AMENDMENT 7

Tabulation of Revisions

FSAR Section	Reason for Revision
2.1	Update of population distribution tables.
2.2	Deletion of requirement for H_2S detectors.
2.4 & 2.5	Update of groundwater and geology sections.
8.2	Switchyard design change to ring bus and transmission line name change.
8.3	Specify method of instrument cable installation in raceways.
9.2	Update essential chilled water system FEMA.
10.4	Update AFW system FEMA.

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D. O. Foster
Vice President and General Manager
Vogtle Project

Georgia Power
the southern electric system

May 29, 1984

Director of Nuclear Reactor Regulation
Attention: Ms. Elinor G. Adensam, Chief
Licensing Branch #4
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, D.C. 20555

File: X7N00.07
X7BC35
Log: GN-358

NRC DOCKET NUMBERS 50-424 AND 50-425
CONSTRUCTION PERMIT NUMBERS CPPR-108 AND CPPR-109
VOGTLE ELECTRIC GENERATING PLANT - UNITS 1 AND 2
FSAR AMENDMENT NUMBER 7

Dear Mr. Denton:

Georgia Power Company, acting on its own behalf and as agent for Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and the City of Dalton, Georgia, hereby submits Amendment 7 to its Application for Operating Licenses for the Vogtle Electric Generating Plant - Units 1 and 2.

This Amendment consists of revised pages for the Final Safety Analysis Report and provides responses to NRC questions transmitted in Ms. Adensam's letter dated March 13, 1984. Substantive changes which were not a result of this letter are tabulated in Attachment 1 to this letter. Also, instructions for inserting this material are included.

In accordance with the requirements of 10 CFR 50.30(b) and (c), three (3) signed originals and sixty (60) copies of Amendment 7 are submitted for your use.

Should you have any questions on the enclosed submittals, do not hesitate to contact us.

Yours truly,

D. O. Foster

D. O. Foster

DOF/KWK/sw
Enclosures
xc: List attached

SWORN AND SUBSCRIBED BEFORE ME, THIS

10th DAY OF May 1984.

Jacqueline P. Smith

Notary Public, Georgia State at Large

xc: M. A. Miller
R. A. Thomas
J. A. Bailey
O. Batum
L. T. Gucwa
G. Bockhold, Jr.
G. F. Trowbridge, Esquire
D. G. Eisenhut

AMENDMENT 7

Tabulation of Revisions

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8.3	Specify method of instrument cable installation in raceways.
9.2	Update essential chilled water system FEMA.
10.4	Update AFW system FEMA.

VEGP-FSAR

INSERTION INSTRUCTIONS

AMENDMENT 7, MAY 1984

Page/Section	Instruction
p. 1.9-9 and 1.9-10	Replace
p. 1.9-37 through 1.9-40	Replace
p. 1.9-57 and 1.9-58	Replace
p. 1.9-105 and 1.9-106	Replace
p. 1.9-117 and 1.9-118	Replace
p. 2-vii and 2-viii	Replace
p. 2-xi and 2-xii	Replace
p. 2.1.1-1 and 2.1.1-2	Replace
p. 2.1.3-3 through 2.1.3-5	Replace
t. 2.1.3-19	Replace
t. 2.1.3-20, 2 sheets	Replace
t. 2.2.2-5, sheet 1 of 2	Replace
t. 2.2.2-6, sheets 2 and 3 of 10	Replace
p. 2.2.3-13 and 2.2.3-14	Replace
p. 2.2.3-17b and 2.2.3-17c	Replace
t. 2.3.2-1, sheet 1 of 6	Replace
t. 2.4.12-7, sheets 1 and 3 of 3	Replace
p. 2.4.13-1 through 2.4.13-4	Replace/add
p. 2.5.1-37 through 2.5.1-40	Replace
p. 2.5.2-1 and 2.5.2-2	Replace
p. 2.5.2-5 and 2.5.2-6	Replace
p. 2.5.2-11 and 2.5.2-12	Replace
p. 2.5.3-1 and 2.5.3-2	Replace
p. 2.5.4-1 through 2.5.4-4	Replace
p. 2.5.4-7 through 2.5.4-13a	Replace
p. 2.5.4-15 and 2.5.4-16	Replace
p. 2.5.4-19 and 2.5.4-20	Replace
p. 2.5.4-23 through 2.5.4-28	Replace
p. 2.5.4-33 and 2.5.4-34	Replace
t. 2.5.4-1	Replace
t. 2.5.4-2	Replace
t. 2.5.4-3	Replace
t. 2.5.4-4	Replace
t. 2.5.4-5	Replace
t. 2.5.4-8	Replace
t. 2.5.4-9	Replace
t. 2.5.4-10	Replace
t. 2.5.4-11	Replace
t. 2.5.4-12	Replace
p. 2.5.5-1 through 2.5.5-3	Replace
p. 2A-1 through 2A-5	Replace
p. 2B-1 and 2B-2	Replace

Page/Section	Instruction
p. 2B-7 through 2B-10	Replace
p. 2B-15 through 2B-24	Replace
p. 5.4.3-5 and 5.4.3-6	Replace
p. 6.1.2-1 through 6.1.2-4	Replace
p. 6.1.2-5	Delete
t. 6.1.2-1, sheet 3 of 4	Replace
p. 6.2.2-7 and 6.2.2-8	Replace
p. 6.4.1-1 and 6.4.1-2	Replace
p. 6.4.2-3 through 6.4.2-8	Replace
p. 6.4.3-1 and 6.4.3-2	Replace
p. 6.4.4-1 through 6.4.4-4	Replace
t. 6.4.4-1, sheets 13, 14, and 15 of 15	Replace
p. 6.4.6-1	Replace
t. 6.4.6-1	Replace
p. 7.3.6-1 and 7.3.6-2	Replace
t. 7.3.6-1	Replace
f. 7.3.6-1, sheets 4 and 5 of 15	Replace
p. 8-iii and 8-iv	Replace
p. 8.1-7 and 8.1-8	Replace
f. 8.1-1, sheet 2 of 2	Replace
p. 8.2.1-1 and 8.2.1-2	Replace
t. 8.2.1-1, 2 sheets	Replace
t. 8.2.1-2	Replace
t. 8.2.1-3	Add
f. 8.2.1-1	Replace
f. 8.2.1-2	Replace
p. 8.2.2-1 and 8.2.2-2	Replace
p. 8.3.1-15 and 8.3.1-16	Replace
p. 8.3.1-19 and 8.3.1-20	Replace
p. 8.3.1-27b and 8.3.1-28	Replace
p. 8.3.1-33 and 8.3.1-34	Replace
t. 8.3.1-1, 2 sheets	Replace
f. 8.3.1-4	Replace
f. 8.3.1-7, 14 sheets	Replace
p. 8.3.2-3 through 8.3.2-8	Replace
p. 9.1.3-9 and 9.1.3-10	Replace
p. 9.2.2-1 through 9.2.2-4	Replace
t. 9.2.3-1, sheet 2 of 2	Replace
f. 9.2.6-1	Replace
p. 9.2.9-5 and 9.2.9-6	Replace
t. 9.2.9-3, 3 sheets	Replace
p. 9.2.10-1 and 9.2.10-2	Replace
p. 9.4.1-15 through 9.4.1-20	Replace
f. 9.4.1-2, sheets 1 and 3 of 3	Replace
f. 9.4.1-6, sheet 1 of 2	Replace
p. 9.4.7-3 and 9.4.7-4	Replace
p. 9.5.4-3 through 9.5.4-7	Replace
t. 9.5.4-1, sheet 2 of 2	Replace

Page/Section	Instruction
t. 9.5.4-3	Replace
p. 9.5.5-5 through 9.5.5-7	Replace/add
p. 9.5.6-3 through 9.5.6-5	Replace/add
p. 9.5.7-3 through 9.5.7-5	Replace
f. 10.3.2-1, sheet 2 of 3	Replace
f. 10.4.1-1, sheet 3 of 3	Replace
t. 10.4.9-4, 31 sheets	Replace
f. 10.4.9-1, sheet 2 of 2	Replace
p. 11-vii and 11-viii	Replace
p. 11.4.2-3 and 11.4.2-4	Replace
p. 12.3.2-1 and 12.3.2-2	Replace
p. 13.1.2-3 and 13.1.2-4	Replace
p. 13.2.1-7 through 13.2.1-9	Replace
t. 13.2.1-1, 3 sheets	Replace
t. 13.2.1-2, 3 sheets	Replace
t. 13.2.1-3, 3 sheets	Replace
t. 13.2.1-4, 3 sheets	Replace
t. 13.2.1-5, 2 sheets	Replace
p. 13.2.2-3 and 13.2.2-4	Replace
t. 13.2.2-1, sheet 2 of 2	Replace
p. 14.2.8-27 and 14.2.8-28	Replace
p. 14.2.8-79 through 14.2.8-82	Replace
p. 17.2.12-1 and 17.2.12-2	Replace
p. 17.2.15-1 and 17.2.15-2	Replace
Index of NRC questions and responses, sheets i through vi	Replace
f. 241.2-6 (behind tab Feb. 21)	Replace
f. 241.2-11 (behind tab Feb. 21)	Replace
p. Q241.12-1 (behind tab Feb. 21)	Replace
Vol. 32 (Mar. 13 tab and NRC questions and responses)	Add to set

5. C.5 Conform. Refer to Regulatory Guide 1.89 comparison.

6. C.6 Conform. See Regulatory Guide 1.108 comparison.

7. C.7 Conform.

8. C.8 Conform.

9. C.9 VEGP diesels are qualified in accordance with IEEE Std. 387-1977 and IEEE Std. 344-1975. 7

10. C.10 Conform.

11. C.11 Conform. See Regulatory Guide 1.108 comparison.

12. C.12 Conform. Applicable standards are referenced where appropriate.

13. C.13 Conform.

14. C.14 Conform.

Refer to section 8.3 for further discussion.

1.9.10 REGULATORY GUIDE 1.10, REVISION 1, JANUARY 1973, MECHANICAL (CADWELD) SPLICES IN REINFORCING BARS OF CATEGORY I CONCRETE CONTAINMENT STRUCTURES

1.9.10.1 Regulatory Guide 1.10 Position

Procedures given for testing cadwelds include:

1. C.1 Crew qualification.
2. C.2 Visual inspection.
3. C.3 Tensile testing.
4. C.4 Tensile test frequency.
5. C.5 Procedure for substandard tensile test results.

1.9.10.2 VEGP Position

Procedures for testing cadwelds conform with the requirements of Regulatory Guide 1.10.

Refer to section 3.8.1 for discussion on this subject.

1.9.11 REGULATORY GUIDE 1.11, MARCH 1971, INSTRUMENT LINES PENETRATING PRIMARY REACTOR CONTAINMENT 3

1.9.11.1 Regulatory Guide 1.11 Position

This guide describes an acceptable method for designing instrument lines which penetrate the primary containment.

1.9.11.2 VEGP Position

VEGP conforms with this guide with the exception of regulatory position C.1.c. Containment pressure sensing lines are not equipped with isolation valves, which is consistent with Regulatory Guide 1.141.

Four independent containment pressure sensors are provided. These are sealed systems, with bellows seals both inside and outside the containment with sealed liquid filled capillaries between the seals inside and outside the containment for each sensor. The seals outside containment connect directly with the sensing elements for each sensor.

Two containment hydrogen monitors are provided. Each monitor has a sample line and return line which penetrate the containment. All sample lines penetrating the containment are equipped with remote manual operated valves inside and outside the containment.

All other sample lines penetrating the containment are similarly equipped.

Refer to section 6.2.4 for further discussion.

1.9.12 REGULATORY GUIDE 1.12, REVISION 1, APRIL 1974, INSTRUMENTATION FOR EARTHQUAKES

1.9.12.1 Regulatory Guide 1.12 Position

This guide describes seismic instrumentation acceptable to the NRC for meeting Appendix A of 10 CFR 50.

Caps and plugs are used only when required by the specification. See Regulatory Guide 1.37 comparison. Tape near a weld may be removed to clean, setup, and inspect surface.

The contact preservative used on the main condenser is not water flushable; it will be chemically cleaned.

Quality assurance for packaging, shipping, receiving, storage, and handling of NSSS equipment is described in WCAP-8370, Rev. 9A-Amendment 1, Table 17-1. Refer to chapter 17 for further discussion.

The VEGP operations QAP conforms with this guide, which endorses ANSI N45.2.2-1972, with the following clarifications:

1. Paragraph 2.1, Planning (first sentence). The specific items to be governed by the standard shall be identified. However, the standard is part of this operations QAP (section 17.2) and will therefore be applied to those structures, systems, and components which are included in that program.

2. Paragraph 2.3, Results. The methods for performing and documenting tests and inspections are given in section 17.2. The requirements in these sections will be implemented in lieu of the general requirements here.

3. Paragraph 2.5, Measuring and Test Equipment (2.5.2). That equipment which measures quality of the permanent plant items shall be under the calibration and control program; whereas the equipment used to measure secondary conditions, such as warehouse temperature, humidity, etc., will be maintained in good working order and checked for proper functioning when accuracy is in doubt, but not maintained under the calibration and control program. Traceability to calibration records will be provided for equipment included in the calibration and control program. 7

4. Paragraph 2.6, Housekeeping. The warehouse storage areas will be declared Zone IV in accordance with ANSI N45.2.3, and eating will be limited to designated areas. Signs will be posted in these areas accordingly.

5. Paragraph 2.7, Classification of Items. VEGP may choose not to explicitly use the four-level classification system. However, the specific requirements of the standard that are appropriate to

each class will generally be applied to the items suggested in each classification and to similar items.

6. Paragraph 3.2.1, Level A Items. As an alternate to the requirements for packaging and containerizing items in storage to control contaminants (items 4 and 5), VEGP may choose a storage atmosphere which is free of harmful contaminants in concentrations that could produce damage to stored items. Similarly (for item 7), VEGP may delete the need for caps and plugs with an appropriate storage atmosphere and may choose to protect weld-end preparations stored. These clarifications apply to items 4, 5, or 7 and paragraph 3.4, Methods of Preservation.

7. Paragraph 3.3, Cleaning (third sentence). VEGP interprets "documented cleaning methods" to allow generic cleaning procedures to be written which are implemented, as necessary, by trained personnel. Each particular cleaning operation may not have an individual cleaning procedure, but the generic procedures will specify which methods of cleaning or which types of solvent may be used in a particular application.

8. Paragraph 3.4, Methods of Preservation (first sentence). VEGP will conform with these requirements subject to the clarifications of Paragraph 3.2.1, D and E above, and the definition of the phrase "deleterious corrosion" to mean that corrosion which cannot be subsequently removed and which adversely affects form, fit, or function.

9. Paragraph 3.6, Barrier and Wrap Material and Dessicants. This section requires the use of nonhalogenated materials in contact with austentic stainless steel. Refer to Regulatory Guide 1.37 (section 1.9) for the VEGP position.

10. Paragraph 3.7, Containers, Crating, and Skids. In lieu of the requirements of this paragraph, VEGP will use means as needed to provide adequate protection of items in storage.

11. Section 4.2.2, ANSI N45.2.2-1972, Closed Carriers. The use of fully enclosed furniture vans, as recommended in (2) of this section is not considered a requirement. VEGP will assure adequate protection from weather or other environmental conditions by a combination of vehicle enclosure and item packaging.

12. Sections 4.3, 4.4, and 4.5 of ANSI N45.2.2-1972 titled, respectively, Precautions During Loading and Transit, Identification and Marking, and Shipment from Countries Outside the United States. VEGP will conform with the requirements of these sections subject to the clarifications taken to other sections which are referenced therein.

13. Paragraph 5.2, Receiving Inspection Requirements. Preliminary visual inspection will be performed prior to unloading where practical; however, the receiving inspection of record will be performed in an area and in a manner which does not adversely affect the quality of the item being inspected. 7

14. Paragraph 5.3.1, Acceptable. Item acceptance status will be indicated by application of tags, stickers, ribbons, or signs. Storage areas are not designated as accept areas except for bulk items (e.g., rebar, structural steel, aggregate, etc.)

15. Paragraph 5.3.2, Nonconforming. Segregation will be accomplished where practical or where necessary to control the inadvertent use of the item. Otherwise, the use of tags, stickers, ribbons, or signs will be so conspicuous as to imply segregation.

16. Paragraph 5.7, Documentation. Receiving inspection records will provide traceability to the item and its status. Superfluous identification and tagging will not be recorded except when they are the subject of a nonconformance or specifically required by site inspection procedures.

17. Paragraph 6.1.1, Scope. The levels and methods of storage for items between the time of removal from the prescribed storage until placement in the installed location may be relaxed for short periods of time, according to the sensitivity of the item being handled and the elements of contact anticipated during this interval. Where relaxation of storage requirements of this standard are deemed appropriate, the item, conditions, precautions, and followup inspection for assurance that quality of the item has been maintained will be prescribed in project procedures.

a. Example 1.

A motor may be removed from level B storage and moved via open-bed trailer and lifting cranes to the installed location. The relocation will not be permitted during inclement weather, with the motor unprotected; and the transfer will be completed in 2 days. Following installation the prescribed storage environment will be restored, and the motor subjected to inspection to verify that there was no degradation of quality during handling.

b. Example 2.

Reinforcing steel bars, shapes, and outdoor equipment may be handled in staging areas without providing the level of protection from damage, trapping of water, or loss of air circulation normally provided in a level D storage area. The bars, shapes, and equipment will not be allowed to remain in the staging area more than 1 week without providing the normal protection of level D storage. During or following installation, the items will be subjected to inspection to verify that there was no degradation of quality during handling. Once the item is installed, the prescribed storage environment will be maintained except where prohibited by the type of work in progress (e.g., end covers and purges removed to accommodate installation activities).

18. Paragraph 6.1.2, Levels of Storage: Subpart (2) is replaced with the following:

(2) Level B items shall be stored within a fire-resistant, weathertight, and well ventilated building or equivalent enclosure. This building shall be situated and constructed so that it will not normally be subject to flooding; the floor shall be paved, or equal, and well drained. If any water comes in contact with stored equipment, such equipment will be labeled or tagged nonconforming, and then the nonconformance document will be processed and evaluated in accordance with Section 15. Items shall be placed on pallets, shoring, or shelves to permit air circulation. The building shall be provided with heating and temperature control or its equivalent to reduce condensation and corrosion. Minimum

Rated Voltage (V)	Ratio
300 600 1000	>8
5000 8000 15,000	>15

3. C.3 The provisions of Section 4.2.4 pertaining to the duration of the maximum short circuit current are representative of circuits protected by molded-case circuit breakers but are not representative of circuits using other air circuit breakers. The provisions pertaining to the duration of the maximum short-circuit current should be modified as follows:

Service Classfication	Duration(s)
Low-voltage power and control	0.033 (for molded-case circuit breakers) 0.066 (for other air circuit breakers)

4. C.4 Section 6.4.4, Dielectric-Strength Test, should be supplemented, for qualification testing only, by the following:

   (3) Each medium-voltage power conductor shall be given an impulse withstand test by applying a 1.2 x 50 μs impulse voltage test series consisting of three positive and three negative impulse voltages. If flashover occurs on only one test during any group of three consecutive tests, three more shall be made. If no flashover occurs in the second group of tests, the flashover in the first group shall be considered as a random flashover and the equipment shall be considered as having passed the test.

   The test voltages for the above shall be based on the voltage rating of the conductor in accordance with the following table:

Conductor-Rated Voltage (V)	Impulse Voltage (V)
300 and 600	......
1000	......
5000	60,000
8000	95,000
15,000	95,000

5. C.5 The 500-h aging time at minimum aging temperature of Section 6.3.3 is a printing error and should be changed to 5000 h.

6. C.6 The definition of "Double Aperture Seal" in Section 2 is a printing error and should be changed as follows: "Two single aperture seals in series".

7. C.7 The specific applicability or acceptability of the codes, standards, and guides referenced in Section 3 will be covered separately in other regulatory guides, where appropriate.

1.9.63.2 VEGP Position

1. C.1 Protection against single random failure of circuit overload protection devices are as follows:

   a. For medium-voltage circuits, the circuit breaker associated with the load is backed-up by a second load breaker in series. The second breaker is Class 1E.

   b. For 480-V loads fed from load centers, the circuit breaker associated with the load is backed up by series fuses. Primary protection is provided by the individual load circuit breaker.

   c. For 480-V loads fed from motor control centers, a second breaker in series with the primary breaker to each load is used.

   d. For control circuits with sufficient capacity to potentially damage a penetration, backup overload protection is provided. The fault current in other low-energy level control circuits and instrument circuits is limited and does not need backup overload protection. 7

2. C.2 Actual x/r ratio of fault at the penetration conductors is used in determining the fault current.

37. Paragraph 5.3.8, Chemical. Radiochemical Control Procedures, discusses certain procedures to be developed. The VEGP Technical Specifications require chemical tests to be performed periodically during the lifetime of the facility; therefore, VEGP shall provide for those tests in lieu of the ones stated in N18.7-1976.

38. Paragraph 5.3.9 and subsections, Emergency Procedures. As directed by the NRC, GPC will follow a format for emergency operating procedures in accordance with item I.C.1 of NUREG-0737. 7

39. Paragraph 5.2.10, Test and Inspection Procedures, outlines certain requirements for test and inspection procedures. In order to avoid conflict, GPC will prepare test and inspection procedures as stated in section 17.2.

1.9.124 REGULATORY GUIDE 1.124, REVISION 1, JANUARY 1978, SERVICE LIMITS AND LOADING COMBINATIONS FOR CLASS 1 LINEAR-TYPE COMPONENT SUPPORTS

1.9.124.1 Regulatory Guide 1.124 Position

This guide delineates acceptable levels of service limits and appropriate combinations of loadings associated with normal operation, postulated accidents, and specified seismic events for the design of Class 1 linear-type component supports as defined in Subsection NF of Section III of the ASME Code.

1.9.124.2 VEGP Position

In general, VEGP conforms. Additional information is provided in subsection 3.8.3. For the NSSS scope, the following exceptions are taken.

Paragraph C.2 of the regulatory guide presents two methods of estimating the ultimate tensile strength S_u, at temperature. It is believed that method No. 2 is not conservative at elevated metal temperature (in excess of 800°F). In Westinghouse's judgment, values of S_u at these elevated temperatures should be determined by test rather than via the method given in C.2(b).

Paragraph C.4 of the regulatory guide states: "However, all increases, i.e., those allowed by NF-3231.1(a), XVII-2110(a), and F-1370(a), should always be limited by XVII-2110(b) of

Section III." Paragraph XVII-2110(b) specifies that member compressive axial loads shall be limited to two-thirds of critical buckling. Satisfaction of this criteria for the faulted condition is unnecessarily restrictive.

The most significant faulted condition loads on equipment supports result from seismic disturbances and postulated LOCAs, both of which are dynamic events. The allowable faulted condition compressive load should not be limited to two-thirds of critical buckling because these faulted dynamic loads are of extremely short duration, and support members can take impulsive loads that exceed static critical buckling load. Westinghouse will use a compressive axial load of 0.9 of critical buckling since the dynamic buckling capacity of the member is greater than the static buckling capacity.

Paragraph C.6(a) of the regulatory guide appears to erroneously allow the use of faulted stress limits for the emergency condition. Westinghouse will interpret this paragraph as follows: "The stress limits of XVII-2000 of Section III and regulatory position 3, increased according to the provisions of XVII-2100(a) of Section III, should not be exceeded for component supports designed by the linear elastic analysis method."

Westinghouse will use the provisions of F-1370(d) to determine faulted condition allowable loads for supports designed by the load rating method. The method described in paragraph C.7(b) of the regulatory guide is very conservative and inconsistent with the remainder of the faulted stress limits.

In paragraphs B.5 and C.8 of the regulatory guide, Westinghouse takes exception to the requirement that systems whose safety-related function occurs during emergency or faulted plant conditions must meet upset limits. The reduction of allowable stress to no greater than upset limits (which in reality are only design limits since design, normal, and upset limits are the same for linear supports) for support structures in those systems with normal safety-related functions occurring during emergency or faulted plant conditions is overly conservative for components which are not required to mechanically function (inactive components). In addition, Westinghouse believes that emergency and faulted condition criteria are acceptable for active components. However, when these criteria are invoked for active components, any significant deformation that might occur is considered in the evaluation of equipment operability.

Containment Isolation Provisions for Fluid Systems, are generally acceptable and provide an adequate basis for complying with the pertinent containment isolation requirements of Appendix A to 10 CFR 50, subject to the qualifications identified in the guide.

1.9.141.2 VEGP Position

VEGP conforms as discussed in subsection 6.2.4.

1.9.142 REGULATORY GUIDE 1.142, OCTOBER 1981, REVISION 1, SAFETY-RELATED CONCRETE STRUCTURES FOR NUCLEAR POWER PLANTS (OTHER THAN REACTOR VESSELS AND CONTAINMENTS)

1.9.142.1 Regulatory Guide 1.142 Position

This guide endorses the procedures and requirements described in American Concrete Institute (ACI) 349-76 subject to the qualifications provided in this guide.

1.9.142.2 VEGP Position

ACI 318-71 is used in lieu of ACI 349-76.

Refer to subsection 3.8.4 for discussion on this subject.

1.9.143 REGULATORY GUIDE 1.143, REVISION 1, OCTOBER 1979, DESIGN GUIDANCE FOR RADIOACTIVE WASTE MANAGEMENT SYSTEMS, STRUCTURES, AND COMPONENTS INSTALLED IN LIGHT-WATER-COOLED NUCLEAR POWER PLANTS

1.9.143.1 Regulatory Guide 1.143 Position

This guide furnishes design guidance acceptable to the NRC regarding seismic and quality group classification and quality assurance provisions for radioactive waste management systems, structures, and components.

1.9.143.2 VEGP Position

Conform, with the following clarifications:

- Radioactive waste management systems, structures, and components are classified in table 3.2.2-1.

- ACI 318-71 is used for design of concrete structures in lieu of ACI 318-77. 5

See section 11.4 for further discussion.

1.9.144 REGULATORY GUIDE 1.144, REVISION 1, SEPTEMBER 1980, AUDITING OF QUALITY ASSURANCE PROGRAMS FOR NUCLEAR POWER PLANTS

1.9.144.1 Regulatory Guide 1.144 Position

The requirements that are included in ANSI/ASME N45.2.12-1977 for auditing QAPs for nuclear power plants are acceptable to the NRC staff and provide an adequate basis for complying with the pertinent quality assurance requirements of Appendix B to 10 CFR 50, subject to the qualifications identified in the guide.

1.9.144.2 VEGP Position

VEGP conforms with Regulatory Guide 1.144 with the following clarification. VEGP does not conform to the latest revisions of the following ANSI standards: ANSI N45.2, ANSI N45.2.9, and ANSI N45.2.10. VEGP conforms to ANSI N45.2-1971, ANSI N45.2.9-1973 (Draft 11, Revision 0), and ANSI N45.2.10-1973. Conformance to Regulatory Guides 1.28, 1.74, and 1.88 is indicated in this section. The VEGP quality assurance program is described in chapter 17. 7

1.9.145 REGULATORY GUIDE 1.145, AUGUST 1979, ATMOSPHERIC DISPERSION MODELS FOR POTENTIAL ACCIDENT CONSEQUENCE ASSESSMENTS AT NUCLEAR POWER PLANTS

1.9.145.1 Regulatory Guide 1.145 Position

This guide identifies acceptable methods for:

- Calculating atmospheric relative concentration (χ/Q) values.

- Determining χ/Q values on an overall site basis.

- Determining χ/Q values on a directional basis.

LIST OF TABLES (Continued)

2.1.3-18 Population by Annular Rings, 0- to 10-Mile Radius Total

2.1.3-19 Population by Sectors, 20- to 50-Mile Radius Total

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2.2.2-1 Description of Savannah River Plant Facilities

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2.0 SITE CHARACTERISTICS

2.1 GEOGRAPHY AND DEMOGRAPHY

2.1.1 SITE LOCATION AND DESCRIPTION

Figures 2.1.1-1 through 2.1.1-3 show the location of the 3169-acre site within Burke County, Georgia, on the Savannah River at river mile 151.1.

2.1.1.1 Reactor Coordinates

The coordinates of the center of the containment for each of the two units are given below in both latitude and longitude and Universal Transverse Mercator (UTM) coordinates. Latitude and longitude are given to the nearest second and UTM coordinates are given to the nearest 100 m.

Unit	Latitude and Longitude	UTM Coordinates in Zone 17S MG (m)
1	33°08'30" N 81°45'44" W	N 3,666,900 E 428,900
2	33°08'30" N 81°45'48" W	N 3,666,900 E 428,800

3

2.1.1.2 Site Area Map

Figure 1.1-1 shows property lines for the site; boundary and exclusion lines are the same as property lines. Location and orientation of principal plant structures within the site area are shown in figure 1.2.2-1. With the exception of the Georgia Power Company combustion turbine plant, Plant Wilson, there are no commercial, industrial, institutional, recreational, or residential structures within the site area. The nearest point to the exclusion area boundary is the near bank of the Savannah River. Reactor 1 is approximately 3600 ft from the exclusion area boundary, and Reactor 2 is approximately 3900 ft from the exclusion area boundary. A scale that will permit the measurement of distances with reasonable accuracy is shown in figure 1.1-1. The Savannah River is adjacent to the site, as shown in figure 2.1.1-2. 7

2.1.1.3 Boundaries for Establishing Effluent Release Limits

The property lines as shown in figure 1.1-1 are the boundaries for determining effluent release limits. Effluent releases will not exceed the limits of 10 CFR 20.106(a) at the boundary. Access within the property boundary is controlled as discussed in subsection 2.1.2. Effluent release points are discussed in subsection 2.3.5.

sectors. Several segments in this ring in South Carolina contain additional facilities of the Savannah River Plant. The majority of these workers also live in different rings from their work location. Estimated workers in 1987 by segment are: N-20, 2400 employees; NNE-20, 1000 employees; NE-20, 6200 employees; and ENE-20, 500 employees. Socioeconomic base studies completed for the Savannah River Plant show that the majority of plant workers live in the Aiken-Augusta corridor which is comprised of segments N-30 and NNW-30. An additional concentration of industrial employment in this ring is centered in Waynesboro (WSW-20). Most of these workers are estimated to also reside in this segment. Although slight growth in industrial employment at existing and new facilities in the above mentioned segments is anticipated in future years of 2007 and 2028, no significant changes in employment numbers or distribution of facilities is anticipated.

There are no recreational land uses of significance or other sources of daily or seasonal population shifts in the 10- to 20-mile annular ring.

Industrial employment centers in the 20- to 30-mile ring are concentrated in the Augusta area segments NW-30 (3600 employees) and NNW-30 (5368 employees). The majority of these workers live in the same segments, but some live in the adjoining segments of Aiken (N-30) and Columbia County (NW-40).

Additional transient population concentrations are also found in 20- to 30-mile annular rings due to recreational activities on weekends and holidays at several state parks. In Georgia, Magnolia Springs Park near Millen (SSW-30) experiences an estimated daily peak summer (May, June, July, and August) holiday weekend visitor population of 4200. During nonsummer months, the number of daily peak weekend visitors is estimated at 950. On weekdays, visitors are estimated to average approximately 200 during the summer and 75 in the nonsummer months. In South Carolina, two smaller parks also draw some transient visitors. Aiken Park near Windsor (NNE-30) is estimated to draw a maximum of 2000 visitors on a peak summer holiday. In nonsummer months, daily visitors on a peak weekend are estimated to be only 700. Average weekday visitors are estimated to be 100 during the summer and 50 during nonsummer months. Barnwell State Park near Blackville (ENE-30) is smaller, more distant from residential population concentrations, and less subject to seasonal fluctuations. Visitors are estimated to average 700 on a peak holiday and 50 on an average weekday. In future years, some increase in visitors at these parks may occur, although weekend usage is currently near capacity for overnight facilities.

The 30- to 40-mile annular ring contains no significant sources of industrial activity which would result in large transient worker concentrations. The relatively small Rivers Bridge State Park near Ehrhardt, South Carolina (ESE-40), is estimated to attract as many as 700 visitors on a peak holiday and as few as 50 on an average weekday. There is little seasonal fluctuation.

The 40- to 50-mile annular ring has some industrial facilities associated with the cities of Thomson (WNW-50) and Swainsboro (SW-50). The majority of workers live within these segments. Two state parks are located in Georgia within this ring. George L. Smith Park near Twin City (SSW-50) has little seasonal fluctuation in visitors. Peak holiday visitors are estimated to be 500, with 50 visitors on an average weekday. Mistletoe State Park (NW-50) does show seasonal variance in visitors due to its proximity to water at Clarks Hill Reservoir. Visitors are estimated to range from 2200 on a peak summer holiday to 100 on an average summer weekday. In nonsummer months on a peak holiday as many as 800 visitors are estimated to be present. Weekday visitors in nonsummer months are estimated to average 60 persons. This facility is judged to be moderately used at present by the Corps of Engineers. Some increase in usage is expected in the future.

No other activities or attractions produce significant changes in population distribution between segments or in transient population totals on a daily or seasonal basis.

2.1.3.4 Low Population Zone (LPZ)

The LPZ (as defined by 10 CFR 100) for the VEGP is that area falling within a 2-mile radius (figure 2.1.1-3) from the midpoint between the containment buildings. Tables 2.1.3-1 through 2.1.3-16 and table 2.1.3-18 show that the area is expected to remain sparsely populated during the anticipated life of the plant. There is only one road, River Road, within the LPZ, as shown in figure 1.1-1. There are no towns, recreational facilities, hospitals, schools, prisons, or beaches within the LPZ or from the LPZ to a radius of 5 miles.

2.1.3.5 Population Center

Augusta is the nearest population center of more than 25,000 people, with a 1980 population of 47,532 people (U.S. census count). The Augusta corporate limit lies approximately 25 miles from the VEGP reactors. The Augusta corporate city limit 7
was selected as the population center boundary because the

Savannah River flood plain occupies the immediate area southeast of the corporate limits and creates a sharply defined low population density area from the southeast corporate limits to VEGP.

A list of all communities within 30 miles of the plant with populations greater than 1000 persons are identified in table 2.1.3-21 and figure 2.1.3-5. These also identify the largest city within 50 miles of the plant. 4

The 1980 population of Richmond County outside Augusta was approximately 134,097 people; the projected 1990 total population of Richmond County, including Augusta, is approximately 203,000. The only defined significant transient population into and out of the Augusta area to the plant site is that portion of the VEGP construction force expected to live in the Augusta vicinity until 1987. The current population distribution indicates high density within the Augusta city limits and the northern portions of Richmond County and much lower density in the rural southern and eastern portions of Richmond County. Projections through 2028 indicate that these distribution and density patterns will remain essentially the same.

2.1.3.6 Population Density

The cumulative resident population for a distance of 50 miles projected for the expected first year of operation (1987) compared to 500 people/mi^2 is shown in figure 2.1.3-3. Projected to the year 2028, this comparison to 1000 people/mi^2 is shown in figure 2.1.3-4.

2.1.3.7 Methodology

The methodology used to determine population distribution is described in appendix 2A.

TABLE 2.1.3-19

POPULATION BY SECTORS
20- TO 50-MILE RADIUS TOTALS

Sector	1987	1990	2000	2007	2010	2020	2028	
N	38,722	40,221	44,254	48,001	49,889	56,260	61,401	
NNE	49,703	52,147	58,271	64,511	67,186	77,661	87,278	
NE	41,082	43,031	47,672	52,267	54,337	61,935	68,749	
ENE	23,262	24,342	26,862	29,397	30,484	34,599	38,340	
E	13,487	14,068	15,148	16,250	16,726	18,472	19,999	
ESE	15,700	16,277	17,[illegible]	18,678	19,210	21,177	22,898	
SE	15,069	15,541	16,137	17,023	17,404	18,839	20,132	7
SSE	11,504	11,732	11,502	11,657	11,769	12,144	12,537	
S	18,184	18,703	20,378	21,734	22,587	25,363	27,918	
SSW	13,762	14,067	14,749	15,285	15,554	16,461	17,280	
SW	12,706	13,001	13,866	14,563	14,863	15,944	16,879	
WSW	14,397	14,637	15,413	16,118	16,418	17,491	18,410	
W	12,832	13,032	13,711	14,338	14,608	15,574	16,398	
WNW	81,723	84,812	94,121	101,651	104,863	116,949	127,713	
NW	135,141	143,084	163,184	180,490	187,780	215,936	242,202	
NNW	67,084	68,586	75,578	81,680	84,294	94,094	102,848	
Total	564,358	587,281	648,281	703,643	727,972	818,899	900,982	

TABLE 2.1.3-20 (SHEET 1 OF 2)

POPULATION BY ANNULAR RINGS
20- TO 50-MILE RADIUS TOTALS

Year	Ring	Population
1987	20-mile	99,973
	30-mile	171,145
	40-mile	127,787
	50-mile	165,453
	Total	564,358
1990	20-mile	103,310
	30-mile	176,782
	40-mile	133,540
	50-mile	173,649
	Total	587,281
2000	20-mile	113,145
	30-mile	193,077
	40-mile	148,285
	50-mile	193,774
	Total	648,281
2007	20-mile	121,693
	30-mile	207,351
	40-mile	161,846
	50-mile	212,753
	Total	703,643
2010	20-mile	125,351
	30-mile	213,474
	40-mile	167,938
	50-mile	221,209
	Total	727,972

7

TABLE 2.1.3-20 (SHEET 2 OF 2)

Year	Ring	Population
2020	20-mile	138,973
	30-mile	236,258
	40-mile	190,862
	50-mile	252,806
	Total	818,899
2028	20-mile	150,609
	30-mile	256,430
	40-mile	211,891
	50-mile	282,052
	Total	900,982

7

TABLE 2.2.2-5 (SHEET 1 OF 2)

DESCRIPTION OF PRODUCT AND MATERIALS:
SAVANNAH RIVER PLANT
(FACILITIES WITHIN 5 MILES OF VEGP)

Products or Materials	Status	Annual Amounts	Maximum Quantity At Any Time	Mode of Transport	Frequency of Shipment	
400 Area						
Heavy Water Production and Recovery (includes rework, unit, drum cleaning facility, analytical laboratory, extraction plant, and distillation plant)						
Heavy water (D_2O)	Produced	76 tons	330 tons	Truck	3/week	
Tritium	Released	3900 Ci[a]	220,000 Ci	NA	NA	7
Sulfur dioxide (SO_2)	Released	85 tons[b]	NA	NA	NA	
Phosphoric acid	Used	1380 lb	460 lb	Truck	3/year	
Ammonia	Used present	1.5 tons	2.0 tons	Truck	2/year	
Silicone	Not used at present	-	-	-	-	
Trisodium phosphate	Used	5000 lb	1000 lb	Truck	5/year	
Potassium permangate	Used	220 lb	220 lb	Truck	1/year	
Steam and Electric Generating Plant (includes water treatment plant)						
Bituminous coal	Burned	240,000 tons[c]	75,000 tons	Rail	Daily	
Sulfur dioxide	Released (continuous boiler emissions)	9600 tons	-	-	-	
Chlorine	Used	15 tons	34 tons	Truck	Monthly	
Trisodium phosphate	Used	10 tons	2 1/2 tons	Truck	6/year	
Sulfuric acid	Used	175 tons	270 tons	Rail	3/year	
Caustic (NaOH)	Used	290 tons	340 tons	Rail	6/year	
Alum	Used	280 tons	100 tons	Truck	8/year	

TABLE 2.2.2-6 (SHEET 2 OF 10)

Hazardous Substance/ Applicable Facility	Toxicological Data
3. Coal, Bituminous (coal facings, sea coal) RTECS No. GF8300000 Applicable facility: SRF(HWP)	Chiefly amorphous elemental carbon with low percentages of hydrocarbons, complex organic compounds, and inorganic materials. (10-214) Toxic hazard depends upon content of crystalline silicon dioxide. (3-508) Coal dust--an amorphous carbon but sometimes contains hyrocarbons, organic complex salts, and inorganic compounds. Slightly toxic by inhalation. (4-133) ACGIH threshold limit value = 2 mg/m^3 exposure in air (1-441) OSHA exposure limit for respirable coal dust containing less than 5% crystalline silica dioxide = 2.4 mg/m^3; limit for dust containing more than 5% crystalline silica = 10 mg/m^3 (% crystalline silica dioxide + 2). (12-545)
4. Fuel Oil (distillate, gas oil, home heating oil No. 2) RTECS No. LS8950000 Applicable facility: BNFP, SRP(TNX-CMX)	A complex mixture of liquid petroleum hydrocarbon products with flash points above 100°F. (1-700) Several grades available. For example: Kerosene--moderate fire hazard. (3-760) Moderately toxic by inhalation and swallowing. (4-263) Toxic oral dose level for rabbit and rat is 20 g/kg. (2-3) Criteria document recommended standard for airborne exposure to refined petroleum solvents to be 100 mg/m^3 time weighted average. (2-3) May contain suspected carcinogens. (3-760)
5. Material Deleted	7

TABLE 2.2.2-6 (SHEET 3 OF 10)

Hazardous Substance/ Applicable Facility	Toxicological Data
6. Manganese Dioxide, MnO_2 (manganese oxide, manganese binoxide, manganese black, battery manganese, manganese perioxide) RTECS No. OPO35000 CAS No. 1313-13-9 Applicable facility: SRP, SRP(HWP)	Black crystals or powder; soluble in hydrochloric acid; insoluble in water. Oxidizing agent; may ignite organic materials; moderately toxic. (10-535) Moderate fire hazard by chemical reaction; a powerful oxidizer. Must not be rubbed in contact with easily oxidizable matter. Keep away from heat and flammable materials. (3-787) Lowest lethal dose by intravenous route to rabbits = 45 mg/kg. No OSHA, ACGIH, or NIOSH limits listed. Reported in EPA TSCA inventory (July 1979). (2-28) MnO_2 injected intratracheally into rats, in an attempt to stimulate manganese pneumonitis seen in man, produced characteristic histological changes in the lungs. Inhalation exposures of rabbits to MnO_2 dust 4 h daily for from 3 to 6 months at levels of 10 to 20 mg/m³ resulted in decreased hemoglobin and erthrocytes in the blood; Mn pneumonitis did not occur, but fibrotic changes in the lungs resembling those in silicosis were observed. A ceiling exposure limit of 5 mg/m³ is listed for Mn dust and compounds as Mn. (8-250) OSHA standard for manganese = 5 mg/m³ as a ceiling for exposure. (12-542) 3
7. Mercury, Hg (quicksilver) RTECS No. OV4550000 CAS No. 7439-97-6 Applicable facility: SRP	Silvery, extremely heavy liquid. Extremely high surface tension. Insoluble in hydrochloric acid, water, alcohol, and ether; soluble in nitric acid and lipids. High electrical conductivity, noncombustible. Metallic Hg is highly toxic by skin absorption and inhalation of fume or vapor. Tolerance = 0.05 mg/m³ of air. Absorbed by respiratory and intestinal tract; accidental intake of small amounts is stated to be harmless (Merk Index). FDA permits zero addition to be 20

only three, which is less than the Regulatory Guide 1.78 allowable frequency of 30 per year.

Calculation shows that the probability of exceeding the Regulatory Guide 1.78 threshold limit in the control room is small, approaching zero.

C. Gasoline and Fuel Oil on the River

The probabilities of exceeding the Regulatory Guide 1.78 threshold limits in the control room due to a transportation accident on the Savannah River for fuel oil and gasoline are shown in table 2.2.3-16.

2.2.3.1.4.2 Potential Hazard from Major Depots or Storage Areas. The only major depots or storage areas within 5 miles of VEGP are those at the Savannah River Plant and the combustion turbine plant. The chemicals stored at the Savannah River Plant are provided in table 2.2.2-5, and the oils and solvents stored at the combustion turbine plant are provided in table 2.2.3-17.

The Savannah River Plant borders the Savannah River for approximately 17 miles opposite the VEGP site. (See subsection 2.2.2.) Due to the large distance from the chemicals stored at the Savannah River Plant to the control room intake there is no potential hazard to the control room habitability from these chemicals. The calculation shows the probability of exceeding the threshold limit in the control room due to an accident with chlorine is not significant (median value < 10^{-8}). 7

The combustion turbine plant is located approximately 5000 ft from the VEGP power block. The chemicals stored there with the exception of the fuel oil No. 2 are stored in small quantities. Due to the large distance and small quantities of these chemicals, there is no potential hazard to the control room habitability from these substances.

Fuel oil No. 2 tanks for the combustion turbine plant are located east southeast of the power block, approximately 5000 ft. The full capacity of these tanks is 9,000,000 gal. These tanks are surrounded by a dike which would prevent the fuel oil from spreading into a large spill area. The calculation shows that the probability of exceeding the threshold limit in the control room does not exceed 10^{-7}.

2.2.3.1.4.3 Potential Hazard from Onsite Storage Tanks. The storage facilities on the VEGP site are listed in table

2.2.3-18 and are shown in figure 6.4.2-2. The table lists the chemicals, quantities, and their distances from storage to the air intake of the control room.

Several of the chemicals listed in table 2.2.3-18 are excluded from further consideration due to their properties. Those chemicals excluded are:

A. Sodium hydroxide because it is nonvolatile and relatively nontoxic.[12][13]

B. Oxygen because it does not present a potential hazard for control room habitability.

C. Catalyst (benzoyl peroxide) because the melting point is 108°C; so under ambient conditions it is in the solid state.[12][13]

D. Dispersant (NALCO 7319) because vapor of this liquid is nontoxic.

E. Electrohydraulic control fluid (phosphate esters) because no harmful vapors evolve from this chemical under normal operating temperatures.

F. Liquids stored below ground level because significant spills cannot occur.

For the remaining chemicals the releases are postulated to occur during stable weather conditions. The probability of exceeding the toxic limit in the control room is calculated using the following equation:

$$P = f \sum_{a} P_f \, (a) \, P_a \, (C_{cr} > C_{tl}) \, f(a) \, \Delta a$$

where:

f = probability of a chemical release from a storage tank per year.

a = dispersion coefficient depending on Pasquill's categories and determining the dispersion, σy, along the horizontal axis, y, perpendicular to the direction of the plume propagation.

$P_f(a)$ = probability that the toxic chemical plume covers the intake of the control room, given a.

$P_a(C_{cr} \geq C_{tl})$ = probability that the C_{cr} in the control

B. The worst meteorological conditions: Pasquill's stability category G (minimum dispersion coefficient) and minimum windspeed.

C. Duration of 5-acre forest fire is 1.5 to 2 h.[27]

D. The distance from the control room to the nearest forest is 7500 ft.

This conservative model results in a control room concentration of carbon monoxide of less than 200 mg/m^3. This is less than the toxicity limit of 400 mg/m^3. Therefore, offsite forest fires are not considered a credible hazard to control room personnel.

2.2.3.1.5.4 <u>Fire Due to an Accident at Industrial Storage Facilities</u>. There are two major storage facilities in the vicinity of the plant: 7

A. A chlorine storage facility at the Savannah River Plant. The total mass of chlorine is 34 tons. The distance to the plant is about 3 miles. 3 7

B. No. 2 fuel oil storage tanks at Plant Wilson. There are three tanks with a total capacity of 9 million gal. The distance to the plant is 1500 m.

Chlorine is not a flammable gas and therefore is not a fire hazard. 7

The potential fire hazard from the Plant Wilson storage tanks is evaluated below.

Two primary hazards could exist from a large fire[28] at the Plant Wilson storage tanks:

A. A dangerous thermal environment or heat load on the control room structure.

B. A potentially lethal concentration of toxic gases in the intake of the control room.

A comparison with actual fire data[28] shows that an insignificant temperature rise will occur near the control room structure from a fire at a distance of 1500 m. Therefore, a fire at the Plant Wilson facility will not create a thermal environment affecting the control room structure.

The potential for a dangerous concentration of toxic gases that could reach the control room may be created by two types of fire, a fireball or a pool fire.[28][29] A fireball or vapor cloud fire arises if two conditions exist, i.e., the concentration of the fuel-air mixture is within inflammability limits and an ignition source exists in this cloud area.[10] The inflammability limit of a fuel-air mixture is between 1 and 7 percent volume concentration.[11]

Calculations show that for the worst meteorological conditions (Pasquill's stability category G, minimum windspeed, and maximum pool area) the volume concentration of fuel oil-air mixture reaches only 0.05 percent, which is lower than the lower inflammability limit. Therefore, a fireball could not develop and is not considered a potential hazard to control room habitability.

Two types of pool fire could exist, i.e., a partial pool fire (fire occurs just as the fuel starts to run out) or a complete 3
pool fire (ignition occurs after a spill covers a large area). This evaluation considers only the complete pool fire because it is more severe and covers a larger burn area.

The following equation is used to calculate the probability of exceeding the toxicity limits in the control room as a result of a pool fire:

$$P = f \sum_{a} P_f(a)\, P_a\, (C_{cr} > C_{tl})\, f(a)\, \Delta a$$

where:

f	=	the probability of a chemical release from a storage tank and fire per year.
a	=	the dispersion coefficient depending on Pasquill's categories determining the dispersion, σ_y along the horizontal axis y, perpendicular to the direction of plume propagation.
$P_f(a)$	=	the probability that the toxic chemical plume covers the intake of the control room, given a.

TABLE 2.3.2-1 (SHEET 1 OF 6)

NORMALS, MEANS, AND EXTREMES FOR AUGUSTA, GEORGIA

	Temperatures (°F)							Normal Degree Days Base 65°F	
	Normal			Extremes					
Month	Daily Max.	Daily Min.	Monthly	Record Highest	Year	Record Lowest	Year	Heating	Cooling
(a)				31		31			
Jan	57.6	34.0	45.8	80	1975	5	1970	601	6
Feb	60.5	36.1	48.3	86	1962	9	1973	475	8
Mar	67.1	42.0	54.6	88	1974	12	1980	346	23
Apr	90.7	76.9	63.8	93	1980	30	1972	90	54
May	89.1	74.2	71.7	99	1964	35	1971	10	218
Jun	87.0	66.7	78.2	105	1952	47	1972	0	396
Jul	90.9	69.9	80.4	107	1980	59	1951	0	477
Aug	90.2	69.8	79.0	104	1968	54	1968	0	453
Sep	89.2	63.2	74.2	101	1957	36	1967	0	279
Oct	77.0	51.2	64.1	97	1954	22	1952	104	76
Nov	67.1	40.2	53.7	90	1961	15	1970	344	5
Dec	68.7	34.1	46.4	82	1967	5	1981	577	0
Year	75.4	51.4	63.4	107	Jul 1980	5	Dec 1981	2547	1995

TABLE 2.4.12-7 (SHEET 1 OF 3)

WATER LEVEL MEASUREMENTS AT OBSERVATION WELLS
(PRIOR TO CONSTRUCTION POSTPONEMENT OF 1974)

Highest/Lowest Elevation of Ground Water for Year Shown (ft above msl)

Well No.	Surface Elevation	1971 High	1971 Low	1972 High	1972 Low	1973 High	1973 Low	1974 High	1974 Low	Notes
Observation Wells in Water Table Aquifer										
42D	209.7	160	154	159	156	161	160	158	157	
124	260.3	162	161	163	162	170	167	169	163	
129	215.3	155	153	157	154	163	157	160	144	
140	222.4	161	159	161	160	168	165	165	162	
141	230.4	155	154	156	154					
142	224.5	153	152	153	152	160	136	158	144	
143	224.5	155	153	155	143	163	161	160	150	
145	218.7					161	147	155	151	
176	196.4	160	159	161	160	167	165	164	162	
177	213.0	161	161	163	160	170	167	165	162	
178	240.4	159	157	160	157	163	160	159	157	
179	275.9	166	154	171	166	174	170	169	165	
243	213.0			151	146	148	147	147	146	Completed in 1972
244	212.6			165	161	160	130	158	156	Completed in 1972
245	207.6			156	155	163	162	161	159	Completed in 1972
247	211.3			162	159					Completed in 1972
248	166.8			162	161					Completed in 1972
249	192.8			160	159	164	162	162	157	Completed in 1972
Observation Wells in Artesian Aquifer										
24	216.0	122	116	120	116	123	116	122	117	
26	203.8	135	100	107	103	107	102	106	104	
27	210.0	94	79	90	81	98	82	88	79	
29	193.4	107	89	102	97	102	96	99	93	
31	211.0	110	101	112	107	121	107	111	105	
32	214.0	107	102	109	105	111	102	106	100	
34	86.0			102	101					Artesian flow except in 1972
42A	210.5	204	82	102	99	111	107	110	105	1971 high/low not considered valid
101A	210.8	119	117	120	117	121	116	118	113	
121	88.0									Artesian flow
135	200.5	118	104	109	106	110	104			Artesian flow
144	103.2					103	[illegible]	90	83	1971 and 1972 data not available
147	226.2	118	115	118	116	185	[illegible]	119	116	High reading in 1973 not considered valid
246	210.4			118	116	116	[illegible]	113	111	Completed in 1972
Observation Wells in Marl Aquiclude										
42B	210.4	187	118	126	118	139	139			
42C	210.0	152	150	156	152	150	150			

7

7

TABLE 2.4.12-7 (SHEET 3 OF 3)

Well No.	Surface Elevation	Total Depth	Screened Interval From	Screened Interval To	Active	Quarterly Ground Water Levels (ft msl) 1979 2nd	1979 3rd	1979 4th	1980 1st	1980 2nd	1980 3rd	1980 4th
Observation Wells in the Confined Aquifer												
26	203.8	200.0	190.0	200.0	Yes	102.4	103.5	102.9	135.8	102.7	101.4	101.4
27	209.0	190.0	180.0	190.0	Yes	81.6	82.2	(c)	(c)	82.6	82.3	81.1
29	193.4	210.0	200.0	210.0	Yes	(c)	97.3	96.6	104.0	96.9	94.9	95.4
31	216.8	210.0	200.0	210.0	No(d)	107.0	107.9	106.5	111.3	107.1	105.1	105.2
32	217.4	210.0	200.0	210.0	Yes	107.0	106.5	106.5	109.7	107.1	103.8	104.1
33	238.6	220.0	210.0	220.0	Yes	96.0	Dry	96.6	93.1	Dry	(c)	(c)
34	90.5	100.0	90.0	100.0	No(g)	-	-	-	-	-	-	-
246	213.5	230.0	220.0	230.0	Yes	113.5	113.8	112.7	117.2	113.5	111.1	111.3

a. Elevations on sheet 1 of this table are top of PVC riser as surveyed prior to installation of construction bench marks; elevations on sheets 2 and 3 are top of PVC riser as surveyed in 1984 from construction bench marks.

b. Readings are anomolous and not considered reliable; well is considered reparable and will be retained in the ground water monitoring program.

c. No readings taken this period.

d. Has been or is scheduled to be sealed and abandoned due to proximity to ongoing construction.

e. Construction of wells completed December 1979 through January 1980.

f. All currently active wells are intended to be permanently retained for the ground water monitoring program. Some additions/deletions may be required due to construction activities.

g. Well 34 is a flowing well located in the flood plain of the river.

h. Wells were inspected in 1981 and found to be nonfunctional and irreparable. All readings since 1979 are considered unreliable. Well has been sealed and deleted from the ground water monitoring program.

2.4.13 ACCIDENTAL RELEASES OF LIQUID EFFLUENTS IN GROUND AND SURFACE WATER

2.4.13.1 Consideration of Accidental Spill of Radioactive Material in Ground Water

Any fluid containing radioactive nuclides infiltrating the ground at the plant site would first move downward through the unsaturated zone to the water table. After reaching the water table, it would move laterally and discharge to the springs or seeps on the flanks of the adjacent streams and eventually reach the Savannah River. The marl aquiclude will prevent further downward movement toward the confined aquifer. The 7
shortest path to a stream channel flanking the site is toward Mathes Pond, a distance of 2500 ft. The time required for ground water to migrate along this flow path is determined by the permeability and porosity of the materials and the gradient of the water table. Both laboratory and field tests have been performed to determine the permeability of the materials. The hydraulic gradient may be determined from the ground water contours shown in figure 2.4.12-7. The porosity of the sands is estimated to be 45 percent.

Seepage velocity, then, may be determined by the following relationship:

$$v = \frac{ki}{n}$$

where:

v = seepage velocity (ft/year).

k = coefficient of permeability (ft/year). 7

i = hydraulic gradient (dimensionless).

n = porosity (dimensionless).

Over the first 1000 ft of the flow path, the hydraulic gradient is 4.5×10^{-3}. It becomes steeper (10^{-2}) beyond that point, implying a lower permeability. From the range of permeability determinations (10 to 20,000 ft/year from laboratory measurements and 200 to 250 ft/year from field measurements), conservative values of 8000 ft/year for the first 1000 ft of 7
flow path and 200 ft/year beyond the first 1000 ft are assigned.

Using these values, the seepage velocities are determined to be 80 ft/year over the initial 1000 ft of flow path and 4.5 ft/year over the balance. Total time to reach Mathes Pond would be 350 years. This indicates that considerable time would elapse before any radioactive material carried by the water might reach Mathes Pond and before consequently 7 appreciable decay of radioactivity would have occurred.

In addition, any radioactive fluids migrating through these materials would be further dispersed by adsorption on clay particles and by ion exchange effects. The ability to attract radionuclides is measured by the distribution coefficient. Measurements of the coefficient of similar materials at the Savannah River Plant project area indicate this capability is relatively low, but, conservatively, delay in migration of radionuclides would reduce the concentration by at least a factor of 100.

2.4.13.2 Dispersion, Dilution, and Travel Times of Accidental Releases of Liquid Effluents in Surface Waters

The only potentially radioactive tanks above grade are the refueling water storage tank, the reactor makeup water storage tank, and the condensate storage tanks. These tanks are designed and constructed to meet Seismic Category 1 requirements. Each tank has an approximately 2-ft-thick wall and 21-in.-thick roofs constructed of reinforced concrete. The tanks are lined with stainless steel liner plates. High level 7 alarms are provided in the control room to alert the operator of a potential overflow condition. The tanks are surrounded by trenches to collect potential overflow. Provisions are made for sampling water collected in the trenches, and temporary connections are utilized to transfer potentially contaminated water to the liquid radwaste system. Thus no liquid effluent will be released to surface water from these tanks.

An analysis of a radioactive release due to a failure of the most critical radwaste storage tank is provided in subsection 5 15.7.3.

The only direct discharge of radioactive liquids to surface water is from the waste monitor tanks, as discussed in subsection 11.2.3. The release point is shown in figure 2.4.13-1. Normally, the discharge from the liquid waste processing system is combined with blowdown from the circulating water cooling system, the nuclear service cooling water system, 7 and the steam generators as well as other station liquid wastes. If this flow is not sufficient to meet 10 CFR 20 limitations, additional river water is added to the discharge line to further dilute the radioactive wastes. Dilution factors are discussed in paragraph 11.2.3.4. An inadvertent release via the waste processing system or the steam generator blowdown system is prevented by interlocks between radiation monitors RE-018 and RE-021 (section 11.5) and associated downstream, air-operated valves. If the radioactivity in the streams exceeds a predetermined setpoint, then the streams are automatically isolated. In addition, locked closed valves in the waste stream ensure that administrative control of radioactive discharges is maintained.

Should an inadvertent discharge from the waste processing system occur, the release of one entire tank volume results in a release less than the normal annual releases discussed in subsection 11.2.3 and is within the limits of 10 CFR 20, table II, column 2, averaged over a period of 1 year.

Discharge from the stream generator blowdown system (subsection 10.4.8) initially flows to the waste water retention basin. From there, it is pumped to the blowdown sump where it is combined with circulating water dilution flow and other blowdown flows before being discharged to the river. Upstream of the waste water retention basin, the steam generator blowdown is monitored for radioactivity by radiation monitor RE-021. If the monitor detects radioactivity exceeding a predetermined setpoint, the discharges to the waste water retention basis are automatically terminated.

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2.5.1-12. The 5-mile-radius map shows the location of the known and inferred contacts between surface materials at the site. A detailed geologic map of the power block area, figure 2.5.1-23, was prepared from data obtained during the geologic mapping program conducted concurrent with excavation and grading. The geologic map of the power block area and geologic data concerning the area are discussed in paragraphs 2.5.1.2.2 and 2.5.1.2.3. Geologic sections through the power block excavations are shown in figures 2.5.1-24, 2.5.1-26, and 2.5.1-27. The regional geologic map is shown in figures 2.5.1-8 and 2.5.1-9. 7

2.5.1.2.6 Plot Plan

Information concerning the locations of major structures of the plant, including all Seismic Category 1 structures, and exploration and test borings made at the site area is presented in figures 2.5.1-10, 2.5.1-11, and 2.5.1-13. These figures are discussed in subsection 2.5.4. The geologic logs of the borings are discussed in appendix 2B.

2.5.1.2.7 Subsurface Profiles and Plant Foundations

Subsurface profiles showing lithologic correlations from drill hole data are given in figures 2.5.1-14 and 2.5.1-17. Geologic profiles and geologic sections prepared from data obtained during the geologic mapping of the foundation excavations are presented in figures 2.5.1-24 (sheets 1 through 6), 2.5.1-26, and 2.5.1-27. They are discussed in paragraphs 2.5.1.2, 2.5.1.3, and 2.5.4.5. The site ground water conditions are discussed in detail in subsection 2.4.12 and summarized in paragraph 2.5.1.2.8.7. The significant engineering characteristics of the subsurface materials are discussed in subsection 2.5.4. All Seismic Category 1 structures are founded on the Blue Bluff marl or upon compacted structural backfill placed upon the marl. The Blue Bluff marl is a gray-green, hard, sandy to silty, calcareous clay marl with thin limestone lenses, small calcareous nodules, and occasional macrofossils.

2.5.1.2.8 Engineering Geology Evaluation

2.5.1.2.8.1 <u>Engineering Properties of Foundation Materials.</u> The strength of foundation materials, static and dynamic properties, bearing capacities and settlement, rebound and heave, and foundation design criteria are discussed in subsection 2.5.4.

2.5.1.2.8.2 Prior Earthquake Effects. There is no evidence to suggest that surficial or subsurface materials have been affected by prior earthquake activity. No evidence of texture faults were found from any of the site exploration borings or in any of the excavations.

2.5.1.2.8.3 Deformational Zones. Examination of outcrops, excavation exposures, and subsurface samples have revealed that there are no deformational zones within the Blue Bluff marl, which is the foundation material for the major plant structures. Approximately 1000 ft northwest of the major structures, there is, however, a dip reversal of about 3° to the northwest. This gentle dip reversal in the otherwise very gently southeasterly dipping (approximately 30 ft/mi southeasterly) homocline of Tertiary sediments is of depositional origin and does not represent a structural (tectonic) deformation. Paragraph 2.5.1.2.3 contains a discussion of this anomaly.

During the construction phase at VEGP, a comprehensive inspection program was carried out to continuously monitor and assess the condition and character of all excavated marl throughout the power block area. A total of four joints was found in the uppermost strata of the marl. Two were found during routine inspection of the exposed marl surface prior to backfilling, and two were found during inspection of the radwaste solidification building caisson foundation. Each joint 7
was independently investigated and found to be of limited depth and areal extent and of nontectonic origin. Evidence produced by the investigations suggests that the joints were formed either during or immediately following late-stage diagenesis of the marl. Depositional loading from overlying sediments may have been a contributing factor. There is no evidence to suggest that these features are related to any processes that have occurred within recent geologic time.

With the exception of the joints described above, no other fractures, partings, or anomalous features were found in the marl.

2.5.1.2.8.4 Zones of Alternation or Weakness. The Blue Bluff marl is basically unweathered and unaltered, except for the uppermost section, which is up to 5 ft thick and slightly discolored by weathering from gray-green to green. This weathered zone was completely removed in foundation preparation.

2.5.1.2.8.5 Bedrock Stress. Approximately 950 ft of unlithified to poorly lithified sediments overlie the pre-Cretaceous basement rock at the site. Rebound of the Blue Bluff marl, the bearing stratum, is being monitored by in situ instruments at or in the power block excavation. A total of nine heave points were installed between el 104 and 126 ft at the locations shown in figure 2.5.1-38. From 1974 to 1977, 7
rebound ranged from less than 1 to 1.6 in., substantially less than predicted. A discussion of heave is contained in paragraph 2.5.4.10.

2.5.1.2.8.6 Effects of Man's Activity. There are no mining or underground mineral extraction activities occurring on or near the site. Ground water extraction is nominal in this area of low population. Therefore, there are no human activities which will affect site geologic conditions.

2.5.1.2.8.7 Site Ground Water. The principal water-bearing zone in the site vicinity is composed of the Paleocene Ellenton Formation and the Cretaceous Tuscaloosa Formation, which together make up a highly productive artesian aquifer system. This aquifer is widespread throughout the southeastern United States and is variously referred to as the Tuscaloosa aquifer, the Cretaceous aquifer, and the principal artesian aquifer. It is overlain and confined by the Blue Bluff marl member of the Eocene Lisbon Formation. The permeability of the marl layer is very low; hence, it is classified in this report as an aquiclude.

Other less prominent water table aquifers are present throughout the area in the younger sediments overlying the aquiclude. The Eocene Lisbon Formation and Barnwell Group produce ground water in quantities sufficient for local domestic and industrial use; the Miocene Hawthorne Formation and the Quaternary alluvial and terrace deposits produce quantities suitable only for domestic use. The VEGP is founded in the Lisbon Formation. A detailed discussion of site ground water conditions is contained in subsection 2.4.12.

