thermal overloads are bypassed. However, because the valve operators are located inside containment, and containment integrity must be maintained at all times, thermal magnetic breakers are utilized in the feeder circuits for these valves. ~~These circuit breakers are sized such that they will trip between 10 and 20 seconds of valve lock rotor time, so as not to damage the penetration integrity.~~

POST ACCIDENT SAMPLING SYSTEM

Re: P.A.S.S, Meeting between FPL and NRC 8/11/81

Pursuant to the above referenced meeting, Flordia Power & Light is providing the following concerning the Post Accident Sampling System:

1. Section 9.3.6 is revised to include diluted and undiluted samples (see attached),

2. Section 9.3.6.2 is revised by deleting the world "chloride" from 4th paragraph of 9.3.6.2 and from 3rd sentence prior to INSERT "B" (see attached),

3. INSERT "A" of Section 9.3.6.2 is revised to include monitoring dissolved O_2 in accordance with Regulatory Guide 1.97, revision 2 (see attached),

4. INSERT "B" of Section 9.3.6.2 will be revised to include a narrative description of how sample activity is correlated to core relative damage. Revision to this section will be formally transmitted on or before 9/1/81,

5. Flordia Power & Light will also provide the following items 4 months prior to 5% power operating license:

   a) An instrument and analysis appliacability test for the accident environment,

   b) Procedures which correlates isotopic concentration with degrees of core damage.

St Lucie
Aug 11 1-5 PM
P-118

Witt

9.3.6 POST ACCIDENT SAMPLING SYSTEM

The Post Accident Sampling System (PASS) consists of a shielded skid-mounted sample station and a remotely located control panel. The PASS provides a means to obtain and analyze pressurized and unpressurized reactor coolant samples, containment building samples, diluted and undiluted samples.
The Piping and Instrumentation diagrams for the PASS are shown in Figures 9.2.6a and 9.3.6b. Design data is provided in Tables 9.3.10, 9.3.11 and 9.3.12.

9.3.6.1 Design Bases

The PASS is designed in accordance with the criteria stated in Section II.B.3 of Enclosure 3 to NUREG 0737. The quantitative design criteria for the PASS are as follows:

a) The PASS provides a means to promptly obtain a reactor coolant liquid, containment building sump liquid, and containment building gas samples. The combined time required for sampling and analysis is less than three hours.

b) The PASS allows for post-accident sampling with resulting personnel radiation exposure not exceeding the criteria of GDC 19 (Appendix A to 10 CFR Part 50).

c) The PASS is capable of accommodating an initial reactor coolant radiochemistry spectrum corresponding to a postulated release equivalent to that assumed in Regulatory Guide 1.4, Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors, Rev. 2 dated June, 1974, and Regulatory Guide 1.7, Control of Combustible Gas Concentrations in Containment Following a Loss of Coolant Accident, Rev. 2 dated September 1976.

d) The PASS provides a means to remotely quantify pH and the concentrations of total dissolved gas, hydrogen, oxygen and boron in the liquid samples.

e) Sample flow is returned to the containment to preclude unnecessary contamination of other auxiliary systems and to ensure that radioactive waste remains isolated within the containment.

f) Components and piping are designed to Quality Group D (as defined in Regulatory Guide 1.26) non-seismic requirements. The equipment is located downstream of double isolation valves from safety code systems.

9.3.6.2 System Description

The requirements for post-accident sampling of the reactor coolant and containment building atmosphere are met through the Post-Accident Sampling System (PASS). The PASS provides a means to obtain pressurized and unpressurized reactor coolant samples and containment building atmosphere samples. A reactor coolant sample can be drawn directly from the Reactor Coolant System (RCS) whenever the RCS pressure is between 200 psig and 2485 psig. RCS sample lines are provided with orifices inside containment so as to limit the flow from any postulated break in the sample line. At pressures below 200 psig, reactor coolant samples can be drawn from a Safeguards System sample line. This pathway also provides a means of sampling the containment building sump during the recirculation mode of Safeguards System operation. A containment building atmosphere sample can be drawn with containment building pressure between 10 psia and 75 psia. All sample flow is returned to the containment building to preclude unnecessary contamination of other auxiliary systems and to ensure that high level waste remains isolated within the containment. These sample process pathways were selected to insure a representative sample under all modes of decay heat removal. The PASS sampling flow rates are provided in Table 9.3.10.

The PASS consists of a remotely located control panel and a skid-mounted sample station which are designed to maintain radiation exposures to plant personnel as low as reasonably achievable (ALARA) and which is located to minimize the length of sample lines. The PASS is interfaced with the existing reactor coolant and safeguards system sample lines. Post accident sampling does not require an isolated auxiliary system to be placed in operation.

The PASS is a totally closed system (i.e., samples taken from containment are returned to the containment). The grab samples are extracted from sample vessels by injection of a syringe through a septum plug mounted in the vessels. In addition, the PASS sample station skid is provided with a ventilation flowpath that is sized for 333 scfm in air flow from the surrounding room to the ventilation system exhaust. The exhaust air is directed through an activated charcoal filter for iodine removal.

The PASS provides the capability for remote chemical analyses of the reactor coolant including total dissolved gas concentration, dissolved hydrogen and oxygen concentration, boron concentration and pH. Reactor coolant analysis is provided through the use of an undiluted grab sample facility. Shielded grab samples of the depressurized undiluted reactor coolant liquid may be obtained. Unshielded, depressurized and diluted grab samples of the degassed reactor coolant liquid, reactor coolant dissolved gas and containment building atmosphere may also be obtained.

The operation of the PASS for collecting and analyzing reactor coolant and containment building atmosphere samples may be categorized as (1) reactor coolant sample purging, (2) reactor coolant sample gaseous analyses and dilution, (4) undiluted liquid grab sample collection, (5) containment building atmosphere sample purging and dilution, and (6) system flushing. An operation description for these categories is provided below:

Reactor coolant sample purging is accomplised by directing the sample flow through the system isolation valves, the sample vessel/heat exchanger, the pressure reducing throttle valve, and out to the containment building sump. At reactor coolant pressures of less than 200 psig the containment sump sample flow is purged in the same manner using the safeguards pump discharge connection.

Reactor coolant gaseous analysis is performed on a pressurized sample which is collected by isolating the sample vessel/heat exchanger. Total dissolved gas concentration is determined by degassing the sample. This is accomplished by depressurization and circulation by alternate operation of the burette isolation valve and the sample circulation pump. The resulting displacement of liquid into the burette is used to calculate the dissolved gas concentration. The collected gases, which have been stripped from the liquid, are then directed through a float valve for moisture separation and circulated through hydrogen and oxygen analyzers. After recording the hydrogen and oxygen gas concentrations, the gas sample vessel, which contains nitrogen, may be placed on line to dilute the gas volume. This dilution operation reduces the radiation levels such that local samples can be drawn from the gas sample vessel; if desired, by injection of a syringe through a septum plug mounted in the vessel. Prior to sample withdrawal, additional dilution, which may be necessary for this quantification, may be performed by further nitrogen addition, circulation and venting.

O_2 NOT ACCURATE BUT H_2 OK FOR FEW WEEKS

Reactor coolant liquid analyses is accomplished by reinitiating and directing the sample flow through the in-line chemistry analysis equipment. The gas residence chamber and float valve downstream of the throttle valve allows for automatic venting of gases coming out of solution. This venting is required in order to prevent gas bubble interference with flow rate and chemistry measurements in the downstream instrumentation. Boron and pH readings are obtained from the in-line instrumentation. A small fixed volume of depressurized liquid sample (collected in a four-way valve) is then drained to the depressurized liquid sample vessel and a sample is withdrawn in the same manner as described above for the gas sample.

An undiluted liquid grab sample for chloride analysis can be collected by directing reactor coolant purge flow through the undiluted depressurized liquid sample vessel. This vessel is provided with a lead shielded container and cart for transfer of sample to the analysis location. The isolation valves for the vessel are provided with stem extensions penetrating the shielding.

INSERT A

Containment building atmosphere sampling is initiated by opening the containment isolation valves and by using the containment sample pump to purge the air sample through the system. Purge flow is directed back to containment. A sample is manually withdrawn from the containment sample vessel containing nitrogen. The initial nitrogen volume dilutes the sample to levels acceptable for withdrawal. A containment air sample may then be withdrawn from the containment sample vessel in the same manner as described previously for the reactor coolant samples.

System flushing of the liquid and gaseous portions is accomplised by purging with demineralized water and nitrogen, respectively, to reduce personnel exposure during withdrawal of the diluted samples and to reduce contamination plateout between samples.

INSERT A

In accordance with item II.B.3 of NUREG-0737 (pg. 3-67, item 4) PASS has the capability to monitor total dissolved gases and H_2 concentration. The capability of monitoring dissolved O_2 will be in accordance with Regulatory Guide 1.97 rev. 2.

Radionuclide analyses are performed on grab samples. These samples are counted in standard radionuclide counting equipment.

Grab sample techniques are utilized for ___ analysis.

Backup boron analysis is performed using atomic absorption techniques.

Containment hydrogen analyzers are described in Subsection 6.2.5.

INSERT B

9.3.6.3 Component Description

The major PASS components are described in this section. The principal component data summary including design code is provided in Table 9.3.11.

1. Sample Station

The sample station is a free-standing skid-mounted enclosure. The enclosure contains the piping, valves, components and instrumentation necessary to provide the sampling and analysis capability. The enclosure is provided with louvers sized to pass up to 333 scfm from the surrounding room to the ventilation system suction connection in the upper portion of the enclosure. This air flow precludes any possible buildup of radioactive or hydrogen gas and provides for removal of heat generated by internal components. The enclosure is provided with removable panels on all four sides to ensure accessibility for maintenance.

2. Sample Circulation Pump

The sample circulation pump is a peristaltic type postitive displacement pump. This pump is capable of pumping liquids and/or gases. The pump will be used in the total gas, hydrogen, and oxygen gas analyses operations to strip the gases out of solution in the sample fluid and circulate them through the hydrogen and oxygen analyzers.

INSERT B

The estimation of core damage will be done by analyzing gas sample activity (samples from the RCS loop), sump activity, and containment air activity. The total curies available will be determined and related to total activity in the core (based on Chapter 15 data and plant shielding studies) to determine what % of the total core activity was released.

3. Surge Vessel Pump

The surge vessel pump is a progressing cavity (helical) pump. The pump is used to pump down the surge vessel contents to the containment building sump and is also used in the calibration operation of the pH in the liquid sample line.

4. Containment Sample Pump

The containment sample pump is a vacuum pump/compressor unit that operates as a positive displacement compressor using a stainless steel diaphram. The pump is used to collect a containment atmosphere sample and to dilute the sample via circulation through the containment sample vessel.

5. Gas Sample Vessel

The gas sample vessel is a 12,000 ml sample vessel initially filled with nitrogen gas. The vessel supplies the gas analysis loop with nitrogen gas to dilute the radioactive gases present in the sample line. The vessel is equipped with a septum plug which allows the operator to withdraw a diluted gaseous sample with a syringe for radiological analysis.

6. Depressurized Liquid Sample Vessel

The depressurized liquid sample vessel is a 12,000 mll sample vessel. This vessel collects a liquid sample trapped in the four-way valve located above the sample vessel. The vessel is partially filled with demineralized water before the sample is drained into the vessel. Additional demineralized water is then added to obtain the proper dilution factor so that a liquid sample can be withdrawn for radiological analysis. This vessel is equipped with a septum plug for sample withdrawal using a syringe.

7. Containment Sample Vessel

The containment sample vessel is a 12,000 ml sample vessel that is initially filled with nitrogen gas for dilution. The containment sample pump draws a sample from containment and circulates it through the sample vessel where the nitrogen gas dilutes the sample so that it can be withdrawn for radiological analysis. This vessel is equipped with a septum plug for sample withdrawal.

8. Surge Vessel

The surge vessel has a 10 gallon capacity and serves as a vent and drain tank for the depressurized liquid sample vessel and the total gas analysis burette. This vessel can also be filled with buffer solution used to calibrate the in-line pH meter.

9. Sample Vessel/Heat Exchanger

The sample vessel/heat exchanger is a vertically mounted, shell and tube type heat exchanger. The heat exchanger uses component cooling water to cool the reactor coolant sample flow from a maximum RCS temperature of 650^{o} to 120^{o}F to allow low temperature sample analysis. The tube side of the heat exchanger serves as a sample vessel for collection of a pressurized reactor coolant sample.

10. Stainless Steel Burette

The stainless steel burette has a 1,000 ml capacity. The burette is used to determine the amount of total gas present in the sample fluid by measuring a difference in the fluid level of the burette upon degassification of the pressurized reactor coolant sample.

11. Strainer

The strainer is designed to remove insoluble particles which may cause sample station chemistry instrumentation to become plugged. The strainer can be backflushed with demineralized water remotely by operation of valves at the control panel.

12. Grab Sample Facility

The grab sample facility is designed to obtain a 75 cc undiluted sample of reactor coolant liquid. The facility consisted of a lead shielded sample vessel and valves mounted on a cart for transport within the plant. The facility is manually operated.

13. Gas Residence Chamber

The gas residence chamber is a horizontally mounted lead shielded baffled cylindrical vessel. The chamber is used to remove undissolved gases from reactor coolant samples to prevent interference with the in-line process monitors.

14. Charcoal Exhaust Filter

The charcoal filter is designed to remove radioactive iodine and particulate material from the enclosure ventilation exhaust. The filter is mounted in a separate housing located on top of the sample skid enclosure.

9.3.6.4 Instrumentation and Control Description

The major PASS instruments and controls are described in this section. The on-line process monitor data is provided in Table 9.3.12.

1. Control Panel

The panel is designed to meet NEMA-12 requirements. All sample system non-code isolation valves and pumps are controlled from this panel. Indication of all process parameters and chemistry readouts are displayed on the panel. To facilitate system and operability all controls and indications are arranged in a mimic of the system. All process pumps and valves are equipped with hand switches at the control panel.

2. Heat Tracing

The containment building atmosphere sample piping is heat traced to limit plateout of radioiodine and condensation of containment atmosphere vapor. The heat tracing ensures a representative gas sample.

3. Boron Meter

The Boron Meter is a specific gravity measuring device which determines and remotely indicates the concentration of boron present in the liquid sample.

4. pH Meter

The pH meter determines and remotely indicates pH in the liquid sample.

5. Hydrogen Analyzer

The hydrogen analyzer is a thermal conductivity device that determines and remotely indicates the volume percent of hydrogen in the gas stripped from the reactor coolant.

6. Oxygen Analyzer

The oxygen analyzer is a paramagnetic device that determines and remotely indicates the volume percent of oxygen in the gas stripped from the reactor coolant.

9.3.6.5 System Evaluation

The location of the post-accident reactor coolant and containment atmosphere sampling system are in an area of relatively low post-accident background radiation. This ensures compliance with the personnel exposure limits of NUREG 0737 during sampling and analysis. Additional plant shielding along with selective routing of interconnecting piping to the existing sampling system ensures that (1) the exposure limits for personnel are not exceeded and (2) the on-site radiochemistry analysis equipment is available for

post-accident sample analyses. The sample station is also physically separated from safety related equipment such that failure of the associated non-seismic equipment does not cause damage to the safety related equipment.

Cooling water to the reactor coolant sampling system is available during post-accident conditions to enable low temperature sample analyses. Overrides are also available to enable opening of containment isolation valves following a CIAS so that post-accident sampling can be accomplished. Control for the reactor coolant sampling system return containment isolation valve is provided in the control room. An interlock is provided to ensure that this valve and the containment sump isolation valve is open before the system inlet isolation valve is open.

As much as practicable, reactor coolant sampling system connecting piping is pitched downward at least 10 degrees to prevent settling or separation of solids contained by the sample. Traps and pockets in which condensate or crud may settle are avoided since they may be partially emptied with changes in flow conditions and may result in sample contamination.

9.3.6.6 Testing and Inspection

The sample station skid and control panel are equipped with doors for testing and inspection during normal operations. The sample station is provided with removable panels on all four sides for inspection. Each component is tested and inspected prior to installation in the sample system. Instruments are calibrated during initial system installation. Automatic controls are tested for actuation at the proper setpoints. The system is operated and tested upon installation with regard to flow paths, flow capacity and mechanical operability.

Period calibration is performed according to the schedule provided in Table 9.3.13. The PASS is designed to function for six months under post-accident conditions without recalibration. System operability will be tested at a frequency minimum of six months, coinciding with the required six-month Emergency Plan sampling exercise. Such operating tests will check the functioning of all aspects of the system.

9.3.6.7 Operator Training

All FP&L Chemistry Department technicians will be trained both in the classroom and in actual hands-on operations, as a function of the Chemistry Department training program. Operating procedures will be developed and they will be consistent with the recommendations of the PASS supplier (Combustion Engineering).

Table 9.3.10

Post-Accident Sampling System Flow Rates

Source	Nominal Flow
Reactor Coolant Hot Leg	0.2 - 1.0 gpm
Containment Building Sump	0.2 - 1.0 gpm
Containment Atmosphere	0.2 cfm

Table 9.3.11

Design Data for Post-Accident Sampling System Components

1. Sample Circulation Pump

Type	Peristaltic Positive Displacement
Fluid	Post-Accident Reactor Coolant
Suction Pressure (max) psig	5
Suction Temperature (max) °F	160
Rated Flow, gpm	1
Rated Head, ft	50
Code	Non-Code

2. Surge Vessel Pump

Type	Positive Displacement
Fluid	Post-Accident Reactor Coolant
Suction Pressure (max) psig	5
Suction Temperature (max) °F	160
Rated Flow, gpm	1
Rated Head, ft	185
Code	Non-Code

3. Containment Sample Pump

Type	Vacuum Pump/Compressor
Fluid	Post-Accident Containment Atmosphere
Suction Pressure (max) psia	10-75
Suction Temperature (max) °F	300
Rated Flow, cfm	0.2
Maximum Discharge Pressure, psig	95
Code	Non-Code

4. Sample Vessel/Heat Exchanger

Type	Shell (cooling); Tube (sample flow)
Tube Sides:	
Fluid	Post Accident Reactor Coolant
Piping Design Pressure (max) psig	2485
Inlet Temperature (min/max) °F	120/650
Shell Side:	
Fluid	Component Cooling Water
Piping Design Pressure, psig	150
Inlet Temperature (min/max) °F	65/120
Flow (max) gpm	30
Code	Non-Code

Table 9.3.11 (cont'd)

Design Data for Post-Accident Sampling System Components

5. Depressurized Liquid Sample Vessel

Internal Volume, cc	12000 ml
Design Pressure, psig	50
Design Temperature, ^{o}F	200
Operational Pressure, psig	5
Operational Temperature, ^{o}F	120
Material	Stainless Steel 316L
Fluid	Post-Accident Reactor Coolant
Code	Non-Code

6. Gas Sample Vessel

Internal Volume, cc	12000
Design Pressure, psig	50
Design Temperature, ^{o}F	200
Operational Pressure, psig	5
Operational Temperature, ^{o}F	120
Material	Stainless Steel 316L
Fluid	N_2, H_2, O_2, Fission Products
Code	Non-Code

7. Containment Sample Vessel

Internal Volume, cc	12000
Design Pressure, psig	50
Design Temperature, ^{o}F	100
Operational Pressure, psig	0 to 20
Operational Temperature, ^{o}F	275
Material	Stainless Steel 316L
Fluid	Steam, Air, H_2, Fission Products
Code	Non-Code

8. Surge Vessel

Internal Volume, gal.	10
Design Pressure, psig	100
Design Temperature, ^{o}F	200
Operational Pressure, psig	5
Operational Temperature, ^{o}F	120
Material	Stainless Steel 316L
Fluid	Post-Accident Reactor Coolant
Code	Non-Code

<u>Table 9.3.11</u> (cont'd)

<u>Design Data for Post-Accident Sampling System Components</u>

9. <u>Burette</u>

Internal Volume, cc	1000
Design Pressure, psig	100
Design Temperature, °F	200
Operational Pressure, psig	5
Operational Temperature, °F	120
Material	Stainless Steel 316L
Fluid	Post-Accident Reactor Coolant
Code	Non-Code

10. <u>Strainer</u>

Type	"Y" Type Mesh
Particle Size Retention	250 Microns
Operating Pressure, psig	2235
Operating Temperature, °F	621
Design Flow, gpm	2
Operating Flow (max) gpm	1
Clean ΔP (psig @ gpm)	2 @ 1
Loaded ΔP (psig @ gpm)	10 @ 1
Collapse ΔP (psig @ gpm)	70 @ 1

11. <u>Gas Residence Chamber</u>

Design Pressure, psig	130
Design Temperature, °F	350
Operational Pressure, psig	80
Operational Temperature, °F	120
Volume, cc	4600
Fluid	Post-Accident Reactor Coolant
Material	Stainless Steel 316L
Code	Non-Code

12. <u>Exhaust Charcoal Filter</u>

Type	Replaceable Cartridge
Type Element	Activated Charcoal
Design Flow, scfm	333
Operational Flow, scfm	250-333
Operational Pressure	Atmospheric
Fluid	Aux. Bldg. Atmosphere
Clean ΔP, inches water @ scfm	< 1 @ 333
Loaded ΔP, inches water @ scfm	1 @ 333
Code	Non-Code

Table 9.3.12

Design Data for Post-Accident Sampling System Process Instruments

Instrument	Description	Accuracy	Range
Boron Meter	Density Sensor	± 100 ppm	0 to 5000 ppm
pH Meter	Electrode Sensor	± 0.05	3 to 12
Hydrogen Analyzer	Thermal Conductivity Sensor	± 2% of scale	0 to 100%, 0 to 10%
Oxygen Analyzer	Paramagnetic Sensor	± 2% of scale	0 to 25%, 0 to 5%

Table 9.3.13

Instrument Calibration Frequency

Component Identification	Calibration Frequency	Maintenance Frequency	Maintenance or Calibration Technique
Charcoal Filter	-	as req'd	Replace filter when saturated, or when dosage is unacceptable (test with freon)
Pumps	-	as req'd	As required
Valves	-	18 mos.	Functionally test and repair as required
Level Instruments	6 mos.	-	Reset zero and span against known vessel levels
Pressure Instruments	6 mos.	-	Check accuracy against a standard
Pressure Instruments with alarm & control functions	6 mos.	-	Check pressure setpoints
pH Monitor	6 mos.*	-	Calibrate with buffer solution
H_2 & O_2 Meters	6 mos.-1 yr	-	Set zero and span using standard gases
Boron Meter	6 mos.*	-	Check zero, span, and temp. compensator against test boron solution and demineralized water
Flow Meters	6 mos.	-	Check accuracy against a standard
Panalarm	6 mos.	-	Check alarm function

*Calibration frequency can be extended until instrument malfunctions or gets unstable readings in a post-accident situation

???

ST LUCIE FSAR

Question No.

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

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 point. 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 the following safety grade instruments & control devices. Safety grade isolation devices are also provided to isolate signals generated by safety grade equipment to non-safety grade station annunciators and sequence of events recorder.

Tag No.	Device	Function	Class	Channel
1. FIS-14-15 A,B,C,D	Indicator & Bistable	Indicates CCW Flow from RC Pumps & Provides RPS Trip Signal	IE	ma,mb,mc,md
2. FF-14-15 A,B,C,D	Sq Root Extractor	Signal Conditioner & Transmitter Power Supply	IE	ma,mb,mc,md
3. 80XA,b,c,d	10 min. timer	Alarms low CCW flow instantly & Delay Reactor trip for 10 minutes	IE	ma,mb,mc,md
4. CS-206-1,2,3,4*	Control Switch	Provides testability for Indicator - Bistable 10 min. timer	IE	ma,mb,mc,md

*Includes set of safety grade test resistors.

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 judgment 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 of St Lucie Unit 2, and the information available to the operator (see FSAR Subsection 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.

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°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).

No FSAR change required as a result of the above responses.

3.4.2.3.3 Diffuser

Each of the 58 ports is mounted on a 14 foot high riser, with a four foot inside diameter (Figure 3.4-4). To control marine growth, the inside wall of each riser is lined with NOFOUL, a rubber containing bis-(n-tributyltin) oxide (TBTO). TBTO release rates and its effects on biota are discussed in Section 3.6 and 5.3.

3.6.8.4 Bis-(n-Tributyltin) Oxide

NOFOUL rubber is a neoprene rubber base with bis-(n-tributyltin) oxide, otherwise known as TBTO, dissolved in it. TBTO is toxic at low concentrations to barnacles, snails, tube worms, mussels, oysters, encrusting byrozoa, algae and other fouling organisms. The antifouling properties of NOFOUL are maintained by the controlled, slow release of TBTO from the rubber. At St Lucie Unit 2, the lining will be 0.5 inch thick with a five percent concentration of TBTO.

From estimates made by B F Goodrich[3], the following continuous release rates of TBTO from the NOFOUL liner are expected from the St Lucie plant (total area = 10,950 sq ft; discharge pipe water flow rate = 515,000 gpm):

1st year of operation average release rate = 0.039 ppb
1st ten years of operation average release rate = 0.025 ppb
2nd ten years of operation, average release rate = 0.018 ppb

The TBTO is released directly to the ocean from the discharge pipe risers. These data are summarized in Table 3.6-1.

5.1.3.2.3 Effects of NOFOUL

NOFOUL rubber with TBTO (bis (tri-n-butyltin) oxide) as the active ingredient has been tested as an antifoulant on coast guard buoys, sonar domes and recreational boats. Marine paints using TBTO for its antifouling properties have been commercially marketed for the last several years. TBTO is currently registered with the US EPA - (Office of Pesticides) for use as an antifoulant. The proposed use of NOFOUL at St Lucie Unit 2 is consistent with the existing registration guidelines.[4]

TBTO is released from the NOFOUL lining of the discharge pipe risers directly to the Atlantic Ocean at an estimated average concentration range of 0.018 to 0.039 ppb over the life of the plant (see Section 3.6.8.4). The expected degradation pathway of TBTO in water is[5]:

trialkyltin form dialkyltin form monoalkyltin form inorganic tin form
(most toxic) (moderately toxic) (generally non toxic)

where each degradation product is less toxic than TBTO.

TBTO is toxic at low concentrations to barnacles, snails, tube worms, mussels oysters, encrusting bryozoa, algae and other fouling organisms. Results of acute, subacute and chronic toxicity studies for a variety of aquatic species are presented in Table 5.3-3. The lowest concentration of TBTO reported to cause acute effects for any species tested is about 10 ppb (50 percent of the pink shrimp died in 96 hours). For longer

exposure times, the lowest concentration of TBTO reported to cause death is 0.2 ppb (5 percent of the guppies died after a 30 day exposure) and 0.96 ppb (5 percent of the sheepshead minnows died after a 21 day exposure).

In evaluating the potential toxicity of TBTO to biota offshore of Hutchinson Island, three environmental pathways of TBTO were considered. The first case assumes all the released TBTO remains in the water phase and none is lost to the sediments or degraded to other forms. This is a worst case situation for the water phase with respect to organotin. The second case assumes that the released TBTO may associate with the sediment phase. Since TBTO is known to readily associate with organic material and sediments, this situation is considered more realistic. The third case considers the impact of the inorganic tin form (which is assumed to be the eventual degradation product) in the water phase. This situation assumes complete and rapid conversion to the inorganic form. These cases are considered in more detail below.

The first case assumes that all released TBTO is fully mixed in the water phase, with no loss to the sediments. Under these conditions, the expected concentration of TBTO would not exceed that of the maximum discharge (0.039 ppb first year average). The dilution factor, under stagnant conditions, established from hydrothermal studies at the St Lucie plant (assuming a 28°F discharge temperature rise and a 3.5°F surface temperature increase for St Lucie Unit 2) is eight for a volume of approximately one acre-foot. The estimated TBTO concentration after dilution from St Lucie Unit 2 is 0.005 ppb. Both the immediate discharge concentration and the diluted concentration are below those seen to cause acute or chronic effects in the fish species tested to date.

Case two considers the potential partitioning of TBTO between suspended solids in the water column and the water at the St Lucie plant discharge site. Calculations of relative TBTO distributions have been based upon Freundlich isotherm equilibrium constant values reported by Slesinger[6] for TBTO adsorption to sediments. Utilizing a Freundlich equation constant $K = 40$ (ml/g) (conservatively based upon TBTO adsorption to sandy loam soil) and a probable maximum concentration of total suspended solids (TSS) measured at the site (see Table 2.4-5), TBTO mass distribution percentages have been calculated. The results indicate that for TSS levels of 100 ppm or less, more than 99 percent of the mass of the released TBTO will remain in the aqueous phase with less than one percent of the TBTO adsorbed onto suspended solid particles. This calculation appears conservative for the sandy sediment material characteristic of the St Lucie site. Therefore, the case two analysis is similar to the case one situation where adverse impact is not expected to occur.

Case three, the addition of inorganic tin to the water phase through degradation of TBTO, was also examined. If all the TBTO discharged (0.039 ppb first year average discharge) is converted to inorganic tin, the aqueous tin concentration of tin would be 0.016 ppb. After dilution (dilution factor of eight), the expected concentration is 0.002 ppb. Ambient sea water tin concentration has been reported as 0.8 ppb[7]

with a range of 0.002-0.8 ppb(8). This addition of tin to the ambient concentration is expected to have minimal impact on water quality or biota.

These TBTO calculations, including the release rate calculations, are based on a discharge rate of 515,000 gpm. The rate of release of TBTO is independent of the amount of water passing through the pipe. Significant decreases in the discharge rate of 515,000 gpm will result in approximately the same quantity of TBTO released into a smaller volume of water. Thus, higher concentrations of TBTO may be expected in the discharge water at these times. Because of the improved thermal mixing properties of the St Lucie Unit 2 discharge pipeline, this pipeline will be the preferred discharge route for both St Lucie Units 1 and 2. Consequently, operation of either plant will result in normal flow rates through the St Lucie Unit 2 discharge pipeline.

Several swimming areas exist hear the discharge pipeline. Although no information is available on potentially harmful affects of TBTO exposure in water, TBTO concentration level are expected to be very low at any swimming area due to the low initial release rate and the dilution that will occur through mixing in the discharge plume.

In summary, TBTO release from the St Lucie Unit 2 discharge diffuser during normal operation of the plant is not expected to adversely affect water quality or biota as examined in the three cases described above. The TBTO levels expected in these cases are below those seen to cause acute or chronic effects in aquatic species tested to date.

3. Written Communication, B F Goodrich to Ebasco Services, Inc. 1981

4. Written Communication, US EPA to B F Goodrich, 1976

5. Cardarelli, N, 1977. Controlled Release Molluscicides. Environmental Management Laboratory Monograph, University of Akron, Akron, Ohio.

6. Slesinger, A. The Safe Disposal of Organotins in Soil, 1978. in Organotin Workshop Report, M.L. Good, Editor. Sponsored by the Office of Naval Research.

7. NOFOUL Anti-Fouling Rubber. Technical Background Document, B F Goodrich, 1980.

8. Riley, J P and G Skirrow, 1965. Chemical Oceanography Vol 1. Academic Press, New York.

9. Bowen, H J M, 1979. Environmental Chemistry of the Elements. Academic Press, New York.

TABLE 5.3.-3

TBTO TOXICITY

Acute Studies

Species	Exposure Time	Test Condition	Concentration in ppm	Reference
Iteterotis hemichromes	120+hr 120+hr	LC_{50}**	0.03	Cardarelli (1977)[3]
Tilapia nilotica	120+hr	LD_{50}*	0.03	Cardarelli (1977)[3]
Tilapia nilotica	15 days	LD_{70}	0.045	Cardarelli (1977)[3]
Hemichromis sp	15 days	LD_{70}	0.045	Cardarelli (1977)[3]
Carassius auratus (goldifsh)	24hr	LD_{100}	0.075	Cardarelli (1977)[3]
Lebistes reticulatus (guppy)	24hr	LD_{100}	0.075	Cardarelli (1977)[3]
Salmo gairdneri (rainbow trout)	24hr	LD_{100}	0.028	Cardarelli (1977)[3]
Salmo gairdneri (rainbow trout)	48hr	LD_{100}	0.02	Cardarelli (1977)[3]
Lepomis macrochirus (blue gill)	24hr	LD_{50}	0.07	Cardarelli (1977)[3]
Lepomis macrochirus (blue gill)	48hr	LD_{50}	0.0405	Cardarelli (1977)[5]
Aspergillus niger (fungus)		LD_{100}	0.5	Cardarelli (1977)[5]
Bacillus mycoides (bacterium)		LD_{100}	0.1	Cardarelli (1977)[5]
Bulinus tropicus (snail)		LD_{50}	0.01	Cardarelli (1977)[5]
Bulinus contortus (snail)		LD_{100}	0.075	Cardarelli (1977)[5]
Common mummichog	96hr	LC_{50}	0.024	Slesinger 1979 as noted in reference 7.

TABLE 5.3-3

Species	Exposure Time	Test Condition	Concentration in ppm	Reference
Pink shrimp	96hr	LC_{50}	0.011	Slesinger 1979 as noted in reference 7.
Fiddler crabs	96hr	EC_{50}	7.3	Slesinger 1979 as noted in reference 7.
Subacute and Chronic Studies				
Lebistes reticulatus (guppy)	30 day	LC_5	0.0002	Cardarelli (1977)[5]
Lebistes reticulatus (guppy)	60 day	LC_5	0.0014	Cardarelli (1977)[5]
Cyprinodon variegatus (sheepshead minnow)	21 day	LC_{50}	0.00096	Slesinger 1979 as noted in reference 7.
Cyprinodon variegatus (sheepshead minnow)	21 day	LC_0	0.00033	Slesinger 1979 as noted in reference 7.
Cyprinodon variegatus (sheepshead minnow)	177 day	LC_{100}	0.0048	Slesinger 1979 as noted in reference 7.

EC_x = estimated concentration which results in mortality to "x" percent of the test organisms

*LD_x = dose, which results in mortality to "x" percent of the test organisms

**LC_x = concentration which results in mortality to "x" percent of the test organisms

TABLE 1.9B-3

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 1.9B-7 depicts the locations of the CETs.
2.	The primary display will have a spatically oriented core map available on demand, as well as selected readings of individual CET's. Direct readout and hard-copy capability will also be available. Trend capability showing the temperature-time history of representative core exit temperature values will be available on demand. The operator-display device interface will be human-factor designed to provide rapid access to requested displays.
3.	ICC instrumentation design incoporates a minimum of one backup display with the capability of selective reading of a minimum of 16 operable Thermocouples, 4 from each quadrant. All CET temeratures can be displayed within 6 minutes.
4.	The types and locations of displays and alarms are determined for the primary display by performing a human-factors analysis. The QSPDS also incorporates human factors engineering. The use of these display systems will be addressed in operating procedures, emergency procedures, and operator training.
5.	The ICC instrumentation was evaluated for conformance to Appendix B of NUREG-0737 (see table 1.9B-4).
6.	The QSPDS channels are Class 1E, electrically independent, energized from independent station Class 1E power sources and physically separated in accordance with Regulatory Guide 1.75 "Physical Independence of Electric Systems" January 1975 (R1) up to and including the isolation devices.

Item	Response
7.	ICC instrumentation shall be environmentally qualified pursuant to C-E owners group qualification program. The isolation devices in the QSPDS are accessible for maintenance following an accident.
8.	Primary and backup display channels are designed to provide the highest availability possible. The QSPDS is designed to provide 99% availability. The availability of the QSPDS will be addressed in the Technical Specifications.
9.	The quality assurance provision of Appendix B, Item 5, will be applied to the ICC detection instruments as described in the Appendix B evaluation in Table 1.9B-4.

TABLE 1.9B-4

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. The isolation devices in the QSPDS are accessible for maintenance following an accident.
2.	The ICC detection instrumentation through the QSPDS 1E isolators meet the single failure requirements specified in Appendix B of NUREG 0737.
3.	The ICC detection instrumentation through the QSPDS 1E isolators are powered from the Class 1E power sources for channels A and B.
4.	The ICC detection instrumentation through the QSPDS 1E isolators are designed to operate during normal as well as emergency conditions. The availability will be addressed in the technical specification.
5.	Recommendations of the following Regulatory Guides were considered in the design of ICC instrumentation; 1.28 "Quality Assurance Program Requirements (Design & Construction)" 1.30 "Quality Assurance Requirements for the Installation Inspection and Testing of Instrumentation and Electric Equipment". 1.38 "Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants". 1.58 "Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel". 1.64 "Quality Assurance Requirements for the Design of Nuclear Power Plants". 1.74 "Quality Assurance Terms and Definitions". 1.88 "Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records". 1.123 "Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants".

Item	Response
5. (cont'd)	1.144 "Auditing of Quality Assurance Programs for Nuclear Power Plants".
6.	The ICC detection instrumentation outputs are continuously available on the QSPDS displays.
7.	The ICC instrumentation is designed to provide readout display and trending information to the operator.
8.	The inadequate core cooling instrumentation is specifically and singularly identified so that the operator can easily discern their use during an accident condition.
9.	Transmission of signals from instruments of associated sensors between redundant 1E channels or between 1E and non-1E instrument channels are isolated with isolation devices qualified to the provisions of Appendix B.
10.	The QSPDS consists of two redundant channels to avoid interruptions of display due to a single failure. If in the remote chance that one complete QSPDS channel fails, the operator has 1. Additional channels of ICC sensor inputs for cold leg temperature, hot leg temperature, and pressuizer pressure on the control board separate from the QSPDS. 2. The HJTCS and CET have multiple sensors in each channel for the operator to correlate and check inputs. 3. The HJTCS sensor output may be tested by the operator reading the temperature of the unheated thermocouple and comparing to other temperature indications. Further HJTC sensor tests can be performed with special test equipment. 4. Other variables are available to the operator on the Main Control Board for verifying the ICC parameter.
11.	Servicing, testing and calibrating programs shall be consistent with operating technical specifications.
12.	The system design is such as to facilitate administrative control during periods when channels are removed from service.

Item	Response
13.	The system design is such as to facilitate administrative control of access to all setpoints adjustments, 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 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 be capable of periodic testing of instrument channels.

1.0 Figure 6.2-9 and Figure 6.2-10, with respect to containment pressure and temperature responses following a MSLB accident, should be revised to show the containment pressure/temperature response profiles (from time = 0 second to 10^5 seconds following the accident) for use in equipment qualification.

Response See FSAR revised text and new FSAR Figures 6.2-9a and 6.2-9b for containment pressure and temperature responses following a MSLB accident for the range of 0 to 10^5 seconds.

Pipe break locations, break areas, peak pressures and temperatures, times of peak pressure and total energy released to containment are summarized in Table 6.2-4 for each LOCA analyzed. The DBAs are identified in Table 6.2-2.