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2.5.2 VIBRATORY GROUND MOTION

2.5.2.1 Seismicity

All significant historically reported earthquakes, that is, all earthquakes that could have reasonably affected the site region, are considered in this section. The site region as used here is the area bounded by latitudes 30° to 36.5°N and longitudes 78° to 85.5°W. This region encompasses the area within 200 miles of the site. Within this site region all earthquakes of Modified Mercalli intensity greater than IV or Richter magnitude greater than 3.0 are considered. Earthquakes that occurred outside the site region but that were probably felt at the site are also treated. 7

All significant site region earthquakes are shown in figure 2.5.2-1 and listed in table 2.5.2-1. These earthquakes are characterized in figure 2.5.2-1 either by a Roman numeral designating their Modified Mercalli intensity or by an Arabic numeral designating magnitude in the few instances where no intensity estimates are available. Both intensity and magnitude, where available for an earthquake, are given in table 2.5.2-1.

Most of what is known about site region seismicity is based on intensity data. These data are not derived from measurements made by instruments but are only chronicles of the sensible effects of earthquakes on people, structures, and landforms. The intensity scale used throughout this section is the Modified Mercalli Scale of 1931.[1] An abridged version of this scale appears in table 2.5.2-2.

The magnitude of an earthquake depends for its definition upon the amplitude of motion on a standard instrument normalized to take into account the separation of the earthquake location from the instrumental recording site. In the site region several magnitude scales are commonly employed, which are not exactly equivalent. For the purposes of this study these differences are not critically important and, having been acknowledged, are not discussed further. The magnitudes shown for the two events in figure 2.5.2-1 and tabulated for a number of earthquakes in table 2.5.2-1 are undifferentiated but may be thought of as roughly the same as Richter scale local magnitudes, M_L.[2]

The locations of site region earthquakes are given to an accuracy of 1/10° in table 2.5.2-1. This choice implies an uncertainty in epicentral position on the order of 10 km or so. This is estimated to be a fair representation of the uncertainty in earthquake locations for site region events

averaged over the chronological range of their occurrence. Roundoff at the 1/10° level is used in several of the more important sources,[3][4] from which the information in table 2.5.2-1 and figure 2.5.2-1 is compiled, so that it is convenient and logical to follow this convention. However, it must be remembered that the implied 10-km (6-mile) uncertainty is only an average estimate. The epicenters of many of the earlier site region earthquakes are only points on a map placed as near as possible to the center of the area suffering the greatest effects from that event. For some of these events the 7
actual uncertainties in location are realistically measured in several times the 10-km average (6-mile). In contrast, instrumental seismology has undergone significant and rapid growth in the site region over the past decade, so that for some very recent events the 10-km (6-mile) uncertainty is exaggerated.

Distances between each site region epicenter and the site are tabulated in table 2.5.2-1. In view of the uncertainties in earthquake location noted above, these distances are given only to the nearest 5 miles. 3

Finally, table 2.5.2-1 lists the estimated intensity near the site from each site region earthquake. These estimates are based on available felt-report data from several standard sources[3][5] supplemented by a number of specialized references.[6-12] Intensity VI, in association with the August 31, 1886, Charleston, South Carolina, earthquake, is the highest intensity experienced at the site due to these site region events. The earthquake closest to the site was the November 1, 1875, event about 60 miles northwest. This earthquake had a maximum intensity of VI near its epicenter and was felt from Spartanburg and Columbia, South Carolina, to Atlanta and Macon, Georgia, an area of about 200 by 150 miles. This felt-area geometry suggests that it may have been felt at the site with low intensity although no reports are available in the immediate site vicinity.

The earthquake of epicentral intensity greater than or equal to VII occurring nearest the site, exclusive of those earthquakes in the Charleston-Summerville, South Carolina, area, was the Union County, South Carolina, event of January 1, 1913. A recent evaluation of the felt reports from this earthquake[8] indicates an epicentral intensity of VII-VIII and a felt area that does not include the site. Therefore, for this study it is concluded that this earthquake, occurring about 110 miles north, was not felt at the site.

Several other site region earthquakes are estimated to have been felt with intensity less than or equal to IV at the site. These events, which include some aftershocks of the

2.5.2.2 Geologic Structures and Tectonic Activity

The site is located in the Atlantic Coastal Plain province at a point about 25 miles southeast of the boundary between this and the Piedmont province. Within 200 miles of the site are also the Blue Ridge province to the northwest of the Piedmont province and a small section of the Valley and Ridge province northwest of the Blue Ridge province. These physiographic provinces and the site location are shown in figure 2.5.1-1.

Physiographic and geologic descriptions of these provinces may be found in paragraph 2.5.1.1.1. Regional geologic history is discussed in paragraph 2.5.1.1.2. This history consists of important episodes of Paleozoic orogeny, more modest tensional tectonism in the early Mesozoic resulting in Triassic basins and subsequent diabasic intrusions, and essential quiescence since the deposition of the Cretaceous sediments in the coastal plain. Some regional epeirogenic upwarping and arching during the late Eocene ended before Miocene deposition about 25,000,000 years ago.

The Pleistocene and recent history of the site region is largely represented by erosion of the southern Appalachian provinces and flood plain deposition and valley fill associated predominantly with the rivers and larger streams in the Atlantic Coastal Plain province.

In addition to the larger scale regional physiographic provinces and small scale Triassic basins, the Belair fault has been noted in recent studies as a geologic structure of possible interest for evaluations of vibratory ground motion. This fault zone is discussed in paragraph 2.5.1.1.4.1. The most recent investigation of this fault zone[16] concludes that the last episode of movement occurred sometime within the last 60,000,000 years but prior to 23,000 to 2000 years ago. No intermediate age strata have been found that would provide a more definitive date of the last movement of the fault.

2.5.2.3 Correlation of Earthquake Activity with Geologic Structures or Tectonic Provinces

With the exception of the Charleston-Summerville area, seismicity of the site region is generally diffuse. There have been no definite correlations between earthquake epicenters and geologic structures. Except for the Belair fault zone, all faults within 200 miles of the VEGP site are demonstrably not capable, having last moved in the early Mesozoic or even earlier. The evidence on the Belair fault zone is inconclusive as discussed in paragraphs 2.5.1.1.4.1 and 2.5.2.2. However, although lack of movement in the last 35,000 years has not been absolutely demonstrated, there is no correlation of any macroseismicity with this fault, and the general tectonic quiescence of the region argues against its likely significance. In a recent consideration,[17] it was concluded that the Belair fault zone is not a capable fault within the meaning of Appendix A to 10 CFR 100, section 3(g). This convention is followed in this study. 7

During the months of March through August 1982, further studies were made to determine the existence and capability of the postulated Millett Fault introduced in an open-file United States Geological Survey report.[18] No evidence was found in support of the existence of any fault in the region designated by the report. Details of the study can be found in a report entitled Studies of Postulated Millett Fault.[19]

Thus, for the purpose of vibratory ground motion at the VEGP site, historic earthquake activity is most logically correlated with tectonic provinces. Within 200 miles of the site, four distinct tectonic provinces are traditionally recognized. These are the Valley and Ridge, Blue Ridge, and Piedmont provinces of the Southern Appalachian Mountains and the Atlantic Coastal Plain province. The boundaries of these provinces in the site region are shown on figure 2.5.1-8. 7

In this report, the southern Appalachian Mountains provinces are treated as a single region. This usage is for convenience only and is not intended to imply that the distinct Valley and Ridge, Blue Ridge, and Piedmont tectonic provinces, in general, should be considered as a single unit. However, such a usage is adequate within the narrow context of the assumptions employed to determine design vibratory ground motion at VEGP. This point is discussed in paragraph 2.5.2.4. In this report, these three tectonic provinces are called, collectively, the Southern Appalachian Mountains Region.

The Southern Appalachian Mountains Region so defined is bounded on the east, southeast, and south by the fall line and the Atlantic Coastal Plain tectonic province. On the northwest, it is bounded by the Cumberland and Allegheny Plateaus. On the northeast, along structural trend, geologic and seismic discriminates are more tenuous. Here this boundary is chosen to include northern Pennsylvania, northern New Jersey, and southernmost New York State and to exclude the Appalachians north of this area. The outline of the Southern Appalachian Mountains Region in the site region is shown in figure 2.5.2-1. This area is a region of consistent northeast-southwest structural trends. As may be seen in figure 2.5.2-1, epicenters in this area are irregularly distributed, with concentrations in northeast Georgia, northwest South Carolina, and eastern Tennessee in the site region and in Virginia farther to the eration to intensity on a variety of foundations,[32][33] intensity VII-VIII is associated with approximately 0.2 g peak horizontal acceleration. This relationship is appropriate for sites near the zone of energy release or for sites where I_s is not much less than I_o. This is the case for the Atlantic Coastal Plain maximum credible event and approximately the case for the Southern Appalachian Mountains maximum credible event. This condition is not well realized for the Charleston-Summerville seismic zone maximum credible event. Since acceleration attenuates more rapidly than intensity, the use of the empirical relationships noted above is probably very conservative in this case. However, the larger Charleston earthquake is likely to be richer in low frequency ground motion at the site than the other design earthquakes. Thus, for conservatism a single design response spectrum is proposed to define site SSE ground motion. This ground motion is defined in terms of Regulatory Guide 1.60 horizontal and vertical design response spectra[34] normalized to a peak ground acceleration of 0.20 g. These spectra are shown in section 3.7. 7

2.5.2.7 Operating Basis Earthquake (OBE)

As discussed in paragraph 2.5.2.1, the most recent best evidence indicates that the maximum historical intensity at the site was VI, associated with the Charleston earthquake of 1886. A less finely detailed study of attenuation of intensity from that earthquake would indicate a somewhat higher intensity should be expected at the site. For additional conservatism an OBE intensity of VII is adopted. Using the intensity/acceleration relationships noted in paragraph 2.5.2.6, this intensity is associated with a peak horizontal ground surface acceleration on average foundation condition and near the zone of energy release of approximately 0.12 g. This acceleration, and spectra of identical form as those characterized in paragraph 2.5.2.6, are used to define the OBE ground motion at the site and are shown in section 3.7.

A probabilistic estimate of the occurrence of the OBE acceleration at the site during its 40-year operating life may be made based on the work of Algermissen and Perkins.[35] This study shows that the site acceleration with a 90-percent chance of nonexceedence in a 50-year interval is about 0.10 to 0.11 g. Assuming, as is implicit in this characterization, that earthquakes occur as a Poisson point process, this is equivalent to estimating an 8-percent chance of occurrence of a site acceleration exceeding 0.10 to 0.11 g during the 40-year operating life of the plant. The chance of exceeding the 0.12 g OBE is, therefore, somewhat less than this. 7

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2.5.3 SURFACE FAULTING

No evidence of surface faulting has been uncovered in the site area. Detailed stratigraphic study and mapping of the excavations for Category 1 structures are discussed in paragraph 2.5.1.2.2. Mappable lithologic units may be traced unbroken around the perimeter of the excavations, demonstrating the absence of faulting. The 5-mile-radius site investigation showed no evidence of surface displacement that might localize earthquakes in the immediate vicinity of the site. This region has been relatively stable for a considerable length of time, and known faults in the Piedmont province to the west and the Triassic basin underlying the site are inactive. The geology of this area is discussed fully in paragraph 2.5.1.2.

2.5.3.1 Geologic Conditions of the Site

The lithologic, stratigraphic, and structural geologic conditions of the site are presented in paragraphs 2.5.1.2.2 and 2.5.1.2.3. Regional, local, site, and site excavation geologic maps are shown in figures 2.5.1-8, 2.5.1-12, 2.5.1-13, and 2.5.1-23, respectively. The regional geology and geologic history are discussed in paragraph 2.5.1.1.

2.5.3.2 Evidence of Fault Offset

The area within 5 miles of the site is not associated with known or suspected faulting. Geologic sections throughout the site and power block area, which are based on data obtained from field mapping, exploration borings, and mapping of the foundation excavation, reveal no evidence for the existence of any fault offset at the site (figures 2.5.1-12, 2.5.1-13, and 2.5.1-23).

2.5.3.3 Earthquakes Associated with Capable Faults

There are no known capable faults within 5 miles of the site.

2.5.3.4 Investigations of Capable Faults

Field investigations for this project, including exploratory drilling, field mapping, studies of aerial photography, and geophysical studies, show that no capable faults exist within 5 miles of the site. Reversal of the regional dip northwest of the site has been investigated and shown to be related to depositional and erosional processes, as discussed in paragraph 2.5.1.2.3. Stratigraphic irregularities discovered during excavation for power block foundation have been studied and shown to be related to depositional and erosional processes, as discussed in paragraph 2.5.1.2.2.2.

2.5.3.5 Correlation of Epicenters with Capable Faults

See paragraph 2.5.3.3.

2.5.3.6 Description of Capable Faults

No capable faults are known to occur within 5 miles of the site.

2.5.3.7 Zone Requiring Detailed Faulting Investigation

In 1982, the U.S. Geological Survey released Open-File Report 82-156, which postulated the existence of two potentially capable faults within 32 miles of VEGP. According to the report, the Millett fault was located approximately 7 miles south of VEGP, while the Statesboro fault was located approximately 32 miles south of VEGP. The report did not assert that either of the faults were capable, but due to their proximity to the site, especially the Millett fault, a full-scale investigation was undertaken to determine exact location and date of last movement. 7

2.5.3.8 Results of Faulting Investigation

The investigation of the postulated Millett and Statesboro faults was completed with the conclusion that these faults did not exist within the depths to which the investigation extended and that, if they exist at some depth greater than the investigated depth, then they are not capable faults by virtue of the age of undisturbed overlying sediments. The investigative program is described completely in a separate report entitled, Studies of Postulated Millett Fault, prepared by Bechtel Power Corporation, dated October 1982.

2.5.4 STABILITY OF SUBSURFACE MATERIALS AND FOUNDATIONS

2.5.4.1 Geologic Features

There is no evidence that the Blue Bluff marl, which is the bearing stratum, has been subjected to or is potentially subject to subsidence, collapse or uplift due to earthquake, solution processes, or other geological phenomena (paragraph 2.5.1.2). Surface materials, comprised of strata which overlie the marl, have been subjected to and are potentially subject to subsidence due to solution processes (paragraph 2.5.1.2). These materials have been completely removed in the power block, and all Category 1 structures in the plant area are founded directly or indirectly on the marl (paragraphs 2.5.1.2.2 and 2.5.1.2.3.3).

The geologic history (paragraph 2.5.1.2.4) indicates that the
plant site is located upon an area of regional uplift and has
been subjected to subaerial erosion during Quaternary times.
The stratigraphic sequence and investigative work
(paragraph 2.5.1.2) indicate approximately 950 ft of
unlithified to poorly lithified sediments resting upon pre-
Cretaceous basement rock. Rebound in the marl, the 7
bearing stratum has been monitored and is discussed in
paragraph 2.5.4.10.

The surface of the shallow (unconfined) ground water table historically has been approximately el 160 ft. The marl, which is the bearing stratum, is essentially impermeable and is an effective aquiclude comprising the base of the ground water table and the cap of a confined aquifer. The hydrostatic surface elevation of the confined aquifer is approximately 115 ft.

There are no deformational zones, irregular weathering, jointing or fracturing systems, crushed zones, or other indications of structural weakness in the marl which is the bearing stratum (paragraphs 2.5.1.2.3 and 2.5.1.2.8).

There are no materials at the site that are hazardous or may become hazardous due to lack of induration or consolidation, variability, high water content, solubility, or undesirable response to natural or induced conditions.

2.5.4.2 Properties of Subsurface Materials

The subsurface conditions in the plant site may be subdivided into three principal strata. The top stratum consists of sands, silty sands, and clayey sands with occasional clay seams. This stratum, referred to hereinafter as the upper sand stratum (Barnwell Group), is about 90 ft thick. At the base of the upper sand stratum is a shelly limestone (Utley Limestone) which is about 5 ft thick on an average. Below the upper sand stratum is a stratum consisting of a very hard calcareous clay marl (Blue Bluff marl), ranging in thickness from 60 to 100 ft. This stratum is referred to as the marl bearing stratum. The 7 stratum beneath the marl bearing stratum consists principally of dense, coarse to fine sand with minor interbedded silty clay and clayey silt. This unit (Ellenton Formation) is called the lower sand stratum. The thickness of this stratum is estimated to be at least 750 ft.

Based on the results of the site exploration, it was determined that the upper sand stratum would have a potential for liquefaction in the event of a seismic occurrence equivalent to the safe shutdown earthquake (SSE).[1] It was also determined that the shelly limestone layer is characterized by solution channels, cracks, and discontinuities within it. Consequently, it was concluded that the upper sand stratum materials and the shelly limestone layer should be excavated down to the marl bearing stratum and replaced with select sand and silty sand backfill compacted to a sufficient degree to preclude the possibility of liquefaction and to reduce settlement to a 7 tolerable level. With the exception of the auxiliary building, nuclear service cooling water towers, and instrumentation cavity of the containment which are founded on the marl bearing stratum, all the power block structures including the containment basemat and the non-Category 1 turbine building are supported on Category 1 backfill. The location of these structures is shown in figure 1.2.2-1. Compacted fill and marl foundations are indicated in figure 2.5.4-1.

The static and dynamic engineering properties of the three principal soil strata and for compacted Category 1 backfill were determined by field investigation and laboratory testing. The results of all the field and laboratory work and data evaluation are covered in five separate reports.[1-5] A discussion and summary of the static and dynamic soil properties of the upper sand, marl, and lower sand strata 7 are presented in paragraphs 2.5.4.2.1, 2.5.4.2.2, and 2.5.4.2.3, respectively. The static and dynamic soil properties of compacted Category 1 backfill are summarized and discussed separately in paragraph 2.5.4.5.2.

2.5.4.2.1 Properties of Upper Sand Stratum (Barnwell Group)

The static engineering properties of the upper sand stratum are summarized in table 2.5.4-1. A range of values is given for most properties. The standard penetration test data indicate that the relative density of the upper sand stratum is extremely variable and ranges from very loose to dense. The consistency of the clay lenses in this stratum ranges from soft to medium. Unconsolidated undrained triaxial test results from samples in this stratum indicate that the Mohr strength envelope of total stresses may be defined by parameters ranging from about c=2100 lb/ft², $\phi=6°$ to c=440 lb/ft², $\phi=32°$ depending upon the predominance of clay or sand.

Similarly, consolidated undrained triaxial test results ranged from c=1650 lb/ft², $\phi=17°$ to c=4000 lb/ft², $\phi=25°$ for the Mohr strength envelope of total stresses and from $\phi=33°$ to $\phi=34.5°$ for the Mohr strength envelope of effective stresses. The design properties shown in table 2.5.4-2 were developed from the static engineering properties summarized in table 2.5.4-1.

The test data and the procedures used to obtain these data are included in reference 1 and its appendices.

A summary of the design dynamic shear modulus at strain levels of 10^{-4} percent or lower for the upper sand stratum is given in table 2.5.4-3. The basic properties of the upper sand stratum to be used in dynamic analyses are summarized in table 2.5.4-4.

Values of the dynamic shear modulus are computed from <u>in situ</u> shear wave velocity measurements as follows:

$$G = \frac{\gamma}{g}(V_s)^2$$ 7

where:

G = shear modulus (lb/ft²).

γ = unit weight (lb/ft³).

g = acceleration due to gravity (ft/s²).

V_s = shear wave velocity (ft/s).

2.5.4.2.2 Properties of Marl Bearing Stratum (Blue Bluff Marl) 7

The marl bearing stratum is a zone of hard, slightly sandy, cemented, calcareous clay. It is the uppermost stratum capable of supporting heavy structural loads. Consistency of the marl varies from hard to very hard, moderately brittle material resembling a calcareous siltstone or claystone. Seismic explorations indicate a velocity interface about 15 ft below the top of the stratum. The material below that level has a compressional wave velocity approaching 7000 ft/s as compared to about 5000 ft/s for the upper portion of the stratum. This is probably due to some degree of weathering of the upper 15 ft. The static engineering properties of the clay marl bearing stratum are summarized in table 2.5.4-1. Ranges of value are given for the most important properties.

The standard penetration test values range from 10 blows/ft in the weathered marl at the contact with the shell zone to well in excess of 100 blows/ft. The unconsolidated undrained shear strength based on one-point tests ranged from c=260 lb/ft² to c=500,000 lb/ft², with 10,000 lb/ft² being the value adopted for design. Samples that yield undrained strengths less than 10,000 lb/ft² exhibit large strains to failure which normally indicate sample disturbance in brittle materials of this type.

Laboratory tests indicate that the marl bearing stratum is highly preconsolidated. Atterberg limit tests indicate that the plasticity index is between 2 and 70 percent. Using an average of 25 percent this would yield a S_u/p ratio of about 0.2 based on work by Skempton,[4] where S_u is the undrained shear strength and p is the effective consolidation pressure at sample depth. This indicates that the preconsolidation pressure would be 80 k/ft² for the average undrained shear strength of 16.0 k/ft². The average undrained strength is taken to be the average of all samples which failed at strengths less than 50 k/ft². With such a high preconsolidation pressure it would be expected that settlements under structure loads would be small and would occur rapidly as load is applied. The design properties shown in table 2.5.4-2 were developed from the data summarized in table 2.5.4-1. 7

The basic test data and procedures used to obtain these data are contained in reference 1 and its appendixes.

The undrained shear strength of the marl bearing stratum was verified after completion of the power block excavations by testing representative cores. The results of these tests are included in reference 2. These test results verified that the recommended design strength parameter of c=10,000 lb/ft², ϕ=0° is appropriately conservative. Actually, the average undrained shear strength of all core samples that failed was approximately 20 k/ft² and the lowest measured value was 11.7 k/ft². Therefore, all samples tested exceeded the design strength of 10 k/ft². During the excavation the heave of the marl stratum was observed and recorded. Heave values were measured at nine different locations within the power block area. These data are included in reference 2. An average heave of approximately 1.25 in. was measured in the power block 7

2.5.4.3.2 Backfill

For a summary of backfill exploration refer to paragraph 2.5.4.5.2.2.

2.5.4.4 Geophysical Surveys

Geophysical seismic refraction and cross-hole surveys were conducted at the site to evaluate the occurrence and characteristics of subsurface materials. The seismic refraction survey was used to determine depths to seismic discontinuities, based on measured compressional wave velocities. Shallow and deep refraction profiles were obtained throughout the site area, totaling 28,400 and 5000 linear ft, respectively. The cross-hole seismic survey was conducted in the power block area to determine in situ velocity data for both compression and shear waves to a depth of 290 ft (82 ft below sea level) in bore holes 136, 146G, 148, 149, 151, and 154. In this procedure, three-dimensional detectors were lowered into four of the bore holes to equal elevation levels. Energy was generated in a fifth bore hole, at the same elevation level, to determine cross-hole velocities.

The locations of the seismic survey lines, the borings used for cross-hole velocity measurements, and the seismic profiles are shown in figure 2.5.4-2. Table 2.5.4-5 is the compilation of the results of the cross-hole measurements. The seismic velocity zones are summarized and related to other data in table 2.5.4-6. These data were used in determining the elastic moduli, compiled in table 2.5.4-7.

2.5.4.5 Excavation and Backfill

2.5.4.5.1 Excavation

The natural ground surface in the plant area varied between el 200 and 230 ft. The power block area was excavated and graded to an elevation of approximately 130 to 135 ft near the top of the marl bearing stratum which is the clayey marl of the Blue Bluff Member of the Lisbon Formation. In the following and previous discussions, this is called the marl or the clay marl bearing stratum. The excavation for the power block structures at the VEGP site is roughly square in shape; there are three access ramps, one each in the northwest, southeast, and southwest corners of the excavation. It measures approximately 1400 ft on an edge at the top and 1000 ft on an edge at the toe. The side slopes were cut at a gradient of two horizontal to one vertical. The total excavated volume in the power block was approximately 5,000,000 yd^3 including the access ramp. Figure 2.5.1-23 is a geologic map of the excavation as of 1977, before access roads were completed. 3

Within the excavation, a deeper localized excavation was made for the auxiliary building basement (figure 2.5.1-28). This consisted of a rectangular area measuring approximately 120 ft by 440 ft. The base of this excavation was at approximately el 108 ft, and the walls were cut vertically, with a horizontal bench at el 118 ft. The four nuclear service cooling water towers are founded directly on the marl just south of the auxiliary building. The other major power block structures are founded on structural backfill at elevations above the floor of the excavation.

Excavation work was started in May 1974 and postponed on September 12, 1974. The bottom elevation of the excavation averaged approximately 145 ft at this time and close to 900,000 yd^3 of excavation remained. The excavation work was resumed in February 1977 and the auxiliary building excavation was bottomed out in October 1977.

As excavation progressed, the exposed materials were geologically mapped (figure 2.5.1-23), including the deeper localized excavation for the auxiliary building (figures 2.5.1-24 and 2.5.1-25). A discussion of the mapping is presented in paragraph 2.5.4.5.1.2. 7

2.5.4.5.1.1 Excavation Procedures. Excavation work started and progressed very rapidly using scrapers and bulldozers in the upper sands (above the water table) which are at about el 160 ft. Very little, if any, ripping was required because of the sandy nature of the deposits; a maximum rate of 120,000 yd^3/day was attained at the peak of activity. Upon reaching the water table, construction dewatering was begun. The site ground water conditions are discussed in detail in subsection 2.4.12. The procedures utilized during excavation for construction dewatering are discussed in paragraph 2.4.12.1.3.1.

When the excavation reached the zones of hard shell-rich limestone described earlier (Utley Limestone), limited blasting of the rock was utilized to facilitate its removal. Since the shell-rich limestone was immediately above the marl, it was necessary to control any required blasting in such a manner as to protect the underlying marl (marl bearing stratum) from damage. The major portion of the rock was removed by first breaking it with a hydraulic ram mounted on a backhoe, then loading it out with conventional equipment. 7

Excavation of the marl was accomplished by ripping, followed by conventional earth moving. The auxiliary building basement excavation was ‿t with bulldozers and front-end loaders. Trimming of the walls was accomplished with a backhoe. Some of the hard, indurated limestone layers within the marl were first broken with the backhoe-mounted hydraulic ram, then removed by front-end loader. Fine grading of the floor of the power block was accomplished with motor graders in areas underlying future structural backfill and with Gradalls in the nuclear service cooling water tower foundation areas. In the foundation areas, shovels and air hoses were used for cleanup of loose material.

2.5.4.5.1.2 Geologic Mapping Procedures. The geologic mapping and recording of features exposed during excavation are described in the Bechtel Report of Geology and Foundation Conditions (appendix 2B.3). The mapping entailed these phases:

A. Detailed mapping of deposits above the marl; May 1974 to October 1974.

B. Detailed mapping of features within the marl and surveying of the upper contact of the marl; February 1977 to October 1977.

C. Detailed inspection and recording of areas in the marl approved for placement of concrete or backfill; June 1977 to January 1979.

The first phase of mapping was performed in conjunction with the excavation of the sediments above the marl. Features were located in the side slopes of the excavation as the bottom elevation was progressively lowered. The side slopes were cut at a gradient of two horizontal to one vertical, and survey stakes were installed on a grid pattern on the slopes. Locations of geologic features were measured by tape and hand-level methods using the slope stakes as reference points. Accuracy of these measurements is estimated to be within 0.5 ft. Mapping of the 2:1 slopes was recorded in plan on a base map compiled from the project excavation drawings and is shown in figure 2.5.1-23.

The second phase of mapping was accomplished as the marl was exposed and prepared for placement of concrete and backfill. To demonstrate the absence of faulting in the marl, the contact between the marl and the overlying sediments was mapped and recorded with survey accuracy around the perimeter of the excavation. Five hundred seventy-five survey points were established by the geologists along this contact and these points were located instrumentally. The nature of the contact between the points was examined closely for continuity and absence of breaks. The contact is shown in 7 plan view in figure 2.5.1-23, and the details of the survey results are shown in both plan and section in figures 2.5.1-26 and 2.5.1-27.

In addition to examining the upper contact, features within the marl were examined and recorded. The deep excavation for the auxiliary building basement, within the larger power block excavation, provided an excellent opportunity for this. The sides of the excavation exposed a vertical section of approximately 22 ft in height in the marl. A system of reference points was established on the walls of the excavation and stations were established for the purpose of describing locations of features. The stationing system adopted is shown in figure 2.5.1-28. The mapping was recorded in the vertical plane and is presented as geologic sections in figure 2.5.1-24. An explanation of geologic units used for mapping purposes is shown in figure 2.5.1-24 (sheet 7). By referring to figure 2.5.1-28, the location of any section can be easily ascertained. Measurements were made by tape and hand-level methods on the excavation walls. Accuracy is generally within 0.1 ft. 7

The third phase of geologic mapping consisted of detailed inspection and photography of foundation areas rather than mapping in a strict sense. This effort was initiated in June 1977 when the first portion of the auxiliary building basemat excavation (vertical surface) was cleaned off at final grade and prepared for application of a protective seal. Inspection and approval of final grade in the marl has been documented and transmitted from the inspecting Bechtel geologists to GPC. 7

2.5.4.5.1.3 <u>Construction Dewatering</u>. A discussion of construction dewatering is contained in paragraph 2.4.12.1.3.3.1.

2.5.4.5.1.4 <u>Slope Protection</u>. During the early stages of excavation, intense rainfall caused erosion of the 2:1 side slopes of the power block excavation. The uncemented sands above the marl were eroded, resulting in deeply incised gullies in some areas. These gullies were backfilled with the native soil material, and local areas of the slope were regraded. One such area is seen on the geologic map (figure 2.5.1-23) in the upper part of the east slope between stations N83+00 and N84+00. Another larger area exists in the south slope of the access ramp east of station E100+00. After regrading the eroded areas, berms were constructed around the tops of the slopes to control runoff. The surfaces of the slopes were sprayed with the chemical stabilizing agent 7

Petroset, a colorless liquid which sets up and tends to bond the sand grains together. These measures proved to be generally successful in controlling further erosion.

After resumption of excavation work in 1977, erosion problems further down the slopes were encountered due to seepage of the perched ground water out of the slopes. Since stabilizing agents were expected to be ineffective under these conditions, the lower portions of the slopes were blanketed with a transition zone and covered with riprap to improve stability.

At the base of the upper sand stratum where the 2:1 slopes intersected a limestone shell bed (Utley Limestone in figure 2.5.1-22), several cavities of varying size were exposed in the slopes. The largest of these existed in the northwest corner of the power block and had an opening measuring 10 ft by 10 ft. This cavity extended back into the slope some 30 ft before narrowing down to a small size. Other small cavities were encountered at varying intervals all along the north side of the power block excavation. It was necessary to fill these cavities so that an effective buttress would be formed against which the future structural backfill could be placed and compacted. The cavities were first cleaned of loose debris, then backfilled with crushed rock (Georgia State Standard No. 467). The crushed rock was packed into the cavities by means of a 20-ft-long ram attached to the blade of a bulldozer. 7
The large cavity in the northwest corner was effectively filled in this manner to at least a distance of 25 ft back of the entrance.

To retard erosion of temporary slopes in Category 1 backfill placed in the power block excavation, these slopes were sprayed with a commercial compound known by the trade name Glassroot. It consists of a glass fiber material which is sprayed onto the slope, then coated with a film of asphalt emulsion. Other measures which also proved to be effective in controlling erosion of the compacted sandy backfill included the use of gunite, plastic sheeting, and sand bags.

2.5.4.5.1.5 <u>Foundation Cleanup and Protection</u>. As mentioned previously, the Blue Bluff marl (marl bearing stratum) at 7
final grade in foundation areas was exposed using either a motor grader or Gradall. Loose material was then removed by shovel, broom, and air hose. On the vertical walls of the auxiliary building excavation, final trim to neat line was accomplished with a backhoe followed by pick and shovel and air hose techniques.

In all cases where final grade was exposed and cleaned off, the marl surface had to be covered in a manner approved by the geologist within 24 h of exposure. On horizontal surfaces the marl was covered either by structural backfill, a gunite protective layer, or a lean concrete mudmat depending on whether the particular area exposed was in a foundation or backfill area. The vertical walls of the auxiliary building basement excavation were coated with a 4-in.-thick layer of gunite reinforced with welded wire mesh.

In some cases, temporary covers such as loose soil or plastic sheeting were employed when the permanent cover material could not be applied within the 24-h limit. In all cases the temporary cover procedure was approved by either the geologist or the GPC inspector. Before placing the permanent cover material in any foundation area, the marl was inspected and approved by the geologist or soils engineer in accordance with prescribed procedures. 7

2.5.4.5.1.6 <u>Foundation Inspection and Approval Procedures</u>. All areas of marl (Blue Bluff marl) exposed and cleaned off in preparation for placement of concrete or backfill were examined closely for any evidence of loose or soft zones, geologic discontinuities, or unusual geologic features. After confirming the absence of such features, the inspecting geologist photographed and approved the excavated foundation area and documented the approval on a special form. The photographs and approval documents are part of the permanent project records.

2.5.4.5.1.7 <u>Foundation Testing</u>. During the general geologic mapping of the marl and other inspecting functions, a program of coring and testing samples of the marl was conducted to confirm the material properties used for design. The coring and sampling operation was performed under the direction of a Bechtel geologist and a GPC inspector, and the test assignments were made by the Bechtel foundation engineer.

A total of 38 core holes and offset replacement core holes were drilled by the rotary method in the floor of the power block excavation at 29 locations selected by the geologist. The hole locations are shown in figure 2.5.1-23. The marl was cored to depths between 4 and 11 ft beneath the final excavated grade. Selected samples of 4-in.-diameter core were labelled and placed in wooden boxes for permanent storage at the site. Samples selected for laboratory testing were wrapped in cellophane, sealed with wax, and placed in special boxes for transportation to the laboratories of LETCO in Atlanta. 7

The results of the testing program are discussed in paragraph 2.5.4.2.2.

2.5.4.5.2 Backfill

Compacted backfill is placed in the power block area from the top of the marl stratum at approximately el 130 ft to the design elevation for each structure. The plant grade elevation is at 219 ft 6 in. or below. The auxiliary building and nuclear service cooling water towers, containment instrumentation cavity, and radwaste solidification building are supported directly on the marl stratum. The other safety-related power block structures are supported on compacted backfill. The foundation elevations of these structures are given in table 3.7.B.1-2. The radwaste solidification building foundation consists of large diameter drilled caissons extending into the marl stratum. 7

With the exception of an area north of the turbine building and in localized areas around nonsafety-related buried piping above the water table, all backfill in the power block area is compacted to an average of 97 percent of the maximum density determined by American Society of Testing Materials (ASTM) D 1557, with no tests below 93 percent and not more than 10 percent of the tests between 95 and 93 percent. A procedure to achieve the required degree of compaction was developed in a test fill program. The results of the test fill program are discussed in paragraph 2.5.4.5.2.7 and presented in detail in reference 7. 4 7

The area north of the turbine building was compacted to an average of 95 percent of the maximum density determined by ASTM D 1557 with not more than 10 percent of tests between 93 and 95 percent and no test below 93 percent. The static stability and liquefaction analyses (paragraphs 2.5.4.8 and 2.5.4.10) were performed for the case where the power block backfill was assumed compacted to 97-percent relative compaction. A 95-percent relative compaction for the area north of the turbine building between el 185.5 to 219.5 ft has no effect on safety-related structures, since no Category 1 structures rely on this material for a load bearing foundation. The integrity of the turbine building design is not affected because the area does not project below the bottom of the building and does not provide foundation support for the turbine building. Since the area north of the turbine building is away from Category 1 structures and represents less than 10 percent of the total power block backfill, the factor of safety against liquefaction is not affected. 4 7 4

The localized area around nonsafety-related buried piping and similar conduits is compacted with concrete sand or other sands with similar properties to an average of 95 percent of maximum density determined by ASTM D 1557, with no tests below 93 percent and not more than 10 percent of the tests between 93 and 95 percent, unless compacted to an average of 97 percent using Category 1 backfill as defined below for safety-related piping. Typically, this localized area consists of backfill 3 ft above, 1 ft below, and a maximum of 5 ft on either side of nonsafety-related buried piping or similar conduits. Only a few percent of the total power block backfill utilizes this compaction criteria. All such areas are located above the water table so that the factor of safety against liquefaction is not affected. Sand compacted to an average of 95 percent in the limited areas around piping and similar conduits will not affect the structural integrity of any Category 1 structures. Sand compacted to an average of 95 percent will have static and dynamic properties consistent with those properties assumed for design of power block structures and piping. A static cone penetrometer reading of 200 is used to decide on the adequacy of concrete sand or other sands with similar properties between and below nonsafety-related piping in areas where constrained access prevents the use of the sand cone test. 4

Trenches containing safety-related piping or similar conduits are backfilled by placing lean concrete to the bottom of the pipe to provide continuous support and backfilling with Category 1 backfill, using wooden tampers, hand-held power tampers, or hand-held vibratory compactors as required. Use of these methods produces an average compaction of at least 97 percent of the maximum dry density determined in accordance with ASTM D 1557, with no tests below 93 percent and not more than 10 percent of the tests between 93 and 95 percent. Category 1 backfill material compacted between and immediately around pipes has a fines content below 10 percent. Static cone penetrometer readings developed from correlation with sand cone tests are used to decide on the adequacy of the compaction in areas where constrained access prevents the use of the sand cone test.

Lean concrete is used to backfill localized areas where placement of backfill material is impractical.

In addition, the total quantity of material available in stockpile A was estimated to be approximately 600,000 yd^3. Thus, a total quantity of 8,148,000 yd^3 of Category 1 backfill was identified from the aforementioned sources, which was considered more than sufficient for backfill requirements.

2.5.4.5.2.2 Exploration. Field exploration for borrow areas 1, 2, 3, 4, and 5 and stockpiles A and B was accomplished in early 1977. Subsurface exploration involved test pits excavated to a maximum depth of 25 ft by means of a backhoe. A total of 26, 8, 40, 12, and 3 test pits was excavated and logged in borrow areas 1, 2, 3, 4, and 5, respectively. Thirty-four test pits were excavated and logged in the two stockpiles. An appropriate number of jar and bulk samples were taken for laboratory testing.

Borrow area 1-A was investigated in the summer of 1978. Eighteen borings evenly spaced in a grid pattern covering the area were drilled and logged using a hollow stem auger. The borings extended to depths ranging from 13.5 to 66 ft below the existing grade and were terminated at depths below the water table ranging from 0 to 14 ft. Representative soil samples were obtained at 5-ft intervals and whenever a change in soil type occurred.

Investigations in borrow area 1-B were performed in June and July 1979. Sixty borings were drilled and logged during this investigation. Holes were advanced using both rotary drilling and auger drilling techniques. The depth of borings ranged from 40.5 to 81.5 ft below existing grade and were terminated upon reaching the water table. In most of the borings representative split-spoon soil samples were obtained at 5-ft intervals. In some borings sampling was done at 2 1/2-ft intervals. In addition, bulk samples were obtained.

Logs of all test pits and borings drilled in the borrow areas and stockpiles are contained in references 2, 3, and 4. Locations of all test pits and borings are shown in figure 2.5.4-3.

2.5.4.5.2.3 Laboratory Testing. In order to classify the soils in the borrow areas and stockpiles and obtain the static and dynamic engineering properties of compacted backfill, many laboratory tests were performed on samples obtained from the field explorations.

These tests are listed below:

- Laboratory classification of soils.
- Grain size distribution.
- Atterberg limits.
- Moisture content of soil.
- Specific gravity.
- Moisture-density relation.
- Relative density.
- Static consolidated drained triaxial compression.
- Static consolidated undrained triaxial compression.
- Consolidation.
- Stress-controlled consolidated undrained cyclic triaxial.
- Strain-controlled consolidated undrained cyclic triaxial compression.
- Resonant column.
- Triaxial tests to determine volume changes due to cyclic loading.
  - Cyclically loaded without permitting drainage.
  - Cyclically loaded while permitting drainage.

All tests were performed in accordance with applicable ASTM test methods or recognized procedures where no ASTM was available. Details of the test procedures are included in references 2 through 5. 7

2.5.4.5.2.4 <u>Criteria for Category 1 Backfill Suitability</u>. Soil classification test data obtained in accordance with ASTM D 2487, D 2488, D 1140, D 422, D 423, and D 424 were used to identify materials suitable for use as Category 1 backfill in the borrow areas and stockpiles. Cross-sections were developed based on the classification test data to facilitate selective excavation of acceptable material in the borrow sources. Summaries of classification test data and cross-sections for each borrow source are contained in references 2 through 4.

Type of Equipment	Thickness of Lift (in.)	No. of Passes	Speed (ft/min)	Vibrations (per min)
Wacker WS-74 Dual Drum	6	4	60	3000
Wacker 100	6	2	20	630
Ingersoll-Rand SP 24	6	4	60	4000

Table 2.5.4-11 summarizes the results of the hand compaction equipment test fill program.

2.5.4.5.2.8 Nonsafety-Related Pipe Trench Backfill in Power Block Area. Trench backfill for nonsafety-related piping in Category 1 fill areas is compacted to an average of 95 percent relative compaction as defined in paragraph 2.5.4.5.2. The backfill material used is concrete sand with 2 percent or less fines. The sand is saturated and compacted by internal vibration using concrete vibrators.

A test fill program was implemented to determine whether the required degree of compaction could be achieved by the vibrated sand method. The resulting data demonstrate that the compaction above, between, and below the pipes meets the required compaction criteria. Results of the test fill program are summarized in reference 17. 4

2.5.4.5.2.9 Soil-Cement-Flyash Backfill. Plastic backfill consisting of cement, flyash, sand, and water is used as bedding material for Category 2 circulating water lines located in the Category 1 backfill zone north of the turbine building. 7
Plastic backfill is being used in lieu of compacted sand and silty sand backfill because of the difficulty in obtaining the required compaction around the pipes.

Static and dynamic tests were performed on specimens consisting of different proportions of cement, flyash, sand, and water. The tests demonstrated that specimens of plastic backfill tested possess static and dynamic properties comparable to Category 1 backfill. The properties summarized below are of the plastic backfill that is used. The properties correspond to a plastic backfill mix of 65 lb of cement, 385 lb of flyash, 2586 lb of sand, and 469 lb of water per cubic yard of backfill. 7

Plastic unit weight	129.2 lb/ft^3
Slump	5 in.
Air content	3.5 percent
Unconfined compressive strength	
Average at 7 days	20.7 psi
Average at 28 days	30.5 psi
Average at 91 days	61.4 psi
Dry unit weight	
Average at 7 days	114.4 lb/ft^3
Average at 28 days	114.5 lb/ft^3
Average at 91 days	114.5 lb/ft^3
Moisture content	
Average at 7 days	14.0 percent
Average at 28 days	14.2 percent
Average at 91 days	14.6 percent
Cohesion	
Range at approximately 100 days	2100-5000 lb/ft^2

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Angle of friction Range at approximately 100 days	36-48.5°
Range of shear modulus at approximately 100 days, under a confining pressure of 2 ksf for strain level of 10^{-4} percent	4200-4400 lb/ft^2 7
Range of damping at approximately 100 days for strain level of 10^{-4} percent	2.4-2.6 percent

2.5.4.6 Site Ground Water Conditions

Site and regional ground water conditions are discussed in detail in subsection 2.4.12.

Two aquifers underlie the VEGP site. They are hydraulically separated by an aquiclude, identified as the Blue Bluff marl. Ground water in the aquifer underlying the marl is under artesian conditions, while water table conditions exist in the aquifer overlying the marl. No power block excavations extend through the marl; hence, only the water table aquifer will affect structures.

Recharge to the water table aquifer is primarily by direct infiltration of precipitation. Recharge from adjacent areas is minimal, because the general area of the plant is hydraulically isolated by a deeply incised drainage regime which acts as an interceptor to laterally moving ground water. Upon completion of construction, recharge by infiltration will be reduced by a moderate amount by structures, pavements, and surface drainage systems. Future recharge conditions will thus be such that the water table is not expected to rise above its highest recorded level of el 160 ft. Thus, the water table, presently depressed by the power block excavation dewatering system, will be allowed to return to its natural level. Power block structures are designed to accommodate ground water levels exceeding the recorded maximum natural level of el 160 ft; hence, no permanent dewatering system is required.

Prior to excavation the water table in the power block area stood between el 155 and 160 ft. When excavation progressed below this level, significant slope seepage began and temporary the river bed, the river will receive water from the aquifer under a hydraulic gradient sloping to the northeast.

Immense quantities of ground water are stored in the confined aquifer system underlying the region of the VEGP site, and relatively small withdrawals have occurred to date. Although many small communities derive water from wells, the draft on the 7
aquifer is low because of the low population density, limited industrial development, abundant surface waters, and abundant rainfall (which provides high recharge by direct infiltration to the aquifer and precludes the need to use significant quantities of ground water for agricultural purposes). Future use of ground water withdrawals for industrial and domestic use is expected to increase to some degree, but the most conservative estimates of future withdrawals do not project a significant impact on the level of the confined aquifer. This assessment takes into account the plant requirements for the life of the VEGP project, which will draw from the confined aquifer for makeup water (paragraph 2.4.12.1.3).

The phreatic surface of the unconfined aquifer will fluctuate primarily in response to the amount of rainfall. These fluctuations are expected to be small and are of no significance to the plant.

A comprehensive ground water monitoring program has been implemented at the VECP. This program has been designed to keep track of ground water levels and movement in both the confined and unconfined aquifers for the life of the plant and to keep track of levels of ground water accumulating in the compacted backfill inside the power block excavation throughout construction. The program currently consists of 7 observation wells set in the confined aquifer and 11 observation wells set in the unconfined aquifers. Observation wells will be abandoned or added as the need arises, and these numbers may vary from time to time. In addition to the current 20 wells established 7
early in the program, 11 observation wells were installed inside the power block during construction to monitor ground water accumulations in compacted fill. Most of these wells were located at or near future appurtenant structures and were abandoned as the structures were built. Those which were not abandoned are being incorporated into the monitoring program. Table 2.4.12-7 summarizes water levels measured during site exploration. Table 2.4.12-7 summarizes piezometric levels that have been recorded since the monitoring program was initiated.

2.5.4.7 Response of Soil and Rock to Dynamic Loading

This subject is addressed in subsections 3.7.1 and 3.7.2.

2.5.4.8 Liquefaction Potential

The liquefaction potential of the upper sand stratum was evaluated using the standard penetration test blow counts obtained during the investigation and the simplified procedure of Seed and Idriss.[8] This evaluation is described in detail in reference 1 and indicates that the upper sand below the ground water level is susceptible to liquefaction when subjected to the maximum SSE acceleration of 0.2 g. Based on this evaluation the upper sand stratum was removed to an approximate elevation of 130 to 135 ft in the power block area. Select sand and silty sand compacted to 97 percent of the maximum density determined by ASTM D 1557 is placed from the top of the marl stratum to the design elevation of the various power block structures with the exception of an area north of the turbine building as noted in paragraph 2.5.4.5.2. The liquefaction potential of compacted backfill in the power block area was evaluated for the PSAR and is discussed in detail in reference 1. The analysis indicated a factor of safety against liquefaction on the order of 1.9 to 2.0. The analysis was done utilizing cyclic strength data obtained from tests on specimens of compacted backfill.

During the investigations for borrow sources, additional dynamic data were obtained to supplement the cyclic strength data obtained previously and reported in reference 1. Cyclic triaxial tests were performed on compacted specimens of sands obtained from stockpile A and borrow area 1. The cyclic stress ratios versus the number of cycles to 2.5 percent total strain (initial liquefaction) are shown in figures 2.5.4-4 and 2.5.4-5. The results show that the stress ratios for the cleaner sands are substantially lower than for silty sands. In the liquefaction analysis done previously[1] stress ratios for the cleaner sands were used to obtain the safety factor against liquefaction. Therefore, the cyclic stress ratios for the cleaner sands obtained during investigations for borrow material were compared with values obtained during the PSAR investigations. A comparison of the two test data is shown in figures 2.5.4-6 and 2.5.4-7. The comparison indicates that the PSAR data represent a lower bound of test values. If the liquefaction analysis were performed using the upper bound values obtained during the borrow investigation, a factor of safety higher than 1.9 to 2.0 would have been obtained for the design SSE conditions.

From the discussion presented above, it is concluded that there exists an adequate factor of safety against liquefaction for backfill compacted to 97 percent of the maximum density obtained by ASTM D 1557.

2.5.4.9 Earthquake Design Basis

The design bases for the SSE and operating basis earthquake are addressed in paragraphs 2.5.2.6 and 2.5.2.7.

2.5.4.10 Static Stability

2.5.4.10.1 Bearing Capacity of Compacted Backfill and Marl Bearing Stratum Supporting Mat Foundations 7

The ultimate bearing capacity of the backfill is evaluated for the backfill consisting of sand and silty sand compacted to 97 percent of the maximum dry density (ASTM D 1557).

The ultimate bearing capacity of a soil is defined as the load at which shear failure will occur. A factor of safety of at least three is considered acceptable for the allowable bearing capacity for static loads. For dynamic loads a minimum safety factor of two is required. The net ultimate bearing capacity of sand backfill supporting a rectangular foundation above the water table is given by the expression:[9]

$$q_{ult} = \gamma D N_q \left(1 + 0.2\frac{B}{L}\right) + \tfrac{1}{2}\gamma B \left(1 - 0.3\frac{B}{L}\right) N_\gamma - \gamma D$$

where:

q_{ult} = the net ultimate bearing capacity (k/ft^2).

= the total unit weight of the backfill (k/ft^3).

D = depth of embedment of the footing (ft).

B = width of the footing (ft).

L = length of the footing (ft).

N_q, N_γ = dimensionless bearing capacity factors.

For a circular foundation the expression is:

$$q_{ult} = \tfrac{1}{2}\gamma B N_\gamma (0.6) + \gamma D (N_q - 1).$$

If the water table is located at the bottom of a foundation supported by cohesionless material, the values obtained from the above expressions are approximately halved.

For a rectangular foundation supported entirely on the 7
marl bearing stratum, the net ultimate bearing capacity is
given by the expression:[10]

$$q_{ult} = cN_c \left(1 + 0.2\frac{D}{B}\right) \left(1 + 0.2\frac{B}{L}\right)$$

where:

c = undrained shear strength of the marl bearing stratum (k/ft²). 7

N_c = dimensionless bearing capacity factor.

For a circular foundation:

$$q_{ult} = 1.2\ cN_c$$

For sand and silty sand backfill compacted to 97-percent
relative compaction (ASTM D 1557), strength parameters of c=0
and ϕ=34° derived from triaxial test data were used
(paragraph 2.5.4.5.2). For the marl bearing stratum (Blue Bluff 7
marl), strength parameters of c=10 k/ft² and ϕ=0 were used
(paragraph 2.5.4.2.2).

A summary of power block structure loads and allowable bearing
capacity is presented in table 2.5.4-12. The bearing capacity
of compacted backfill was determined to be very high for the
large structures under consideration. Consequently, the
strength of the marl bearing stratum will govern the 7
allowable bearing capacity of the plant structures. Since the
net allowable bearing pressures in all cases far exceed the net
static loads, bearing capacity of the supporting soils is not a
problem. Settlement of structures will therefore govern the
allowable bearing pressures.

2.5.4.10.2 Settlement of Power Block Structures on Mat Foundations

When a load of limited size is applied to a sand stratum, it will undergo shear deformation beneath the loaded area. The vertical component of this deformation is called the "initial" or "immediate" settlement which will occur immediately upon application of the load. Sand and silty sand drain relatively fast upon loading, and therefore long term volume changes with dissipation of pore water pressure do not occur in these soils. Therefore, while estimating settlements in these soils, only immediate settlements based upon the undrained modulus of elasticity were considered.

When a load is applied to a column of saturated clay soil, the clay will deform and pore water pressures will be induced in it. Immediately after the application of the load, little, if any, pore water will be squeezed out and the clay will deform at constant volume. The vertical component of movement is called the initial or immediate settlement. In the course of time, pore water will be squeezed out of the clay and its volume will decrease. The vertical component of this volume decrease is known as "consolidation" settlement. Therefore, for estimating settlements in the clay bearing stratum, both immediate and consolidation settlements were taken into consideration.

Soil stresses and settlements were computed using the Settlement Problem Oriented Language (SEPOL) computer program developed at Massachusetts Institute of Technology.[11] Both the sand backfill and the clay bearing stratum were treated as layered systems and divided into layers of different thickness. The SEPOL program computes the stress and strain at the midpoint of each layer based on the theory of elasticity. The initial settlement for each layer is computed as the strain at the midpoint of the layer times the layer thickness.

The consolidation settlement was computed using the following formula:[12][13]

$$\rho_c = \frac{C_c h}{1 + e_o} \log \frac{(\sigma_v' + \Delta\sigma_v)}{\sigma_v'}$$

where:

ρ_c = consolidation settlement.

C_c = compression index.

h = layer thickness.

e_o = initial void ratio.

σ_v' = <u>in situ</u> effective vertical stress at middepth of the layer.

$\Delta\sigma_v$ = effective additional vertical stress at middepth of the layer due to the surface load.

Initial settlement was computed using an average undrained Young's modulus of 1500 k/ft² for the compacted backfill obtained from static triaxial tests. For the marl bearing stratum an undrained Young's modulus ranging from 4000 to 10,000 k/ft² was used in the computations. The lower bound value was the value reported in the PSAR. The upper bound 7 value was estimated based on heave data measured during excavation in the power block area.

The other soil parameters used in the settlement computations are as follows:

7

Soil Parameter	Sand, Silty Sand Backfill	Marl Bearing Stratum
Moist unit weight (lb/ft^3)	120	-
Saturated unit weight (lb/ft^3)	130	115
Submerged unit weight (lb/ft^3)	68	53
Poisson's ratio	0.4	0.5

For computing the consolidation settlement, the marl bearing stratum was divided into four layers of 10, 20, 20, and 20 ft in thickness, respectively. Owing to the highly preconsolidated nature of the marl bearing stratum, the compression index (C_c) used in the above formula was taken equal to the rebound index (C_r) obtained from the rebound curve of the void ratio versus log pressure plots developed from one-dimensional consolidation tests.[1] The value of $C /1+e_o$ was determined for each consolidation test, and an average of 0.0046 was used for settlement calculations. 7

The results of the settlement analysis of the power block structures are presented in figure 2.5.4-8. The estimated total range of settlements at the center and corner of each structure are shown. The indicated range of total settlements was obtained by adding the settlements that will occur in the compacted backfill and in the marl bearing stratum. The total settlements do not include settlements in the marl bearing stratum as a result of fill under foundations, since these settlements will occur prior to placement of building loads. 7

It may be observed that the total settlements shown in figure 2.5.4-8 include consolidation settlement in the marl bearing stratum. Due to the highly preconsolidated nature of the marl stratum, the computed consolidation settlements are extremely small, compared to the immediate settlements. Approximately 90 percent of the gross load of each structure results from the dead load. In view of these factors, about 7

B. Nine heave point tips with polyvinyl chloride protective sleeves were installed at selected locations approximately 5 ft below the eventual bottom of the excavation.

C. Invar steel reading rods were lowered through each protective sleeve to mate with the heave point tip. The rods were tensioned to alleviate any "snaking" and to rigidly clamp them into position.

D. The heave point tip elevation was determined by conducting a first order level survey from a benchmark to the top of the reading rods.

The locations of the heave points are shown in figure 2.5.4-9. Three of the heave points were damaged after installation; therefore, data from only six heave points are available. A report of heave point measurements is presented in reference 16 and summarized in table 2.5.4-13. The data show that the measured heave of the marl stratum ranged from 0.6 to 1.7 in., with an average of 1.25 in. Results are also plotted in figure 2.5.4-10.

2.5.4.13.2 Settlement Monitoring

The foundation design parameters for all power block structures were based on measured soil parameters obtained by field exploration and laboratory testing. The structures and the interconnecting piping are designed for building settlement. A settlement monitoring program was initiated to record settlements at various locations in the structures. The monitoring program consists of two permanent benchmarks installed as reference points for measurements and a total of 111 monitoring points. The locations of settlement markers are shown in figure 2.5.4-11. A survey reading is taken on each marker at approximately 60-day intervals prior to startup and at 30-day intervals after startup. The total settlements and differential settlements for the various structures are determined from these readings. 7

2.5.4.14 Construction Notes

There have been no significant construction problems, apart from the erosion of Category 1 backfill, that occurred as a result of heavy rainfall in early November 1979. Areas within the power block subjected to erosion are described in detail in a report submitted to the Nuclear Regulatory Commission.[14] The report outlined steps that had been initiated subsequent to the erosion to repair the affected and adjacent areas and to facilitate resumption of backfilling operations in the power block area. Also included in the report were recommended methods of repair and a description of future erosion and ground water control measures to prevent a recurrence of the problem.

All erosion in the power block backfill was satisfactorily repaired according to recommended procedures, with the exception of minor deviations that were necessitated by practical considerations.

Extensive field and laboratory tests were performed to verify the extent of disturbed material in the eroded areas. These tests were used to verify the competency of the backfill adjacent to the foundations of various Category 1 structures. The evaluation of the effect of erosion on Category 1 structure foundations was based on data developed during testing and visual observations made during the entire period of repair. The data and evaluation are contained in reference 15. The field testing and evaluations described in reference 15 provided adequate data which defined the disturbed zones in Category 1 backfill. All erosion was successfully repaired. This evaluation has established that there is no detrimental effect on the existing structures as a result of the heavy rainfall of early November 1979.

2.5.4.15 Standard Review Plan Evaluation

The Standard Review Plan calls for probabilistic as well as deterministic analyses of liquefaction potential at the site. The liquefaction analyses performed for VEGP were of the deterministic type only.

The foundation properties for materials underlying Seismic Category 1 structures are known with much greater accuracy at VEGP than at most nuclear power plant sites. This is because all potentially liquefiable foundation materials have been removed and replaced with homogeneous, well-compacted structural 1
backfill. All Seismic Category 1 structures are founded either on this backfill or on the underlying very competent marl.

The deterministic evaluation of the liquefaction potential described in subsection 2.5.4 involved use of extensive laboratory test data that covered the upper and lower bound cyclic shear strengths of compacted Category 1 backfill. The deterministic analyses have demonstrated (paragraph 2.5.4.8) that an adequate factor of safety exists against liquefaction.

The backfill supporting Category 1 structure foundations has been placed under extremely well-controlled conditions and exceeds the minimum design compaction requirements (97 percent of the

TABLE 2.5.4-1

ENGINEERING PROPERTIES OF SITE SOILS

Static Properties	Upper Sand Stratum (Barnwell Group)	Marl Bearing Stratum (Blue Bluff Marl)	Lower Sand Stratum (Ellenton Formation)
In situ dry density (lb/ft^3)	41-120	51-155	69-118
In situ moisture content (percent)	5-86	3.2-60.6	15-45
Degree of saturation (percent)	18-100	100	-
ASTM D 1557 maximum dry density (lb/ft^3)	101-125	-	-
Optimum moisture content (percent)	7.5-17.4	-	-
Unconsolidated undrained shear strength c (lb/ft^2) and 0°	440-2100, 6°-32°	260-500,000, 0°	-
Consolidated undrained shear strength c (lb/ft^2) and 0°	1650-4000, 17°-25°	-	-
Consolidated drained shear strength c (lb/ft^2) and 0°	0, 33°-34.5°	-	-
Standard penetration test (blows/ft) range/average	2-60 / 30	10-100+ / 100+	70-100+ / 100+
Liquid limit (percent)	NP[a]	19-111	NP
Plastic limit (percent)	NP	15-55	NP
Plasticity index (percent)	NP	2-70	NP
Poisson's ratio	0.4-0.46	0.5	-
Porosity	-	0.403-0.619	-
Permeability (ft/year)	200-350	-	-
Specific gravity	2.67-2.74	2.37-2.84	-
Modulus of elasticity (k/ft^2)	-	86-25,000	-

a. Majority of material nonplastic (NP): clay layers had liquid limit greater than 100.

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TABLE 2.5.4-2

ENGINEERING PROPERTIES FOR DESIGN

Static/Properties	Upper Sand Stratum (Barnwell Group)	Marl Bearing Stratum (Blue Bluff Marl)	Lower Sand Stratum (Ellenton Formation)
In situ dry density (lb/ft^3)	94	88	94
In situ moisture content (percent)	25	35	24
Degree of saturation (percent)	88	100	-
ASTM D 1557 maximum dry density (lb/ft^3)	115.2	-	-
Optimum moisture content (percent)	12.4	-	-
Unconsolidated undrained shear strength c (lb/ft^2) and 0°	2300, 6°	10,000, 0°	-
Consolidated undrained shear strength c (lb/ft^2) and 0°	1000, 18°	-	-
Consolidated drained shear strength c (lb/ft^2) and 0°	0, 34°	-	-
Standard penetration test (blows/ft)	30	100+	100+
Porosity	-	0.497	-
Poisson's ratio	0.4	0.5	-
Permeability upper sand stratum (ft/year)	350	-	-
Specific gravity	2.70	2.72	-
Modulus of elasticity (k/ft^2)	-	4000-10,000	-

TABLE 2.5.4-3

DESIGN VALUES OF SHEAR MODULUS[a]

In Situ Soils: 7

Elevation (ft)	Shear Modulus (lb/ft^2)
210 to 180	2.3×10^6
180 to -770	11.6×10^6

a. The values refer to shear modulus at strains of approximately 10^{-4} percent or lower.

TABLE 2.5.4-4

IN SITU SOILS - BASIC SOIL PROPERTIES FOR DYNAMIC DESIGN[a]

7

Stratum Designation	Elevation (ft)	Unit Weight (lb/ft^3) Moist	Saturated	Submerged	Poisson's Ratio
Upper sand stratum	225 to 135	115	115	52.6	0.4 to 0.46
Marl bearing stratum	135 to 70	-	115	52.6	0.5
Lower sand stratum	70 to -770	-	115	52.6	0.4 to 0.46

a. In sandy soils the specific value of Poisson's ratio within the given range will be the most conservative value for the particular dynamic analysis being carried out.

Figures describing the variation of shear modulus and damping ratio with shear strain for clay marl bearing stratum and lower sand stratum are provided in subsections 3.7.B.1 and 3.7.B.2.

TABLE 2.5.4-5

COMPILATION OF SHEAR WAVE DATA[a]

Depth (ft)	Elevation[b] (ft)	Compression Wave Velocity (ft/s)	Shear Wave Velocity (ft/s)
0-15	208-193	1400	600[c]
20	188	2500	1000
30	178	2800	1000
40	168	2500	900
50	158	4600	1000
60	148	5200	1200
70	138	5100	1400
80	128	6600	1600
90	118	6700	1700
100	108	6900	1800
110	98	6600	1700
120	88	6400	1700
130	78	6600	1800
140	68	6500	1700
150	58	6800	1600
160	48	6600	1600
170	38	6800	1800
180	28	6600	--
190	18	6500	1800
200	8	6600	1800
210	-2	6600	1700
220	-12	6600	1800
230	-22	6700	1800
240	-32	6400	1700
250	-42	6500	1800
260	-52	6700	1800
270	-62	6800	1800
280	-72	6700	1800
290	-82	6700	1700

a. From cross-hole measurements or as noted. 7

b. Ground surface elevations average 208 ft above sea level in this area.

c. From surface data.

TABLE 2.5.4-8

DESIGN STATIC PROPERTIES FOR BACKFILL COMPACTED TO 97-PERCENT RELATIVE COMPACTION (ASTM D 1557)

Soil Properties	Sand, Silty Sand	
Unit weights (lb/ft^3)		
Moist	126	
Saturated	132	
Submerged	69.6	7
Effective shear strength parameters		
Cohesion or c (k/ft^2)	0	
Angle of internal friction or ε (degrees)	34	
Undrained modulus of elasticity or E (k/ft^2)	1500	
Poisson's ratio (ν)	0.4	
Compression index	-	

TABLE 2.5.4-9

DESIGN DYNAMIC PROPERTIES FOR BACKFILL COMPACTED TO 97-PERCENT RELATIVE COMPACTION (ASTM D 1557)

Soil Properties		Sand, Silty Sand	
Unit weights (lb/ft^3)			
Moist		126	
Saturated		132	
Submerged		69.6	7
Poisson's ratio		0.33	
Damping ratio		See figure 3.7.B.1-8.	
Shear modulus at strain of 10^{-4} percent[a]			
Elevation (ft)	Depth (ft)	Shear Modulus (lb/ft^2)	
210	10	2.3×10^6	
195	25	3.6×10^6	
165	55	5.3×10^6	
150	70	5.7×10^6	
130	90	6.2×10^6	

a. Shear modulus $G = 1000\ k_2(\sigma'_m)^{1/2}\ lb/ft^2$, where $k_2 \approx 79$.

Variation of shear modulus with strain is given in figure 3.7.B.2-5.

TABLE 2.5.4-10

SUMMARY OF TEST FILL RESULTS FOR HEAVY EQUIPMENT COMPACTION

Test Fill No.	Material From Stockpile[a]	Roller	Roller Speed (mph)	Number of Passes	Lift Thickness (in.)	Field Density Method	Depth of Test (in.)	Number of Field Density/ Compaction Tests	Percent of Tests: 97% Compaction	Percent of Tests: 93 to 95% Compaction	Percent of Tests: 93% Compaction	Remarks
I	C	SPF 60 and Raygo 600A	1.5	2 each	6	Sand cone	12	24	0	0	0	Acceptable
							18	24	0	0	0	
						Nuclear	12	24	8	0	0	
							18	24	8	0	4	
II	C	Raygo 600A	1.5	4	6	Sand cone	12	24	0	0	0	Acceptable
							18	-	-	-	-	
						Nuclear	12	24	0	0	0	
							18	-	-	-	-	
III	A	SPF 60 and Raygo 600A	1.5	2 each	6	Sand cone	12	24	33	4	0	Acceptable
							18	-	-	-	-	
						Nuclear	12	24	100	46	29	
							18	-	-	-	-	
IV	A	Raygo 600A	1.5	4	6	Sand cone	12	24	4	0	0	Acceptable
							18	-	-	-	-	
						Nuclear	12	24	96	42	46	
							18	-	-	-	-	
V	A	SP 60	3	3	12	Sand cone	12	24	42	8	0	Not acceptable
							18	6	83	17	0	
						Nuclear	12	24	100	4	96	
							18	6	100	50	50	
VI	C	SP 60	2, 1.5	3	12	Sand cone	12	24	0	0	0	Acceptable
							18	6	0	0	0	
						Nuclear	12	24	33	8	8	
							18	6	67	17	17	
VII	B	Raygo 600A	1.5	4	6	Sand cone	12	10	30	20	0	Incon-clusive
							18	-	-	-	-	
						Nuclear	12	10	100	10	90	
							18	-	-	-	-	

a. Letters refer to designations in figure 2.5.4-3.

TABLE 2.5.4-11

SUMMARY OF TEST FILL RESULTS FOR HAND COMPACTION EQUIPMENT

Test Fill No.	Material From Stockpile[a]	Roller	Roller Speed (mph)	Number of Passes	Lift Thickness (in.)	Field Density Method	Depth of Test (in.)	Number of Field Density/ Compaction Tests	Percent of Tests: 97% Compaction	Percent of Tests: 93 to 95% Compaction	Percent of Tests: 93% Compaction	Remarks
1	C	Wacker 74 Dual Drum	0.68	4	6	Sand cone	12	8	8	0	0	Acceptable
2	C	Wacker 100 Jumping Jack	0.23	2	6	Sand cone	12	8	8	0	0	Acceptable
3	C	Ingersoll-Rand-SP 24	0.68	4	6	Sand cone	12	16	15	1	0	Acceptable

a. Letters refer to designations in figure 2.5.4-3.

TABLE 2.5.4-12

SUMMARY OF RESULTS OF BEARING CAPACITY ANALYSIS[a]

		Static			Dynamic
Structure	Supporting Stratum	Net Ultimate Bearing Pressure (k/ft^2)	Net Foundation Pressure (k/ft^2)	Factor of Safety	Maximum Permissible Foundation Pressure (k/ft^2)
Diesel generator building	Backfill	65.3	1.46	45	32.7
Turbine building	Backfill	56.6	-0.01	Very high	28.3
Fuel handling building (el 173 ft)	Backfill	67.9	-1.33	Very high	34.0
Control building	Backfill	58.4	-0.59	Very high	29.2
Reactor containment building	Backfill	61.7	0.37	Very high	30.9
Fuel handling building (el 154 ft)	Backfill	72.4	-2.21	Very high	36.2
Nuclear service cooling water tower	Clay bearing stratum	61.7	2.92	21	30.9
Auxiliary building	Clay bearing stratum	64.2	1.61	40	32.1

a. Net ultimate bearing pressures of clay bearing stratum will govern and are presented.

For structures supported on backfill, net foundation pressures shown are net pressures transmitted to the top of clay bearing stratum. For structures supported on clay bearing stratum, net foundation pressures shown are the net pressures below foundation mat.

2.5.5 STABILITY OF SLOPES

2.5.5.1 Slope Characteristics

Category 1 slopes consisted of excavation cut slopes and 7
temporary backfill slopes. The excavation slopes were cut in
the upper sand stratum and shell zone at two horizontal to one
vertical. The lower 5 ft of the cut was in the clay bearing
stratum. Parameters for design of the excavation slopes were
based on data developed for the upper sand and clay bearing
strata (paragraph 2.5.4.2). A total stress design shear
strength of $c=0$, $\phi=34°$ was used for the upper sand stratum and
$c=10{,}000\ lb/ft^2$, $\phi=0°$ for the clay bearing stratum (table
2.5.4-2).

Temporary fill slopes were constructed at a minimum of 1.5
horizontal to one vertical where the slope height exceeded 3 ft
except for a few deviations which are addressed in references 1 7
and 2. Slopes or portions of slopes of heights less than 3 ft
were placed with stable side slopes. Except for north of the
turbine building, fill slopes consisted of sand and silty sand
material compacted to an average of 97 percent of the maximum
density by American Society of Testing Materials (ASTM) D 1557.
Fill slopes north of the turbine building consisted of sand and
silty sand backfill compacted to an average of 95 percent of the
maximum density by ASTM D 1557. Parameters for design of
temporary fill slopes were based on data developed for compacted
Category 1 backfill (paragraph 2.5.4.5). Design effective
stress parameters of $C'=0$, $\phi=34°$ were used in analyzing
temporary fill slopes.

2.5.5.2 Design Criteria and Analysis

The stability of the excavation cut slopes in in situ soil was 7
determined using a computer program based on a modification of
the Swedish Slip Circle method of slices analysis.[1] The
slopes were analyzed for stability by assuming the material
below the water table to be dewatered. A peripheral dewatering
system is being used to control ground water and will be
continued until backfilling is completed above the ground water
table. In a dewatered condition, the factor of safety against
sliding for a slope of two horizontal to one vertical was
determined to be 1.3. This was considered satisfactory for a
temporary construction slope. Earthquake forces were not
considered in the design of these slopes since they are
temporary during the construction period only.

For temporary fill slopes (1.5 horizontal to one vertical), slope stability analysis was performed using the Integrated Civil Engineering Systems LEASE computer program.[4]

The analysis revealed that a deep seated sliding failure will not occur, and any instability in the fill will be manifested in the form of minor raveling of the fill surface if it is steeper than the effective angle of skin friction. Infinite slope analysis based on the design friction angle of 34° indicated that temporary fill slopes will have a minimum factor of safety against raveling of 1.01. This was considered satisfactory for temporary fill slopes in a dewatered condition.

Surcharge loadings, such as buildings, on the top of a slope will affect the slope stability. To prevent loss of bearing capacity for the structure foundation and to ensure slope stability, buildings were located a sufficient distance away from the top of the slope. When situations arose during construction that required a building to be placed near a temporary fill slope, each case was analyzed to determine the minimum setback distance.

2.5.5.3 Log of Borings

Log of borings is listed in references 5, 6, and 7.

2.5.5.4 Compacted Backfill

This subject is discussed in paragraph 2.5.4.5.2.

REFERENCES

1. Letter, with attachments, from D. E. Dutton of GPC to J. P. O'Reilly of the NRC, dated January 8, 1980.

2. Bechtel Power Corporation, Final Report on Dewatering and Repair of Erosion in Category 1 Backfill in Power Block Area, August 1980. 7

3. U.S. Corps of Engineers, "The Method of Slices," Civil Works Engineering Manual, SM 1110-2-1902.

4. Berkley, W. A., and Christian, J. T., "ICES LEASE-1: A Problem Oriented Language for Slope Stability Analysis," User's Manual, Soil Mechanics Publication No. 235, Massachusetts Institute of Technology, April 1969.

5. Bechtel Power Corporation, Report on Backfill Material Investigations, Vogtle Electric Generating Plant, January 1978.

6. Bechtel Power Corporation, Report on Backfill Material Investigations, Addendum No. 1, Vogtle Electric Generating Plant, October 1978.

7. Bechtel Power Corporation, Report on Backfill Material Investigations, Addendum No. 2, Vogtle Electric Generating Plant, November 1979.

APPENDIX 2A

POPULATION DISTRIBUTION METHODOLOGY

2A.1 INTRODUCTION

This appendix documents the procedures followed in the preparation of paragraphs 2.1.3.1 and 2.1.3.2 of the Final Safety Analysis Report (0 to 50 miles) and paragraphs 2.1.2.1 and 2.1.2.2 of the Operating License Stage Environmental Report (50 to 500 miles). Included with a step-by-step documented review of the procedures is a presentation of the methodology used, a table of definitions, a review of the materials used, a discussion of the assumptions made, and a section addressing the procedures to follow should the submitted figures need updating.

2A.2 DEFINITIONS

OPB: OPB is an acronym for the Office of Planning and Budget, State of Georgia.

SDC: SDC is an acronym for the State Data Center, State of South Carolina.

Sector: A sector is one of the 16 compass divisions comprising the area within any given circle centered on VEGP.

Segment: A segment is an area bounded by two sector divisions and two arcs.

USGS Quadrangle Maps: United States Geological Survey quadrangle maps are topographical maps bounded by parallels of latitude and meridians of longitude. Quadrangles covering 7 1/2 min of latitude and longitude are published at the scale of 1:24,000 (1 in. = 2000 ft.) Quadrangles covering 15 min of latitude and longitude are published at the scale of 1:62,500 (1 in. mile).

2A.3 ASSUMPTIONS

The major assumptions taken to determine population distribution were as follows:

A. The population density within the Savannah River Plant is zero.

B. The percentage of each county's population in a segment for 1980 will not change over the forecasted time span.

C. The curvature of the earth will not have a significant effect on the construction of rings and sectors for the 500-mile radius.

D. Due to possible human error in construction, rings are estimated to be accurate within ±1/2 mile.

E. Population changes at Fort Gordon over the forecasted period are addressed in the OPB projections.

F. Population projections made for the area within a 500-mile radius of VEGP were based on 1980 census data and county population projections obtained from the OPB and the SDC.

G. The extrapolation method of population projections for county and subcounty areas is generally more accurate than the differential and share methods.

2A.4 MATERIALS

The materials used to determine population distribution were:

A. The USGS quadrangle maps of the affected area.

B. The 1980 state maps depicting the affected counties.

C. U.S. Census Bureau figures indicating the population and number of housing units of the counties and cities in the affected area for 1980.

D. The OPB and the SDC county and city projections for the years 1990, 2000, 2010, and 2020.

E. The 1980 population figures for military installations in the area.

F. A house to house survey of the area within 5 miles of the VEGP site conducted in 1980. 7

The USGS quadrangle maps were used as the base maps for construction of rings and sectors and for the transcription of county and city boundaries; they were chosen as base maps because of their detailed representation of housing patterns. The OPB and SDC projections were chosen for future population estimates because of the high accuracy of their projections as demonstrated by a narrow margin of error between 1980 projected and actual population figures.

2A.5 METHODOLOGY

Described in the steps below is the methodology used to determine population distribution:

A. Locate the center of VEGP on the USGS quadrangle maps. Construct concentric circles on the quadrangle maps at distances of 1 through 10, 20, 30, 40, 50, 60, 70, 85, 100, 150, 200, 350, and 500 miles.

B. Divide the constructed circles into sectors of 22 1/2° with each sector centered on one of the 16 compass points, e.g., true north, north-northeast.

C. Transcribe the city and county boundaries located within a 500-mile radius of VEGP to USGS quadrangle maps.

D. Estimate from the quadrangle maps the percentage of each city's and county's population that lies in each affected section.

E. Caclulate from 1980 census statistics the percentage of each county's population that lies in each affected section.

F. Assume that the percentage of each county's population that resides in each affected segment remains the same over the forecasted time span.

G. Prepare population projections for the first year of plant operation (1987 for Unit 1) and beyond by first determining the margin of error for previous projections completed by the OPB and the SDC (the difference between 1980 population forecasts and 1980 census figures). Using the margin of error, adjust projections for the census years, the midpoint in the plant's operating life, and the endpoint in the plant's operating life.

H. Estimate a segment's population for any year by multiplying each affected county's adjusted population projection for that year by the percentage of that county's population which is in the segment.

To estimate a county's population for the anticipated first year of plant operation, the following methodology was used:

A. Subtract the county's previous census decade's count from the next projected census decade's estimate, divide by 10, and multiply this number times the number of years into the decade the first year of plant operation occurs.

B. Add the figure obtained in item A to the previous decade's estimate to obtain a county's estimated population for the anticipated initial year of plant operation. For example, assuming a starting date of 1987, the estimated population of county X for section A lying entirely within that county is determined as follows:

$$\frac{M - N}{10} \times 7 = 0.7M - 0.7N$$

$$0.7M - 0.7N + N = 0.7\,(M-N) + N$$
$$= \text{estimated population for 1987}$$ 7

where:

M = 1990 estimated population for county X.

N = 1980 population count for county X.

For segments within 50 to 500 miles, statewide projected growth rates were used to determine individual county forecasts. Population estimates within 5 miles of VEGP were based on a 1980 house to house survey of the area. Multifamily housing units related to construction worker demand were included in the population estimates for 1987. It was assumed that these housing units will continue to be in use through 1989, estimated completion year of Unit 2. However, projections for 1990 and beyond do not include construction-related housing. 7

2A.6 PROCEDURES

Population distribution by sector for the area within a 500-mile radius of VEGP was determined in the following manner:

A. Base maps showing county boundaries within a 500-mile radius were overlain with annular rings and sectors.

B. Each segment's county composition was visually estimated. For example, sector 16-30 is composed of 4 percent Aiken County and 14 percent Richmond County.

C. All counties lying within the 500-mile radius were listed with their 1980 population. Cities over 25,000 were subtracted from county figures if they lay in more than one segment, or if the county lay in more than one segment. For example:

	1980 Population
Etowah County	103,057
Gadsden City	-47,255
Remaining population	55,802

Each city was listed with the segment or segments in which it lay.

D. Each segment's 1980 population was determined by multiplying the percentage of each county represented by its remaining 1980 population (U.S. Census Bureau).

APPENDIX 2B

GEOLOGY

2B.1 INTRODUCTION

Comprehensive areal geology and site specific foundation investigations and examinations of the VEGP site have been completed. The results and conclusions are described and contained in section 2.5 and subsection 2.4.12. The geologic logs and geophysical logs are submitted under a separate cover. A table of drilling statistics is presented in table 2B-1. A description of foundation conditions encountered during construction is contained in subsection 2B.3.1.

2B.2 FIELD INVESTIGATIONS

A total of 370 borings was drilled for the primary geologic and site specific foundation investigations for the plant facilities. The drill logs of 354 of these borings are submitted as described in section 2B.1. The remaining 16 borings were done for the revised locations of the cooling towers and the drill logs for these borings are included in the report Foundations Investigations for Natural Draft Hyperbolic Cooling Towers, Addendum, prepared by Bechtel Power Corporation, December 1978. Selected marl core samples from principal borings have been placed in protective storage; table 2B-2 provides an inventory of these core samples. An additional 12 borings were made for the studies of the postulated Millett Fault conducted in 1982. These borings are offsite and are described in detail in the report Studies of Postulated Millett Fault, dated October 1982. Logs of these borings are included in that report.

2B.3 REPORT OF GEOLOGY AND FOUNDATION CONDITIONS

2B.3.1 INTRODUCTION

This report presents the results of geologic work performed in conjunction with the excavation of the power block areas at the VEGP site. The purpose of the work was to identify, locate, and record details of the geologic structure, stratigraphy, and lithology of the soil and rock strata encountered in the excavation. In addition, samples of foundation rock were obtained for testing of physical properties.

The geologic work was performed by Bechtel geologists during the period May 1974 through October 1977 with certain tasks continuing on an as-needed basis. This time period included the initial startup of the construction work, the interim postponement of work between September 1974 and July 1976, and the subsequent restart of construction.

The work performed included detailed geologic mapping of the soil and rock strata exposed in the power block excavation, and coring and testing of the Blue Bluff marl, which forms the foundation for power block structures and structural backfill. This marl has sometimes been referred to as the "clay bearing stratum." Geologic mapping was accomplished by recording the details of stratigraphy, structure, and lithology of the various soil and rock deposits on a base map prepared from excavation drawings. Mapping of the vertical surfaces of the auxiliary building excavation walls was recorded on geologic sections coinciding with the surfaces of the walls. All geologic mapping was performed using hand surveying techniques with the exception of the recording of the upper contact of the marl layer. This was recorded by instrumental survey of 575 points established by the geologists. Photography was employed as an aid to mapping and to provide a record of foundation geologic features.

As areas of the marl were cleaned off at final grade in the excavation, they were inspected and signed off by a qualified geologist or soil engineer. The documentation for the approved foundation areas was submitted to Georgia Power Company for permanent retention. 7

Subsection 2B.3.2 of this report presents a brief summary of conclusions from the studies performed. Subsection 2B.3.3 presents the details of the geologic structure, stratigraphy, and lithology of the various geologic materials encountered in the excavation. Ground water conditions encountered during the reference period are described. Geologic mapping procedures are discussed in detail. Subsection 2B.3.4 describes the excavation geometry along with the procedures utilized for advancing the excavation down to final grade. Temporary dewatering methods are described as are measures taken for protection of the side slopes from erosion. Foundation cleanup and protection procedures are discussed, and inspection and approval procedures are outlined. The marl testing program carried out to confirm the design physical properties of this material is discussed, and reference is made to the backfill report(1) in which the test results are compiled. The monitoring of rebound of the marl due to unloading by excavation of the overlying deposits is described. Subsection 2B.3.5 presents detailed conclusions drawn from the work described in the preceding sections. The features described in the report

The formational boundary between the Lisbon Formation and Barnwell Group coincides with the upper contact of the marl.

2B.3.3.3.2 Lisbon Formation

The middle Eocene Lisbon Formation is represented in the site area by the Blue Bluff marl which forms the foundation for structures and backfill in the power block area. The marl has a total thickness of about 70 ft in the site area. The upper approximate 25 ft of the marl were exposed in excavations and mapped in detail. A vertical section between el 108.6 ft (final excavated grade) and 132 ft was exposed in the auxiliary building basement excavation. Ten subunits were recognized and mapped in this vertical section. The subunits, designated A through J, are shown in figure 2.5.1-24. 7

Unit A, near the top of the excavation walls, is generally above el 128 ft and includes the marl from this point up to the upper contact of the marl with the Utley Limestone Member of the Barnwell Group. It consists of dark gray silty to clayey marl with very fine light gray to white fine sandy laminations, which are undulatory and discontinuous. Scattered shell fragments and well-cemented lenses of sand up to 0.1 ft thick are present locally. The laminations are oriented parallel to the lower contact of the unit, and parting along the laminations is common. Unit A is dense and well consolidated. Surfaces exposed to the atmosphere tend to dessicate rapidly. Unit A interfingers with the underlying unit B. This is especially evident in the south wall in the vicinity of stations 0 + 70, 1 + 50, and 4 + 30. (See figure 2.5.1-24, sheets 2, 4, and 5.) The contact with unit B is everywhere gradational.

Unit B, directly beneath unit A, is continuous around the auxiliary building basement walls and varies from 1 to over 4 ft in thickness. It consists of massive to faintly laminated gray sandy marl. It has a sugary texture and does not tend to dessicate as readily as unit A. This property provides an easy means for differentiating the units after exposure to the atmosphere. Unit B is dense but poorly cemented and contains widely scattered shell fragments.

A subunit of B, designated B_1, has been identified and is present locally within B. This subunit consists of laminated sandy marl, which is locally fossiliferous. Subunit B_1 has been mapped at the base of B in the easterly portions of the north and south wall and the east wall. (For example, see figure 2.5.1-24, sheet 3.) The contacts between B and B_1 are highly gradational.

Unit B is in turn underlain by a thin, relatively discontinuous but laterally extensive limestone, designated unit C. This limestone is light gray, well indurated, and exhibits conchoidal fracture. It is continuous in the west end of the south wall but becomes discontinuous east of station 0 + 80. East of station 3 + 65, the limestone becomes a series of small, irregular discontinuous pods at varying elevations. (See figure 2.5.1-24, sheet 4.) Where exposed in the north, east, and west walls, the limestone forms discontinuous lenses at a relatively consistent elevation. It averages about 1 ft in thickness and dips slightly to the east, being present at about el 127 to 128 ft at the west end of the auxiliary building and 125 ft at the east end.

During excavation of the auxiliary building basement, the irregularity of portions of unit C led to a special study to determine whether the irregularities could be related to fault offset. The concern was that lenses and pods of the limestone occurring at slightly different elevations might have been offset from one another. The study focused on an area of the south walls at station 2 + 80 and the north wall at station 1 + 70. (See figure 2.5.1-24, sheets 2 and 4.) As both excavation and mapping of stratigraphically lower units progressed, it became very evident that the irregularities of unit C were due to processes other than faulting. The continuity of the lower units in the areas of interest precluded the possibility of fault offset. A report was prepared[4] which concluded that the only plausible explanation for the observed irregularities was a combination of erosional and depositional processes.

Underlying the limestone of unit C is medium gray, highly fossiliferous, sandy to silty marl, designated unit D. This zone, averaging 8 ft in thickness, is continuous around the walls of the auxiliary building excavation. The lithology of unit D is very uniform and its upper and lower contacts are quite sharp. An abundance of pelecypods retaining both valves characterizes this unit. Near the base, a number of very hard, lime-cemented pods and lenses are present at roughly equivalent elevations and have highly gradational contacts with the surrounding marl. These pods and lenses are believed to represent accumulations of calcium carbonate cement leached from the surrounding fossiliferous marl. They are collectively considered to be a subunit of D, designated D_1.

Unit E underlies D and is a thin, relatively continuous impure limestone. It is light gray, very well indurated, and fossiliferous. It averages 1 ft in thickness and varies in elevation from 121 ft in the northwest corner of the auxiliary building to 116 ft in the southeast corner. Locally, unit E is difficult to distinguish from D_1. This is seen in the north wall between stations 1 + 40 and 1 + 70 (figure 2.5.1-24, sheet 2) where E is discontinuous and D_1 is represented by some fairly continuous lenses. In these cases unit E is arbitrarily selected as the unit displaying the sharpest contacts with surrounding units, and the one stratigraphically in between the overlying unit D and underlying unit F. The similarity between portions of E and D_1 suggests that both may be cemented deposits resulting from leaching and redeposition of calcium carbonate from the overlying fossiliferous deposits. The relative continuity of E indicates a basic permeability change occurring at that horizon in the geologic past. This is a basis for differentiating the overlying unit D from the underlying unit F.

Unit F, like D, is a fossiliferous marl, which is continuous around the basement excavation walls. It is medium gray, sandy to silty, and varies in thickness from 1 to 4 ft. It is dense and well consolidated but poorly cemented and tends to dessicate upon exposure to the atmosphere. Unit F includes some cemented limy pods similar to D_1. These have gradational contacts with the surrounding material and appear to be secondary in origin.

Unit G is light to dark gray laminated marl, which is present locally as lenses interfingering with units F and H. It is relatively continuous in the westernly portion of the south wall but pinches out at station 1 + 50. It reappears between stations 1 + 85 and 2 + 25 (figure 2.5.1-24, sheets 4 and 5) but then disappears for the remainder of the south wall. It is present in portions of the west and north walls and is absent in the east wall. The unit is characterized by very fine sinuous and discontinuous sandy laminations, scattered shell fragments, and small lenticular clay pods. It contains scattered carbonaceous lenses and is well consolidated.

Unit H underlies G and consists of massive gray marl, which is continuous around the excavation. It is dense, well consolidated, and poorly cemented. Shell fragments are sparse in the upper part of the unit but become increasingly abundant towards the base. Unit H varies in thickness from 1 to 6 ft.

Unit I underlies H and is similar to unit E. It is a thin, relatively continuous light gray impure limestone, which is generally less than 1 ft thick. It is continuous around the excavation walls with the exception of the east wall between station 0 + 79 and the south end of the wall where it is absent.

Unit J, the deepest marl unit exposed in the auxiliary building excavation, consists of medium gray, massive, fossiliferous marl similar to the stratigraphically higher units D and F. It is continuous around the excavation walls with the exception of the east end of the excavation where the upper contact of the unit dips beneath the base of the excavation.

From the preceding descriptions it is seen that the portion of the marl section exposed in the auxiliary building excavation represents cycles of fossil abundance and absence, interspersed with the formation of secondary limestone pods and lenses as a result of leaching of calcium carbonate from fossiliferous zones. Erosional and depositional processes have combined to create some of the interfingering of units as well as irregularity of some of the limestone layers.[4]

The upper contact of the Lisbon Formation was exposed around the perimeter of the power block excavation because it exists at an elevation higher than the top of the more localized auxiliary building excavation. The top of the Lisbon Formation corresponds with the top of the Blue Bluff marl. This upper contact was examined in detail and surveyed. It varies from a high elevation of 138.6 ft on the north side of the excavation to a low of 132.0 ft on the south side. The contact is erosional with very minor relief present. The uppermost few feet of the marl is locally weathered to a greenish color, and bioturbations (disturbance of the sediment due to the activity of organisms) were noted locally. 7

2B.3.3.3.3 Barnwell Group

Deposits of the upper Eocene Barnwell Group overlie the Blue Bluff marl of the Lisbon Formation and include all of the sediments exposed in the side slopes of the power block excavation. The contact between Barnwell Group and Lisbon Formation deposits is a disconformity, representing a hiatus in the depositional history of the site.

As mentioned previously, four distinct units within the Barnwell deposits have been recognized and are described in this section. These units include, from oldest to youngest: The Utley Limestone Member, the Twiggs Clay Member, the Irwinton Sand Member, and the Tobacco Road Sand Member. These units are illustrated in the stratigraphic column in figure 2.5.1-22.

Although examined and described in detail, the deposits between the top of the Blue Bluff marl and approximate el 170 ft could not be mapped in detail. (See figure 2.5.1-23.) Consequently, the geologic map of the power block excavation (figure 2.5.1-23) shows only the detailed lithology of the Tobacco Road Sand and the upper portion of the Irwinton Sand. This was due to extensive slumping of the slopes when excavation and dewatering were suspended during the period between September observed which might indicate a hydraulic connection with the deeper artesian aquifer below the marl.

Seepage from the side slopes of the power block excavation continued during this period with gradual decline in the elevation of the top of the seepage zone. The zone of seepage was effectively obscured when the side slopes were lined with a blanket of riprap up to el 160 ft. Temporary construction dewatering was continued throughout a significant portion of the 7
construction period.

2B.3.4 EXCAVATION AND FOUNDATION CONSIDERATIONS

2B.3.4.1 General

The excavation for the power block structures for Units 1 and 2 at the VEGP site is roughly square in shape, with two access ramps exiting from the southeast and southwest corners of the excavation. It measures approximately 1400 ft on an edge at the top and 1000 ft on an edge at the toe. The side slopes were cut a gradient of 2:1. The total excavated volume in the power block was approximately 5 million yd^3 including the access ramps.

The original ground surface in the power block area varied from an elevation of about 200 ft to slightly over 230 ft. The major portion of the excavation bottomed in the marl layer at approximately el 130 ft.

Within this larger excavation, a deeper localized excavation 7
was made for the auxiliary building basemat. This consisted of a rectangular area measuring approximately 120 ft by 440 ft. The base of this excavation was at el 108.6 ft, and the walls were cut vertically with a horizontal bench at el 118 ft. The other major power block structures are founded primarily on structural backfill at elevations above the floor of the excavation.

The excavation is shown in plan view in figure 2.5.1-23. This figure shows only the access road at the southeast corner since the one in the southwest corner was graded after geologic mapping had been performed on the slopes as shown in the figure.

Excavation work was started in May 1974 and postponed on September 12, 1974. The bottom elevation of the excavation averaged approximately 145 ft at this time and close to 900,000 yd^3 of excavation remained. The excavation work resumed by February 1977, and the auxiliary building excavation was bottomed out in October 1977.

2B.3.4.2 Excavation Procedures

Excavation work started and progressed very rapidly in the upper sands above the water table at el 160 ft. A large fleet of bulldozers and scrapers was assembled for the job. Very little, if any, ripping was required because of the sandy nature of the deposits; and progress was extremely fast, attaining a maximum rate of 120,000 yd^3/day at the peak of activity. Upon reaching the water table, excavation progress was significantly slowed because of the tendency of the equipment to mire in the saturated sands. At this point construction dewatering was begun. The procedures utilized for dewatering are discussed in the following section, but the general approach consisted of trenching a system of parallel ditches to permit drainage from the area between the ditches. Once dry, these areas would be excavated by bulldozers and scrapers while the ditches were progressively deepened to maintain dry conditions between the ditches. Excavation below water in the ditches was accomplished by means of two draglines.

When the excavation reached the zones of hard Utley Limestone described earlier, limited blasting of the rock was utilized to facilitate its removal. Since the limestone to be removed directly overlaid the marl, which was to form the foundation for structural backfill, it was necessary to control the blasting in such a manner as to protect the underlying marl from damage.

First, the stipulation was made that the contractor not use explosives if conventional methods could be used, even if some difficulty resulted. Further, the use of explosives would be discontinued in any case, if, in the opinion of the engineer, the marl might be damaged as a result of blasting. Blast holes were not permitted to penetrate lower than el 135 ft, and a minimum stem of 18 in. was recommended below the charge in each hole. It was recommended that no blast holes exceed 3 in. in diameter and that the maximum charge weight should not exceed 30 lb per delay. The maximum allowable powder factor was set at 1 lb/yd^3.

Because of the concern for protecting the marl, only very limited blasting of the limestone was performed. The major portion of the rock was removed by first breaking it with a hydraulic ram mounted on a backhoe, then loading it out with conventional equipment.

Excavation of the marl was accomplished by ripping, followed by conventional earth moving. The auxiliary building basement excavation was cut with bulldozers and front-end loaders. Trimming of the walls was accomplished with a backhoe. Some of the hard, indurated limestone layers within the marl described in paragraph 2B.3.3.3.2 were first broken with the backhoe-mounted hydraulic ram, then removed by front-end loader. Fine grading of the floor of the power block was accomplished with motor graders in areas underlying future structural backfill and with Gradalls in the nuclear service cooling water tower foundation areas. In the foundation areas, shovels and air hoses were used for cleanup of loose material.

2B.3.4.3 Construction Dewatering

The construction dewatering system utilized in the power block excavation consisted of a system of east-west dewatering ditches connected by a north-south ditch leading to a sump and pumping plant in the southwest corner of the excavation. Because of the low permeability of the deposits, the dewatering consultant, Mr. R. Y. Bush, decided that a conventional well-point system would be ineffective, hence the ditch and sump approach.[5] This scheme proved to be successful when the invert elevation of the ditches was maintained 15 to 20 ft below the adjacent grade. This permitted conventional procedures in reasonably dry materials.

Upon reaching the marl, the system of ditches and sump was replaced by a perimeter drainage system as shown in figure 2.4.12-3. This consisted of a buried porous concrete pipe around the perimeter of the power block excavation feeding into three small sumps at the toe of the south slope. Water pumped from the sumps was discharged to debris basin No. 1 southeast of the power block. The buried porous concrete pipe was encased in a granular filter material which was carried up the surface of the adjacent 2:1 slope to about el 160 ft. This filter blanket was placed so that there was a minimum of 4 ft of filter material measured horizontally from the face of the slope out to the face of the filter blanket. (See figure 2.4.12-3.) 7

This dewatering scheme proved to be entirely successful and construction in the marl layer was able to proceed under totally dry conditions.

2B.3.4.4 Slope Protection

During the early stages of excavation, intense rainfall of short duration caused severe erosion of the 2:1 side slopes of the power block excavation. The uncemented sands rapidly washed out forming deeply incised gullies in some areas. These gullies were backfilled with the native soil material and local areas of the slope regraded. One such area is seen on the geologic map (figure 2.5.1-23) in the upper part of the east slope between stations N83 + 00 and N84 + 00. Another larger area exists in the south slope of the access ramp each of station E100 + 00. After regrading the eroded areas, berms were constructed around the tops of the slopes to control runoff. The surfaces of the slopes were sprayed with the chemical stabilizing agent Petroset, a colorless liquid that sets up and tends to bond the sand grains together. These measures proved to be reasonably successful in controlling further erosion.

After the resumption of excavation work in 1977, erosion problems further down the slopes were encountered due to seepage of the perched ground water out of the slopes. Since stabilizing agents were expected to be ineffective under these conditions, the lower portions of the slopes were blanketed with riprap to improve stability. The riprap was subsequently covered with a finer grained filter transition material.

Where the 2:1 slopes intersected the cavernous limestone deposit, several cavities of varying sizes were exposed in the slopes. The largest of these existed in the northwest corner of the power block and had an opening measuring 10 ft by 10 ft. This cavity extended back into the slope some 30 ft before narrowing down to a small size. Other small cavities were encountered at varying intervals all along the north side of the power block excavation. It was necessary to fill these cavities so that an effective buttress would be formed against which the future structural backfill could be placed and compacted. This consideration did not require complete filling of the cavities since a prism of fill material placed in the entrance and extending some distance into the cavity would provide an unyielding mass against which the structural backfill could be placed. The cavities were first cleaned of loose debris, then backfilled with crushed rock (Georgia State Standard No. 467). The crushed rock was packed into the cavities by means of a 20-ft-long ram attached to the blade of a bulldozer. This method proved to be very successful and actually resulted in the crushed rock being forced into small crevices, effecting an essentially complete filling of some of the cavities. The large cavity in the northwest corner was effectively filled in this manner. From the volume of crushed rock forced into the cavity, it was estimated that the cavity was completely filled to at least a distance of 25 ft back of the entrance.

To retard erosion of temporary slopes in Category 1 backfill placed in the power block excavation, these slopes were sprayed with a commercial compound known by the trade name Glassroot.

It consists of a glass fiber material which was sprayed onto the slope and then coated with a film of asphalt emulsion. This proved to be effective in controlling erosion of the compacted sandy backfill but only for a limited period of time. By late 1979, the glassroot/asphalt coating began to show signs of excessive deterioration. Consequently, the slopes were stripped clean and recoated with gunite, which proved to be more durable and easier to maintain. 7

2B.3.4.5 Foundation Cleanup and Protection

As mentioned previously, the marl at final grade in foundation areas was exposed using either a motor grader or Gradall. Loose material was then removed by shovel, broom, and airhose. On the vertical walls of the auxiliary building excavation, final trim to neat line was accomplished with a backhoe followed by pick and shovel and airhose techniques.

In all cases where final grade was exposed and cleaned off, the marl surface had to be covered in a manner approved by the geologist within 24 h of exposure. On horizontal surfaces the marl was covered either by structural backfill or by mudmat concrete depending upon whether the particular area exposed was in a foundation or backfill area. The vertical walls of the auxiliary building basement excavation were coated with a 4-in.-thick layer of gunite reinforced with welded wire mesh.

In some cases temporary covers such as loose soil or plastic sheeting were employed when the permanent cover material could not be applied within the 24-h limit. In all cases the temporary cover procedure was approved by either the geologist or the Georgia Power Company inspector. Before placing the permanent cover material in any foundation area, the marl was inspected and approved by the geologist or soil engineer in accordance with the procedures described in the following section.

2B.3.4.6 Foundation Inspection and Approval Procedures

All areas of marl exposed and cleaned off in preparation for placement of concrete or backfill were examined closely for any evidence of loose or soft zones or geologic discontinuities. After confirming the absence of such features, the inspecting geologist documented the approval of the area on field foundation approval forms. These field approval forms were transmitted to the Georgia Power Company site personnel for permanent retention. At intervals, the forms were countersigned by the supervising geologist and soil engineer for the project.

In addition, photographs of the foundation areas were taken. These were logged and transmitted to Georgia Power Company for permanent retention in the field office.

2B.3.4.7 Foundation Testing

As a part of the general marl geologic mapping and inspecting functions, it was decided to carry out a program of coring and testing samples of the marl to confirm the material properties used for design. It was desired to obtain samples for record purposes. The coring and sampling operation was performed under the direction of the geologist and inspector, and the test assignments were made by the soils engineer. 7

A total of 38 core holes was drilled by rotary methods in the floor of the power block excavation at locations selected by the geologist. The hole locations are shown in figure 2.5.1-23. The marl was cored to depths between 4 and 11 ft beneath the ground surface. Four-in.-diameter core samples were obtained, labelled, and placed in wooden boxes for permanent storage at the site. Samples for testing were selected by the geologist. These were then wrapped in cellophane, sealed with wax, and placed in special boxes for transportation to the laboratories of Law Engineering Testing Company in Atlanta.

A total of 31 core samples was tested for moisture content, bulk unit weight, unconfined compressive strength, and shear strength from one-point unconsolidated-undrained triaxial shear tests. The average wet unit was found to be 105.6 lb/ft^3, while the average moisture content was 36.2 percent. The average deviator stress at failure in the strength tests was 39.14 k/ft^2 (272 psi). A complete summary of test results is found in appendix 7 of reference 1. The results obtained are in the range anticipated and show that the marl is a competent foundation material.

2B.3.4.8 Foundation Rebound Monitoring

In order to monitor the rebound occurring in the Blue Bluff marl layer as a result of removal of approximately 100 ft of the overlying materials, the specialist firm of Goldberg, Zoino, Dunnicliff Associates was commissioned to provide in situ instrumentation. A total of nine heave points was installed at the bottom of drill holes made for this purpose. The heave points were installed at the locations shown in figure 2B-1, between approximate el 104 and 126 ft.

Throughout the excavation period, elevation changes of the heave points were surveyed. The measured heave is summarized in the table below:

Heave Point No.	Period From	Period To	Measured Heave (in.)
1	6/22/74	8/07/77	1.1
2	6/16/74	6/22/76	1.4
3	6/16/74	10/02/74	0.6
5	6/16/74	2/26/77	1.7
7	6/16/74	6/05/77	1.2
9	6/30/77	8/07/77	1.5

More complete data is presented in appendix 6 of reference 1.

The measured heave was substantially less than that predicted.

2B.3.5 CONCLUSIONS

The detailed geologic mapping of the strata exposed in the power block excavation at the VEGP site has better defined the structure and stratigraphy of this area. A much more comprehensive and detailed picture of the site geology has emerged as a result of this effort. The general conclusions of the PSAR[2] have been confirmed.

Two separate marker horizons in the Irwinton Sand have been mapped around the side slopes of the power block. Both horizons are continuous and unbroken, demonstrating the absence of faulting in these materials. The upper contact of the stratigraphically lower Blue Bluff marl of the Lisbon Formation has been mapped with survey accuracy and has also been found to be uninterrupted by offsets. Subunits within the marl have been mapped around the walls of the auxiliary building basement excavation. These zones were likewise found to be undisturbed by faulting. Minor stratigraphic irregularities noted were shown to be related to erosional and depositional processes.[4] 7

Surface depressions and subsidence features mapped in the upper sands were found to be related to collapse of solution cavities in the underlying limestone. Detailed examination of the exposed marl and surveying of its upper surface configuration has shown that the marl is free of solution cavities such as those present in the overlying limestone. The marl was found to contain no freely draining water and its function as an aquiclude was confirmed.

Where the side slopes of the power block intersected solution cavities in the limestone layer, these cavities were backfilled with crushed rock to provide a firm buttress against which structural backfill could be placed and compacted. The backfilling of the cavities was inspected and found to be adequate.

Areas of the marl exposed at final grade were inspected, approved, and protected in an adequate manner as described in the report. All foundation areas inspected were found to expose sound competent marl suitable for supporting the backfill and plant structures.

The coring and testing of the marl at selected locations in the power block yielded results which confirm the design parameters used. Results of the rebound monitoring program showed that the measured rebound was less than that predicted, giving additional evidence of the competency of the marl.

The results of the geologic work described in this report lead to the conclusion that the VEGP site is suitable for design and construction of a multiple-unit nuclear generating plant. No geologic hazards were found to exist that might affect safety and licensing considerations.

REFERENCES

1. Bechtel Power Corporation, Report on Backfill Material Investigations, two volumes, January 1978.

2. Georgia Power Company, Alvin W. Vogtle Nuclear Plant Preliminary Safety Analysis Report, chapter 2.

3. Huddleston, Paul, Georgia Geological Survey, Personal Communication, 1978. 7

4. Bechtel Power Corporation, Report on Stratigraphic Irregularities Exposed in the Auxiliary Building Excavation, February 1978.

5. Bush, R. Y., Consulting Engineer, Dewatering Study - Alvin W. Vogtle Nuclear Plant, January 12, 1973. (See also subsequent correspondence.)

BIBLIOGRAPHY

Bechtel Power Corporation, Interim Report of Geologic Conditions - Power Block Excavating, October 23, 1974.

representative sample. This connection is located close to the same weld connection at the pump discharge and is in the same relative position in each loop.

The hot and cold leg bypass manifold discharge lines join downstream of the manifold and discharge into a common line. The combined bypass flow passes through a flow indicator before being discharged to the suction side of the reactor coolant pump.

Resistance temperature detectors extend directly into the flow paths to minimize the instrument time delay. Two isolation valves in series are provided on each side of the temperature detector manifold to allow for resistance maintenance. The valve nearest the connection to the main coolant piping is located above the elevation of the reactor vessel nozzles to permit valve repair during cold shutdown, without draining the RCS. In addition, vents and drains are provided for each manifold, to be used in conjunction with the isolation valve for maintenance.

Signals from the temperature detectors are used to compute the reactor coolant ΔT (temperature of the hot leg, T_{hot}, minus the temperature of the cold leg, T_{cold}), and an average reactor coolant temperature, T_{avg}. The ΔT and T_{avg} for each loop is indicated on the main control board. 7

5.4.3.3 Design Evaluation

Piping load and stress evaluation for normal operating loads, seismic loads, blowdown loads, and combined normal, blowdown, and seismic loads is discussed in section 3.9.N.

5.4.3.3.1 Material Corrosion/Erosion Evaluation

The water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications. (See subsection 5.2.3.)

Periodic analysis of the coolant chemical composition is performed to monitor the adherence of the system to desired reactor coolant water quality listed in table 5.2.3-3. Maintenance of the water quality to minimize corrosion is accomplished using the CVCS and sampling system which are described in chapter 9.

The design and installation are in compliance with the ASME Code, Section III. Pursuant to this, all pressure-containing welds out to the second valve that delineates the RCS boundary are accessible for inservice examination as required of ASME Code, Section XI, and are fitted with removable insulation.

5.4.3.3.2 Sensitized Stainless Steel

Sensitized stainless steel is discussed in subsection 5.2.3.

5.4.3.3.3 Contaminant Control

Contamination of stainless steel and Inconel by copper, low melting temperature alloys, mercury, and lead is prohibited. Colloidal graphite is the only permissible thread lubricant.

Prior to application of thermal insulation, the austenitic stainless steel surfaces are cleaned and analyzed to a halogen limit of 0.0015 mg chloride/dm^2 and 0.0015 mg fluoride/dm^2.

5.4.3.4 Tests and Inspections

The RCS piping quality assurance program is given in table 5.4.3-2.

Volumetric examination is performed throughout 100 percent of the wall volume of each pipe and fitting in accordance with the applicable requirements of Section III of the ASME Code for all pipe 27 1/2 in. and larger. All unacceptable defects are eliminated in accordance with the requirements of the same section of the code.

A liquid penetrant examination is performed on all accessible surfaces of each finished fitting, in accordance with the criteria of the ASME Code, Section III. Acceptance standards are in accordance with the applicable requirements of the ASME Code, Section III.

The pressurizer surge line conforms to SA-376, Grade 304, 304N, or 316 with supplementary requirements S2 (transverse tension tests) and S6 (ultrasonic test). The S2 requirement applies to each length of pipe. The S6 requirement applies to 100 percent of the piping wall volume.

The end of pipe sections, branch ends, and fittings are machined back to provide a smooth weld transition adjacent to the weld path.

6.1.2 ORGANIC MATERIALS

6.1.2.1 Protective Coatings

Certain coatings, which are in common industrial use, may deteriorate in the post-accident environment and may contribute substantial quantities of foreign solids and residue to the containment sump. Consequently, protective coatings used inside the containment, excluding components limited by size and/or exposed surface area, are demonstrated to withstand the design basis accident (DBA) conditions and meet the intent of American National Standards Institute (ANSI) N101.2 (1972), Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities, as well as the recommendations of Regulatory Guide 1.54 Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants. Information regarding conformance with Regulatory Guide 1.54 is provided in table 6.1.2-1 and further conformance information for nuclear steam supply system (NSSS) equipment has been submitted to the Nuclear Regulatory Commission (NRC) for review via reference 1 and accepted via reference 2.

A. Regulatory Guide 1.54 is imposed for items located within the containment building as follows:

   1. For shop priming of liner plate, structural steel, and fabricated shapes.

   2. For shop priming of fabricated pipes, tanks, heating, ventilation, and air-conditioning (HVAC) ducts, and equipment.

   3. For field finish painting of steel where called for in drawings and specifications.

   4. For surfacing of concrete where indicated in drawings and specifications.

B. Regulatory Guide 1.54 is implemented by requirements as follows:

   1. Use of specific coatings systems which are prequalified to ANSI N101.2.

   2. Surface preparation standards.

   3. Surface profile requirements.

4. Application of the coating systems in accordance with the paint manufacturer's instructions.

5. Inspections and nondestructive examinations.

6. Identification of all nonconformances. Coatings which do not conform with Regulatory Guide 1.54 are limited in use and are evaluated on a case basis relative to impact on plant safety. An inventory of unqualified coatings is maintained to ensure appropriate control of coatings inside containment. 7

7. Certifications of compliance and/or documentation procedures to satisfy project requirements.

8. The vendor's procedures are subject to review prior to application, and the vendor's implementation of the specification requirements is monitored.

C. Regulatory Guide 1.54 is not imposed for the following:

1. Surfaces to be insulated.

2. Surfaces "contained" within a cabinet or enclosure; for example, the interior surfaces of ducts.

3. Field repair to any small areas previously coated with a qualified coating system such as: 7

   a. Bolt heads, nuts, and miscellaneous fasteners.

   b. Damage resulting from spot, tack, or stud welding.

   Field touchup and repair of large areas shall be in accordance with Regulatory Guide 1.54.

4. Small "production line" items such as small motors, handwheels, pipe supports, snubbers, electrical cabinets, control panels, loudspeakers, etc., where special painting requirements would be impracticable.

5. Stainless steel or galvanized surfaces.

6. Coating used for the banding of piping.

7. Concrete designated to receive a sealer coat only.

D. The majority of the coatings specified for use inside the containment are the inorganic type (ethyl silicate inorganic zinc). The mode of failure of inorganic zinc is powdering rather than blistering and delamination. This failure mode minimizes the accumulation of solid debris in the containment sumps. Any particles of appreciable size that do occur either settle out prior to reaching the sump screens or are trapped by the sump filter screens. The screen opening size (1/8 in.) is smaller than the line piping, the residual heat removal heat exchanger tubes, the spray nozzles, pump running clearances, and clearances in the reactor core so particles that could potentially block the system are filtered out. (Refer to section 6.2 for a discussion of the sump design and consideration given to screen clogging.) 7

A coating schedule for items inside the containment is given in tables 6.1.2-2 and 6.1.2-3. Approximate paint film thickness and exposed surface area for major components and structures inside the containment are also provided. The painted areas of valve operators, miscellaneous parts on the reactor coolant pump drives, and instrumentation are considered insignificant. Exposed concrete in the containment is coated as indicated in table 6.1.2-2.

Protective coatings for use on NSSS components in the reactor containment have been evaluated as to their suitability in post-DBA conditions. Tests have shown that the inorganic zinc, epoxy, and modified phenolic systems are the most desirable of the generic types evaluated for use inside containment. This evaluation[1] considers resistance to high temperature and chemical conditions anticipated during a loss-of-coolant accident, as well as high radiation resistance.

6.1.2.2 Other Organic Materials

A listing of other organic materials in the containment is included in table 6.1.2-4. The materials listed are not protective coatings applied to surfaces of nuclear facilities.

REFERENCES

1. Letter NS-CE-1352, C. Eicheldinger (Westinghouse) to C. J. Heltemes, Jr. (NRC), dated February 1, 1977.

2. Letter, C. J. Heltemes, Jr. (NRC) to C. Eicheldinger (Westinghouse), dated April 27, 1977.

3. Picone, L. F., "Evaluation of Protective Coatings for use in Reactor Containment," WCAP-7198-L (Proprietary), April 1968, and WCAP-7825 (Nonproprietary), December 1971.

TABLE 6.1.2-1 (SHEET 3 OF 4)

Regulatory Guide 1.54 Position	Position on Non-NSSS Components	Position on NSSS Components
nate documentation consistent with the requirements of Appendix B to 10 CFR 50 is also considered acceptable.	4. Application of the coating systems are made in accordance with the paint manufacturer's detailed instructions. 5. Inspections and nondestructive testing are performed. 6. Nonconformances are identified and evaluated as discussed in paragraph 6.1.2.1.B. 7. Certifications of compliance and/or documentation procedures are furnished to satisfy project requirements.	o Electrical cabinets. Since these items are procured from a large number of vendors, and individually have very small surface areas, it is not practical to enforce the complete set of stringent requirements which are applied to Category 1 items. Another painting specification is used in these procurement documents. This specification defines to the vendors the requirements for: 7 1. Use of specific coating systems which are qualified to ANSI N101.2. 2. Surface preparation. 3. Application of the coating systems in accordance with the paint manufacturer's instructions.
D. Sections 3 and 4 of ANSI N101.4-1972 delineate quality assurance requirements for coating materials and surface preparation of substrates. Coatings and cleaning materials used with stainless steel should not be compounded from or treated with chemical compounds containing elements that could contribute to corrosion, intergranular cracking, or stress corrosion cracking. Examples of such chemical compounds are those containing chlorides, fluorides, lead, zinc, copper, sulfur, or mercury where such elements are leachable or where they could be released by breakdown of the chemical compounds under expected environmental conditions (e.g., by radiation). This limitation is not intended to prohibit the use of trichlorotri-fluoroethane which meets the requirements of Military Specification MIL-C-81302b for	D. Conform. Only cleaners/solvents which contain less than 100 ppm of halogens are acceptable.	The vendor's compliance with the requirements is also checked during quality assurance surveillance activities in the vendor's plant. These measures of control provide a high degree of assurance that the protective coatings will adhere properly to the base metal and withstand the postulated accident environment within the containment building. Category 3 - Small Equipment Category 3 equipment consists of the following: • Transmitters. • Alarm horns. • Small instruments. • Valves. • Heat exchanger supports. These items are procured from several different vendors and are painted by the vendor in accordance with conventional industry practices. Because the total exposed surface area is very small, Westinghouse does not specify further

D. Active components of the containment spray system are capable of being tested during plant operation. Provisions are made for inspection of major components at appropriate times specified in ASME Boiler and Pressure Vessel Code, Section XI.

E. The containment spray system components are designed to remain functional during the accident environment and to withstand the dynamic effect of the accident.

F. The containment spray system in conjunction with the containment cooling system is capable of removing sufficient thermal energy and subsequent decay heat from the containment atmosphere following the postulated LOCA or MSLB accident to maintain the containment pressure below design values.

G. The containment spray system is designed and fabricated to codes consistent with Regulatory Guide 1.26 as described in table 3.2.2-1 and Seismic Category 1 in accordance with Regulatory Guide 1.29. The power supply and control functions are in accordance with Regulatory Guide 1.32.

6.2.2.2.1.2 Power Generation Design Bases. The containment spray system has no power generation design bases.

6.2.2.2.2 System Design

6.2.2.2.2.1 General Description. The containment spray system is designed to the codes and standards identified in table 3.2.2-1; flood design is discussed in section 3.4; missile protection is discussed in section 3.5. Protection against dynamic effects associated with the postulated rupture of piping is discussed in section 3.6. Environmental design and equipment qualification is discussed in section 3.11. The actuation system is discussed in section 7.3.

6.2.2.2.2.2 System Description. The containment spray system, shown schematically in figure 6.2.2-3, consists of two pumps, spray ring headers and spray nozzles, valves, and connecting piping. Initially, water from the refueling water storage tank (RWST) is mixed with NaOH from the spray additive tank and is used for the containment spray followed by water recirculated from the containment emergency sump.

At the RWST low-low level alarm the operator may initiate switchover of the emergency core cooling system (ECCS) pumps to the recirculation mode of operation. Following ECCS switchover the operator manually realigns the spray system to take suction from the containment emergency sumps. The RWST is sized to give the operator a minimum of 20 min from receipt of the low alarm until initiation of switchover. Adequate transfer allowance is provided to allow the operator to perform the switchover sequence without securing the containment spray pumps. The total amount of borated refueling water injected into the containment by the charging, safety injection, residual heat removal, and containment spray pumps will provide a sump pH of 8.5 or above when mixed with the contents of the spray additive tanks which have been injected. 7

No single failure can prevent the switchover of one of the two redundant containment spray trains, which consists of a pump and spray header arrangement. The containment pressure transient analysis shows that only one of the two redundant spray trains is necessary to prevent containment pressure from reaching the containment design point. Thus, even if one train is not available following the switchover, the remaining operating train is sufficient to control containment pressure, assuming that four of the eight containment fan coolers are also in operation.

6.2.2.2.2.3 Component Description. The mechanical components of the containment spray system are described in this section. Component design parameters are given in table 6.2.2-4. Parts of the system in contact with borated water are stainless steel or an equivalent corrosion-resistant material.

Corrosion tests have been performed on the materials that the spray would come in contact with, e.g., the paint on the inside of the containment structure. (Tests are detailed in WCAP-7825.) These tests have shown that no significant amount of corrosion products is produced. Those corrosion products or any chemical precipitation of appreciable size that does occur is trapped by the sump filter screen. The screen size is smaller than the line piping, residual heat removal heat exchanger tubes, and the spray nozzles, so that particles which could potentially block the system will be filtered out. The spray nozzle material (stainless steel, SA351) was chosen for its resistance to corrosion. Tests have been performed on this material in the same type of NaOH boric acid environment that the nozzle would see during spray actuation. (Corrosion tests of austenitic stainless steel are detailed in WCAP-7803.) The resulting corrosion levels were very low.

6.4 HABITABILITY SYSTEMS

The control room habitability systems include missile protection; radiation shielding; radiation monitoring; chlorine and smoke detection capability; air filtration, adsorption, and pressurization; and air-conditioning, lighting, personnel support, and fire protection equipment. (Refer also to section 3.1 for a discussion on conformance with 10 CFR 50, Appendix A, General Design Criterion 19.) 7

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

6.4.1 DESIGN BASES

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

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

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

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

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

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

The habitability systems provide the capability to detect and protect control room personnel from smoke, chlorine, and 7
airborne radioactivity.

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

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

A single active failure of any component of the control room essential HVAC system, assuming a loss of offsite power, does not impair the ability of the system to function. Each train of the control room HVAC system is connected to a separate and independent Class 1E power supply. 3

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

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

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

stainless steel, has face guards on both sides, and is water and fire resistant. HEPA filter elements are manufactured and tested prior to installation in accordance with MIL-F-51068, as modified by Nuclear Regulatory Commission Health and Safety Information Issue 306. The filter element minimum acceptance criterion is removal of 99.97 percent of 0.3-µm thermal-generated, monodispersed dioctyl phthalate particles.

E. Carbon Adsorbers

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

F. Cooling Coil

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

G. Emergency Filtration Train Fans

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

H. Control Room Return Fan

The emergency control room return fans are Seismic Category 1 and are capable of delivering 24,740-ft^3/min flowrate. Fan and motor materials are suitable for operation under the environmental conditions associated with the postulated DBA.

I. Ductwork and Dampers

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

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

J. Control Room Access Doors

To minimize inleakage, the control room access doors are equipped with self-closing devices that shut the doors automatically following the passage of personnel. Alarms are also provided to annunciate if any of the doors are open after a changeover to emergency operation. Two sets of electrically interlocked doors with a vestibule between, acting as an airlock, are provided at each of the two entrances and the emergency exit to the combined control room and associated spaces.

K. Isolation Dampers

System isolation dampers are capable of automatically closing in 6 s after receipt of an actuation signal,
as verified by manufacturer testing. The isolation 7
dampers are tested as bubbletight dampers for zero leakage.

L. Chlorine Detectors

Redundant chlorine detectors are installed in the control room ventilation outside air intake plenum. These detectors indicate the presence of chlorine in concentrations of 1 ppm. Response time is 8 s at

5 ppm chlorine concentration with the alarm setpoint of 1 ppm.

M. Radiation Detectors 7

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

N. Smoke Detectors

Redundant smoke detectors are installed in each control room ventilation outside air intake (a total of four detectors). These detectors indicate the presence of smoke entering the control room envelope from outside. Redundant smoke detectors are also installed inside the control room envelope. These smoke detectors detect smoke inside the control room envelope.

Each smoke detector actuates an alarm in the control room on the HVAC control panel.

O. Breathing Apparatus

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

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

6.4.2.3 Leaktightness

The exfiltration and infiltration analyses are performed using the methods and assumptions given in American Society of Heating, Refrigerating, and Air-Conditioning Engineers Handbook of Fundamentals and Regulatory Guide 1.78. The leakage rates were calculated using the following equations:

A. Penetrations and Doors

$$q = 4005A \sqrt{P}$$

where:

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

A = leak path flow area (ft^2).

P = differential pressure (in. WG).

4005 = unit conversion factor.

B. Dampers

Leaktightness is determined from actual test data on dampers.

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

Table 6.4.2-2 provides a listing of leakage data and total leakage rates for potential leak paths. For analysis of exfiltration from the pressurized control room envelope, a positive 1/4-in. WG pressure differential is considered for all leak paths resulting in a total outleakage of 260 ft^3/min. For analysis of infiltration to the unpressurized control room envelope, a negative 1/8-in. WG pressure differential is considered for all leak paths resulting in a total inleakage of 185 ft^3/min, although the control room envelope is pressurized during normal operation. The normal outside air supply is designed to pressurize the control room to 1/4 in. WG and is sized to deliver up to 3000-ft^3/min flowrate into the control room during the normal mode of operation. Based on the rate of outleakage, this flowrate is adequate to maintain a 1/4-in. positive pressure in the control room envelope during normal operation.

6.4.2.4 Interaction with Other Zones and Pressurized Equipment

The outside air intake duct is located such that:

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

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

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

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

A. The control room is maintained at 1/4-in. WG pressure above atmospheric to prevent infiltration of air during normal conditions. The volume of the control room and other space protected by the habitability system is approximately 180,000 ft^3. The outside air supply of 3000 ft^3/min for the normal mode ensures pressurization of the area in excess of 1/4 in. WG so that all flow of air through the potential leakage paths, doors, ductwork, filtration units, and cable penetrations is outward and not inward. The outside air intake is through the plenum system at el 281 ft 0 in. The inlet to the plenum is through openings at the upper part of the building above the roof. The plenum system is designed as a Seismic Category 1 structure, which is an integral part of the building structure.

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

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

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

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

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

1. At the northwest corner of the control room.

2. In the south wall of the control room.

3. At the locked emergency exit in the east wall of the control room.

The doorways to the control room are each arranged with two sets of doors acting as an airlock. The doors are provided with seals to reduce leakage and to maintain pressurization. The doors are provided with alarms for security and to alert the operator if any of the doors are open.

F. The ductwork for the essential HVAC system for the control room under accident conditions is separated from connections to other areas or to the normal operating HVAC air handling units by two Seismic Category 1, bubbletight dampers independently actuated and powered by the two engineered safety features trains. Each isolation damper automatically closes when an emergency air handling unit is started in the corresponding safety train. The emergency air handling units start automatically on any of the following signals: safety injection, toxic gas in the outside air intake, or high radiation levels in the outside air intake. In the event of high chlorine levels in the outside air intake, the control room is automatically isolated from the outside intake. Under emergency conditions, filters are used for the makeup 7

6.4.3 SYSTEM OPERATIONAL PROCEDURES

The control room normal and emergency airflow schematic is shown in figure 9.4.1-1.

6.4.3.1 Normal Mode

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

6.4.3.2 Emergency Mode (High Radiation, Safety Injection)

The detection of high radiation levels in the control room outside air intake shall cause the initiation of the control room isolation (CRI) signal. The CRI signal causes activation of the essential air filtration units followed by the closure of 3 the isolation dampers between the normal and essential systems. The control room normal air handling units will automatically trip as the isolation dampers close. After automatic activation of both trains for emergency operation, one train may be manually transferred to the emergency standby mode from the control room, while the other train continues to operate in the emergency mode. During this mode of operation, conference room, kitchen, and toilet exhaust ducts are also isolated through automatic closure of the isolation dampers on the receipt of the CRI signal.

6.4.3.3 Isolation Mode (Toxic Gas)

Isolation mode of the control room emergency HVAC system occurs when a toxic gas signal is initiated due to the presence of toxic gas (chlorine) in the outside air intake. The toxic gas 7 signal automatically activates both trains of emergency air filtration system and closes the isolation dampers in the outside air intake. The normal air handling units are automatically tripped and isolated following the actuation of the emergency units.

In this mode of operation both essential air filtration units run in the recirculation mode without outside air. The air from the control room is continually recirculated, cooled, and filtered by the essential air filtration units. Upon verification of one train of essential air filtration unit operation, the control room operator may manually isolate the other train and put it in emergency standby mode from the control room.

After making sure that there is no toxic gas in the intake duct, the control room operator manually purges the normal HVAC system before it is put back into service.

6.4.3.4 Smoke Removal Mode

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

When there is smoke inside the control room, interior smoke detectors are actuated and sound the alarm in the control room. The operator analyzes the situation, closes isolation dampers for all filtration units if necessary, and activates the solenoid valve, then manually closes the isolation dampers to isolate the control room. 3

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

When there is smoke outside the control room, the smoke detectors in the outside air intake plenum actuate the annunciator alarms in the control room. The operator then analyzes the situation on the HVAC panel and, if necessary, actuates the isolation mode described previously in paragraph 6.4.3.3.

6.4.4 DESIGN EVALUATIONS

6.4.4.1 Radiological Protection

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

6.4.4.2 Toxic Gas Protection

Control room protection from the effects of toxic gases is in accordance with Regulatory Guide 1.78 as discussed in subsection 2.2.3. The analysis of potential sources for toxic gases is presented in subsection 2.2.3, and the probability of exceeding the toxic concentration limits at the control room intake was determined to be less than the 10^{-7} criterion of Standard Review Plan 2.2.3. Therefore, no further analysis is required for the chemicals stored or shipped past the site.

As required by Regulatory Guide 1.95, control room protection is provided against chlorine which could enter the control room. The distance of the chlorine storage for the nuclear service cooling water system is 195 m. (See figure 6.4.2-2.) While this is 5 m less than the minimum storage distance for a 1-ton cylinder (200 m) given in Regulatory Guide 1.95, Table 1, the difference is not significant, and the intent of Regulatory Guide 1.95 is met as shown by the analysis in subsection 2.2.3. 7

6.4.4.3 Implementation of Design Bases

Control room habitability system components discussed in paragraph 6.4.2.2.2 are arranged in redundant safety-related ventilation trains as shown in figure 9.4.1-1. The location of components and ductwork within the control room envelope ensures an adequate supply of filtered air to all areas requiring access as shown in figure 6.4.2-1.

By using chilled water cooling coils, the control room essential air-conditioning system maintains the temperature between 70°F and 80°F and the relative humidity below 50 percent. The control room pressure is maintained at least 1/4 in. WG above atmospheric pressure during normal operation. The control room essential air-conditioning system maintains the same temperature and humidity conditions when operating in the emergency and isolation modes.

The control room air-conditioning system is capable of removing sensible and latent heat loads of 1.1×10^6 Btu/h and 2.2×10^5 Btu/h, respectively, which includes consideration of equipment heat loads and minimum personnel occupancy requirements. The transfer to emergency or isolation operation mode does not create a hazard for CO_2 buildup. In case of emergency operation, there is a supply of outside air of 260 ft^3/min and the long term equilibrium for CO_2 will remain below one part per thousand for a five-person occupancy. In case of isolation mode operation, where the control room is sealed, the critical level of 3 percent would be reached in 5 days for an occupancy of five persons. The technical support center will provide an additional habitable location to relieve crowding in the control room as discussed in paragraphs 9.4.1.8 and 9.5.10.2.

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

The control room air purification system and shielding designs are based on the most limiting design basis assumptions contained in Regulatory Guide 1.4. Automatic transfer of the control room from the normal heating, ventilation, and air-conditioning (HVAC) system to the essential system is accomplished upon receipt of a control room isolation signal which is generated on receipt of the high-radiation signal from the outside air intake duct radiation detector, the safety injection actuation signal, or the high-toxic gas signal from the outside air intake duct toxic gas detector. Transfer to the essential system also may be manually initiated from the control room. Local audible alarms warn the operators to shut the self-closing doors should they be open for some reason after transfer to the emergency mode. Refer to subsection 7.3.6 for a discussion of the actuation logic.

The airborne fission product source term in the reactor containment following the postulated loss-of-coolant accident (LOCA) is assumed to leak from the containment at a rate of

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

Air within the control room is recirculated continuously through the emergency air-conditioning units, which contain upstream high-efficiency particulate air (HEPA) filters, charcoal adsorbers, downstream HEPA filters, cooling coil, and fan, to control the room temperature and airborne radioactivity. The outside air required for pressurization is mixed with the return air before it enters the filtration unit. During the emergency mode of operation, the control room HVAC is designed to pressurize the control room to 1/4-in. WG pressure to prevent unfiltered inleakage.

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

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

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

Redundant chlorine detectors are provided in the control room air intake plenum upstream from the isolation dampers. These detectors meet single failure criteria. Alarms and control logic are provided to warn the operators and automatically 7 isolate the control room when chlorine is present in hazardous quantities. The sensitivity of the detectors and the closing time of the valves is such that the amount of chlorine introduced when homogeneously distributed throughout the control room is below allowable concentrations in accordance with Regulatory Guides 1.78 and 1.95. Within 10 s after arrival of chlorine at 1 ppm, the detectors initiate complete closure of the isolation dampers to the control room. Refer to subsection 7.3.6 for a discussion of the actuation logic. In the event of a toxic chemical release, the detectors in the control room ventilation system outside air intake and the related logic function to stop the normal HVAC units and exhaust fans, close the outside air intake and exhaust dampers, and start the emergency HVAC units in the isolation mode. This limits the amount of toxic gas entering the control room to the amount that leaks through doors, dampers, and other openings. Air infiltration rates during the isolation mode are discussed in paragraph 6.4.2.3. 7

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

To protect against high airborne radioactivity inside the control room, the control room HVAC system is automatically transferred from the normal mode to the essential mode of operation upon receipt of a control room outside air intake high radiation signal. Transfer of the system to essential or isolation modes may also be initiated manually from the control room or automatically upon receipt of an outside air intake high-toxic gas signal. Local, audible alarms warn the operators to shut the self-closing doors, should the doors be open after the transfer. 3

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

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

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks	Go To Item No.
56.	HV12163 air-operated on-off dampers NO/FC	Remain open to allow flow of air in normal and smoke modes, and close on CRI and toxic modes so that EFU will provide HVAC	A	Inadvertent closed	Position indicating lights	None. Damper can be manually opened.	Common to Units 1 and 2	57
			B, C	Fail to close	Position indicating lights	None. Item 55 available.		
			D	Inadvertent closed	Position indicating lights	None. Damper can be manually opened.		
57.	1-1531-B7-002-000 fan, fan shaft bearing, motor, etc.	Provide motive power to circulate air	B, C, D	Mechanical failure	Flow alarm, low; temperature alarm, high	None. Loss of train A. Train B available.		58
58.	1-1531-B7-004-000 fan, fan shaft, bearing, motor, etc.	Provide motive power to circulate air	B, C, D	Mechanical failure	Flow alarm, low; temperature alarm, high	None. Loss of train B. Train A available.		59
59.	Cl_2 monitor 1AT1S12110	Monitor Cl_2 concentration of intake air, and alarms at Cl_2 concentration, and isolates intake air	C	Fail to give alarm at high Cl_2 concentration	Cl_2 concentration alarm high on Cl_2 monitor 1AT1S12112	None. Automatic isolation of Unit 1 side intake by closing dampers 1HV12114 and 1HV12115. Use Unit 2 air intake.	If Cl_2 concentration is also high in Unit 2 air intake go on recirculation mode with no outside air intake.	60
				False alarm	No alarm on Cl_2 monitor 1AT1S12112	None. Cl_2 concentration is not high.		