Figure 6.2-8 gives the rate of energy distribution inside containment for the LOCA containment pressure DBA. The long-term performance is essentially the same for all the LOCA cases. All mechanisms of energy storage within the containment are addressed. Included are the vapor energy (steam plus air), sump (liquid) energy, and energy contained in heat sinks. Table 6.2-10 summarizes the containment energy distribution at several key points in time. For the most severe Reactor Coolant System pipe breaks this table shows the distribution of energy prior to the accident, at the time of peak pressure, at the end of the blowdown phase, at the end of the core reflood phase (cold leg breaks), and steam generator energy release during the post-reflood phase (peak pressure only).

Main Steam Line Breaks

Analyses are performed to show that the containment design pressure is not exceeded even if the following single active failures are postulated: (1) loss of one containment heat removal train (i.e., two fan coolers and one spray pump); or (2) MSIV failure to close; or (3) main feedwater isolation valve (MFIV) failure to close. The assumptions for each case are discussed more fully in Subsection 6.2.1.4.2. | 0

The peak containment pressure is calculated to occur following the DBA 102 percent power MSLB with a failure of one MSIV assuming the availability of offsite power. The peak containment temperature is calculated to occur following the DBA 102 percent power MSLB with the failure of one of the trains of the Containment Heat Removal System with the availability of offsite power. The containment pressure and temperature transients for the most severe MSLB pressure and temperature cases are shown on Figures 6.2-9 through 6.2-12. Insert * Figures 6.2-12 and 13 show the calculated transient containment vessel surface temperature and shield wall temperature gradients, respectively, for the containment temperature DBA. Pipe break locations, break areas, peak pressures and temperatures, times of peak pressure, initial power level, single active failure assumed and total energy released to the containment are summarized in Table 6.2-4 for each MSLB analyzed. The DBAs are identified in Table 6.2-2. | 0

Figures 6.2-14 and 15 are plots of the condensation heat transfer coefficient versus time for the containment pressure and temperature DBAs. The Uchida heat transfer coefficient contained in the unmodified CONTEMPT-LT computer code is used for the analysis of all secondary system breaks.

The containment analyses for the MSLBs are performed using all the containment initial conditions, heat sinks and methodology assumed for the LOCA analyses except for the following:

a) For the MSIV and MFIV failure cases, two containment spray pumps operate and spray 5,300 gpm of water at 100 F into the containment.

* Figures 6.2-9a and 6.2-10a show the long term temperature and pressure history of the containment pressure DBA.

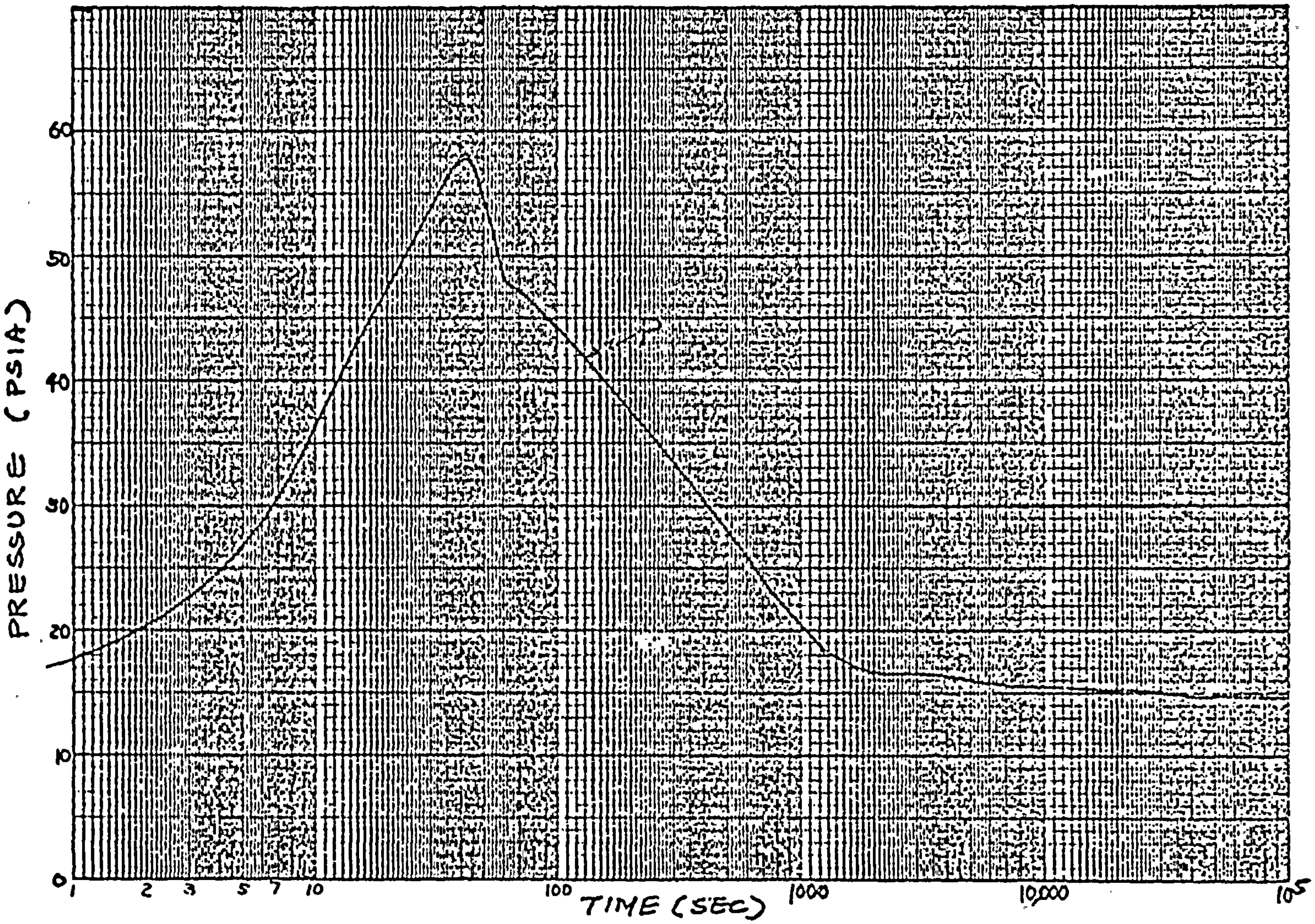


FIG. 6.2-9a CONTAINMENT PRESSURE — MSLB-MSIV FAILURE AT 102% POWER.

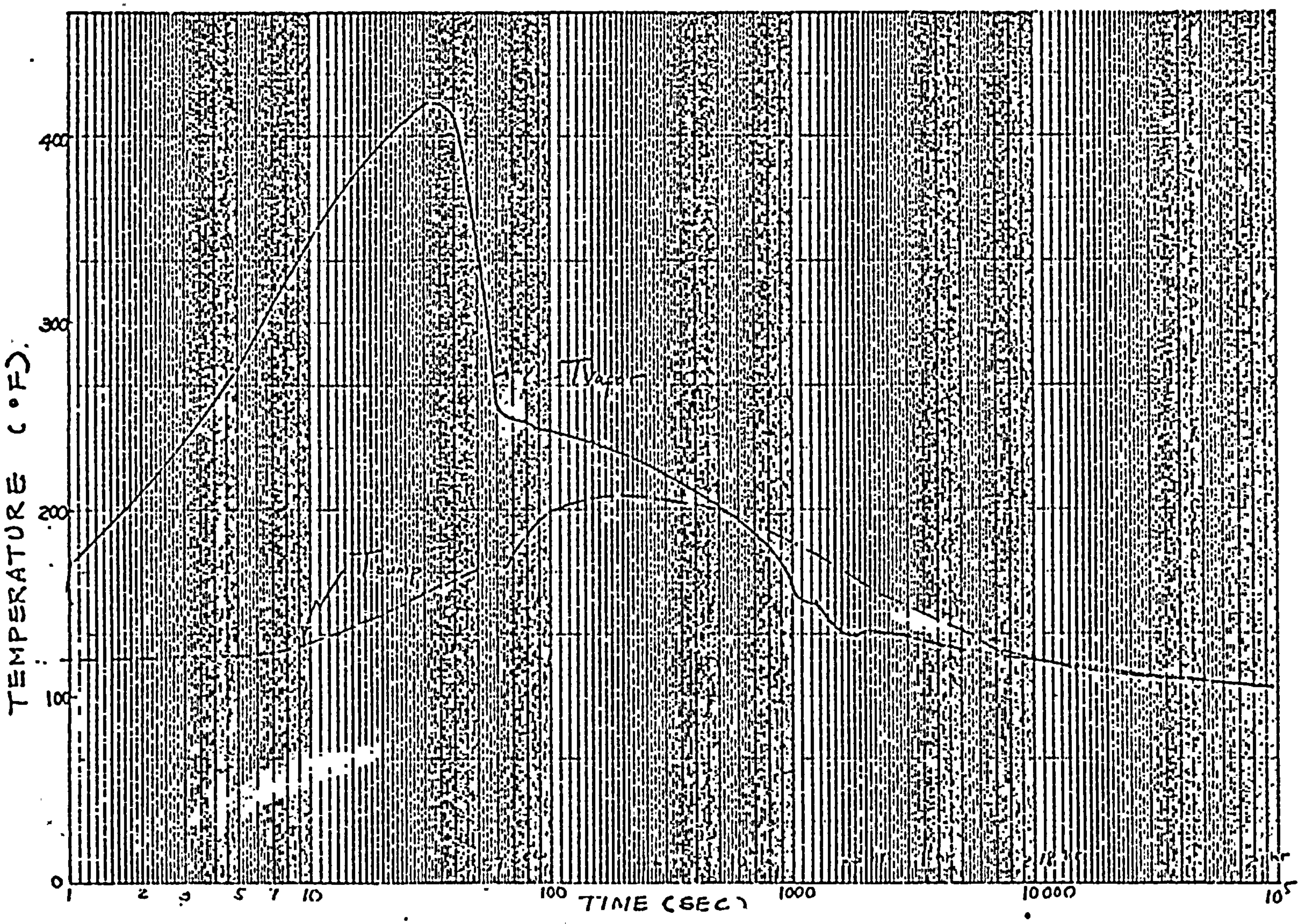


FIG. 6.2-10a CONTAINMENT TEMP. - MSLB-MSIV FAILURE AT 102 % POWER

2.0 For compartment (e.g., reactor cavity, secondary shield wall area, and pressurizer area) structural design evaluations, provide the design differential pressure and discuss whether the design differential pressure is uniformaly 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.

Design differential pressures for the primary shield wall have been spatially varied from a peak value of 86 PSI with provision for dynamic load factor.

See revised FSAR Table 6.2-3 and new FSAR Figure 6.2-25.

TABLE 6.2-3

PRINCIPAL CONTAINMENT DESIGN PARAMETERS

Parameter	Design	Margin[1]
Containment		
Internal design pressure, psig (LOCA)	44.0	5.26%
(MSLB)	44.0	1.36%
Shell surface design temperature, F	264 @ 44 psig	Refer to Figure 6.2-12
Differential design pressure, psid	0.70	16.6%
Net free volume, 10^6 ft^3	2.50	Not applicable
Design leak rate, percent free volume per day at 44.0 psig	0.5	Not applicable
Shield Building		
External design pressure, psig	3.0	387%
Subcompartments	Civil	
Reactor cavity design wall loading, psid	172	100%
Steam generator compartment design wall loading, psid	24.0	307%
Pressurizer compartment design upper wall loading, psid	14.0	977%

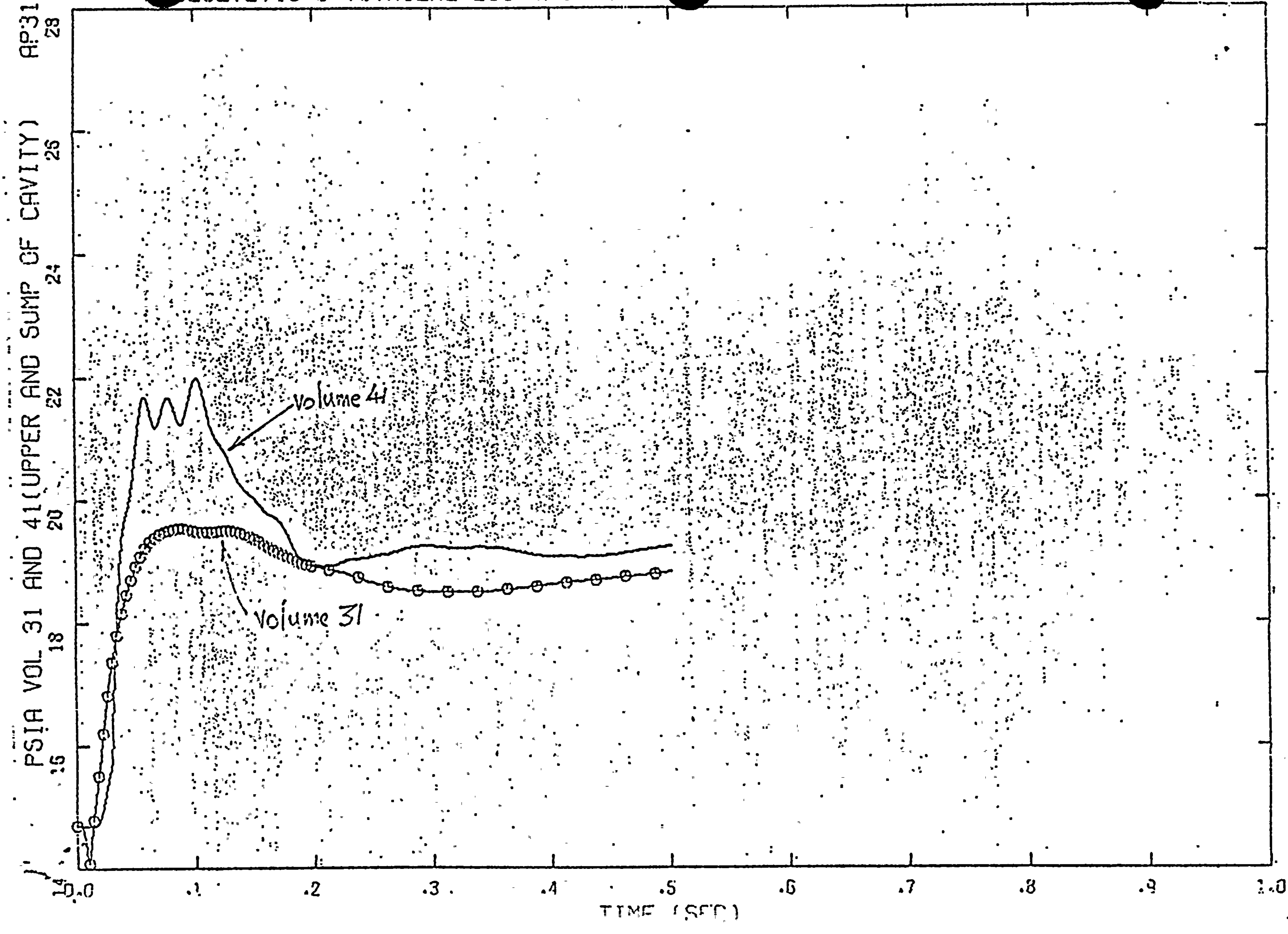
NOTES:

(1) Margin (%) = ~~100~~ $\dfrac{\text{design value} - \text{peak calculated value}}{\text{peak calculated value}} \times 100$

Actual margin, i.e. the margin between design values and peak calculated values when using realistic or median parameter values would be much larger.

FIG 62-25n

2CE(2,10-6-78)RC2R2-200 IN2 DI. GU BK RVNOZZL.5REL.ACT/OVSN 1.1 2/14/78



Question
3.0

Provide analyses to determine the external forces and moments, resulting from postulated hot leg and cold leg ruptures within the reactor cavity, on reactor vessel supports. If applicable, similar analyses should be performed for steam generator and/or pressurizer compartments that may be subject to pressurization where significant component support loads may result. For each analysis, provide the following information:

(1) Provide and justify the pipe break type, area, and location. Specify whether the pipe break was postulated for the evaluation of the compartment structural design, component support design, or both.

Response

FSAR Table 6.2-13 is a summary of postulated pipe ruptures for the containment subcompartment analysis. Contained in this table is the pipe break location, description of the break, break area and release rate data and table numbers.

Pipe break locations were chosen based upon the high stress point criteria in accordance with Reg. Guide 1.46 and SRP 3.6.2. Refer to MEB question #2 attached.

The peak leads tabulated from each of the pipe breaks listed on Table 6.2.13 was applied to the corresponding structure. In all cases it has been found that the structural design was adequate to withstand the differential forces resulting from the break. Table 6.2-3 (see revised table contained in answer to CSB branch question #2) provides a comparison between the peak calculated force and the structural design.

The major components of the RCS are designed to withstand the forces associated with the design basis pipe breaks. These pipe thrust forces at the break location, resultant subcompartment differential pressurization forces and internal asymmetri hydraulic forces acting in the reactor internals. A complete description of the evaluation of the plant faulted condition for these components is provided in the response to MEB questi #35 attached.

The major portion of the Asymetric Analysis has been completed MEB question response #35 contains a table (Table 1), that provides the current asymmetric loading analysis schedule for both the major components and the structural design indicating the anticipated completion date for each item.

ATT. TO CSB QUES. 3

Mech. Eng. Branch

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 Criteria Used to Define Break Locations for Pipe Whip Analysis

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 Piping 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.

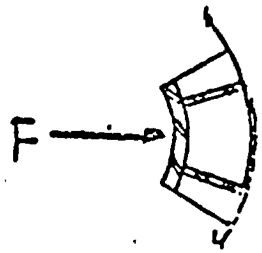
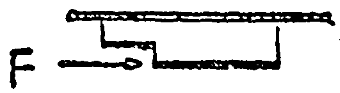
3) For the partial area guillotine type pipe breaks at the reactor inlet and outlet nozzles and the steam generator inlet nozzles, the methods of Reference (1) were employed to calculate the flow areas and opening times of the break at these locations. The stiffness values are provided in Table 3.6-2 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

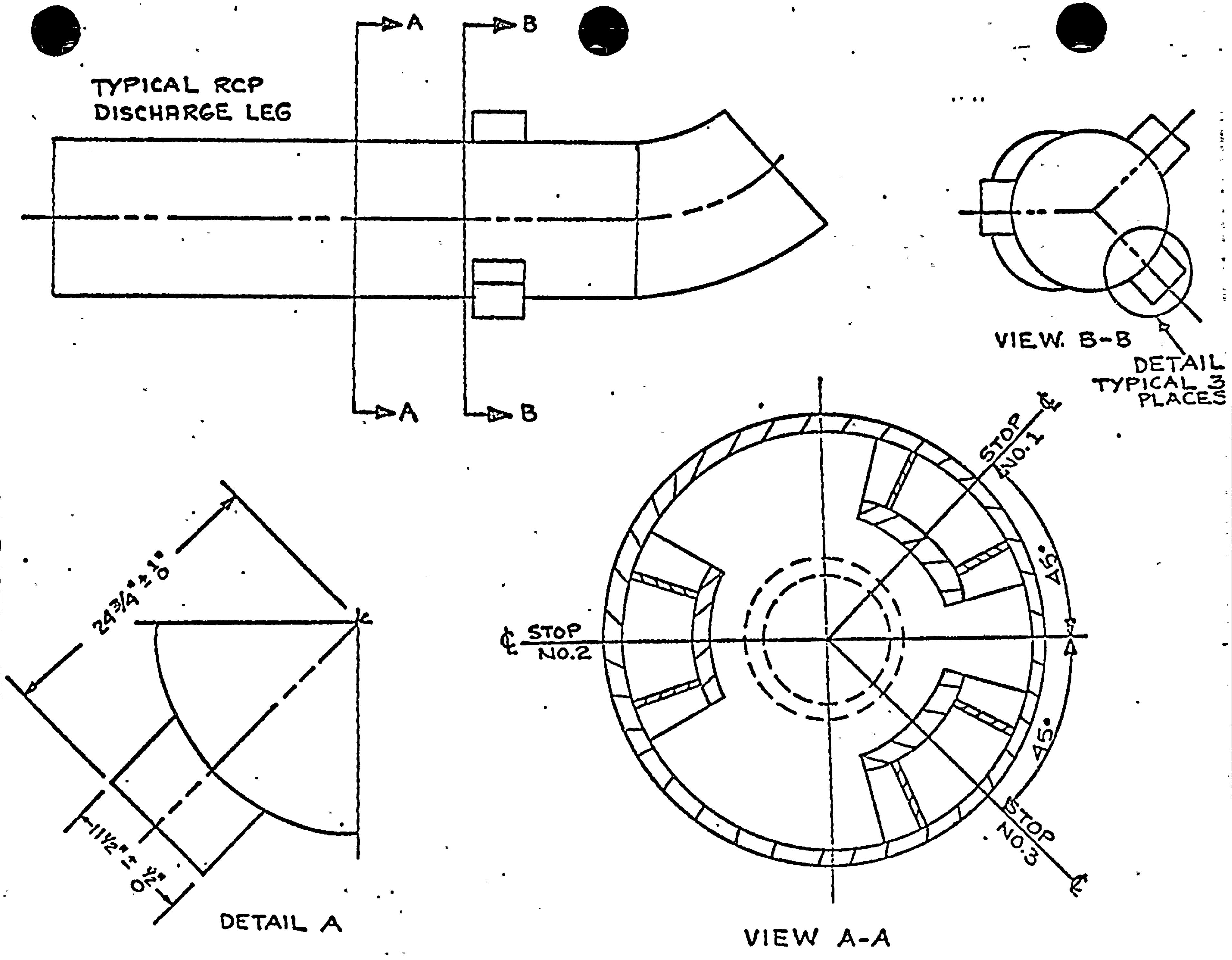
DIRECTION \ PIPE STOP \ STOP		STIFFNESS (K/IN)			REMARKS
		STOP No. 1	STOP No. 2	STOP No. 3	
RADIAL	2A1	300.3×10^3	295.1×10^3	299.3×10^3	
	2A2	356.2×10^3	252.9×10^3	355.9×10^3	
	2B1	222.6×10^3	222.8×10^3	221.0×10^3	
	2B2	319.2×10^3	366.7×10^3	319.3×10^3	
LONGITUDINAL	2A1	49.6×10^3	71.0×10^3	48.8×10^3	
	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	

PIPE BREAK AREAS AND BREAK OPENING TIMES

PARTIAL AREA GUILLOTINES

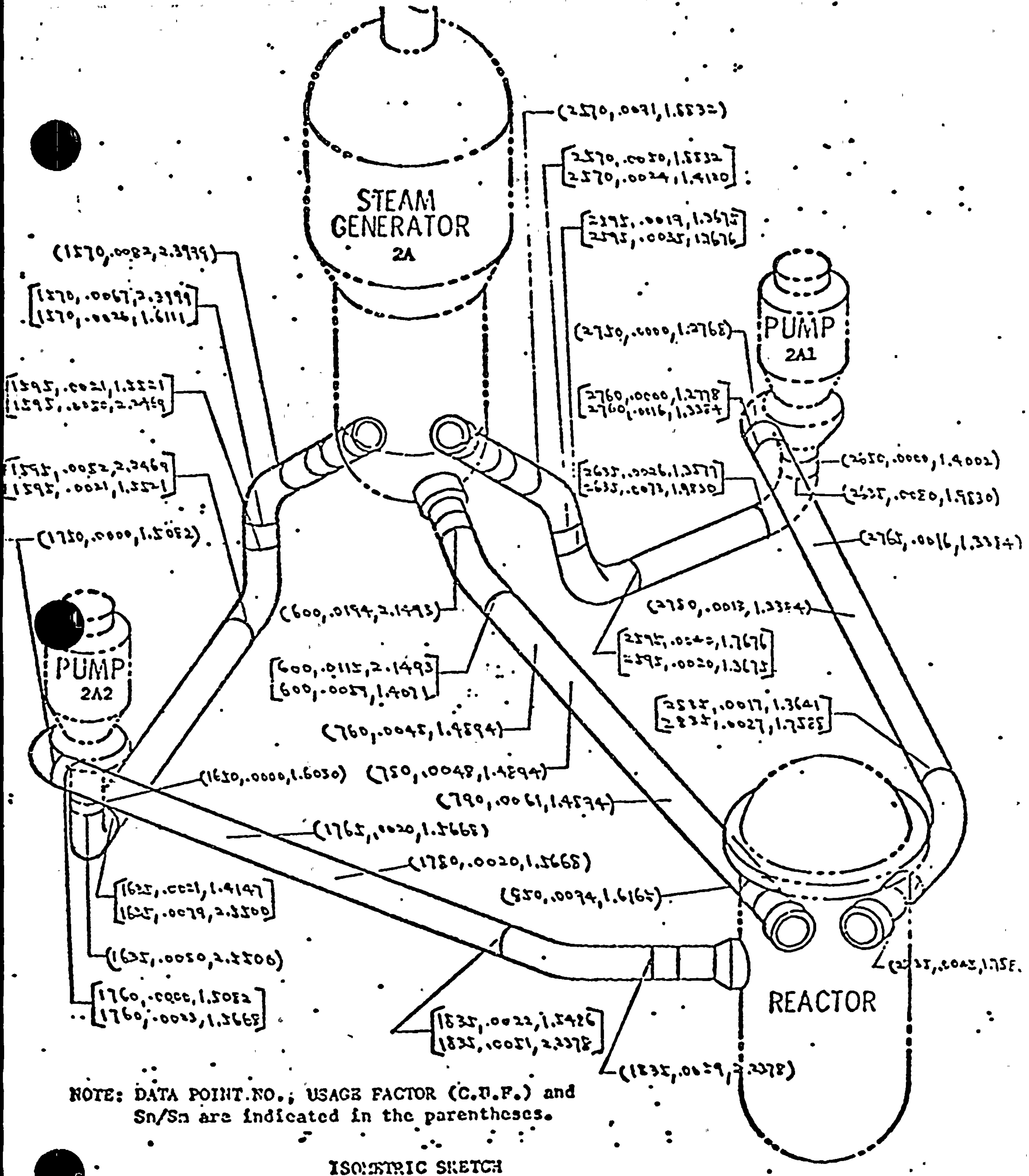
TABLE 3.6-3

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.



DISCHARGE LEG PIPE RESTRAINTS

FIGURE 3.6-3

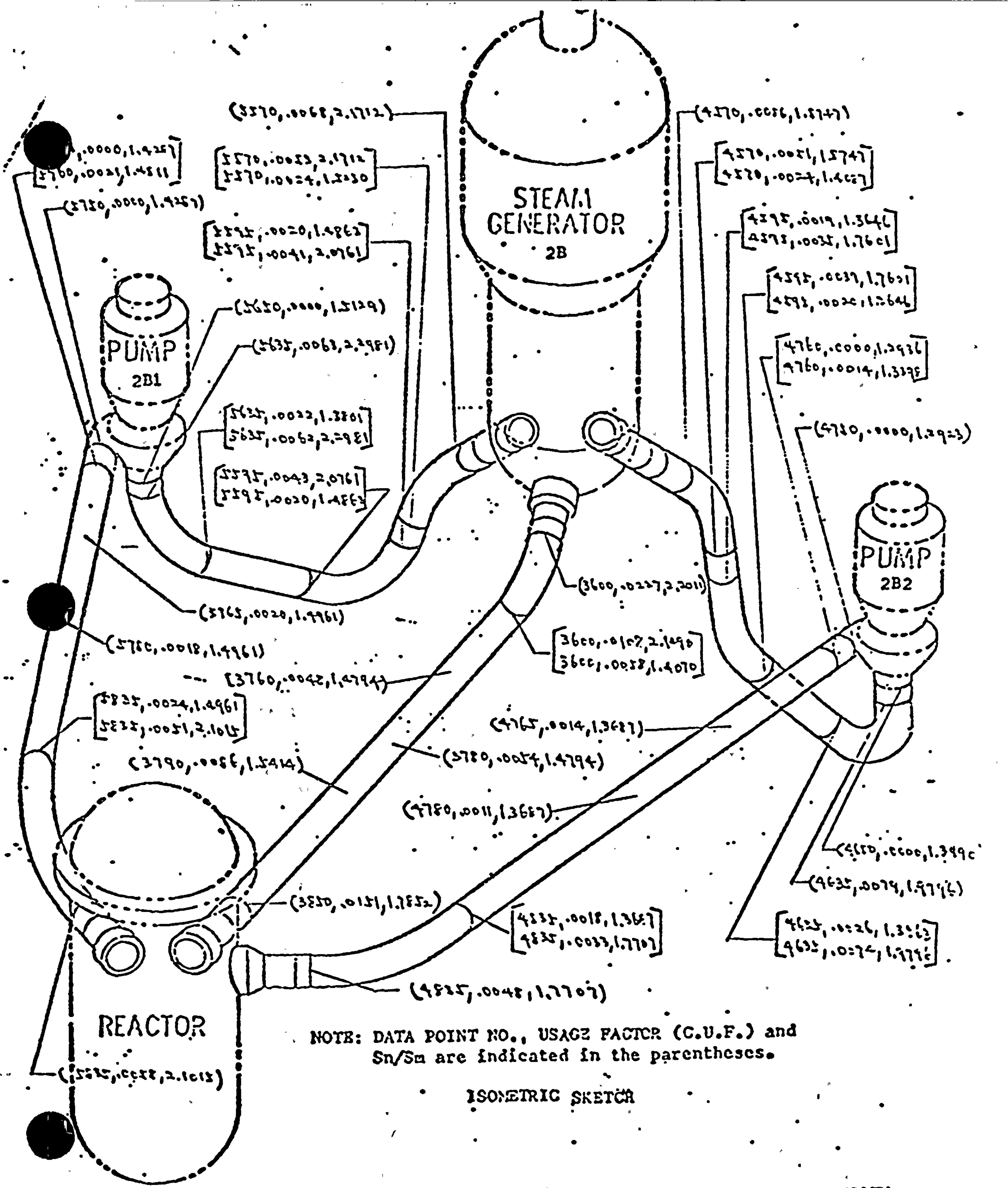


NOTE: DATA POINT NO., USAGE FACTOR (C.U.F.) and Sn/Sm are indicated in the parentheses.

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



NOTE: DATA POINT NO., USAGE FACTOR (C.U.F.) and Sn/Sm are indicated in the parentheses.

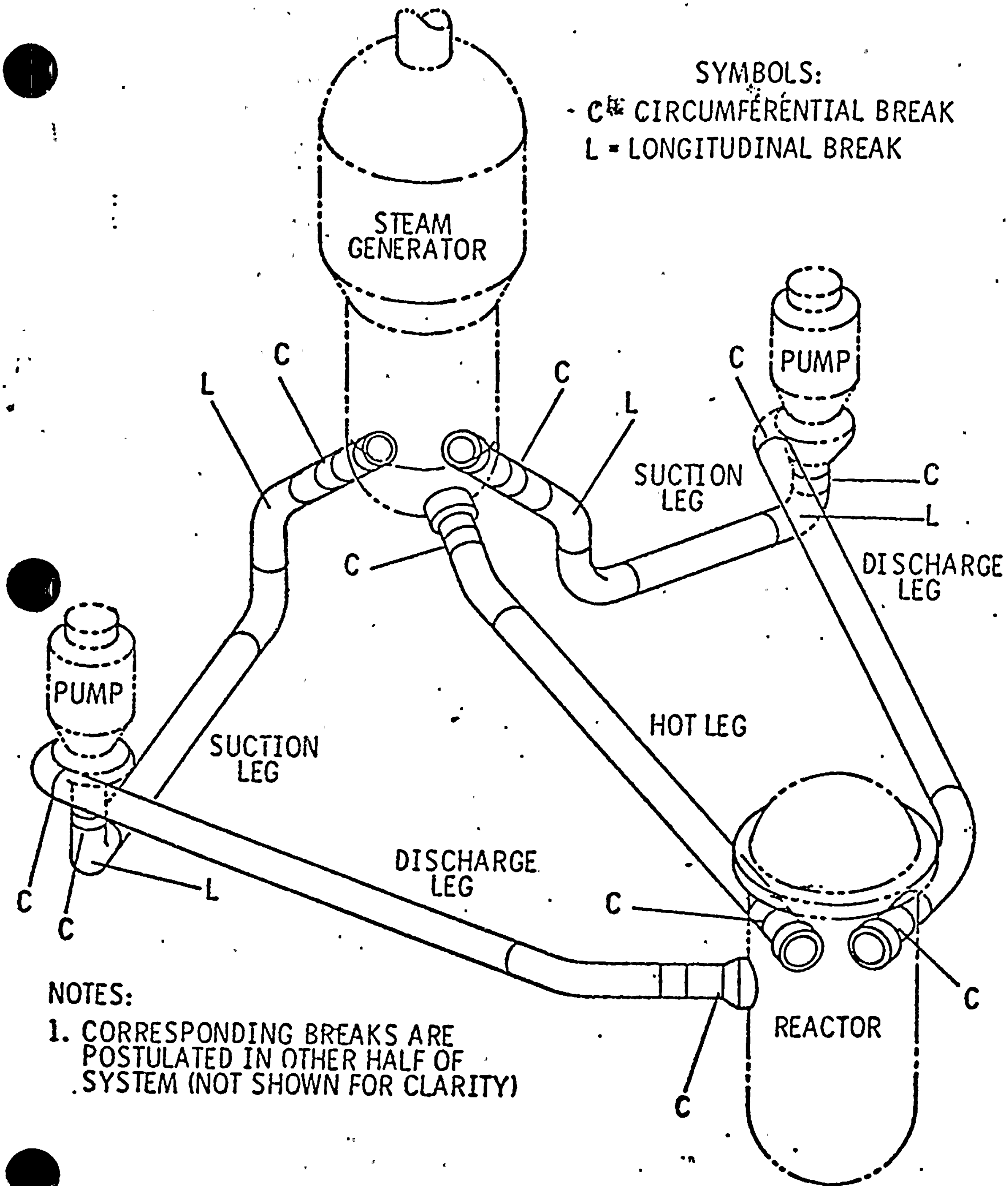
ISOMETRIC SKETCH

CUMULATIVE USAGE FACTOR AND NORMALIZED PRIMARY PLUS SECONDARY STRESS INTENSITY RANGE RESULTS FOR SEISMIC LOADING (LOOP 2A)

FIGURE 3.6-4
SHEET 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

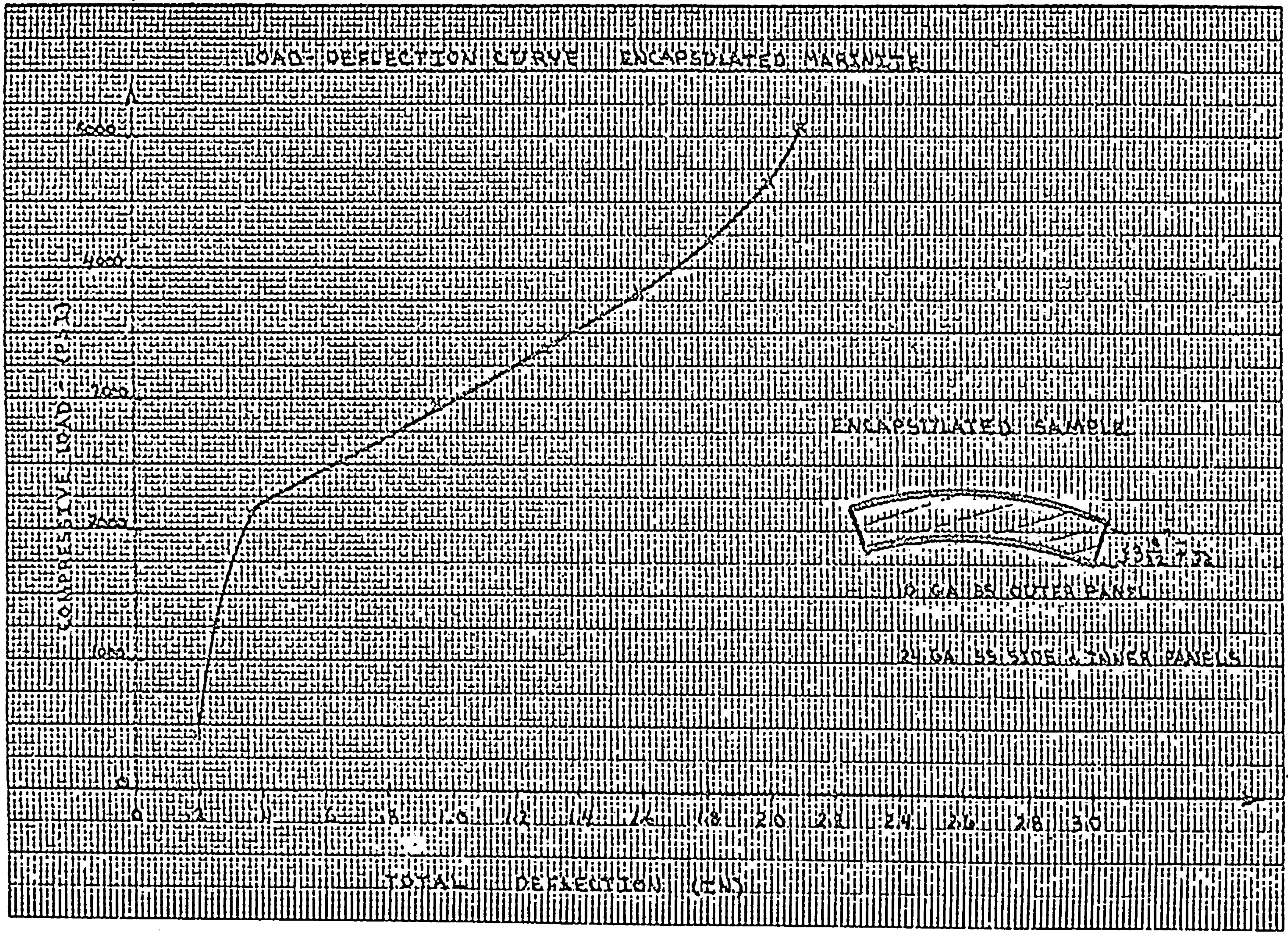

LOAD-DEFLECTION CURVE ENCAPSULATED MARINITE
COMPRESSIVE LOAD
5000
4000
3000
2000
1000
0
0 .2 .4 .6 .8 1.0 1.2 1.4 1.6 1.8 2.0 2.2 2.4 2.6 2.8 3.0
TOTAL DEFLECTION (IN)
ENCAPSULATED SAMPLE
24 GA SS SIDE & INNER PANELS

FIGURE 3.65

ATT. TO CSB QUES 3

MECH. ENG BRANCH

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

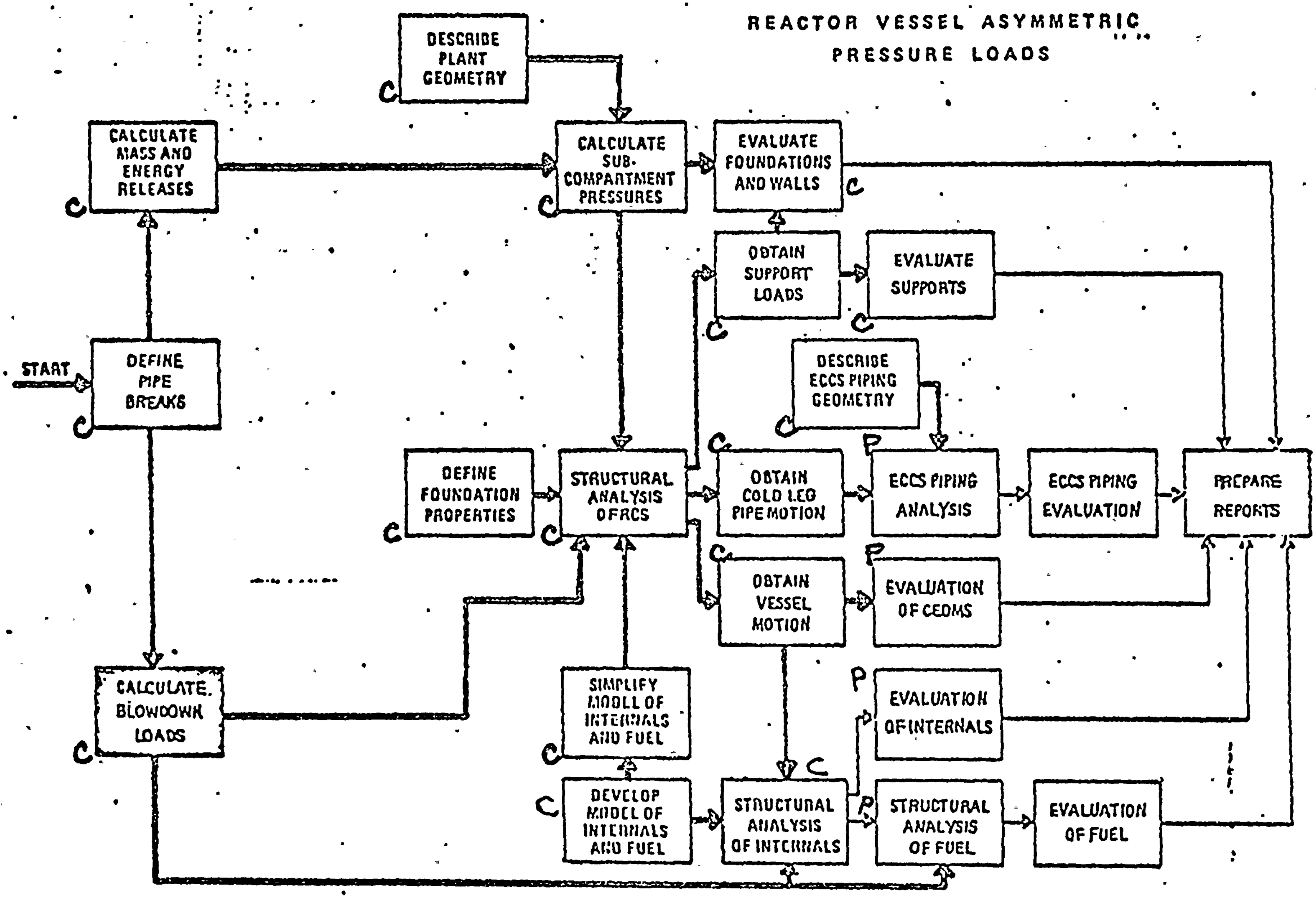
Component/Structure	Assessment Status	Evaluation Basis	Reference	Comments
Reactor Pressure Vessel	Complete	Plant Specific Analysis	FSAR 3.9.1.4.1	Complete
Steam Generators	"	"	"	"
Reactor Coolant Pumps	"	"	"	
Reactor Vessel Supports	"	"	"	
Steam Generator Supports	"	"	"	
Reactor Coolant Pump Supports	"	"	"	
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

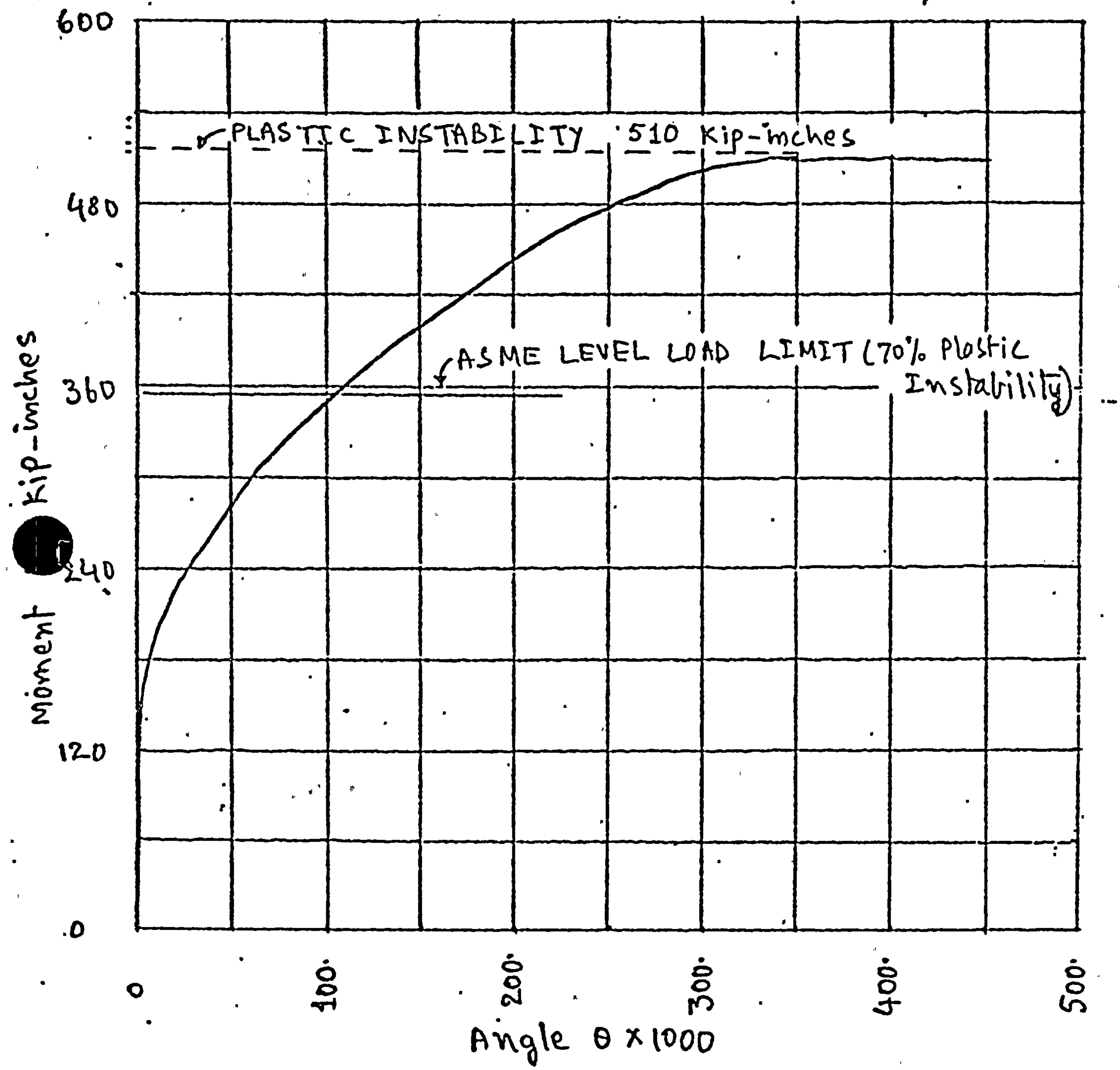
ST. LUCIE 2 CEDM

- 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.

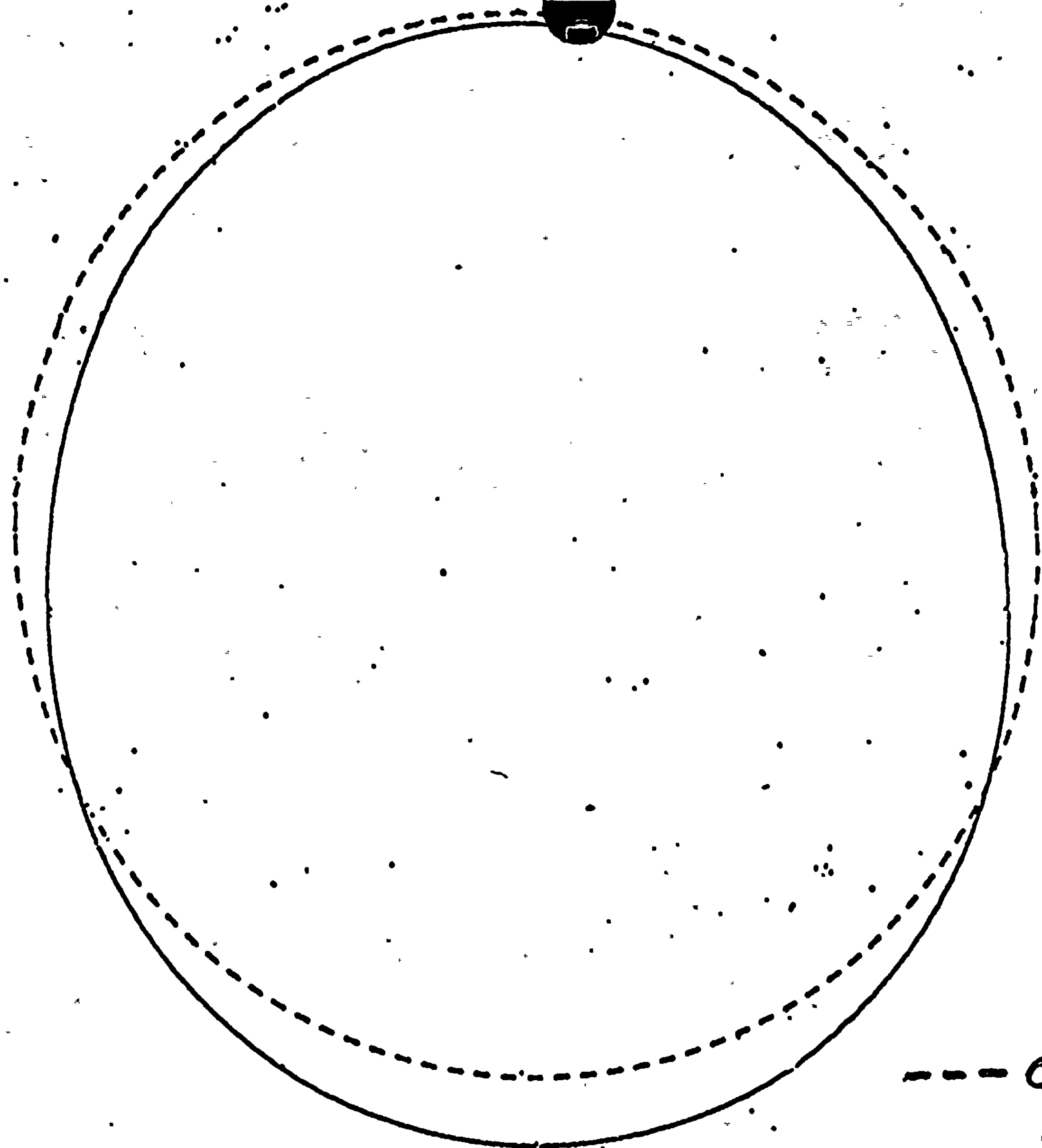
- ANALYSIS IS EXPECTED TO BE COMPLETED BY SEPTEMBER 30, 1981

Received 7/31/84

INSERT TO Q #35

A calculation of the deformation of the St. Lucie 2 RC piping when subjected to the maximum moment allowed by Section III, NB 3652 was performed. The attached material shows the results of that calculation.

P35



--- ORIGINAL SHAPE

—— DEFORMED SHAPE

EXAGGERATED BY A FACTOR OF 5

SUCTION ELBOW TOTAL DISP. AT MIDDLE SECTION

EFFECT OF MOMENT OF 60.2×10^{6} IN-lb

3.9.1.4 <u>Consideration for the Evaluation of the Faulted Condition</u>

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 non-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.

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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 for 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.

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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 NC 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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Reactor internals are designed according to Subsection NG of the ASME Code, Section III, with the exception of stamping and a code stress report.

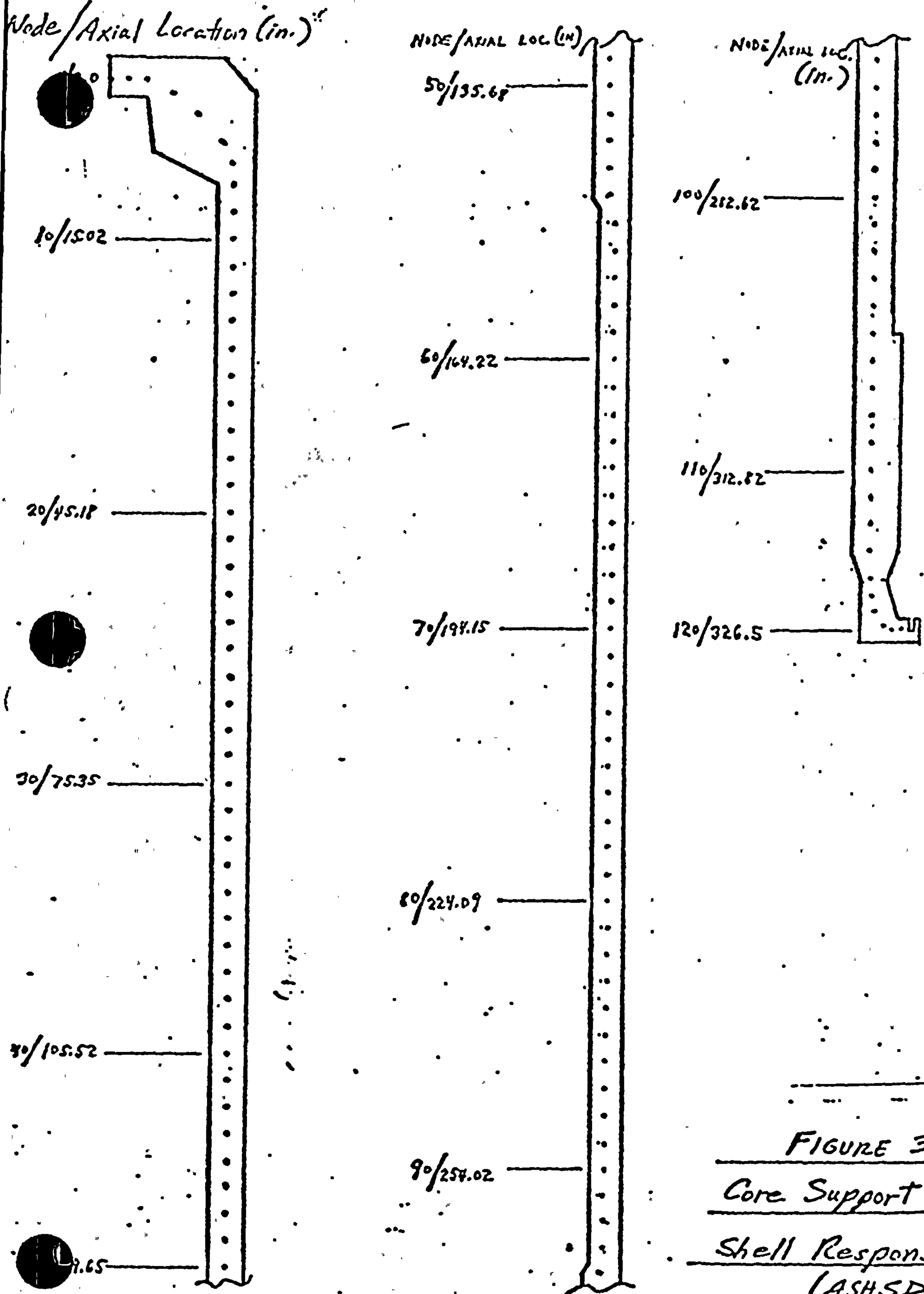


FIGURE 3.9-1
Core Support Barrel
Shell Response Model
(ASHSD)

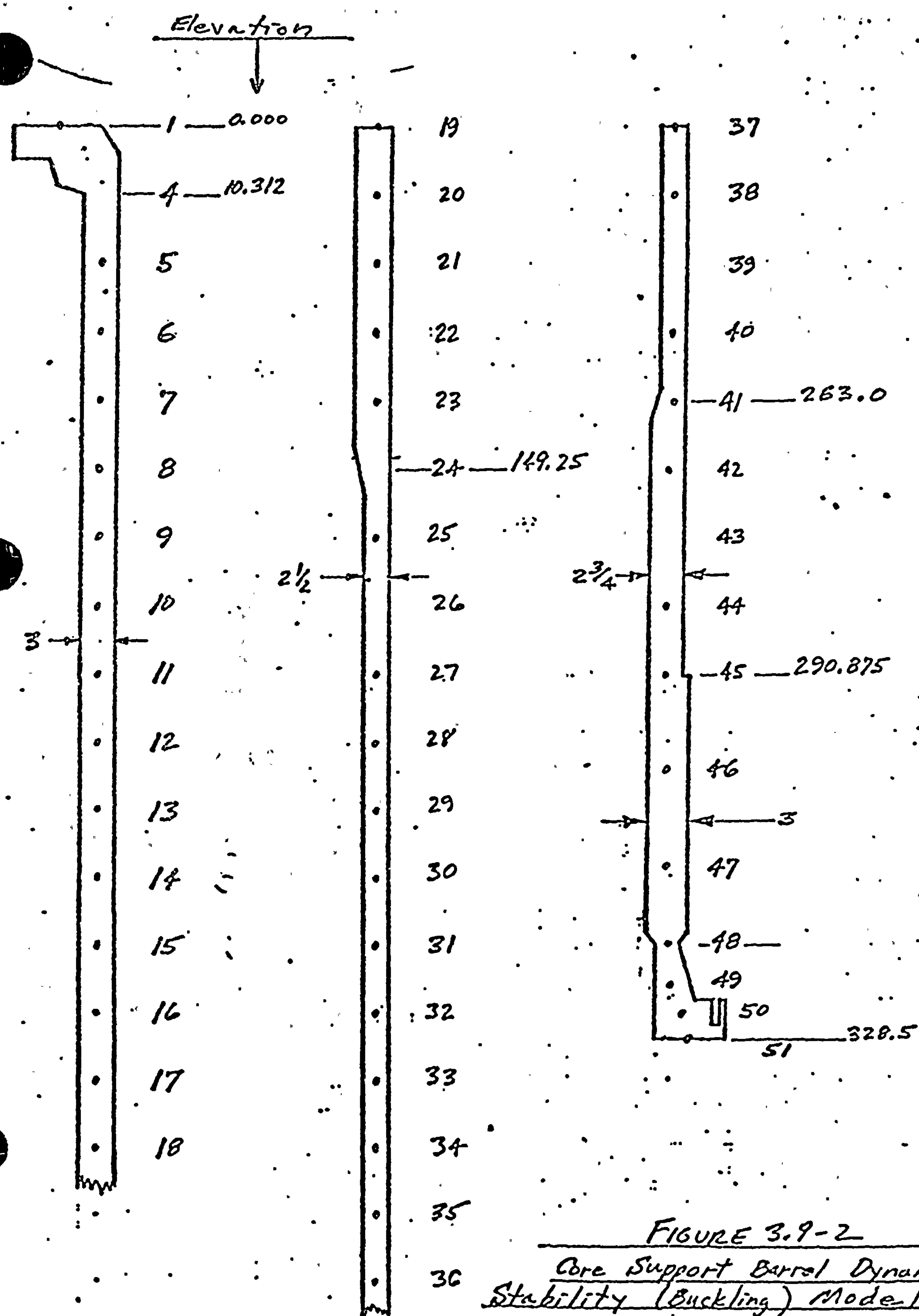


FIGURE 3.9-2

Core Support Barrel Dynamic Stability (Buckling) Model

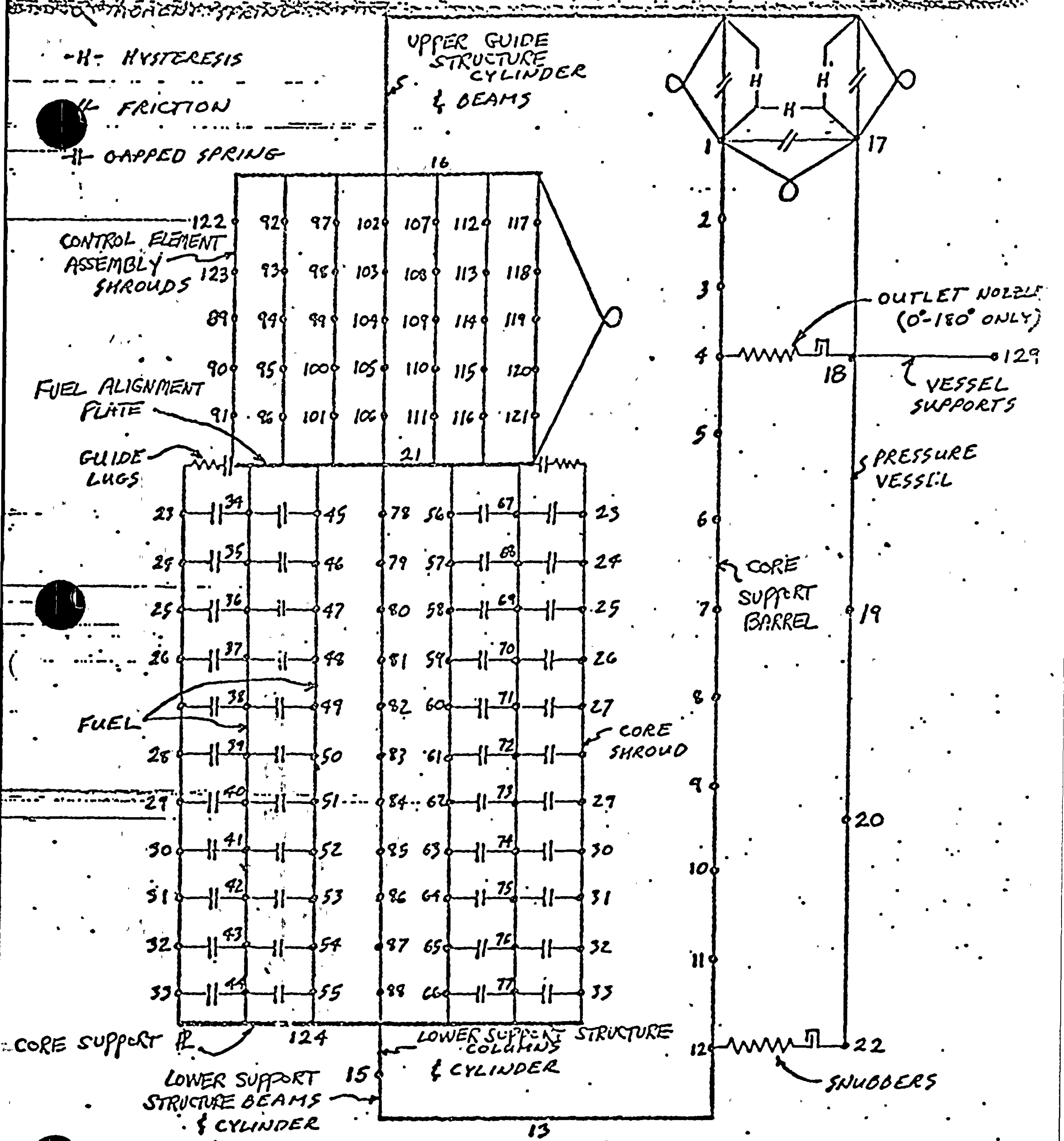


FIGURE 3.9-3

Reactor Internals Lateral LOCA Model (CESHOCK)

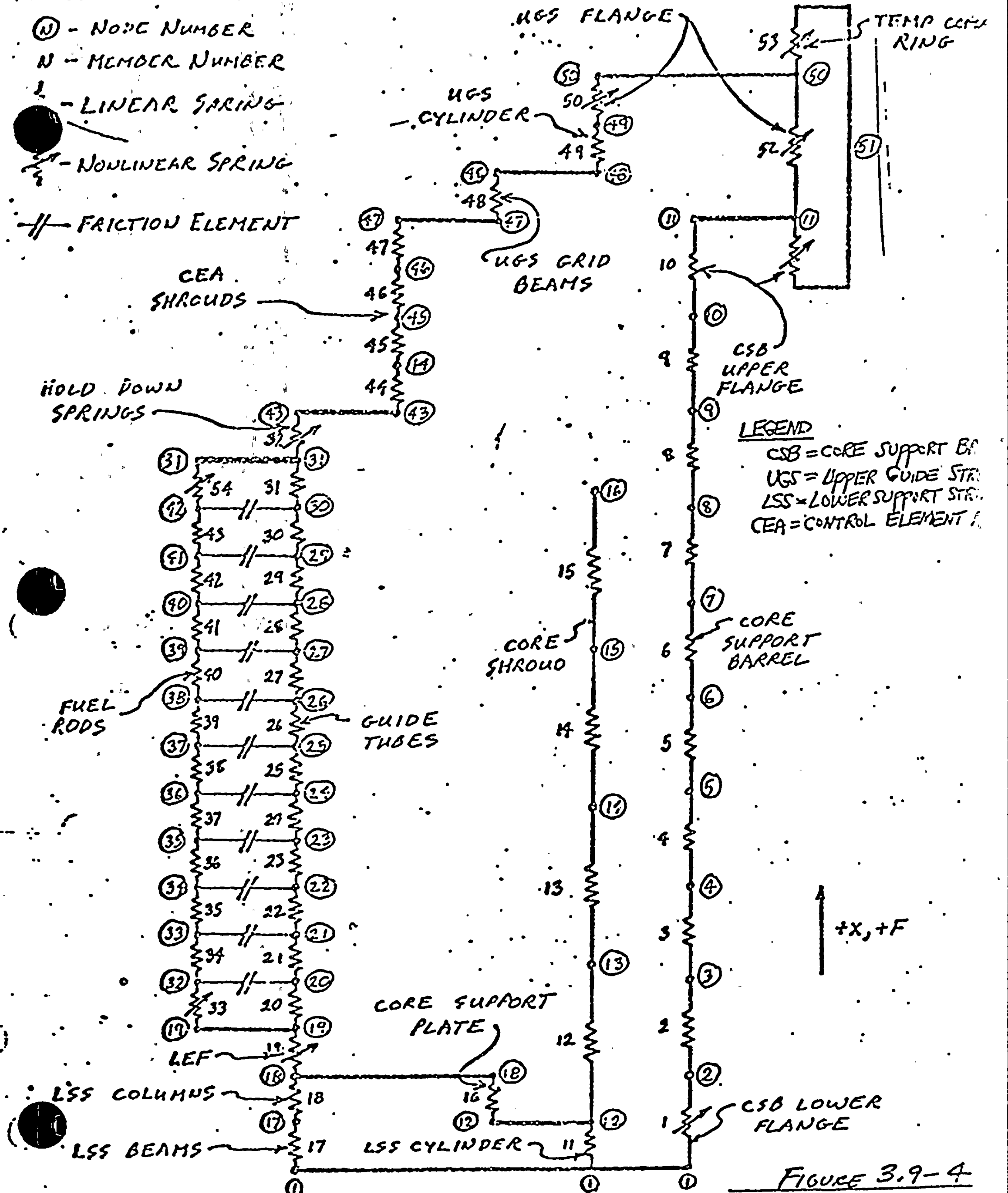


Figure 3.9-4

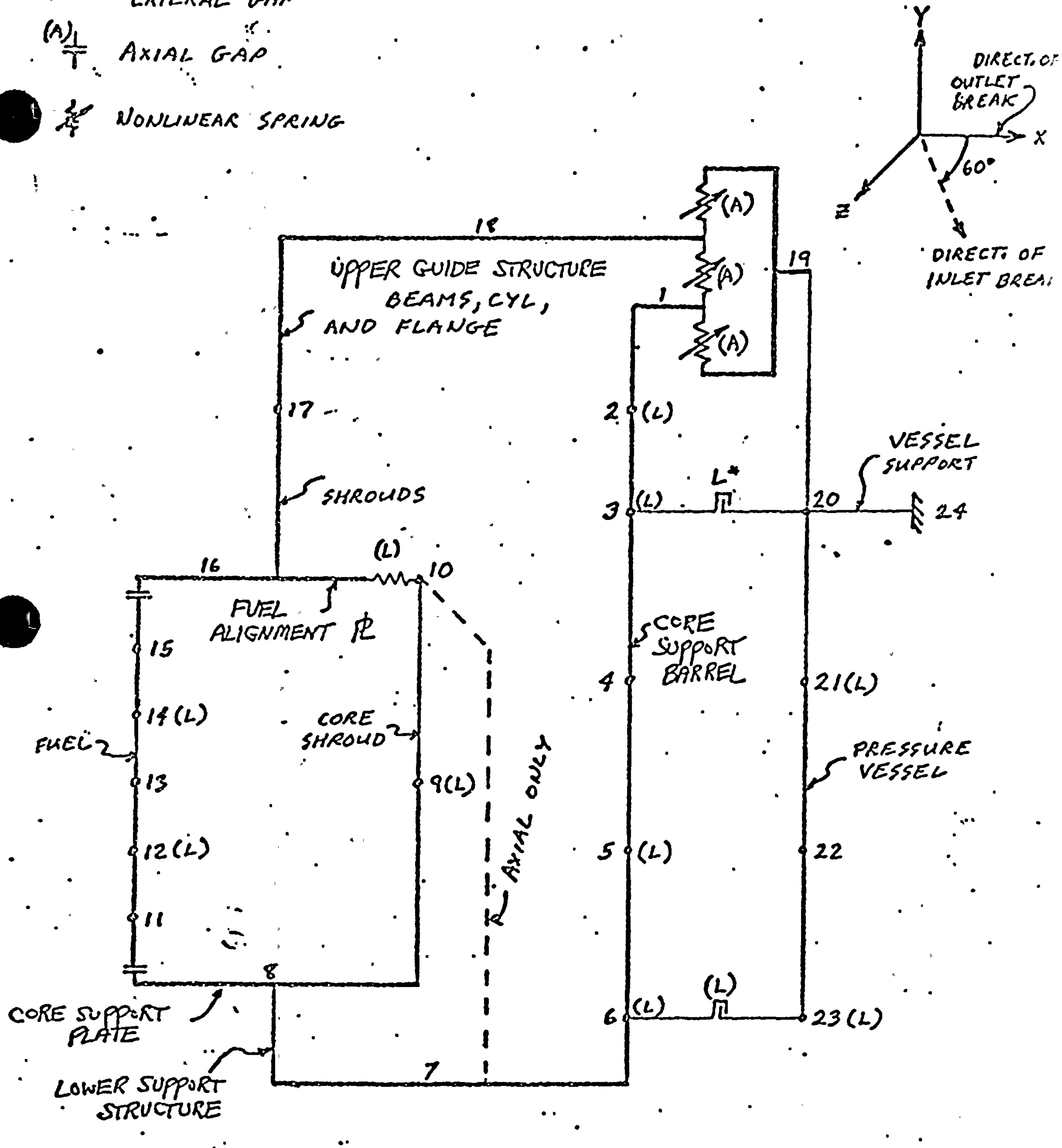
Reactor Internals Verti

LOCA Model

LATERAL GAP

(A) AXIAL GAP

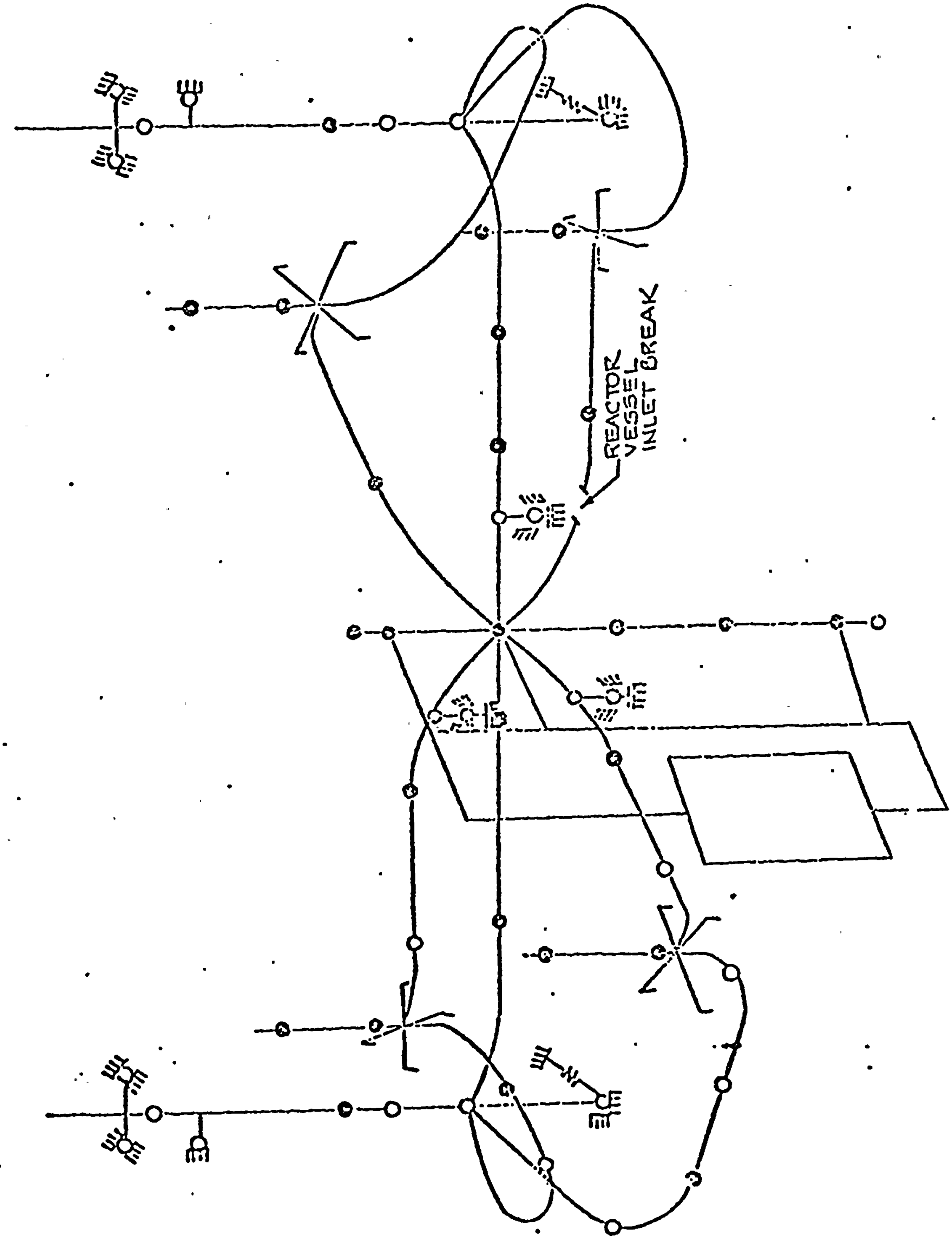
NONLINEAR SPRING



* - X DIRECTION ONLY

FIGURE 3.9-5

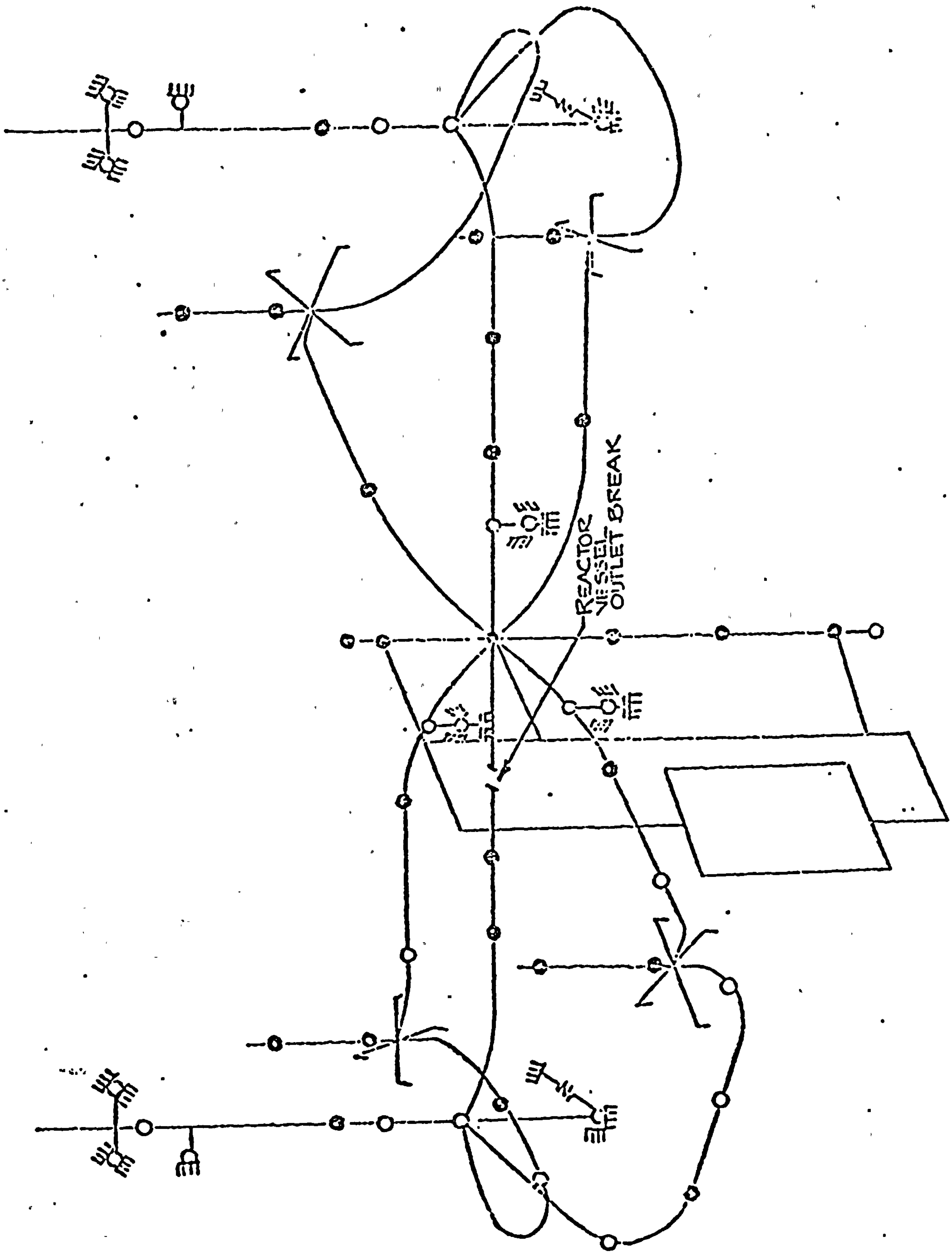
Reactor Internals Vertical/Horizontal Reduced Model