7

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks	Go To Item No.
60.	Cl monitor 1AT1S12112	Monitor Cl_2 concentration of intake air, alarms at high Cl_2 concentration, and isolates intake air	C	Fail to give alarm at high Cl_2 concentration	Cl_2 concentration alarm high on Cl_2 monitor 1AT1S12110	None. Automatically isolate Unit 1 side intake by closing dampers 1HV12115 and 1HV12115. Use Unit 2 air intake.	If Cl_2 concentration is also high in Unit 2 air intake, go on recirculation mode with no outside air intake	61
				False alarm	No alarm on Cl_2 monitor 1AT1S12110	None. Cl_2 concentration is not high.		
61.	Smoke monitor 1AE12167	Monitor smoke in intake air and alarms at high smoke concentration and isolates intake air	C	Fail to give smoke alarm at high smoke concentration	Smoke alarm high on smoke monitor 1AE12166	None. Automatically isolate Unit 1 side intake by closing dampers 1HV12114 and 1HV12115. Use Unit 2 air intake.	If smoke concentration is also high on Unit 2 air intake, go on recirculation mode with no outside air intake	62
				False alarm	No alarm on smoke monitor 1AE12166	None. Smoke concentration is not high.		
62	Smoke monitor 1AE12166	Monitor smoke in intake air and alarms at high smoke concentration and isolates intake air	C	Fail to give smoke alarm at high smoke concentration	Smoke alarm high on smoke monitor 1AE12167	None. Automatically isolate Unit 1 side intake by closing dampers 1HV12114 and 1HV12115. Use Unit 2 air intake.	If smoke concentration is also high in Unit 2 air intake go on recirculation mode with no outside air intake	63
				False alarm	No alarm on smoke monitor 1AE12167	None. Smoke concentration is not high.		
63.	Radiation monitor 1RE12117	Monitor radiation in intake air and alarms at high radiation level	C	Fail to give radiation alarm at high radiation	Radiation alarm high on radiation monitor 1RE12116	None. Use EFU to filter iodine. Item 66 available also.		64
				False alarm	No alarm on radiation monitor 1RE12116	None. Radiation level is not high.		

TABLE 6.4.4-1 (SHEET 15 OF 15)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks	Go To Item No.
64.	Radiation monitor 1RE12116	Monitor radiation in intake air, and alarms at high radiation level	C	Fail to give radiation alarm at high radiation	Radiation alarm high on radiation monitor 1RE12117	None. EFU to filter iodine. Item 65 available also.		
				False alarm	No alarm on radiation monitor 1RE12117	None. Radiation level is not high.		

a. Plant operating modes are as follows:

A - Normal mode: HVAC normal units (NU) operating; outside and recirculation supply air; positive room pressure relative to the atmosphere.

B - Emergency mode: HVAC essential filtration units (EFU) operating; outside and recirculation supply air; positive room pressure relative to the atmosphere.

C - Toxic mode: EFU operating; recirculation only; zero pressure differential; outside smoke, chlorine. 3 7

D - Smoke purge mode: HVAC NU operating; outside air only; negative room pressure relative to the atmosphere (smoke inside control room).

6.4.6 INSTRUMENTATION REQUIREMENT

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

Instrumentation required for actuation of the control room essential HVAC system is discussed in paragraph 6.4.2.2.2 and in subsection 7.3.6. The control room ventilation logic diagram is shown in figure 7.3.6-1.

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

The chlorine detector sensitivity and response time are provided in paragraph 6.4.2.2.2 and table 7.3.6-1. 7

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

TABLE 6.4.6-1

CONTROL ROOM HVAC INDICATIONS AND ALARMS

Control room differential pressure (high or low alarm)

Control room area radiation (indication and high alarm)

Control room smoke (high alarm)

Smoke in control room intake (high alarm)

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

Chlorine gas in control room intake (recorded and high alarm) 7

Fan operating status

Isolation damper position

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

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

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

Temperature in charcoal filter (indication and high alarm)

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

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

Open control room access doors after transfer to the emergency mode (alarm)

7.3.6 CONTROL ROOM VENTILATION ISOLATION

7.3.6.1 Description

Upon detection of high airborne chlorine concentration, the normal supply of outside air to the control room is terminated, as described in sections 6 4 and 9.4, and the control room air is recycled and filtered. For high gaseous radioactivity levels, a small supply of fresh makeup air is provided, and the control room is maintained at a set positive pressure to prevent the ingress of the local ambient atmosphere. Normal ventilation is restored only by manual operation by the plant operator and is maintained only if the local ambient atmosphere poses none of the monitored hazards. 7

7.3.6.1.1 System Description

A. Actuating Circuits

The gaseous radioactivity level and the chlorine content of the air provided to the main control room from the local ambient atmosphere are each monitored by four separate and independent monitoring systems. 7

The signals from these monitors are transmitted to bistables in the engineered safety features actuation system. If acceptable levels are exceeded, the control room is isolated, as described above.

The sensitivities and response times of these monitors are listed in table 7.3.6-1.

In addition to the above, control room isolation is initiated manually. 3

B. Logic

The control room ventilation isolation actuation system logic is included in figure 7.3.6-1. The actuation signal is transmitted to each actuated device and, subject to the provisions of bypass or override, causes each device to assume its safe state.

C. Bypass

Bypass of the containment atmosphere gaseous radioactivity signal is provided, as shown in figure 7.3.6-1, to allow for control room ventilation system operation during those times when no containment purge is in progress and the containment gaseous radioactivity level exceeds the trip setting.

Manual override is available by means of pull-to-lock switches on the fans.

D. Interlocks

There are no interlocks on these controls.

E. Sequencing

The control room ventilation isolation system is powered from the Class 1E power system and energized on the first (0.5 s) step of the load sequencing, except for the control room filter units and return fan motors which stop on the 40.5 s step.

F. Redundancy

Controls are provided on a one-to-one basis with the mechanical equipment so that the controls preserve the redundancy of the mechanical equipment. Redundancy is provided in the chlorine and gaseous radioactivity monitors, the actuation signals, and manual actuation switches. 7

G. Diversity

Diversity of actuation is provided in that the control room ventilation system may be isolated by either an automatic system or by operator manual actuation. Diversity is provided by actuation from the gaseous radioactivity, chlorine monitors, and manual switches. 7

H. Actuated Devices

Table 7.3.6-2 lists the actuated devices.

I. Supporting System

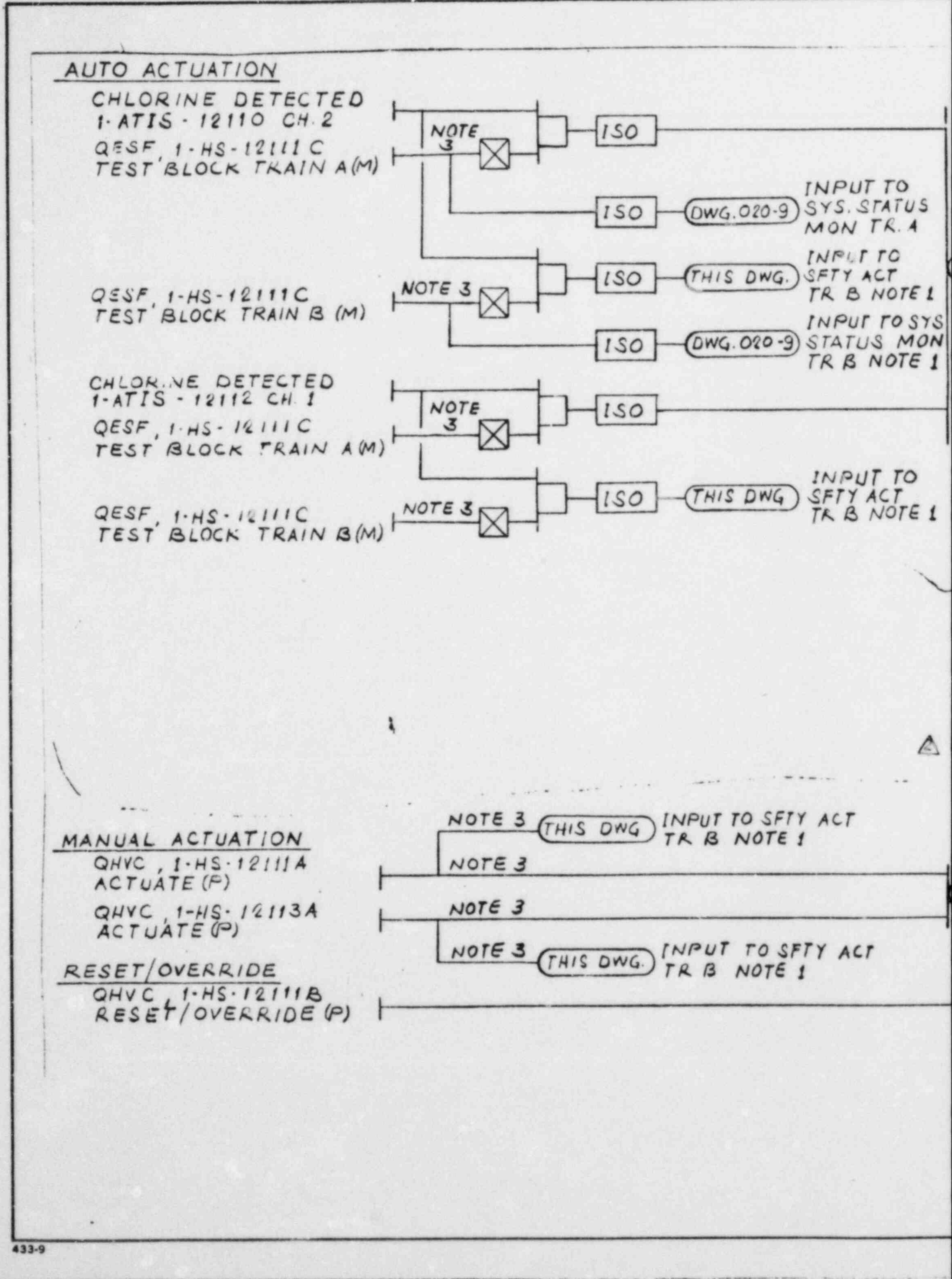
The supporting system required for the controls is the vital Class 1E ac system described in section 8.3.

TABLE 7.3.6-1

CONTROL ROOM VENTILATION ISOLATION CONTROL SYSTEM MONITOR SENSITIVITIES AND RESPONSE TIMES

Type	Concentration Setpoint for Isolation		Limiting Isotope	Response Time
	$\mu Ci/cm^3$	ppm		
Gaseous Radio-activity	$3x10^{6}$	-	Kr 85	(a)
Chlorine	-	5	-	Less than 20 s
Smoke	-	-	-	Manual actuation 7

a. Response time is radiation-level dependent.

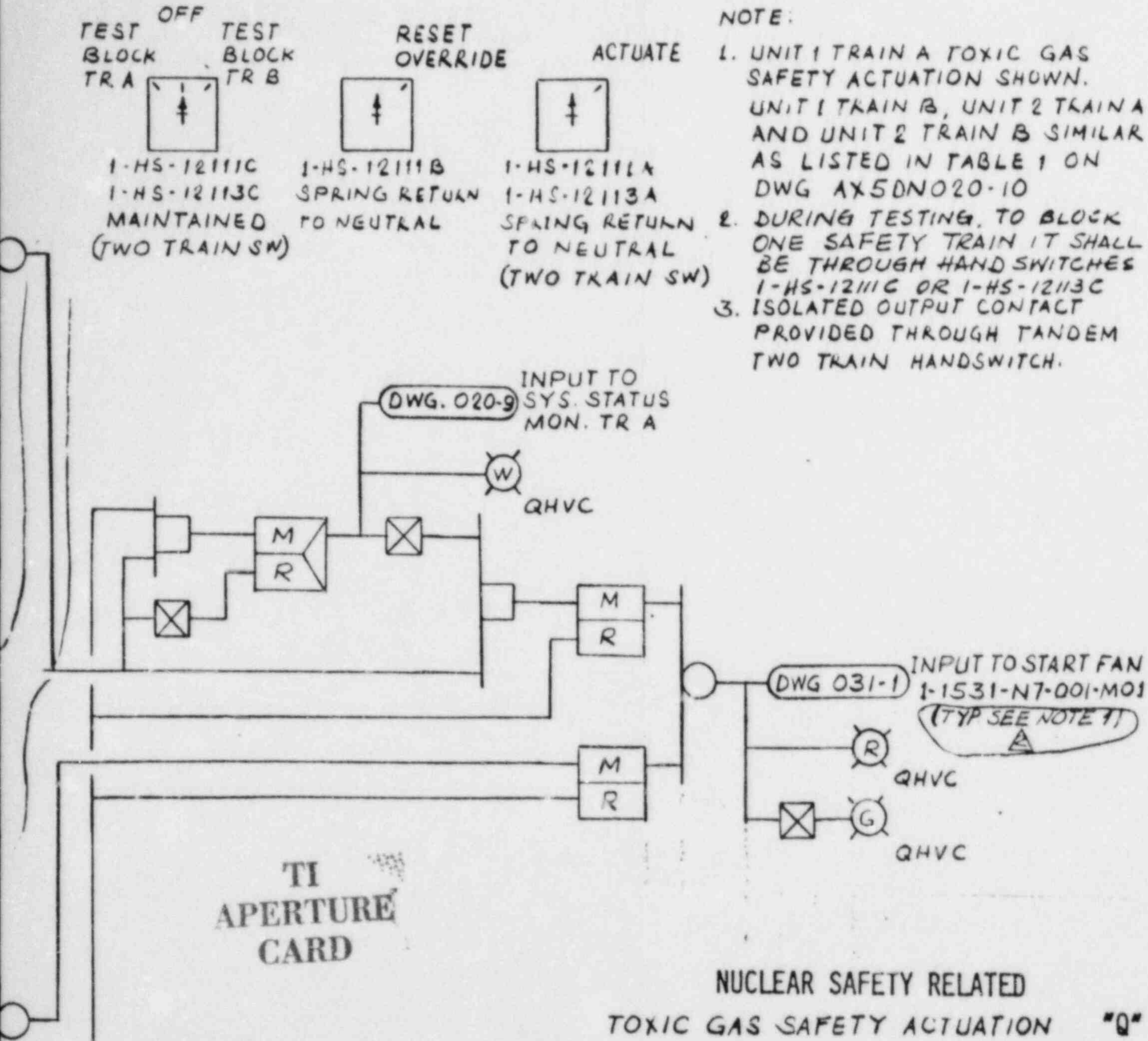

AUTO ACTUATION
CHLORINE DETECTED
1-ATIS - 12110 CH. 2
QESF, 1-HS-12111C
TEST BLOCK TRAIN A (M)
NOTE 3
ISO
ISO
DWG. 020-9
INPUT TO SYS. STATUS MON TR. A
ISO
THIS DWG.
INPUT TO SFTY ACT TR B NOTE 1
QESF, 1-HS-12111C
TEST BLOCK TRAIN B (M)
NOTE 3
ISO
DWG. 020-9
INPUT TO SYS STATUS MON TR B NOTE 1
CHLORINE DETECTED
1-ATIS - 12112 CH. 1
QESF, 1-HS-12111C
TEST BLOCK TRAIN A (M)
NOTE 3
ISO
ISO
THIS DWG
INPUT TO SFTY ACT TR B NOTE 1
QESF, 1-HS-12111C
TEST BLOCK TRAIN B (M)
NOTE 3
MANUAL ACTUATION
QHVC, 1-HS-12111A
ACTUATE (P)
NOTE 3
THIS DWG
INPUT TO SFTY ACT TR B NOTE 1
NOTE 3
QHVC, 1-HS-12113A
ACTUATE (P)
NOTE 3
NOTE 3
THIS DWG.
INPUT TO SFTY ACT TR B NOTE 1
RESET/OVERRIDE
QHVC, 1-HS-12111B
RESET/OVERRIDE (P)

433-9

Also Available On
Aperture Card

NOTE:

1. UNIT 1 TRAIN A TOXIC GAS SAFETY ACTUATION SHOWN. UNIT 1 TRAIN B, UNIT 2 TRAIN A AND UNIT 2 TRAIN B SIMILAR AS LISTED IN TABLE 1 ON DWG AX5DN020-10
2. DURING TESTING, TO BLOCK ONE SAFETY TRAIN IT SHALL BE THROUGH HAND SWITCHES 1-HS-12111C OR 1-HS-12113C
3. ISOLATED OUTPUT CONTACT PROVIDED THROUGH TANDEM TWO TRAIN HANDSWITCH.



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VIP X5AA04-18

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AX5DN020-7 REV. 2

Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	CONTROL ROOM VENTILATION ISOLATION LOGIC DIAGRAM
		FIGURE 7.3.6-1 (SHEET 4 OF 15)

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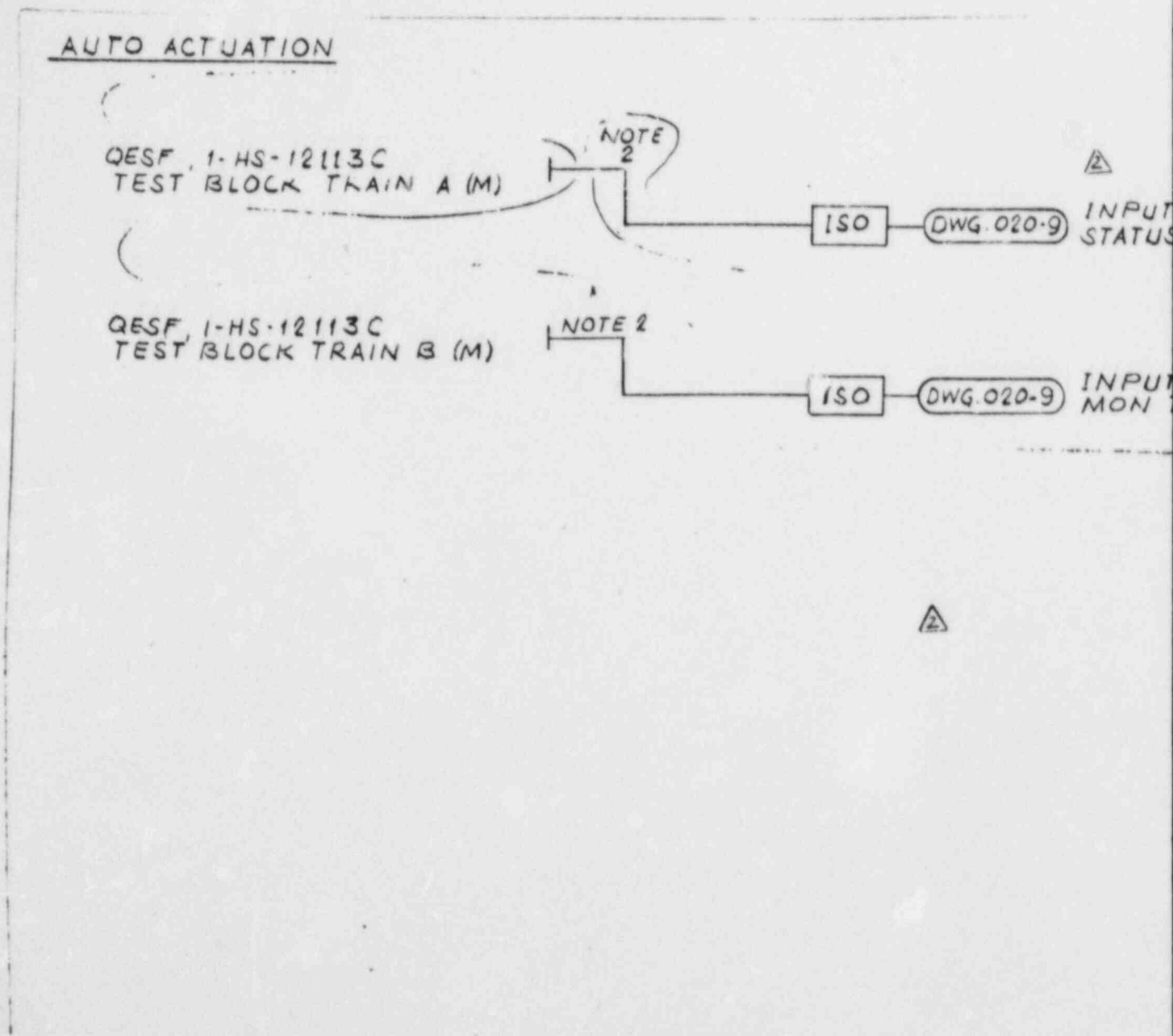

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NOTE:

1. LOGIC CONTINUATION SHOWN ON DWG AX5DN020-7 AND AX5DN020-9. OTHER NOTES REFER TO DWG AX5DN020-7.
2. ISOLATED OUTPUT CONTACT PROVIDED THROUGH TANDEM TWO TRAIN HANDSWITCH

TI
APERTURE
CARD

REF. DWGS.
P&ID AX4DB206-1, 2 & 3
E. D. 1X3D-BG-C04E.F
2X3D-BG-C04C.F

NUCLEAR SAFETY RELATED

Amend. 7 5/84
AX5DN020-8 REV. 2

Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	CONTROL ROOM VENTILATION ISOLATION LOGIC DIAGRAM
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22. Regulatory Guide 1.118, Periodic Testing of Electric Power and Protection Systems.

23. Regulatory Guide 1.128, Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants.

24. Regulatory Guide 1.129, Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants.

25. Regulatory Guide 1.131, Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants.

C. IEEE Standards

The onsite power system is generally designed in accordance with IEEE Standards 279, 308, 317, 323, 334, 336, 338, 344, 379, 382, 383, 384, 387, 450, and 484.

1. IEEE 279-1971, Criteria for Protection Systems for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.22.

2. IEEE 308-1974, Criteria for Class 1E Power Systems for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.32.

3. IEEE 317-1976, Electrical Penetration Assemblies in Containment Structures for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.63.

4. IEEE 323-1974, Qualifying Class 1E Equipment for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.89.

5. IEEE 334-1974, Type Tests of Continuous Duty Class IE Motors for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.40.

6. IEEE 336-1971, Installation, Inspection, and Testing Requirements for Instrumentation and Electric Equipment During the Construction of Nuclear Power Generating Stations. Refer to Regulatory Guide 1.30.

7. IEEE 338-1977, Criteria for the Periodic Testing of Nuclear Power Generating Station Class 1E Power and Protection Systems. For application of 7

this standard to various systems, refer to paragraph 7.1.2.7 and to Regulatory Guide 1.118.

8. IEEE 344-1975, Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations. Seismic qualification of Class 1E electric equipment and the extent of compliance with IEEE 344-1975 are discussed in section 3.10. Also refer to Regulatory Guide 1.100.

9. IEEE 379-1972, Application of the Single Failure Criterion to Nuclear Power Generating Station Class 1E Systems. Refer to Regulatory Guide 1.53.

10. IEEE 382-1972, Type Test of Class 1 Electric Valve Operators for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.73.

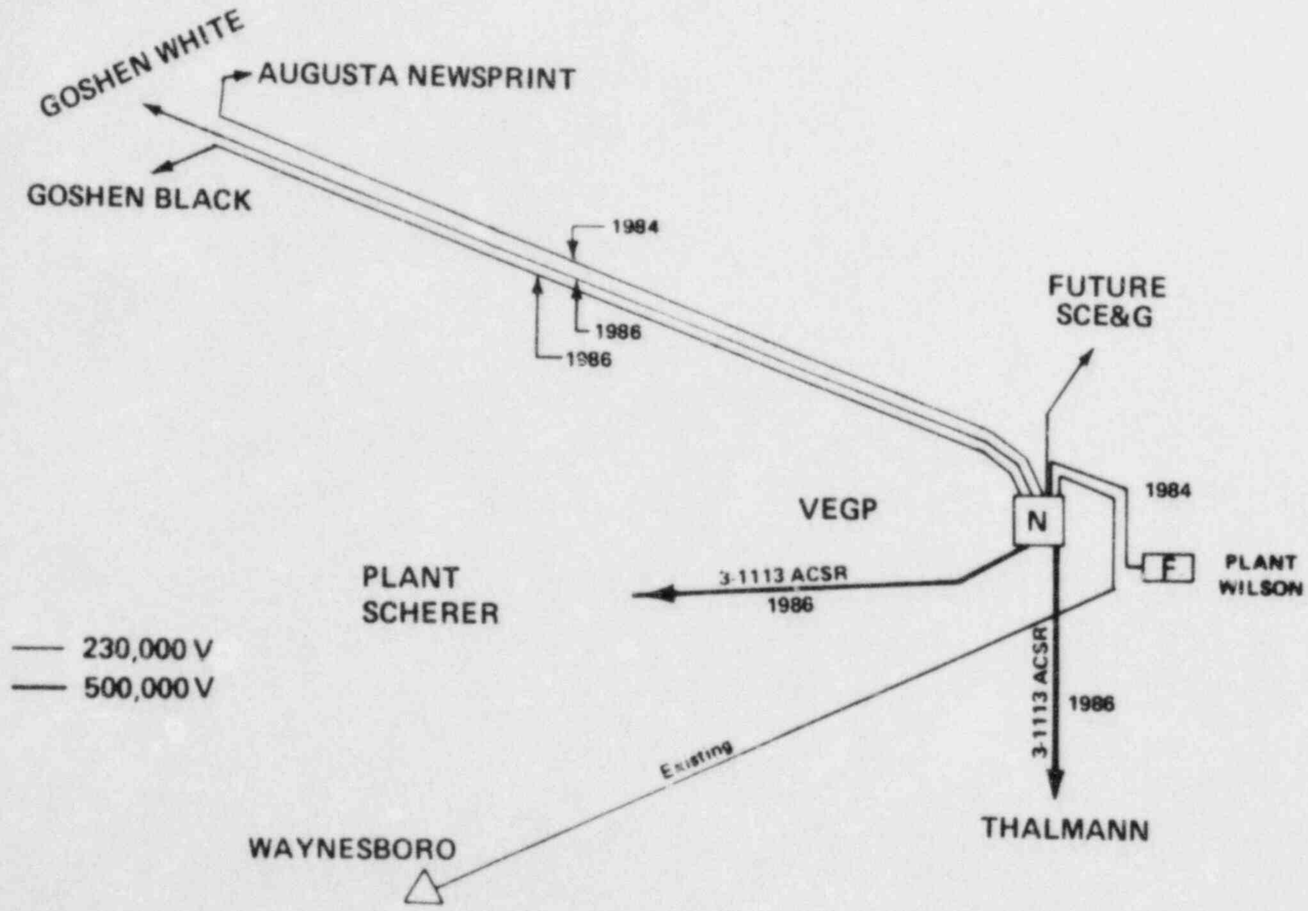
11. IEEE 383-1974, Type Test of Class 1E Electric Cables, Field Splices, and Connections for Nuclear Power Generating Stations. Refer to Regulatory Guide 1.131.

12. IEEE 384-1974, Criteria for Independence of Class 1E Equipment and Circuits. Refer to Regulatory Guide 1.75.

13. IEEE 387-1972, Criteria for Diesel-Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations. Conformance with the design criteria of IEEE 387-1972 is discussed in paragraph 8.3.1.1.3, which addresses the details of the standby power supply. Also refer to Regulatory Guide 1.9.

14. IEEE 450-1975, Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations. Refer to Regulatory Guide 1.129.

15. IEEE 484-1975, Installation Design and Installation of Large Lead Storage Batteries for Generating Stations and Substations. Refer to Regulatory Guide 1.128.



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Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

THE SOUTHERN COMPANY GRID SYSTEM

FIGURE 8.1-1 (SHEET 2 OF 2)

433-9

8.2 OFFSITE POWER SYSTEM

8.2.1 SYSTEM DESCRIPTION

The Southern Company transmission system supplies the offsite ac energy for operating the safety-related buses as well as startup and shutdown of Units 1 and 2.

Each unit represents about 10 percent of the total installed capacity of the Georgia Power Company system in 1987 and about 4 percent of the total installed capacity of the Southern Company system in 1987.

Unit 1 is connected to the 230-kV switchyard through a step-up transformer, and Unit 2 is connected to the 500-kV switchyard through a step-up transformer. Two 500/230-kV autotransformers connect the two transmission substations together. The offsite sources are the 230-kV and 500-kV lines from the transmission system.

8.2.1.1 Offsite Sources

Figure 8.1-1 shows the Southern Company transmission system plan for 1987. Construction of the 230- and 500-kV lines is summarized in table 8.2.1-1. The transmission lines are not considered to have any unusual features, and the occasional crossings of transmission lines as listed in table 8.2.1-1 are normal design practice for the Georgia Power Company system.

The 230- and 500-kV transmission systems are designed to deliver power to the various portions of the Georgia Power Company service area safely, efficiently, and dependably. As a result, the system offers a very dependable power source for the required offsite loads and is the preferred power source for the safety-related loads of the plant.

There are five 230-kV lines, one of which is the connection to the Plant Wilson switchyard, and two 230/500-kV autotransformers that connect the 230- and 500-kV switchyards. These transmission elements at the 230-kV bus comprise the offsite sources to the 230-kV switchyard. The lines approach the plant site on five rights-of-way, from the north-west and south. System load studies indicate that this arrangement has the capacity and capability to supply the power necessary for the safety loads of one unit while placing the other unit in cold shutdown. 7

The transmission line structures of both the 230- and 500-kV systems are designed to withstand standard light loading conditions as specified in the National Bureau of Standards Handbook No. 8 (National Electric Safety Code Part 2).

8.2.1.2 Switchyard

The 230- and 500-kV switchyards are arranged as shown in figures 8.2.1-1 and 8.2.1-2. The 230-kV breaker-and-a-half arrangement is used to incorporate the redundancy offered by having two energized buses with three breakers to service each 7
pair of connections. The 500-kV ring bus arrangement allows two breakers to service each terminal connection.

The switchhouse, located in the switchyard, contains two independent 125-V batteries, the primary and secondary relaying for the transmission lines, and the breaker failure relaying. It also contains the 480-V metal-clad switchgear and motor control centers for the substation.

Two trip coils are provided in each circuit breaker for independent tripping from the primary and secondary relaying systems. Redundant closing coils are not provided in each 230-kV circuit breaker. However, the 125-V dc supplies are arranged to ensure that at least one offsite source is available upon the loss of either substation battery. Table 8.2.1-2 shows the 230-kV circuit breaker close circuits supplied by each battery. Each circuit breaker will have independent gas supplies and air supply for the pneumatic mechanism. Table 8.2.1-3 shows the 500-kV circuit breaker control circuits supplied by each battery. 7

Two feeders emerge from the 230-kV substation to supply power to the reserve auxiliary transformers for both Units 1 and 2. (The arrangement is shown in figure 8.3.1-1.) Offsite source No. 1 supplies Unit 1 reserve auxiliary transformer 1NXRA and Unit 2 reserve auxiliary transformer 2NXRB. Offsite source No. 2 supplies Unit 1 reserve auxiliary transformer 1NXRB and Unit 2 reserve auxiliary transformer 2NXRA. These two offsite sources are separated physically as they leave the 230-kV sub-station and are arranged so that no one event such as a falling line, tower, or other structure will damage both lines.

The secondary windings of the reserve auxiliary transformers are connected to the various groups of metal-clad switchgear by cable buses. Buses from transformers 1NXRB and 2NXRA are 3
carried in underground trenches from the transformers to the turbine building wall. The other buses are run overhead to the turbine building.

TABLE 8.2.1-1 (SHEET 1 OF 2)

SUMMARY OF 230- AND 500-kV LINE CONSTRUCTION

Line Name	VEGP - Augusta Newsprint	VEGP - Scherer	VEGP - Thalmann	Wilson Combustion Turb.	Future VEGP - S. Carolina Elec. & Gas	VEGP - Goshen Black	VEGP - Goshen White
Remote termination	Goshen Subs.	Scherer Subs.	Thalmann Subs	Comb. Turb. Bus	-	Goshen Subs.	Goshen Subs.
Operating voltage (kV)	230	500	500	230	230	230	230
Scheduled completion	1972 (line)	1986	1986	1984	1986	1986	1986
Line length (mi)	20	150	153	1.5	20	20	20
R/W width (ft)	275	150	150	125	-	275	275
Line placement on R/W	62.5 ft from edge of R/W	Center	Center	Center	-	Goshen Black and White on same R/W	Goshen Black and White on same R/W
Terrain	Flat	Flat to rolling	Flat to rolling	Flat	Flat	Flat	Flat
Conductor type/size	1351 MCM 54/19 ACSR	Bundle 1113 MCM ACSR	Bundle 1113 MCM ACSR	1351 MCM 54/19 ACSR	- -	Bundle 795 ACSR	Bundle 795 ACSR
Phase/phase clearance (ft)	20	28	28	20	-	23	23
Phase/ground clearance at max. oper. condition (ft)	25	33	33	25	-	25	25
Unusual oper. conditions	-	-	-	-	-	-	-

3 7

TABLE 8.2.1-1 (SHEET 2 OF 2)

Line Name	VEGP - Augusta Newsprint	VEGP - Scherer	VEGP - Thalmann	Wilson Combustion Turb.	Future VEGP - S. Carolina Elec. & Gas	VEGP - Goshen Black	VEGP - Goshen White
Major trans. line crossing	230-kV VEGP to Goshen White; 230-kV VEGP to Goshen Black	230-kV Goshen to Harllee Branch Steam Plant 230-kV Warrenton to Harllee Branch Steam Plant; 115-kV Warrenton to Washington EMC No. 8; 230-kV East Social Circle to Harllee Branch Steam Plant; 230-kV Eatonton to Harllee Branch Steam Plant; 230-kV Klondike to Harllee Branch Steam Plant; 115-kV Porterdale to Arkwright Steam Plant; 115-kV Goshen to Waynesboro	230-kV Plant Wilson to Waynesboro; 230-kV Effingham to Statesboro; 115-kV Effingham to Treutlen; 115-kV Claxton to Boulevard; 230-kV Effingham to Little Ogeechee; 115-kV Ludowici to Riceboro; 115-kV Ludowici to West Brunswick; 115-kV Jesup to West Brunswick	None	None	230-kV VEGP to Augusta Newsprint	230-kV VEGP to Augusta Newsprint

3 7

TABLE 8.2.1-2

THE ASSIGNMENT OF 230-kV CIRCUIT BREAKER SUPPLIES TO SUBSTATION BATTERIES

	Battery No. 1			Battery No. 2			
230-kV CB	Line Relaying[a]	Close	Trip No.	Line Relaying[a]	Close	Trip No.	
161760	P	X	1			2	
161860	P	X	1	S		2	
161960	P		2	S	X	1	
161750[b]	P	X	1	S		2	
161850[b]	P	X	1	S		2	
161950[b]	P		2	S	X	1	
161710	P	X	1	S		2	
161810	P	X	1	S		2	
161910	P		2	S	X	1	7
161730	S	X	1	P		2	
161830	S		2	P	X	1	
161930	S		2	P	X	1	
161720	P	X	1	S		2	
161820	P	X	1	S		2	
161920	P		2	S	X	1	
161740	P	X	1	S		2	
161840	P	X	1	S		2	
161940	P		2	S	X	1	

a. P denotes primary; S denotes secondary.

b. Future.

TABLE 8.2.1-3

THE ASSIGNMENT OF 230-kV CIRCUIT BREAKER SUPPLIES TO SUBSTATION BATTERIES

	Battery No. 1			Battery No. 2		
500-kV PCB	Line Relaying[a]	Close	Trip No.	Line Relaying[a]	Close	Trip No.
161520	P	X	1	S		2
161620	P	X	1	S		2
161660	P		2	S	X	1
161540	S	X	1	P		2
161649	S		2	P	X	1

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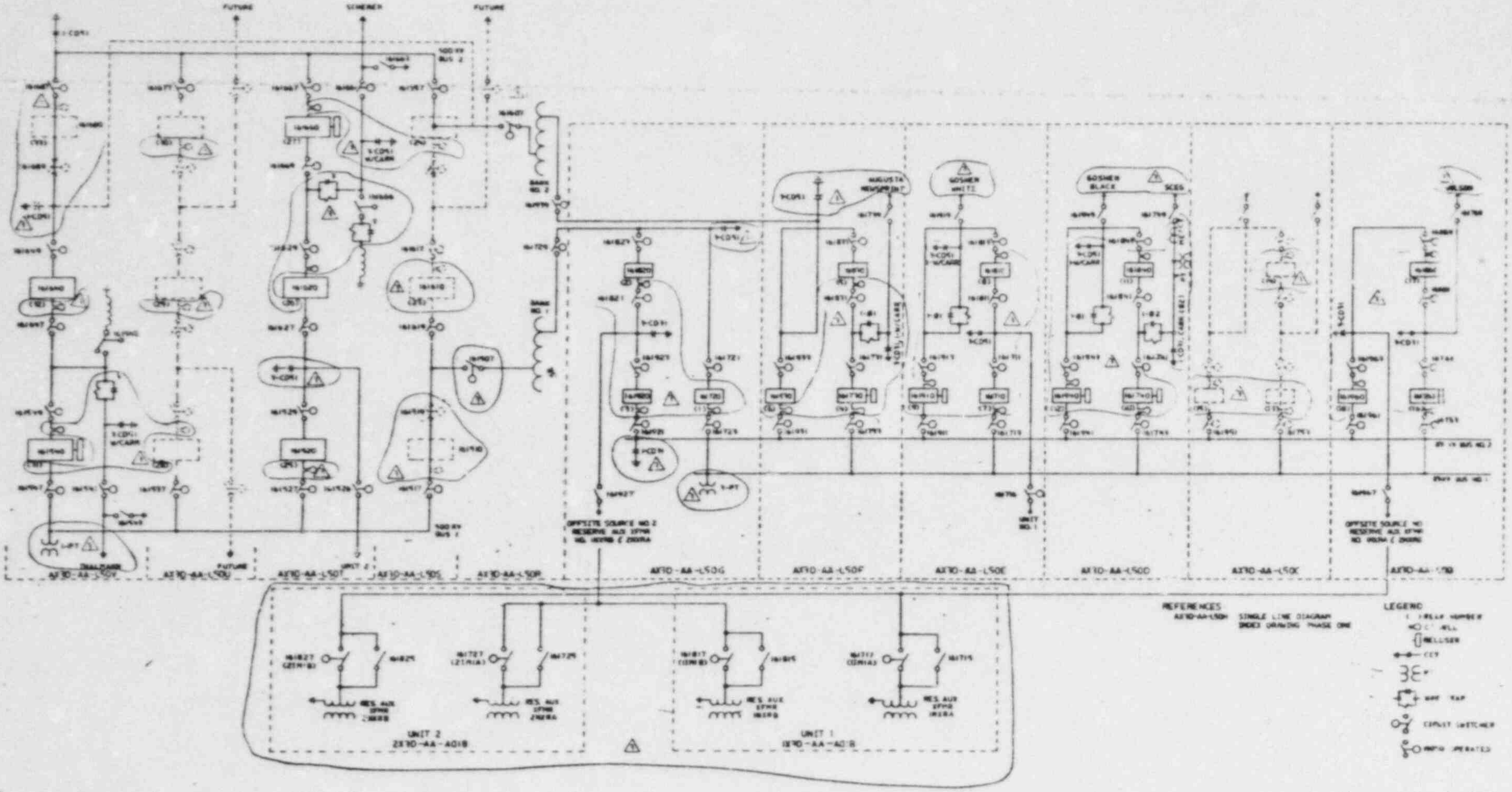
a. P denotes primary; S denotes secondary.



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Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

SWITCHYARD ARRANGEMENT

FIGURE 8.2.1-1

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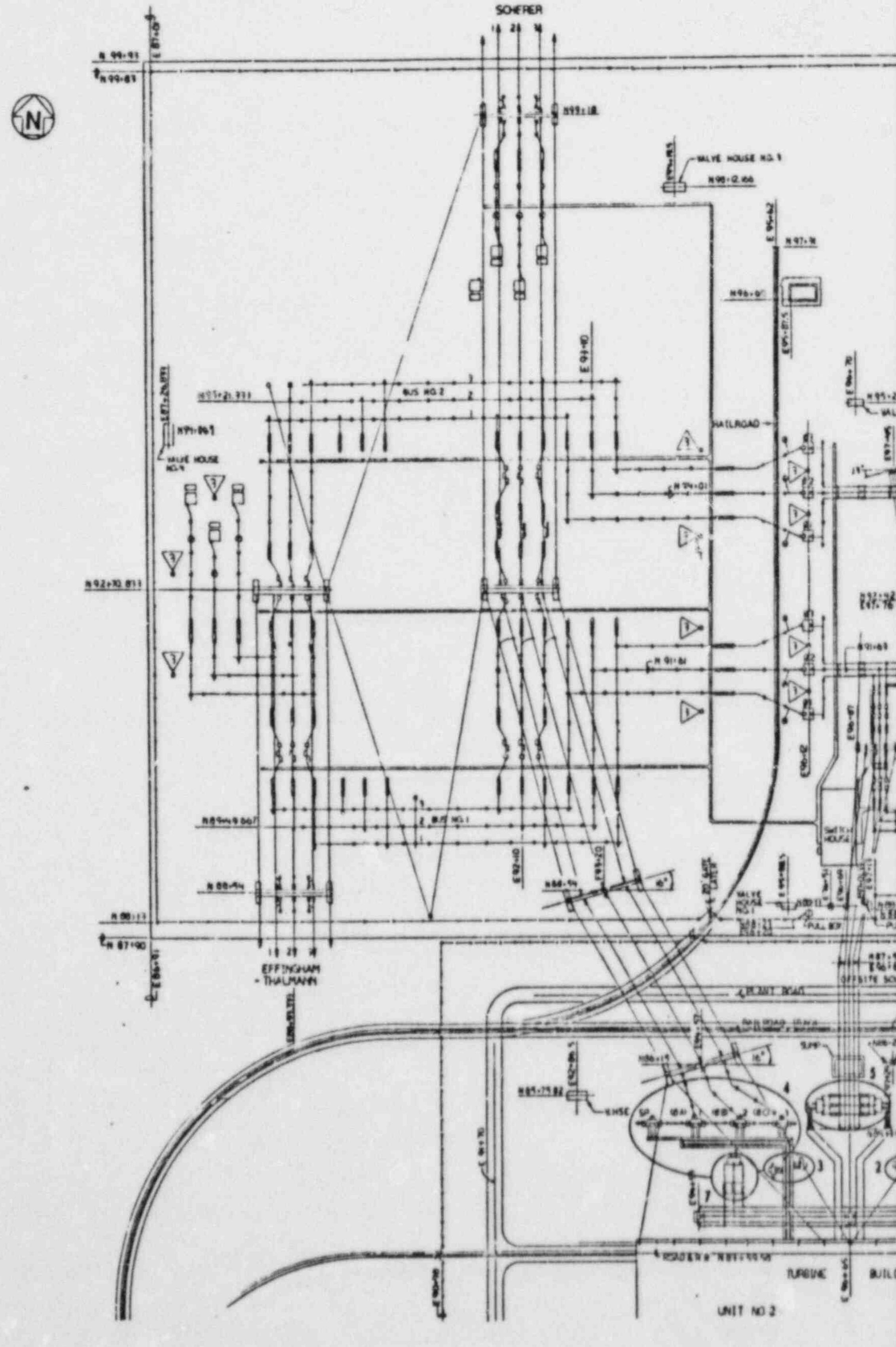
SCHERER
EFFINGHAM - THALMANN
BUS NO. 2
BUS NO. 1
RAILROAD
VALVE HOUSE NO. 1
PLANT ROAD
TURBINE
UNIT NO 2
N

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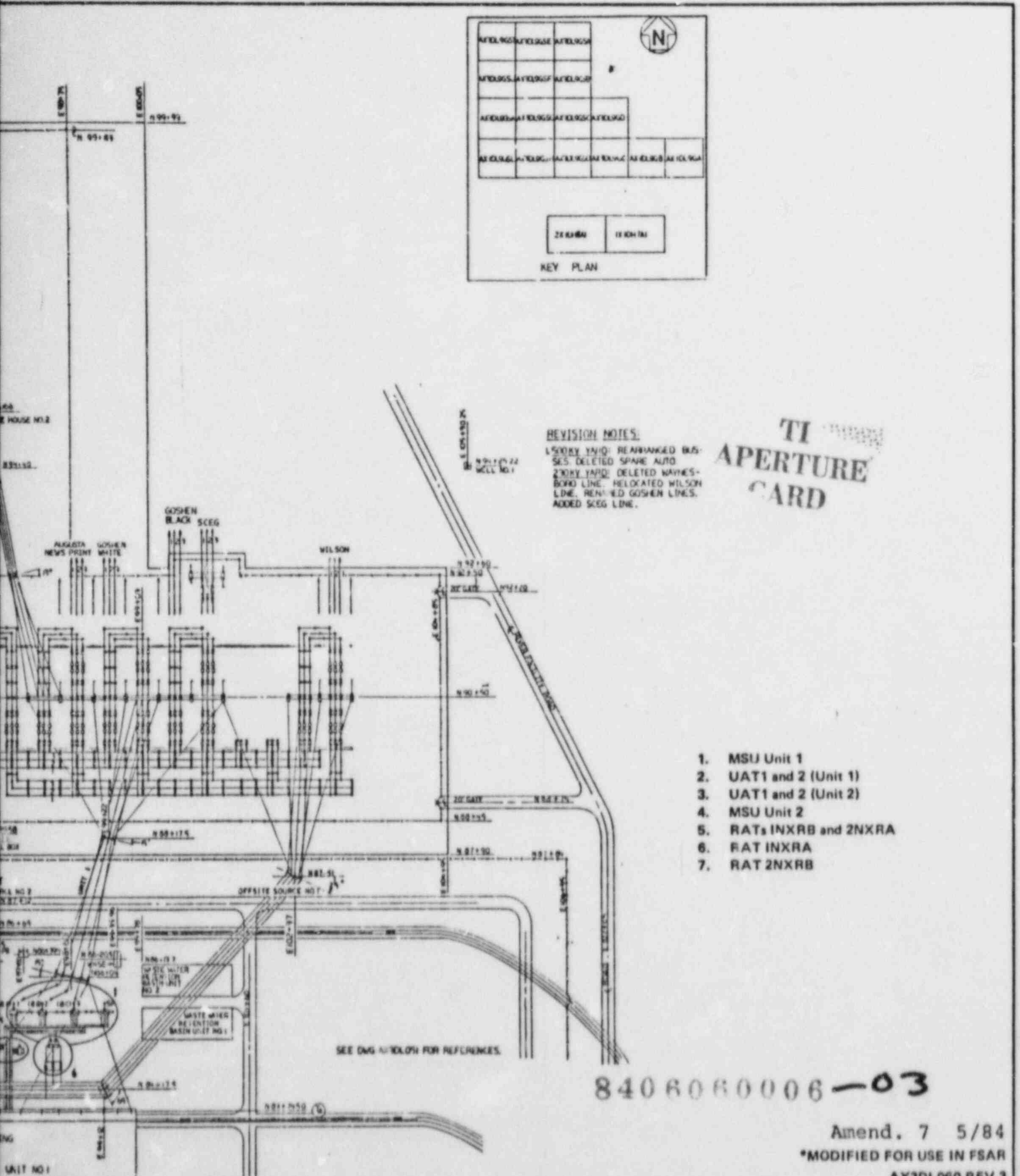

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Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	ULTIMATE DEVELOPMENT - SUBSTATION
		FIGURE 8.2.1-2

8.2.2 ANALYSIS

8.2.2.1 Loss of VEGP Unit 1 or 2 or the Largest Unit

A study simulating 1987 peak conditions has been made to determine the effect of the loss of VEGP Unit 1 on the Georgia Power Company transmission system and its ability to maintain continuity of service to the loads. This study reveals that the transmission system is adequate to maintain continuity of service to the load areas and the offsite power to the safety-related loads at the plant site.

A study simulating 1989 peak conditions has been made to determine the effect of the loss of either VEGP Unit 1 or 2 on the Georgia Power Company transmission system and its ability to maintain continuity of service to the loads. This study reveals that the transmission system is adequate to maintain continuity of service to the load areas and the offsite power to the safety-related loads at the plant site.

A study simulating 1989 peak conditions has been made to determine the effect of the loss of both Units 1 and 2 and the ability of the offsite source to supply emergency and safety-related loads at VEGP. It was found that the offsite 7
transmission is adequate. The voltage at the VEGP 230-kV bus is above 98 percent under any normal planning criteria.

The loss of the largest unit (Bowen No. 3 or 4) of the Georgia Power Company system does not result in the loss of the offsite power to the safety-related buses at the plant site.

8.2.2.2 VEGP Voltage Operating Range

The 230-kV bus voltage will not be less than 225 kV (98 percent) or greater than 237 kV (103 percent) for all system-loading conditions and under severe contingencies such as loss of any large generating plant, including VEGP itself, or loss of any transmission element. The above 230-kV bus voltages take into consideration VEGP Unit 1 and Unit 2 shutdown and/or loss-of-coolant accident loads.

8.2.2.3 VEGP Transient Stability

A transient stability study simulating 1987 and 1989 summer peak/spring valley loading conditions has been made to determine the transmission line, bus arrangement, and/or special equipment requirements to ensure stable operation of VEGP Units 1 and 2. These extreme system loading conditions ensure that the stability performances of VEGP are analyzed under all reactive loading conditions or power factor conditions. The following contingencies are simulated for which VEGP is required to remain stable:

A. Three-phase fault with breaker failure anywhere in the system.

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B. Sudden loss of any large generating plant.

C. Sudden loss of all lines on any common right-of-way.

D. Sudden loss of any large aggregation of load or load center anywhere in the system.

Of these contingencies, it was found that a three-phase fault close to VEGP with breaker failure at VEGP substation results in the largest transient swing for Units 1 and 2. Specific stability performances of VEGP are discussed below.

A. Unit 1 - 1987 Summer Peak and Spring Valley Contingencies

Unit 1 is stable for all three-phase faults with any one breaker failure and a delayed fault clearing time of nine cycles. Maximum rotor angle swing for VEGP Unit 1 is approximately 50 net electrical degrees. The 230-kV substation at VEGP is designed such that no more than one transmission line and one 500/230-kV autotransformer bank are lost after any three-phase fault where breaker failure is involved.

B. Units 1 and 2 - 1989 Summer Peak and Spring Valley Contingencies

Units 1 and 2 are stable for all three-phase faults with breaker failure and a delayed fault clearing time of nine cycles. Maximum rotor angle swing for Unit 1 is less than 47 net electrical degrees and for Unit 2 approximately 70 net electrical degrees. The 500-kV substation at VEGP is also designed such that no more than one transmission line and one 500/230-kV autotransformer bank are lost after any three-phase fault at the plant where breaker failure is involved.

C. Frequency Decay Rate

The maximum frequency decay rate possible from theoretical considerations for the 230-kV and 500-kV systems is 5 Hz/s and 5.4 Hz/s, respectively. These frequency decay rates are the theoretical maximums that occur with the simultaneous tripping of many 500-kV, 230-kV and 115-kV lines such that a large island is formed in which all generation, other than one VEGP unit, is off line. The probability for such a scenario is immeasurably small. If for the improbable scenario just described, one additional major generating unit is in operation, the expected frequency decay rate is reduced to approximately voltage during normal operation; however, the time delay has been selected to prevent unwanted tripping and undervoltage-induced damage to the safety-related loads. Load shedding and tripping of the incoming breaker is provided by two-out-of-four undervoltage logic.

A two-out-of-four undervoltage logic set at 88.5 percent of nominal voltage with a time delay of 10 s is also provided to initiate an alarm in the control room to warn the operators of a degraded voltage condition. An SIS subsequent to the initiating of this alarm does not separate the auxiliary power system from the offsite power system. Studies have been performed which indicate that at the degraded voltage trip setpoint indicated above, based on the worst case motor thermal damage curve, the permanently connected Class 1E loads will not be damaged. These studies also indicate that adequate voltage is provided to allow starting of the loads.

After a diesel generator has been started and reaches rated voltage and frequency, the generator circuit breaker connecting it to the corresponding 4.16-kV bus closes, energizing that bus and the associated load center transformers. Each diesel generator is designed to accept loads within 9.5 s after receipt of a start signal, and all automatically sequenced loads are connected to the Class 1E bus within 30.5 s thereafter. (Refer to figure 8.3.1-2.) Relays at the diesel generator detect generator-rated voltage and frequency conditions and provide a permissive interlock for the closing of the respective generator circuit breaker. Upon loss of the preferred source of power without a LOCA, the load sequencer system initiates the starting of the diesel generators, trips the 4.16-kV perferred power supply breaker, and sheds all loads. The load sequencer for each diesel then automatically initiates the starting of the safe shutdown loads. When an SIS is present, connection of the diesel generator to the 4.16-kV bus is not made unless the preferred source of power is lost (4.16-kV bus undervoltage).

Following diesel start and connection to the Class 1E bus, the loads are automatically sequenced onto the bus at programmed 5-s time intervals. The load shed feature is bypassed during sequencing of loads. A fast responding exciter and voltage regulator ensure voltage recovery of the diesel generator after each load step, in accordance with requirements of

Regulatory Guide 1.9. Field flashing is utilized on the diesel generators for fast voltage buildup during the start sequence.

Should a LOCA occur during load sequencing or after sequencing is completed, the SIS will restart the sequencer, which will sequence those loads required for LOCA conditions. No load shedding other than the nonsafety-related loads identified in figure 8.3.1-2 will occur.

Once load sequencing has been completed, the load shed and resequence capability is reinstated for an undervoltage sensed at the 4.16-kV Class 1E bus. Logic has been provided that prevents more than three undervoltage conditions from being recognized within a 2-h period. The first and second undervoltage signal will initiate load shed and resequence of the required loads. The third undervoltage signal will initiate a load shed only. Reinstatement of sequencing can be accomplished by manually resetting a timer located at 7
the sequencer. This limitation is provided to prevent automatically exceeding the manufacturer's recommendations concerning motor start capability of two successive starts within a 2-h period.

A breaker in the 4.16-kV Class 1E bus supplies power to the selected nonsafety loads listed in figure 8.3.1-2. If an SIS is not present, this breaker is closed by the sequencer. Should an SIS be present, this breaker is automatically tripped if it had been previously closed. After it has been tripped and the SIS has been manually reset, the operators can close it under administrative control to reenergize the selected nonsafety loads, should their operation be desired.

The voltage levels at safety-related buses are optimized for the expected load conditions throughout the anticipated range of voltages by the setting of no-load transformer taps. The tap setpoints are based upon the design voltage ranges available from the reserve auxiliary transformers and the unit auxiliary transformers. The Technical Specifications indicate the voltage setpoint parameters of the diesel generators to be compatible with the transformer tap setpoints. Verification of the proper tap selection will be accomplished by actual measurement in the field.

buses in accordance with design requirements and that subsequent loading of the onsite sources is through the load sequencer.

f. Demonstrate full load-carrying capability for 24 h, of which 22 h are at a load equivalent to the continuous rating of the diesel generator and 2 h at a load equivalent to the 2-h rating of the diesel generator.

g. Demonstrate functional capability at full load temperature conditions by rerunning the test phase outlined in item d above immediately following item f above. 7

h. Demonstrate proper operation during diesel generator load shedding, including a test of the loss of the largest single load and of complete loss of load. Verify that the overspeed limit is not exceeded.

i. Demonstrate the ability to:

- Synchronize the diesel generator unit with the offsite system while the unit is connected to the emergency load.
- Transfer the emergency load to the offsite system.
- Isolate the diesel unit from offsite systems.
- Restore the diesel generator unit to standby status.

j. Demonstrate that the capability of the diesel generator unit to supply emergency power within the required time is not impaired during periodic testing mentioned in item 2 above.

k. Demonstrate that the engine will perform properly if switched from one fuel oil supply to another.

l. Demonstrate that the load shed feature is bypassed during sequencing and that it is reinstated properly once sequencing is completed.

4. The test procedures will specifically state that the diesel generator unit is to be reset at the conclusion of the test to allow an automatic start when required.

I. Fuel Oil Storage and Transfer Systems

The diesel generator fuel oil system is described in subsection 9.5.4.

J. Diesel Generator Cooling and Heating Systems

The diesel generator cooling water system is described in subsection 9.5.5.

K. Instrumentation and Control Systems for Standby Power Supply

Equipment is provided in the control room for each diesel generator for the following operations:

- Manual starting and stopping.
- Manual and automatic synchronization.
- Manual frequency and voltage setting.
- Emergency stop.
- Governor and voltage regulator manually actuated droop and reset.

A transfer switch is provided in each diesel room for local remote control selection. The switch is normally in the remote position, whereby the engineered safety features system senses an accident or loss of preferred power and starts the diesel. The transfer switch is placed in the local position to allow manual operation of the diesel locally when it is out for maintenance. Equipment is provided locally at each diesel generator for manual starting in case of a control room evacuation. The local emergency start functions to start the diesel generator, regardless of the position of the transfer switch.

Equipment is provided at each local control panel for the following operations (when the transfer switch is in the local position):

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8.3.1.1.11 Motor-Operated Valves with Power Lockout

The motor-operated valves that require power lockout to meet BTP ICSB 18 and that have the means to accomplish power lockout are listed and outlined as follows:

A. The following motor-operated valves power lockout and restoration capability is accomplished at the main control board:

HV-8806	Safety injection pump suction from refueling water storage tank
HV-8835	Safety injection pump cold leg injection
HV-8802A, B	Safety injection pump hot leg injection
HV-8840	Residual heat removal pump hot leg injection
HV-8809A, B	Residual heat removal pump cold leg injection
HV-8813	Safety injection pump miniflow isolation

B. The following motor-operated valve power lockout is accomplished by drawing the circuit breaker from the motor control center during startup and maintained in the racked out position during reactor power operation: 7

HV-8808A, B, C, D	Accumulator isolation valves

In addition, the emergency core cooling system motor-operated valves (item A) are provided with valve position-indicating 3
light boxes to provide a continuous indication of valve position.

The Technical Specifications list these valves and their required positions.

8.3.1.1.12 Containment Building Electrical Penetrations

The electrical penetrations are protected from damage resulting from overcurrent conditions through the use of redundant overcurrent protective devices as indicated in paragraph 1.9.63.2. The use of series Class 1E fuses for backup protection on the 480-V switchgear power circuits is justified by the fact that fuses are passive devices which have proven coordination characteristics and reliability. The Technical Specifications will address the effects of thermal cycling of

1. Where the minimum vertical separation is not maintained, a barrier is installed which extends at least 1 ft on each side of the tray system when the trays are arranged in stacks and at least 3 ft on each side where the trays cross each other.

2. Where the minimum horizontal separation is not maintained, a barrier is installed which extends from at least 1 ft above (or to the ceiling) to at least 1 ft below (or to the floor) the tray system.

E. Where raceways of different separation groups are brought to a single enclosure, separation is accomplished by the use of conduit routed in opposite directions from the enclosure, using the enclosure as a barrier.

Non-Class 1E circuits are electrically isolated from Class 1E circuits, and Class 1E circuits from different separation groups are electrically isolated with the use of isolation devices, shielding and wiring techniques, physical separation (in accordance with Regulatory Guide 1.75 for circuits in raceways), or an appropriate combination thereof.

When isolation devices are used to isolate Class 1E circuits from non-Class 1E circuits, the circuits within or from the Class 1E equipment or devices to the isolation device(s) are identified as Class 1E and are treated as such. Beyond the isolation device(s) these circuits are identified as non-Class 1E and are separated from Class 1E circuits in accordance with the separation criteria described above.

Power and control cables are installed in conduit or ventilated bottom trays (punched or ladder type). Solid tray covers are used in all outdoor locations and indoors where trays run in areas where falling debris is a problem. Instrumentation cables are routed in conduit or solid bottom cable tray with solid tray covers. 7

Separate trays are provided for each voltage service level: 13.8 kV, 4.16 kV, 480 V , 120 V ac and 125 V dc, control, and instrument. Vertically stacked trays are arranged from top to bottom as follows:

- 13.8 kV.
- 4.16 kV.

- 480-V power from load centers.
- 480-V low voltage power and 120 V ac or 125 V dc with loads of 10 A or more.
- Control.
- Instrument.

In general a minimum of 10-in. vertical spacing is maintained between trays of different service levels within the same stack.

With the exception of lighting panel feeders, which are routed in trays, lighting circuits are routed in conduit or utilize aluminum sheath (ALS) cable. Lighting circuits inside containment utilize conduit or copper sheath (CUS) cable.

Raceways from safety-related groups A and C are located in the lower cable spreading room. Raceways from safety-related groups B and D are located in the upper cable spreading room. Group N raceway is routed into both upper and lower cable spreading rooms.

All raceways installed in Seismic Category 1 structures have seismically designed supports. Trays and rigid conduit are not attached rigidly to Seismic Category 1 equipment.

Raceways running between Seismic Category 1 structures are designed in the following manner to prevent damage to the raceway or associated cabling during seismic events. Conduits running between structures are either connected with a minimum of 2 ft of flexible conduit or are provided with expansion/ deflection fittings. Cable trays running between structures are supported independently in each Category 1 structure with no rigid mechanical connection of the tray at the interface. Those cables which require maintained spacing are not tied down to the tray for a distance of 5 ft on either side of the interface.

A high energy line break analysis and missile impact study is performed for all rooms or compartments containing large rotating machinery or high energy piping. Where hazards to safety-related raceways are identified, a predetermined minimum separation is maintained between the break and/or missile source and any safety-related raceway, or a reinforced concrete barrier designed to withstand the effects of each hazard is placed to prevent damage to raceway of redundant systems. The hazards analysis is further described in appendix 3F.