RV ASYMMETRIC LOADS ANALYSIS

RV SUPPORT LOADS

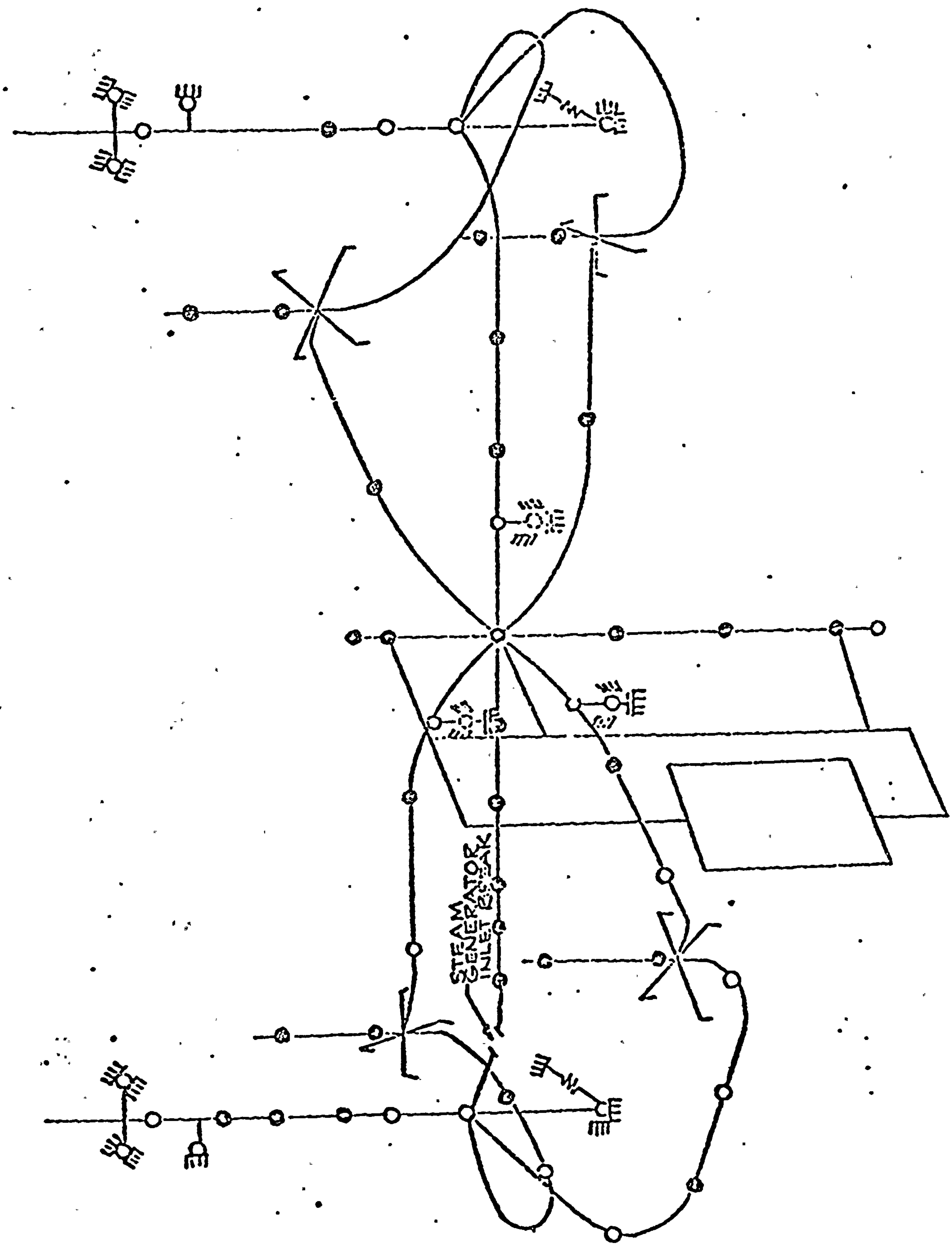
FIGURE 3.9-13



RV ASYMMETRIC LOADS ANALYSIS

RV SUPPORT LOADS

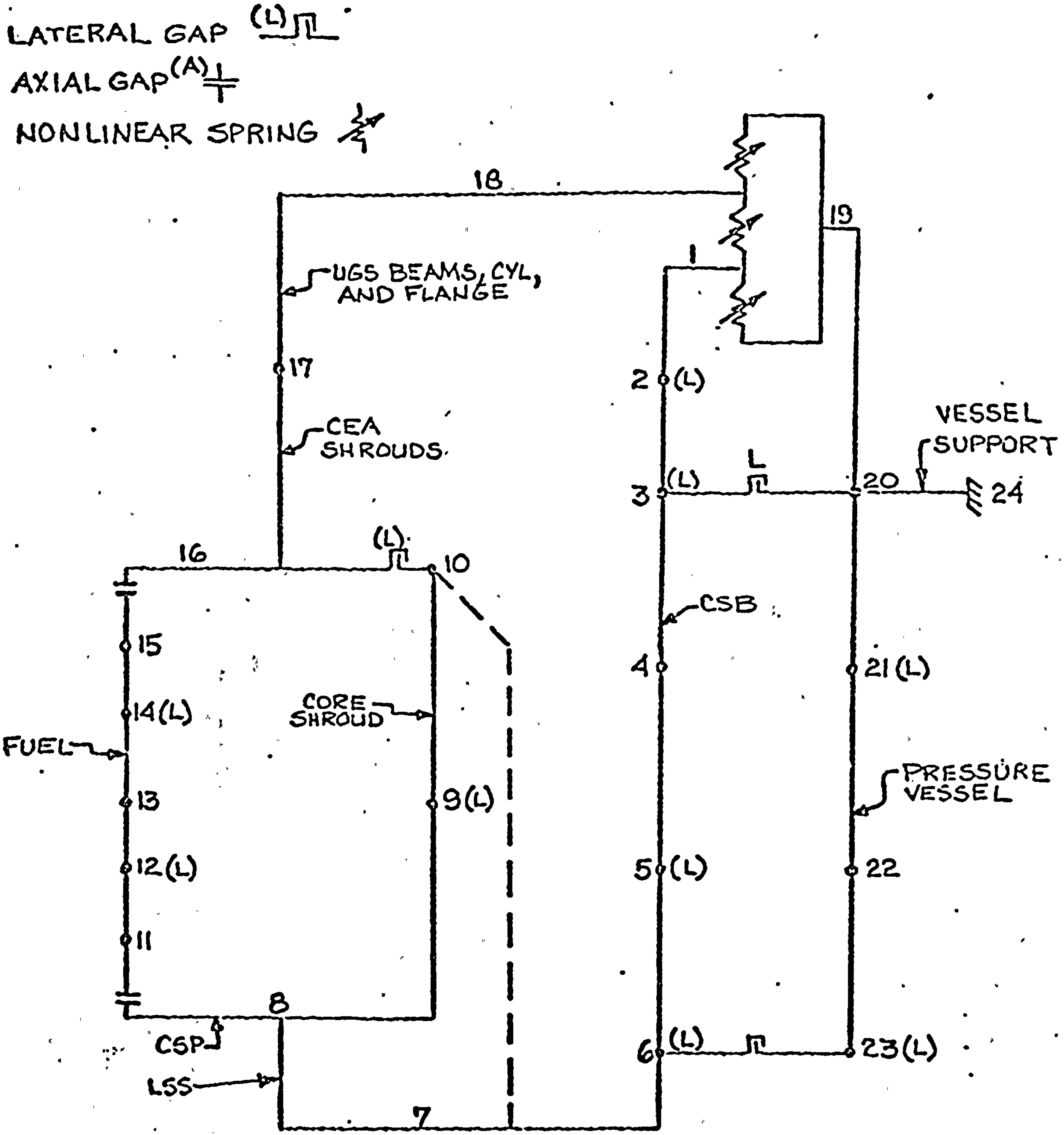
FIGURE 3.9-20



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 3
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, 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.

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
SLIDING BASE			
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	Y_1	1.85	2.716
(per pair of bolts)	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	RSS MOMENTS 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

3. Provide analyses to determine the external forces and moments, resulting from postulated hot leg and cold leg ruptures within the reactor cavity, on reactor vessel supports. If applicable, similar analyses should be performed for steam generator and/or pressurizer compartments that may be subject to pressurization where significant component support loads may result. For each analysis, provide the following information:

(2) For each compartment, provide a table of blowdown mass flow rate and energy release rate as function of time for the break which was used for the component support evaluation.

Response

FSAR Table 6.2-13 is a summary of postulated pipe ruptures for containment subcompartment analysis. The last column in this table "Release Rate Data Table Numbers" will refer to, for each compartment, a table of blowdown mass flow rate and energy release rates as a function of time for the break which was used for the component support evaluation.

Question

3. Provide analyses to determine the external forces and moments, resulting from postulated hot leg and cold leg ruptures within the reactor cavity, on reactor vessel supports. If applicable, similar analyses should be performed for steam generator and/or pressurizer compartments that may be subject to pressurization where significant component support loads may result. For each analysis, provide the following information:

(3) Describe and justify the nodalization sensitivity studies performed for the major component supports evaluation (if different from the strucutural analysis model), where transient forces and moments acting on the components are of concern. Where component loads are of primary interest, show the effect of noding variations on the transient forces and moments. Use this information to justify the nodal model selected for use in the component supports evaluation.

Response The analysis performed for the major component supports does not differ from the structural analysis model. As discribed in FSAR subsection 6.2.1.2.3 divisions between subcompartment are determined by the physical flow restrictions within each compartment. A flow restriction is defined by the presence of an object in the flow path that changes the flow area in that direction, with the subdivision defined at the point of minimum flow area. This minimum flow area becomes the junction flow area used in the RELAP 4 analysis For the models constructed for the reactor cavity and secondary shield wall area flow restrictions included the presence of steel and concrete supports, doorways, vent shafts and gratings, as well as large equipment such as the reactor vessel, primary piping, the steam generator, reactor coolant pumps and the pressurizer. By choosing node boundaries at the various physical flow restrictions, a method consistent with the lumped-parameter calculation model used by RELAP 4 and described above, calculated differential pressures and consequent support loads are realistically maximized. The nodalization sensitivity study performed for the Shearon Harris PSAR (Docket 50-400, 401, 402 and 403) shows that the peak calculated differential pressure is very sensitive to an increasing number of nodes until that number equals the number defined by physical flow restrictions. Increasing the subdivision of the compartment is unwarranted and can lead to unrealistic results if these "fictitious junctions" are modeled. The subcompartment models discussed below take account of all physical flow restrictions present in a manner identical to that shown to be optimum by the sensitivity study.

Table 6.2-25 presents the overall results of the subcompartment analyses. The reactor cavity, Secondary Shield Wall and Pressurizer Area Design evaluation is described in FSAR Subsection 6.2.1.2.3.

Question

3. Provide analyses to determine the external forces and moments, resulting from postulated hot leg and cold leg ruptures within the reactor cavity, on reactor vessel supports. If applicable, similar analyses should be performed for steam generator and/or pressurizer compartments that may be subject to pressurization where significant component support loads may result. For each analysis, provide the following information:

(4) Graphically show the pressure (psia) and differential pressure (psi) response as functions of time for a representative number of nodes to indicate the spatial pressure response. Discuss the basis for establishing the differential pressure on components.

Response

FSAR Table 6.2-25 list the Results of the Subcompartment Analysis. In this table the peak node pressure, and peak differential pressure is listed. Along with these valves a figure is referenced for both of those values.

The component and support loads for the Steam Generator, Reactor Coolant Pump, and Pressurizer were determined by equivalent static analyses. A load factor of two on the calculated thrust, jet impingment, and subcompartment pressure loads is employed to account for the dynamic response of the structure. The model employed for static analysis is shown in Figure 3.9-18.

Question

3. Provide analyses to determine the external forces and moments, resulting from postulated hot leg and cold leg ruptures within the reactor cavity, on reactor vessel supports. If applicable, similar analyses should be performed for steam generator and/or pressurizer component support loads may result. For each analysis, provide the following information:

(5) Provide the peak and transient loading on the major components used to establish the adequacy of the support design. This should include the load forcing functions (e.g., $f_x(t)$, $f_y(t)$, $f_z(t)$) and transient moments (e.g., $M_x(t)$, $M_y(t)$, $M_z(t)$ as resolved about a specific identified coordinate system. The centerline of the break nozzle is recommended as the X-axis and the center line of the vessel as the Z axis. Provide the projected area used to calculate these loads and identify the location of the area projections on plan and section drawings in the selected coordinate system. This information should be presented in such a manner that confirmatory evaluations of the loads and moments can be made.

ponse

Refer to FSAR Tables 6.2-25 and 6.2-26 for a discussion on the peak and transient loading on the major components used to establish the adequacy of the support design.

The mass and energy release data that was utilized for the structural design is identical to that used for component support design verification. Therefore, the peak and transient forces provided in FSAR Figures 6.2-23 thru 6.2-30 were utilized for both the structural and component design, where applicable. The analysis of the RCS components (i.e., Reactor Vessel, Steam Generator, RC Pumps, Pressurizer and RC Piping) due to the asymmetric pressure loadings is provided in revised FSAR Section 3.9.1.4.1. A tabulation of results and comparison with the appropriate allowables is also provided.

Question

4. Figure 6.2-71, regarding containment isolation valves, should be revised to show the containment isolation valve arrangements for each containment penetration. In addition, the isolation valve arrangements shown in this figure should be consistent with the valve arrangements as shown in the system flow diagrams.

Response

The attached figures show the containment isolation valve arrangement for each containment penetration. These figures will be placed in the FSAR via Amendment 6.

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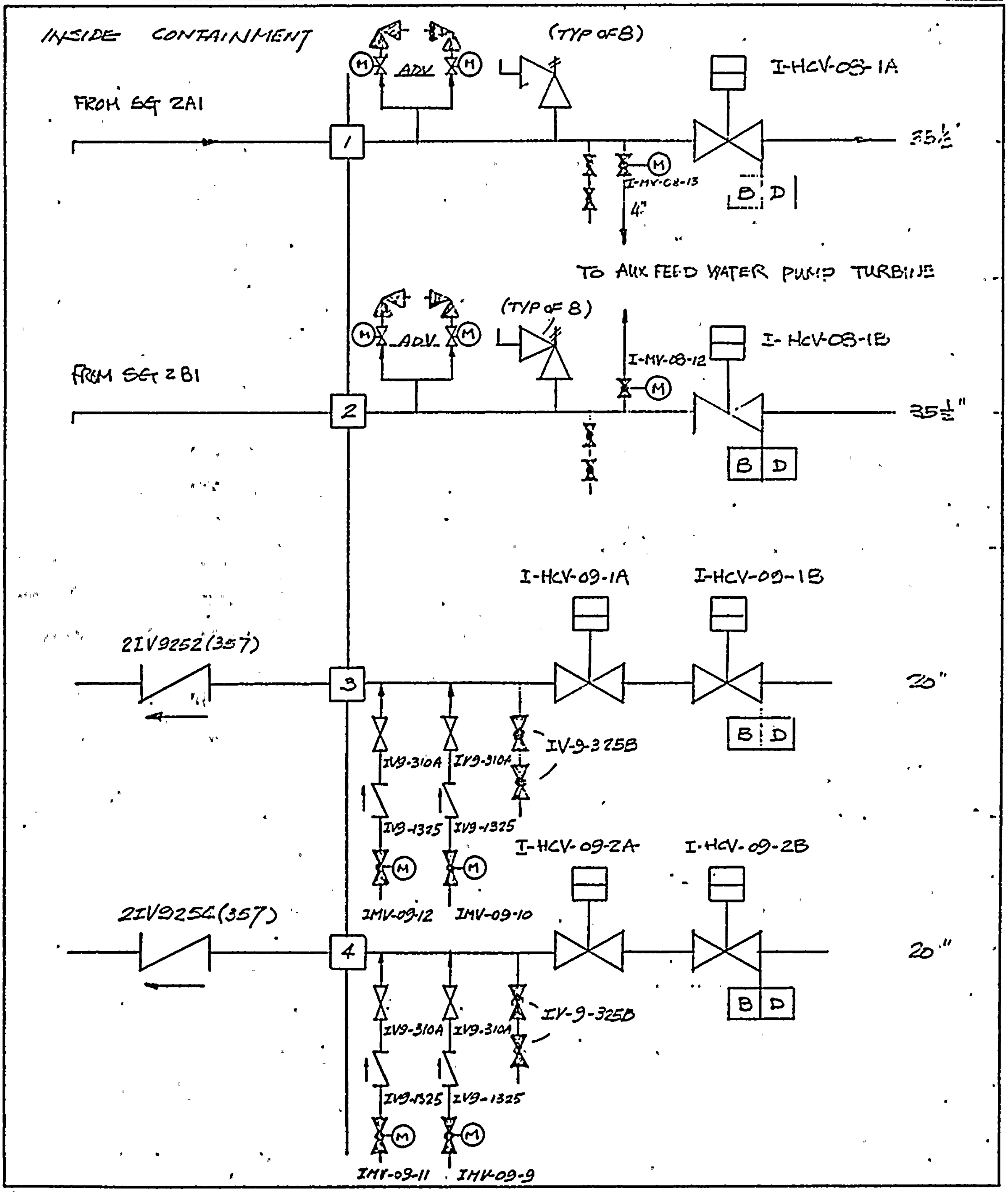
SUBJECT ____



FORM 561 REV 7-71

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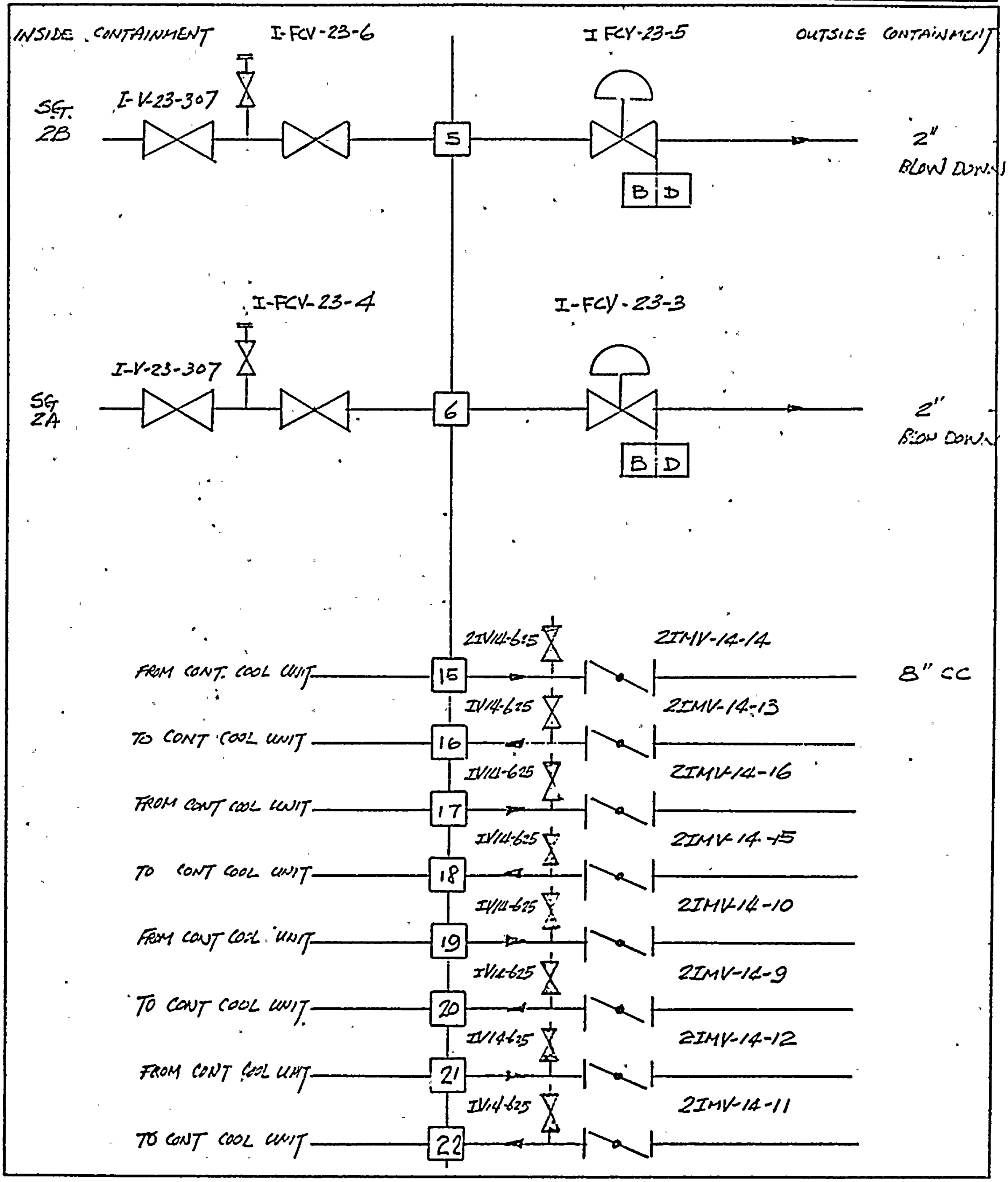

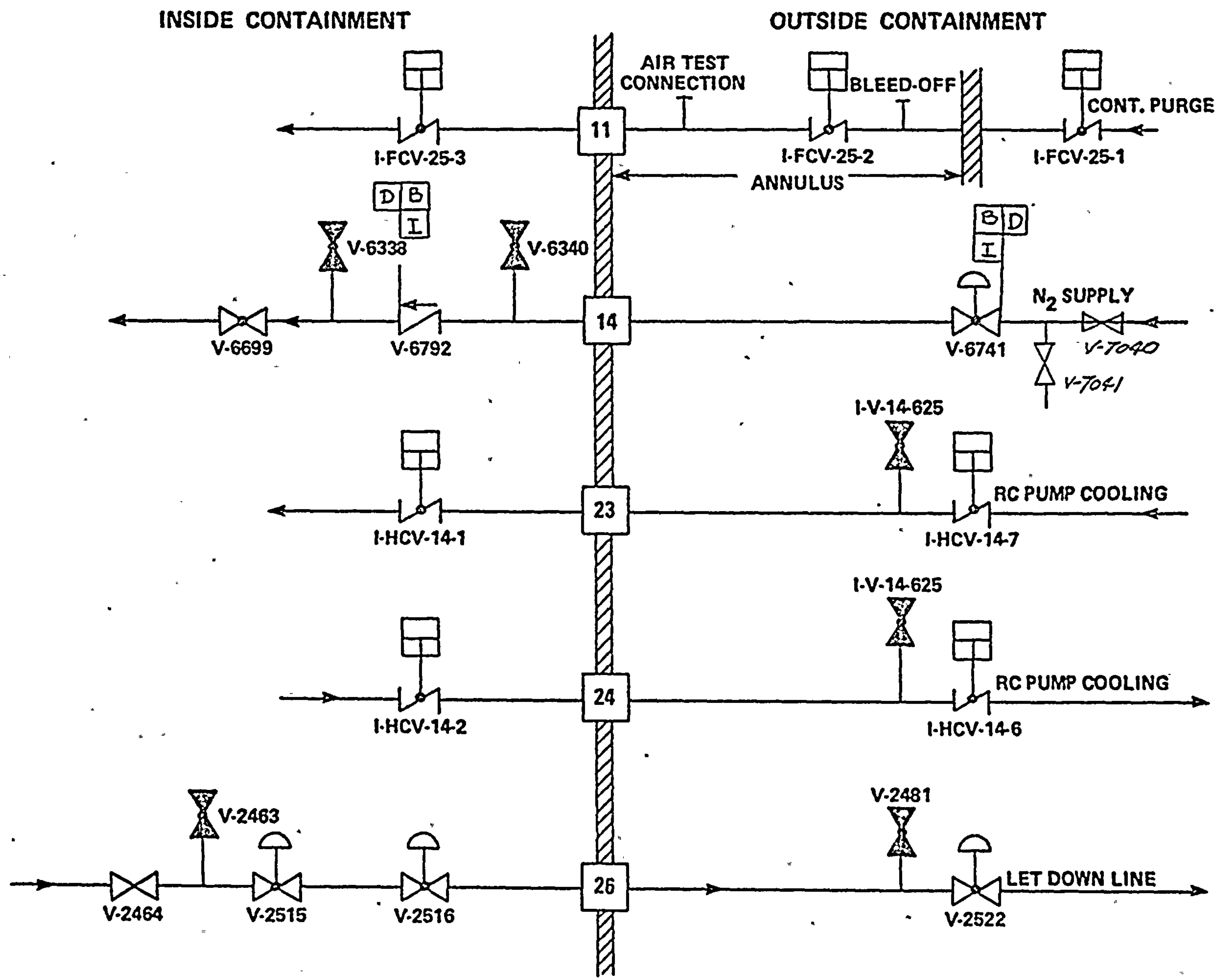

AMENDMENT NO. 0 (12/80)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT ISOLATION
VALVE TESTING – SHEET 2
FIGURE 6.2-70

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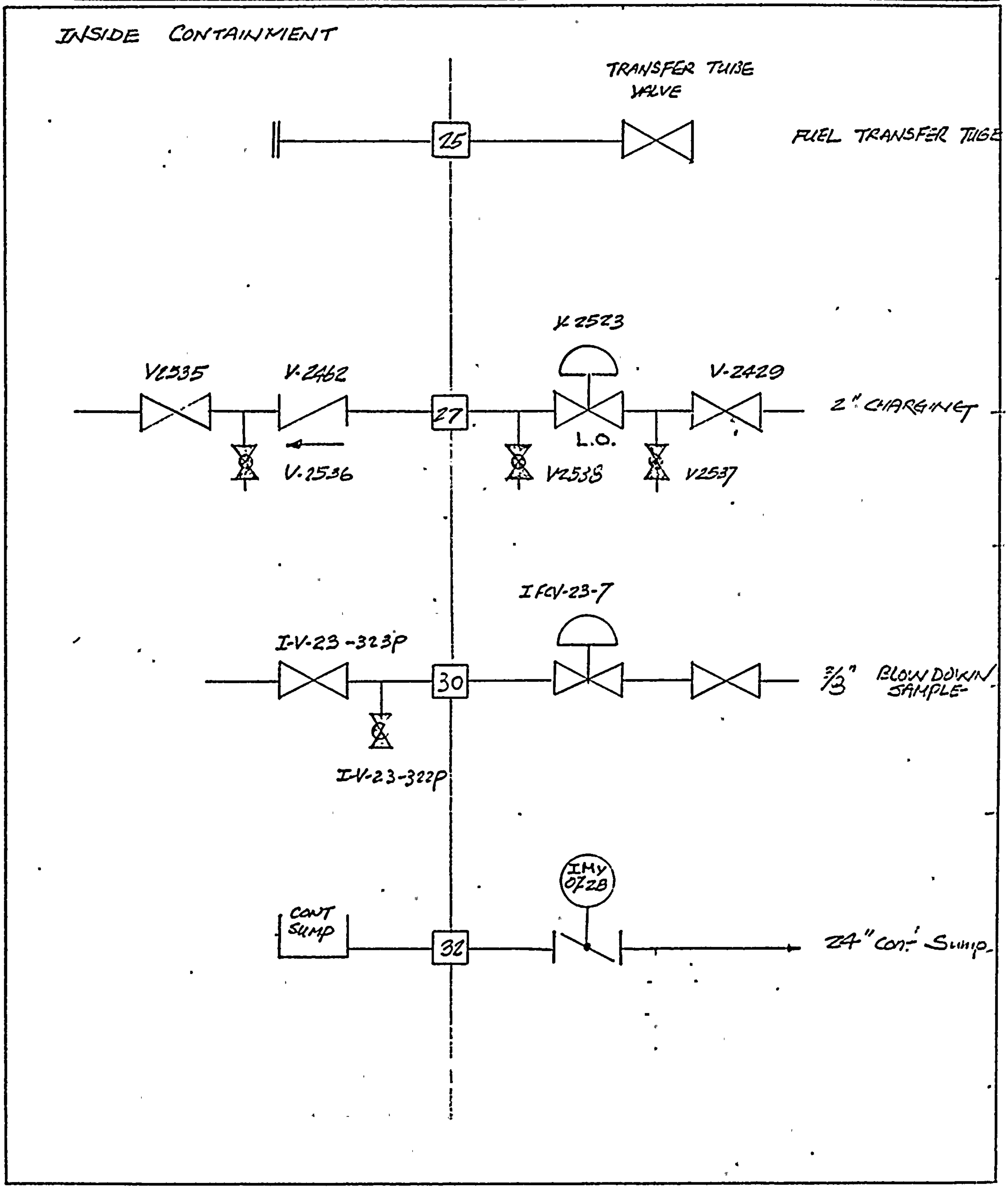

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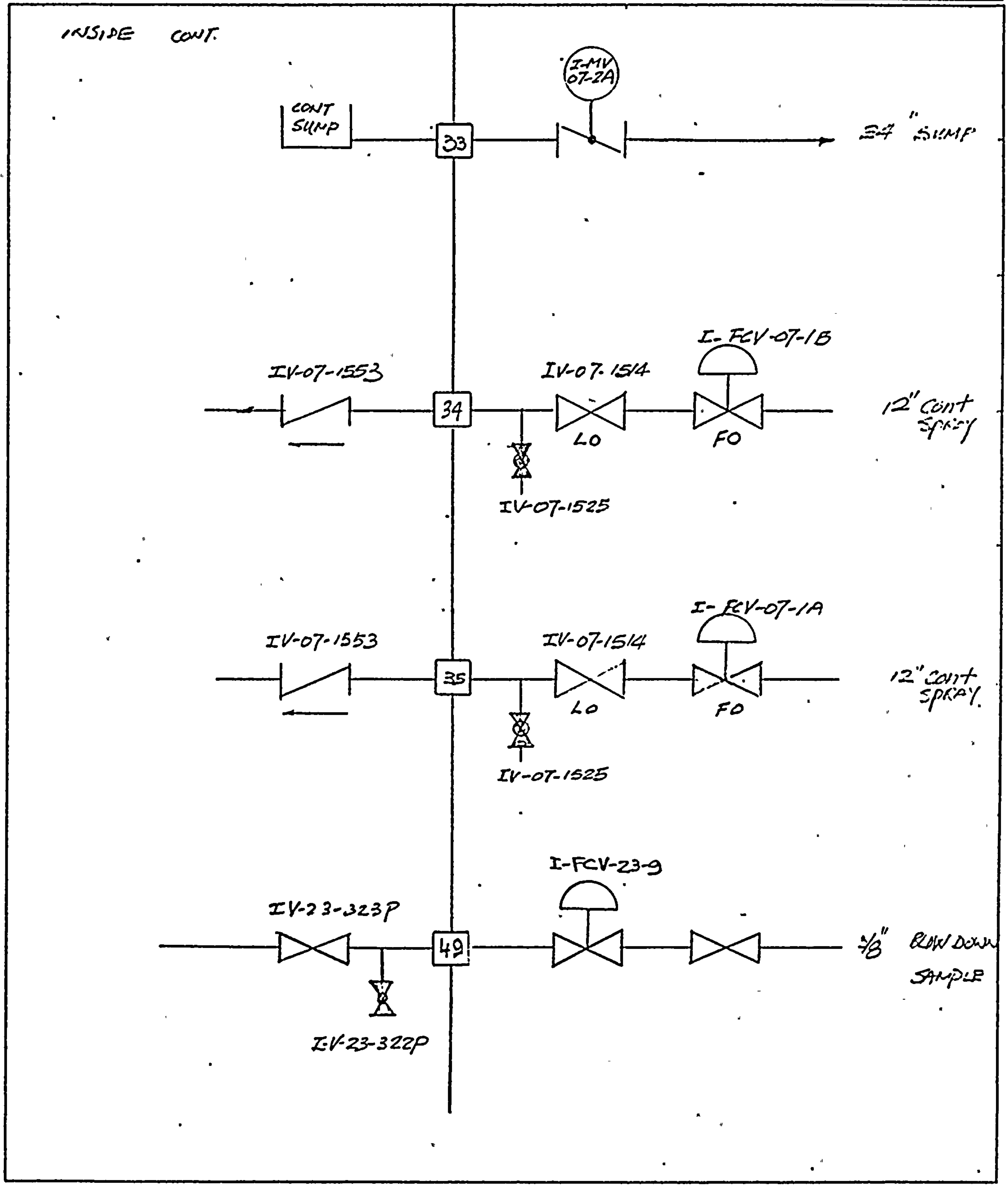

FORM 581 REV 7-71

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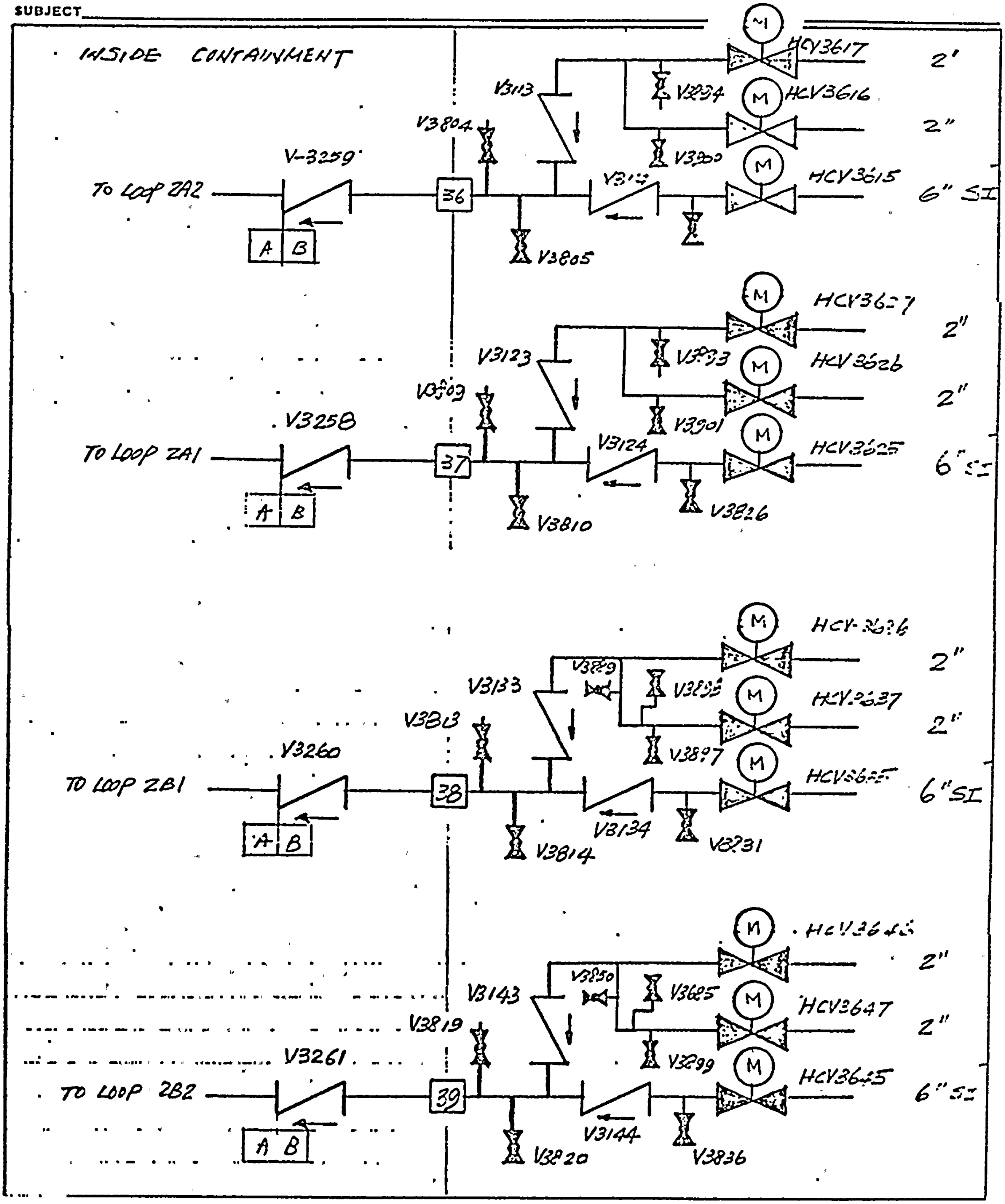
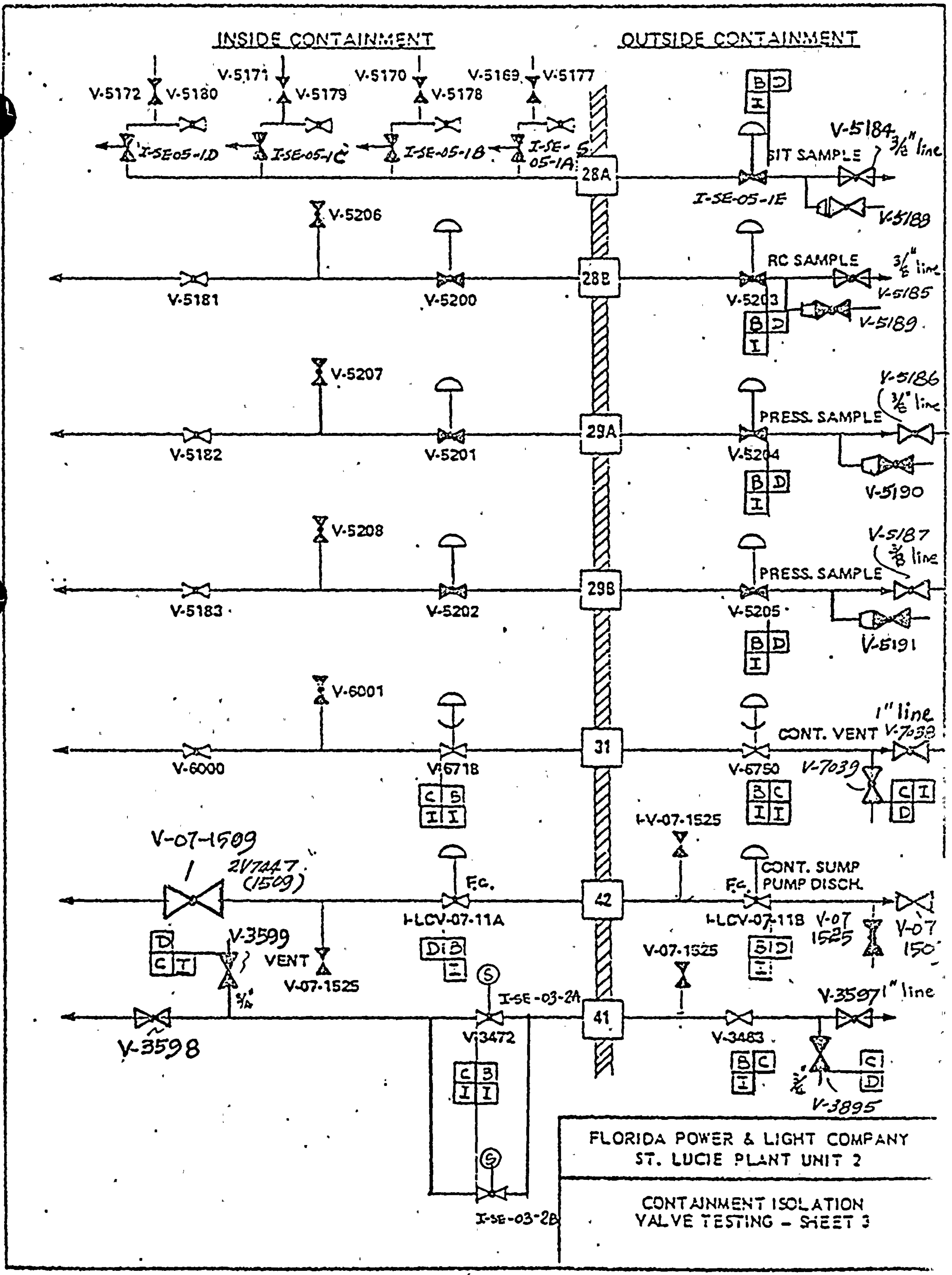


FORM 581 REV 7-71


INSIDE CONTAINMENT
OUTSIDE CONTAINMENT
V-5172 V-5180
V-5171 V-5179
V-5170 V-5178
V-5169 V-5177
I-SE05-1D
I-SE-05-1C
I-SE-05-1B
I-SE-05-1A
28A
I-SE-05-1E
SIT SAMPLE
V-5184 3/8" line
V-5188
V-5206
V-5181
V-5200
28B
V-5203
RC SAMPLE
3/8" line
V-5185
V-5189
V-5207
V-5182
V-5201
29A
V-5204
PRESS. SAMPLE
V-5186 3/8" line
V-5190
V-5208
V-5183
V-5202
29B
V-5205
PRESS. SAMPLE
V-5187 3/8 line
V-5191
V-6001
V-6000
V-6718
31
V-6750
CONT. VENT
1" line V-7038
V-7039
V-07-1509
2V7447 (1509)
F.C.
I-LCV-07-11A
42
I-V-07-1525
CONT. SUMP PUMP DISCH.
I-LCV-07-11B
V-07 1525
V-07 150
V-3599
VENT
V-07-1525
V-07-1525
I-SE-03-2A
V-3472
41
V-3483
V-3597 1" line
V-3598
V-3895
I-SE-03-2B
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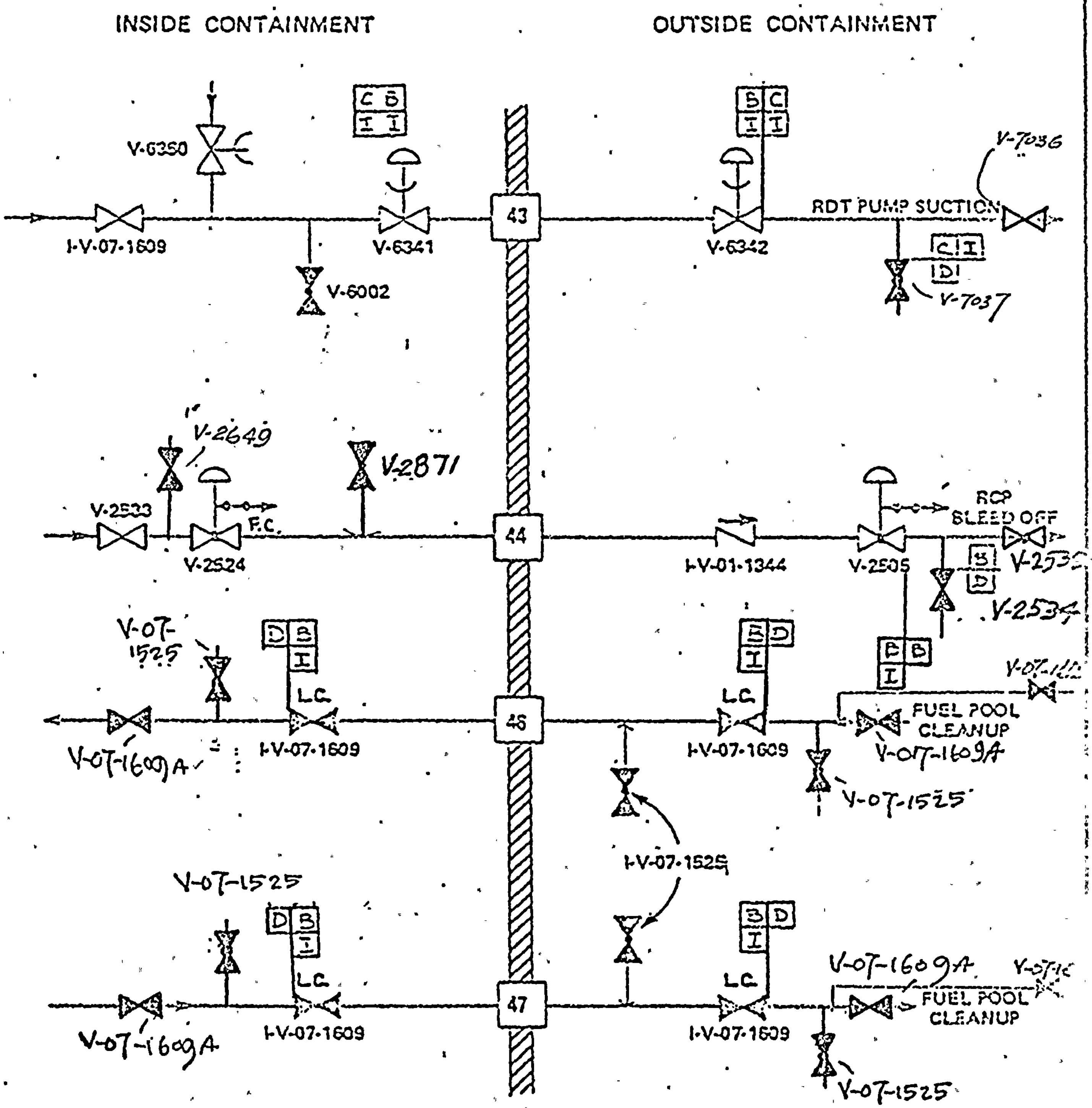
ST. LUCIE PLANT UNIT 2
CONTAINMENT ISOLATION
VALVE TESTING - SHEET 3



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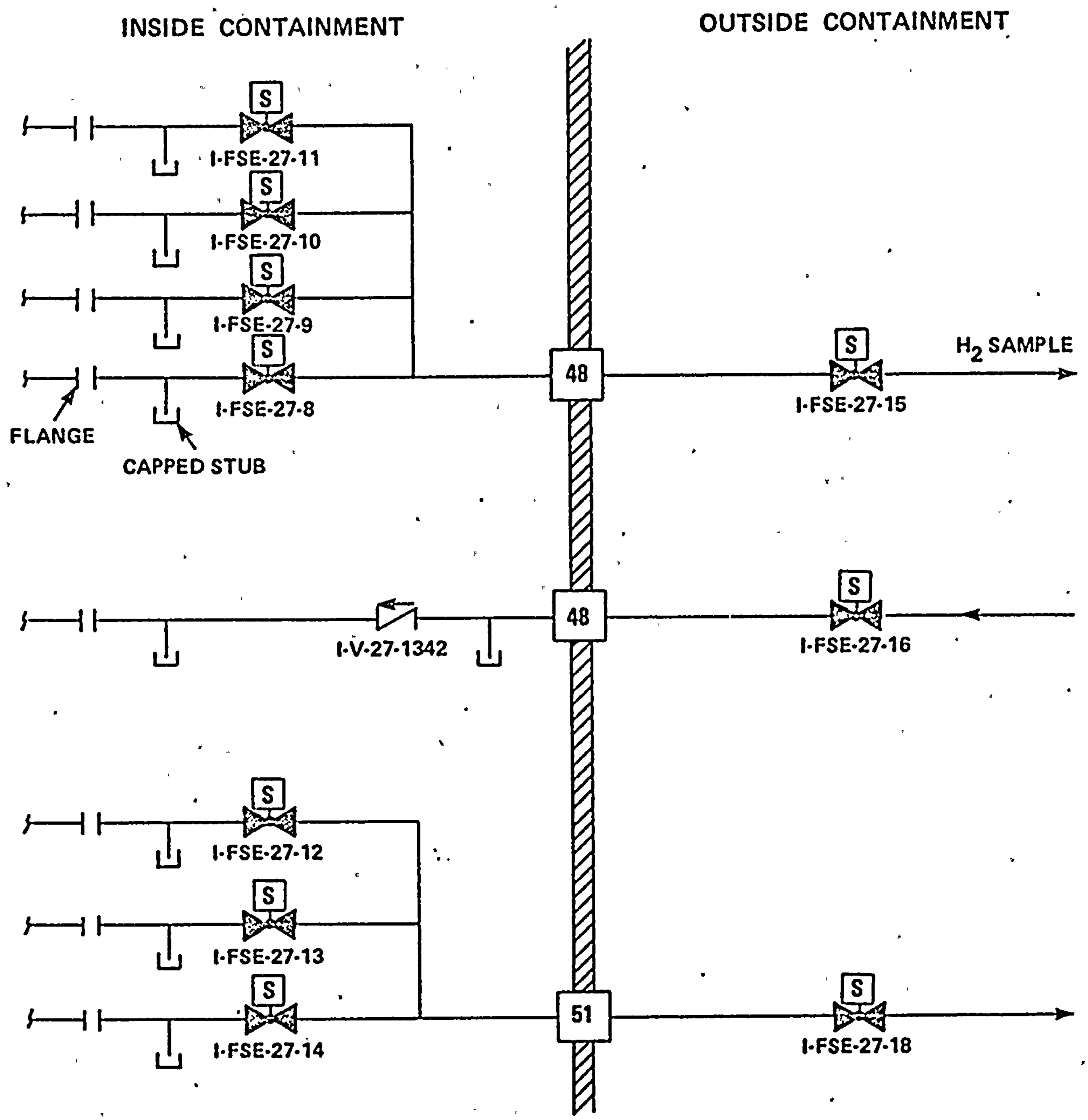
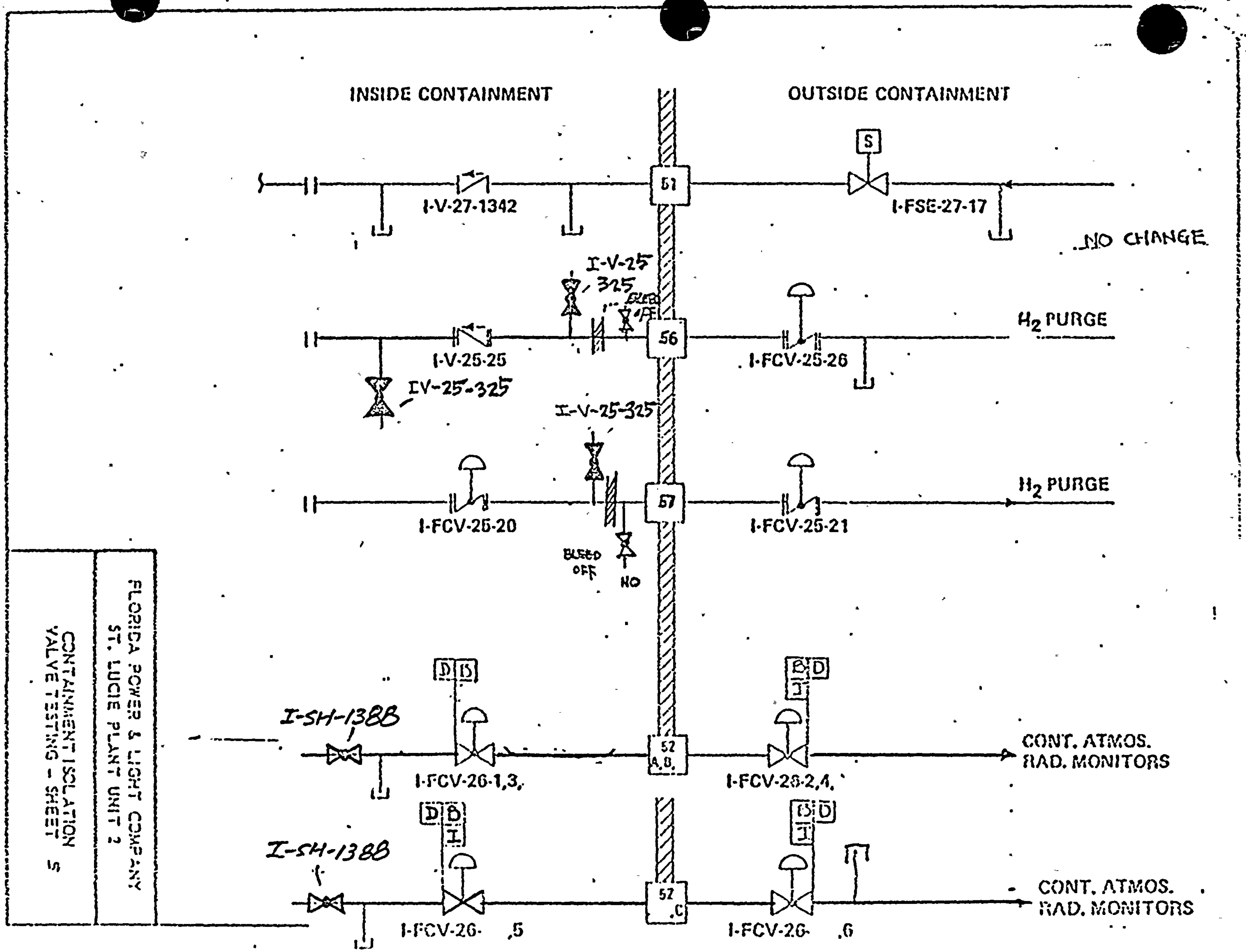
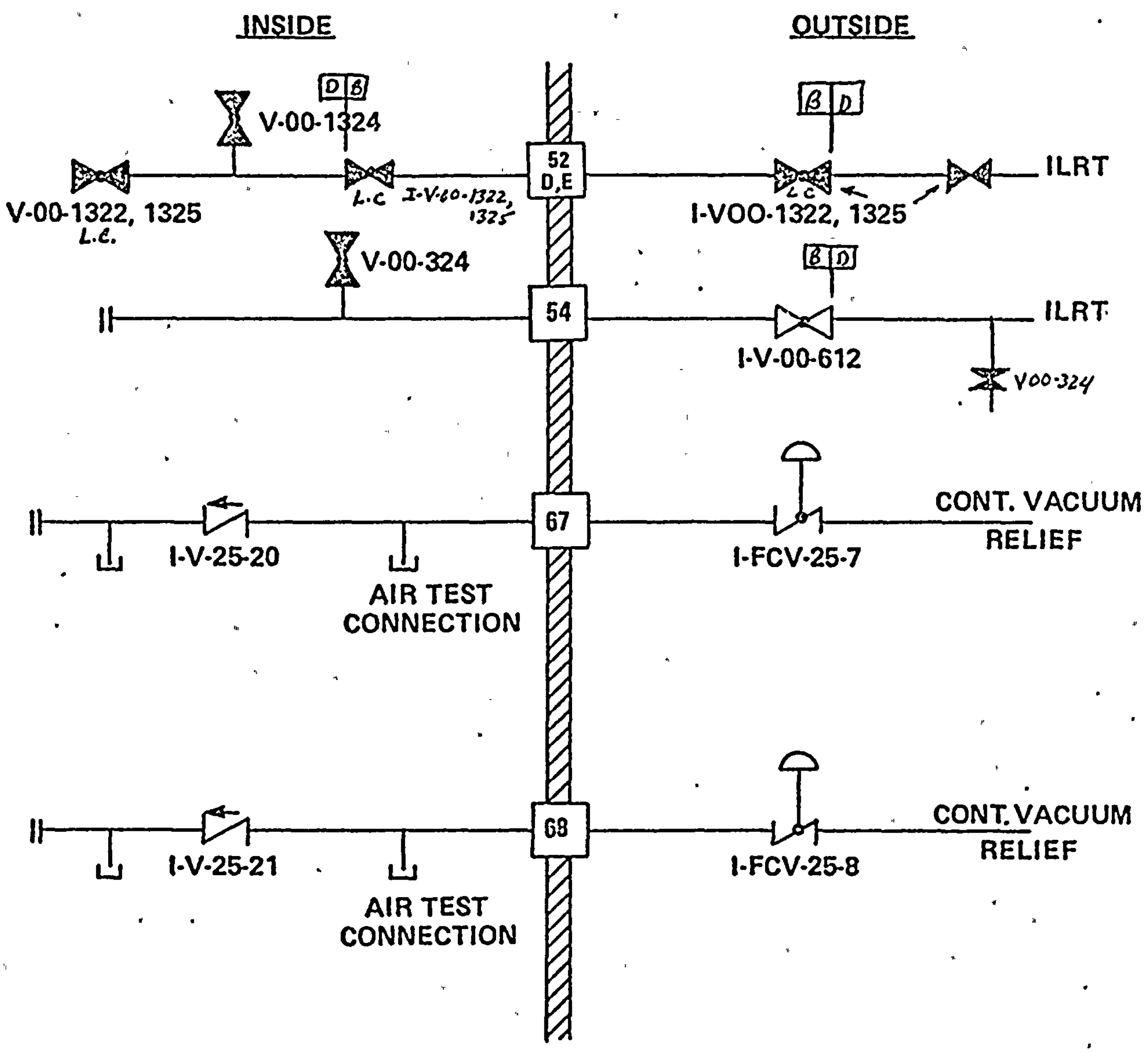
CONTAINMENT ISOLATION
VALYE TESTING – SHEET 4



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT ISOLATION
VALVE TESTING – SHEET 5
FIGURE 6.2-73


INSIDE CONTAINMENT
OUTSIDE CONTAINMENT
51
S
I-V-27-1342
I-FSE-27-17
NO CHANGE
I-V-25
325
BLEED OFF
56
H2 PURGE
I-V-25-25
I-FCV-25-26
IV-25-325
I-V-25-325
57
H2 PURGE
I-FCV-25-20
I-FCV-25-21
BLEED OFF
NO
FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2
CONTAINMENT ISOLATION
VALVE TESTING - SHEET 5
I-SH-1388
52 A,B,
I-FCV-26-1,3,
I-FCV-26-2,4,
CONT. ATMOS.
RAD. MONITORS
I-SH-1388
52 C
I-FCV-26- ,5
I-FCV-26- ,6
CONT. ATMOS.
RAD. MONITORS



AMENDMENT NO. 0 (12/80)

FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT UNIT 2

CONTAINMENT ISOLATION
VALVE TESTING – SHEET 7
FIGURE 6.2-75

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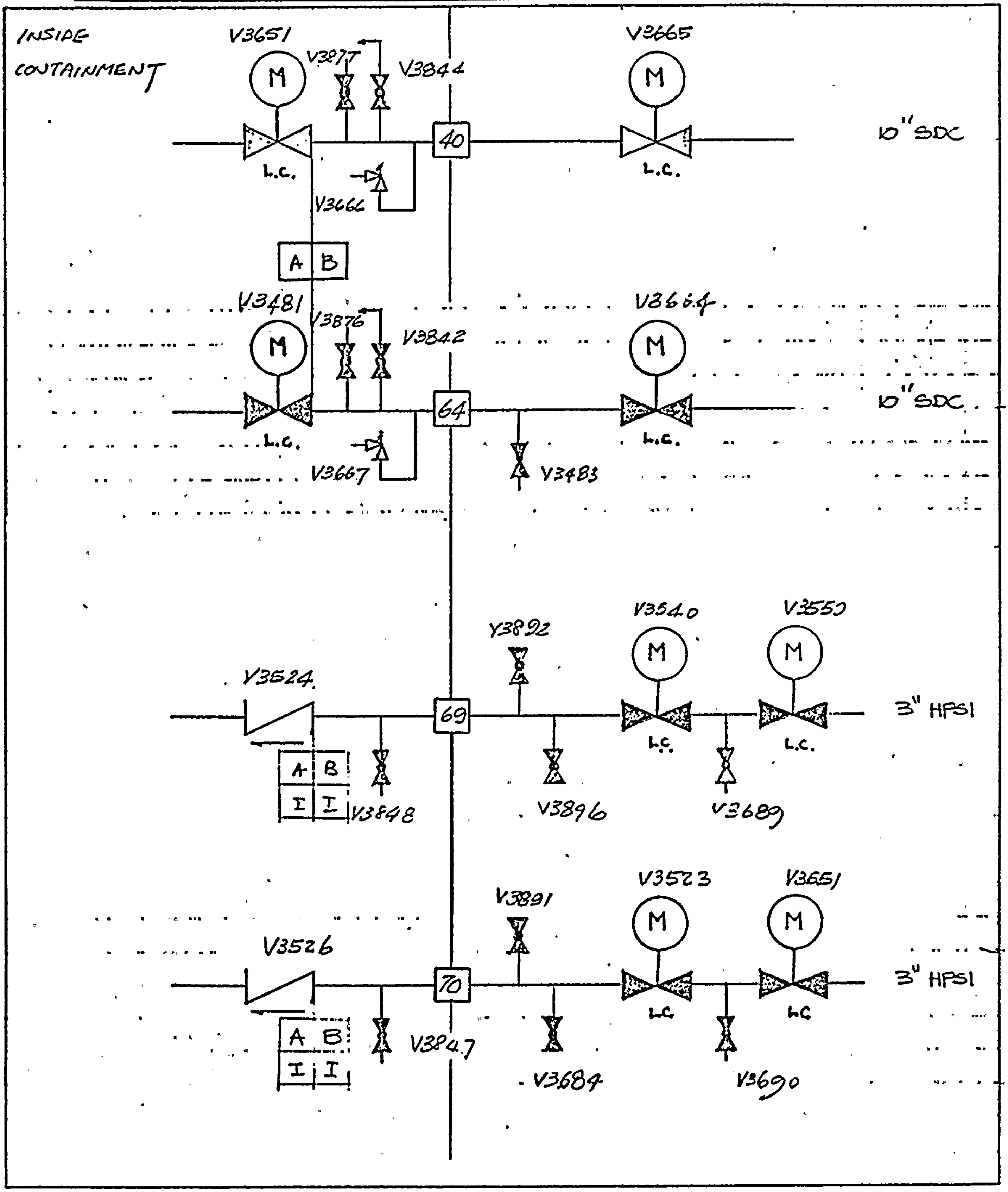

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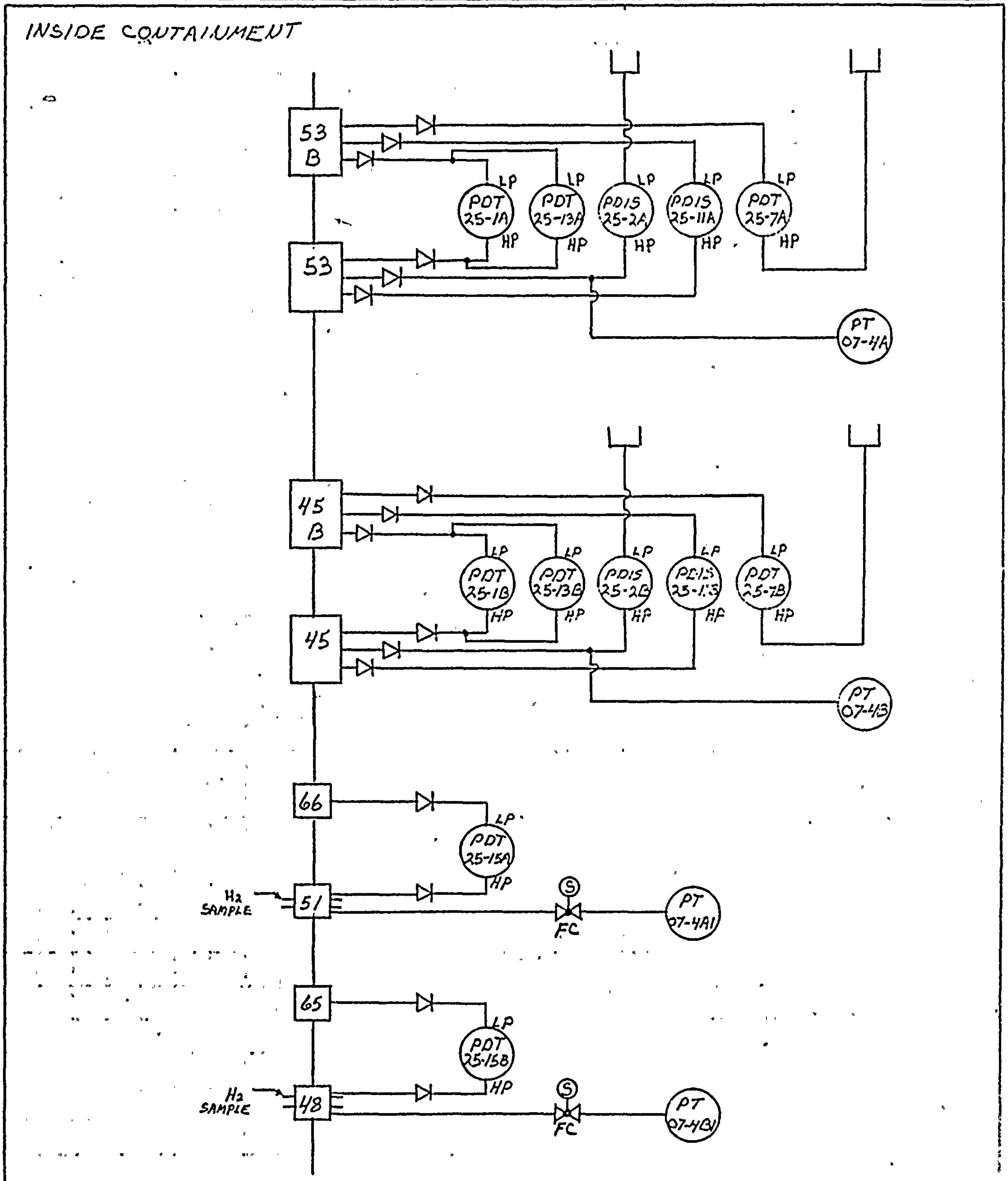
SUBJECT I & C PENETRATIONS sh. 1 of 2



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EBASCO SERVICES INCORPORATED

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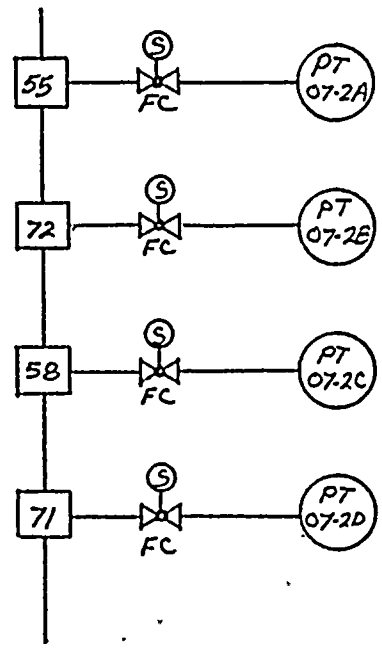
CLIENT________

PROJECT________

SUBJECT I & C Penetrations sh 2 of 2

INSIDE CONTAINMENT



FORM 581 REV 7-71

Question 5

FSAR Sections 6.2.4.1.1 and 7.3.1.1.4 indicate that either a high containment pressure signal or a high containment radiation level signal will generate a containment isolation actuation signal. However, SRP Section 6.2.4 also recommends that a high radiation signal should not be considered one of the diverse containment isolation parameters. Therefore, we request that the safety injection actuation signal should be used as one of the parameters for the initiation of containment isolation, and the above cited FSAR sections should be revised accordingly.

Response 5

The Safety Injection Actuation Signal (SIAS) will be used as one of the parameters for initiation of Containment Isolation.

[Qu]estion

6. FSAR Section 6.2.4.4 indicates that the following penetrations will not be considered possible sources of bypass leakage and, therefore, will not be subject to Type C leak rate testing:
a) Main steam (Penetrations 1 and 2);
b) Feedwater (Penetrations 3 and 4);
c) Steam generator blowdown (Penetrations 5 and 6); and
d) Steam generator blowdown sampling (Penetrations 30 and 49).

In order for us to determine the acceptability of this, discuss the conditions that will exist or the action to be taken to assure that outleakage will not occur after a LOCA for a period of 30 days. In this regard, discuss the pressure response of the steam generators relative to the containment pressure, in the short term, and the feasibility of reflooding the steam generators, in the long term, to preclude outleakage.

Response

The Main Steam System, Main Feedwater System, Steam Generator Blowdown and Blowdown Sampling System are connected to a closed seismic Category I, Quality Group B system inside containment and are therefore classified as GDC 57 systems in accordance with 10CFR50 Appendix A. These systems are maintained at a temperature and pressure condition that is higher than the containment atmosphere during normal plant operations.

During accident conditions, the Main Steam and Feedwater Isolation valves will close upon receipt of a MSIS (high containment pressure or low S.G. pressure) while the Steam Generator Blowdown and Blowdown Sampling Isolation valves will close upon receipt of a CIAS (high containment pressure or high containment radiation). FSAR Figure 6.2A (attached to CBS question #1) provides the containment pressure response for the worst break scenario and illustrates that the containment atmosphere ri[ses] to a peak of 58.4 psia and reduces to atmosphere pressure within the first day post-LOCA. Therefore, the Steam Generator inventory that existed prior to the accident will be available post-LOCA, and will act as a steam seal at the onset of the accident. Subsequent to the decay of the steam generator pressure and level, the Auxiliary Feedwater System will automatically maintain the steam generator level to guarantee the pressure of a water seal and thereby preclude bypass leakage.

Question

7. FSAR Section 6.2.4.2 indicates that only one isolation valve outside containment is provided for the isolation of each of the containment emergency sump suction lines. For this type of isolation valve arrangement, the piping between the containment and the valve should be enclosed in a leak-tight or controlled leakage housing (as described in SRP Section 6.2.4) leakage housing. If, in lieu of a housing, conservative design of the piping and valve is assumed to preclude a break of piping integrity, the design should conform to the requirement of SRP Section 3.6.2. Also, design of the valve and/or the piping compartment should provide the capability to detect leakage from the valve shaft and/or bonnet seals and terminate the leakage. Therefore, discuss the design of the containment emergency sump suction penetrations (Penetrations 32 and 33), and the leakage detection and control provisions.

Response

The emergency sump suction penetrations process lines are enclosed in a leak-tight housing, (i.e., carbon steel guard pipes) which extend from the sump inside containment to the Containment Isolation Valve located outside containment. Each guard pipe is directly welded to a steel containment vessel nozzle and acts as an extension of the containment in both directions. Passing through each guard pipe is the stainless steel sump suction line. These lines are welded to the guard pipe in the sump so that water cannot enter the annulus formed by the concentric pipes. Outside containment the suction lines are sealed to the guard pipes by means of a stainless steel bellows to allow for thermal movement. FSAR Figure 3.8-6 provides a detailed description of this type IV penetrations.

The containment isolation valves are located in the Reactor Auxiliary Building pipe tunnel which is a controlled leakage area. Leakages from these systems are directed to the ECCS room sump which is provided with safety grade, seismic Category I level indications. A backup seismic Category I level indicator is also provided in each ECCS room sump to alert the operator of any abnormal condition. The ECCS area is also provided with two safety related radiation monitors to measure the airborne effluent. A complete description of these monitors is provided in FSAR Section 11.5.2.2.10.

Question 8

Table 6.2-52, "Containment Penetration and Isolation Valve Information," should be revised to designate the fuel transfer tube (Penetration 25) and charging line (Penetration 27) as direct bypass leakage paths.

Response 8

FSAR Table 6.2-52 will be revised to designate the fuel transfer tube (Penetration 25) as a direct bypass leakage path.

The charging line (Penetration 27) is not considered a credible source of bypass leakage following a LOCA. Charging Pumps 2A and 2B are automatically started following receipt of a Safety Injection Actuation Signal (SIAS) and are powered by the emergency diesel generators. Thus, after an accident flow is directed into containment through this penetration precluding bypass leakage by establishing a water seal. If the pumps were not operating radioactive contaminants are prevented from reaching the environment by a minimum of three seismically qualified, Safety Class 2 check valves in series.These design features virtually eliminate any possibility of bypass leakage.

Question

9. Provide the information as required by NUREG-0737 concerning the following TMI Action Plan items:

a) II.E.4.2 - Containment Isolation Dependability;
b) II.F.1.4 - Containment Pressure Monitor; and
c) II.F.1.6 - Containment Hydrogen Monitor

Response

The information as required by NUREG 0737 concerning the following TMI Action Plan items has or will be incorporated into the St Lucie 2 FSAR.

a) II.E.4.2 - Containment Isolation Dependability information is contained in Appendix 1.9A and is attached for your use.

b) II.F.1.4 - Containment pressure monitor information is attached to the question/response. This information will appear in Amendment 5 to the St Lucie Unit 2 FSAR to be issued August 17, 1981.

c) II.F.1.6 - Containment Hydrogen Monitor information is contained in Appendix 1.9A item II.F.1(c) from there we refer you to Subsection 6.2.5.2.1 in which we completely describe the Containment Hydrogen Analyzer Subsystem. This is also attached for your information and use.

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 actuation 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 continuous indication of containment pressure will be provided in the 0 control room, in addition to recording.

b) A continuous indication and recording of water level in the reactor cavity sump will be provided in the control room. The following will be provided:

1) A permanently installed narrow range reactor cavity sump level 0 instrument will cover the range from the bottom of the reactor cavity sump to elevation 0.0 ft inside the containment. 1

2) Permanently installed redundant wide range containment water level instrument will cover the range from elevation -1.0 ft to the elevation on equivalent to 600,000 gallons inside the containment.

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

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 TMI Containment Water Level Monitors

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 323-1974 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.

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.

In addition to the redundant CGCS, the Continuous Containment Purge/Hydrogen Purge System is available for fission product removal and hydrogen purge following a LOCA.

6.2.5.2 System Design

6.2.5.2.1 Containment Hydrogen Analyzer Subsystem

The Containment Hydrogen Analyzer System consists of two redundant subsystems as shown on Figure 6.2-62, consisting of the sample and return piping, associated valves, hydrogen analyzer, grab sample cylinder, sample pump, moisture separator, cooler, instruments, calibration gas line and reagent gas line.

Each of the redundant subsystems is physically separate and operates independently of the other, and is powered from an independent onsite power source. No single failure can result in a total loss of hydrogen concentration measurement capability. Failure of one train is annunciated in the control room.

Components of the system are accessible for periodic inspection and maintenance. The system is designed to permit local calibration at periodic intervals with a reference hydrogen gas standard (span gas) and a zero hydrogen content reference gas. The system is independent of any system used during normal plant operation, so that plant operation does not impose restrictions on such testing.

The Containment Analyzer System is designed to seismic Category I and applicable Quality Group B requirements. Components at the hydrogen analyzer system, including pumps, valves and tubing are specified to ASME Code Section III, Code Class 2. Instrumentation and controls and electric equipment associated with the system are Class 1E. Conformance to applicable IEEE Standards is discussed in Chapter 7, Sections 3.10 and 3.11.

The system is initiated by manual operator action from the control room. No action outside the control room is necessary for system operation. However calibration can be done only at the local panel.

Once initiated, the system draws a continuous air sample from one of the sample points inside containment. Sampling valves can be manually controlled to analyze any sample point. The air is passed through the detector, analyzed, and pumped back into containment. Analyzer readings are recorded in the control room, and an alarm is actuated if concentration is above three percent. Alarm is also provided for low flow and high temperature of the sample gas. Design and performance data for the analyzer is listed in Table 6.2-54. 0

The system is designed for 40 years of normal and one year post-LOCA environmental condition and the components are qualified to operate under the applicable environmental conditions as described in Section 3.11.

The operating principle of the hydrogen analyzer is thermal conductivity of the sample. Air samples are drawn from any of the following sample points

inside containment:

a) Containment dome

b) Upper Containment ~~Lower Containment~~ | 0

c) Pressurizer enclosure

d) Vicinity of reactor coolant pump (RCP) 2A1

e) Vicinity of reactor coolant pump 2A2

f) Vicinity of reactor coolant pump 2B1

g) Vicinity of reactor coolant pump 2B2

These points provide broad coverage of the containment for hydrogen monitoring and constitute a redundant independent H_2 Sampling System. Sampling lines originating from the containment dome, pressurizer, RCP 2A1 and RCP 2A2 areas constitute one independent train of the H_2 Sampling System. The other train consists of sampling lines originating from the upper containment, RCP 2B1 and RCP 2B2 areas. Each train of the sampling lines has a common header inside the containment and penetrates the containment in a separate penetration assembly.

As discussed in Subsection 6.2.2.2, there is adequate mixing of containment atmosphere so that local stratification or pocketing of hydrogen does not occur. The analyzer cubicles are located at elevation 19.5 ft of the Reactor Auxiliary Building (RAB). The analyzer system control panel is located in the control room.

A grab sample chamber located at elevation 19.5 ft of the RAB is provided to permit hydrogen concentration measurement independent of the containment hydrogen analyzer detector.

6.2.5.2.2 Containment Hydrogen Recombiner Subsystem

The containment hydrogen recombiners control hydrogen in containment by using heat to cause recombination of liberated hydrogen with free oxygen in the air to form water.

The hydrogen recombiner system is described in Westinghouse Topical Report WCAP 7709-L[18] and shown on Figure 6.2-63. Supplement 1 through 4 of WCAP 7709-L were accepted by NRC on May 1, 1976. It is designed seismic Category I and Quality Group B requirements.

Each recombiner consists of a thermally insulated vertical metal duct with electric resistance metal sheathed heaters provided to heat a continuous flow of containment air to a temperature which is sufficient to cause a reaction between the hydrogen and the oxygen in the air. The recombiner is provided with an outer enclosure to provide protection from water spray coming from the Containment Spray System. The recombiner consists of an inlet preheater section, a heater-recombination section, a mixing chamber, and a cooling/exhaust section. Mixing of containment air is by the con-

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	RSS MOMENTS 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

4. Provide analyses to determine the external forces and moments, resulting from postulated hot leg and cold leg ruptures within the reactor cavity, on reactor vessel supports. If applicable, similar analyses should be performed for steam generator and/or pressurizer compartments that may be subject to pressurization where significant component support loads may result. For each analysis, provide the following information:

For each compartment, provide a table of blowdown mass flow rate and energy release rate as function of time for the break which was used for the component support evaluation.