TABLE 8.3.1-1 (SHEET 1 OF 2)

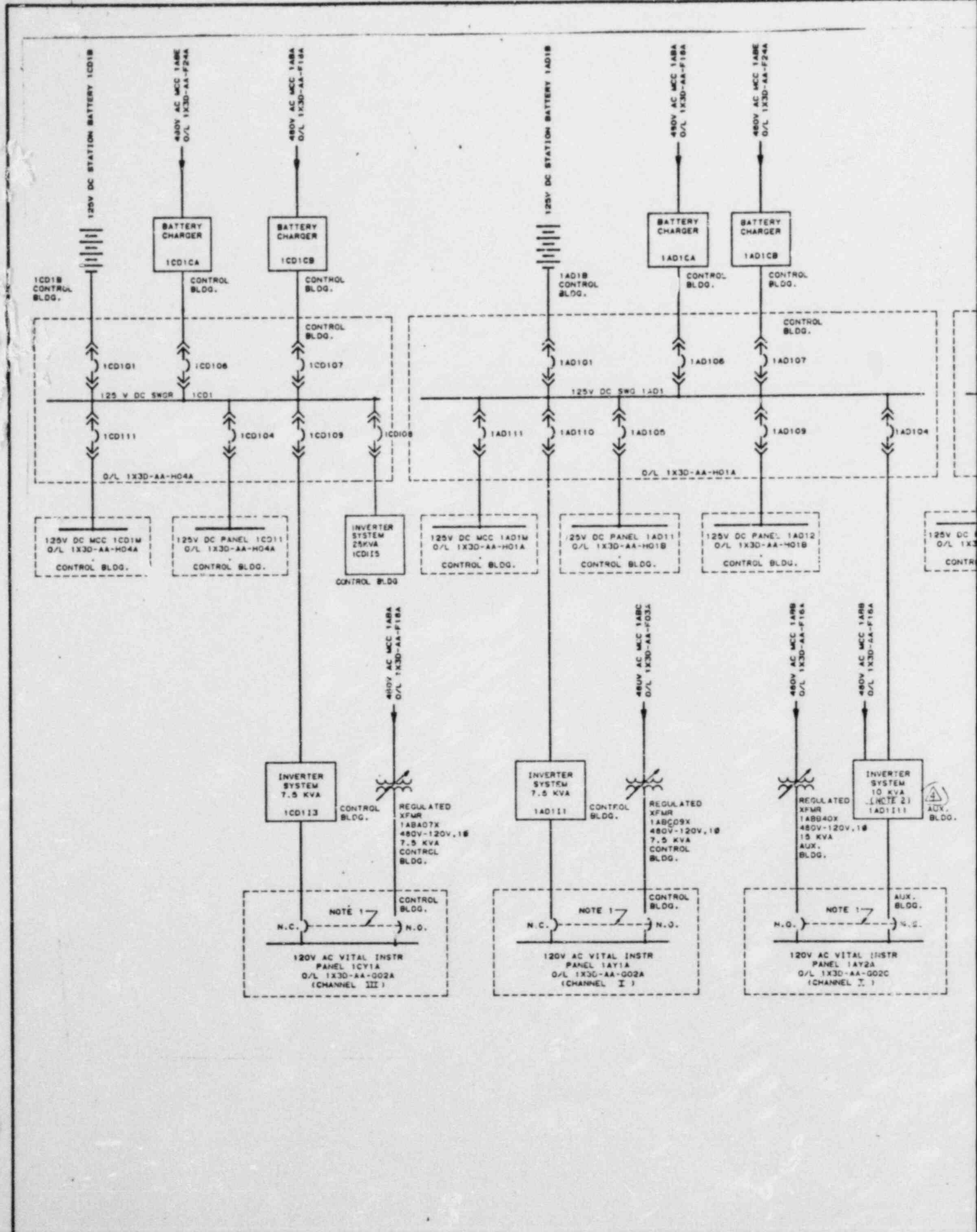
DIESEL GENERATOR ANNUNCIATOR POINTS

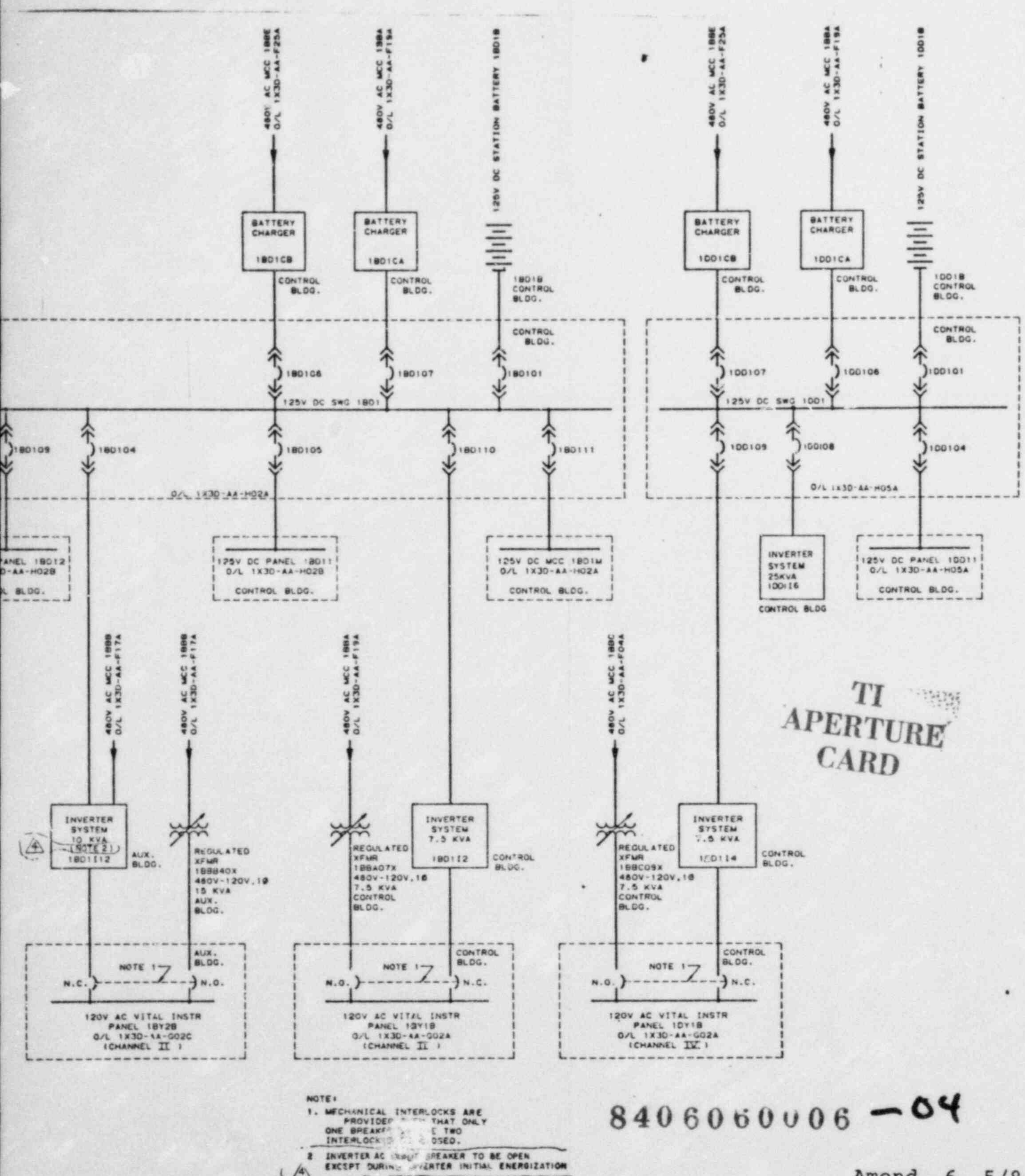
1. Low temperature lube oil - in
2. Low temperature lube oil - out
3. High temperature lube oil - in
4. High temperature lube oil - out
5. Trip - high temperature lube oil
6. Low level lube oil
7. Trip - high temperature bearing
8. Trip - high crankcase pressure
9. Trip - vibration
10. Trip - overspeed
11. Low temperature jacket water - in
12. Low temperature jacket water - out
13. High temperature jacket water - in
14. High temperature jacket water - out
15. Trip - high temperature jacket water
16. Low pressure jacket water
17. Trip - low pressure jacket water
18. Low level jacket water
19. High jacket water temperature sensor malfunction
20. Generator trouble
21. High generator bearing temperature
22. High generator control panel temperature
23. Low excitation
24. Generator fault

TABLE 8.3.1-7 (SHEET 2 OF 2)

25. Trip - generator differential
26. Maintenance lock out
27. Low pressure lube oil
28. Trip - low pressure lube oil
29. Low pressure turbo oil - right
30. Low pressure turbo oil - left
31. Trip - low pressure turbo oil
32. High ΔP fuel oil filter
33. Low pressure fuel oil
34. Low level main tank
35. Low level day tank
36. High level day tank
37. Low pressure control air
38. Low pressure starting air
39. High pressure starting air
40. Failed to start
41. Switch not in auto
42. Barring device engaged
43. Panel intrusion
44. High engine control panel temperature
45. Emergency start
46. Diesel generator bypassed[a]

a. This alarm is displayed on the system status monitoring panel in the control room only.


125V DC STATION BATTERY 1CD1B
480V AC MCC 1ABE O/L 1X3D-AA-F24A
480V AC MCC 1ABA O/L 1X3D-AA-F18A
BATTERY CHARGER 1CD1CA
BATTERY CHARGER 1CD1CB
1CD1B CONTROL BLDG.
CONTROL BLDG.
CONTROL BLDG.
CONTROL BLDG.
1CD101
1CD106
1CD107
125 V DC SWGR 1CD1
1CD111
1CD104
1CD109
1CD108
O/L 1X3D-AA-H04A
125V DC MCC 1CD1M O/L 1X3D-AA-H04A CONTROL BLDG.
125V DC PANEL 1CD11 O/L 1X3D-AA-H04A CONTROL BLDG.
INVERTER SYSTEM 25KVA 1CD115
CONTROL BLDG
125V DC STATION BATTERY 1AD1B
480V AC MCC 1ABA O/L 1X3D-AA-F18A
480V AC MCC 1ABE O/L 1X3D-AA-F24A
BATTERY CHARGER 1AD1CA
BATTERY CHARGER 1AD1CB
1AD1B CONTROL BLDG.
CONTROL BLDG.
CONTROL BLDG.
CONTROL BLDG.
1AD101
1AD106
1AD107
125V DC SWG 1AD1
1AD111
1AD110
1AD105
1AD109
1AD104
O/L 1X3D-AA-H01A
125V DC MCC 1AD1M O/L 1X3D-AA-H01A CONTROL BLDG.
125V DC PANEL 1AD11 O/L 1X3D-AA-H01B CONTROL BLDG.
125V DC PANEL 1AD12 O/L 1X3D-AA-H01B CONTROL BLDG.
480V AC MCC 1ABA O/L 1X3D-AA-F18A
480V AC MCC 1ABC O/L 1X3D-AA-F03A
480V AC MCC 1ABB O/L 1X3D-AA-F16A
480V AC MCC 1ABB O/L 1X3D-AA-F16A
INVERTER SYSTEM 7.5 KVA 1CD113
CONTROL BLDG.
REGULATED XFMR 1ABA07X 480V-120V,1Ø 7.5 KVA CONTROL BLDG.
INVERTER SYSTEM 7.5 KVA 1AD111
CONTROL BLDG.
REGULATED XFMR 1ABC09X 480V-120V,1Ø 7.5 KVA CONTROL BLDG.
REGULATED XFMR 1ABB40X 480V-120V,1Ø 15 KVA AUX. BLDG.
INVERTER SYSTEM 10 KVA (NOTE 2) 1AD111
AUX. BLDG.
CONTROL BLDG.
NOTE 1
N.C.
N.O.
120V AC VITAL INSTR PANEL 1CY1A O/L 1X3D-AA-G02A (CHANNEL III)
CONTROL BLDG.
NOTE 1
N.C.
N.O.
120V AC VITAL INSTR PANEL 1AY1A O/L 1X3D-AA-G02A (CHANNEL I)
AUX. BLDG.
NOTE 1
N.O.
120V AC VITAL INSTR PANEL 1AY2A O/L 1X3D-AA-G02C (CHANNEL I)



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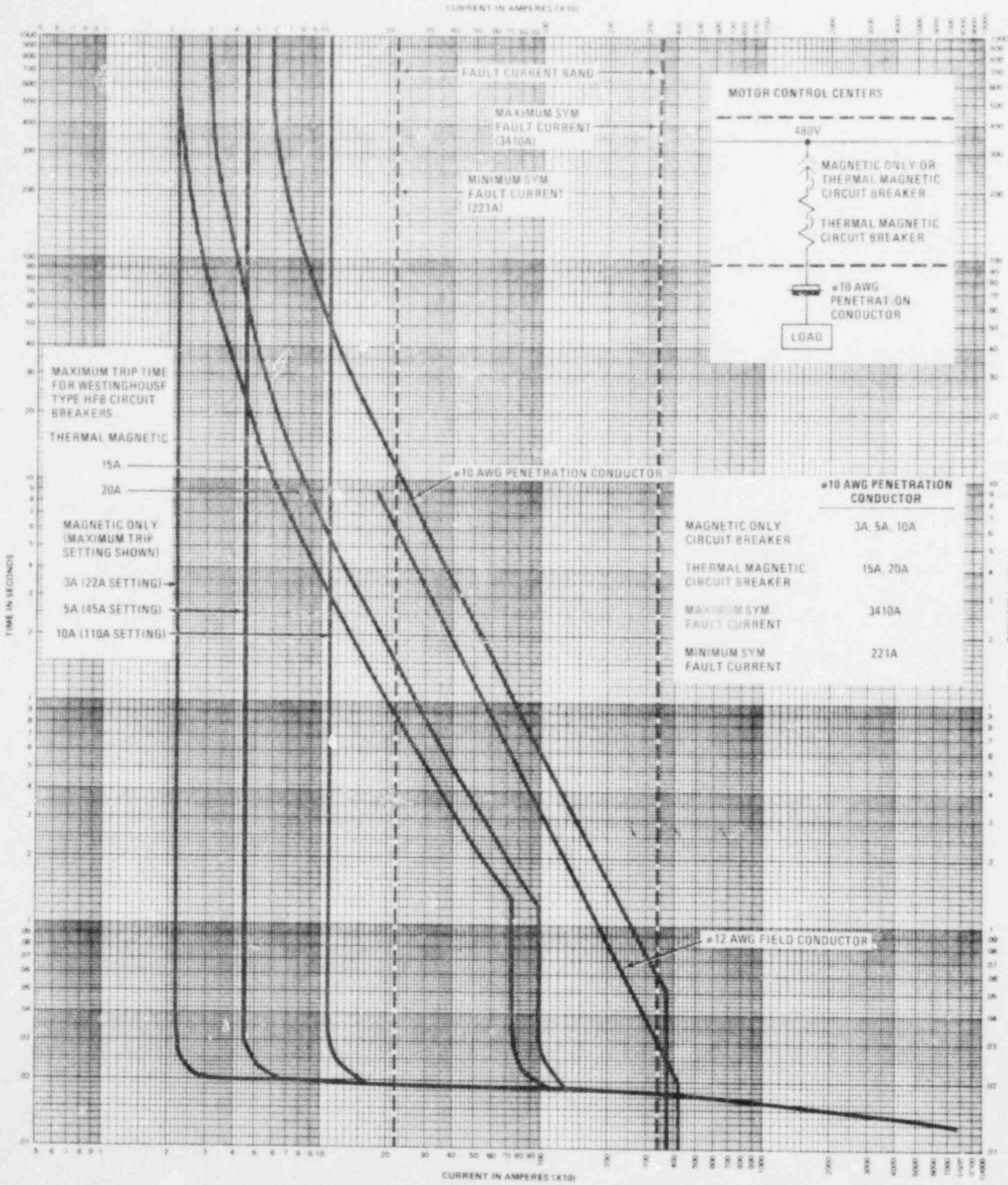
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CLASS 1E DC AND 120-VOLT AC POWER SUPPLY

FIGURE 8.3.1-4



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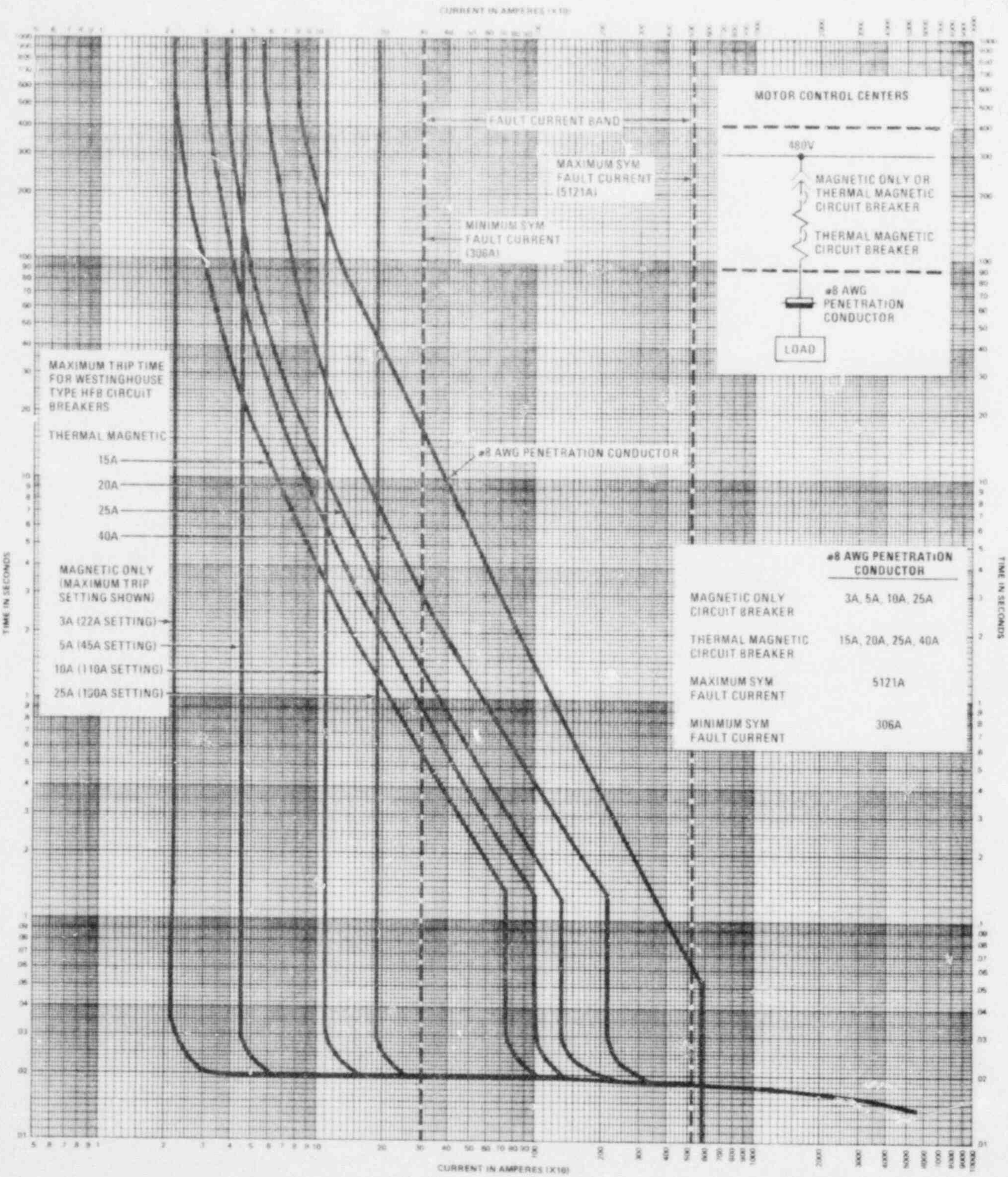
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND 2

PENETRATION OVERCURRENT PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 1 OF 14)

433-9



	#8 AWG PENETRATION CONDUCTOR
MAGNETIC ONLY CIRCUIT BREAKER	3A, 5A, 10A, 25A
THERMAL MAGNETIC CIRCUIT BREAKER	15A, 20A, 25A, 40A
MAXIMUM SYM FAULT CURRENT	5121A
MINIMUM SYM FAULT CURRENT	306A

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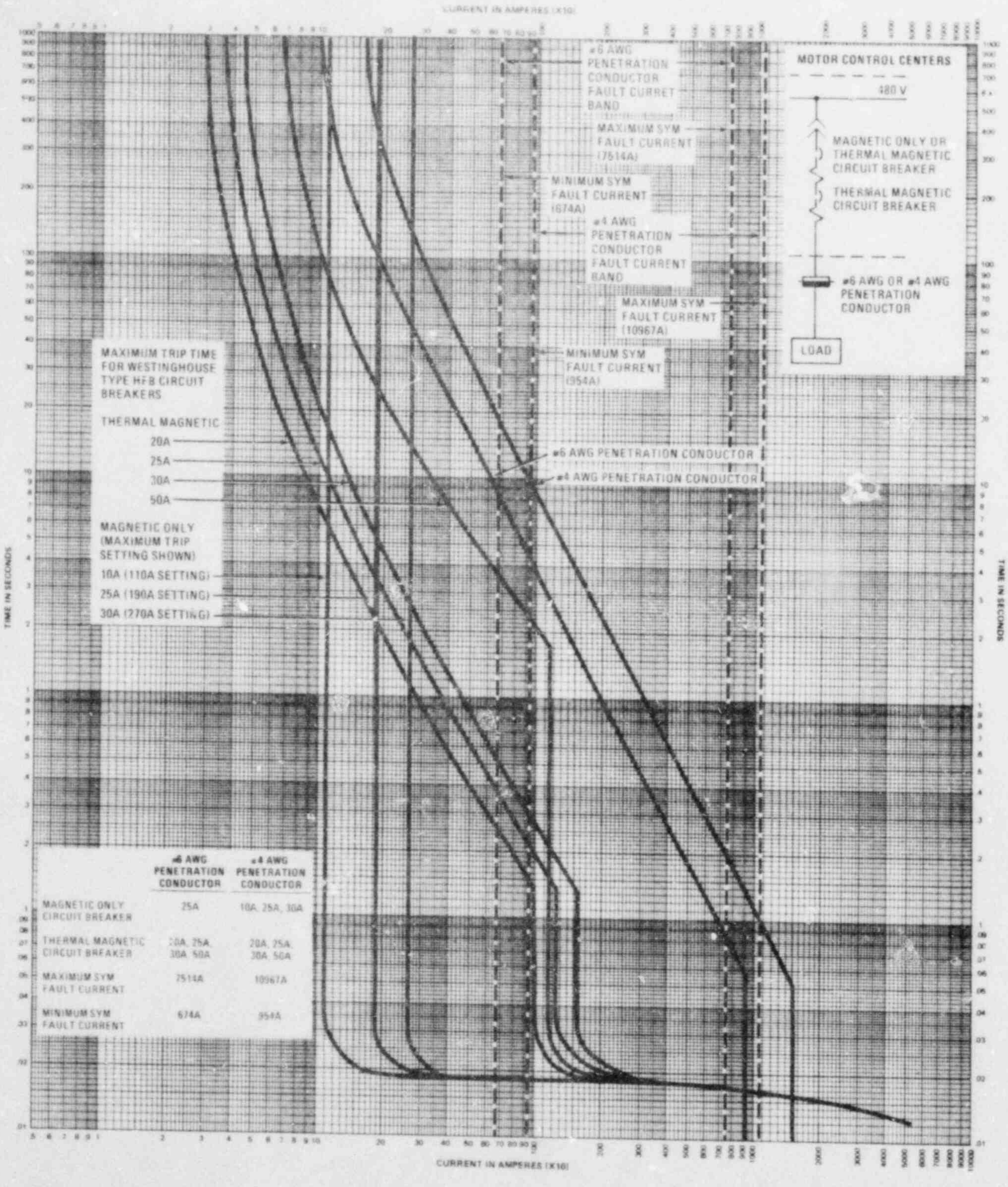
VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND 2

PENETRATION OVERCURRENT PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 2 OF 14)

433-9



	#6 AWG PENETRATION CONDUCTOR	#4 AWG PENETRATION CONDUCTOR
MAGNETIC ONLY CIRCUIT BREAKER	25A	10A, 25A, 30A
THERMAL MAGNETIC CIRCUIT BREAKER	20A, 25A, 30A, 50A	20A, 25A, 30A, 50A
MAXIMUM SYM FAULT CURRENT	7514A	10967A
MINIMUM SYM FAULT CURRENT	674A	954A

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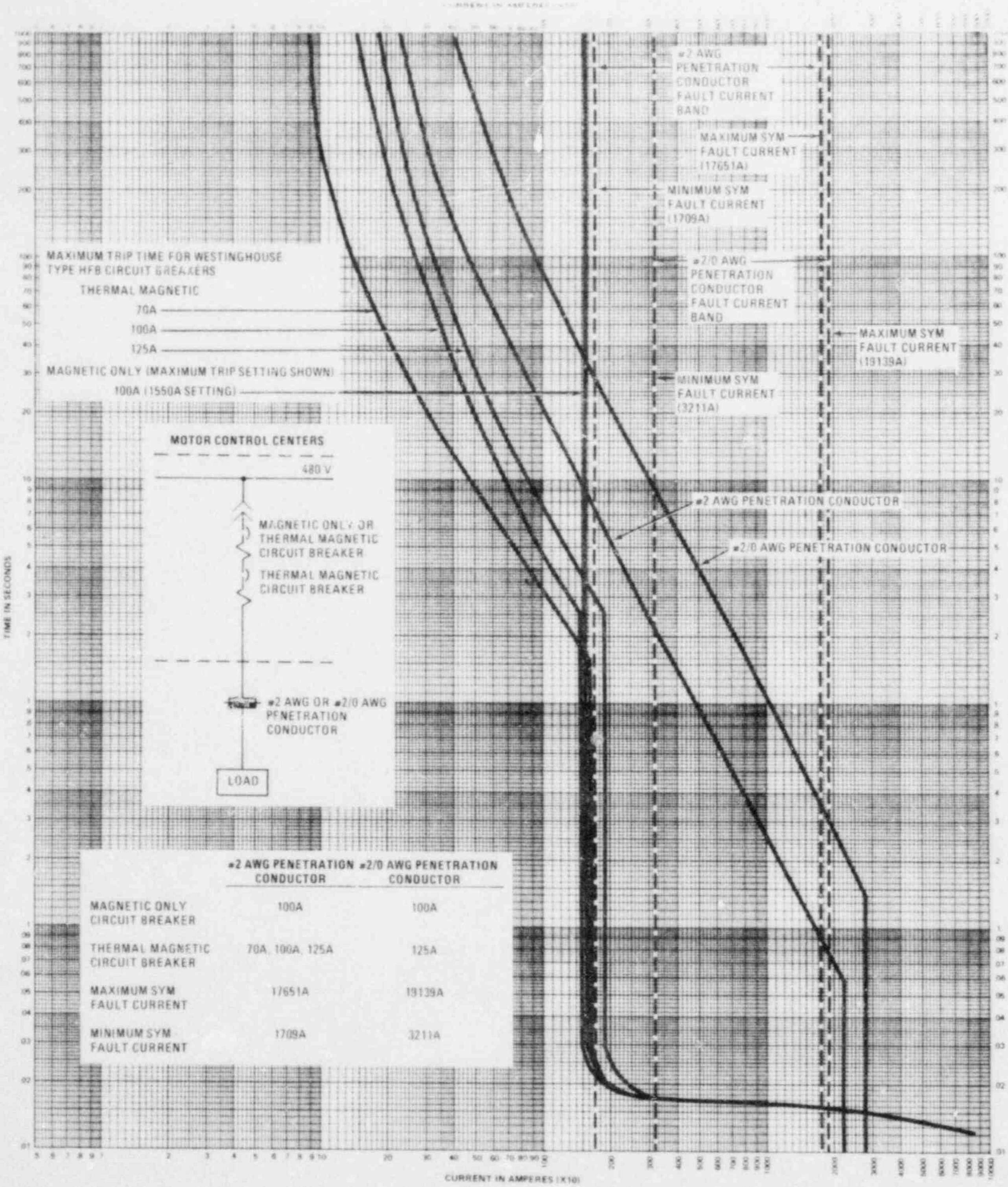
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND 2

PENETRATION OVERCURRENT
PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 3 OF 14)



	#2 AWG PENETRATION CONDUCTOR	#2/0 AWG PENETRATION CONDUCTOR
MAGNETIC ONLY CIRCUIT BREAKER	100A	100A
THERMAL MAGNETIC CIRCUIT BREAKER	70A, 100A, 125A	125A
MAXIMUM SYM FAULT CURRENT	17651A	19139A
MINIMUM SYM FAULT CURRENT	1709A	3211A

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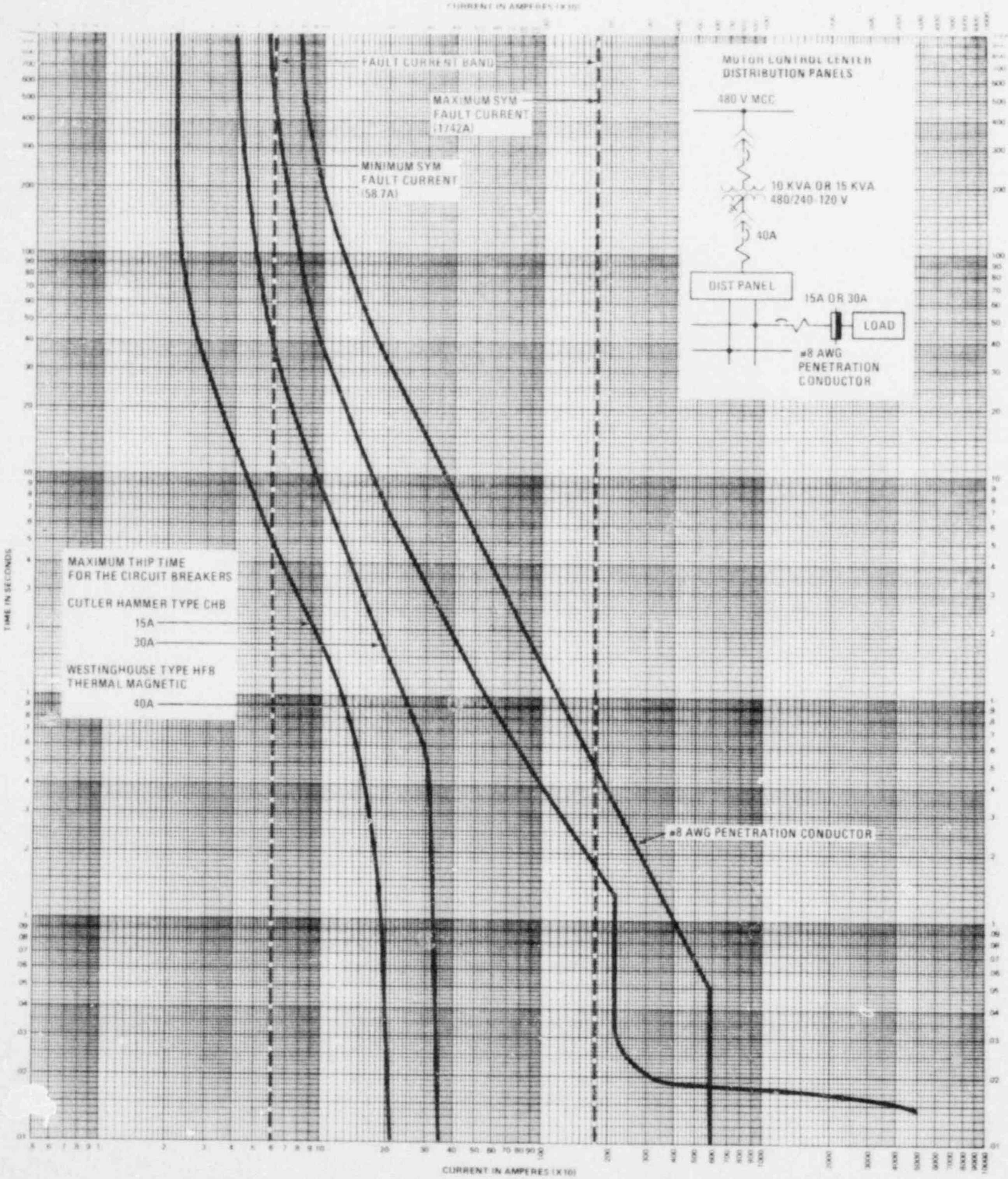
Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND 2

PENETRATION OVERCURRENT PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 4 OF 14)

433-9



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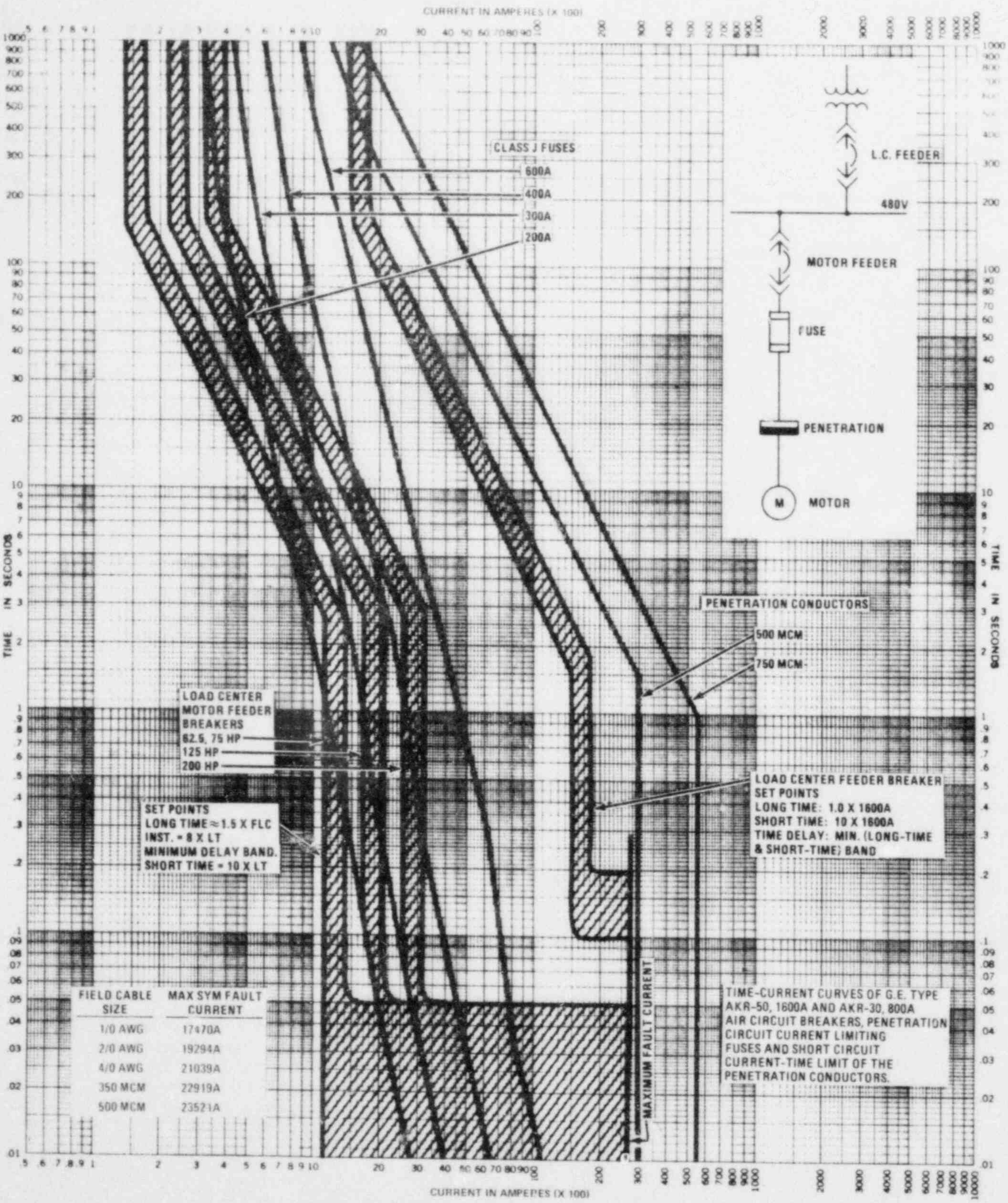
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND 2

PENETRATION OVERCURRENT
PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 5 OF 14)

433-9



FIELD CABLE SIZE	MAX SYM FAULT CURRENT
1/0 AWG	17470A
2/0 AWG	19294A
4/0 AWG	21039A
350 MCM	22919A
500 MCM	23521A

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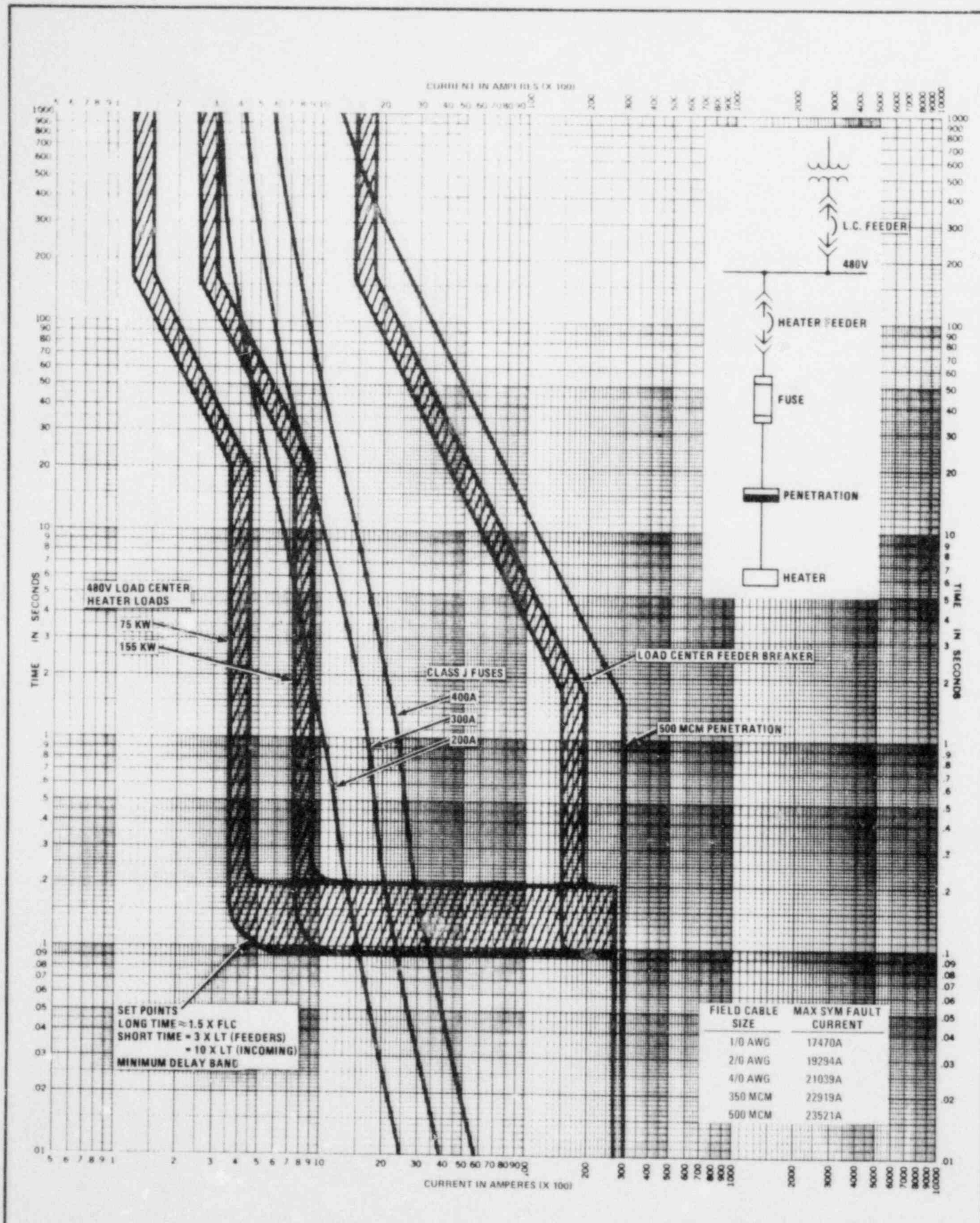
Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PENETRATION OVERCURRENT
PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 6 OF 14)

433-9



FIELD CABLE SIZE	MAX SYM FAULT CURRENT
1/0 AWG	17470A
2/0 AWG	19294A
4/0 AWG	21039A
350 MCM	22919A
500 MCM	23521A

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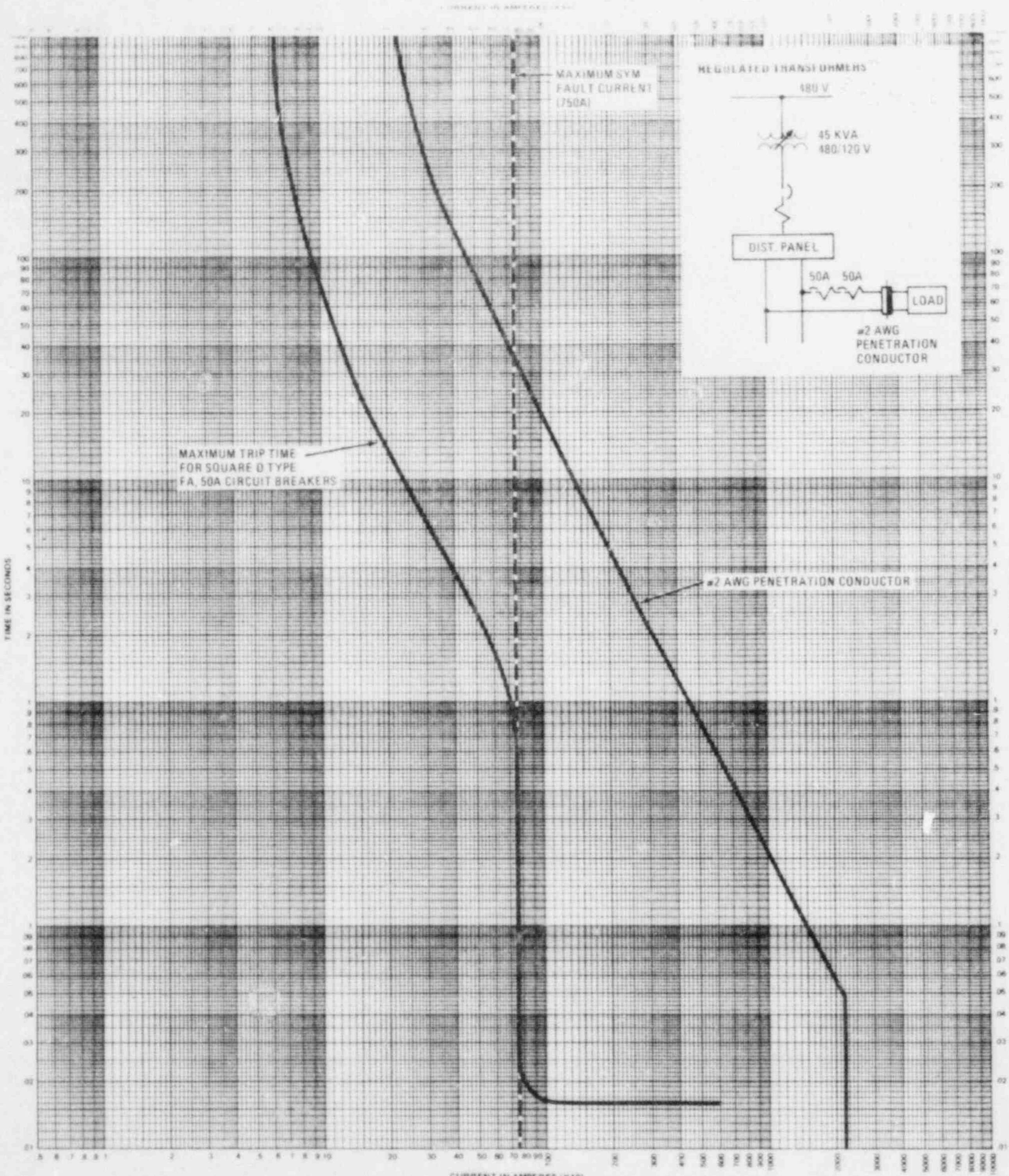
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PENETRATION OVERCURRENT
PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 7 OF 14)

433-9



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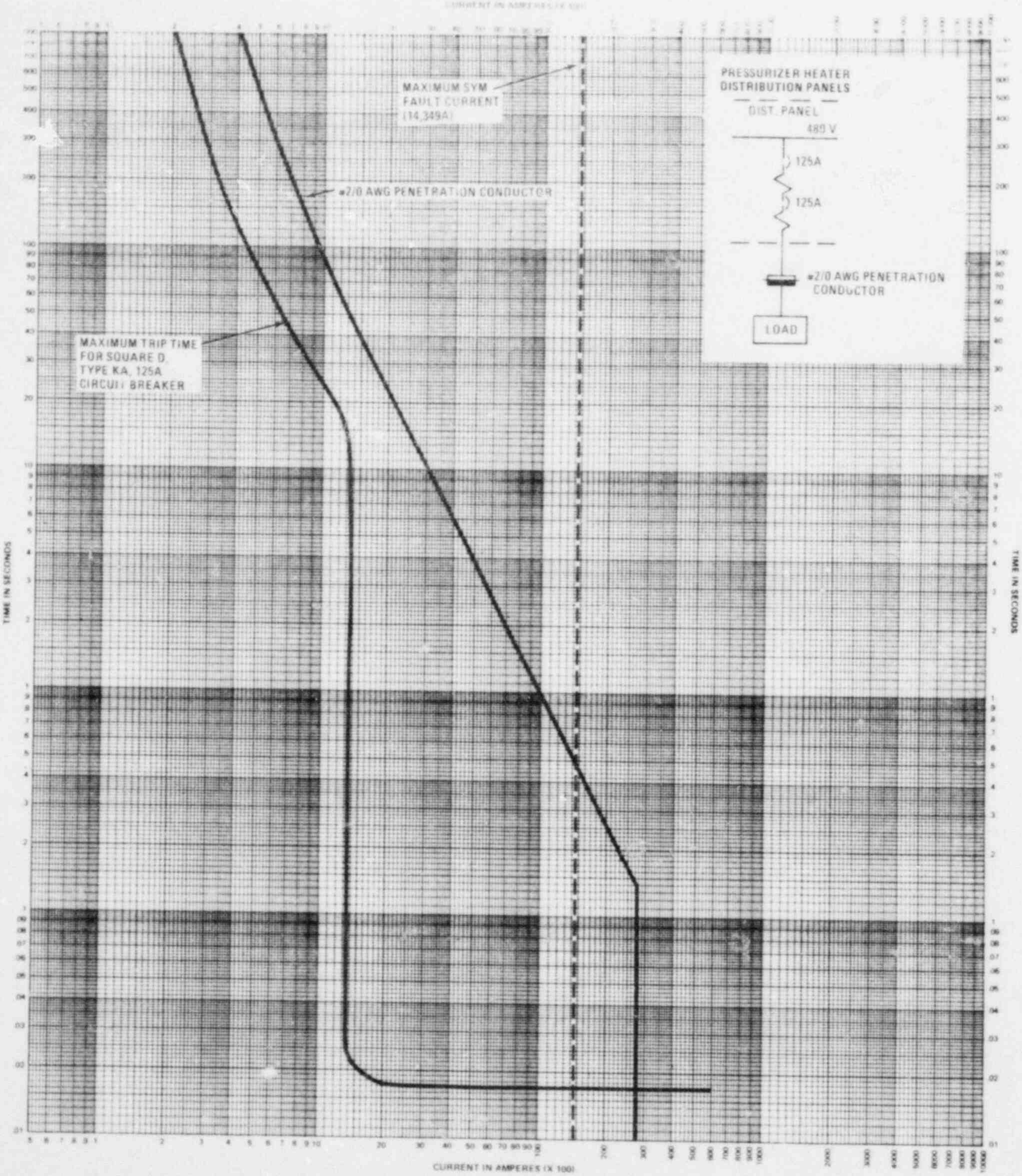
VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND 2

PENETRATION OVERCURRENT PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 8 OF 14)

433-9



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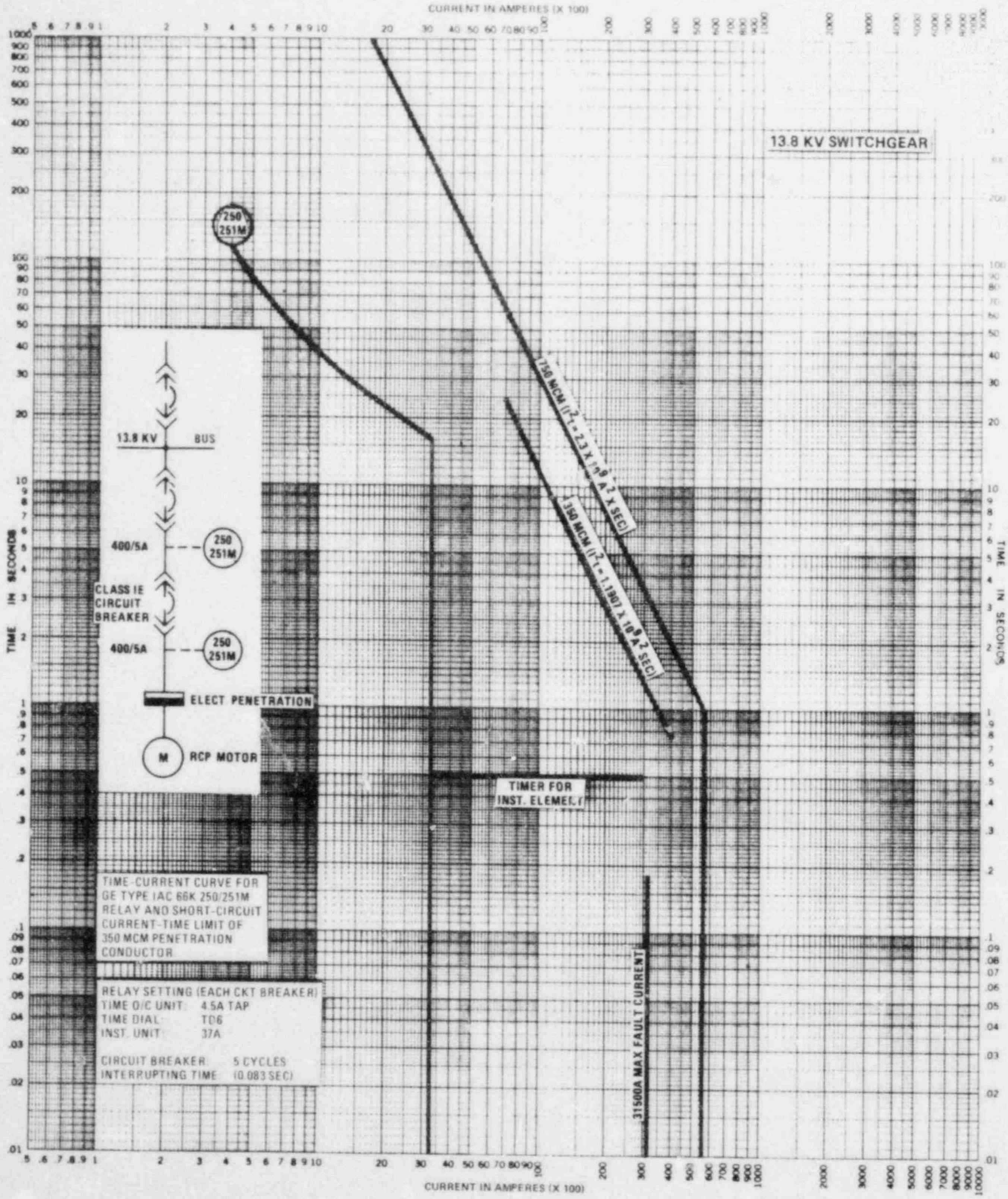
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND 2

PENETRATION OVERCURRENT
PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 9 OF 14)

433-9



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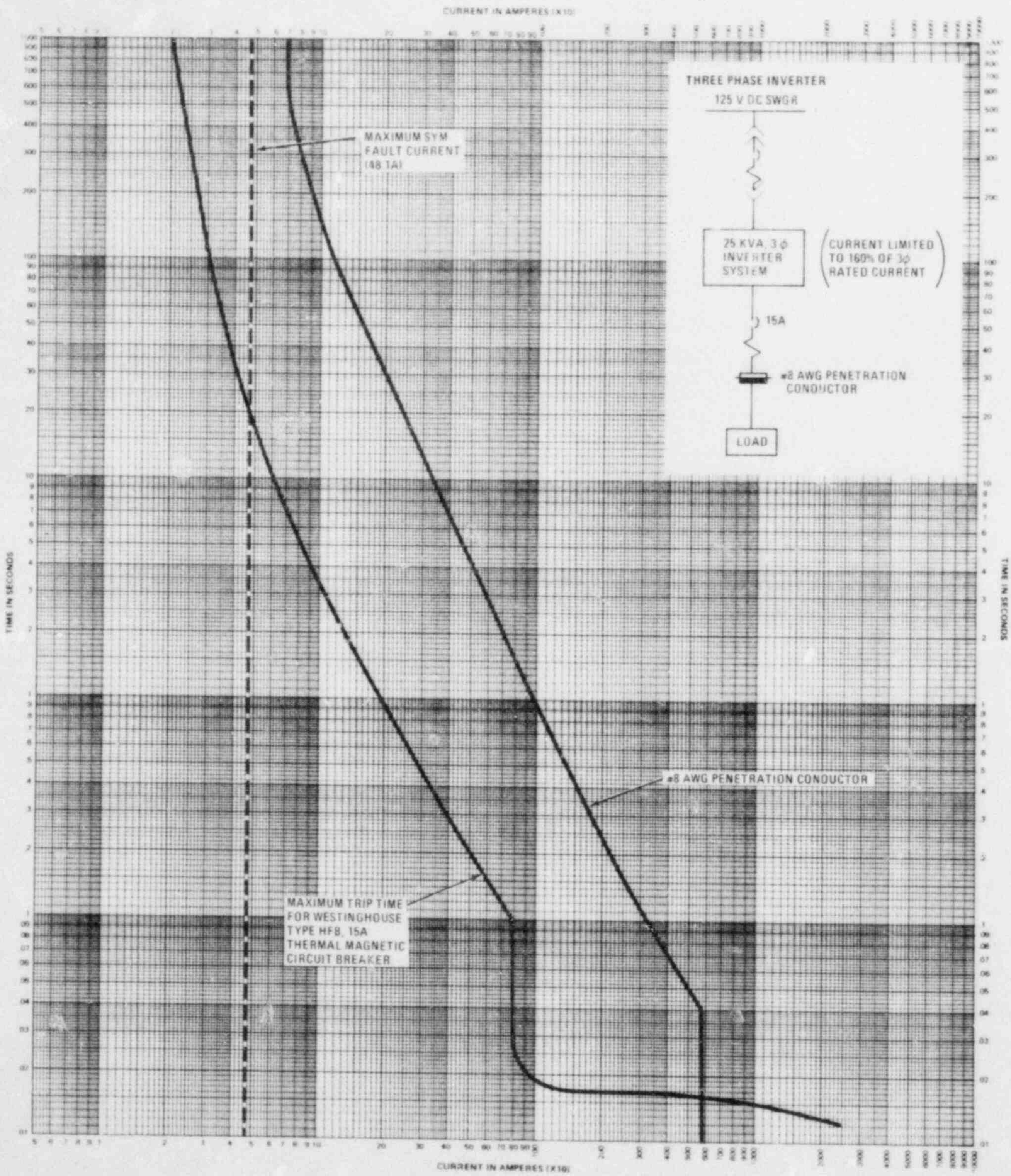
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PENETRATION OVERCURRENT
PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 10 OF 14)

433-9



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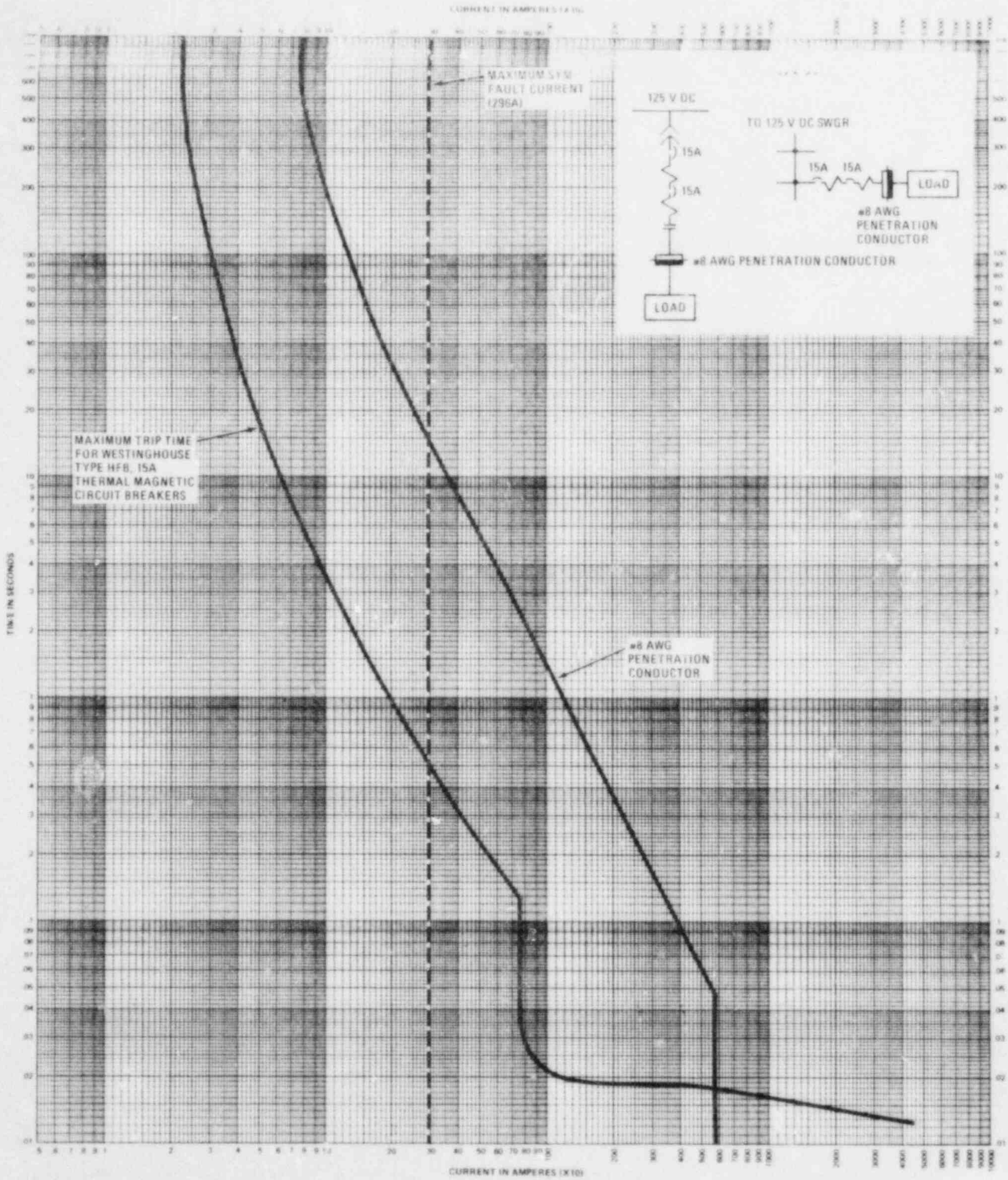
VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND 2

PENETRATION OVERCURRENT PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 11 OF 14)

433-9



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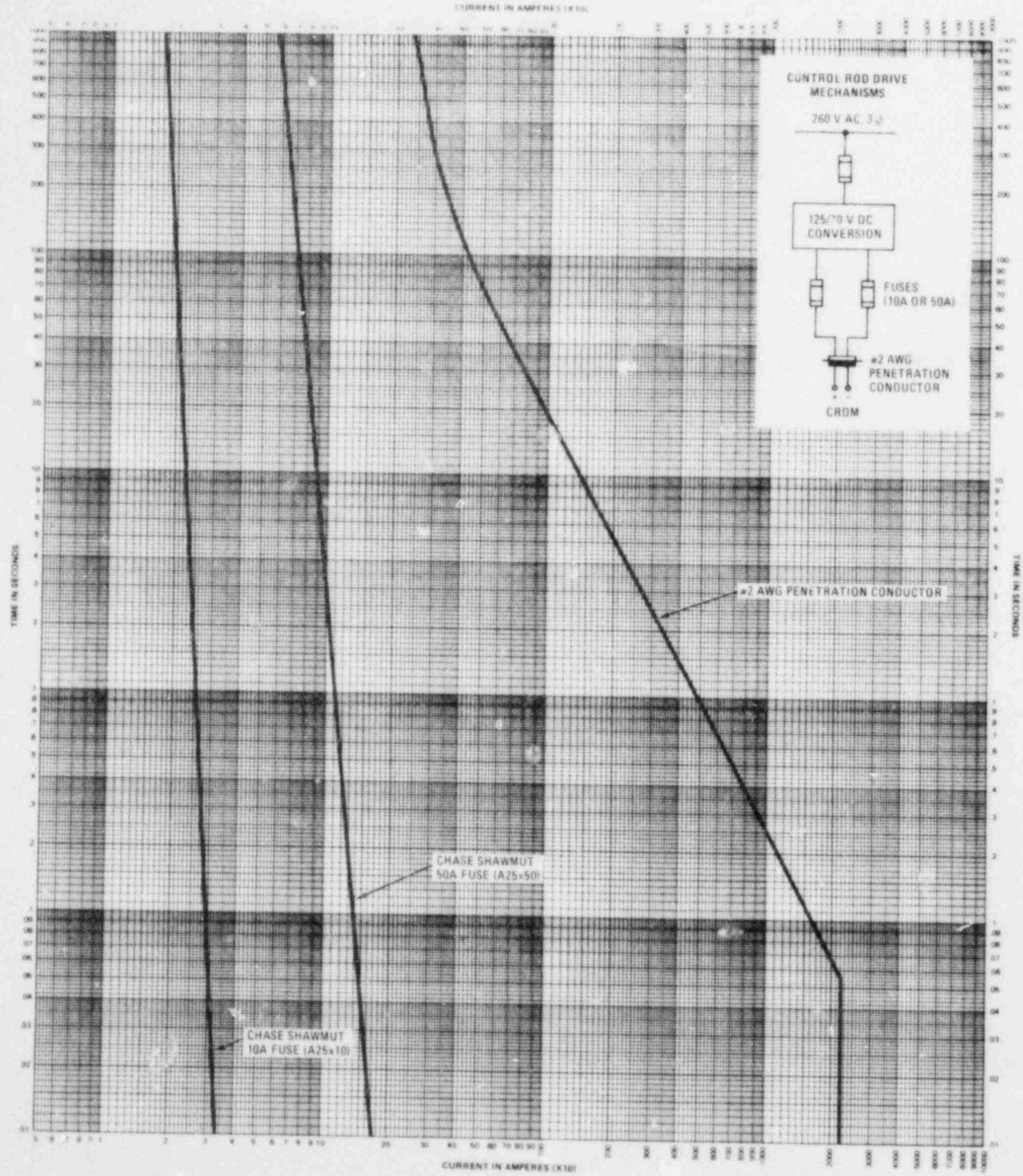
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND 2

PENETRATION OVERCURRENT PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 12 OF 14)



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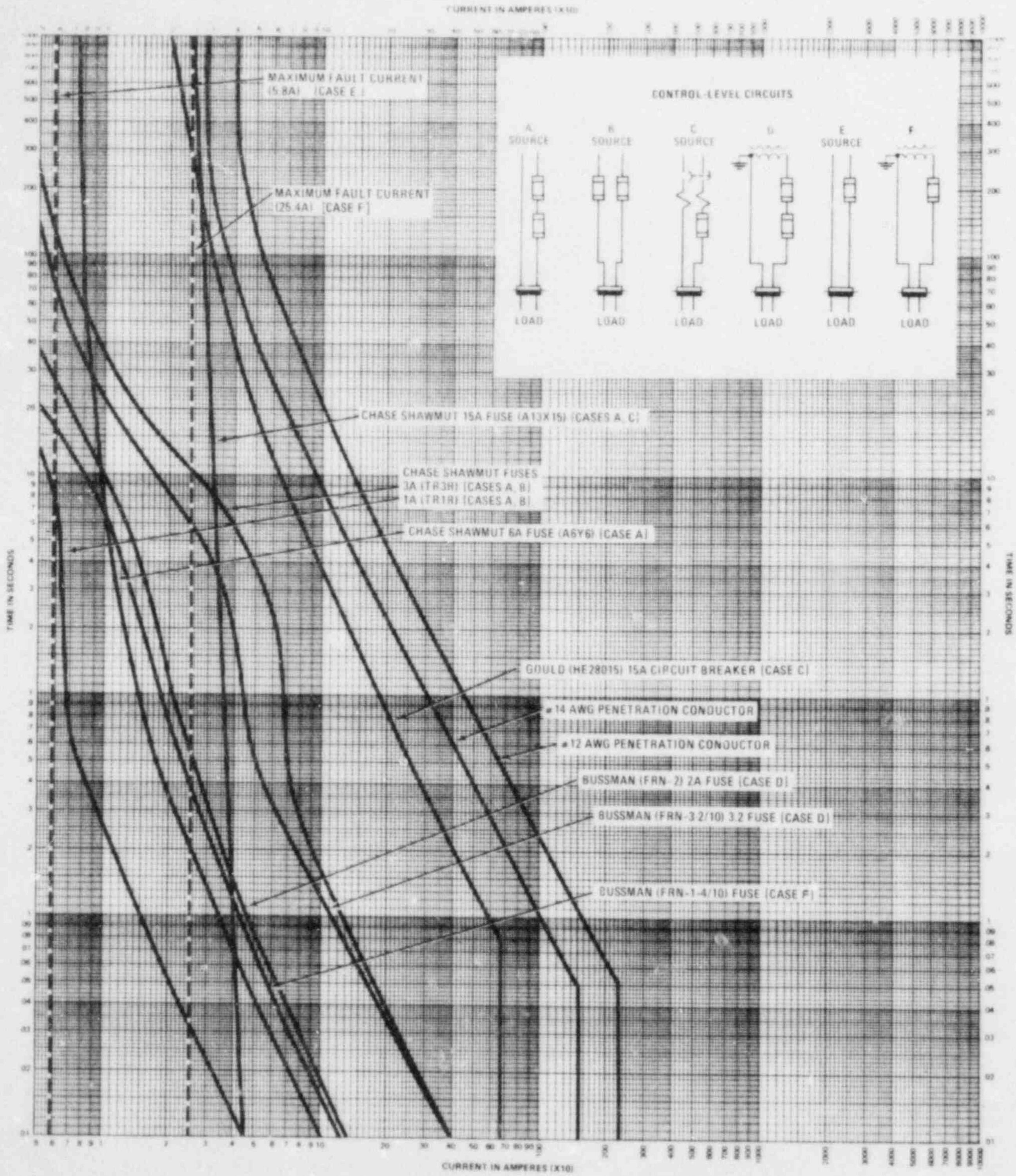
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND 2

PENETRATION OVERCURRENT PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 13 OF 14)

433-9



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VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

PENETRATION OVERCURRENT PROTECTION COORDINATION CURVES

FIGURE 8.3.1-7 (SHEET 14 OF 14)

single-line diagrams listed in this figure. The switchgear is of metal clad construction and is equipped with two-pole drawout type locally controlled air circuit breakers. The continuous current ratings and trip ratings are given on the single-line diagrams. The specific loads connected to the various systems can be identified by reference to the single-line diagrams indicated in figure 8.3.1-4.

The dc distribution panels connected to each dc switchgear bus supply safety-related loads as indicated on the single-line diagrams. The breakers are of molded case construction. The main bus and breaker ratings are given on the single-line diagrams referenced in figure 8.3.1-4.

Systems A and C receive power from train A 480-V ac engineered safety features (ESF) buses, and systems B and D receive power from train B 480-V ac ESF buses. System A is described here; systems B, C, and D are identical with the exception that system D does not include a motor control center. The equipment numbering used is identical for all four systems, with the first letter indicating the system.

Figure 8.3.1-4 shows the overall 125-V dc safety features systems to be provided for Unit 1. The Unit 2 systems are essentially identical. Battery 1AD1B feeds into dc switchgear designated 1AD1. Normal and backup battery chargers designated 1AD1CA and 1AD1CB are fed from ESF motor control centers 1ABA and 1ABE. The 125-V dc system A is formed at the switchgear 1AD1, and power is fed to motor control center 1AD1M, inverter 1AD1I1 and 1AD1I11, and dc distribution panels 1AD11 and 1AD12. Note that systems C and D have only one dc distribution panel and inverter per system.

Each 125-V dc motor control center supplies power to safety features motor-operated valves. The 125-V dc distribution panels supply power for safety features control, switching, and field flashing for the emergency diesel generators. See tables 8.3.2-1 through 8.3.2-4 for load lists.

System C provides all power required for successful operation of the turbine-driven auxiliary feedwater pump, with the exception of the steam generator-to-auxiliary feedwater turbine motor-operated valves (redundant valves) which are provided power from the system A and B dc motor control centers. The specific associated loads can be identified by reference to the single-line diagrams as shown in figure 8.3.1-4 for the system A, B, and C dc distribution equipment.

8.3.2.1.2 The Unitized 125-V dc Nonsafety Features Systems

The four unitized 125-V dc nonsafety features systems include 59-cell lead-calcium batteries and are similar in design to the safety features systems, the only difference being the number of distribution panels and inverters on each system and the absence of motor control centers. Figure 8.3.1-6 shows the 125-V dc nonsafety features systems. The Unit 2 systems are essentially identical. Batteries are sized in accordance with IEEE 485 to have sufficient capacity to supply the required loads for 2 h. They are sized at a minimum temperature of 70°F. All other sizing criteria are the same as for the 125-V dc safety features systems. The only interface with safety features systems is that one battery charger in each system receives power from non-ESF 480-V ac buses, which in turn are powered from ESF ac buses. However, these buses are shed on a safety injection signal. The battery charger design is similar to that of the safety features battery chargers. The same criteria as outlined in paragraph 8.3.2.1.1 apply to the nonsafety vital ac buses inverter systems. The plant annunciator, auxiliary relay rack 1, rod control motor generator set controller, boron recycle waste gas processing panel, waste evaporator control panel, and recycle evaporator control panel are also specified to operate over a 105- to 140-V dc input range.

Battery sizes are:

- 1475 Ah at 3-h rate; 2060 A for 1 min.
- 1838 Ah at 3-h rate; 2795 A for 1 min.
- 1690 Ah at 3-h rate; 2330 A for 1 min (two batteries of this size).

The 125-V dc nonsafety features systems supply dc power to nonsafety motors, control, switching, and instrumentation as shown on the single-line diagrams identified in figure 8.3.1-6.

8.3.2.1.3 Common 125-V dc Nonsafety Features Systems

There are seven common 125-V dc nonsafety systems: the river intake structure, the service building, the switchyard (two systems), the technical support center, and the security system (two systems). The river intake structure and the service building each have a 59-cell lead-calcium battery, a distribution panel, a normal battery charger, and a backup battery charger. These systems receive 480-V ac power from normal buses. The switchyard system has two batteries, two distribution panels, and three battery chargers. A further description 7 is provided in paragraph 8.2.1.2. Each system has a normal battery charger with a backup charger shared between both systems. Note that Unit 1 will supply power to all three battery chargers until Unit 2 construction is complete. After Unit 2 is complete, its switchyard battery charger will be switched to a Unit 2 normal bus. These batteries are sized as discussed in paragraph 8.3.2.1.2, with the exception of the technical support center battery which has been sized to supply required loads for 1 h.

Battery sizes are:

- River intake structure - 57 Ah at 3-h rate; 111 A for 1 min.
- Service building - 260 Ah at 3-h rate; 500 A for 1 min.
- Switchyard - 260 Ah at 3-h rate; 500 A for 1 min (two batteries of this size).
- Technical support center - 1475 Ah at 3-h rate; 2060 A for 1 min.
- Security central alarm station - 1811 Ah at 3-h rate; 2500 A for 1 min.
- Security secondary alarm station - 983 Ah at 3-h rate; 1400 A for 1 min.

The 125-V dc common nonsafety features systems supply dc power for control, switching, vital security and technical support center loads, and the plant telephone/page communication system as shown in the single-line diagrams identified in figure 8.3.1-8.

8.3.2.1.4 Ventilation

Battery rooms are ventilated to remove the gases that may be produced during charging of the batteries. The ventilation system for the ESF batteries is safety related. See section 9.4.5 for a further discussion of the associated ventilation systems.

8.3.2.1.5 Maintenance and Testing

All components of the 125-V dc systems will undergo periodic maintenance tests to determine the condition of each individual subsystem. Batteries are checked for liquid level, specific gravity, and cell voltage and are visually inspected following the manufacturer's recommended guidelines for procedures. An initial composite test of onsite ac and dc power systems will be performed as a prerequisite to initial fuel loading. This test will establish that the capacity of each battery is sufficient to satisfy a real-time safety load demand profile under the conditions of a loss-of-coolant accident (LOCA) and simultaneous loss of offsite power. Thereafter, periodic capacity tests will be conducted in accordance with IEEE 450, Regulatory Guide 1.129, and the manufacturer's schedule recommended for cyclic test discharge/equalizing charge rates. These tests will ensure that the battery has the capacity to continue to meet safety load demands. Battery chargers are periodically checked by visual inspection and performance tests.

Testing will be done according to the following:

A. The specific gravity, electrolyte temperature and level, and voltage of the pilot cell of each battery will be measured and logged monthly.

B. The specific gravity, electrolyte temperature and level, and voltage of each cell from each battery will be measured and logged quarterly.

C. Once each refueling cycle but not to exceed 18 months, the batteries will be subjected to a performance discharge test. The specific gravity and voltage of each cell will be measured after the discharge and logged.

8.3.2.2 Analysis

The regulatory guides regarding dc power systems are discussed in section 1.9 and subsection 8.1.4. Compliance with the general design criteria is discussed in section 3.1. Table 8.3.2-5 is the failure modes and effects analysis.

The 125-V dc systems A and C form the train A safety features dc system. Their normal and backup chargers receive power from two Class 1E train A motor control centers. The 125-V dc systems B and D form the train B safety features dc system. Their normal and backup chargers receive power from two Class 1E train B motor control centers. The train C and D battery chargers are qualified as isolation devices in accordance with IEEE 384 and Regulatory Guide 1.75. The train A safety features dc system supplies power to train A loads, and the train B safety features dc system supplies power to train B loads. Each individual system (A, B, C, and D) supplies power to a separate instrument channel (1, 2, 3, or 4). In this way, separation between the independent systems is maintained, and the power provided to the chargers can be from either offsite or onsite sources (General Design Criterion 17). The dc system is so arranged that the probability of an internal system failure resulting in loss of dc power is extremely low. Important system components are either self-alarming locally and/or in the control room upon failure or capable of being tested during service to detect faults. Each battery set is located in its own ventilated room. All abnormal conditions of important system parameters are annunciated in the main control room. The safety features battery circuit breakers have dedicated annunciation in the main control room which alarm on a circuit breaker open condition. There is no cross-connection between the independent 125-V dc systems.

The design of the 125-V dc safety features systems provided for VEGP is based on the criteria described in IEEE 308 and 450. Each battery consists of 59 lead-calcium storage cells, designed for the specific service in which they are to be used. Ample capacity is available to serve the loads connected to the system for the duration of the time that alternating current is not available at the station site. Each division of Class 1E equipment is provided with a separate 125-V dc system to avoid a single failure involving more than one system. Batteries are located in well-ventilated rooms which limit hydrogen concentration to less than 2 percent by volume. A hydrogen survey is performed during preoperational checkout to verify that the ventilation system limits hydrogen concentration to this level in accordance with Regulatory Guide 1.128. Adequate aisle space and space above cells are provided.

Eyewash facilities are provided in all battery rooms. They are designed to preclude spilling of water from these facilities on the battery installation.

Seismic Category 1 battery racks provide for the mounting of battery cells in a two-step configuration.

The same criteria as that indicated in paragraph 8.3.1.1.12 applies to dc circuits that are connected to containment penetrations. See figure 8.3.1-7 for the overcurrent protection coordination curve for the dc feeders (General Design Criterion 50).

Fire detection sensors and alarms are provided as described in subsection 9.5.1.

Before installation, cells are stored in a clean, level, dry, and cool location. Extremely low ambient temperatures and localized sources of heat are avoided. During installation, any cell with electrolyte level 1/2 in. or more below the top of the plates is replaced.

Each battery charger has enough capacity for the steady-state operation of connected loads required during normal operation while maintaining its battery in a fully charged condition. Each battery charger and battery charger supply has sufficient capacity to restore a battery from a fully discharged state to a fully charged state within 12 h while supplying the normal steady-state loads. The battery charger supply is from an engineered safety features system motor control center within its division. Battery chargers are provided with disconnecting means and feedback protection. The chargers are specified to limit dc current feedback during loss of ac input power to 0.200 A under any condition. Periodic tests will be performed to ensure the readiness of the system to deliver the required power (General Design Criterion 18). A qualified ground detector system provides indication of any grounds which may occur in the system.

Battery current and system voltage indications are provided in the main control room for each dc system.

The following common annunciator windows are provided in the main control room for each dc system:

A. Switchgear trouble (combines undervoltage, ground, and circuit breaker tripped).

B. Battery charger trouble (combines ac input undervoltage, dc output overvoltage, and loss of dc output).

C. Inverter trouble (nuclear steam supply system-supplied dc input voltage low, dc input voltage high, ac output voltage low; balance of plant-supplied vital bus inverter: reverse transfer, fuse blown, output transfer 7 switch improper position, circuit breaker tripped, overload dc undervoltage, output ac overvoltage, and output ac undervoltage; residual heat removal valve inverter: output or input circuit breaker tripped, overload, output voltage low, output voltage high, input dc voltage low, and fan failure).

D. 125-V dc panel trouble (combines undervoltage, ground, and branch breaker overload).

E. 125-V dc motor control center trouble.

F. Battery circuit breaker open alarm (dedicated alarm).

via the transfer canal when the gate between the pool and canal is open.

B. Spent Fuel Pool Dewatering

The most serious failure of this system would be complete loss of water in the storage pool. In accordance with Regulatory Guide 1.13, the design of the SFPCPS limits the loss of coolant that could be caused by maloperation or failure of system components such that spent fuel does not become uncovered.

The spent fuel pool cooling pump suction connections are located near the normal water level so that the pool cannot be gravity drained. Each return line contains an antisiphon hole to prevent the possibility of gravity draining of the pool via these lines. Finally, the lines to and from the skimmer/strainers are located near the normal water level.

The accidental opening of the gate between the spent fuel pool and the transfer canal, if the canal is dry, would lower the water level approximately 6 ft, leaving about 18 ft of water over the top of the spent fuel assemblies.

Makeup water sources are provided to replace evaporative and minor leakage losses. These sources include the refueling water storage tank, the reactor makeup water storage tank, the demineralized water storage tank, and the recycle holdup tanks. Makeup to the spent fuel pit should be started upon a low-level alarm signal from the spent fuel pool level instrumentation. 7

The spent fuel pool, transfer canal, and spent fuel cask loading pit have stainless steel liners welded to embedments in the walls and floors. At every liner weld seam continuous drains are provided for leak detection. These are interconnected and drain to a collection point which is monitored to determine whether leakage is occurring.

C. Water Quality

Only a very small amount of water is interchanged between the refueling canal and the spent fuel pool, as fuel assemblies are transferred in the refueling process. Whenever a fuel assembly with defective cladding is transferred from the fuel transfer canal to the spent fuel pool, a small quantity of fission products may enter the spent fuel cooling water. The purification loop removes fission products and other contaminants from the water. By maintaining radioactivity concentrations, excluding tritium, in the spent fuel pool water at or below 5×10^{-3} µCi/g for dominant gamma-emitting isotopes, the dose rate at the surface of the pool is 2.5 mrem/h or less.

9.1.3.6 Tests and Inspections

Active components of the SFPCPS are in either continuous or intermittent use during normal system operation. Periodic visual inspection and preventive maintenance are conducted using normal industry practice.

No special equipment tests are required, since system components are normally in operation when spent fuel is stored in the fuel pool.

Sampling of the fuel pool water for gross activity and particulate matter concentration is conducted periodically. The layout of the components of the SFPCPS is such that periodic testing and inservice inspection of this system are possible. Details of the inservice inspection program are outlined in section 6.6.

A. Instrumentation Application

The instrumentation provided for the SFPCPS is discussed in the following paragraphs. Alarms and indications are provided as noted.

B. Temperature

Instrumentation is provided to measure the temperature of the water in the spent fuel pool and to give local indication as well as annunciation in the control room when normal temperatures are exceeded.

Instrumentation is also provided to give local indication of the temperature of the spent fuel pool water as it leaves either heat exchanger.

C. Pressure

Instrumentation is provided to measure and give local indication of the pressures in the spent fuel pool pump suction and discharge lines and in the skimmer pump discharge line. Instrumentation is also provided

9.2.2 COMPONENT COOLING WATER SYSTEM

The component cooling water (CCW) system provides cooling for the spent fuel pool (SFP) during all plant operating modes and for the residual heat removal system (RHRS) during normal shutdown and emergency conditions. The CCW system also serves as an intermediate system or barrier between the reactor coolant system and the nuclear service cooling water (NSCW) system which is open to the atmosphere.

9.2.2.1 Design Bases

Protection of the CCW system from wind and tornado effects is discussed in section 3.3. Flood design is discussed in section 3.4. Missile protection is discussed in section 3.5. Protection against dynamic effects associated with the postulated rupture of piping is discussed in section 3.6. Environmental design is discussed in section 3.11.

9.2.2.1.1 Safety Design Bases

A. The CCW system is designed to transfer reactor heat energy from the RHRS to the NSCW system at a rate sufficient to avoid fuel or core damage following a loss-of-coolant accident (LOCA). This safety design basis is in accordance with 10 CFR 50, General Design Criterion 44, Cooling Water.

B. The CCW system is designed to provide the cooling waterflow for removal of heat from the seal coolers for the RHR pumps and from the spent fuel pool heat exchangers.

C. The CCW system is designed so that a single failure of any component, assuming the loss of offsite power, cannot impair the system's capability to comply with its safety-related heat removal function.

D. The CCW system is designed to remain functional during and after a safe shutdown earthquake (SSE).

E. Active components of the CCW system are capable of being periodically inspected and tested during plant power generation operation. Provisions are made for suitable inspection of important components at appropriate times. Design is pursuant to 10 CFR 50, General Design Criteria 45, Inspection of Cooling Water System, and 46, Testing of Cooling Water System.

F. The CCW system is designed to remove reactor decay heat at a sufficient rate to bring the reactor to a cold shutdown condition in 36 h with a loss of offsite power and assuming the most limiting single active failure in accordance with Regulatory Guide 1.139.

9.2.2.1.2 Power Generation Design Bases

A. The CCW system provides a continuous supply of cooling water to the SFP heat exchanger during all normal operating and normal shutdown conditions and during refueling. However, during the first fuel cycle of power generation, neither train of the CCW system is 7
required to provide cooling to the SFP heat exchanger.

B. The CCW system is designed with lower pressures than the NSCW system to prevent potentially radioactive leakage into the NSCW system.

C. The CCW system is designed in a manner which prevents long-term corrosion that may degrade system performance.

D. The CCW system is equipped with radiation monitoring capability.

9.2.2.1.3 Codes and Standards

Codes and standards applicable to the CCW system are listed in table 3.2.2-1. The CCW system is designed and constructed in accordance with American Society of Mechanical Engineers (ASME) Section III, Class 3, except for the CCW chemical addition tank and associated piping.

9.2.2.2 <u>System Description</u>

9.2.2.2.1 General Description

The CCW system is shown in figure 9.2.2-1. The system consists of two separate 100-percent redundant trains. Each train supplies cooling water to one spent fuel pool heat exchanger, to one RHR heat exchanger, and to the seal cooler of the RHR pump aligned with that RHR heat exchanger.

Each CCW train consists of one heat exchanger, three 50-percent capacity pumps, one CCW surge tank, one chemical addition tank, and associated piping, valves, and instrumentation.

9.2.2.2.2 Component Description

A summary of design parameters for major system components is provided in table 9.2.2-1.

A. Pumps

The CCW pumps are centrifugal pumps, rated at 5000 gal/min at a 160-ft head. The pumps are driven by 300-hp motors.

B. Heat Exchangers

The CCW heat exchangers are shell and tube type, two-pass flow on the tube side, rated at 129.1×10^6 Btu/h.

C. Surge Tanks

The surge tanks are horizontal cylindrical atmospheric tanks with a capacity of 2000 gal each.

9.2.2.2.3 System Operation

The CCW system functions as a closed loop system. The heat loads of the CCW system are provided in table 9.2.2-2. The CCW pumps take suction from the shell side of the CCW heat exchangers and circulate the CCW through the components to be cooled, back to the shell side of the CCW heat exchanger, where the collected heat is transferred to the NSCW system which in turn transfers the heat to the ultimate heat sink. Refer to subsections 9.2.1 and 9.2.5 for details of the NSCW system and ultimate heat sink, respectively.

There are three 50-percent-capacity CCW pumps in each train. The third pump serves as a standby and allows maintenance to be performed on one pump.

The surge tank is connected to the main CCW line on the suction side of the pumps and functions to ensure that the system is kept filled and pump net positive suction head (NPSH) requirements are maintained. Makeup water is added to the surge tank as required from the reactor makeup water storage tank and/or the demineralized water storage tank. To ensure against radioactive release should the CCW be contaminated, surge tank overflow is connected in the CCW drain tank and either returned to the CCW system or treated prior to offsite disposal.

One train is operated during normal power generation. However, during the first fuel cycle of power generation, neither train of the CCW system is required to provide cooling to the SFP heat exchanger. Both trains are automatically started by an engineered safety feature (ESF) signal. Both trains can be operated during plant shutdowns, although only one train is required to bring the plant to cold shutdown conditions with loss of offsite power and assuming the most limiting single active failure. 7

9.2.2.3 Safety Evaluation

A. The nominal CCW system cooling capacity is 129×10^6 Btu/h for each train. During two-train cooldown, the maximum heat load is 116×10^6 Btu/h, and cold shutdown is achieved in 17 h. During one-train cooldown, the peak heat load is approximately 171×10^6 Btu/h, and cold shutdown is achieved in 29 h. Thus, the CCW system satisfies the cold shutdown requirements of Regulatory Guide 1.139 and Branch Technical Position RSB 5-1. During accident conditions, the heat load on the CCW system is 96.6×10^6 Btu/h and therefore less than cold shutdown. Hence, the CCW system is capable of performing its duty of removing heat at the required rate.

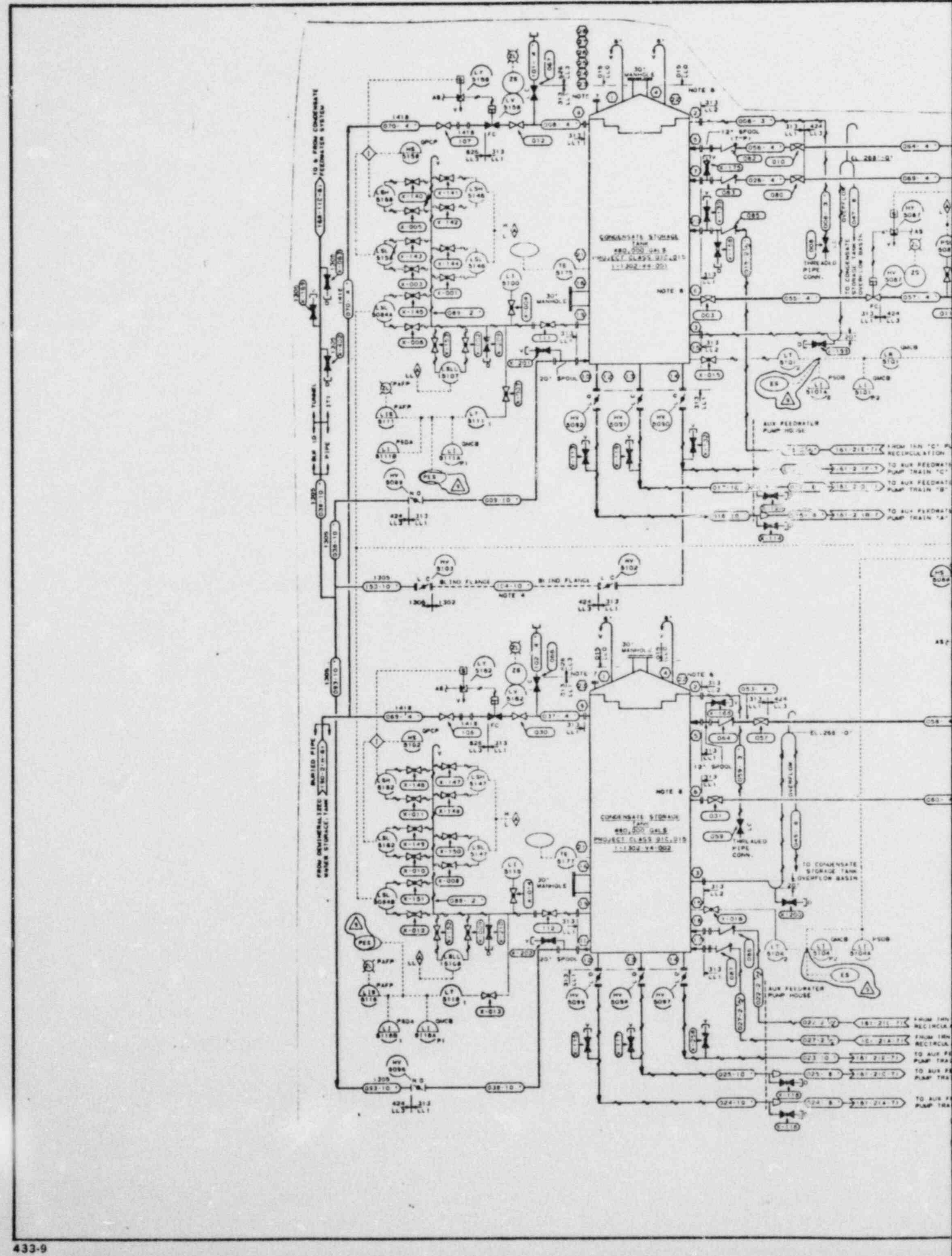
B. There are three 50-percent-capacity pumps in each train of the CCW system. Thus, the failure of one pump does not impair the function of that train. Either train has the heat removal capacity necessary to bring the plant to a cold shutdown in less than 36 h. Therefore, even the failure of one train would not prevent the system from meeting the requirements. The failure modes and effects analysis is presented in table 9.2.2-3.

C. The safety-related portion of the system is designed and constructed as Seismic Category 1, so that it will remain functional during and after a SSE. The CCW chemical addition tank and associated piping is nonsafety related. This portion of the system is isolated from the safety-related process flow path by locked closed, safety-related manual valves.

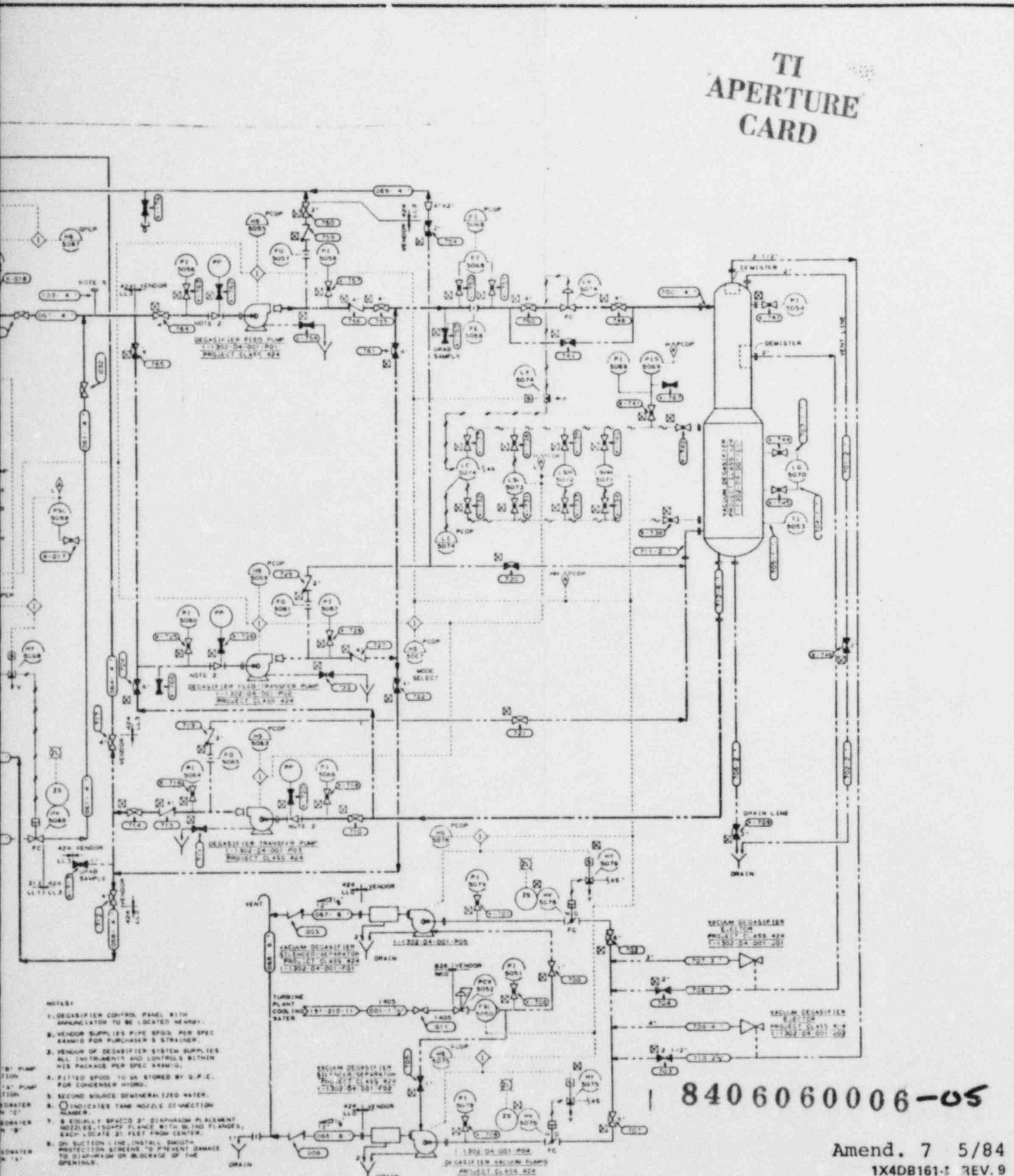
D. Periodic inservice inspection is performed in accordance with the requirements for ASME Section III, Class 3 components as described in subsection 3.9.6.

TABLE 9.2.3-1 (SHEET 2 OF 2)

Demineralizer Regeneration Equipment	Capacity
Sulfuric acid transfer pump (1)	10 gal/min vs. 70 ft, vertical submerged, centrifugal
Sulfuric acid neutralization pump (1)	43 gal/h vs. 220 psig, positive displacement 3
Caustic soda transfer pump (1)	10 gal/min vs. 70 ft, vertical submerged, centrifugal 7
Caustic pump (1)	240 gal/h vs. 105 psig, positive displacement
Neutralization sump transfer pump (4)	400 gal/min vs. 40 ft, vertical submerged, centrifugal 3
Demineralized water storage tank	250,000 gal, covered with a diaphragm Material specs: plates - SA240TP304 structural - SA479TP304
Demineralized water transfer pumps (3)	275 gal/min vs. 150 ft, horizontal centrifugal
Demineralized water transfer booster pumps (2)	310 gal/min vs. 130 ft, horizontal centrifugal


CONDENSATE STORAGE TANK
480,000 GALS
PROJECT CLASS 91C,015
1-1302-V4-001
CONDENSATE STORAGE TANK
480,000 GALS
PROJECT CLASS 91C,015
1-1302-V4-002
AUX FEEDWATER PUMP HOUSE
TO CONDENSATE STORAGE TANK OVERFLOW BASIN
BLIND FLANGE
30" MANHOLE
20" SPOOL
12" SPOOL
NOTE 4
NOTE 8
THREADED PIPE CONN.
OVERFLOW

Also Available On
Aperture Card



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Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	CONDENSATE STORAGE AND DEGASIFIER SYSTEM FIGURE 9.2.6-1

series-connected 1500-ton chiller condensers. The series-connected evaporator sections of the chiller system are designed to provide a nominal 6050-gal/min flow of about 44°F chilled water to the coils of various cooling units located throughout the plant. Automatic standby operation is provided for both chiller and pumps.

B. Expansion Tank

The expansion tank is used to:

1. Maintain system pressure by allowing the water to expand when the water temperature increases.

2. Provide a collection point for air bubbles released from the system.

3. Provide makeup water to the system from the demineralized water storage system.

C. Chemical Feed Tank

The chemical feed tank provides chemical mixing in the system to provide control against corrosion.

9.2.9.2.2.3 System Operation. The normal chilled water system forms a link between the heat receiver of the various air cooling units throughout the plant and the heat sink of the service water system. Heat picked up at the coils and transferred by the chilled water is pumped past the chemical addition feed input point and the air separator to the suction of the operating chilled water pump. The operating pump discharges to the evaporator section of the operating chiller. Chilled by the refrigeration circuit, the water leaves the evaporator at about 44°F to return to the coils.

The system has three complete chillers and pumps. Normally, two operate in series and one chiller is on standby. Any two of the three pumps in parallel operate with the chillers to provide chilled water to the single primary normal chilled water loop.

The condenser of the chiller is cooled by the turbine plant water system.

9.2.9.2.3 Safety Evaluation

Because the normal chilled water system has no safety design basis, no safety evaluation is provided.

9.2.9.2.4 Tests and Inspections

The chilled water piping circuits are hydrostatically tested and balanced to provide design flowrates and temperatures within a tolerance of $\pm$10 percent. Active component performance is monitored by various instruments on the chiller and piping.

9.2.9.2.5 Instrument Applications

Chiller and pumps are operable from the main control room and the remote shutdown panel. Indicators are displayed in the main 7 control room and the remote shutdown panel for pump status. Local pressure and temperature indicators display the appropriate system parameters associated with the chiller and pumps.

TABLE 9.2.9-3 (SHEET 1 OF 3)

ESSENTIAL CHILLED WATER SYSTEM FAILURE MODES AND EFFECTS ANALYSIS

Item No.	Description of Component	Safety Function	Plant Operating Mode[a]	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability
1	No. 15 breaker on 1ABA 480-V 1E bus. Train A normally closed (NC)	Provide continuity and protection to motor starter, item 2	A	Inadvertent open; fail to close when required	MCC alarm	None; loss of train A; train B available
2	No. 15 motor starter for item 3, normally open (NO)	Provide continuity to chilled water (CW) pump motor	A	Fail to close or remain closed	Pump motor indicating light	None; loss of train A (only if fails to close); train B available
3	1-1592-P7-001-M01, control building (CB) ESF CW pump and motor, normally deenergized (ND), train A	Provide motive power to circulate cooling water	A	Fail to start and operate	Flow alarm [illegible]-control room MCC alarm Flow indicator-control room Pump motor indicating light	None; loss of train A; train B available
4	V186, check valve, NC	Allow waterflow and prevent backflow	A	Fail to open or remain open; fail to close when required	Flow alarm low-control room MCC alarm Flow indicator-control room Pump motor indicating light	None; loss of train A; train B available
5	No. 6 breaker on 1AA02 4.16-kV bus, train A	Provide continuity and protection to motor, item 6	A	Fail to close or remain closed	Switchgear alarm Breaker position indicating light Chiller panel indicating light	None; loss of train A (only if fails to close); train B available

TABLE 9.2.9-3 (SHEET 2 OF 3)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability
6	1-1592-C7-001-000, CB ESF chiller, train A, ND	Provide chilled water for cooling	A	Fail to operate	Temperature alarm high-control room Chiller panel indicating light Temperature indicator-control room Switchgear alarm Flow indicating switch in control room	None; loss of train A; train B available
7	No. 15 breaker on 1BBA, 480-V 1E bus; train B NC	Provide continuity and protection to motor starter, item 2	A	Inadvertent open	MCC alarm	None; loss of train B; train A available
8	No. 15 motor starter for item 9; NO	Provide continuity to chilled water pump motor	A	Fail to close or remain closed	Pump motor indicating light	None; loss of train B (only if fails to close); train A available
9	1-1592-P7-002-M01; No. 15 motor starter; item 3; train B	Provide motive power to circulate cooling water	A	Fail to start and operate	Flow alarm low-control room MCC alarm Flow indicator-control room pump motor indicating light	None; loss of train B; train A available
10	V187, check valve, NC	Allow waterflow and prevent backflow	A	Fail to open	Flow alarm low-control room MCC alarm Flow indicator-control room pump motor indicating light	None; loss of train B; train A available

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TABLE 9.2.9-3 (SHEET 3 OF 3)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability
11	No. 22 breaker on 1BA03; 4.16-kV bus, train B	Provide continuity and protection to ESF chiller, item 12	A	Fail to close or remain closed	Switchgear alarm Breaker position indicating light Chiller panel indicating light	None; loss of train B (only if fails to close); train A available
12	1-1592-C7-002-000, CB ESF chiller, train B, ND	Provide chilled water for cooling	A	Fail to operate	Temperature alarm high-control room Chiller panel indicating light Temperature indicator-control room Switchgear alarm Flow indicating switch in control room	None; loss of train B; train A available
13	Chilled water pump 1-1592-P7-001-000	Provide chilled water for cooling	A	Mechanical failure	Flow alarm low; flow indicating switch in control room Temperature alarm high	None; loss of train A; train B available
14	Chiller water pump 1-1592-P7-002-000	Provide chilled water for cooling	A	Mechanical failure	Flow alarm low; flow indicating switch in control room Temperature alarm high	None; loss of train B; train A available

a. A - Both trains start and operate on safety injection signal.

9.2.10 TURBINE PLANT CLOSED COOLING WATER SYSTEM

The function of the turbine plant closed cooling water system is to provide chemically treated, demineralized water for the removal of heat from nonsafety-related heat exchangers in the turbine building and to reject the heat to the circulating water system.

9.2.10.1 Design Bases

9.2.10.1.1 Safety Design Bases

The turbine plant closed cooling water system is not required for the safe shutdown of the plant and has no safety design basis.

9.2.10.1.2 Power Generation Design Bases

The turbine plant closed cooling water system provides corrosion-inhibited, demineralized cooling water to the equipment shown in table 9.2.10-2 during all modes of normal plant operation.

During power operation the turbine plant closed cooling water system provides a continuous supply of cooling water to turbine plant equipment at a maximum temperature of 110°F, with a circulating water inlet temperature of 94°F.

The cooling water is treated with corrosion inhibitor and uses demineralized water for makeup. The system is equipped with a pot feeder to add chemicals to the system.

The heat sink for the turbine plant closed cooling water system is the circulating water system. Circulating water is provided on the tube side of the turbine plant closed heat exchangers.

Makeup to the system is provided at a rate of 1 percent of cooling waterflow.

The surge tank provides a minimum of 30 s of active storage.

Either pump or closed heat exchanger may be down for maintenance without impairing the function of the system.

The turbine plant closed cooling water pumps are provided ac power from the 480-V switchgear bus. The pumps are not required for safe shutdown of the plant; therefore, no connection to the emergency diesels is required.

9.2.10.2 System Description

9.2.10.2.1 General Description

The turbine plant closed cooling water system is shown in figure 9.2.10-1. The system consists of one surge tank, one chemical addition pot, two pumps, two heat exchangers (connected in parallel), and associated piping, valves, controls, and instrumentation. Heat is removed from the turbine plant closed cooling water system via the closed cooling water heat exchanger by the circulating water system, which is described in subsection 10.4.5.

A closed water sample is periodically taken for analysis to ensure that the water quality meets the chemical specifications given in table 9.2.10-1 for the services indicated in table 9.2.10-2.

The surge tank is vented to the atmosphere and provides storage to accommodate volumetric changes due to thermal expansion and contraction in the system. Demineralized water is provided to the surge tank for makeup to the system.

9.2.10.2.2 Component Description

Codes and standards applicable to the turbine plant closed cooling water system are listed in table 3.2.2-1. 7

A. Turbine Plant Closed Cooling Water Surge Tank

The closed cooling water surge tank is covered and vented; it is constructed of carbon steel. The tank is located in the turbine building. Demineralized water makeup is provided by a level control valve. The capacity of the tank is 610 gal.

B. Turbine Plant Closed Cooling Water Chemical Addition Pot

The closed cooling water chemical addition tank is constructed of carbon steel. Provisions for makeup water and addition of the chemicals are included. The tank is located in the turbine building. The capacity of the tank is 12 gal.

9.4.1.8 Onsite Technical Support Center HVAC

The onsite technical support center normal HVAC consists of a chilled water system and air handling unit, supply and exhaust systems, and recirculation filtration unit.

The onsite technical support center HVAC supply system provides conditioned outside and recirculated air for ventilation and cooling during normal plant operations and following an abnormal occurrence or accident in which the plant is required to be placed in a safe shutdown condition. The system provides filtration of outside and recirculated air following post-accident radiological releases. The system is shown schematically in figure 9.4.1-6. Table 9.4.1-4 provides design parameters for major components in the system.

9.4.1.8.1 Design Bases

9.4.1.8.1.1 Safety Design Bases. The normal HVAC system located in the technical support center does not perform any safety-related function. Failure of the system will not compromise any safety-related equipment, component, or structures.

9.4.1.8.1.2 Power Generation Design Bases

A. The onsite technical support center normal HVAC system provides a suitable environment for personnel and equipment during normal and post-accident operation, including provision for post-accident radiological releases.

B. The HVAC system provides a supply of cooling air sufficient to maintain area temperatures at 75±5°F.

C. During accident conditions a filtration unit provides filtered cooling air meeting the requirements of 10 CFR 50, Appendix A, General Design Criterion 19, for airborne contaminants and providing for personnel breathing requirements for continuous occupancy of 25 people. The filtration unit also inhibits infiltration of contaminated air by pressurizing the technical support center with outside air.

D. The system provides the capability to detect and protect the onsite technical support center personnel from smoke, chlorine, and airborne radioactivity. 7

E. Portable air breathing equipment and anticontamination clothing is provided for an occupancy of 25 people.

9.4.1.8.2 System Description

9.4.1.8.2.1 General Description. The normal HVAC system for the onsite technical support center consists of an air-cooled water chiller unit, a pump and expansion tank, an air handling unit, a filtration unit, duct heaters for heating and humidity control, exhaust fans, and instrumentation and controls associated with the above equipment. The seismic and quality classifications of components, instrumentation, and ducting are given in table 3.2.2-1.

9.4.1.8.2.2 Component Description.

A. Chilled Water Unit

The water chiller is an air-cooled unit with dual compressors and six air cooling fans. The unit is located on the roof of the technical support center.

B. Chilled Water Pump and Expansion Tank

The chilled water pump is a centrifugal, motor-driven pump located in the mechanical HVAC room on the first floor of the building. The expansion tank is a steel tank located in the HVAC room and provided with appropriate instrumentation.

C. Air Handling Unit

The technical support center air handling unit consists of steel housing, a medium-efficiency filter, cooling coils, a humidifier, and a centrifugal fan. The unit is located in the mechanical HVAC room.

D. Filtration Unit

The emergency filtration unit consists of steel housing, a prefilter, an electric heating coil, upstream HEPA filters, a charcoal adsorber, downstream HEPA filters, and a supply fan. The supply fan is a backward inclined, centrifugal fan with variable inlet vanes to compensate for the increase in filtration resistance as the dust loading increases. The unit is located in the mechanical HVAC room.

E. Exhaust Fans

The exhaust fans are centrifugal fans driven by electric motors.

F. Duct Heaters

The duct heaters are electric resistance heaters mounted directly on the duct for temperature and humidity control.

G. Humidifier

The humidifier is an electric resistance-heated type mounted inside the access section of the air handling unit. The unit is provided with an integral control panel. A matching high limit humidistat is provided in the return air duct.

H. Access Doors

To minimize inleakage, the access doors to the technical support center are equipped with self-closing devices that shut the doors automatically following the passage of personnel. Two sets of doors, with a vestibule between, acting as an airlock, are provided at each of the three entrances to the technical support center.

I. Isolation Dampers

System isolation dampers are capable of automatically closing within 6 s after receipt of an actuation signal, as verified by testing. The isolation dampers are tested as bubble-tight dampers for zero leakage.

J. Radiation Detectors

Radiation detectors are provided to monitor the outside air supply and area radiological conditions. A detector is installed in the outside air intake duct. The unit is responsive to as low as 10^{-6} $\mu Ci/cm^3$ of Xe-133. Area detectors are provided for each of the cathode ray tube display rooms and the technical support center work area. These detectors have a range of 10^{-2} to 10^{-3} mR/h.

K. Smoke Detectors

A smoke detector is installed in the outside air intake duct. This detector indicates the presence of smoke entering the area from outside. The smoke detector actuates an alarm in the technical support center HVAC control panel.

L. Chlorine Detector

A chlorine detector is installed in the onsite technical support center ventilation outside air intake plenum. This detector indicates the presence of chlorine in concentrations of 1 ppm. Response time is 8 s at 5 ppm chlorine concentration with the alarm setpoint of 1 ppm. 7

M. Breathing Apparatus

Self-contained portable breathing equipment with air bottles is stored within the habitability area of the technical support center.

9.4.1.8.2.3 System Operation.

9.4.1.8.2.3.1 Normal Mode. The onsite technical support center air-conditioning system operates during normal modes of operation. Prefiltered outside air from the intake plenum at el 233 ft 2 in. is mixed with recirculated air and filtered through a medium-efficiency filter, cooled to 56°F, and discharged into a duct system that distributes the air to the onsite technical support center area. Each zone is provided with variable flow control to regulate the temperature at varying load conditions. Outside air is preheated with a thermostatically controlled electric duct heater. A zone electric duct heater, controlled by a zone thermostat, regulates the temperature of the CRT display room, computer room, and communications room. Outside air is supplied to makeup for air exhausted from the battery and toilet areas. The ventilation system is designed to limit the hydrogen concentration to less than 2 percent by volume within the battery area in accordance with Regulatory Guide 1.128. The exhaust air from the battery room and toilet area is exhausted through a normal exhaust fan to the atmosphere at el 241 ft 0 in.

9.4.1.8.2.3.2 Emergency Mode. When high radiation or smoke is detected in the air intake duct, an alarm sounds at the onsite technical support center control panel. An operator action is required to activate the emergency filtration system. The emergency filtration system, when activated, automatically processes all of the outdoor air together with approximately 25 percent of the recirculated air through the filtration unit.

In the initial actuation of the emergency filtration system, a parallel signal is initiated to deenergize the onsite technical support center battery room and toilet exhaust fans and dampers. The continuous influx of outdoor air with no positive exhaust is designed to pressurize the area to 0.25 in. WG during the emergency operation. After the filtration process, the filtered air is mixed with the balance of recirculated air for further conditioning by the normal supply system.

9.4.1.8.2.3.3 Isolation Mode. When it becomes apparent that total isolation is required, such as detection of toxic gases in the outside air intake plenum, a hand switch is provided to close the outside air intake damper to obtain 100-percent recirculation. Under this mode of operation, the emergency filtration system continues to operate while the onsite technical support center battery and toilet exhaust fans and dampers remain deenergized. During this mode of operation, the onsite technical support center area is at atmospheric pressure.

The emergency filtration system continues to operate until manually reset.

9.4.1.8.2.3.4 Chilled Water. The onsite technical support center air-conditioning system consists of a room cooler, air-cooled condensing unit, water pump, and interconnecting chilled water lines that collect room heat and dispose it to the atmosphere.

The air-cooled condensing unit is a package-type unit consisting of a hermetically sealed compressor-motor, air-cooled condenser, controls, and prepiped refrigerant connections. Chilled water is processed to provide a water temperature differential of 10°F between the incoming and outgoing water system. Chilled water is pumped to the room cooler through distribution pipes with modulating valves to vary the flow of chilled water to the room air cooler to satisfy room temperature design.

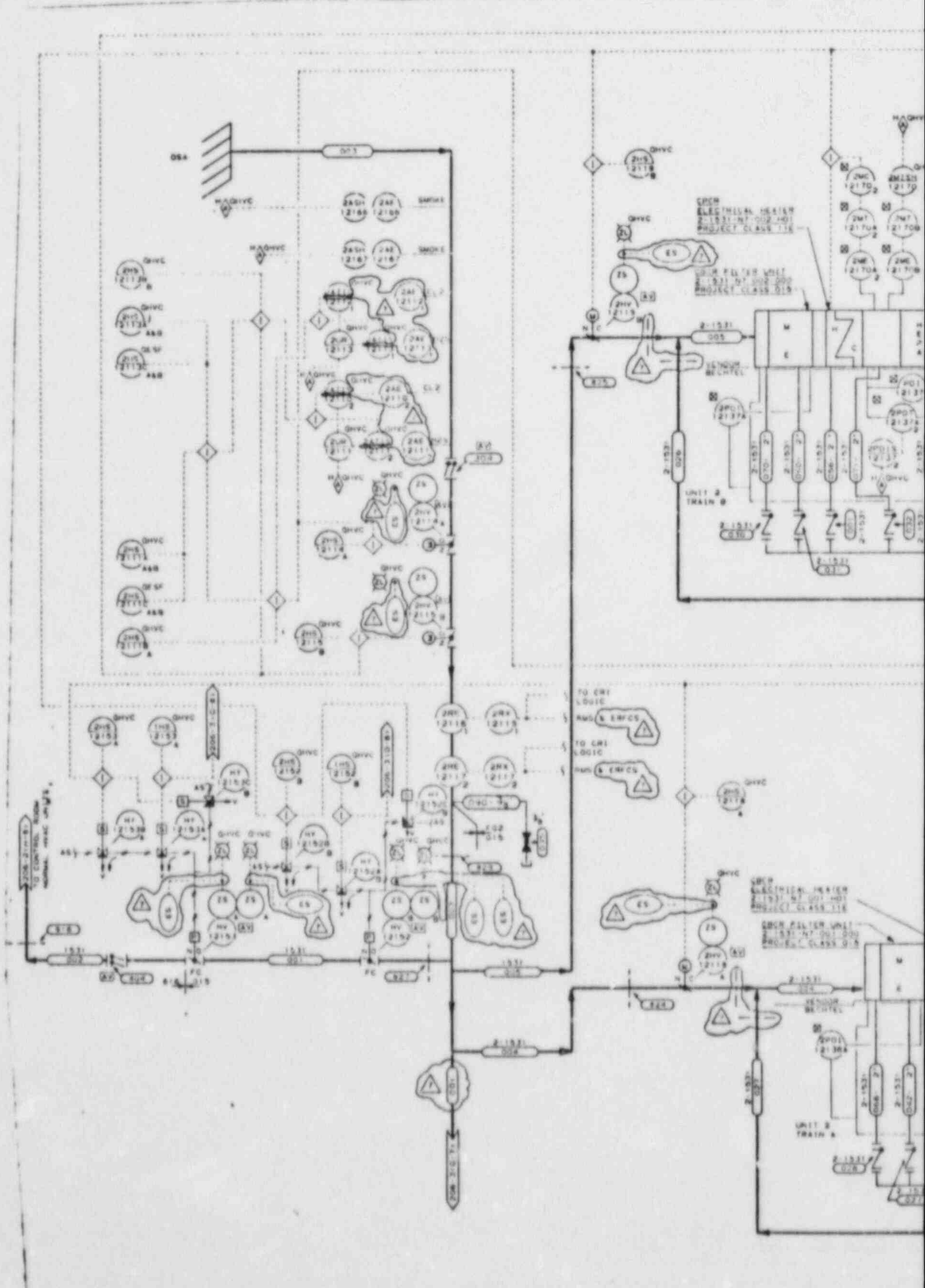
9.4.1.8.2.4 Safety Evaluation. Since the onsite technical support center HVAC system has no safety design bases, no safety evaluation is provided.

9.4.1.8.2.5 Tests and Inspections. The system is designed to permit periodic inspection. The system is tested for function and capability in the preoperational testing. Testing of the onsite technical support center HVAC is essentially the same as the testing described in paragraph 9.4.1.6.

9.4.1.8.2.6 Instrumentation Application. Two area radiation monitors are provided to warn personnel of unacceptable radiation levels. Alarm and indication are provided in the technical support center system support panel located in the communications room of the onsite technical support center and the main control room. Smoke, radiation, and chlorine detection 7
capability is also provided in the supply air duct with alarms in the system support panel.

The following instrumentation is provided in the onsite technical support center:

- Alarm on high-pressure differential across filter unit.
- Alarm on high temperature in charcoal filter.
- Alarm on low airflow.
- Position indication of isolation dampers.
- Indication of operational status of the fans.



NOTES:

1. TORNADO DAMPER NO. 303 & 4UV SHALL BE PROJECT CLASS 015.
2. FOR ESSENTIAL CHILLED WATER TRAIN A, SEE DWG 1440B233. FOR TRAIN B, SEE DWG 1440B234.

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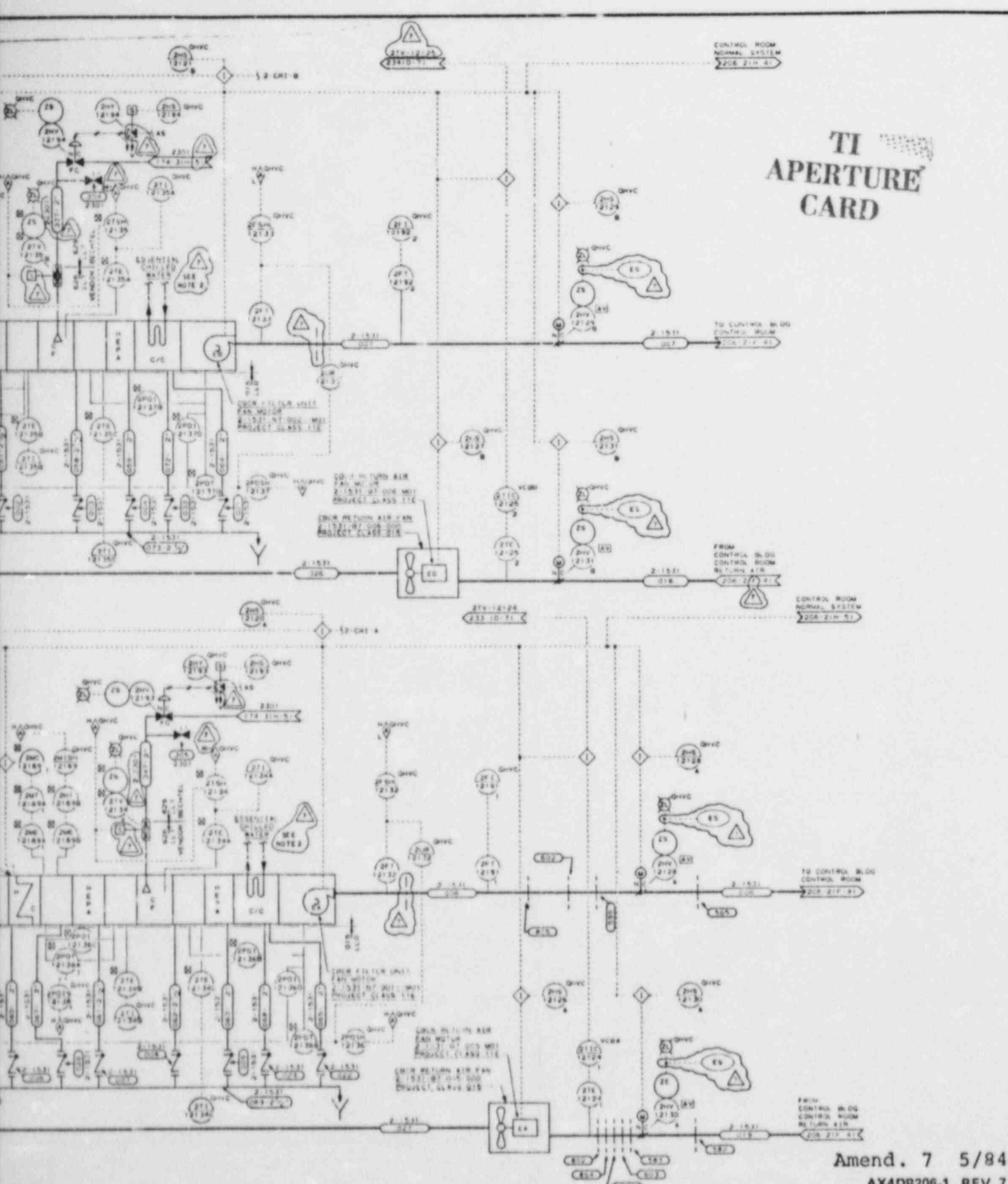

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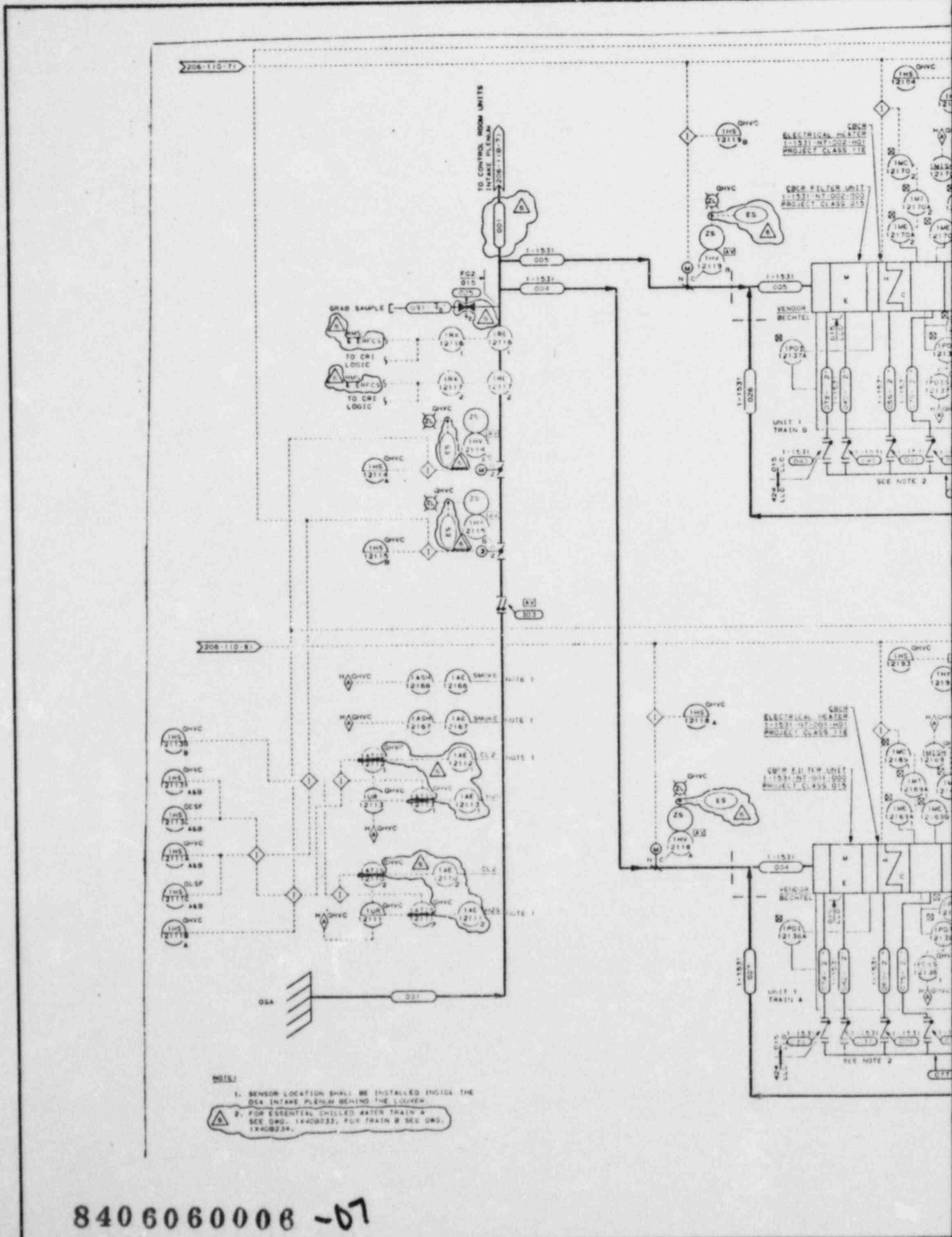
AX4DB206-1 REV. 7

Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTROL BUILDING CONTROL ROOM
HVAC SYSTEMS LEVEL 1

FIGURE 9.4.1-2 (SHEET 1 OF 3)



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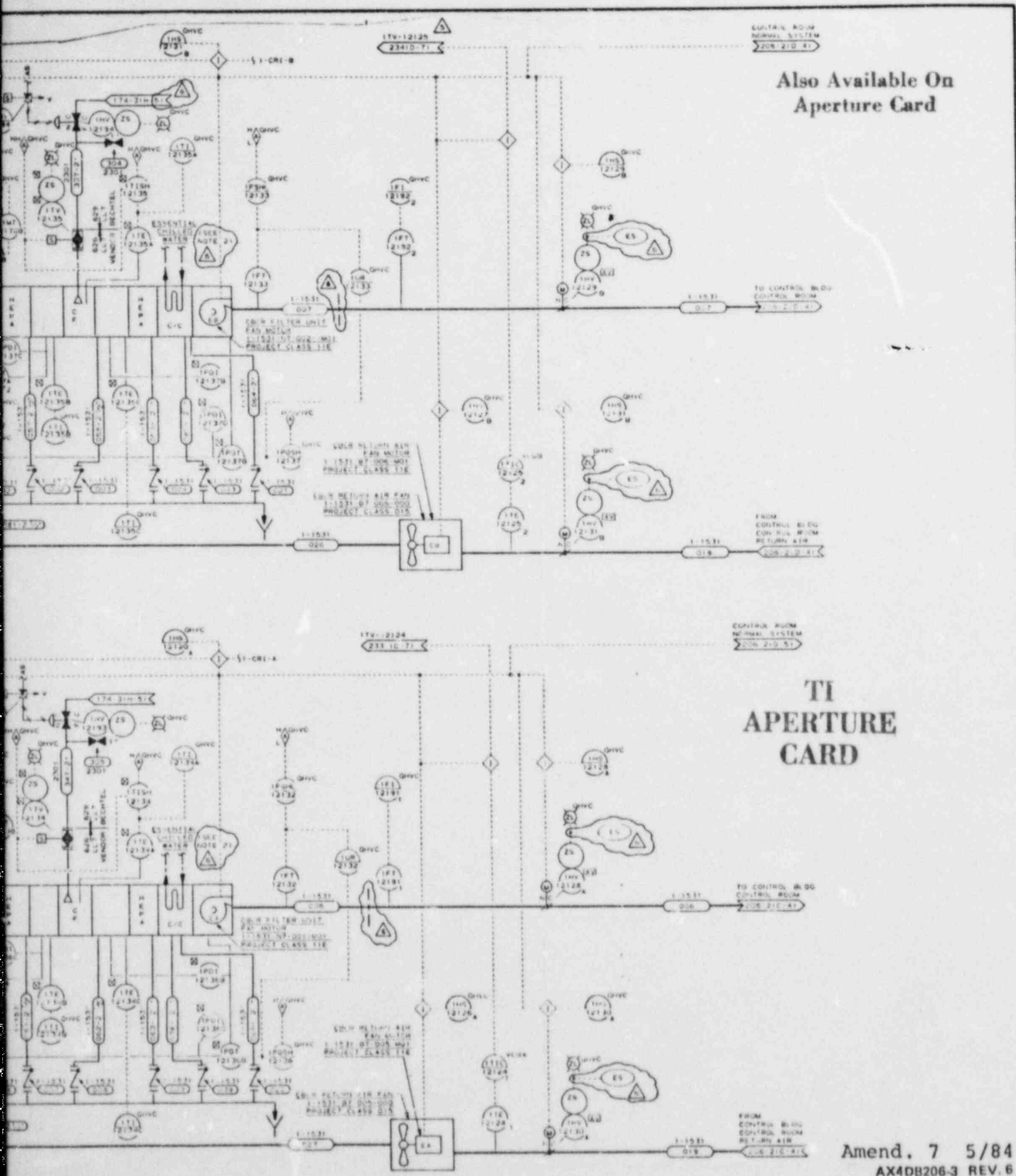

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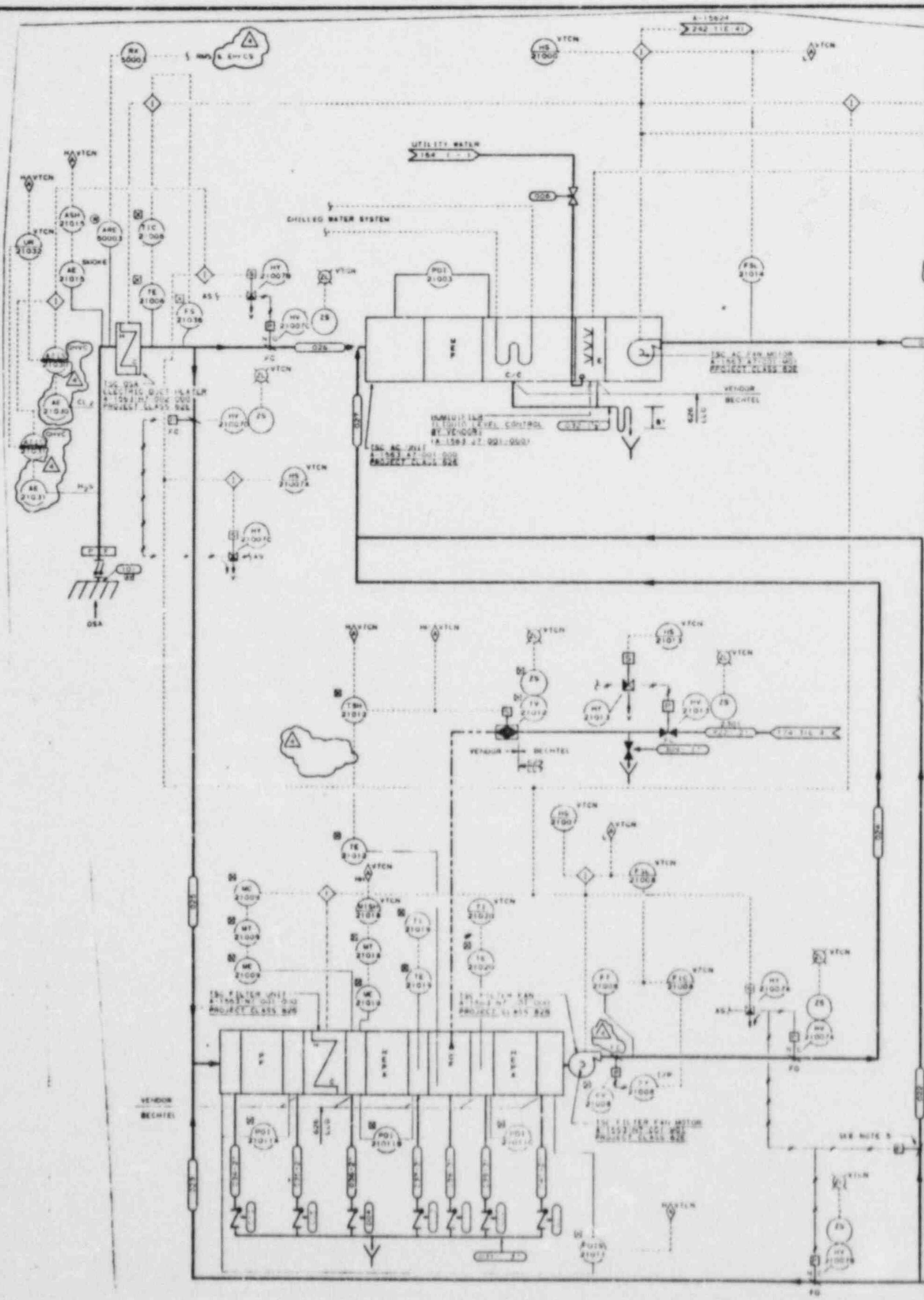
AX4DB206-3 REV. 6

Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

CONTROL BUILDING CONTROL ROOM
HVAC SYSTEMS LEVEL 1

FIGURE 9.4.1-2 (SHEET 3 OF 3)



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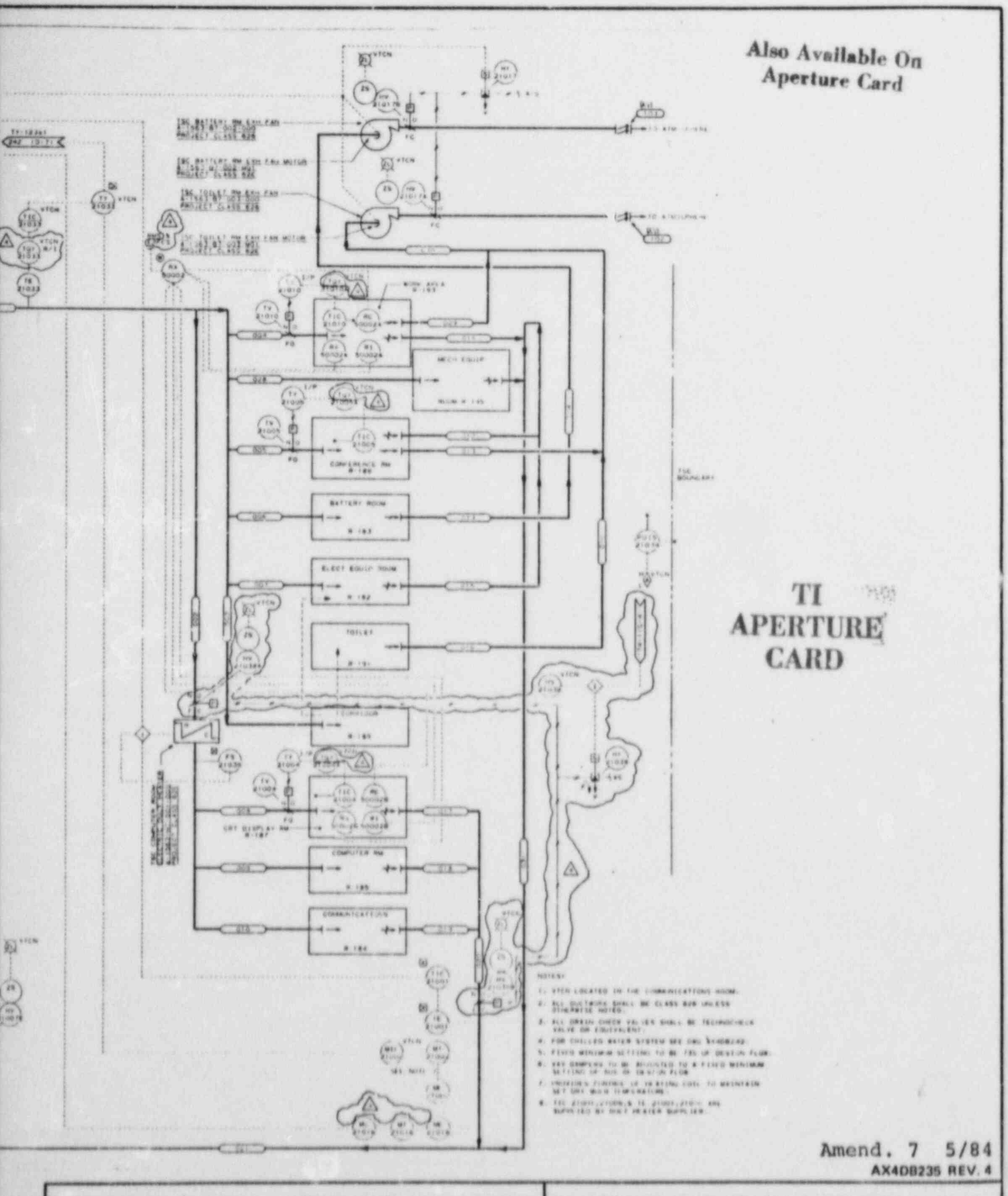

Amend. 7 5/84
AX4DB235 REV. 4

Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ONSITE TECHNICAL SUPPORT CENTER
HVAC SYSTEM

FIGURE 9.4.1-6 (SHEET 1 OF 2)

D. ESF Supply Fans

The two 50-percent-capacity ESF exhaust fans for each diesel generator room are heavy duty, vaneaxial type, directly driven by electric motors. These fans are located in the penthouse of the diesel generator building and are provided with backdraft dampers.