Response

FSAR Table 6.2-13 is a summary of postulated pipe ruptures for containment subcompartment analysis. The last column in this table "Release Rate Data Table Numbers" will refer you to, for each compartment, a table of blowdown mass flow rate and energy release rates as a function of time for the break which was used for the component support evaluation.

Question 5

Provide analyses to determine the external forces and moments, resulting from postulated hot leg and cold leg ruptures within the reactor cavity, on reactor vessel supports. If applicable, similar analyses should be performed for steam generator and/or pressurizer compartments that may be subject to pressurization where significant component support loads may result. For each analysis, provide the following information:

Describe and justify the nodalization sensitivity studies performed for the major component supports evaluation (if different from the strucutural analysis model), where transient forces and moments acting on the components are of concern. Where component loads are of primary interest, show the effect of noding variations on the transient forces and moments. Use this information to justify the nodal model selected for use in the component supports evaluation.

Response

Divisions between subcompartment are determined by the physical flow restrictions within each compartment. A flow restriction is defined by the presence of an object in the flow path that changes the flow area in that direction, with the subdivision defined at the point of minimum flow area. This minimum flow area becomes the junction flow area used in the RELAP 4 analysis. For the models constructed for the reactor cavity and secondary shield wall area flow restrictions included the presence of steel and concrete supports, doorways, vent shafts and gratings, as well as large equipment such as the reactor vessel, primary piping, the steam generator, reactor coolant pumps and the pressurizer. By choosing node boundaries at the various physical flow restrictions, a method consistent with the lumped-parameter calculation model used by RELAP 4 and described above, calculated differential pressures and consequent support loads are realistically maximized. The nodalization sensitivity study performed for the Shearon Harris PSAR (Docket 50-400, 401, 402 and 403) shows that the peak calculated differential pressure is very sensitive to an increasing number of nodes until that number equals the number defined by physical flow restrictions. Increasing the subdivision of the compartment is unwarranted and can lead to unrealistic results if these "fictitious junctions" are modeled. The subcompartment models discussed below take account of all physical flow restrictions present in a manner identical to that shown to be optimum by the sensitivity study.

Table 6.2-25 presents the overall results of the subcompartment analyses. The reactor cavity, Secondary Shield Wall and Pressurizer Area Design evaluation is described in FSAR Subsection 6.2.1.2.3.

Question

Provide analyses to determine the external forces and moments, resulting from postulated hot leg and cold leg ruptures within the reactor cavity, on reactor vessel supports. If applicable, similar analyses should be performed for steam generator and/or pressurizer compartments that may be subject to pressurization where significant component support loads may result. For each analysis, provide the following information:

Graphically show the pressure (psia) and differential pressure (psi) response as functions of time for a representative number of nodes to indicate the spatial pressure response. Discuss the basis for establishing the differential pressure on components.

Response

FSAR Table 6.2-25 list the Results of the Subcompartment Analysis. In this table the peak node pressure, and peak differential pressure is listed. Along with these values a figure is referenced for both of those values.

The component and support loads for the Steam Generator, Reactor Coolant Pump, and Pressurizer were determined by equivalent static analyses. A load factor of two on the calculated thrust, jet impingment, and subcompartment pressure loads is employed to account for the dynamic response of the structure. The model employed for static analysis is shown in Figure 3.9-18.

Question

8 Figure 6.2-71, regarding containment isolation valves, should be revised to show the containment isolation valve arrangements for each containment penetration. In addition, the isolation valve arrangements shown in this figure should be consistent with the valve arrangements as shown in the system flow diagrams.

Response

The attached figures show the containment isolation valve arrangement for each containment penetration. These figures will be placed in the FSAR via Amendment 6.

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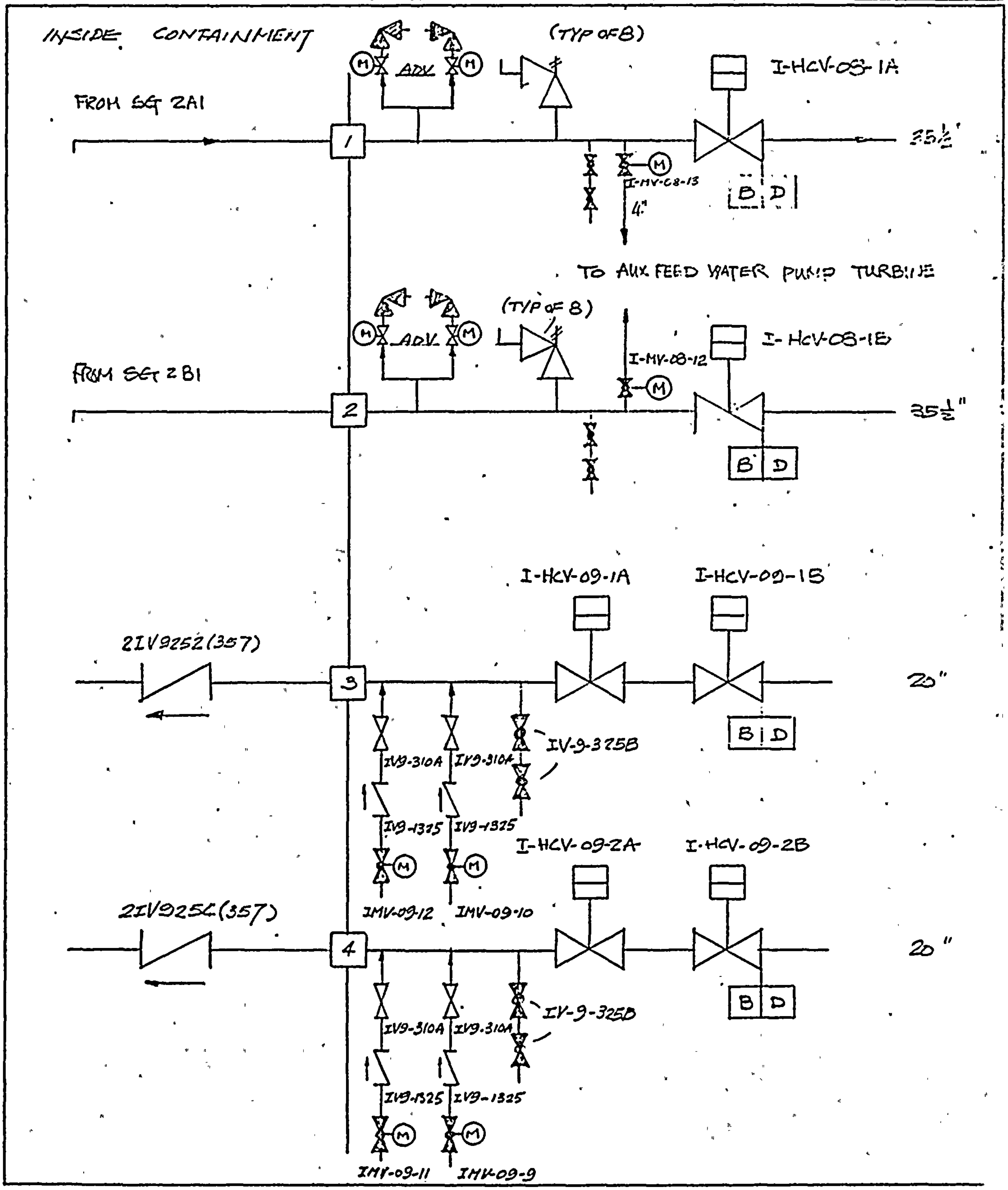

FORM 581 REV 7-71

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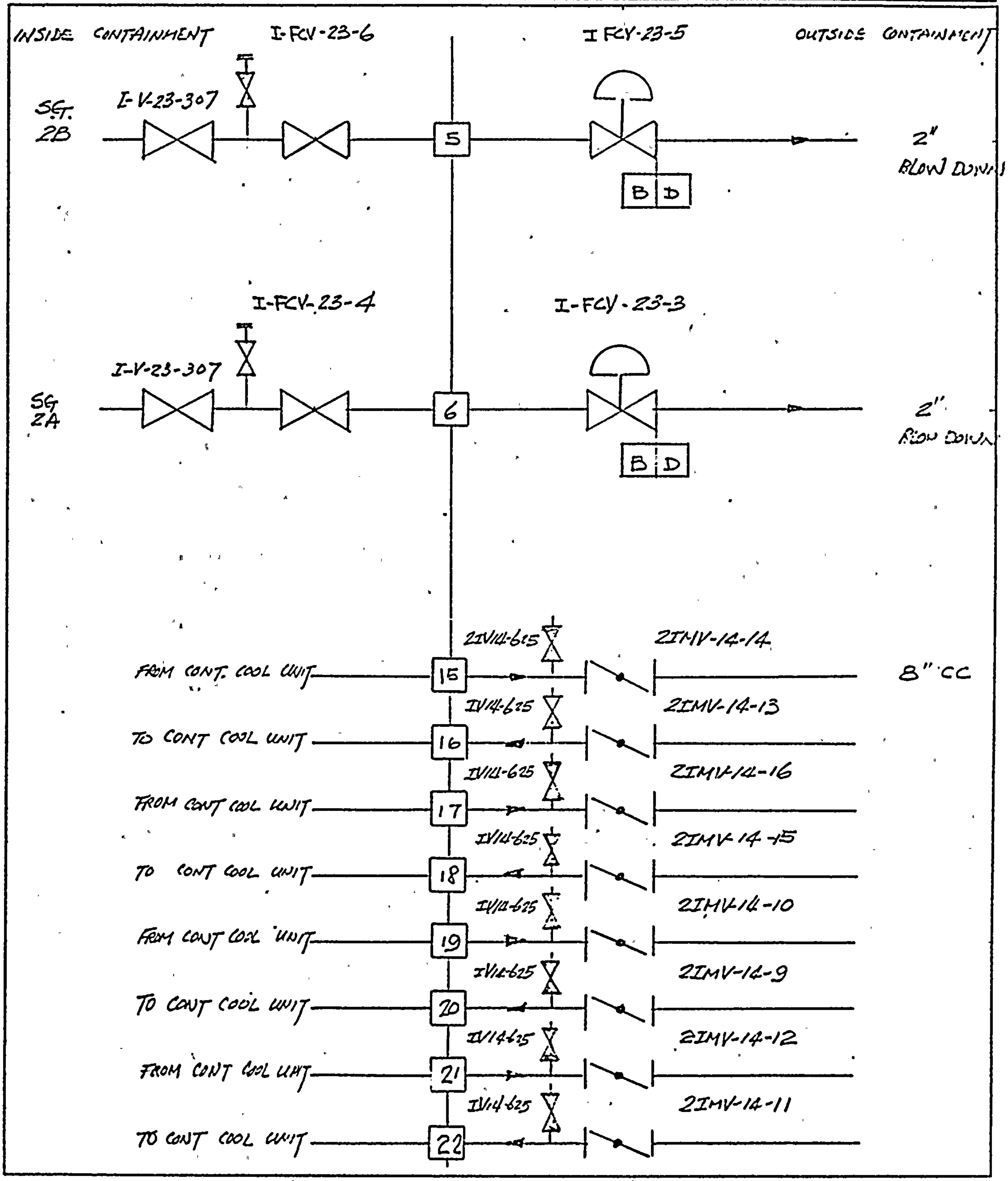

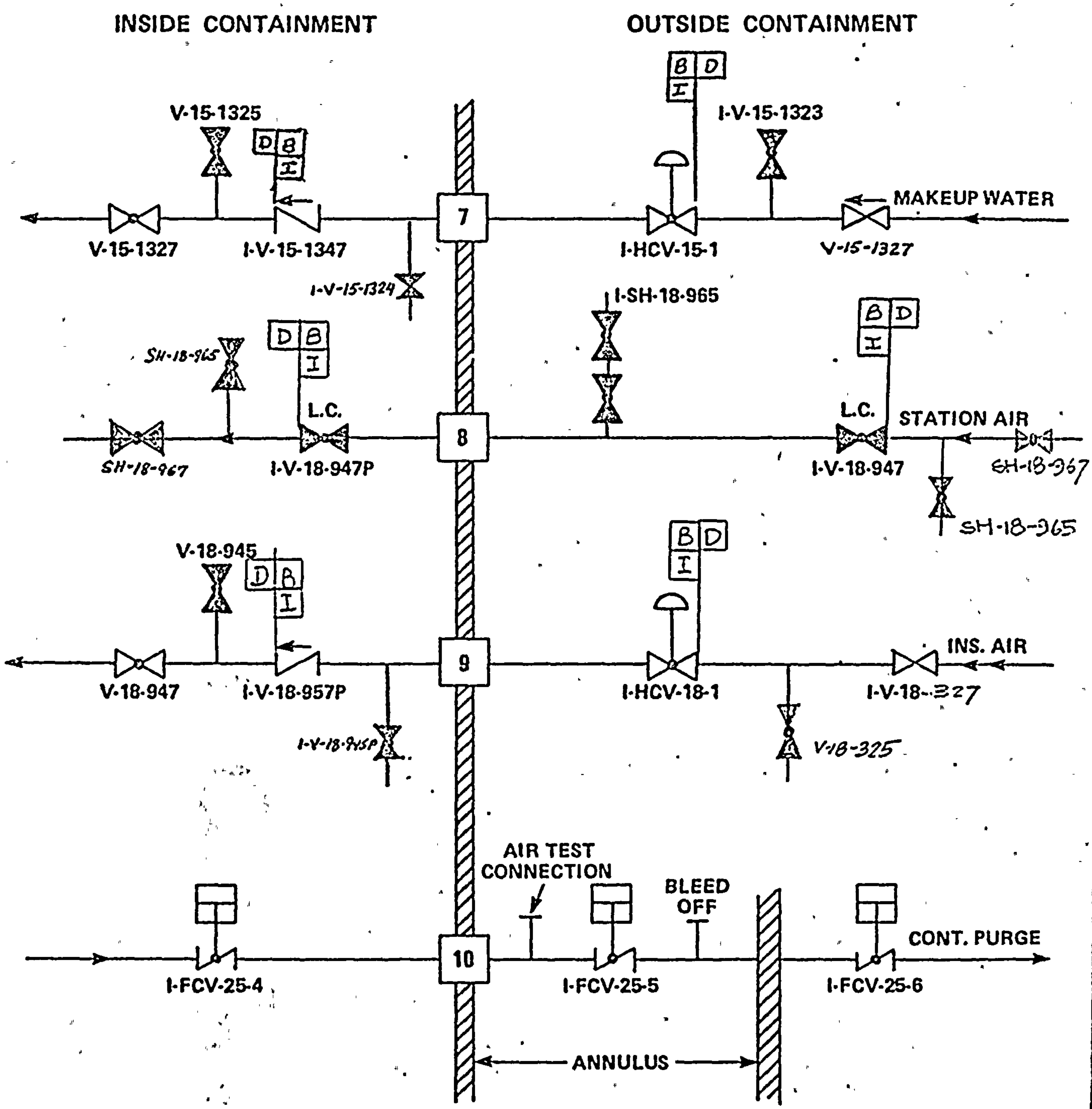

AMENDMENT NO. 0 (12/80)

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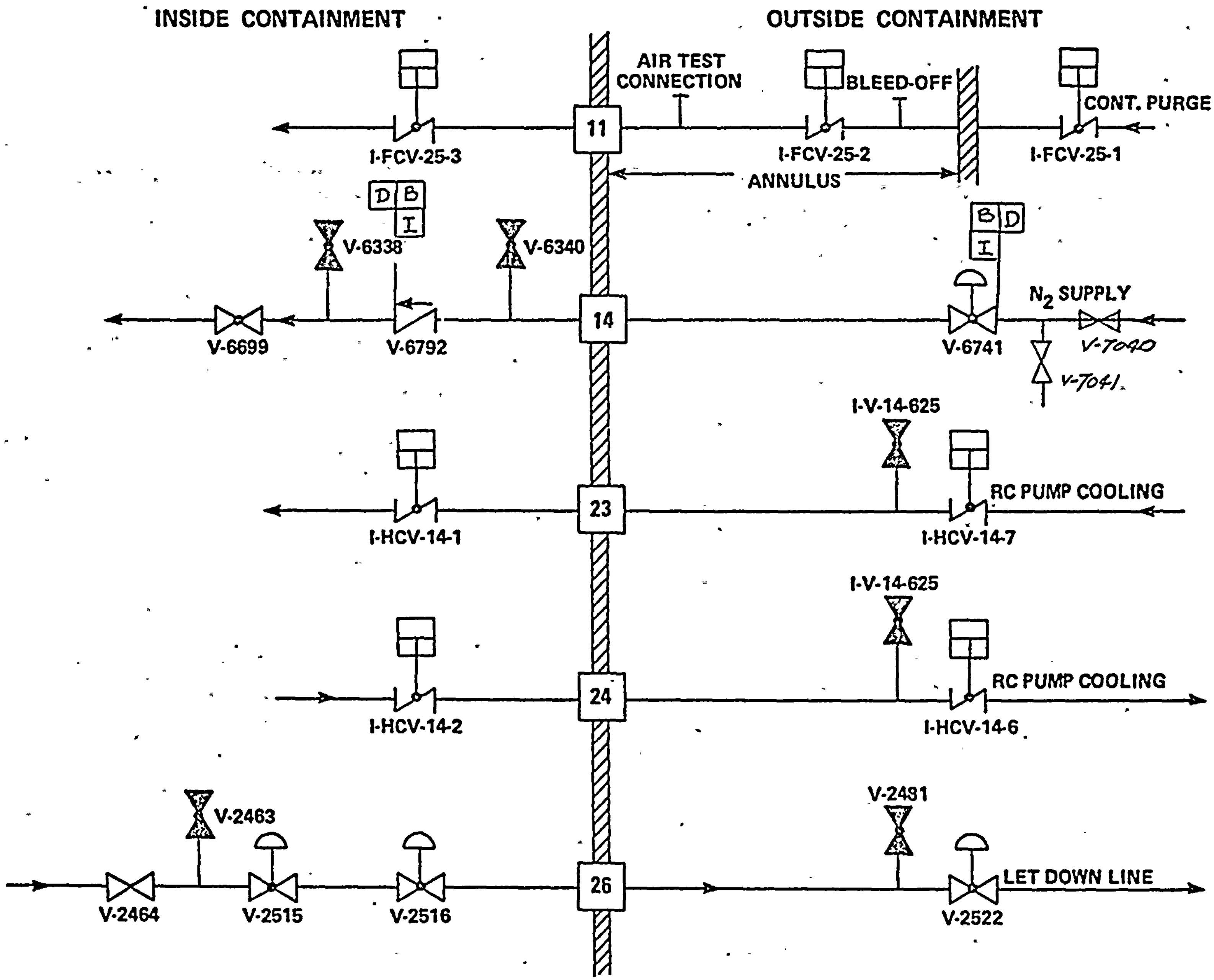
ST. LUCIE PLANT UNIT 2

CONTAINMENT ISOLATION
VALVE TESTING – SHEET 1
FIGURE 6.2-69



AMENDMENT NO. 0 (12/80)

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CONTAINMENT ISOLATION
VALVE TESTING – SHEET 2
FIGURE 6.2-70

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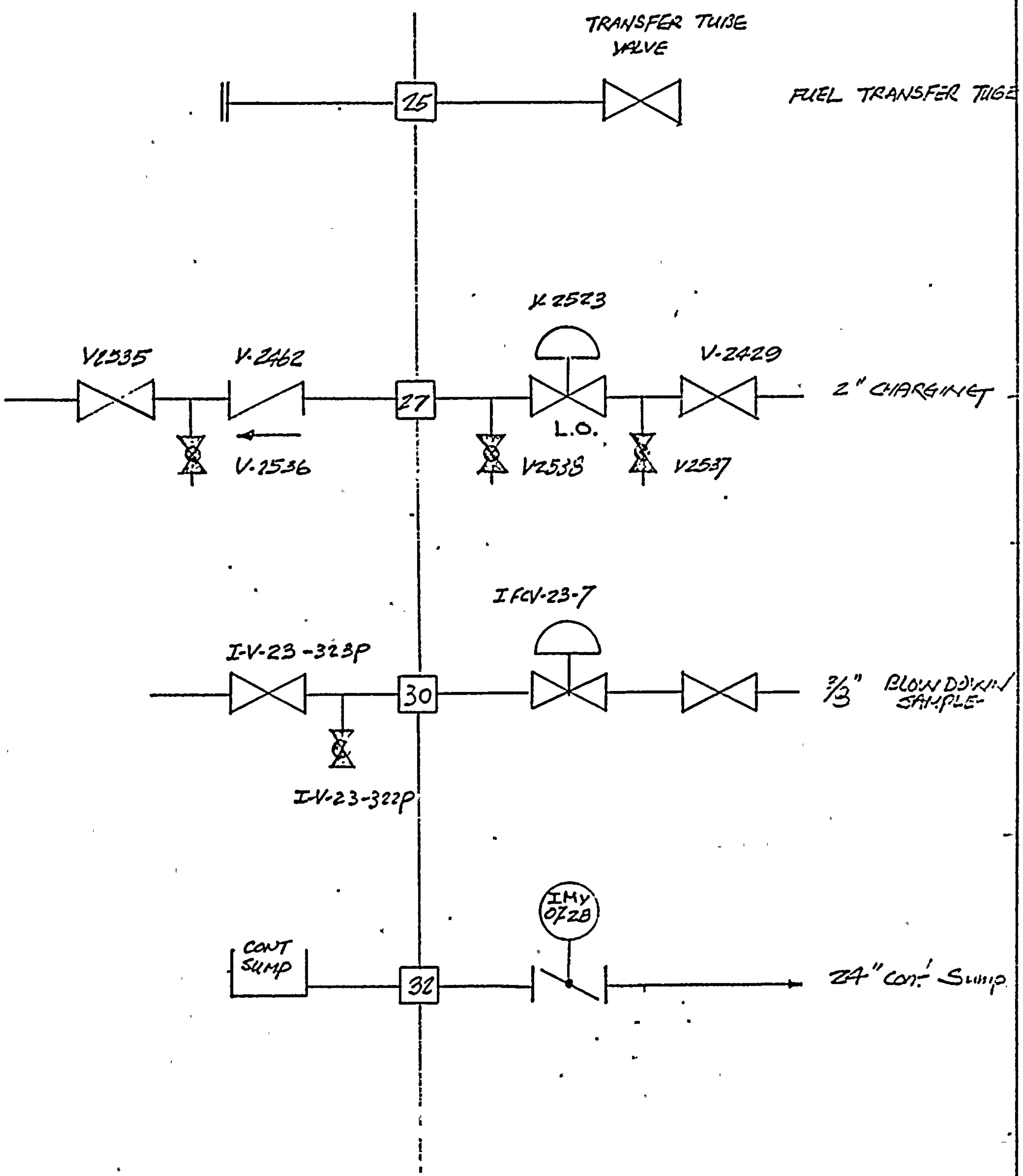
SUBJECT ____

INSIDE CONTAINMENT



FORM 561 REV 7-71

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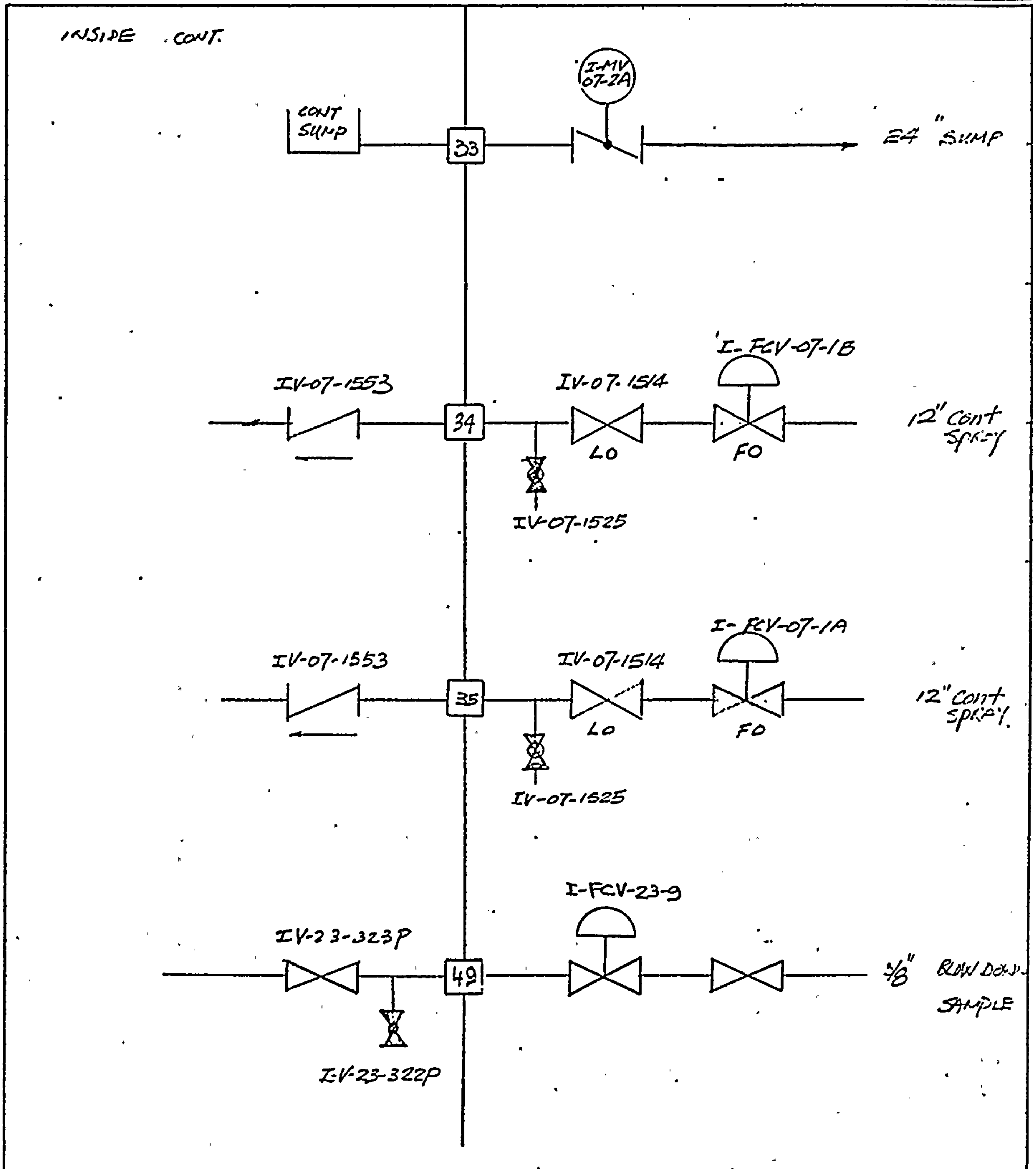


FORM 581 REV 7-71

inside containment:

a) Containment dome

b) Upper Containment ~~Lower Containment~~ 0

c) Pressurizer enclosure

d) Vicinity of reactor coolant pump (RCP) 2A1

e) Vicinity of reactor coolant pump 2A2

f) Vicinity of reactor coolant pump 2B1

g) Vicinity of reactor coolant pump 2B2

These points provide broad coverage of the containment for hydrogen monitoring and constitute a redundant independent H_2 Sampling System. Sampling lines originating from the containment dome, pressurizer, RCP 2A1 and RCP 2A2 areas constitute one independent train of the H_2 Sampling System. The other train consists of sampling lines originating from the upper containment, RCP 2B1 and RCP 2B2 areas. Each train of the sampling lines has a common header inside the containment and penetrates the containment in a separate penetration assembly.

As discussed in Subsection 6.2.2.2, there is adequate mixing of containment atmosphere so that local stratification or pocketing of hydrogen does not occur. The analyzer cubicles are located at elevation 19.5 ft of the Reactor Auxiliary Building (RAB). The analyzer system control panel is located in the control room.

A grab sample chamber located at elevation 19.5 ft of the RAB is provided to permit hydrogen concentration measurement independent of the containment hydrogen analyzer detector.

6.2.5.2.2 Containment Hydrogen Recombiner Subsystem

The containment hydrogen recombiners control hydrogen in containment by using heat to cause recombination of liberated hydrogen with free oxygen in the air to form water.

The hydrogen recombiner system is described in Westinghouse Topical Report WCAP 7709-L[18] and shown on Figure 6.2-63. Supplement 1 through 4 of WCAP 7709-L were accepted by NRC on May 1, 1976. It is designed seismic Category I and Quality Group B requirements.

Each recombiner consists of a thermally insulated vertical metal duct with electric resistance metal sheathed heaters provided to heat a continuous flow of containment air to a temperature which is sufficient to cause a reaction between the hydrogen and the oxygen in the air. The recombiner is provided with an outer enclosure to provide protection from water spray coming from the Containment Spray System. The recombiner consists of an inlet preheater section, a heater-recombination section, a mixing chamber, and a cooling/exhaust section. Mixing of containment air is by the con-

492.10 With regard to the Analog Core Protection Calculator, provide a listing of the algorithms used, discuss their verification and evaluation.

Response

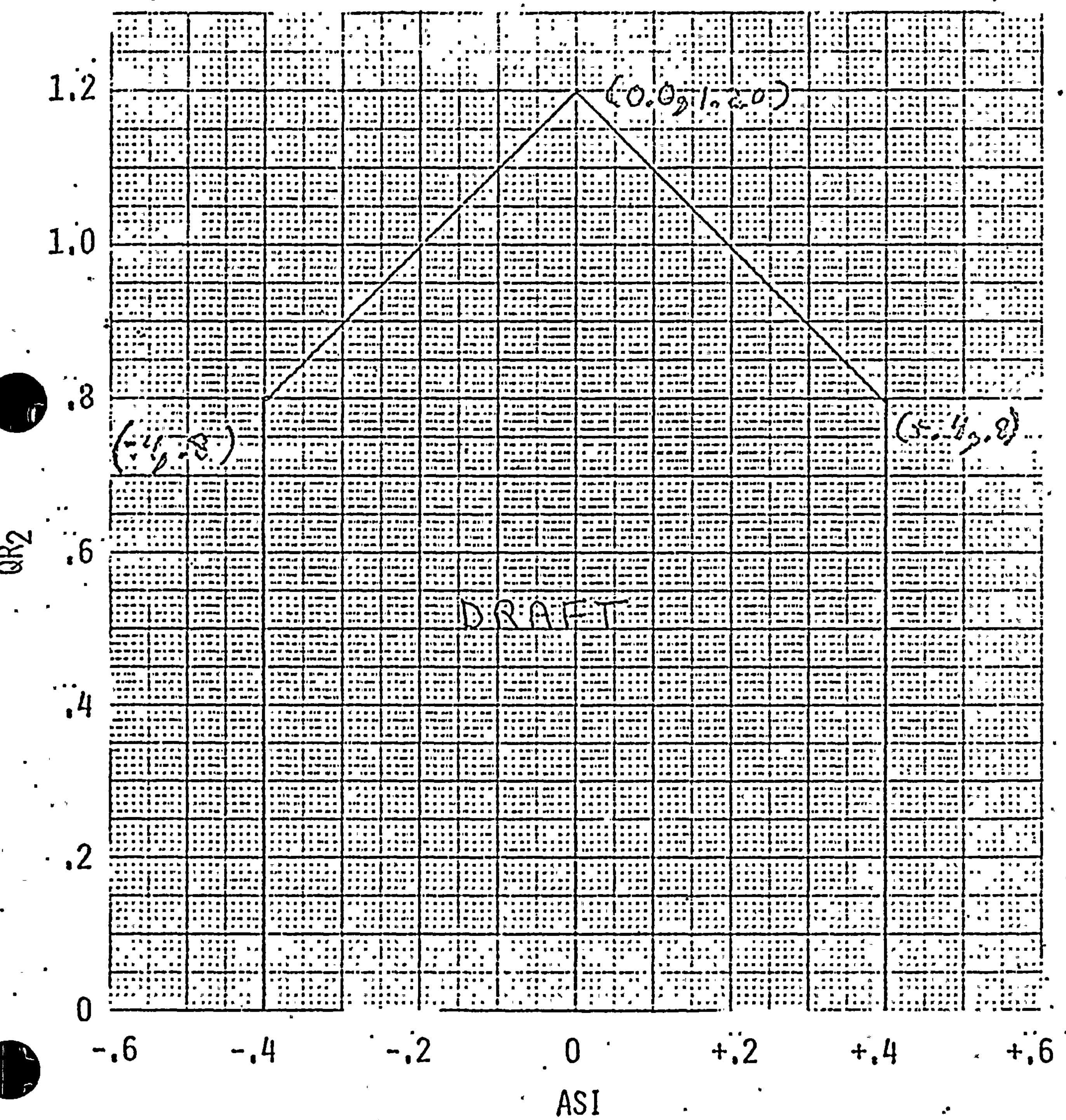
The algorithm for the Thermal Margin/Low Pressure Limiting Safety System Setting (LSSS) has been discussed in the answer to question 492.9.

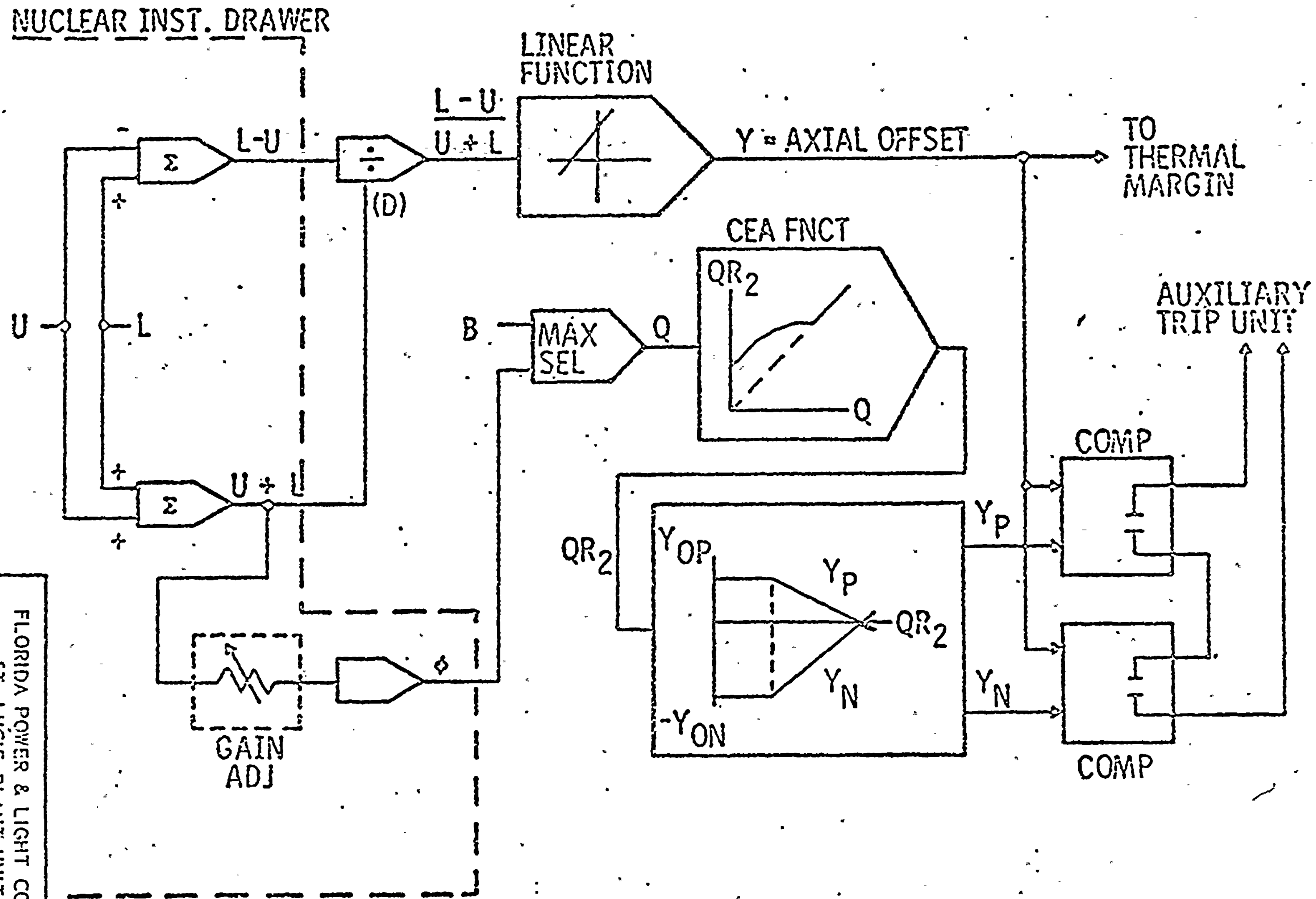
The "algorithm" for the Local Power Density (LPD) LSSS results in a trip limit-line of power vs. axial shape index as shown in the attached figure. FSAR Figure 7.2-16 is the LPD trip functional diagram.

The verification and evaluation of the LPD trip limits are discussed in CENPD-199-P "CE Setpoint Methodology". As noted in the answer to question 492.9, C-E is currently updating this report for final NRC review and approval.

Figure 492.10-1

ST. LUCIE UNIT 2
CPC-2 LOCAL POWER DENSITY TRIP





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ST. LUCIE PLANT UNIT 2

LOCAL POWER DENSITY TRIP
FIGURE 7.2-16

SL-2 Round One Questions

440.25 (15.3.3) Provide a detailed analysis on the consequences of a RCP shaft seizure event. Justify selection of limiting single failures. The time at temperature studies which justify your claims of peak clad temperature being limited to 1300°F are not accepted by the staff. In assessing fuel failures, any rod which experiences a DNBR of less than 1.19 must be assumed failed. Confirm that the results of the analysis meet the acceptance criteria of SRP 15.3.3.(2). Provide your assumptions on flow degradation due to the locked rotor in the faulted loop, and reference appropriate studies which verify these assumptions. Also provide a similar analysis for the locked rotor event presented in section 15.3.4.1, and show that acceptable consequences result.

Response:

The justification for the selection of limiting single failures was presented in the response to NRC Question 440.9. For the one pump resistance to forced flow with a loss of offsite power as a result of turbine trip event, the percent of fuel pins with CE-1 DNBR less than 1.19 should not be used to determine fuel failure since; (1) a CE-1 DNBR less than 1.19 does not mean that a given fuel pin will experience DNB, and (2) DNB does not necessarily result in fuel failure. For these reasons, the approach proposed by NRC for calculation of fuel failures is unduly conservative. A more reasonable, yet still conservative, method of calculating fuel failures, presented in CENPD-183, was submitted to NRC in July 1975. Using this method for St. Lucie Unit No. 2 results is postulated DNB and assumed failure of 13% of the fuel pins as presented in the FSAR. The percentage should be used in evaluating the consequences of this accident. The description and justification of the C-E method is provided in the response to NRC Question 440.11.