9.4.7.2.3 System Operation

During normal plant power operation, the diesel generator room is ventilated by the non-ESF fan exhausting to the atmosphere at el 266 ft 0 in. Supply air for the normal ventilation is drawn in through motor-operated intake dampers in the wall openings located on the first floor (el 224 ft 0 in.). The exhaust fan motors are started automatically by separate room thermostats whenever the temperature in the building exceeds thermostat settings of 90°F.

Each of the 10 unit heaters operates on a separate thermostatic control to maintain a 50°F minimum still-air temperature by heating and recirculating the air in the room. These heaters operate automatically and independently from the ventilation system. The fuel oil day tank room exhaust fan exhausts air to the atmosphere at el 241 ft 0 in.

One ESF fan starts automatically on a diesel generator running/start signal. A second ESF fan is thermostatically controlled and starts automatically on a high temperature of 90°F in the diesel generator building. During emergency operation, the airflows are reversed, and the air is drawn in through the openings at level 2 (el 266 ft 0 in.) and exhausted through the openings at el 224 ft 0 in. 7

9.4.7.3 Safety Evaluation

A. The ESF supply fans are sized to supply sufficient outside air to hold the maximum temperature in the building to the required limits.

B. Two 50-percent-capacity fans are provided to ensure that a single failure cannot cause complete loss of the safety function, as indicated in table 9.4.7-2.

C. The ESF supply fans are connected to the safety bus of the same train as the diesel generator in that room. Thus, a failure of one emergency power train cannot cause loss of function of the redundant generator and power train.

D. The safety-related portions of the diesel generator building ventilation system are located in the diesel building, which is designed to withstand the effects of earthquakes, tornadoes, hurricanes, floods, tornado missiles, and other appropriate natural phenomena. The ESF fans are designed and constructed as Seismic Category 1 to ensure that they will function during and after a safe shutdown earthquake (SSE). Sections 3.3, 3.4, 3.5, 3.7, and 3.8 provide the bases for the adequacy of the structural design of the diesel generator building.

9.4.7.4 Tests and Inspections

The system is designed to permit periodic inspection; it is tested for function and capability in the preoperational testing. Fans are tested in accordance with Air Moving and Conditioning Association (AMCA) Standard 210.[1]

9.4.7.5 Instrumentation Applications

Unit heaters are controlled by thermostats. Air flowing through the ESF supply fans is monitored by temperature and flow instrumentation. These fans are operable from both the control room and remote shutdown panel.

The following instrumentation for the diesel generator building ventilation system is provided in the control room:

- Alarm for high temperature in the diesel generator building.
- Alarm for low temperature in the diesel generator building.
- Alarm for low airflow.
- Position indication of intake and discharge louvers.
- Indication of the operational status of fans.

Should continuous operation of the generator for more than 7 days be required, it will be necessary to refill the diesel fuel oil storage tank. Prior to filling the storage tank, the diesel fuel system is aligned to supply the diesel engine from the full storage tank by opening the locked closed valve that cross-connects the diesel fuel transfer pump discharge piping. The empty tank is then isolated by closing the respective discharge valves for the diesel fuel transfer pump. After the tank has been filled and any sediment has been allowed to settle, the original fuel oil tank is ready to supply fuel again, if needed, by opening the fuel transfer pump discharge valves on the original tank and by closing the cross-connect valve. Further precautions taken to prevent detrimental effects of sediment on diesel performance include basket 3
strainers in the diesel fuel oil piping, a duplex fuel oil strainer, and a duplex fuel oil filter on each engine.

The tanks are not provided with cathodic protection; therefore, a liberal corrosion allowance of 1/8 in. has been provided. The tanks are installed in accordance with the Occupational Safety and Health Administration (OSHA) 29 CFR 1910 Subpart H, Hazardous Materials, Section 1910.106. The tanks are located just under ground level at 220 ft above sea level. Since the water table is at 165 ft above sea level, ground water seepage is not a problem. Each tank has a sump and a sampling line from which water and condensation can be removed.

9.5.4.2.1.2 Diesel Generator Fuel Oil Transfer Pumps. The fuel oil transfer pumps are of the submerged, vertical-centrifugal type. Each pump has a capacity of 25 gal min, (approximately 3 times the 8.1-gal/min full-load consumption rate of the associated diesel generator). The pump motor and the discharge head are mounted on a plate, fitted with a gasket, and bolted to the pump support flange at the top of the tank. A pump house encloses the transfer pumps and associated piping above the storage tank. There is no fixed fire protection water system inside the pump house; therefore, 7
spurious actuation of a fire protection system cannot occur. The pump is located in the sump near the bottom of the tank with the pump bearings always immersed in the pumped fluid.

9.5.4.2.1.3 Diesel Generator Fuel Oil Day Tanks. The diesel generator fuel oil day tanks each contain 1250 gal to provide approximately 2.6 h of operation for its associated diesel engine at the maximum operating load without resupply from a diesel generator fuel oil storage tank. The tanks are located within the diesel generator building, as shown in figure

1.2.2-28. The day tanks are located in the corners of the diesel generator rooms and are completely separated from the remainder of the diesel generator rooms by 3-h rated fire barriers. The day tanks are elevated to ensure a slight positive pressure exists at the suction of the engine-mounted fuel pumps. The day tanks are apart from any sources of ignition or high-temperature surfaces. The fuel oil piping is run in a piping trench from the tank to the engine. The fuel oil piping on the engine is located away from hot surfaces. Tank fittings provide for external tank fill, water removal, recirculation, and instrumentation. The fuel oil day tank is vented to the outside of the diesel generator building with a 3-in. line which has a flame arrestor at the end. The vent line 7
and the flame arrestor are missile protected. Since venting is to the outside atmosphere, there will not be any buildup of combustible gases.

9.5.4.2.1.4 <u>Piping and Tank Surfaces</u>. The exterior surfaces of the fuel oil storage tanks are coated with coal epoxy for corrosion protection of the tank surface. The tank 5
interiors are protected by an inorganic zinc coating for corrosion protection. Portions of the diesel fuel oil piping between the fuel oil storage tanks and the day tanks are buried, with the remainder being located in Seismic Category 1 structures and piping trenches inside the diesel generator buildings.

9.5.4.2.2 System Operation

The fuel oil storage tanks for the diesel generators are replenished from trucks (or other mobile suppliers) as required to maintain a 7-day supply for each diesel generator installation. Each storage tank is equipped with a 4-in. vent line that runs to the diesel generator fuel oil storage tank valve house located between the train A and train B transfer pumphouses that cover the center of each of the underground fuel storage tanks. The vent line is terminated in the valve house and is fitted with a flame arrestor and a 180° bend at the end. The roofs of the transfer pumphouse and the valve house are approximately 3 ft 6 in. and 13 ft 6 in., respectively, above grade el 218 ft 6 in. These elevations are above the maximum flood level based on the probable maximum precipitation. The 4-in. tank fill line runs to the valve house and is extended just to the outside of the valve house wall. Each fill line incorporates a locked closed valve, which is located inside the valve house, and a screwed filler cap at the end to preclude the entrance of water. The fill line is approximately 48 in. above grade. The vent point is

approximately 6 ft higher than the storage tank fill opening.
Each fill line has a strainer located downstream of the locked
closed valve to prevent entrance of deleterious solid material
into the tank. A water removal port is located above the tank 3
sump.

Each transfer pump takes suction from a diesel generator fuel
oil storage tank and discharges fuel oil to a diesel generator
fuel oil day tank. Each pump is capable of supplying its
diesel generator installation and, simultaneously, increasing
the inventory in the fuel oil day tank. A fuel oil transfer
pump is automatically started and stopped by a day tank level
switch. The second pump is turned on automatically in the event 3
of low discharge pressure from the lead pump or day tank low-low
level. Any overflow is returned to the storage tank via the
recirculation line. (The capacity of the recirculation line
exceeds that of the transfer pump.) The day tanks are installed
to provide a positive suction head to the engine-driven fuel oil
pumps. The filter in the day tank discharge line is monitored
by measuring differential pressures across the filter and by
providing a high differential pressure alarm in the control room
and locally. There is a pump discharge interconnection, with
locked closed valves, between fuel trains of the same generating
unit, as well as an interconnection, with locked closed valves,
between Unit 1 and Unit 2.

In the event the diesel fuel oil degenerates during storage, it can be transferred from the diesel fuel oil storage tanks by using the transfer pumps and piping, which are interconnected with locked closed valves, to the plant's auxiliary boiler fuel oil tanks. Biocides and other fuel additives are introduced to the tanked fuel oil to prevent deterioration of the oil, accumulation of sludge in the storage tanks, and the growth of algae and fungi.

Georgia Power Company has contract oil suppliers with terminals
in North Augusta, South Carolina; Macon, Georgia; and Savannah,
Georgia. Additional fuel oil can be delivered to VEGP within
24 h, if necessary, from several sources. Also, it should be
noted that Georgia Power's combustion turbine plant located
adjacent to VEGP Units 1 and 2 could be a source of emergency
No. 2 fuel oil if necessary. Three tanks at the combustion
turbine plant have a combined capacity of over 9 million gal.
These tanks are normally kept at 95 percent of full capacity.
Trucks will primarily be used to deliver fuel oil resupply to
the site and to transfer fuel oil from Plant Wilson under normal
conditions. A secondary method of delivering fuel oil would be
by rail or by means of the Savannah River. Delivery of the fuel 7
oil to VEGP under extremely unfavorable environmental conditions
will be included in plant procedures.

9.5.4.3 Safety Evaluation

A. The total capacity of the underground diesel generator fuel oil storage tanks is sufficient for 7 days of operation of the safety-related loads as required for each diesel generator for a design basis accident. Within this period, the operator can arrange for additional fuel to be delivered to the plant site by truck, rail, barge, etc. There is complete physical redundancy of active components in the diesel generator fuel oil system. An independent fuel supply train consisting of a fuel storage tank, a day tank, transfer pumps, piping, and valves is provided for each diesel generator. Two transfer pumps are provided for each fuel supply train so that any pump can be removed for repair without affecting the redundancy of the fuel oil supply system. Each pump is powered from the bus on which the diesel generator it serves is connected. Failure of a pump or a diesel generator would not affect the operability of any component in another train.

B. The results of a failure modes and effects analysis are given in table 9.5.4-2. Each diesel generator and its supporting systems are completely enclosed in separate compartments. Any high- or moderate-energy line failures occurring in one diesel generator compartment would not affect the redundant diesel. Thus, the effect of line breaks is no more severe than a single failure in a diesel system. Details of the criteria for protection from high- and moderate-energy line breaks are given in section 3.6.

C. The diesel generator fuel oil system is designed in accordance with Seismic Category 1 and Quality Group C requirements as specified in section 3.2.

D. Maintenance of the fuel oil above the cloud point is achieved by enclosing the equipment in heated buildings, burial below the frostline, or heat tracing.

9.5.4.4 Tests and Inspections

The diesel generator fuel oil system receives a nil ductility transition (NDT) examination in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section III, Class 3 incident to routine construction tests and inspections. The diesel generator fuel oil system operability is demonstrated during regularly scheduled tests of the diesel generator. Fuel reserve for testing is supplied by sizing the storage tanks to contain fuel in excess of the volume required for 7 days of operation of the safety-related loads as required under accident conditions. Samples of diesel fuel are analyzed periodically to ensure that the fuel quality requirements of the Technical Specifications, which are based on Regulatory Guide 1.137, are satisfied.

9.5.4.5 Instrumentation Applications

The transfer pumps can be operated from the control room. Alarms and indications of tank levels and transfer pump status are displayed in the control room. A secondary means of tank level determination is provided by dipsticks or sounding ports. Day tank level switches start and stop the fuel oil transfer pumps and activate a day tank low level alarm. The fuel oil storage tank transfer pumps are automatically started when the level in the day tank decreases to 680 gal. The day tank low level alarm annunciates when the level decreases to 625 gal. The fuel oil storage tank transfer pumps are automatically stopped when the day tank level has increased to 1190 gal. Low level in the fuel oil storage tank is alarmed when the level decreases to 61,000 gal. Table 9.5.4-3 provides indicating and alarm devices associated with the fuel oil system. 3

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TABLE 9.5.4-1 (SHEET 2 OF 2)

Design pressure/temperature (psig/°F)	14/200
Material	Carbon steel
Code	ASME Section III, Class 3
Seismic design	Category 1
Piping, fittings, and valves	
Design pressure (psig)	35
Design temperature (°F)	100
Material	Carbon steel
Design code	
Safety-related portion	ASME Section III, Class 3
Truck fill line (to the first valve connection)	ANSI B31.1
Flame arrestors (storage and day tanks)	Manufacturer's standards

7

TABLE 9.5.4-3

STANDBY DIESEL GENERATOR FUEL OIL STORAGE AND TRANSFER SYSTEM INDICATING AND ALARM DEVICES

Parameter	Indication		Alarm	
	Control Room	Local	Control Room	Local
Storage tank level	Yes	Yes	Yes	Yes
Day tank level	Yes	Yes	Yes	Yes
Transfer pump motor-running lights	Yes	No	No	No
Fuel oil pressure	No	Yes	Yes	Yes
Filter differential pressure	No	Yes	Yes	Yes
Strainer differential pressure	No	Yes	No	No

7

features equipment continues to be powered by its associated diesel generator.

The diesel generator can operate for several days at no load
without adverse effects. The diesel manufacturer has performed
a factory idle endurance test on one of their model DSRV-16-4
engines. The engine was operated for 7 full 24-h days on no
load at synchronous speed and then loaded to 4000 kW, which is
57 percent of VEGP's full design load (7000 kW), at the end of
the 7-day period. The engine was able to accept the 4000-kW
load within 1 s with a voltage and frequency dip of 2.6 and 3.8
percent, respectively. This test step load exceeds any step
load applied in the VEGP design, except for transformer
energization. Transformer energization is of such a short
duration (less than 0.5 s) that the diesel generator will not be
affected by this load. See table 8.3.1-2 for the diesel 7
generator loading profile.

Based on the performance of their model DSRV-16-4 engine (same model as VEGP engines) tested with a large load connected within a short time interval, the engine manufacturer has concluded that the specified VEGP environmental conditions will not affect the capability of their engines to carry the step loadings required for VEGP after 7 days operating with no load at synchronous speed.

To reduce the possibility of accumulation of combustion and lube oil products in the exhuast system at low loads, the engine can be operated at greater than 50 percent load for a 1-h period for each 24-h period of unloaded operation. Above the 30 percent load rating, the engine may be run continuously, as required.

9.5.5.3 Safety Evaluation

A. The diesel generator cooling water system components are sized to allow sufficient cooling of the engine to prevent overheating while operating at 110 percent of nameplate rating on days with the warmest expected air temperature.

B. The diesel generator cooling water system is designed to Seismic Category 1 requirements as defined in section 3.2. Systems, equipment, and components that are not Seismic Category 1 and whose failure could impair the functioning of the cooling water system are upgraded in design to meet the requirements of Seismic Category 1.

C. The cooling water subsystem for each generator is capable of supplying cooling water without augmentation from other sources. The cooling water pump is driven by its associated diesel engine. Because of these arrangements and the redundancy of emergency diesel generator design and installation, a failure of any single component of the diesel generator cooling water system cannot result in a complete loss of the emergency onsite power supply. A single failure in the cooling water system is assessed as a failure of the associated diesel generator; in such a circumstance, safe shutdown is attained and maintained by the redundancy of the standby diesel generator installation. Table 9.5.5-2 provides failure modes and effects analysis for the system.

D. The diesel generator cooling water system also contains a keep-warm subsystem that circulates water through the diesel engine cooling water jacket to promote the engine's starting capability. Failure of the system is annunciated by a jacket cooling water low-temperature alarm at 140°F. Operators are also alerted to potential cooling or freezing of the diesel cooling water by the low-temperature alarm for the diesel generator room; this alarm is sounded at 50°F.

E. The entire diesel generator system, including the cooling water system, may be tested during all normal modes of power plant operation. During these tests, jacket water pressures and temperatures are monitored to ensure that the heat exchangers, jacket water pump, and three-way thermostatic valve are functioning properly. In standby status, operability of the heater and electric circulating pump is evident by inspection. All components of the diesel generator cooling water system are available for inspection at all times. Detection and control of leakage is visual and manual.

9.5.5.4 Tests and Inspections

Actual testing of the diesel generator system is discussed in section 8.3. Visual inspections, pressure and leak testing in accordance with the governing American Society of Mechanical Engineers (ASME) code, and operational checks of the cooling system components are performed as the unit is installed. The diesel generator cooling water system is operationally checked during the periodic testing of the diesel generator system. The keep-warm system is operationally checked during diesel generator shutdown periods.

9.5.5.5 Instrumentation Applications

Indications of system temperatures and pressures are provided in the diesel generator room. High- and low-temperature, low jacket water pressure, and low standpipe level alarms are provided in the diesel generator room and the main control room.

To prevent spurious trips, three temperature switches are provided and two-out-of-three logic is employed to initiate diesel generator trip. Diesel generator instrumentation is further discussed in subsection 8.3.1.

9.5.6.2.1.6 Air Start Solenoid Valves. Each starting air system is equipped with two air start solenoid valves, connected in parallel, so that failure of one solenoid valve does not compromise the operability of the system.

The piping downstream of the receiver is provided with a drainline to remove any moisture which may accumulate. A Y-strainer is installed upstream of the parallel air start valves to prevent oil and particulate from fouling these valves. Periodic testing of the diesel confirms operability of these valves.

9.5.6.2.2 System Operation

The air receivers for each diesel engine are maintained at operating pressure by compressors. The compressors start when air receiver pressure drops to 225 psig and stop when pressure is increased to 250 psig. Two compressors are provided. Each compressor keeps one receiver pressurized. A check valve in the air receiver charging line ensures that a broken line from the compressor will not affect the receiver. The air dryers and aftercoolers ensure that the starting air is dry.

When the diesel generator set receives a start signal, all four solenoid valves are energized simultaneously, allowing starting air to flow to each cylinder, using air from both air start systems independently. Thus, if one air start system fails to operate, the second will start the diesel generator set without waiting for a second start attempt and without switching from the first air start system to the second. When a start signal is initiated, either manual or automatic, the starting air valves (HV-9068A and B and HV-9070A and B) will all open, admitting air to both banks of cylinders on the engine. The air distributor for each bank will properly time the opening of the air valve in each cylinder head to admit air to the cylinder whose piston is in proper position for the starting effort. As soon as the engine has fired and is running on its own power, a speed switch cuts the electrical circuit to the starting air valves and causes the valves to close. The speed switch is set to cut off the electrical circuit to the starting air valves at 7
an engine speed of approximately 300 rpm. Also, the air valve in each cylinder head cannot admit starting air to the cylinder if the cylinder has fired. This is due to the differential pressure between the starting air pressure and the pressure of combustion inside the cylinder. Normally, after two to three engine revolutions the engine will fire and no starting air will be used to rotate the engine, even though the engine has not reached a speed of 300 rpm. When receiver pressure drops to 150 psig, the automatic starting sequence is stopped, but manual start attempts may be made as long as both receivers are

connected to their respective cylinder banks and until pressure drops to approximately 90 psig. Starting air pressure below 90 psig is not sufficient to turn the engine, and the receivers must be recharged at this point.

An air-cooled refrigerated type dryer is provided upstream of
the starting air receiver tank to remove water vapor from the
compressed air before it reaches the receiver tank. The dryer
is designed for an ambient temperature range of 35°F (minimum)
and 120°F (maximum). The air dryer is designed to run
continuously; i.e., it does not cycle on and off with the air
compressor. Compressed air, saturated with water vapor and
entering the dryer, is precooled by the outgoing refrigerated
air in the air-to-air heat exchanger. The precooled air then
enters the air-to-refrigerant heat exchanger (refrigeration
evaporator) where it is cooled by giving up heat to the
refrigeration system. As the air cools, water vapor condenses
into liquid droplets which are separated out of the air stream
by a separator and automatically discharged by a draintrap. The 7
cold air then exits after it has passed through the other side
of the air-to-air heat exchanger, where it is warmed by the
incoming hot air. This reheating increases the air's effective
volume and prevents pipe sweating downstream. A constant
temperature at all load conditions is maintained in the
air-to-refrigerant heat exchanger by means of a hot gas bypass
valve in the refrigeration system. This means of refrigeration
control also allows for efficient noncycling operation of the
refrigeration compressor.

Rating conditions for compressed air capacities of the air dryer are in accordance with Class H of the NFPA-recommended standard NFPA T3.27.2(1975) -- 100 psig and 100°F saturated inlet compressed air conditions, 100°F ambient temperature, and a 33°F to 39°F pressure dew point. The evaporator control circuit is factory set at 35°F. Based on the above conditions, the rated capacity for the air dryer is 170 sf^3/min, which is approximately twice the capacity of the starting air compressor. Therefore, the pressure dew point set for the air dryer is more than 10°F below the minimum ambient temperature of 50°F.

9.5.6.3 Safety Evaluation

A. Compressed air for each diesel is stored in an individual storage and starting system. Each system holds sufficient air to start the diesel five times under a no-load condition without compressor assistance. The continuous availability of the air starting system keeps the diesel engine in constant readiness.

B. The solenoid air start valves are installed in parallel in each system. If one valve fails to operate, the parallel valve will supply starting air. A failure of a compressor is indicated by an air receiver low-pressure alarm; this alarm prompts the operator to take corrective action. Each air receiver contains sufficient air when the low-pressure alarm occurs to start its associated diesel engine at least five times. The duration of each start is about 3 s or two to three engine revolutions. A single active failure in either air starting system does not compromise the ability of the standby power system to accomplish its function. Table 9.5.6-2 summarizes the failure modes and effects analysis for the starting air system.

C. The diesel engine starting system, except for the air compressors, aftercoolers, and air dryers, is designed in accordance with Seismic Category 1 requirements as specified in section 3.2.

D. The design of the system allows all active components of the system to be separately tested during plant power generation operation, as discussed in paragraph 9.5.6.4 below.

9.5.6.4 Tests and Inspections

The starting air compressors for each diesel engine are tested periodically to ensure continued operability. Compressor suction air filters are periodically checked for cleanliness. During the preoperational testing of the diesel generator, the entire compressed starting air system is operated to ensure 100-percent capability. Due to the redundancy of the starting air system, all testing can be performed without affecting normal plant operations or safety systems.

9.5.6.5 Instrumentation Applications

Each compressor and air receiver is furnished with instrumentation consisting of locally mounted pressure switches, pressure indicators, and overpressure protection devices. The pressure switches support the automatic control modes of compressor and receiver operation. Low starting air pressure of 210 psig and diesel start failure are annunciated locally and in the control room. Diesel generator instrumentation is further described in subsection 8.3.1.

unit or start the engine to prevent the extreme lube oil viscosities which accompany low lube oil temperatures.

During starting or operation of the diesel generator, failure of the lubrication system engine-driven pump results in unsatisfactorily low lube oil pressure. Receipt of a low lube oil pressure signal from the two-out-of-three trip logic system will shut down the diesel engine during either routine or design basis accident operation. (The low lube oil pressure shutdown signal is not bypassed or defeated during accident conditions.) Since each redundant load group is powered by an associated diesel generator, a low lube oil pressure trip of one diesel generator does not result in a complete loss of the engineered safety features.

Loss of cooling to the lube oil cooler would cause a high lube oil temperature condition and alarm which would ultimately result in a high jacket water temperature and subsequent diesel generator trip upon activation of its two-out-of-three trip logic system. The redundant diesel generator would continue to supply engineered safety features equipment associated with the redundant train.

Engine crankcase vacuum is provided by two crankcase ventilating fans which will keep the crankcase pressure at approximately minus 2 in. of water. Failure of the fans will not impair the operation of the engine but would cause the crankcase pressure to rise to a point slightly above atmospheric.

Normal small quantities (10 to 20 gal) of lube oil makeup can be introduced by using a hose inserted in the dipstick tube or the 2-in. oil fill line. Large quantities of replacement oil can be introduced to the sump tank by means of a portable electric motor-driven pump from a tank truck by using a hose inserted in the 2-in. oil fill line.

9.5.7.3 Safety Evaluation

A. The engine-driven lube oil pump provides oil to the engine bearings during engine operation. Oil is kept at a constant pressure and temperature by use of regulating valves, recirculation lines, and a lube oil cooler. After engine shutdown or during periods of standby status, the motor-driven keep-warm pump and heater keep the bearings lubricated and warm.

B. The diesel generator lubrication system is designed in accordance with Seismic Category 1 requirements as specified in section 3.2. System equipment, and components which are not Seismic Category 1 and whose failure could impair the functioning of the lubrication system are upgraded in design to Seismic Category 1.

C. The lubricating oil supply to each diesel generator is sized to provide diesel generator lubrication. The lubrication subsystem for each generator is capable of supplying lube oil without augmentation from other sources. The lube oil pump is driven by the diesel engine with which it is associated. Because of these arrangements and the redundancy of emergency diesel generator design and installation, a failure of any single active component of the diesel generator lubrication system cannot result in a complete loss of the standby power source. A single failure is assessed as a failure of the diesel generator with which it is associated; in such a circumstance, safe shutdown is attained and maintained by the appropriate redundant diesel generator installation. Table 9.5.7-2 provides a summary of the failure modes and effects analysis for the lubrication system.

D. The diesel generator lubrication system is provided with an electric motor-driven keep-warm pump and immersion heater unit which circulates 150°F lube oil through the engine. Extreme lube oil viscosities which accompany low lube oil temperatures are thus prevented, and quick starting of the diesel engine is ensured. Failure of the unit is annunciated by a lube oil low temperature alarm at 140°F. Diesel generator room low air temperature is annunciated at 50°F. Either alarm prompts operator investigation and remedial action.

E. All active components are capable of being tested during power generation operation to ensure proper functioning of the system, as discussed in paragraph 9.5.7.4.

9.5.7.4 Tests and Inspections

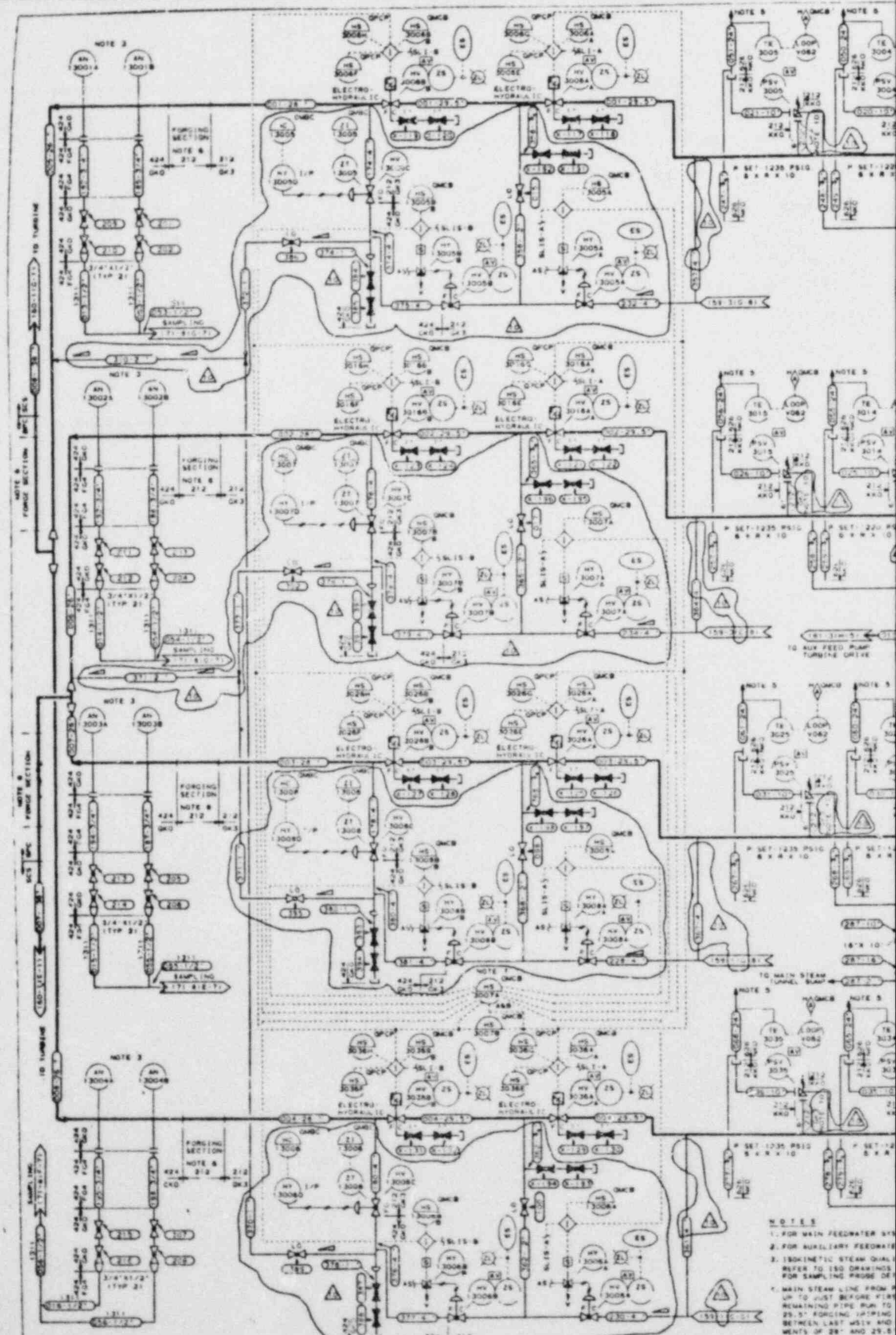
The diesel generator lubrication system is operationally tested during the startup and checkout of the diesel generator. Lube oil pressure and temperature are monitored to ensure operability of the engine-driven pump and the recirculation lines. Operation of the electric pump and heater is evidence of their operability. Inspection and testing of the system can be performed without disturbing normal plant operations. The diesel oil is checked according to the manufacturer's 7 recommended schedule to ensure it meets the engine manufacturer's specifications. The duplex strainers are valved for full flow through one side only. Strainers may be removed and inspected for the buildup of impurities on a periodic basis. The complete lubrication system is thoroughly flushed before initial startup to ensure that no foreign matter is in the system. 7

9.5.7.5 Instrumentation Applications

Instrumentation provided for the diesel generator lubrication system includes pressure and temperature switches, indicators, and automatic protection devices. The temperature and pressure switches support the automatic control modes of lubrication operation. Remote control and indication are provided for each system in the control room, as well as at the standby diesel control panel in the diesel generator building. Low lube oil pressure, high and low lube oil temperatures, and high diesel generator bearing temperatures are alarmed in the control room and in the diesel generator room. In addition, local indications associated with the lube oil system that are provided include oil temperature indication and lube oil filter differential pressure indication. A dipstick is provided to positively verify crankcase oil level. A low lube oil pressure signal during operation of the engine initiates a diesel generator trip. To prevent spurious trips, three pressure switches are provided and two-out-of-three logic is employed to initiate a diesel generator trip. The lube oil level in the lube oil sump tank will be sensed by two devices. One is a bubbler-type level instrument with the readout indicator located on the local engine control panel. The other device is a low-level displacer-type switch which will alarm the annunciator signal on the local engine control panel and the control room.

Setpoints for instrumentation associated with the diesel generator lubrication system are in accordance with the engine manufacturer's recommendations.

During surveillance testing, any alarm condition would be immediately verified by the operator utilizing instrumentation at the diesel generator location; confirmation at the local area would likely result in diesel generator shutdown, further investigation, and repairs. Diesel generator lube oil system instrumentation is also described in section 8.3. Diesel generator lubrication system indicating devices are listed in table 9.5.7-3.



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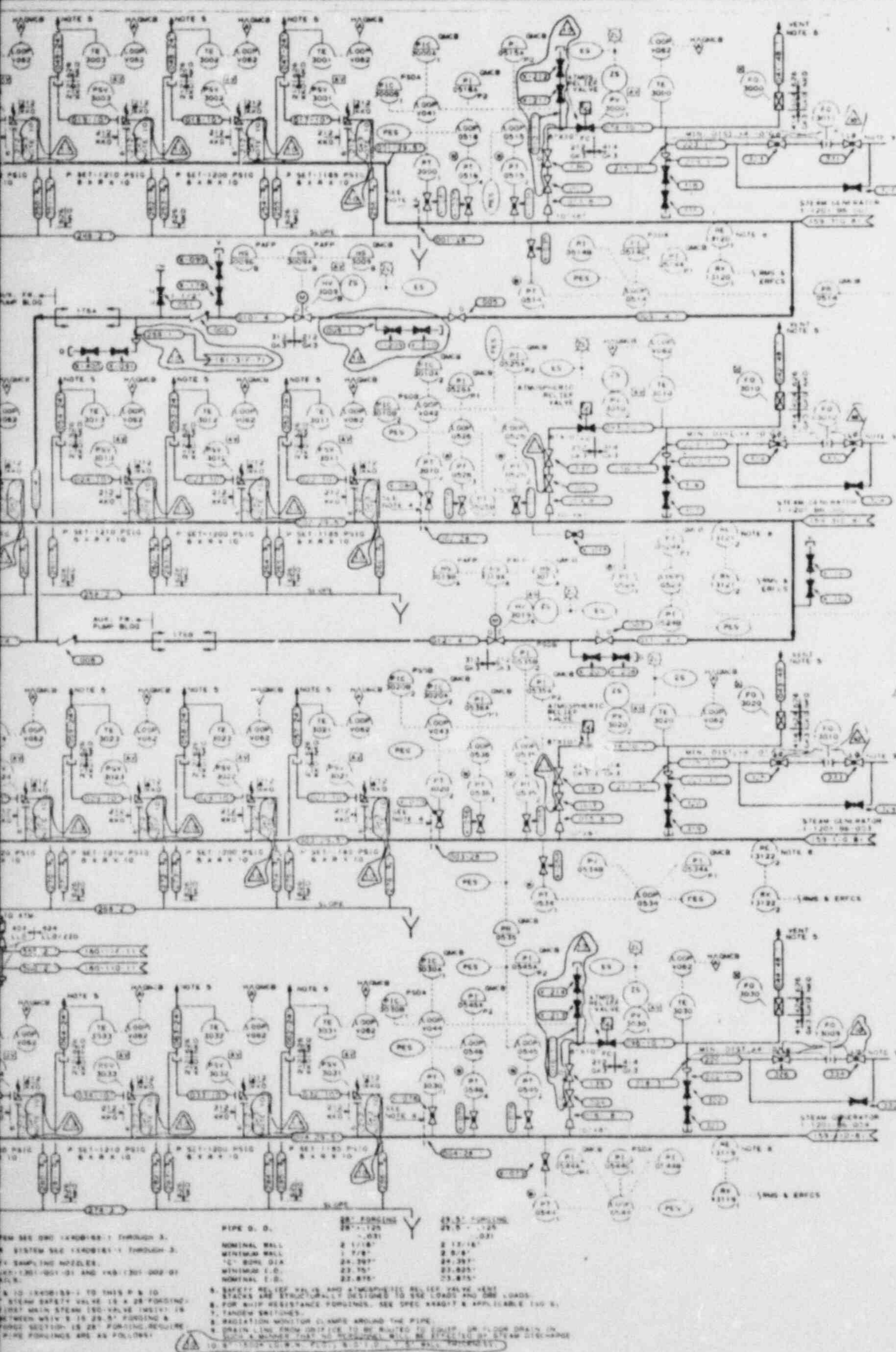

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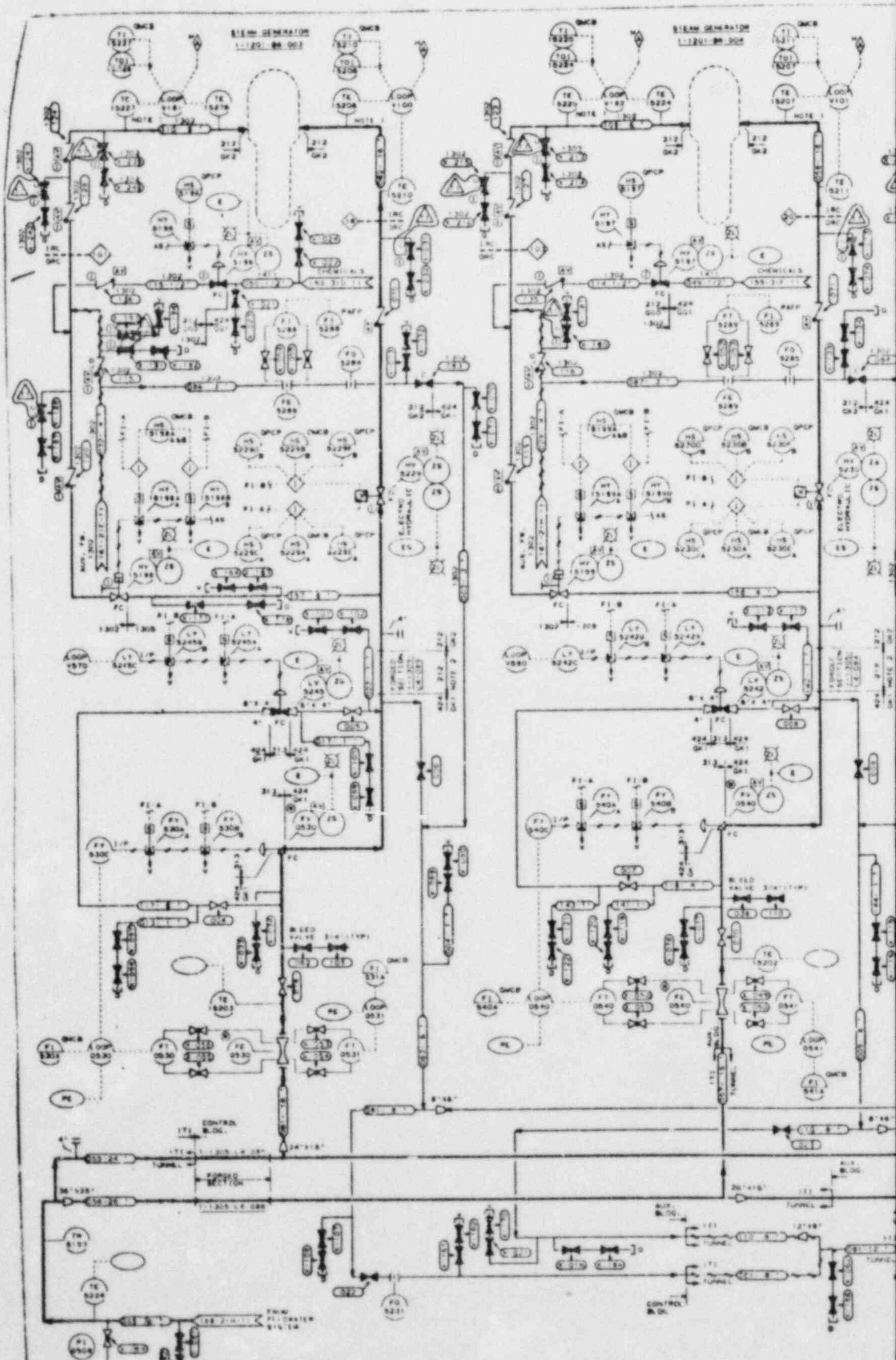
1X4DB159-2 REV.10

Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	MAIN STEAM SUPPLY SYSTEM
		FIGURE 10.3.2-1 (SHEET 2 OF 3)



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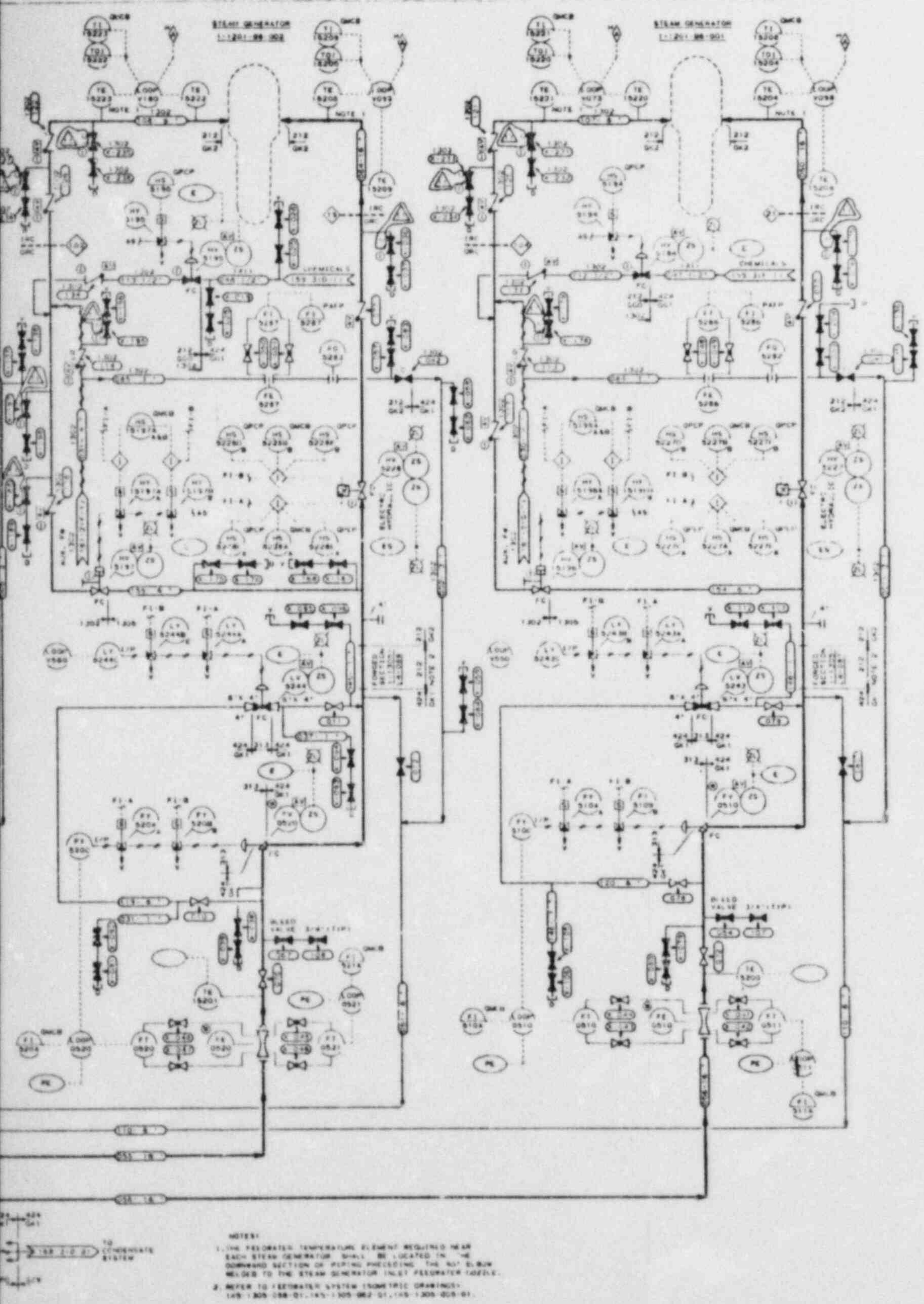

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Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	CONDENSATE AND FEEDWATER SYSTEM FIGURE 10.4.1-1 (SHEET 3 OF 3)

TABLE 10.4.9-4 (SHEET 1 OF 31)

AUXILIARY FEEDWATER SYSTEM
FAILURE MODES AND EFFECTS ANALYSIS

Item No.	Description of Component[a]	Safety Function	Plant Operating Mode[b]	Failure Mode(s)	Method of Failure Detection[c]	Failure Effect on System Safety Function Capability	General Remarks
1	Condensate tank makeup valve LV-5158, normally closed, fail closed air-operated valve	Maintains inventory or condensate storage tank V4-001 at nominal level of 480,000 ± 22,750 gal; also prevents inventory loss post-SSE	All	1A. Fails closed or fails to open upon command	1A. Position lights on QPCP coincident with low water level alarm LSL-5146 on QMCB	1A. None - One tank contains sufficient reserve without makeup to satisfy Regulatory Guide 1.139 with regard to 4 h at hot standby followed by a 5-h cooldown to RHR cut-in at RCS temperature of 350°F.	Total capacity of both tanks is 960,000 ± 45,500 gal.
				1B. Fails open or fails to close upon command	1B. Position lights on QPCP coincident with high water level alarm LSH-5146 on QMCB	1B. None - Tank may overflow, but surrounding dike holds more than 30-min makeup at maximum flow thus permitting operator corrective action.	
2	Condensate tank makeup valve LV-5162, normally closed, fail closed air-operated valve	Same as item 1, except tank is V4-002	All	Same as item 1	Same as item 1, except water level alarms are LSL-5147 and LSH-5147 on QMCB	None - Same as item 1	See item 1
3	Degasifier feed pump suction valve HV-5087, normally open, fail closed, air-operated valve	Isolates condensate storage tank V4-001 from degasifier manually or upon low pump suction pressure	All	3A. Fails closed or fails to open upon command	3A. Position lights on QPCP	3A. None - Degasification not required for safe shutdown. Also, tank diaphragm limits oxygen buildup.	The degasifier is used periodically to control concentration of dissolved oxygen in the tanks to reduce potential for corrosion of the steam generators and the AFW piping (see also item 1).

TABLE 10.4.9-4 (SHEET 2 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
				3B. Fails open or fails to close upon command	3B. Position lights on QPCP coincident with low pump suction pressure alarm PSL-5087 on QPCP	3B. None - Possible loss of tank inventory, but connection located above minimum level required for AFW reserve.	
4	Degasifier feed pump suction valve HV-5088, normally open, fail closed, air-operated valve	Same as item 3, except for condensate storage tank V4-002	All	Same as item 3	Same as item 3, except low suction pressure alarm is PSL-5088 on QPCP	None - Same as item 3	See item 3
5	Not used						
6	Not used						
7	AFW pump suction valve HV-5119, normally closed MOV, train A	Admits water from condensate storage tank V4-002 to suction of motor-driven AFW pump P4-003 upon depletion of condensate storage tank V4-001 (valve actuated by remote-manual operation from either the control room or shutdown panel PSDA)	7A. Modes 1 and 2	7A1. Fails closed or fails to open upon command with condensate storage tank V4-001 depleted	7A1. Position lights on PSDA or QMCB, plus low suction pressure (PI-5129A on QMCB or PI-5129B on PSDA), plus open indication for pump miniflow valve FV-5155 on QMCB and PSDA due to low pump flow	7A1. None - AFW pumps P4-001 and P4-002 available to satisfy AFW requirements taking suction from tank V4-002 via HV-5113 and HV-5118, respectively. (Tank V4-001 presumed depleted. See item 21.)	For discussion of the ability of the AFW pumps to satisfy system requirements during various failure modes, see items 10, 11, and 12. Irrespective of source, pump miniflow returned to tank V4-002 (see also item 2). For the effects of loss of all ac power, see item 67.
				7A2. Spurious opening while tank V4-001 not depleted and pump running	7A2. Position lights on PSDA or QMCB and reduced tank V4-002 inventory (LI-5116A and LI-5104 on QMCB, LI-5116B on PSDA, and LI-5104A on PSDB)	7A2. None - Both tanks supplying AFW simultaneously but total consumption not affected. Also, makeup (see item 1) presumed available during modes 1 and 2.	

TABLE 10.4.9-4 (SHEET 3 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			7B. Modes 3 and 4	7B1. Same as item 7A1	7B1. Same as item 7A1	7B1. None - Same as 7A1	
				7B2. Same as item 7A2	7B2. Same as item 7A2	7B2. None - Same as item 7A2, except makeup not operable, but not required (see item 1A)	
			7C. Mode 6	7C1. Same as item 7A1	7C1. Same as item 7A1	7C1. None - Same as item 7A1	
				7C2. Same as item 7A2	7C2. Same as item 7A1	7C2. None - Same as item 7B2	
			7D. Mode 7	7D. Spurious opening	7D. Position indicator on QMCB or PSDA	7D. None - No loss of tank V4-002 inventory, since pump P4-003 is not operating.	
			7E. Mode 5	7E1. Same as item 7A1	7E1. Same as item 7A1	7E1. None - Same as item 7A1, except only pump P4-002 available, but this is sufficient for safe shutdown.	
				7E2. Same as item 7A2	7E2. Same as item 7A2	7E2. None - Same as item 7B2	
8	AFW pump suction valve HV-5118, normally closed MOV, train B	Same as item 7, except to suction of motor-driven AFW pump P4-002 and shutdown panel is PSDB	8A. Modes 1 and 2	8A1. Same as item 7A1	8A1. Same as item 7A1, except pressure indicators are PI-5128A on on QMCB or PI-5128B on PSDB, and miniflow valve FV-5154 position indicated on QMCB and PSDB	8A1. None - AFW pumps P4-001 and P4-003 available to satisfy AFW requirements taking suction from tank V4-002 via HV-5113 and HV-5119, respectively.	Same as item 7
				8A2. Same as item 7A2	8A2. Same as item 7A2	8A2. None - Same as item 7A2	

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TABLE 10.4.9-4 (SHEET 4 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			8B. Modes 3 and 4	8B. Same as items 7A1 and 7A2	8B. Same as items 8A1 and 8A2, respectively	8B. None - Same as items 7B1 and 7B2, respectively	
			8C. Mode 6	8C. Same as items 7A1 and 7A2	8C. Same as items 8A1 and 8A2, respectively	8C. None - Same as items 7C1 and 7B2, respectively	
			8D. Mode 7	8D. Spurious opening	8D. Position lights on QMCB or PSDB	8D. None - No loss of tank V4-002 inventory, since pump P4-002 is not operating.	
			8E. Mode 5	8E1. Same as item 7A1	8E1. Same as item 8A1	8E1. None - Same as item 8A1, except only pump P4-003 available, but this is sufficient for safe shutdown.	
				8E2. Same as item 7A2	8E2. Same as item 7A2	8E2. None - Same as item 7B2	
9	AFW suction valve HV-5113, normally closed, dc-operated MOV, train C	Same as item 7, except to suction of turbine-driven AFW pump P4-001, and controlled from the control room and AFW panel PAFP	9A. Modes 3 and 4	9A1. Fails closed or fails to open upon command with condensate storage tank V4-001 depleted	9A1. Position lights on QMCB or PAFP, plus low pump suction pressure PI-5110A or PI-5110B on QMCB or PAFP, respectively	9A1. None - AFW pumps P4-002 and P4-003 available to satisfy AFW requirements taking suction from tank V4-002 via HV-5118 and HV-5119, respectively.	Turbine-driven AFW pump not ordinarily used during modes 1 and 2. (For discussion of the ability of of the AFW pumps to satisfy system requirements during various failure modes, see items 10, 11, and 12.) The condensate storage facility is sized to accommodate 30-min spillage at turbine-driven pump (TDP) runout to allow for operator action to isolate the tur-

TABLE 10.4.9-4 (SHEET 5 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
							bine and/or the TDP (for mode 5, see item 9B). For the TDP, irrespective of source, the miniflow is returned to tank V4-001 via fixed flow orifice FO-5109.
				9A2. Spurious opening while tank V4-001 not depleted and TDP pump running	9A2. Same as item 7A2, except position indicator on QMCB or PAFP	9A2. None - Both tanks supplying AFW simultaneously, but total consumption not effected. Makeup not operating but not required.	
			9B. Mode 5	9B. Fails open or fails to close upon command	9B. Same as item 9A2	9B. None - Manually operated valve HV-5097 can be closed to isolate pump, and HV-3009 (item 14) and HV-3019 (item 15) closed to stop turbine.	
			9C. Mode 6	9C. Same as items 9A1 and 9A2	9C. Same as items 9A1 and 9A2, respectively	9C. None - Same as items 9A1 and 9A2, respectively	
			9D. Mode 7	9D. Spurious opening	9D. Position indicator on QMCB or PAFP	9D. None - No loss of tank V4-002 inventory, since pump P4-001 is not operating.	

TABLE 10.4.9-4 (SHEET 6 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
10	Motor-driven AFW pump P4-003 (train A)	Provides AFW to SGs 1 and 4 automatically as required or by remote manual actuation from the control room or shutdown panel	10A. Modes 1, 2, and 3	10A. Fails to start or stops running when required	10A. Pump status light shows green on QMCB or PSDA, plus low discharge pressure indicators PI-5141A and PI-5141B on QMCB or PSDA, respectively. Also miniflow valve FV-5155 (item 27) is open.	10A. None - Motor-driven AFW pump (MDP) P4-002 available to satisfy 100% of AFW requirements. TDP P4-001 also available if required.	For HELB in TDP discharge (mode 5, items 10D and 11D), only one MDP is required to satisfy AFW requirements. (For the effects of loss of all ac power, see item 67.)
			10B. Mode 4, SG 1 or 4	10B. Spurious start or failure to stop upon command	10B. Pump status light shows red on QMCB or PSDA with same low pressure indicators as for item 10A, plus low discharge pressure alarm PSL-5149 on QMCB if break upstream of flow limiting orifices.	10B. None - MDP P4-002 and TDP P4-001 operate automatically to to satisfy AFW requirements. Thirty-minute spillage through break accounted for in condensate tank sizing.	
			10C. Mode 4, SG 2 or 3	10C. Fails to start or stops running	10C. Same as item 10A	10C. None - TDP P4-001 operates automatically to satisfy AFW requirements.	
			10D. Mode 5	10D. Fails to start or stops running	10D. Same as item 10A	10D. None - MDP P4-002 operates automatically to satisfy AFW requirements.	
			10E. Mode 6	10E. Fails to start or stops running	10E. Same as item 10A	10E. None - MDP P4-002 and TDP P4-001 available.	

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TABLE 10.4.9-4 (SHEET 7 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
11	Motor-driven AFW pump P4-002 (train B)	Same as item 10, except provides AFW to SGs 2 and 3 and shutdown panel is PSDB	11A. Modes 1, 2, and 3	11A. Fails to start or stops running when required	11A. Pump status light shows green on QMCB or PSDB, plus low discharge pressure indicators PI-5140A or PI-1541B on QMCB and PSDB, respectively. Also, miniflow valve FV-5154 (item 28) is open.	11A. None - Same as item 10A, except MDP P4-003 provides backup AFW capability along with TDP P4-001.	See item 10
			11B. Mode 4, SG 2 or 3	11B. Spurious start or failure to stop upon command	11B. Pump status light shows red on QMCB or PSDB, plus same low pressure indicators as item 11A, plus low discharge pressure alarm PSL-5148 on QMCB	11A. None - Same as item 10B, except backup MDP is P4-003.	
			11C. Mode 4, SG 1 or 4	11C. Fails to start or stops running when required	11C. Same as item 11A	11C. None - Same as item 10C	
			11D. Mode 5	11D. Fails to start or stops running	11D. Same as item 11A	11D. None - MDP P4-003 operates automatically to satisfy AFW requirements.	
			11E. Mode 6	11E. Fails to start or stops running	11E. Same as item 11A	11E. None - Same as item 10E, except backup MDP is P4-003.	

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TABLE 10.4.9-4 (SHEET 8 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
12	Turbine-driven AFW pump P4-001 (train C, with dc-powered controls)	Same as item 10, except provides AFW to all four SGs	12A. Mode 3	12A. Fails to start or stops running with steam admission valve HV-5106 (item 13) open	12A. Low pump discharge pressure alarm PSL-5108, plus low speed indication SI-15109A on QMCB, SI-15109B on PAFP, and SI-15109 on PAFT	12A. None - MDPs P4-002 and P4-003 provide 100% of of AFW requirements.	The turbine-driven AFW pump not ordinarily used during modes 1 and 2. (For FMEA of turbine steam admission valve, see item 13; and for main steam supply valves, see items 14 and 15.)
			12B. Mode 4 any SG	12B. Same as item 12A	12B. Same as item 12A	12B. None - Same as item 12A. Also, the MDPs satisfy minimum AFW requirements with allowance for 30-min spillage from faulted feedline.	
			12C. Mode 5	12C. Continues to run or fails to stop upon command	12C. Same as item 12A, except high pump speed indication SI-15109A on QMCB, SI-15109B on PAFP, and SI-15109C on PAFT; HV-5106 position lights on PAFP or QMCB show valve open	12C. None - MDPs P4-002 and P4-003 provide 100% of AFW requirements. The condensate storage tank capacity accounts for 30-min spillage at pump runout conditions. Main steam turbine supply valves HV-3009 (item 14) and HV-3019 (item 15) can be closed to terminate turbine steam supply.	
			12D. Mode 6	12D. Fails to start or stops running (HV-5106 open)	12D. Same as item 12A	12D. None - MDPs P4-002 and P6-003 available.	

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TABLE 10.4.9-4 (SHEET 9 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
13	AFW TDP turbine steam admission valve, normally closed dc-powered MOV, train C	Controls steam admission to TDP turbine driver	13A. Modes 3, 4, and 6	13A. Fails closed or fails to open upon command	13A. Position lights on QMCB or PAFP coincident with low pump discharge pressure alarm PSL-5108 on QMCB	13A. None - MDPs P4-002 and P4-003 provide 100% of AFW requirements. (See also item 12B, mode 4.)	The turbine-driven AFW pump not ordinarily used for modes, 1, 2, or 7. (For FMEA of TDP, see item 12; and for main steam supply valves, see items 14 and 15.)
			13B. Mode 5	13B. Fails open or fails to close upon command	13B. Same as item 13A	13B. None - Same as item 12C	
14	Steam supply valve HV-3009 from SG 1 to TDP P4-001 turbine, normally open dc-powered MOV, train B	Admits steam from SG 1 to TDP turbine and also provides for isolation of the downstream piping in the event of a line break	14A. Modes 3, 4, and 6	14A. Fails closed or fails to open upon command	14A. Valve position lights on QMCB or PAFP	14A. None - 100% redundant steam supply to the TDP provided via HV-3019 from SG 2. Also, MDPs P4-002 and P4-003 provide 100% of AFW requirements.	See also table 10.3.3-1, item 33
			14B. Mode 5	14B. Fails open or fails to close upon command	14B. Same as item 14A	14B. None - TDP steam admission valve can be closed to terminate steam supply. (See also item 12 for pump redundancy and design of CST capacity.)	
15	Steam supply valve HV-3019 from SG 2 to TDP P4-001 turbine, normally open dc-powered MOV, train A	Same as item 14A, but from SG 2	15A, Modes 3, 4, and 6	15A. Fails closed or fails to open upon command	15A. Valve position lights on QMCB or PAFP	15A. None - Same as item 14A, except redundant steam supply from SG 1 via HV-3009.	See also table 10.3.3-1, item 34. For containment isolation function, see table 6.2.4-1, item 19.
			15B. Mode 5	15B. Fails open or fails to close upon command	15B. Same as item 15A	15B. None - Same as item 14B	

TABLE 10.4.9-4 (SHEET 10 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
16	Check valve 1301-U4-006 in steam supply line to TDP turbine from SG 1	Prevents crossflow between main steam lines to prevent blowdown of SG 2 in the event of MSLB in the No. 1 main steam line	16A. Mode 6 (MSLB in SG 1)	16A. Fails open	16A. Gradual decrease of water level in SG 2	16A. None - TDP performance degraded but MDPs available. Degrading upon break location, HV-3009 can be closed to terminate blowdown from SG 2 and permit continued TDP operation.	See also table 10.3.3-1, item 35
			16B. Modes 3, 4, and 5	16B. Fails closed	16B. None	16B. None - Same as item 14A	
17	Check valve 1301-U4-008 in steam supply line to TDP turbine from SG 2	Same as item 16, except SG designations reversed	17A. Mode 6 (MSLB in SG 2)	17A. Fails open	17A. Gradual decrease of water level in SG 1	17A. None - Same as item 16A, except HV-3019 can be closed to terminate blowdown from SG 1 and permit continuous TDP operation.	See also table 10.3.3-1, item 36
			17B. Modes 3, 4, and 5	17B. Fails closed	17B. None	17B. None - Same as item 15A	
18	Not used						
19	Not used						
20	Not used						
21	Not used						
22	Not used						
23	Not used						

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TABLE 10.4.9-4 (SHEET 11 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
24	Check valve 001 in MDP P4-003 discharge	Prevents reduction in AFW flow to SG via backflow through P4-003 when pump is not running	24A. Modes 1, 2, and 3	24A. Fails closed with MDP P4-003 running	24A. Position indicators for miniflow valve FV-5155 on QMCB or PSDA show FV-5155 open	24A. None - Same as item 10A	See item 10
			24B. Mode 4, SG 2	24B. Same as item 24A	24B. Same as item 24A	24B. None - Same as item 10C	
			24C. Mode 5	24C. Same as item 24A	24C. Same as item 24A	24C. None - Same as item 10D	
			24D. Mode 6	24D. Same as item 24A	24D. Same as item 24A	24D. None - Same as item 10E	
			24E. All	24E. Fails open with MDP P4-003 not running	24E. None	24E. None - Stop checks 043 and 046 prevent backflow, thus ensuring adequate AFW flow.	
25	Check valve 002 in MDP P4-002 discharge	Same as item 24, except pump is MDP P4-002	25A. Modes 1, 2, and 3	25A. Fails closed with MDP P4-002 running	25A. Position lights for miniflow valve FV-5154 on QMCB or PSDB show FV-5154 open	25A. None - Same as item 11A	See item 10
			25B. Modes 4, SG 1 or 4	25B. Same as item 25A	25B. Same as item 25A	25B. None - Same as item 11C	
			25C. Mode 5	25C. Same as item 25A	25C. Same as item 25A	25C. None - Same as item 11D	
			25D. Mode 6	25D. Same as item 25A	25D. Same as item 25A	25D. Same as item 11E	
			25E. All	25E. Fails open with MDP P4-002 not running	25E. None	25E. None - Stop checks 037 and 040 prevent backflow, thus ensuring adequate AFW flow.	

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TABLE 10.4.9-4 (SHEET 12 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
26	Check valve 014 in TDP P4-001 discharge	Same as item 24, except pump is TDP P4-001	26A. Mode 3	26A. Fails closed with TDP P4-001 running	26A. None	26A. None - Same as item 12A	See item 12
			26B. Mode 4, any SG	26B. Same as item 26A	26B. None	26B. None - Same as item 12B	
			26C. Mode 6	26C. Same as item 26A	26C. None	26C. None - Same as item 12D	
			26D. All	26D. Fails open with TDP P4-001 not running	26D. None	26D. None - Stop checks 017, 020, 023, and 026 prevent backflow, thus ensuring adequate AFW flow.	
27	AFW pump P4-003 miniflow valve FV-5155, normally open MOV, train A	Opens automatically or manually from PSDA to ensure MDP P4-003 miniflow requirements are statisfied at all times	27A. Modes 1, 2, 3, 4, and 6	27A1. Fails open with MDP P4-003 running	27A1. Position lights on QMCB or PSDA	27A1. None - Reduced flow available from MDP P4-003, but MDP P4-002 and TDP P4-001 are available.	See item 10 for effect of loss of one MDP for HELB at TDP discharge (mode 5). Thirty-min operator response time may be a factor in preventing damage from pump cavitation.
				27A2. Fails closed with MDP P4-003 running	27A2. Same as item 27A1	27A2. None - Under some conditions MDP P4-003 may cavitate, but MDP P4-002 and TDP P4-001 are available.	
			27B. Mode 5	27B1. Same as item 27A1	27B1. Same as item 27A1	27B1. None - Reduced flow available from MDP P4-003, but MDP P4-002 satisfies 100% AFW requirements.	