The flow coastdown which was used in the analysis of the one pump resistance to forced flow is presented in Figure 440.25-1. This figure shows the variation of core flow fraction with time. The seized shaft is assumed to instantaneously stop at time 0.0 with the seized rotor acting only as a resistance to flow. This coastdown was generated using the COAST code as documented in CENPD-98 (see Reference 440.25-1).

Reference:

1. "Coast Code Description", CENPD-98, April 2, 1973.

A change to the FSAR, ~~Section~~ Appendix 15.C.3. , accompanies this response.

Figure 440.25-1
St. Lucie-2
Seized Shaft

Core Flow Fraction versus Time

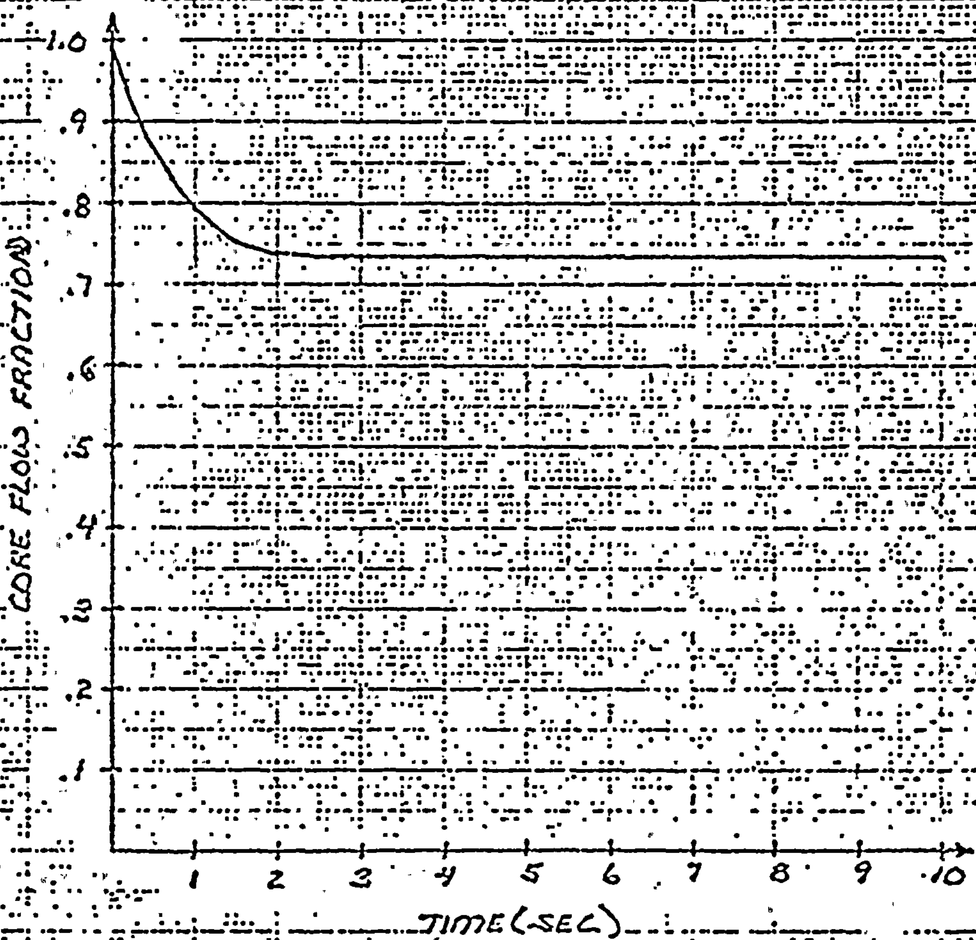
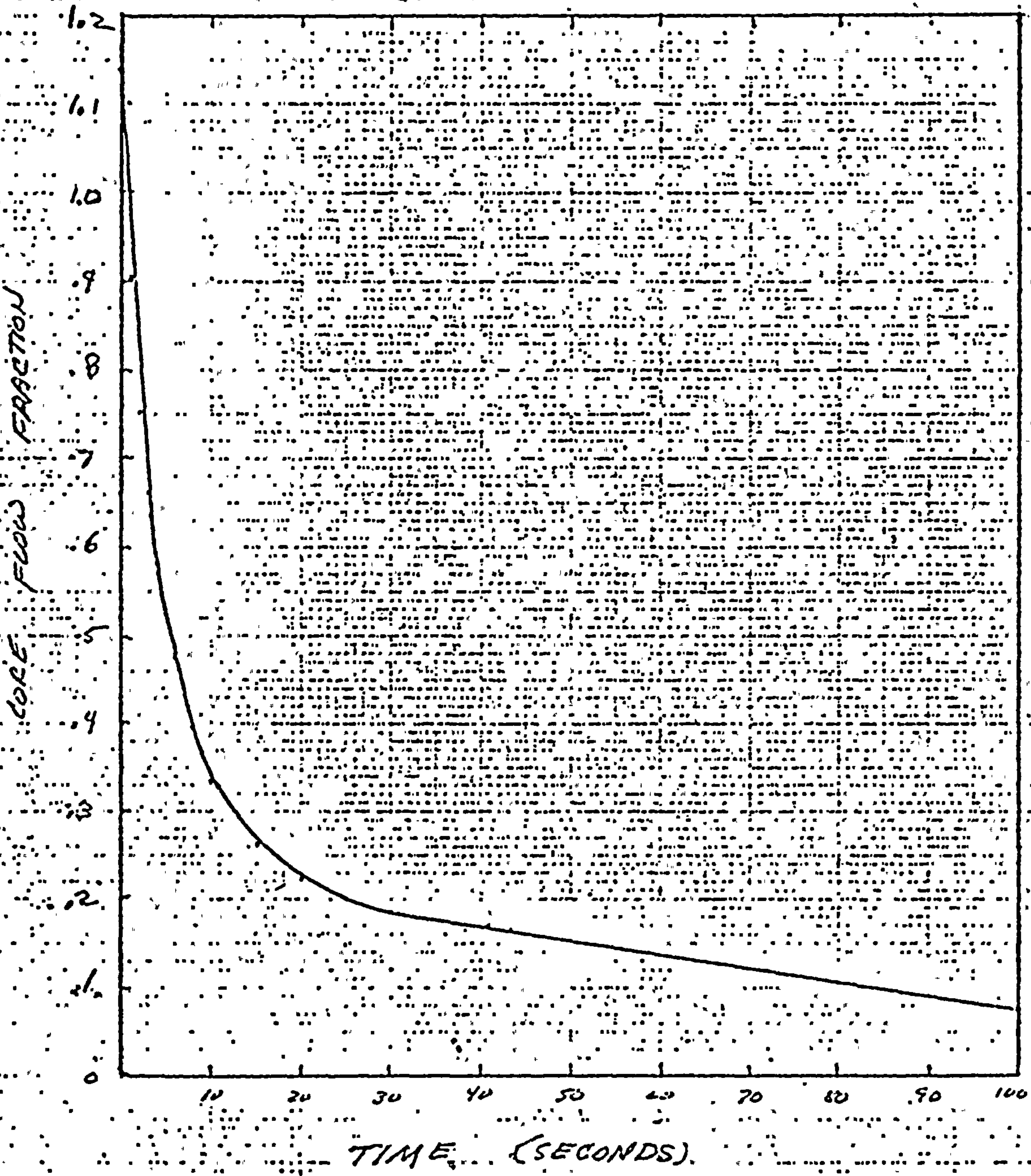


Figure 440.25-2
St. Lucie Unit 2
Seized Shaft + LOAC
Core Flow Fraction Vs. Time



DRAFT

8/18/81

SL-2 Round One Questions

440.28 (15.4.2) Your FSAR indicates that operational procedures allow detection of a boron dilution event 15 minutes prior to criticality. This is not acceptable. The staff will require that alarms be available to alert the operator to a boron dilution transient 15 minutes prior to criticality (30 minutes when in refueling mode). Show that the plant is protected for all postulated boron dilution events assuming the worse single active failure. In particular, consider the failure of the first alarm. If a second alarm is not provided, show that the consequences of the most limiting unmitigated boron dilution event meet the staff criteria and are acceptable. Also, indicate for all six modes, what alarms would identify to the operators that a boron dilution event was occurring. Confirm that the results of these analyses meet the acceptance criteria for these events per SRP 15.5.1.

Response:

SRP 15.4.6 requires that at least 15 minutes is available from the time the operator is made aware of an unplanned boron dilution event to the time a loss of shutdown margin occurs during power operation (automatic control and manual modes), startup, hot standby, and cold shutdown. For MODES 1 through 6 any of several alarms and/or indications will provide the operator with at least 15 minutes (For MODE 6, 30 minutes) to terminate the event before the shutdown margin is lost.

The indications and/or alarms available to alert the operators that a boron dilution event is occurring in each of the operational modes are outlined below.

1. The following control room indications and corresponding pre-trip alarms are available for MODES 1 and 2: a high power or, for some set of conditions, a high pressurizer pressure trip in MODE 1 or a high logarithmic power level trip in MODE 2. Furthermore, a high T_{AVG} alarm may also occur prior to trip.

2. In MODES 3 and 4 with CEAs withdrawn, the high logarithmic power level trip and pre-trip alarm will provide an indication to alert the operator of an inadvertent boron dilution.

3. In MODES 3, 4, and 5 with CEAs fully inserted and in MODE 6, a high neutron flux alarm on the startup flux channels will provide indication of any boron dilution event. Limiting boron dilution events in subcritical operating modes will be analyzed to establish the startup channel alarm setpoint and reset time. The times to complete loss of shutdown margin, and hence reactivity insertion rates, and neutron flux responses at the startup channel excore detectors will be determined such that the startup channel alarm setpoints based on these responses satisfy the requirements of SRP 15.4.6.

   This alarm will be powered by an onsite power source in the event the offsite power is lost.

The times to loss of shutdown margin calculated for the postulated boron dilution event represent the fastest credible dilution rates and, therefore, the shortest time for each mode. Consideration of additional single failures would not increase the dilution rate, and therefore, would not reduce the time to loss of shutdown margin. The only failure of significance involves the loss of the indications that alert the operators to a boron dilution. In MODES 1 and 2, there are no single active failures that result in the loss of any of the RPS alarms used to alert the operators that a boron dilution is in progress. In MODES 3, 4, 5, or 6, in case one or both startup flux channel alarms become inoperable, the operators would be required to implement operational procedure guidelines which would assure detection of a boron dilution event. In MODES 3, 4, and 5; the guidelines are based on determining the RCS boron concentration by either boronometer or RCS sampling at frequencies which depend on the mode of operation. No single active failure can eliminate more than one of the methods of monitoring or determining the RCS boron concentration. In MODE 6, the boron dilution event is precluded becasue the manual isolation valve (V 2183) in the makeup water line and the primary makeup water supply to charging pump isolation valve (V 2180) are normally locked closed in this mode.

A change to the FSAR, Sections 15.4.2.4 and 7.7.1, accompanies this response.

7.7.1.1.10.3 Turbine Runback

The following inputs cause a turbine runback:

a) One main feedwater pump tripped

b) Two heater drain pumps tripped

The runback input causes a contact to close in the DEH runback circuitry. The turbine runs back at a predetermined rate until the contact opens at which time the runback is stopped. In the case of the heater drain pumps, the runback is stopped at 70 percent of full load as determined by first stage pressure, and in the other case the runback is stopped when feedwater flow and steam flow are equal.

INSERT BB

7.7.1.2 Design Comparison

The design differences between the control systems in the St Lucie Unit 2 design scope and the control systems provided for the reference plant are discussed in this section.

7.7.1.2.1. Reactivity Control Systems

The RRS is functionally identical to that supplied for St Lucie Unit 1 (NRC Docket 50-335).

The CEDMCS combines the Control Element Drive System (CEDS) and the coil power programmers (CPP) into one integrated system thus reducing the interfacing required between the previous two separate subsystems. The CEDMCS is functionally identical to the CEDS/CPP of St Lucie Unit 1 with the following changes:

The CEAs are controlled in subgroups consisting of four or five CEAs located symmetrically about the core;

All timing functions within the CEDMCS are performed using digital techniques to increase the accuracy and flexibility of the integrated system;

The CEA withdrawal prohibit (CWP) is effective in all modes, and CWP can be bypassed at the operator's module;

While the CEDMCS is in the automatic sequential mode, either or both part-length CEA (PLCEA) groups can be inserted or withdrawn, but motion of individual CEAs or PLCEAs is not possible;

While in the automatic sequential mode, the CEA motion inhibit (CMI) cannot be bypassed and the system can handle up to 91 CEAs.

7.7.1.2.2 Reactor Coolant Pressure Control System

The reactor coolant pressure control system is functionally identical to that supplied for St Lucie Unit 1 (NRC Docket 50-335).

7.7.1.2.3 Pressurizer Level Control System

The Pressurizer Level Control System is functionally identical to that supplied for St Lucie Unit 1 (NRC Docket 50-335).

7.7.1.2.4 Feedwater Regulating System

The Feedwater Regulating System is functionally identical to that supplied for St Lucie Unit 1 (NRC Docket 50-335).

7.7.1.2.5 Steam Dump and Bypass Control System

The Steam Dump and Bypass Control System is functionally identical to that supplied for St Lucie Unit 1 (NRC Docket 50-335).

7.7.1.2.6 Analog Display System

The Analog Display System is functionally identical to the metrascope supplied for St Lucie Unit 1 (NRC Docket 50-335).

7.7.1.2.7 Boron Control System

The boronometer is functionally identical to that supplied for Waterford Steam Electric Station Unit 3 (NRC Docket 50-382). The only difference is that the recording range is switch selectable for 0-1250 ppm and 0-5000 ppm. For any differences in the control of boration and deboration see Subsection 9.3.4. 0

7.7.1.2.8 Incore Instrumentation

The Incore Instrumentation System is similar to that supplied for Arkansas Nuclear One-Unit 2 (NRC Docket 50-368). The difference being 44 detector assemblies vs 56 on St Lucie Unit 2.

7.7.1.2.9 Excore Neutron Flux Monitoring System

The start-up and control channels of the Excore Neutron Flux Monitoring System are functionally identical to that supplied on System 80 (NRC Docket STN-50470F). The safety channels are of a new design but based on System 80 circuitry.

7.7.1.2.10 Digital Data Processing System 0

The Digital Data Processing System is functionally identical to that supplied for St. Lucie Unit 1 (NRC Docket 50-335). The only difference is that the Unit 2 system has redundant computers. 0

P INSERT CC

Insert BB

7.7.1.1.11 Boron Dilution Alarm System

Reactivity control in the reactor core is affected, in part, by soluble boron in the reactor coolant system. The Boron Dilution Alarm System (Figure 7.7-8) utilizes the startup channel nuclear instrumentation signals to detect a possible inadvertent boron dilution event while in Modes 3-6. There are two redundant and independent channels in the Boron Dilution Alarm System (BDAS) to ensure detection and alarming of the event.

The BDAS contains logic which will detect a possible inadvertent boron dilution event by monitoring the startup channel neutron flux indications. When these neutron flux signals increase (during shutdown) to equal or greater than the calculated alarm setpoint, alarm signals are initiated to the Plant Annunciation System. The alarm setpoint will only follow decreasing or steady flux levels, not an increasing signal. The current neutron flux indication and alarm setpoint (per channel) are displayed. There is also a reset capability to allow the operator to acknowledge the alarm and initialize the system.

The BDAS will be powered from an offsite power source with an onsite backup power source.

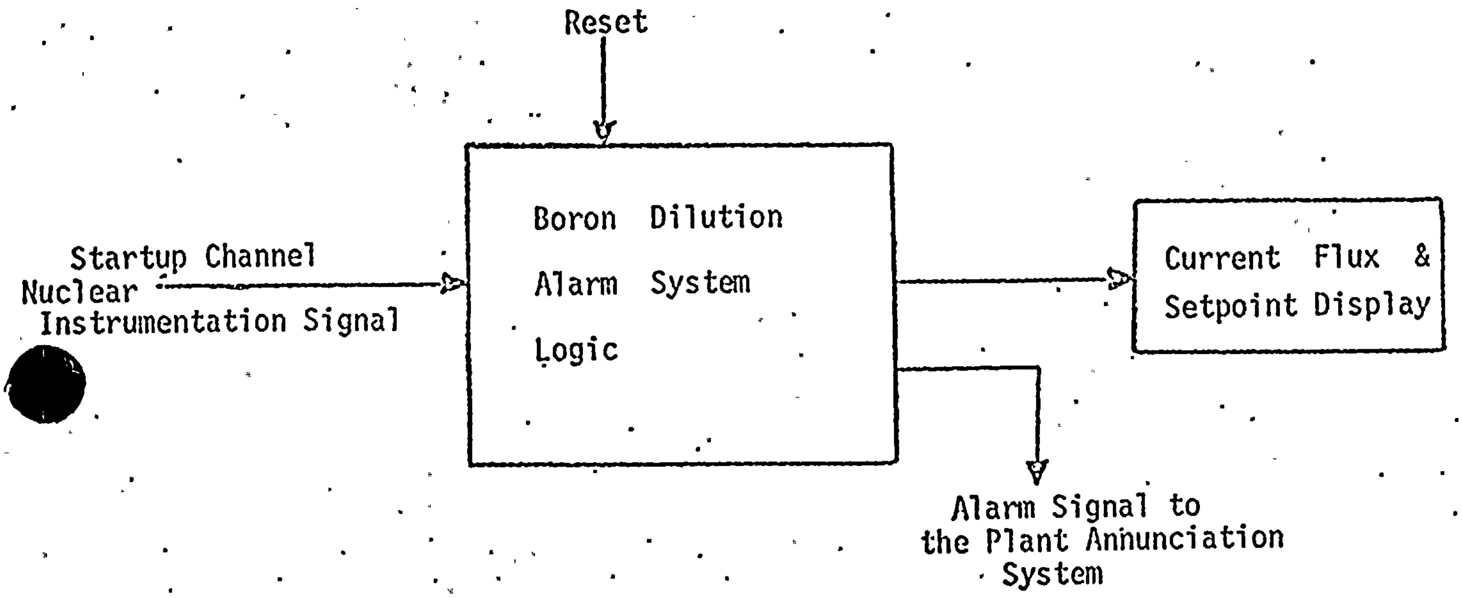
Insert CC

7.7.1.2.11 Boron Dilution Alarm System

The Boron Dilution Alarm System is an addition to the St. Lucie Unit 2 design. There is no functional comparison to St. Lucie Unit I (NRC Docket 50-335).

FIGURE 7.7-8

BORON DILUTION ALARM
SYSTEM SIMPLIFIED BLOCK DIAGRAM



Note: Only one of two identical channels is shown.

15.4.2.4 Limiting Loss of Shutdown Margin Event - Slow Positive Reactivity Insertion

15.4.2.4.1 Identification of Event and Causes

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 event combination resulting in the closest approach to the complete loss of shutdown margin. The Slow Positive Reactivity Insertion was identified as the most limiting event because no other Infrequent event affects shutdown margin. 2

The event groups and event combinations evaluated and the significance of the approach to the loss of shutdown margin acceptance guideline for each are indicated in Table 15.4.2-1. 2

The slow positive reactivity insertion may occur due to a closure of a boron flow control valve or a malfunction of the makeup controller which causes a boron dilution. 2

The most limiting initiating event resulting in a slow positive reactivity insertion is a malfunction of the makeup controller mode selector switch in the dilute mode. This may occur by a failure in the boron control system which causes continuation of the makeup operation after a planned dilution has been completed. This failure results in the maximum possible dilution rate.

The other initiating event which can cause a slow positive reactivity insertion is the failure of the solenoid in the boron flow control valve in the boric acid line with the boron control system in the automatic or borate modes. This failure results in termination of the boron flow to the RCS and thus could approach the loss of shutdown margin at the same rate as a makeup mode selector switch malfunction. However, this event yields a low flow alarm in the boric acid line which alerts the operator at the initiation of the event. The makeup mode selector switch malfunction would not produce an immediate alarm and therefore is more limiting than the inadvertent closure of the boron flow control valve.

Analysis of a slow positive reactivity insertion event initiated during each of the six operational modes defined in the Technical Specifications was performed. These analyses show that Mode 5 (cold shutdown) results in the least time available for detection and termination of the event. This is because the shutdown margin requirement which will be specified by the Technical Specifications is smallest in Mode 5 (i.e., two percent $\Delta\rho$ subcritical). Insert #1. In either Mode five or Mode six, and with the RCS level lowered, administrative procedures governing the frequency of boric acid sampling will preclude reaching criticality. 44c 44c.

15.4.2.4.2 Sequence of Events and Systems Operations

Table 15.4.2.4-1 presents a chronological list and timing of system actions which occur following a boron dilution event. Refer to Table 15.4.2.4-1 while reading this and the following section. The success paths referenced are those given on the sequence of events diagram (SED), Figure 15.4.2.4-1.

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 15.4.2.4-1 may be used to determine when, after the initiating event, each action occurs.

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 15.4.2.4-2 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;4.2.4-3 contains a matrix which describes the extent to which safety systems are assumed to function during the transient.

The success paths in the sequence of events diagrams, Figure 15.4.2.4-1, are as follows: 2

Reactivity Control: a high neutron flux alarm on the startup flux channel.

The operator is alerted to a decrease in Reactor Coolant System (RCS) boron concentration either through sampling, boronometer indications, ~~or by startup flux channel indications~~. He turns off the charging pumps and closes the letdown control valves in order to halt further dilution. The operator then turns off the primary makeup pump and closes the primary makeup isolation valve to stop the flow of primary makeup water to the charging pumps. Next, he increases the RCS boron concentration by opening the boric acid gravity feed line from the boric acid makeup tank to the charging pump suction and restarting the charging pumps to provide borated water to the RCS. Letdown flow may be diverted to the flash tank to increase the rate of boration. 440.28

FP&L is reviewing a proposed method of providing <u>redundant</u> indications of boron dilution that utilize control room indication and RCS sampling at varying frequencies (depending on plant operating mode). FP&L will advise the NRC of the results of this review. 4

15.4.2.4.3 Analysis of Effects and Consequences

a) Mathematical Model

Complete mixing of boron in the RCS and equal letdown and charging flowrates are assumed. The rate of change of boron concentration during a dilution in which water without boron is added and coolant at the time dependent RCS boron concentration is removed is described by the following differential equation:

4) Complete mixing of the boron in the RCS is assumed because of the large RCS mass circulation by a minimum of one low pressure safety injection pump operating in the shutdown cooling mode, compared to the relatively small mass added through the charging pumps.

5) The critical boron concentration at cold shutdown with all CEAs in is 845 ppm including uncertainties. The inverse boron worth is 55.8 ppm/% $\Delta\rho$ which includes uncertainties. Applying uncertainties to this number in the most conservative direction. The initial subcritical boron concentration for the cold shutdown mode is found by adding the product of the inverse boron worth and the minimum shutdown margin required (i.e., two percent $\Delta\rho$) to the critical boron concentration. The resulting minimum initial boron concentration in Mode 5 is 956.6 ppm. 2

INSERT #2 440.27

The parameters discussed above are summarized in Table 15.4.2.4-4. 2

c) Results

The conservative parameters listed in Table 15.4.2.4-4 are used in Equation 3 to calculate the time to criticality during a Slow Positive Insertion. The minimum possible time to dilute from two percent $\Delta\rho$ sub-critical to criticality is 62 minutes. Operational procedures which include periodic monitoring of the RCS boron concentration and periodic monitoring of the startup flux channels allow detection of the event with at least 15 minutes available to terminate the event before criticality is reached. 2

INSERT #3 440.28

The Slow Positive Reactivity Insertion in ~~Mode 5~~ (the limiting case presented above) does not result in any pressure or temperature perturbations in the RCS because the event is terminated before criticality is reached. Other principal RCS and secondary system parameters are not perturbed by this event.

As the RCS boron concentration is reduced by the dilution, positive reactivity is inserted. This causes the two percent $\Delta\rho$ subcriticality margin to be reduced but the core does not become critical.

15.4.2.4.4 Conclusions

This evaluation shows that the plant response to a Slow Positive Reactivity Insertion will produce results within the acceptance guideline for Infrequent events in Table 15.0-4.

TABLE 15.4.2.4-1

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR SLOW POSITIVE REACTIVITY INSERTION

Time (Sec)	Event	Analysis Set Point or Value	Success Paths: Reactivity Control	Reactor Heat Removal	Secondary System Integrity	Primary System Integrity				
0	Makeup mode selector switch malfunction, RCS boron concentration, ppm	957								
1800	Operator detects event through operating procedures	INSERT #4								
~~2700~~ 3720	Operator turns off charging pumps to terminate the event. ~~RCS boron concentration, ppm~~	~~879~~	X							

Inserts to 15.4.2.4

INSERT 1. The indications and/or alarms available to alert the operators that a boron dilution event is occurring in each of the operational modes are outlined below.

1. The following control room indications and corresponding pre-trip alarms are available for MODES 1 and 2: a high power or, for some set of conditions, a high pressurizer pressure trip in MODE 1 or a high logarithmic power level trip in MODE 2. Furthermore, a high TAVG alarm may also occur prior to trip.

2. In MODES 3 and 4 with CEAs withdrawn, the high logarithmic power level trip and pre-trip alarm will provide an indication to alert the operator of an inadvertent boron dilution.

3. In MODES 3, 4, and 5 with CEAs fully inserted and in MODE 6, a high neutron flux alarm on the startup flux channels will provide indication of any boron dilution event.

4. In MODE 5 with the RCS partially drained for system maintenance, the startup flux channel alarm will provide indication of any boron dilution event. In this plant condition, administrative controls would allow operation of only one charging pump at a maximum rate of 44 gpm. Plant operating procedures will require that the power to the other two charging pumps be removed and their breakers locked out.
This drained down case is less limiting than the MODE 5 event presented above.

The operational procedure guidelines, in addition to these indications and/or alarms, will assure detection and termination of the boron dilution event before the shutdown margin is lost in accordance with the requirement of SRP 15.4.6.

INSERT 2. The critical boron concentration with CEAs withdrawn (All Rods Out); the inverse boron worth, and the net rod worth for the cold shutdown conditions are 984.5 ppm, 55.8 ppm/%$\Delta\rho$, and 2.5%$\Delta\rho$ respectively, including uncertainties. The critical boron concentration value of 845 ppm was obtained by subtracting the product of the inverse boron worth and the net rod worth from the critical boron concentration with all rods out.

INSERT 3. A high neutron flux alarm on the startup flux channel will assure detection of a boron dilution event with at least 15 minutes prior to criticality as per the requirements of SRP 15.4.6.

INSERT 4. 2820 | High neutron flux alarm on the startup flux channel alerts operator to a boron dilution event.

8/18/81

440.38 (6.3) Discuss the provisions and precautions for assuring proper system filling and venting of ECCS to minimize the potential for water hammer and air binding. Address piping and pump casing venting provisions and surveillance frequencies.

Response

The ECCS system is provided with sufficient drainage capability on the piping low points and system vents on the piping high points to assure that air will not be entrained in the system. The ECCS components are provided with vent and drainage capability. The HPSI pumps, LPSI pumps, and shutdown heat exchangers are provided with component vents and drains as shown in Figure 1.2-34. The piping vents and drains are shown on Figure 6.3-1a and 6.3-1b. Prior to system operation, the ECCS piping and components will be adequately vented in order to minimize the potential for water hammer and air binding.

Administrative procedures will be written to ensure that the ECCS piping and components are properly drained and filled.

8/18/81

440.39 (6.3) Identify all ECCS valves that are required to have power locked out; confirm they are included under the appropriate Technical Specifications, with surveillance requirements listed.

Response

The ECCS valves that are required to have power locked out are listed below. The Technical Specification section of the St. Lucie-2 FSAR is currently being generated. Surveillance requirements for these valves will be listed.

1) V-3550, V-3551 - Hot Leg Injection Isolation Valves. "Power rack out required to motor during plant power operation".

2) V-3614, V-3624, V-3634, V-3644 - SIT Isolation Valves. "Power rack out to motor required when pressurizer pressure greater than 700 psig."

3) V-3613, V-3623, V-3633, V-3643 - SIT Vent Valves. Power to those valves is removed in the control room during normal operation.

8/18/81

440.41 Identify the plant operating conditions under which certain automatic safety injection signals are blocked to preclude unwanted actuation of these systems.

Describe the alarms available to alert the operator to a failure in the primary or <u>secondary system</u> during this phase of operation and the time available to mitigate the consequences of such an accident.

<u>Response</u>

While the plant is in power operation, the safety injection signals may not be blocked. During the interim phase, while RCS pressure is being reduced to refueling mode, it becomes necessary to partially block the SIAS.

A safety injection block is provided to permit shutdown depressurization of the Reactor Coolant System (RCS) without initiating safety injection. This block is accomplished manually after pressurizer pressure has been reduced and a permissive signal is generated by the Engineered Safety Features Actuation System. This blocking procedure is under strict administrative control; block and block permissive is 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 that point, the block is automatically removed. The block circuit complies with the single failure criterion in IEEE 279-1971.

The SIAS block removes only the pressurizer pressure signal from the SIAS trip logic. The high containment pressure transmitters still remain in direct connection with the trip logic. Should an event occur whereby the containment pressure is sufficiently raised, high containment pressure alarms sound on RTG B-206 and the SIAS is initiated automatically, regardless of the pressurizer signal block.

The Technical Specifications will permit blockage of the SIAS in plant modes 5 and 6, while the shutdown cooling system is in operation. In these modes protection against overpressurization of the Reactor Coolant and Shutdown Cooling System, due to a spurious actuation of the HPSI, is provided by relief valves V-3666 and V-3667 in the SDC suction lines. FSAR Tables 7.5-1 and 10.4-5 indicates the display instrumentation and their alarms which are available to the operator to establish primary and secondary system conditions.

During cold shutdown or refueling (modes 5 and 6) should a loss of coolant occur, level guages in the containment and cavity sump and the safeguards room sump with alarms would alert the operator of such an accident. During the plant cooldown, operator action is required to continually monitor the S.G. secondary water level and feedwater flow. Because of this the operator is aware of the secondary system conditions.

During a refueling, for specific maintenance tasks, it is expected that some instrumentation will be inoperable. Administrative procedures will assure that the operator will be able to assess the status of the primary and secondary systems for the specific situations.

8/18/81

440.44 A reported event has raised a question related to the conservatism of NPSH calculations with respect to whether the absolute minimum available NPSH has been taken by the staff as a fixed number supplied through the applicant by either the architect engineer or the pump manufacturer. Since a number of methods exist and the method used can affect the suitabilty or unsuitability of a particular pump, it is requested that the basis on which the required NPSH was determined be branded (i.e., test, Hydraulic Institute Standards) for all the ECCS pumps including the testing inaccuracies be provided.

Response

The required NPSH of the St. Lucie Unit 2 ECCS pumps is confirmed by test. The high pressure safety injection pumps are supplied by Bingham-Willamette Co. These pumps are tested in accordance with the ASME power test code 8.2 (centrifugal pumps). Each of the St. Lucie Unit 2 HPSI pumps were tested for the NPSH required at the runout flow. Similar pumps were also supplied for St. Lucie Unit 1. Each of the St. Lucie Unit 1 pumps were also tested for the NPSH required. The results show (see following table) little variance between pumps for similar flow.

The LPSI pumps are supplied by Ingersol-Rand. The NPSH characteristic is confirmed by test. Both of the St. Lucie Unit 2 LPSI pumps were tested. The Hydrualic Institute Standards were used for the tests.

NPSH TEST RESULTS FOR ST. LUCIE UNITS 1 AND 2

St. Lucie Unit 1 HPSI Pumps	GPM	NPSH (ft)
#200113	640	19.7
#200114	640	19.9
#200115	640	19.6
St. Lucie Unit 2 HPSI Pumps		
#14210014 (spare pump)	640	19.9
#14210015	631	19.0
#14210016	639	19.4
St. Lucie Unit 2 LPSI Pumps		
#1076149	3000	13.0
#1076150	3000	-11.0

The NPSH vs. flow curves for the St. Lucie Unit 2 HPSI and LPSI pumps are shown in Figures 6.3-3a, 6.3-3b, 6.3-4a, and 6.3-4b.

8/18/81

440.51 (6.3) In the event of early manual reset of the safety injection actuation signal (SIAS) followed by a loss of offsite power during the injection phase, operator action may be required to reposition ECCS valves and restart some pumps. The staff requires that operating procedures specify SIAS manual reset not to be permitted for a minimum of 10 minutes after a LOCA. Provide the administrative procedures to ensure correct load application to the diesel generators in the event of loss of offsite power following an SIAS reset.

Response

The SIAS can only be reset when the initiating signal has been removed; i.e. normal conditions have been reestablished. If the signal that generates an SIAS is still present, the SIAS cannot be reset.

Following a loss of offsite power subsequent to an SIAS manual reset, the safety injection pumps and valves will not load onto the diesels if the conditions that require automatic safety injection are not present. However, if the conditions that require automatic safety injection are present after the manual SIAS reset followed by loss of offsite power, the safety injection pumps and valves will sequence onto the diesels automatically. No operator action is required.

During low pressure operation of the safety injection system, during shutdown cooling; the operating procedures will require the operator to manually load the low pressure safety injection pumps onto the diesel generator following a loss of offsite power.

The required actions that would provide SIAS when the pressurizer pressure signal is locked out (during depressurization for shutdown) are given below.

An SIAS is initiated by a low pressurizer pressure signal or a high containment pressure signal. There are four independent pressure transmitters each for the containment and the pressurizer. In order to allow depressurization of the pressurizer (i.e. system) a safety injection block is provided by manually blocking only the pressurizer transmitter's signals to the SIAS trip logic. The containment pressure transmitters remain in direct connection with the SIAS trip logic. Therefore, an incident which would raise the containment pressure sufficiently will automatically initiate an SIAS (no operator action is required).

If necessary, the operator can manually initiate an SIAS, as described in FSAR Section 7.3.1.1.1. Should the situation be evaluated as requiring less than full actuation, the operator can align the safeguard pumps on a component basis to provide makeup water for the reactor coolant system.

8/18/81

Question 440.54

Describe the means provided for ECCS pump protection including instrumentation and alarms available to indicate degradation of ECCS pump performance. Our position is that suitable means should be provided to alert the operator to possible degradation of ECCS pump performance. All instrumentation associated with monitoring the ECCS pump performance should be operable without offsite power, and should be able to detect conditions of low discharge flow.

Describe during post-LOCA operation (injection mode and recirculation mode).

Response 440.54

Below are listed instrumentation used in conjunction with the Low and High Pressure Safety Injection (LPSI and HPSI) pumps for use in determining pump performance:

1. P-3314 and P-3315 are used for LPSI 2A and 2B, respectively. They are used to determine pump discharge pressure. They have indicators on local panels.

2. P-3316 and P-3318 are used for HPSI 2A and 2B, respectively. They determine pump discharge pressure, and have indicators on local panels.

3. F-3301 and F-3306 determine total flow (minus any miniflow) for LPSI 2B and 2A, respectively. They indicate, record, and control the flow. The recorder is usable as an indicator by the operator. There is an indicator display on the Hot Shutdown Panel.

4. F-3312 (LPSI A), F-3322 (LPSI A), F-3332 (LPSI B), and F-3342 (LPSI B) are used to determine flow through the various LPSI flow branches - they have indicator displays in the control room.

5. F-3317 and F-3327 determine total SDC flow from HPSI 2A and 2B, respectively. The results are recorded in the control room.

6. F-3315 and F-3325 determine total SDC flow from HPSI 2A and 2B, respectively. The results are displayed on an indicator in the control room.

7. F-3313, F-3323, and F-3343 determine branch flow from HPSI pumps A and B. The flows determined are recorded in the control room.

8. F-3311, F-3321, and F-3341 determine branch flow from HPSI pumps A and B. The results are displayed on an indicator in the control room.

9. Low flow alarms are being added to the LPSI and HPSI pumps. These alarms will have emergency power.

8/18/81

Question 440.58

List all ECCS valve operations and controls that are located below the maximum flood level following a postulated LOCA or main steam line break. If any are flooded, evaluate the potential consequences of this flooding both for short and long-term ECCS functions and containment isolation. List all control room instrumentation lost following these accidents.

Response 440.58

The maximum flooding event, which results from a large LOCA, will cause the water level inside containment to reach an elevation of 26 feet. This conservatively assumes that the entire contents of the Reactor Coolant System drains and that the Refueling Water Tank was at its overflow level at the time of the accident.

The operation of safety related equipment in a post-LOCA, potentially submerged, environment will be addressed in accordance with NUREG 0588 Appendix E and will be submitted by November 30, 1981. As stated in FSAR section 3.11.6 this study will confirm that no essential equipment will be lost as a result of the maximum postulated post accident containment water level.

8/18/81

440.59 (6.3) (If) it is our position that the SIS hotleg injection valves should be locked closed with power removed during normal plant operation in order to prevent premature hotleg injection following a LOCA.

Response

The hotleg SIS injection valves (V-3540, V-3523, V-3550, and V-3551) do not have power removed during normal plant operation because there are two (redundant) valves in each line. Administrative procedures ensure that these valves are locked closed in the control room. In addition, each set of valves is provided with an open/closed status indication in the control room.

8/18/81

Question 440.61

During our reviews of license applications we have identified concerns related to the containment sump design and its effect on long term cooling following a Loss of Coolant Accident (LOCA).

These concerns are related to (1) creation of debris which could potentially block the sump screens and flow passages in the ECCS and the core, (2) inadequate NPSH of the pumps taking suction from the containment sump, (3) air entrainment from streams of water or steam which can cause loss of adequate NPSH, (4) formation of vortices which can cause loss of adequate NPSH, air entrainment and suction of floating debris into the ECCS and (5) inadequate emergency procedures and operator training to enable a correct response to these problems. Preoperational recirculation tests performed by utilities have consistently identified the need for plant modifications.

The NRC has begun a generic program to resolve this issue. However, more immediate actions are required to assure greater reliability of safety system operation. We therefore require you take the following actions to provide additional assurance that long term cooling of the reactor core can be achieved and maintained following a postulated LOCA.

1. Establish a procedure to perform an inspection of the containment, and the containment sump area in particular, to identify any materials which have the potential for becoming debris capable of blocking the containment sump when required for recirculation of coolant water. Typically, these materials consist of: plastic bags, step-off pads, health physics instrumentation, welding equipment, scaffolding, metal chips and screws, portable inspection lights, unsecured wood, constuction materials and tools as well as other miscellaneous loose equipment. "As licensed" cleanliness should be assured prior to each startup.

2. Institute an inspection program according to the requirements of Regulatory Guide 1.82, item 14. This item addresses inspection of the containment sump components including screens and intake structures.

3. Develop and implement procedures for the operator which address both a possible vortexing problem (with consequent pump cavitation) and sump blockage due to debris. These procedures should address all likely scenarios and should list all instrumentation available to the proper operator (and its location) to aid in detecting problems which may arise, indications the operator should look for, and operator actions to mitigate these problems.

4. Pipe breaks, drain flow and channeling of spray flow released below or impinging on the containment water surface in the area of the sump can cause a variety of problems; for example, air entrainment, cavitation and vortex formation.

   Describe any changes you plan to make to reduce vortical flow in the neighborhood of the sump. Ideally, flow should approach uniformly from all directions.

Question 440.61 (Cont'd) (8/18)

5. Evaluate the extent to which the containment sump(s) in your plant meet the requirements for each of the items previously identified; namely debris, inadequate NPSH, air entrainment, vortex formation, and operator actions.

The following additional guidance is provided for performing this evaluation.

(1) Refer to the recommendations in Regulatory Guide 1.82 (Section C) which may be of assistance in performing this evaluation.

(2) Provide a drawing showing the location of the drain sump relative to the containment sump.

(3) Provide the following information with your evaluation of debris:

(a) Provide the size of openings in the fine screens and compare this with the minimum dimensions in the pumps which take suction from the sump (or torus), the minimum dimensions in any spray nozzles and in the fuel assemblies in the reactor core or any other line in the recirculation flow path whose size is comparable to or smaller than the sump screen mesh size in order to show that no flow blockage will occur at any point past the screen.

(b) Estimate the extent to which debris could block the trash rack or screens (50 percent limit). If a blockage problem is identified, describe the corrective actions you plan to take (replace insulation, enlarge cages, etc.)

(c) For each type of thermal insulation used in the containment, provide the following information:

(i) type of material including composition and density,

(ii) manufacturer and brand name,

(iii) method of attachment,

(iv) location and quantity in containment of each type,

(v) an estimate of the tendency of each type to form particles small enough to pass through the fine screen in the suction lines.

(d) Estimate what the effect of these insulation particles would be on the operability and performance of all pumps used for recirculation cooling. Address effects on pump seals and bearings.

Response 440.61 (8/18)

1. St Lucie will institute an inspection program to verify that the containment is free of debris that may lead to blockage of or damage to the ECCS sump. These inspections will assure that the containment and sump are in the "as licensed" state of cleanliness prior to each reactor startup.

2. The sump inspection program will include an examination of sump structures, such as intakes and screens, as outlined in Regulatory Guide 1.82.

3. Long term cooling operating procedures will require periodic verification of system performance to insure safe operation under recirculation conditions.

4. The dynamic effects associated with pipe whip and jet impingement of all high energy lines in the vicinity of the sump have been evaluated. In no case would any high or moderate energy piping failure compromise the functional capability of the ESF sump when it is required. Therefore, the sump model test outlined in the response to question 440.60 will not simulate spray flows impinging on the containment water surface. However, various screen blockage tests will be performed to simulate worst case approach flow and flow channeling conditions.

5.1. The St Lucie Unit 2 sump consists of one large full capacity reservoir which physically separates the redundant ESF suction lines by approximately 15 feet. The sump design, described in detail in FSAR section 6.2.2.2.3, meets all the requirements of Regulatory Guide 1.82 with the exception that only one sump is provided. The literal intent of this last requirement is satisfied by the use of fine screen to separate the suction lines.

5.2. The relative locations of the Reactor Cavity and containment sumps can be seen on FSAR figure 1.2-10.

5.3. a) The sump design incorporates a ninety (90) mil fine mesh filter screen to protect the suction piping from entrained particles. These screens are sized to eliminate all particles too large to pass through the reactor fuel assemblies which is the most restrictive flow path in the system. Particles smaller than this will pass through all system components including reactor, pumps, heat-exchangers and spray nozzles.

b) Debris generated inside containment as a result of an accident will be confined between the primary and secondary shield walls. Large debris generated here is prevented from reaching and possibly damaging the sump by the Seismic Category I trash racks located at the secondary shield wall openings. Although it is believed that this design will minimize debris at the sump, model tests will be performed assuming blockage of half of the vertical screens and all of the horizontal screens.

Response 440.61 (Cont'd) (8/18)

5.3. (Cont'd)

c) A description of the various types of insulation expected to be used inside containment and an estimate of the quantities appear in FSAR Table 6.2-40.

d) As stated previously, particles small enough to pass through the fine screens can pass through the systems without deleterious effects. Pump operability is not expected to be impaired.

6.* The Reactor Drain Tank, located in the sump, is designed to remain in place following an accident. The effect of uplift loads resulting from the submergence of an empty tank have been analyzed and found to be well within the capabilities of the holdown bolts. A Containment Isolation Signal (CIS) isolates the tank and stops the drain pumps.

*Response 6 address additional NRC concern expressed in the review meeting of July 23 and 24, 1981 regarding Reactor Drain Tank.

440.62 The submittal for the LOCA analyses does not address the effects of steam generator tube plugging. The effect of a decrease in steam generator tube flow area is an increase in the peak cladding temperature (when the peak occurs during the reflood portion of the transient). If the analyses provided are considered to support generators with plugged tubes, describe the extent of the plugging the analyses support and the method used to account for the plugging. If steam generator tube plugging was not considered, the applicant will be required to perform additional ECCS analyses prior to operation with plugged generator tubes. In either case, the applicant is required to include an interface requirement on the validity of the LOCA analyses (acceptance criteria of 10CFR50.46) and the Technical Specification limit for the number (or percentage) of allowable plugged steam generator tubes.

Response to Question 440.62

The St. Lucie Unit 2 ECCS analysis does not assume any steam generator tubes are plugged. The effect of tube plugging has been treated on an as needed basis for C-E operating plants and to date tube plugging has been minimal. In one example, an ECCS analysis was performed assuming 500 tubes per SG plugged which, represents approximately 6% of the unplugged total. The predicted ECCS performance changed very little and the allowable peak linear heat generation rate remained unchanged from the case with no SG tubes plugged. The method of analysis for the assessment of ECCS performance with a portion of the SG tubes plugged is provided in the Reference.

Since the NSSS design utilized in the referenced calculation is similar to the St. Lucie Unit 2 design, a similar conclusion is anticipated for this plant.

Presently, St. Lucie Unit 2 has 47 steam generator tubes which have been plugged, which represents approximately 0.6% of the unplugged total. This is significantly below the 6% plugged analysis which demonstrated minimal change in ECCS performance and no change in the allowable peak linear heat generation rate.

Based on this, C-E feels that the current ECCS performance analysis, which does not consider steam generator tube plugging, remains applicable and no new analysis is required unless tube plugging becomes more significant.

FSAR sections 6.3.3.2.3 and 6.3.3.3.3 have been modified to state that no tubes are assumed to be plugged.

pump flow is credited. The actual delay time will not exceed 30 seconds following a SIAS. In the large break analysis, no operator action has been assumed

6.3.3.2.3 Core and System Parameters | 0

The significant core and system parameters used in the large break calculations are presented in Table 6.3-7. The Peak Linear Heat Generation Rate was assumed to occur in the top of the core, the conservative location as identified in Section IV.A.4 of Reference 2. A conservative beginning-of-life moderator temperature coefficient (+0.5 x 10^{-4} $\Delta\rho$/F) was used in all large break cases. Q440.62

INSERT AA

The initial steady state fuel rod conditions were determined as a function of burnup using the FATES(7) computer program. The limiting condition for ECCS performance was determined to occur for a hot rod average burnup of 620 MWD/MTU. A parameter study was performed which demonstrates that clad temperature and oxidation were maximized at this exposure. The results of this study are presented on Figure 6.3-13.

6.3.3.2.4. Containment Parameters

Subsection 6.2.1.5 discusses in detail the containment parameters assumed in the ECCS analysis. The values for these parameters were chosen to minimize containment pressure such that a conservative determination of the core reflood rate was made. Pressure suppression equipment startup times were selected at their minimum values corresponding to offsite power being available

6.3.3.2.5 Break Spectrum

In general, all possible break locations are considered in a LOCA analysis. However, as demonstrated in other Appendix K LOCA calculations (References 8 and 9 for example), hot leg ruptures and cold leg ruptures on the suction side of the reactor coolant pump, yield clad temperatures substantially lower than those observed for cold leg ruptures on the discharge side of the pump. Pump discharge leg ruptures are limiting due to the minimizing of blowdown core flow and reflood rate for the break location. Thus, only these breaks need to be considered in order to identify that rupture which results in the highest clad temperature or largest amount of clad oxidation. Since core flow is a function of break size, calculations have been performed for both guillotine and slot breaks over a range of break sizes up to twice the flow area of the cold leg. A list of the breaks examined appears in Table 6.3-8 which refer to Figures 6.3-5 through Figures 6.3-11. | 0

6.3.3.2.6 Results and Conclusions

The important results of this analysis are summarized in Table 6.3-9 and the transient behavior of important NSSS parameters is shown in the figures listed in Tables 6.3-10 and 11 which refer to Figures 6.3-5 through 6.3-11 and Figures 6.3-9 respectively. Peak clad temperature vs. break size is

Based on these assumptions, the following credit is taken for injection flow in the small break analysis. For a discharge leg break:

75% of the flow from one HPSI pump
50% of the flow from one LPSI pump
100% of the flow from three safety injection tanks
50% of the flow from one charging pump

and for breaks in other locations:

100% of the flow from one HPSI pump
100% of the flow from one LPSI pump
100% of the flow from four safety injection tanks
100% of the flow from one charging pump 1

Table 6.3-12 presents the high and low pressure safety injection pump flow rates assumed at each of the four injection points as a function of reactor coolant system pressure.

6.3.3.3.3 Core and System Parameters

The significant core and system parameters used in the small break calculations are presented in Table 6.3-13. The peak linear heat generation rate of 15.0 kw/ft was assumed to occur 15 percent from the top of the active core. A conservative beginning-of-life moderator temperature coefficient of $+0.2 \times 10^{-4} \Delta\rho/^{\circ}F$ was used. Q440.62

INSERT AA

The initial steady state fuel rod conditions were obtained from the FATES [7] computer program. The small break analysis assumed the same hot rod average burnup as was found limiting in the large break analysis described in Subsection 6.3.3.2. However, since the small break analysis conservatively used a higher PLHGR than did the large break analysis (15.0 kw/ ft vs 13.0 kw/ft) the fuel rod parameter values given in Table 6.3-13 differ from those in Table 6.3-7.

6.3.3.3.4 Containment Parameters

The small break analysis does not credit any rise in containment pressure. Therefore, other than the initial containment pressure, which is assumed to remain constant, no containment parameters are employed for this analysis. The initial containment pressure was assumed to be 0.0 psig.

6.3.3.3.5 Break Spectrum

Five breaks were analyzed to characterize the small break spectrum. Four breaks, ranging in size from 0.5 ft^2 to 0.015 ft^2 were postulated to occur in the pump discharge leg. The 0.5 ft^2 break was also analyzed for the large break spectrum (Subsection 6.3.3.2) and is defined as the transition break size [3]. One break representing a fully open pressurizer relief valve with an equivalent area of 0.008 ft^2 was postulated to occur in the top of the pressurizer. The equivalent area is based on the design flow requirements of the relief valve as utilized in the C-E small break evaluation model [3]. Table 6.3-14 lists the various break sizes and locations examined for this analysis.

Insert AA

The ECCS performance analyses, as performed, do not account for steam generator tube plugging which may occur during the plant's lifetime.

Rockwell International

August 18, 1981

Ebasco Services, Inc.
Agents for Florida Power & Light, St. Lucie
2 World Trade Center, 83rd Floor
New York, NY 10048

Attention: R. Raghavan

Subject: Florida Power and Light Co.
St. Lucie Unit No. 2
32" MSIV Ebasco PO 422528
Rockwell S.O. No. 36-11000

In response to your TWX dated July 31, 1981 Rockwell is providing the following interim response relative to "as delivered" valve bonnet and main disk thicknesses for pressure retaining purposes:

Based on "on-going" iterative finite element analysis the bonnet thickness is at least 30 percent greater and the main disk thickness is at least 25 percent greater than minimum thickness required for pressure retention purposes. The exact percentages and other considerations for thickness allowances for corrosion and mechanical loads will be identified in our final report scheduled for completion this month.

Edward J. Majewski Jr.

Edward J. Majewski, Jr.
Project Engineering Supervisor
Rockwell International

dp

cc: N. Mangieri - FL-9
R. D. Norden
B. R. Black
S. B. Odum
B. E. Hildreth

EBASCO SERVICES INCORPORATED

NEW YORK

BY J. CHIANG DATE 8.12.81

SHEET 0 OF 11

CHKD. BY J. CHEN DATE 8/15/81

OFS NO. 2524.902 DEPT. NO. 551

CLIENT FPL

PROJECT ST. LUCIE 2

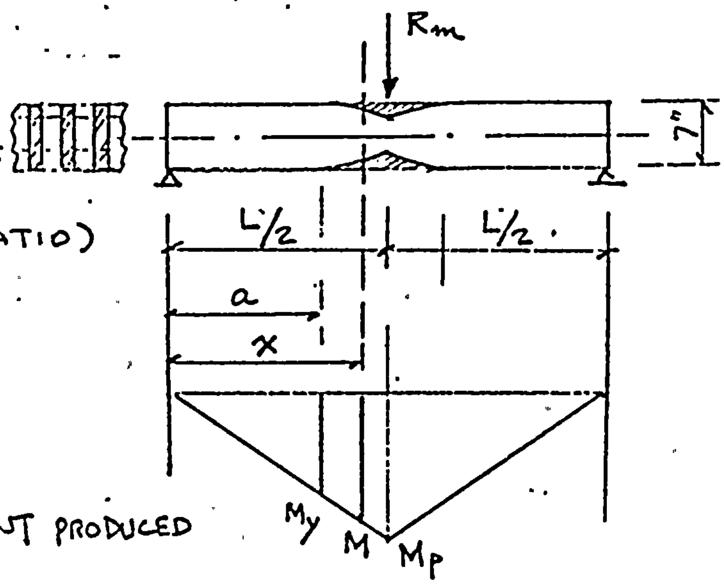
SUBJECT STRUCTURAL DESIGN ADEQUACY AUDIT — MISSILE PROTECTION

INDEX OF REVIEW OF SIMPLY SUPPORTED GRATING SUBJECT A CONCENTRATED TORNADO MISSILE LOAD

FORM 881 REV 7-71

REVIEW OF SIMPLY SUPPORTED GRATING SUBJECT A CONCENTRATED TORNADO MISSILE LOAD

PLASTIC DESIGN METHOD:



I. REVIEW PROCEDURES FOR BENDING:

1. ASSUME μ (DUCTILITY RATIO)

2. COMPUTE $R_m = \dfrac{i\,\omega}{\sqrt{2\mu - 1}}$ *

3. $M = \dfrac{R_m \cdot L}{4} + M'$;

   IN WHICH M' IS THE MOMENT PRODUCED BY OTHER LOADS

4. COMPUTE M/M_y

   WHERE $M_y = F_y \cdot S$ & S = ELASTIC SECTION MODULUS

5. $1 \le \dfrac{M}{M_y} \le 1.5$ TO BE TESTED, WHERE 1.5 = SHAPE FACTOR FOR A RECTANGULAR SECTION

   IF $M/M_y > 1.5$ TRY LARGER μ

   IF $M/M_y < 1.0$ TRY SMALLER μ

   REPEAT CALCULATION FROM STEP 2

6. COMPUTE $\mu = \dfrac{1}{\sqrt{3 - 2\dfrac{M}{M_y}}}$ ** ; IF $1 < \mu < 10$, DESIGN IS OK (SEE PLOTTED CURVE)

* SEE GRATING DESIGN FOR REFERENCE (G-838 SH. 8)

** REFER TO "PLASTIC METHODS OF STRUCTURAL ANALYSIS" BY B.G. NEAL, P.P. 174.
REWRITE EQ. 5.8 WITH $\mu = \dfrac{K}{K_y}$

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NEW YORK

BY J. CHIANG DATE 8.4.81 SHEET 3 OF 11

CHKD. BY [illegible] DATE 8/15/81 OFS NO. 2524.902 DEPT. NO. 6[illegible]

CLIENT FPL

PROJECT ST. LUCIE 2

SUBJECT STRUCTURAL DESIGN ADEQUACY AUDIT — MISSILE PROTECTION

REVIEW OF GRATING FOR 12"ϕ X 15'-0 SCH. 40 PIPE AS MISSILE :

SPAN = 8'-0

BEARING BARS $7 \times \frac{3}{8}$ @ $1\frac{3}{8}$ c/c

CROSS BARS $1\frac{1}{4} \times \frac{1}{4}$ @ 2 c/c T & B

$S = 26.73 \ IN^3/FT$

$A = 7 \times 0.375 \times 12/1.375 = 22.9 \ IN^2/FT.$

1. ASSUME $\mu = 10$ & MISSILE HITS @ ℄ SPAN

2. COMIUPTE Rm :

$k = 182. \ ^{K}/_{IN}$ (SEE GRATING DESIGN P. 16 OF 30)

$$\omega = \sqrt{\frac{k}{m_e + m_m}} = \sqrt{\frac{182 \times 1000}{1.502 + 1.924}} = 230.5 \ ^1/_{SEC}$$ (MASS FACTOR = 0.33 IN PLASTIC RANGE)

$$R_m = \frac{i\,\omega}{\sqrt{2\mu - 1}} = \frac{1.924 \times 1.392 \times 230.5}{\sqrt{2 \times 10 - 1}} = 141.6^K$$

3. $M = \frac{R_m \cdot L}{4} + \underset{7.16}{0.358 \times 2.5} \times 8^2/8 = 290.4 \ ^{K\text{-}FT}$

4. $M_y = F_y \times S = \frac{36 \times 26.73 \times 2.5}{12} = 200.5 \ ^{K\text{-}FT}$

5 $\frac{M}{M_y} = \frac{290.4}{200.5} = 1.448 \ \begin{matrix} < 1.5 \\ > 1.0 \end{matrix}$

5a. REPEAT STEP 1 TO 5, AS SHOWN IN TABLE

6 $$\mu = \frac{1}{\sqrt{3 - 2\frac{M}{M_y}}} = \frac{1}{\sqrt{3 - 2 \times 1.492}} = 8.69$$ (CLOSE)

ASSUMED μ	$\frac{M}{M_y}$	COMPUTED μ
10	1.448	3.11
9.8	1.463	3.69
9.7	1.471	4.15
→ 9.42	1.493	8.69
9.4	1.495	10
9.0	1.528	–

$1 < \mu < 10$ DESIGN IS OK

FORM 581 REV 7-71

EBASCO SERVICES INCORPORATED

NEW YORK

BY J.CHIANG DATE 8.4.81 SHEET 4 OF 11

CHKD. BY J CHIN DATE 8/13/81 OFS NO. 2524.902 DEPT. NO. 650

CLIENT FPL

PROJECT ST. LUCIE 2

SUBJECT STRUCTURAL DESIGN ADEQUACY AUDIT - MISSILE PROTECTION

REVIEW OF GRATING DESIGN — SPAN = 8'-0

CHECK SHEAR WHEN 12"ϕ x 15'-0 SCH. 40 PIPE MISSILE STRIKES AT 1/4 SPAN

1. ASSUME $\mu = 10$ & MISSILE HITS @ 1/4 SPAN

2. COMPUTE R_m:

$k = 232.2$ K/IN

$$\omega = \sqrt{\frac{232.2 \times 1000}{1.502 + 1.924}} = 260.3$$

$$R_m = \frac{i\,\omega}{\sqrt{2\mu - 1}} = \frac{1.924 \times 1.392 \times 260.3}{\sqrt{19}} = 160.0^K$$

3. $V = 0.75 \times R_m + .358 \times 2.5 \times 8/2 = 124.^K$

$$f_v = 1.5 \times \frac{124}{2.5 \times 22.9} = 3.25 \text{ ksi} < 0.96 \times \frac{36}{\sqrt{3}} = 19.95 \text{ ksi}$$

OK.

FORM 581 REV 7-71

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BY J. CHIANG DATE 8.4.81 SHEET 5 OF 11

CHKD. BY J. CHEN DATE 8/15/81 OFS NO. 2521.902 DEPT. NO. 160

CLIENT FPL

PROJECT ST. LUCIE 2

SUBJECT STRUCTURAL DESIGN ADEQUACY AUDIT – MISSILE PROTECTION

REVIEWING GRATING

SPAN = 10'-8

CHECK BENDING:

1. ASSUME $\mu = 10$ & MISSILE 12"Φ x 15'-0 SCH. 40 PIPE HITS @ ℄ SPAN

2. COMPUTE R_m

$k = 102.3$ K/IN (SEE GRATING DESIGN SH.22)

$$\omega = \sqrt{\frac{k}{m_e + m_m}} = \sqrt{\frac{102,300}{2.01 + 1.924}} = 161.3 \ \frac{1}{SEC}$$

$$R_m = \frac{i\,\omega}{\sqrt{2\mu - 1}} = \frac{1.924 \times 1.392 \times 161.3}{\sqrt{19}} = 99.1^{K}$$

3. $M = \frac{R_m \cdot L}{4} + \frac{0.358 \times 2.5}{12.8} \times 10.7^2/8 = 277.8^{K\text{-}FT}$

4. $M_y = 200.5^{K\text{-}FT}$

5. $\frac{M}{M_y} = \frac{277.8}{200.5} = 1.386$

5a, REPEAT STEP 1 TO 5, AS SHOWN IN TABLE;

ASSUMED μ	$\frac{M}{M_y}$	COMPUTED μ
10	1.386	2.09
9	1.461	3.609
8.7	1.487	6.19
→ 8.64	1.492	8.0
8.6	1.495	10.8
8	1.551	—

6 $\mu = \frac{1}{\sqrt{3 - 2\frac{M}{M_y}}} = \frac{1}{\sqrt{3 - 2 \times 1.492}} = 8.0$

(CLOSE)

$1 < \mu < 10$ OK.

CHECK SHEAR

BY COMPARING THE R_m VALUE WITH THE 8'-0 SPAN'S, SHEAR IS OK.

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NEW YORK

BY J. CHIANG DATE 8.4.81 SHEET 6 OF 11

CHKD. BY J CHEN DATE 8/5/81 OFS NO. 3551.702 DEPT. NO. 650

CLIENT FPL

PROJECT ST. LUCIE 2

SUBJECT STRUCTURAL DESIGN ADEQUACY AUDIT — MISSILE PROTECTION

REWIEW GRATING

SPAN = 5'-0

1. ASSUME $\mu = 10$ & MISSILE HITS AT ℄ SPAN.

2. COMPUTE R_m

$k = 290.5^{K/IN}$ (SEE GRATING DESIGN P. 19 OF 30)

$$\omega = \sqrt{\frac{290{,}500}{m_e + m_m}} = \sqrt{\frac{290{,}500}{0.939 + 1.924}} = 318.5;$$

$$m_e = \frac{0.33 \times 2.5 \times 88 \times 5}{32.2 \times 12} = 0.939 \ \frac{\#\text{-SEC}^2}{\text{IN}}$$

$$R_m = \frac{i\,\omega}{\sqrt{2\mu - 1}} = \frac{1.924 \times 1.392 \times 318.5}{\sqrt{19}} = 195.7^{K}$$

3. $M = \dfrac{R_m \cdot L}{4} + 0.358 \times 2.5 \times 5^2/8 = 247.4^{K\text{-}FT}$ 2.8

4. $M_y = F \times S = \dfrac{36 \times 26.73 \times 2.5}{12} = 200.5^{K\text{-}FT}$

5. $\dfrac{M}{M_y} = \dfrac{247.5}{200.5} = 1.234$

5a. REPEAT STEP 1 TO 5, AS SHOWN IN TABLE

ASSUMED μ	$\frac{M}{M_y}$	COMPUTED μ
10	1.234	1.371
9	1.304	1.596
8	1.387	2.105
7.	1.489	6.73
6.9	1.5	-

6. $\mu = \dfrac{1}{\sqrt{3 - 2\frac{M}{M_y}}} = \dfrac{1}{\sqrt{3 - 2 \times 1.489}} = 6.73 \cong 7.$

$\therefore \ 1 < \mu < 10$ OK.

EBASCO SERVICES INCORPORATED
NEW YORK

BY J. CHIANG DATE 8.4.81 SHEET 7 OF 11
CHKD. BY J. CHEN DATE 8/15/81 OFS NO. 2524.902 DEPT. NO. 65
CLIENT FPL
PROJECT ST. LUCIE 2
SUBJECT STRUCTURAL DESIGN ADEQUACY AUDIT – MISSILE PROTECTION

REVIEW GRATING DESIGN

SPAN = 5'-0

CHECK SHEAR:

1. ASSUME $\mu=10$ & MISSILE 12"ϕ x 15'-0 SCH. 40 PIPE @ 1/4 SPAN

2. COMPUTE R_m:

$$R_m = \frac{i\,\omega}{\sqrt{2\mu-1}} = \frac{1.924 \times 1.392 \times 309.2}{\sqrt{19}} = 190^K$$ (SEE G.838 SH.8 SH. 21 OF 30)

3. $V = 0.75\,R_m + 0.358 \times 2.5 \times 5/2$
$= 144.7$ KIPS

$$f_v = 1.5 \times \frac{V}{A} = \frac{1.5 \times 144.7}{2.5 \times 22.9} = 3.79 \text{ KSI} < 0.96 \times \frac{36}{\sqrt{3}}$$ OK

FORM 581 REV 7-71

EBASCO SERVICES INCORPORATED

NEW YORK

BY J. CHIANG DATE 8.12.81 SHEET 8 OF 11

CHKD. BY I. CHEN DATE 8/15/81 OFS NO. 2524 902 DEPT. NO. 650

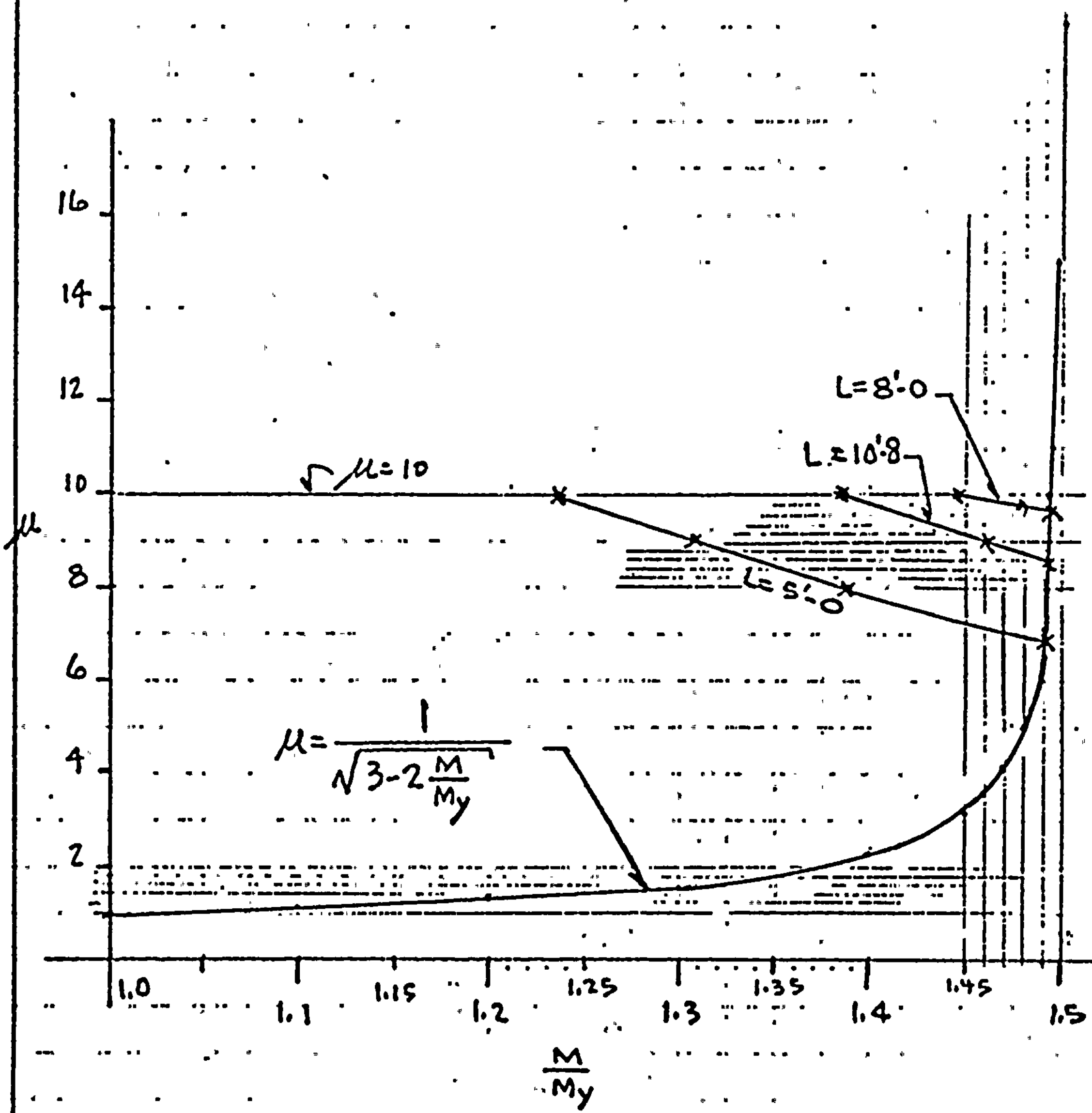
CLIENT FPL

PROJECT ST. LUCIE 2

SUBJECT STRUCTURAL DESIGN ADEQUACY AUDIT — MISSILE PROTECTION

REVIEW OF SIMPLY SUPPORTED GRATING SUBJECT A CONCENTRATED TORNADO MISSILE LOAD:

CURVES OF COMPUTED μ VS ASSUMED μ IN VARIOUS SPANS OF GRATING



$\frac{M}{M_y}$	COMPUTED μ
1.00	1.000
1.10	1.118
1.20	1.291
1.30	1.581
1.40	2.236
1.45	3.162
1.46	3.536
1.47	4.082
1.48	5.00
1.49	7.071
1.492	7.906
1.494	9.128
1.496	11.180
1.498	15.811
1.50	∞

FORM 581 REV 7-71

THE PLASTIC METHODS OF STRUCTURAL ANALYSIS

B. G. Neal

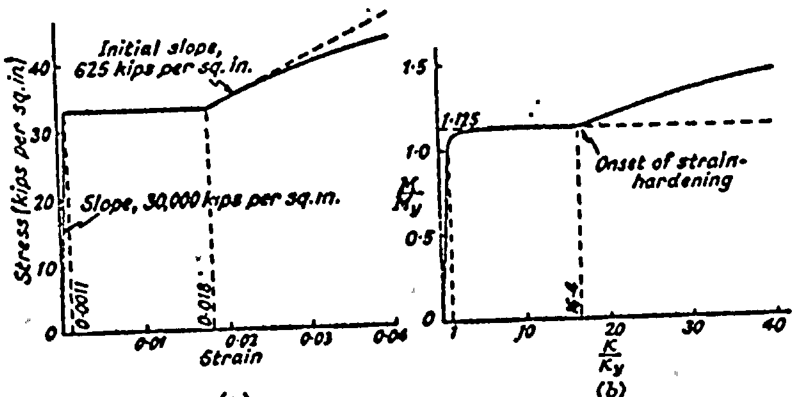
M.A., Ph.D., M.I.C.E., M.I.Mech.E., A.M.I.Struct.E.

Professor of Applied Science
Imperial College of Science and Technology

CHAPMAN & HALL LTD
and
SCIENCE PAPERBACKS

COPY OF REFERENCE 9 OF 11

which are discussed in Section 6.2, have indicated that the material of rolled steel joists exhibits either a small or zero drop of stress at yield. However, the particular feature of the assumed stress-strain relation which is of especial interest is that it includes the strain-hardening range. The strain ε_s at which strain-hardening commences is 0·018 whereas the strain ε_y at the yield point is 0·0011, so that the ratio of ε_s to ε_y is $\frac{0\cdot018}{0\cdot0011}$, or 16·4. A further implicit assumption in the analysis is that of homogeneity. This is rather difficult to justify in view of the fact



(a) Stress-strain relation. (b) Bending moment-curvature relation: $A_f = A_w$.

Fig. 5.8. Bending moment-curvature relation for I-section with strain-hardening (after Hrennikoff).

that the stress-strain relations obtained from tensile specimens cut from various positions in rolled steel joists are known to vary widely, as pointed out in Section 6.2.

To simplify the analysis it was assumed that the thickness of the flanges was negligible in comparison with the depth of the beam, so that each flange area could be regarded as concentrated at a constant distance from the neutral axis. With this assumption the form of the bending moment-curvature relation depends only on a single parameter, namely, the ratio of the total flange area A_f to the web area A_w. Up to the curvature at which strain-hardening develops in the outermost fibres, the analysis was a simple extension of the theory which has just been given for a

beam of rectangular cross-section. To determine the bending moment for a given curvature, and thus a given linear distribution of strain across the section, it was only necessary to add the bending moment due to the rectangular web to the bending moment due to the flanges, which is equal to the product of the stress in a flange, its area, and the depth of the beam. At higher curvatures, a process of step-by-step integration became necessary.

Four values of the ratio of total flange area to web area were considered, namely, 0, 0·5, 1·0 and 1·5. The value zero corresponds to the case of a beam of rectangular cross-section, and the other values cover the range of standard I-sections. The results were presented in the form of curves, and for the purpose of accurate calculation were tabulated for the case in which this ratio is 1·0, so that $A_f = A_w$. The bending moment-curvature relation for a beam of I-section of this type, as derived from these tabulated results, is shown in Fig. 5.8(*b*). The results are plotted non-dimensionally, the ordinates being the ratio of the bending moment to the yield moment and the abscissae being the ratio of the curvature to the curvature at yield. It is readily verified that for such a cross-section the shape factor α is 1·125, so that $M_p = 1{\cdot}125\ M_y$. It will be seen from the figure that strain-hardening commences when $\frac{\kappa}{\kappa_y} = 16{\cdot}4$, this being the ratio of ε_s to ε_y.

Further results were also tabulated which enable the load-deflection curves of statically determinate beams and simple statically indeterminate beams and frames to be derived. Some applications of this work will be given in Sections 5.3 and 5.4.

For a more general treatment of the problem of determining bending moment-curvature relations from any assumed form of stress-strain relation, the work of Nadai [7] may be consulted. Several comparisons with experimental results for light alloy beams have been made, for instance by Rappleyea and Eastman [8] and by Dwight,[9] and the case of a light alloy beam of rectangular section which is subjected to bending moments about axes other than the principal axes has been discussed by Barrett.[10]

5.3 Load-deflection relations for simply supported beams

For a beam resting on two simple supports the bending moment distribution in the beam for a given loading is known from

considerations of statics alone. Once the bending moment-curvature relation is specified the curvature at any section is known, and the deflected form of the beam can then be found by integration. In the first place beams of rectangular cross-section will be considered, with the bending moment-curvature relation of equation 5.6; subsequently, some of the results obtained by Hrennikoff[2] for joists with the bending moment-curvature relation of Fig. 5.8(*b*) will be given.

Beam of rectangular cross-section with central concentrated load

Consider a uniform beam of rectangular cross-section, breadth b and depth h, which is simply supported over a span l, as shown in

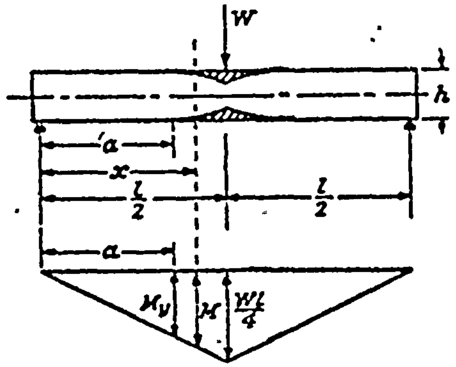


Fig. 5.4. Simply supported rectangular section beam with central concentrated load.

Fig. 5.4. It will be assumed that the relation between bending moment and curvature in the yielded regions is the relation given by equation 5.6, and for simplicity it will be assumed in the first place that $f_U = f_L$, so that

$$\frac{M}{M_y} = \frac{1}{2}\left[3 - \left(\frac{\kappa_y}{\kappa}\right)^2\right] \quad . \quad . \quad . \quad . \quad 5.8$$

This relation corresponds to the assumption of the ideal-plastic stress-strain relation of Fig. 1.4(*b*).

The bending moment diagram for the beam is as shown in Fig. 5.4, the central bending moment being $\frac{1}{4}Wl$. Yield first occurs at the centre of the beam when this bending moment

reaches the value M_y. The corresponding value of the load, W_y, is therefore given by the equation

$$M_y = \tfrac{1}{4} W_y l \quad . \quad . \quad . \quad . \quad 5.9$$

If the load is increased to a value W greater than W_y, the yield moment M_y will be attained at some distance a from the supports, as shown in the figure. In the central portion of the beam where the bending moment exceeds M_y, yield occurs, and plasticity spreads inwards towards the neutral axis. The general form of the plastic zones thus created is shown in the figure; a derivation of the shape of the elastic-plastic boundary will be given later. Eventually, collapse occurs when the central bending moment reaches the value M_p, so that plasticity has spread right down to the neutral axis at the centre of the beam. The corresponding collapse load W_c is given by the equation

$$M_p = \tfrac{1}{4} W_c l$$

Using equation 5.9 it follows that

$$\frac{W_c}{W_y} = \frac{M_p}{M_y} = 1{\cdot}5,$$

since the shape factor for a rectangular beam has the value 1·5.

From statical considerations it follows that

$$M_y = \tfrac{1}{2} W a$$

Combining this equation with equation 5.9, it is found that

$$a = \frac{l}{2}\left(\frac{W_y}{W}\right) \quad . \quad . \quad . \quad . \quad 5.10$$

Since the slope at the centre of the beam is zero, by symmetry, the central deflection δ is seen to be given by the integral

$$\delta = \int_0^{\frac{l}{2}} x\kappa \, dx \quad . \quad . \quad . \quad . \quad 5.11$$

where x is measured from the left-hand support. For $0 < x < a$, the beam is elastic, so that the curvature κ is equal to $\frac{x}{a}\kappa_y$. For $a < x < \frac{l}{2}$, the beam has partly yielded, so that the relation between bending moment and curvature is given by equation 5.8. Solving this equation for κ, it is found that

$$\kappa = \frac{\kappa_y}{\sqrt{3 - 2\frac{x}{a}}}, \text{ for } a < x < \frac{l}{2},$$