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TABLE 10.4.9-4 (SHEET 13 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
				27B2. Same as item 27A2	27B2. Same as item 27A1	27B2. None - Same as item 27A2, except only MDP P4-002 is available; this is sufficient for this case.	
28	AFW P4-002 miniflow valve FV-5154, normally open MOV, train B	Same as item 27, except MDP is P4-002 and manual control from PSDB	28A. Modes 1, 2, 3, 4, and 6	28A1. Fails open with MDP P4-002 running	28A1. Position indicator on QMCB or PSDB	28A1. None - Reduced flow available from MDP P4-002, but MDP P4-003 and TDP P4-001 are available.	See items 27 and 10
				28A2. Fails closed with MDP P4-002 running	28A2. Same as item 28A1	28A2. None - Under same conditions, MDP P4-002 may cavitate, but MDP P4-003 and TDP P4-001 are available.	
			28B. Mode 5	28B1. Same as item 28A1	28B1. Same as item 28A1	28B1. None - Reduced flow available from MDP P4-002, but MDP P4-003 satisfies 100% AFW requirements.	
				28B2. Same as item 28A2	28B2. Same as item 28A1	28B2. None - Same as item 28B1, except only MDP-003 available; this is sufficient for this case.	

TABLE 10.4.9-4 (SHEET 14 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
29	AFW control valve HV-5139 from MDP P4-003 to SG 1, normally open MOV, train A	Regulates AFW flow from MDP P4-003 to SG 1 via remote manual control from QMCB and PSDA; opens automatically upon MDP automatic start signal	29A. Modes 1, 2, and 3	29A. Fails closed or fails to open upon command	29A. Position indicator ZI-5139A and light on QMCB or position indicator ZI-1539B and light on PSDA	29A. None - No flow to SG 1 from MDP P4-003, but MDP P4-002 and TDP P4-001 are available. Also, MDP P4-003 still supplies AFW SG 4.	For FMEA of MDP P4-003, see item 10. For system capability to withstand 30-min spillage. See item 10. HV-5122 can be closed to isolate TDP P4-001 from SG 1 for mode 4 (item 29B).
			29B. Mode 4, SG 1	29B. Fails open or fails to close upon command	29B. Same as item 29A	29B. None-MDP P4-003 can be turned off to terminate spillage. MDP P4-002 and TDP P4-001 supply 100% of flow.	
			29C. Mode 4, SG 4	29C. Fails closed or fails to open upon command	29C. Same as item 29A	29C. None - MDP P4-003 not effective, but MDP P4-002 available to feed SGs 2 and 3. Also, TDP P4-001 available. MDP P4-003 can be turned off and HV-5120 can be closed to terminate AFW spillage from No. 4 feedline.	
			29D. Mode 5	29D. Fails closed or fails to open upon command	29D. Same as item 29A, plus zero flow indication to SG 1; FI-5152A on QMCB, FI-5152B on PSDA, and FI-5152C on PAFP	29D. None - MDP P4-003 still supplies SG 4 while MDP P4-002 supplies SGs 2 and 3.	
			29E. Mode 6 (LOCA)	29E. Fails closed or fails to open upon command	29E. Same as item 29A	29E. None - Same as item 29A	

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Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			29F. Mode 6, MSLB in SG 1	29F. Fails open or fails to close upon command	29F. Same as item 29A	29F. None - Same as item 29B.	
30	AFW control valve HV-5137 from MDP P4-003 to SG 4, normally open MOV, train A	Same as item 29, except SG 4	30A. Modes 1, 2, and 3	30A. Same as item 29A	30A. Same as item 29A, except position indicators are ZI-5137A on QMCB and 5137B on PSDA	30A. None - Same as item 29A, except no flow to SG 4, but with flow to SG 1 from P4-003.	See items 29 and 10. HV-5120 can be closed to isolate TDP P4-001 from SG 4 for mode 4 (item 30B).
			30B. Mode 4, SG 4	30B. Same as item 29B	30B. Same as item 30A	30B. None - Same as item 29B	
			30C. Mode 4, SG 1	30C. Same as item 29C	30C. Same as item 30A	30C. None - Same as item 29C, except HV-5122 can be closed to terminate AFW spillage from No. 1 feedline.	
			30D. Mode 5	30D. Same as item 29D	30D. Same as item 30A, plus zero flow indication to to SG 4; FI-5150A on QMCB, FI-5150B on PSDA, and 5150C on PAFP	30D. None - Same as item 29D, except MDP P4-003 still supplies SG 1.	
			30E. Mode 6 (LOCA)	30E. Same as item 29E	30E. Same as item 30A	30E. None - Same as item 30A	
			30F. Mode 6, MSLB in SG 4	30E. Same as item 29F	30E. Same as item 30A	30E. None - Same as item 29B	

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TABLE 10.4.9-4 (SHEET 16 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
31	AFW control valve HV-1534 from MDP P4-002 to SG 3, normally open MOV, train B	Same as item 29, except from MDP P4-002 to SG 3 and control from QMCB and PSDB	31A. Modes 1, 2, and 3	31A. Modes 29A	31A. Same as item 29A, except position indicators are ZI-5134A on QMCB and ZI-5134B on PSDB	31A. None - No flow to SG 3 from MDP P4-002, but MDP P4-003 and TDP P4-001 are available. Also, MDP P4-002 still supplies AFW to SG 2.	See items 10 and 29. HV-5127 can be closed to isolate TDP P4-001 from SG 3 for mode 4 (item 31B).
			31B. Mode 4, SG 3	31B. Same as item 29B	31B. Same as item 31A	31B. None - MDP P4-002 can be turned off to terminate spillage. MDP P4-002 and TDP P4-001 supply 100% AFW flow.	
			31C. Mode 4, SG 2	31C. Same as item 29C	31C. Same as item 31A	31C. None - MDP P4-002 not effective, but MDP P4-003 is available to feed SGs 1 and 4. Also, TDP P4-001 is available. MDP P4-002 can be turned off and HV-5125 closed to terminate spillage.	
			31D. Mode 5	31D. Same as item 29D	31D. Same as item 31A, plus zero flow indication to SG 3; FI-5153A on QMCB, FI-5153B on PSDB, and FI-5153C on PAFP	31D. None - MDP P4-002 still supplies SG 2 while MDP P4-003 supplies SGs 1 and 4.	
			31E. Mode 6 (LOCA)	31E. Same as item 29E	31E. Same as item 31A	31E. None - Same as item 31A	
			31F. Mode 6 (MSLB in SG 3)	31F. Same as item 29F	31F. Same as item 31A	31F. None - Same as item 31B	

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TABLE 10.4.9-4 (SHEET 17 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
32	AFW control valve HV-5123 from MDP P4-002 to SG 2, normally open MOV, train B	Same as item 31, except from MDP P4-002 to SG 2	32A. Modes 1, 2, and 3	32A. Same as item 29A	32A. Same as item 29A, except position indicators are ZI-5132A on QMCB and ZI-1532B on PSDB	32A. None - Same as item 31A, except no flow to SG 2, but with flow from MDP P4-002 to SG 3.	See items 10 and 29. HV-5125 can be closed to isolate TDP P4-001 from SG 2 for mode 4 (item 32B).
			32B. Mode 4, SG 2	32B. Same as item 29B	32B. Same as item 32A	32B. None - Same as item 31B	
			32C. Mode 4, SG 3	32C. Same as item 29C	32C. Same as item 32A	32C. None - Same as item 31C, except HV-5127 can be closed to terminate AFW spillage from No. 3 feedline.	
			32D. Mode 5	32D. Same as item 29D	32D. Same as item 32A, plus zero flow indication to SG 2; FI-5151A on QMCB, FI-5151B on PSDB, and FI-5151C on PAFP	32D. None - Same as item 31E, except MDP P4-002 still supplies SG 3.	
			32E. Mode 6 (LOCA)	32E. Same as item 29E	32E. Same as item 32A	32E. None - Same as item 32A	
			32F. Mode 6 (MSLB in SG 2)	32F. Same as item 29F	32F. Same as item 32A	32F. None - Same as item 31B	
33	AFW control valve HV-5127 from TDP P4-001 to SG 3, normally open dc-powered MOV, train C	Regulates AFW flow from TDP P4-001 to SG 3 via remote manual control from QMCB and PAFP; opens automatically upon TDP auto start signal	33A. Mode 3	33A. Same as item 29A	33A. Same as item 29A, except position indicators are ZI-5127A on QMCB and ZI-1527B on PAFP	33A. None - No flow to SG 3 from TDP P4-001, but MDPs P4-002 and 003 are available. Also, TDP P4-001 still supplies AFW to SGs 1, 2, and 4.	See items 12 and 19. The faulted SG (mode 4, item 33C) can be isolated from its respective MDP by closing the appropriate AFW control valve. Mode 5 is not applicable since break is assumed to be upstream of flow control valves.

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Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			33B. Mode 4, SG 3	33B. Same as item 29B	33B. Same as item 33A	33B. None - TDP P4-001 can be turned off and HV-5134 closed to terminate spillage. MPDs P4-002 and P4-003 provide 100% AFW flow.	
			33C. Mode 4, SG 1, 2, or 4	33C. Same as item 29C	33C. Same as item 33A	33C. None - TDP P4-001 still supplies two effective steam generators. Also, MDPs P4-002 and P4-003 available. (See remarks.)	
			33D. Mode 6 (LOCA)	33D. Same as item 29E	33D. Same as item 33A	33D. None - Same as item 33A	
			33E. Mode 6 (MSLB in SG 3)	33E. Same as item 29F	33E. Same as item 33A	33E. None - Same as item 33B	
34	AFW control valve HV-5125 from TDP P4-001 to SG 2, normally open, dc-powered MOV, train C	Same as item 33, except to SG 2	34A. Mode 3	34A. Same as item 29A	34A. Same as item 29A, except position indicators are ZI-5125A on QMCB and ZI-5125B on PAFP	34A. None - Same as item 33A, except no flow from TDP P4-001 to SG 2, but with flow to SGs 1, 3, and 4.	See items 12, 29, and 33
			34B. Mode 4, SG 2	34B. Same as item 29B	34B. Same as item 34A	34B. None - Same as item 33B, except HV-5132 can be closed to isolate SG 2.	
			34C. Mode 4, SG 1, 3, or 4	34C. Same as item 29C	34C. Same as item 34A	34C. None - Same as item 33C (see remarks item 33)	
			34D. Mode 6 (LOCA)	34D. Same as item 29E	34D. Same as item 34A	34D. None - Same as item 34A	

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Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			34E. Mode 6 (MSLB in SG 2)	34E. Same as item 29F	34E. Same as item 34A	34E. None - Same as item 34B	
35	AFW control valve HV-5122 from TDP P4-001 to SG 1, normally open dc-powered MOV, train C	Same as item 33, except to SG 1	35A. Mode 3	35A. Same as item 29A	35A. Same as item 29A, except position indicators are ZI-5122A on QMCB and ZI-5122B on PAFP	35A. None - Same as item 33A, except no flow from TDP P4-001 to SG 1, but flow to SGs 2, 3, and 4.	See items 12, 29, and 33
			35B. Mode 4, SG 1	35B. Same as item 29B	35B. Same as item 35A	35B. None - Same as item 33B, except HV-5139 can be closed to isolate SG 1.	
			35C. Mode 4, SG 2, 3, or 4	35C. Same as item 29C	35C. Same as item 35A	35C. None - Same as item 33C (see remarks item 33)	
			35D. Mode 6 (LOCA)	35D. Same as item 29E	35D. Same as item 35A	35D. None - Same as item 35A	
			35E. Mode 6 (MSLB in SG 2)	35E. Same as item 29E	35E. Same as item 35A	35E. None - Same as item 35B	
36	AFW control valve HV-5120 from TDP P4-001 to SG 4, normally open dc-powered MOV, train C	Same as item 33, except to SG 4	36A. Mode 3	36A. Same as item 29F	36A. Same as item 29A, except position indicators are ZI-5120A on QMCB and ZI-5120B on PAFP	36A. None - Same as item 33A, except no flow from TDP P4-001 to SG 4, but with flow to SGs 1, 2, and 3	See items 12, 29, and 33
			36B. Mode 4, SG 4	36B. Same as item 29B	36B. Same as item 36A	36B. None - Same as item 33B, except HV-5137 can be closed to isolate SG 4.	
			36C. Mode 4, SG 2, 3, or 4	36C. Same as item 29C	36C. Same as item 36A	36C. None - Same as item 33C (see remarks item 33)	

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Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			36D. Mode 6 (LOCA)	36D. Same as item 29E	36D Same as item 36A	36D. None - Same as item 36A	
			36E. Mode 6 (MSLB in SG 4)'	36E. Same as item 29F	36E. Same as item 36A	36E. None - Same as item 36B	
37	Stop-check valve 046 in AFW supply from MDP P4-003 to SG 1	Prevents AFW backflow when MDP P4-003 not running and HV-5139 open	37A. Modes 1, 2, and 3	37A. Fails closed with MDP P4-003 running and HV-5139 open	37A. None	37A. None - Same as item 29A	
			37B. Mode 4, SG 4	37B. Same as item 37A	37B. None	37B. None - Same as item 29C	
			37C. Mode 5	37C. Same as item 37A	37C. Zero flow indication to SG 1 (see item 29D)	37C. None - Same as item 29D	
			37D. Mode 6 (LOCA)	37D. Same as item 37A	37D. None	37D. None - Same as item 29E	
			37E. All	37E. Fails open with MDP P4-003 not running and HV-5139 open	37E. None	37E. None - Other check valves in flow path prevent backflow. Also, HV-1539 can be closed.	
38	Stop-check valve 043 in AFW supply from MDP P4-003 to SG 4	Same as item 37, except HV is HV-5137	38A. Modes 1, 2, and 3	38A. Same as item 37A, except HV-5137 open	38A. None	38A. None - Same as item 30A	
			38B. Mode 4, SG 1	38B. Same as item 38A	38B. None	38B. None - Same as item 30C	
			38C. Mode 5	38C. Same as item 38A	38C. Zero flow indication to SG 4 (see item 30D)	38C. None - Same as item 30D	
			38D. Mode 6 (LOCA)	38D. Same as item 38A	38D. None	38D. None - Same as item 30E	

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Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
			38E. All	38E. Same as item 37E,, except HV-5137 open	38E. None	38E. None - Same as item 37E, except HV-5137 can be closed.	
39	Stop-check valve 040 in AFW supply from MDP P4-002 to SG 3	Prevents AFW backflow when MDP P4-002 not running and HV-5134 open	39A. Modes 1, 2, and 3	39A. Fails closed with MDP P4-002 running and HV-5134 open	39A. None	39A. None - Same as item 31A	
			39B. Mode 4, SG 2	39B. Same as item 39A	39B. None	39B. None - Same as item 31C	
			39C. Mode 5	39C. Same as item 39A	39C. Zero flow indication to SG 3 (see item 31D)	39C. None - Same as item 31D	
			39D. Mode 6 (LOCA)	39D. Same as item 39A	39D. None	39D. None - Same as item 31E	
			39E. All	39E. Fails open with MDP P4-002 not running and and HV-5134 open	39E. None	39E. None - Other check valves in flow path prevent backflow. Also, HV-5134 can be closed.	
40	Stop-check valve 037 in AFW supply from MDP P4-002 to SG 2	Same as item 39, except HV is HV-5132	40A. Modes 1, 2, and 3	40A. Same as item 39A, except HV-5132 open	40A. None	40A. None - Same as item 32A	
			40B. Mode 4, SG 3	40B. Same as item 40A	40B. None	40B. None - Same as item 32C	
			40C. Mode 5	40C. Same as item 40A	40C. Zero flow indication to SG 3 (see item 32D)	40C. None - Same as item 32D	
			40D. Mode 6 (LOCA)	40D. Same as item 40A	40D. None	40D. None - Same as item 32E	
			40E. All	40E. Same as item 39E, except HV-1532 open	40E. None	40E. None - Same as item 39E, except HV-5132 can be closed.	

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TABLE 10.4.9-4 (SHEET 22 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
41	Stop-check valve 026 in AFW supply from TDP P4-00[illegible] to SG 3	Prevents AFW backflow when TDP P4-001 not running and HV-5127 open	41A. Mode 3	41A. Fails closed with TDP P4-001 running and HV-5127 open	41A. None	41A. None - Same as item 33A	See items 12 and 33
			41B. Mode 4, SG 1, 2, or 4	41B. Same as item 41A	41B. None	41B. None - Same as item 33C	
			41C. Mode 5	41C. Fails open with HV-5127 open	41C. None	41C. None - Same as item 12C. Also, HV-5127 can be closed.	
			41D. Mode 6 (LOCA)	41D. Same as item 41C	41D. None	41D. None - Same as item 33D	
			41E. All except 5	41E. Fails open with TDP P4-001 not running and HV-5127 open	41E. None	41E. None - Other check valves in flow path prevent backflow. Also, HV-5127 can be closed.	
42	Stop-check valve 023 in AFW supply from TDP P4-001 to SG 2	Same as item 41, except HV is HV-5125	42A. Mode 3	42A. Same as item 41A, except HV-5125 open	42A. None	42A. None - Same as item 34A	See item 12, 33, and 34
			42B. Mode 4, SG 1, 3, or 4	42B. Same as item 42A	42B. None	42B. None - Same as item 34C	
			42C. Mode 5	42C. Fails open with HV-5125 open	42C. None	42C. None - Same as item 12C. Also, HV-5127 can be closed.	
			42D. Mode 6 (LOCA)	42D. Same as item 42A	42D. None	42D. None - Same as item 34D	
			42E. All except 5	42E. Same as item 41E, except HV-5125 open	42E. None	42E. None - Same as item 41E, except HV-5125 can be closed.	

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Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
43	Stop-check valve 026 in AFW supply from TDP P4-001 to SG 1	Same as item 41, except HV is HV-5122	43A. Mode 3	43A. Same as item 41A, except HV-5122 open	43A. None	43A. None - Same as item 35A	See items 12, 33, and 35
			43B. Mode 4, SG 2, 3, or 4	43B. Same as item 43A	43B. None	43B. None - Same as item 35C	
			43C. Mode 5	43C. Fails open with HV-5122 open	43C. None	43C. None - Same as item 12C. Also, HV-5122 can be closed.	
			43D. Mode 6 (LOCA)	43D. Same as item 43A	43D. None	43D. None - Same as item 35D	
			43E. All except 5	43E. Same as item 41E, except HV-5122 open	43E. None	43E. None - Same as item 41E, except HV-5122 can be closed.	
44	Stop-check valve 017 in AFW supply from TDP to SG 4	Same as item 41, except HV is HV-5120	44A. Mode 3	44A. Same as item 41A, except HV-5120 open	44A. None	44A. None - Same as item 36A	See items 12, 33, and 36
			44B. Mode 4, SG 2, 3, or 4	44B. Same as item 41A	44B. None	44B. None - Same as item 36C	
			44C. Mode 5	44C. Fails open with HV-5120 open	44C. None	44C. None - Same as item 12C. Also, HV-5120 can be closed.	
			44D. Mode 6 (LOCA)	44D. Same as item 44A	44D. None	44D. None - Same as 36D	
			44E. All except 5	44E. Same as item 41E except HV-5120 open	44E. None	44E. None - Same as item 41E, except HV-5120 can be closed.	

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Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
45	Stop-check valve 113 in AFW supply lines to SG 1	Prevents backflow from No. 1 feedwater bypass line whenever the AFW system not in operation	45A. Mode 7	45A. Fails open	45A. None	45A. None - Other check valves in flow path prevent backflow.	
			45B. Modes 1 through 6	45B. Fails closed	45B. Zero flow indication to SG 1; FI-5152A on QMCB, FI-5152B on PSDA, and FI-5152C on PAFP	45B. None - Same as item 29D, plus TDP P4-001 available to supply AFW to to SGs 2, 3, and 4.	
46	Stop-check valve 114 in AFW supply line to SG 2	Same as item 45, except for No. 2 feedwater bypass line	46A. Mode 7	46A. Fails open	46A. None	46A. None - Same as item 45A	
			46B. Modes 1 through 6	46B. Fails closed	46B. Zero flow indication to SG 2; FI-5151A on QMCB, FI-5151B on PSDB, and FI-5151C on PAFP	46B. None - Same as item 32D, plus TDP P4-001 is available to supply AFW to SGs 1, 3, and 4.	
47	Stop-check valve 115 in AFW supply line line to SG 3	Same as item 45, except for No. 3 feedwater bypass line	47A. Mode 7	47A. Fails open	47A. None	47A. None - Same as item 45A	
			47B. Modes 1 through 6	47B. Fails closed	47B. Zero flow indication to SG 3; FI-5153A on QMCB, FI-5153B on PSDB, and FI-5153C on PAFP	47B. None - Same as item 31D, plus TDP P4-001 is available to supply AFW to SGs 1, 2, and 4.	
48	Stop-check valve 116 in AFW supply line to SG 4	Same as item 45, except for No. 4 feedwater bypass line	48A. Mode 7	48A. Fails open	48A. None	48A. None - Same as item 45A	
			48B. Modes 1 through 6	48B. Fails closed	48B. Zero flow indication to SG 4; FI-5150A on QMCB, FI-5150B on PSDA, and FI-5150C on PAFP	48B. None - Same as item 30D. plus TDP P4-001 is available to supply AFW to SGs 1, 2, and 3.	

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TABLE 10.4.9-4 (SHEET 25 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
49	Feedwater bypass isolation valve HV-15196, normally open, fail closed air-operated valve	Isolates feedwater bypass line to SG 1 upon feedwater isolation signal; admits main feedwater to AFW nozzle during power generation	49A. Modes 1 through 6	49A. Fails open or fails to close upon command	49A. Position lights on QMCB	49A. None - Check valve 053 prevents backflow or injection of AFW into main feedwater nozzle.	This valve is normally open only during power generation.
			49B. Mode 7	49B. Fails closed or fails to open upon command	49B. Position lights on QMCB	49B. None - AFW path not affected. All main feedwater enters via main feedwater nozzle.	
50	Feedwater bypass isolation valve HV-15197, normally open, fail closed air-operated valve	Same as item 49, except for SG 2	50A. Modes 1 through 6	50A. Same as item 49A	50A. Same as item 49A	50A. None - Same as item 49A, except check valve is 118.	See item 49
			50B. Mode 7	50B. Same as item 49B	50B. Same as item 49B	50B. None - Same as item 49B	
51	Feedwater bypass isolation valve HV-15198, normally open, fail closed air-operated valve	Same as item 49, except SG 3	51A. Modes 1 through 6	51A. Same as item 49A	51A. Same as item 49A	51A. None - Same as item 49A, except check valve is 120.	See item 49
			51B. Mode 7	51B. Same as item 49B	51B. Same as item 49B	51B. None - Same as item 49B	
52	Feedwater bypass isolation valve HV-15199, normally open, fail closed air-operated valve	Same as item 49, except for SG 4	52A. Modes 1 through 6	52A. Same as item 49A	52A. Same as item 49A	52A. None - Same as item 49A, except check valve is 119.	See item 49
			52B. Mode 7	52B. Same as item 49B	52B. Same as item 49B	52B. None - Same as item 49B	

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TABLE 10.4.9-4 (SHEET 26 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
53	Feedwater bypass check valve 117	Prevents backflow of SG 1 AFW flow into main feedwater system whenever latter not operating	53A. Modes 1 through 6	53A. Fails open	53A. None	53A. None - Condensate storage facility sized to accommodate loss due to 30-min backflow. Also, HV-15196 can be closed.	See item 10
			53B. Mode 7	53B. Fails closed	53B. None	53B. None - Same as item 49B	
54	Feedwater bypass check valve 118	Same as item 53, except for SG 2	54A. Modes 1 through 6	54A. Fails open	54A. None	54A. None - Same as item 53A, except HV is HV-15197.	See item 10
			54B. Mode 7	54B. Fails closed	54B. None	54B. None - Same as item 49B	
55	Feedwater bypass check valve 120	Same as item 53, except for SG 3	55A. Modes 1 through 6	55A. Fails open	55A. None	55A. None - Same as item 53A, except HV is HV-15198.	See item 10
			55B. Mode 7	55B. Fails closed	55B. None	55B. None - Same as item 49B	
56	Feedwater bypass check valve 119	Same as item 53, except SG 4	56A. Modes 1 through 6	56A. Fails open	56A. None	56A. None - Same as item 53A, except HV is HV-15199.	See item 10
			56B. Mode 7	56B. Fails closed	56B. None	56B. None - Same as item 49B	
57	AFW line check valve 121	Prevents blowdown of SG 1 or auxiliary building overpressurization in the event of an HELB in the SG 1 AFW line outside containment	57A. All but AFW HELB	57A. Fails closed	57A. Same as item 45B, except none for mode 7	57A. None - Same as item 45B	
			57B. AFW HELB	57B. Fails open	57B. None	57B. None - Check valve 125 provides redundancy	

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TABLE 10.4.9-4 (SHEET 27 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
58	AFW line check valve 125	Same as item 57	58A. All but AFW HELB	58A. Fails closed	58A. Same as item 57A	58A. None - Same as item 45B	
			58B. AFW HELB	58B. Fails open	58B. None	58B. None - Check valve 121 provides redundancy.	
59	AFW line check valve 122	Same as item 57, except for SG 2 and for control building overpressure protection	59A. All but AFW HELB	59A. Fails closed	59A. Same as item 46B, except none for mode 7	59A. None - Same as item 46B	
			59B. AFW HELB	59B. Fails open	59B. None	59B. None - Check valve 126 provides redundancy.	
60	AFW line check valve 126	Same as item 59	60A. All but AFW HELB	60A. Fails closed	60A. Same as item 59A	60A. None - Same as item 46B	
			60B. AFW HELBA	60B. Fails open	60B. None	60B. None - Check valve 122 provides redundancy.	
61	AFW line check valve 124	Same as item 59, except for SG 3	61A. All but AFW HELB	61A. Fails closed	61A. Same as item 47B, except none for mode 7	61A. None - Same as item 47B	
			61B. AFW HELB	61B. Fails open	61B. None	61B. None - Check valve 128 provides redundancy.	
62	AFW line check valve 128	Same as item 61	62A. All but AFW HELB	62A. Fails closed	62A. Same as item 61A	62A. None - Same as item 47B	
			62B. AFW HELB	62B. Fails open	62B. None	62B. None - Check valve 124 provides redundancy.	

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TABLE 10.4.9-4 (SHEET 28 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
63	AFW line check valve 123	Same as item 57, except for SG 4	63A. All but AFW HELB	63A. Fails closed	63A. Same as item 48B, except none for mode 7	63A. None - Same as item 48B	
			63B. AFW HELB	63B. Fails open	63B. None	63B. None - Check valve 127 provides redundancy.	
64	AFW line check valve 127	Same as item 63	64A. All but AFW HELB	64A. Fails closed	64A. Same as item 63A	64A. None - Same as item 48B	
			64B. AFW HELB	64B. Fails open	64B. None	64B. None - Check valve 123 provides redundancy.	
65	TDP steam line drain valve HV-5178, normally closed MOV, not train aligned	Opens manually from QMCB or automatically to drain excessive amounts of condensate from TDP steam supply line	Modes 3, 4, 5, and 6	65A. Fails open	65A. Position light on QMCB	65A. None - Possible degraded TDP P4-001 performance, but MDPs are available.	
				65B. Fails closed	65B. Position light on QMCB	65B. None - Condensate will drain via FO-15133. Also, turbine accepts water slugs.	
66	TDP steam line drain isolation valve HV-5181, normally open, failed open solenoid valve, not train aligned	Isolates TDP steam supply line from non-Q portion of drain line to condenser manually from QMCB	Modes 3, 4, 5, and 6	66A. Fails open	66A. Position light on QMCB	66A. None - Normal failed position, also same as item 65A	
				66B. Fails closed	66B. Position light on QMCB	66B. None - Drain not operable, but turbine accepts water slugs.	

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TABLE 10.4.9-4 (SHEET 29 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
67	System components powered from essential ac bus: HV-5119 (item 7), HV-5118 (item 8), MDP P4-003 (item 10), and MDP P4-002 (item 11)	Refer to items 7, 8, 9, and 10 as indicated	Mode 8	Both MDPs fail to operate and the HVs remain in position (normally closed)	Status lights indicate loss of all ac power, plus all pump valve indicators remain dark	None - TDP P4-001 (item 12) provides 100% of AFW requirements. All valves, controls, etc., associated with the TDPs are dc powered from emergency battery supply.	See also items 9, 12, 13, 14, and 15 for discussion of valves associated with operation of TDP P4-100.
68	Chemical injection system isolation valve HV-5194 (normally closed, fail closed air-operated valve, non-1E)	Provides isolation of SG 1 from chemical injection system by remote-manual control from QPCP	All	68A. Fails closed or fails to open upon command 68B. Fails open or fails to close upon command	68A. Position light on QPCP 68B. Same as item 68A	68A. None - SG chemistry control not required for safe shutdown. 68B. None - Check valve 133 provides isolation.	
69	Chemical injection system isolation valve HV-5195 (normally closed, fail closed air-operated valve, non-1E	Same as item 68 except for SG 2	All	69A. Fails closed or fails to open upon command 69B. Fails open or fails to close upon command	69A. Position light on QPCP 69B. Same as item 69A	69A. None - Same as item 68A 69B. None - Check valve 134 provides isolation	
70	Chemical injection system isolation valve HV-5196 (normally closed, fail closed air-operated valve, non-1E	Same as item 68 except for SG 3	All	70A. Fails closed or fails to open upon command 70B. Fails open or fails to close upon command	70A. Position light on QPCP 70B. Same as item 70A	70A. None - Same as item 68A 70B. None - Check valve 136 provides isolation.	

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Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
71	Chemical injection system isolation valve HV-5197 (normally closed, fail closed air-operated valve, non-1E	Same as item 68 except for SG 4	All	71A. Fails closed or fails to open upon command	71A. Position light on QPCP	71A. None - Same as item 68A	
				71B. Fails open or fails to close upon command	71B. Same as item 71A	71B. None - Check valve 135 provides isolation.	
72	Check valve 133 in chemical injection line to SG 1	Prevents loss of AFW through failure of the chemical injection system	All	72A. Fails closed	72A. None	72A. None - Same as item 68A	
				72B. Fails open	72B. None	72B. None - HV-5122 and HV-5139 can be closed to prevent loss of AFW inventory.	
73	Check valve 134 in chemical injection line to SG 2	Same as item 72	All	73A. Fails closed	73A. None	73A. None - Same as item 68A	
				73B. Fails open	73B. None	73B. None - HV-5125 and HV-5132 can be closed to prevent loss of AFW inventory.	
74	Check valve 136 in chemical injection line to SG 3	Same as item 72	All	74A. Fails closed	74A. None	74A. None - Same as item 68A	
				74B. Fails open	74B. None	74B. None - HV-5127 and HV-5134 can be closed to prevent loss of AFW inventory.	

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TABLE 10.4.9-4 (SHEET 31 OF 31)

Item No.	Description of Component	Safety Function	Plant Operating Mode	Failure Mode(s)	Method of Failure Detection	Failure Effect on System Safety Function Capability	General Remarks
75	Check valve 135 in chemical injection line to SG 4	Same as item 72	All	75A. Fails closed	75A. None	75A. None - Same as item 68A	
				75B. Fails open	75B. None	75B. None - HV-5120 and HV-5137 can be closed to prevent loss of AFW inventory.	

a. P&IDs - 1X4DB159-2, rev 8; 1X4DB161-1, rev 8; 1X4DB161-2, rev 8; 1X4DB161-3, rev 8; 1X4DB168-3, rev 10.

Logic Diagrams - 1X5DN108-1, rev 3, 1X5DN109-1, rev 1; 1X5DN109-2, rev 0; 1X5DN117-1, rev 2; 1X5DN120-1, rev 2; 1X5DN120-2, rev 3; 1X5DN120-3, rev 1; 1X5DN120-4, rev 2; 1X5DN120-5, rev 2; 1X5DN120-6, rev 1; 1X5DN121-1, rev 2; 1X5DN121-2, rev 2; 1X5DN122, rev 2; 1X5DN122-2, rev 2.

b. Mode 1, plant startup; mode 2, plant cooldown; mode 3, loss of normal feedwater coincident with loss of offsite power (LOP); mode 4, auxiliary feedline rupture coincident with LOP; mode 5, HELB in TDP discharge coincident with LOP; mode 6, safety injection coincident with LOP; mode 7, power generation; and mode 8, loss of all ac power.

c. In general, valve and other indicators will illuminate either on the main control board or on the shutdown panel, but not on both simultaneously, depending on the position of the transfer switch.

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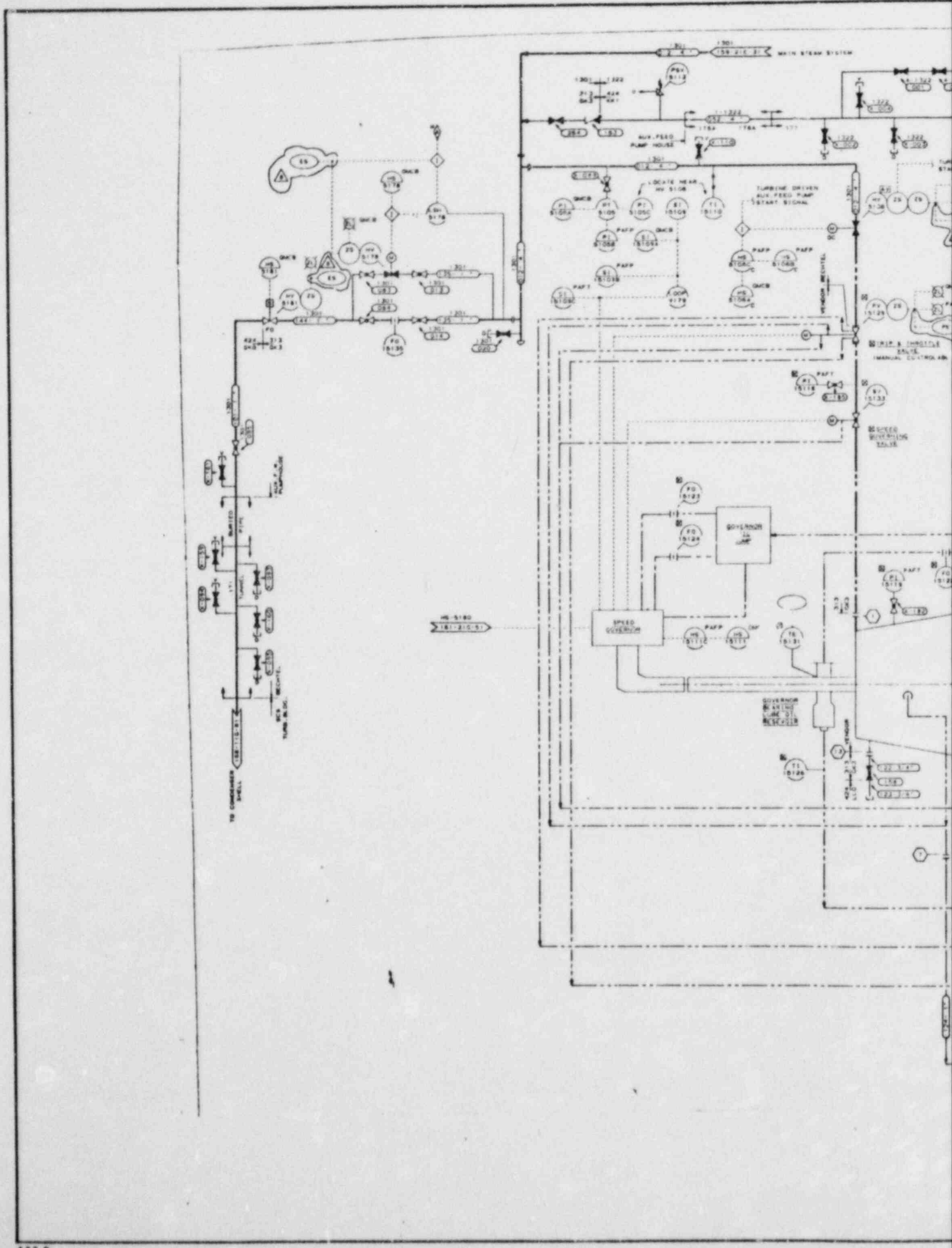
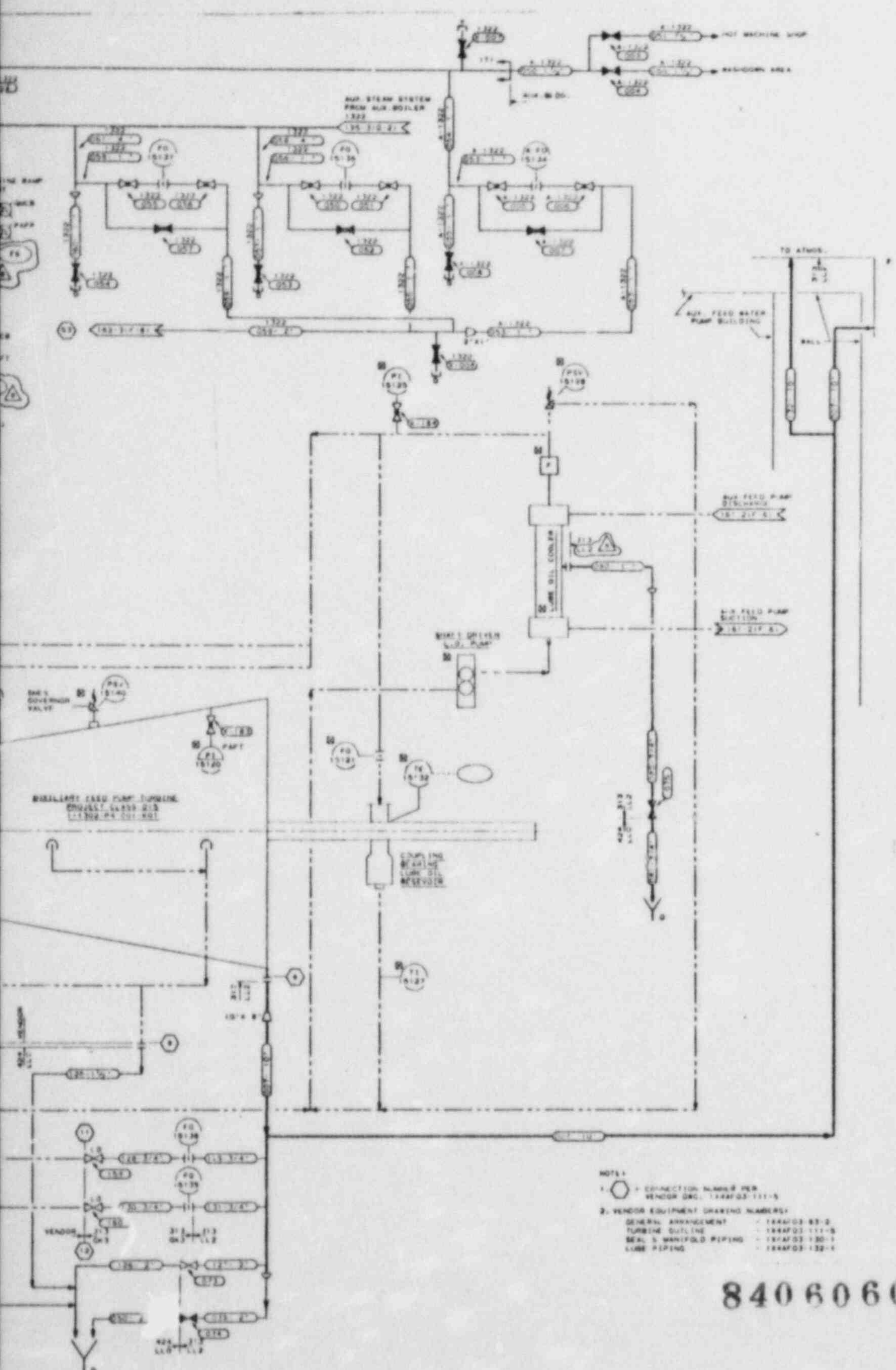

MAIN STEAM SYSTEM
AUX. FEED PUMP HOUSE
LOCATE NEAR HV 5108
TURBINE DRIVEN AUX. FEED PUMP START SIGNAL
VENDOR
TRIP & THROTTLE VALVE (MANUAL CONTROLLER)
SPEED GOVERNING VALVE
GOVERNOR
SPEED GOVERNOR
GOVERNOR BEARING LUBE OIL RESERVOIR
BURIED PIPE
TO CONDENSER SHELL

Also Available On Aperture Card



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1X4DB161-3 REV. 8

Georgia Power — VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	AFW PROCESS AND INSTRUMENTATION DIAGRAM
	FIGURE 10.4.9-1 (SHEET 2 OF 2)

LIST OF TABLES (Continued)

11.5.5-3 Conditions of Service for Post-Accident Radiation Monitors

11.5.5-4 Alarm Setpoints for Post-Accident Radiation Monitors

LIST OF FIGURES

11.2.1-1 Waste Processing System - Liquid

11.2.2-1 LWPS Process Flow Diagram

11.3.2-1 Waste Processing System - Gas

11.4.2-1 Radwaste Volume Reduction and Solidification System P&ID

11.4.2-2 Radwaste Volume Reduction System P&ID

11.4.2-3 Backflushable Filter System P&ID

11.4.2-4 Schematic of Liquid/Slurry Drumming Operation

11.4.2-5 Schematic of Volume Reduction Operation

11.4.2-6 Schematic of Cartridge Filter Solidification Operation at Radwaste Solidification Building

11.4.2-7 Schematic of Dry Product Drumming Operation

11.5.2-1 Radiation Monitoring System Block Diagram

11.5.2-2 Safety Subsystem Block Diagram

11.5.2-3 PERMS Communication Console

11.5.2-4 Three-Channel Airborne Monitoring Assembly

11.5.2-5 Monitoring Locations for Liquid Release Pathways

11.5.2-6 PERMS Normal Gaseous Effluent Release Pathway

2. The drum is prelined with cement with an integral cavity to accept a filter. Polymer is added after the filter is positioned.

Section 11.2 provides the bases for the quantity of evaporator concentrates and chemical drain wastes, while reference 1 provides the bases for the remaining quantities presented in table 11.4.2-4.

Section 11.1 provides the bases for the quantity of primary and secondary resins. Section 11.2 provides the basis for the quantity of evaporator concentrates and chemical drain wastes, while reference 1 provides the basis for the remaining quantities presented in table 11.4.2-4. The tankage in the solid waste management system as presented in table 11.4.2-7 provides sufficient holdup capacity for a minimum of 30 days.

11.4.2.2 Component Description

Codes and standards applicable to the solid waste management system are listed in table 3.2.2-1. The solid waste management system is housed within buildings designed to meet the seismic requirements of Regulatory Guide (RG) 1.143. Conformance with RG 1.143 is to the extent specified in section 1.9.

Solid waste management system equipment design parameters are presented in table 11.4.2-7. The following is a functional description of the major system components:

A. Spent Resin Transfer Tanks

Provide for transfer of spent resins (liquid waste processing system and steam generator blowdown system) from the radwaste transfer building to the radwaste solidification building.

B. Spent Resin Transfer Pumps

Provide the motive flow to transfer spent resin between spent resin transfer tanks and to the spent resin waste feed tanks.

C. Backflushable Filter Crud Transfer Tank

Provides holdup capacity for the backflushable filter crud between the backflushable filter crud tank in the auxiliary building and the spent resin waste feed tank in the radwaste solidification building.

D. Backflushable Filter Crud Transfer Pump

Provides the motive flow to transfer crud from the auxiliary building to the spent resin waste feed tank in the solidification building.

E. Evaporator Concentrates Waste Feed Tanks

Provide for sampling, chemistry control, and feed of chemical drain tank wastes, concentrated wastes from the liquid waste evaporators, and boron recycle evaporator to either the liquid/slurry waste solidification system or the volume reduction system.

F. Spent Resin Waste Feed Tanks

Provide for sampling, chemistry control, and feed of spent resins from the liquid waste processing system, the steam generator blowdown system, or the condensate polishing demineralizer system to either the liquid/slurry waste solidification system or the volume reduction system.

G. Caustic Addition Tank and Metering Pumps

Provide chemistry control to the evaporator concentrates tank, spent resin waste feed tanks, and volume reduction scrub loop.

H. Decant Station

Provides a batch tank with the capability for dewatering spent radioactive resins and backflushable filter crud and maintaining a homogeneous slurry. A progressive cavity, positive displacement pump is provided for decanting excess water from the slurry, and a positive displacement metering pump is provided for accurate transfer to the liquid/slurry drumming station for solidification.

I. Liquid/Slurry Waste Drumming Station

Receives 55-gal drums containing a predetermined quantity of cement and a mixing weight and injects into the drums a predetermined quantity of slurry from the decant station and/or a predetermined quantity of concentrated wastes from the evaporator concentrates waste feed tanks. The drum is tumbled for proper mixing of the contents to complete the solidification process.

12.3.2 SHIELDING

The bases for the nuclear radiation shielding and the shielding configurations are discussed in this subsection.

12.3.2.1 Design Objectives

The objective of the plant radiation shielding is to reduce personnel and population exposures, in conjunction with a program of controlled personnel access to and occupancy of radiation areas, to levels that are within the dose standards of 10 CFR 50 and are as low as reasonably achievable (ALARA) within the dose standards of 10 CFR 20. Shielding and equipment layout and design are considered in ensuring that exposures are kept ALARA during anticipated personnel activities in areas of the plant containing radioactive materials, utilizing the design recommendations given in Regulatory Guide 8.8, paragraph C.3, where practicable.

Four plant conditions are considered in the nuclear radiation shielding design:

A. Normal, full-power operation.

B. Shutdown operation.

C. Spent resin transfer (radwaste areas and radwaste portion of the auxiliary building only).

D. Emergency operations (for required access to safety-related equipment).

The shielding design objectives for the plant during normal operation (including anticipated operational occurrences), for shutdown operations, and for emergency operations are listed below:

A. To ensure that radiation exposure to plant operating personnel, contractors, administrators, visitors, and approximate site boundary occupants are ALARA and within the limits of 10 CFR 20.

B. To ensure sufficient personnel access and occupancy time to allow normal anticipated maintenance, inspection, and safety-related operations required for each plant equipment and instrumentation area.

C. To reduce potential equipment neutron activation and to mitigate the possibility of radiation damage to materials.

D. To provide sufficient shielding for the control room so that for design basis accidents (DBAs) the direct dose plus the inhalation dose (calculated in chapter 15) will not exceed the limits of 10 CFR 50, Appendix A, General Design Criterion 19.

12.3.2.2 General Shielding Design

Shielding is provided to attenuate direct radiation through walls and penetrations and scattered radiation to less than the upper limit of the radiation zone for each area shown in figure 12.3.1-1. General locations of the plant areas and equipment discussed in this subsection are shown in the general arrangement drawings of section 1.2. Design criteria for penetrations are consistent with the recommendations of Regulatory Guide 8.8 and are discussed in paragraph 12.3.1.1.2.

The material used for most of the plant shielding is ordinary concrete with a bulk density of approximately 137 lb/ft^3. 7
Whenever poured-in-place concrete has been replaced by concrete blocks, design ensures protection on an equivalent shielding basis as determined by the density of the concrete block selected. Water is used as the primary shield material for areas above the spent fuel storage area.

12.3.2.2.1 Containment Shielding Design

During reactor operation, the containment protects personnel occupying adjacent plant structures and yard areas from radiation originating in the reactor vessel and primary loop components. The concrete containment wall and the reactor vessel and steam generator compartment shield walls reduce radiation levels outside the containment to less than 0.25 mrem/h from sources inside containment. The containment wall is a reinforced, prestressed concrete structure completely 3
surrounding the nuclear steam supply system. The wall and dome are of a minimum 3 ft 9 in. thickness

For DBAs, the containment shield and the control room shielding reduce the plant radiation intensities from fission products inside the containment to acceptable emergency levels, as defined by 10 CFR 50, Appendix A, General Design Criterion 19, for the control room. (See paragraph 12.3.2.2.7.)

superintendents and supervisors with regard to activities at VEGP. The supervisor-operations reports to the superintendent-operations and assists in his responsibilities. The supervisor-operations shall possess a senior operators license.

The shift supervisor is responsible for seeing that plant operations are conducted in accordance with appropriate standing orders, plant operating procedures, and technical specifications. The shift supervisor's principal responsibility is ensuring safe plant operation during his assigned shift as addressed in the requirements of item I.A.1.2 of NUREG-0737. The shift supervisor shall possess a senior operators license.

Under the supervision of the shift supervisor, the shift foreman shall assist the shift supervisor with his duties and responsibilities and shall possess a senior operators license.
In addition, he keeps a record of all shift activities and
establishes unit load as directed by the load dispatcher or as
emergency conditions dictate. Reporting to the shift supervisor 3
or shift foreman are the plant operators, assistant plant
operators, and plant equipment operators.

The shift technical advisor reports to the shift supervisor
during emergencies and acts to provide both perspective in
assessment of plant conditions and dedication to the safety of
the plant. During normal operations, the shift technical 7
advisor will report to the senior shift technical advisor, who
reports to the superintendent-operations. The shift technical 3
advisor position meets the intent of NUREG-0660, as clarified by
NUREG-0737, item I.A.1.1. The shift technical advisor position
may be eliminated if the qualifications of the shift supervisor
are upgraded. Section 13.2 describes shift technical advisor
training, and subsection 13.1.3 describes shift technical
advisor qualifications.

Assistant plant operators monitor the status and make
adjustments as needed to maintain control of the various plant
processes. Most of their duties are confined to the control
room, although they perform routine inspections in other areas
of the plant. The operating crew may make radiation and
containment surveys within the plant. (In addition to the
control room personnel, a health physics technician is on duty
during plant operations.) The Technical Specifications state 3
the shift manning requirements for all modes of operation.

The succession to responsibility for overall operation of the plant and the authority to issue standing or special orders, in the event of absences, incapacitation of personnel, or other emergencies, shall be as follows:

A. Plant manager.

B. Assistant plant manager.

C. Superintendent-operations.

D. Senior reactor operator-licensed superintendent as designated by the plant manager.

E. Operations supervisor.

F. Shift supervisor.

G. Shift foreman.

13.1.2.2.3 Engineering, Health Physics, Laboratory, and Maintenance Supervision

The superintendent-plant engineering and services reports to an assistant plant manager and supervises the engineering staff. Reporting to him are the plant engineering supervisors and a fire protection specialist. (See subsection 9.5.1 for description of fire protection program.) The functions of his staff are to monitor plant performance, provide technical support for plant operation, provide writing support, and interface with other groups to ensure proper engineering support for plant operations. The plant engineering supervisors report to the superintendent-plant engineering and services and aid in his duties and responsibilities. The plant engineering supervisors normally determine when to call consultants and contractors for dealing with complex problems beyond the scope of the company's staff. This position, therefore, corresponds closely to that identified as "engineer in charge" by ANSI 18.1-1971.

The health physics superintendent reports to an assistant plant manager and is responsible for the radiation protection program. He verifies that waste shipments or releases of radioactivity from the plant comply with federal, state, and local regulations. Also he ensures that appropriate monitoring devices and protective clothing are available. He is responsible for radiation monitoring devices used by personnel entering the plant and for the maintenance of all required radiation exposure records of plant support and visiting personnel.

lectures pertinent to that section. Any section grade less than 80 percent but greater than 70 percent will require attendance at requalification lectures pertinent to that section within 12 months from the examination date.

An overall grade of less than 80 percent correct on an annual written examination, a section grade of less than 70 percent, or an unsatisfactory performance evaluation will require an operator or senior operator to be relieved of licensed duties so that he may participate in an accelerated requalification program. This will be documented with written notification to the individual and to the appropriate department head. An operator or senior operator who has been relieved may return to his licensed duties following completion of accelerated requalification training in areas where he was weak, including a grade of not less than 80 percent correct on examinations given over such areas.

C. Lecture Examinations

Written examinations will be given to individuals who received less than 80 percent on the pertinent section of the annual examination covering material presented in the program lecture series. A grade of less than 80 percent on any required lecture series examination shall require a licensed operator to be rescheduled for additional instruction and testing on that subject within the next 3 months. The 3 months may be extended by the length of time of any refueling outage falling within that period. Lectures presented for information of major upcoming events and/or plant modifications may be documented by attendance record.

13.2.1.3.3 Instructor Qualification and Requalification Program

The qualification and requalification program for instructors as described below includes requirements of NUREG-0737, item I.A.2.3.

A. Initial Qualification

The training department will use a qualification
checklist to establish the initial qualification
requirements for all new instructors and for 7
instructors whose teaching responsibilities are going
to significantly change. These special qualification
checklists shall include the following requirements:

1. The instructor's supervisor will review the employee's background and establish qualification goals and qualification deadlines. Besides other qualifications, the following minimum goals will be established:

   a. For new instructors who do not have a classroom teaching background, the employee will have to present a lecture to a group of experienced instructors before lecturing plant students. The company's instructor course as a minimum shall satisfy this requirement.

   b. For instructors who teach licensed students, before the new instructor conducts a comprehensive program, the employee will meet NRC requirements by obtaining the appropriate certification. This requirement does not prevent noncertified members of the training staff from teaching licensed personnel in the instructor's area of expertise.

2. The superintendent-nuclear training shall approve the qualification checklist at the time of issue and shall approve the final qualification of each instructor. 7

Before these instructors teach integrated response, transients, and simulator courses to licensed operators, they will demonstrate their competence by successful completion of a senior reactor operator examination. The qualifying examination may be administered by GPC until the NRC is able to fully support item I.A.3.1 of NUREG-0737 requirement for VEGP.

B. Certified Instructor Requalification

Licensed or certified instructors will complete the requirements of the licensed operator requalification program annually by teaching, performing, or taking examinations for each required element of the requalification program. Conducting simulator training will be considered the same as supervising license duties in the plant control room. If an instructor is not involved in the preceding requalification program, he may renew his certification by preparing for and taking or conducting a comprehensive audit examination. Instructors who fail to complete these annual instructor requalification requirements will not teach integrated plant response to licensed students until they renew their certification.

TABLE 13.2.1-1 (SHEET 1 OF 3)

LICENSED OPERATOR ONSITE TRAINING SYLLABUS - PERSONNEL WITH COMMERCIAL WESTINGHOUSE REACTOR LICENSE OR NRC CERTIFICATION (ANY SUPERVISOR, STAFF, OR OPERATOR POSITION)

Description	Type	Minimum Integral Duration
Nuclear power plant theory Fundamentals of reactor theory General core design Radiological safety and radiation hazards	Classroom or self-study	1 week
VEGP systems and procedures Procedures for design and operating changes Reactor coolant system mechanical design Reactivity control mechanisms and indications Reactor safety systems Emergency and reserve systems Containment and shielding Radiation monitoring system Auxiliary systems Radioactive waste	Classroom or self-study	1 week
VEGP license and technical specifications License conditions and limitations Design and operating limitations Procedures for design and operating changes	Classroom	1 week

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TABLE 13.2.1-1 (SHEET 2 OF 3)

Description	Type	Minimum Integral Duration
Fuel handling and core alterations Facilities and procedures	Classroom	3 days
Control room operations General operating characteristics Specific operating characteristics Load changes Operating limitations Standard, emergency, and plant procedures Control manipulation Mitigating core damage Incore instrumentation Excore instrumentation Vital instrumentation Primary chemistry Radiation monitoring Gas generation Transients	Simulator and classroom[a]	4 weeks (including 80 VEGP simulator h)
VEGP walkthrough		
Previous senior reactor operator license	VEGP	3 weeks
Previous reactor operator license	VEGP	3 weeks
Upgrade to senior reactor operator from reactor operator license or certification	Senior reactor operator on-the-job training at an operating reactor (similar plant)[c]	3 months[b]

TABLE 13.2.1-1 (SHEET 3 OF 3)

Description	Type	Minimum Integral Duration
Review and audit		1 week

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a. All topics are classroom and simulator training.

b. Not required for cold license applicants.

c. After initial fuel load, shift assignment will be made at VEGP. 4 7

TABLE 13.2.1-2 (SHEET 1 OF 3)

LICENSED OPERATOR ONSITE TRAINING SYLLABUS - PERSONNEL WITH COMMERCIAL REACTOR LICENSE OR NRC CERTIFICATION (ANY SUPERVISOR, STAFF, OR OPERATOR POSITION)

Description	Type	Minimum Integral Duration
Nuclear power plant theory Fundamentals of reactor theory General core design Radiological safety and radiation hazards	Classroom or self-study	1 week
VEGP systems and procedures Procedures for design and operating changes Reactor coolant system mechanical design Reactivity control mechanisms and indications Reactor safety systems Emergency and reserve systems Containment and shielding Radiation monitoring system Auxiliary systems Radioactive waste	Classroom or self-study	4 weeks
VEGP license and technical specifications License conditions and limitations Design and operating limitations Procedures for design and operating changes	Classroom	1 week

TABLE 13.2.1-2 (SHEET 2 OF 3)

Description	Type	Minimum Integral Duration
Fuel handling and core alterations Facilities and procedures	Classroom	3 days
Control room operations General operating characteristics Specific operating characteristics Load changes Operating limitations Standard, emergency, and plant procedures Control manipulation Mitigating core damage Incore instrumentation Excore instrumentation Vital instrumentation Primary chemistry Radiation monitoring Gas generation Transients	Simulator and classroom[a]	5 weeks (including 100 VEGP simulator h)
VEGP walkthrough		
Previous senior reactor operator license	VEGP	5 weeks
Previous reactor operator license	VEGP	5 weeks
Upgrade to senior reactor operator from reactor operator license or certification	Senior reactor operator on-the-job training at an operating reactor (similar plant)[c]	3 months[b]

4
7
4

TABLE 13.2.1-2 (SHEET 3 OF 3)

Description	Type	Minimum Integral Duration
Review and audit		1 week

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a. All topics are classroom and simulator training.

b. Not required for cold license applicants.

c. After initial fuel load, shift assignment will be made at VEGP. 4 7

TABLE 13.2.1-3 (SHEET 1 OF 3)

LICENSED OPERATOR ONSITE TRAINING SYLLABUS - PERSONNEL WITH 1 YEAR OF MILITARY PWR EXPERIENCE AS A REACTOR OPERATOR, ENGINEERING WATCH SUPERVISOR, OR ENGINEERING OFFICER (ANY SUPERVISOR, STAFF, OR OPERATOR POSITION)

Description	Type	Minimum Integral Duration	
Nuclear power plant theory Fundamentals of reactor theory General core design Radiological safety and radiation hazards	Classroom or self-study	3 weeks	7
VEGP systems and procedures Procedures for design and operating changes Reactor coolant system mechanical design Reactivity control mechanisms and indications Reactor safety systems Emergency and reserve systems Containment and shielding Radiation monitoring system Auxiliary systems Radioactive waste	Classroom or self-study	4 weeks	7 4
VEGP license and technical specifications License conditions and limitations Design and operating limitations	Classroom	1 week	

TABLE 13.2.1-3 (SHEET 2 OF 3)

Description	Type	Minimum Integral Duration	
Procedures for design and operating changes			
Fuel handling and core alterations Facilities and procedures	Classroom	3 days	
Control room operations General operating characteristics Specific operating characteristics Load changes Operating limitations Standard, emergency, and plant procedures Control manipulation Mitigating core damage Incore instrumentation Excore instrumentation Vital instrumentation Primary chemistry Radiation monitoring Gas generation Transients	Simulator and classroom[a]	5 weeks (including 100 VEGP simulator h)	4
VEGP walkthrough	VEGP	5 weeks	
On-the-job training	Shift assignment at an operating commercial reactor (similar plant)[c]	3 months[b]	7 4

TABLE 13.2.1-3 (SHEET 3 OF 3)

Description	Type	Minimum Integral Duration
Review and audit		1 week

---

a. All topics are classroom and simulator training.

b. Not required for cold license applicants.

c. After initial fuel load, shift assignment will be made at VEGP. 4 7

TABLE 13.2.1-4 (SHEET 1 OF 3)

LICENSED OPERATOR ONSITE TRAINING SYLLABUS - PERSONNEL WITH DEGREE IN ENGINEERING OR APPLICABLE SCIENCES (ANY SUPERVISOR, STAFF, OR OPERATOR POSITION)

Description	Type	Minimum Integral Duration
Nuclear power plant theory Fundamentals of reactor theory General core design Radiological safety and radiation hazards	Classroom or self-study	5 weeks 7
VEGP systems and procedures Procedures for design and operating changes Reactor coolant system mechanical design Reactivity control mechanisms and indications Reactor safety systems Emergency and reserve systems Containment and shielding Radiation monitoring system Auxiliary systems Radioactive waste	Classroom or self-study	6 weeks 7
VEGP license and technical specifications License conditions and limitations Design and operating limitations	Classroom	1 week

4

TABLE 13.2.1-4 (SHEET 2 OF 3)

Description	Type	Minimum Integral Duration
Procedures for design and operating changes		
Fuel handling and core alterations Facilities and procedures	Classroom	3 days
Control room operations General operating characteristics Specific operating characteristies Load changes Operating limitations Standard, emergency, and plant procedures Control manipulation Mitigating core damage Incore instrumentation Excore instrumentation Vital instrumentation Primary chemistry Radiation monitoring Gas generation Transients	Simulator and classroom[a]	5 weeks (including 100 VEGP simulator h)

4

TABLE 13.2.1-4 (SHEET 3 OF 3)

Description	Type	Minimum Integral Duration	
VEGP walkthrough	VEGP	5 weeks	
On-the-job training	Shift assignment at an operating reactor (similar plant)[c]	3 months[b]	7 4
Review and audit		1 week	

a. All topics are classroom and simulator training.

b. Not required for cold license applicants. 7

c. After initial fuel load, shift assignment will be made at VEGP. 4

TABLE 13.2.1-5 (SHEET 1 OF 2)

LICENSED OPERATOR ONSITE TRAINING SYLLABUS (PLANT OPERATOR OR ASSISTANT PLANT OPERATOR)

Description	Type	Minimum Integral Duration
Nuclear power plant theory Mathematics Fundamentals of reactor theory General core design Reactor and health physics and radiological safety Materials Thermodynamics Fluid mechanics Heat transfer	Classroom	12 weeks[a]
VEGP systems for electrical and reactor control (including procedures) Reactor coolant system mechanical design Reactivity control mechanisms and indicators Reactor safety systems Emergency and reserve systems Containment shielding Radiation monitoring systems Auxiliary systems	Classroom and VEGP tours	12 weeks[a]
Control room operations General operating characteristics Load changes Operating limitations	Simulator and classroom[b]	6 weeks (including 100 VEGP simulator h)

4

TABLE 13.2.1-5 (SHEET 2 OF 2)

Description	Type	Minimum Integral Duration
Standard, emergency, and plant procedures		
Control manipulations		
Mitigating core damage		
Incore instrumentation		
Excore instrumentation		
Vital instrumentation		
Primary chemistry		
Radiation monitoring		
Gas generation		
Transients		
On-the-job training	Shift assignment at an operating reactor (similar plant)[d]	3 months[c]
Review, audit, and VEGP walkthrough	Classroom, simulator, VEGP, and self-study	6 weeks

4

7

4

a. Nuclear power plant theory and VEGP systems for electrical and reactor control contain over 900 h of college level education and are considered the equivalent of 60 semester h.

b. All topics are classroom and simulator training.

c. Not required for cold license applicants.

d. After initial fuel load, shift assignment will be made at VEGP.

4 7

program are completed and selected elements of the continuing program are addressed as appropriate. This special program may include exemption testing to ensure qualification.

Foremen will receive the following training.

Curriculum Outline	Approximate Duration
Plant administrative controls for supervisors	3 days
Labor relations	3 days
New supervisor (or leadership)	1 week

E. Continuing Foremen Training

Foremen will normally attend continuing training on a quarterly basis until all programs from the VEGP health physics/chemistry schools are completed. 7

F. Health Physics/Chemistry Supervisor Qualifications and Training

The health physics/chemistry supervisors will have the qualifications required of health physics/chemistry foremen and will normally attend a similar continuing training program.

G. Incumbents and New Employees

Personnel with experience that exceeds Nuclear Regulatory Commission (NRC) commitments may fill a position in the career path provided that the health physics/chemistry superintendent certifies that the employee's experience qualifications exceed the position requirements. The training department may also accept prior training or experience to fill specific course requirements.

13.2.2.1.2 Instrumentation and Controls Training Program

A. Initial Training

New employees assigned to perform instrumentation and controls maintenance will complete this initial training program before being assigned to perform independent trouble shooting.

Curriculum Outline	Approximate Duration	
General employee badge and health physics training	6 h	
Respirator training	2 h	
Industrial safety and first aid	4 h	
New employee fire training	2 h	
New employee quality assurance training	1 h	
General pressurized water reactor systems and procedures	1 week	
General balance of plant systems and procedures	1 week	
Mechanical/electrical skills for instrumentation and controls	1 week	
Mitigating core damage (commensurate with responsibilities)	4 h	4

B. Continuing Training

After completing initial qualification, instrumentation and controls personnel will usually attend each quarter a program from the following instrumentation and controls schools.

Curriculum Outline	Approximate Duration
Analog electronics	1 week
Digital electronics	1 week
Test equipment	1 week
Process instrumentation	1 week
Process control systems	1 week

C. Annual Requalification Training or Exemption Testing

Instrumentation and controls technicians will complete annual requalification training or exemption testing to make them aware of and review important changes made to plant emergency and disaster, radiation protection, security, and respirator procedures.

D. Initial Foremen Training (and Student Engineers)

Normally, foremen will have progressed from the initial qualification program through most of the continuing courses before being selected for their position. For personnel who do not follow this path, a special qualification program will be designed to ensure that all elements of the initial qualification

TABLE 13.2.2-1 (SHEET 2 OF 2)

Simulator and Classroom Topics	
Natural circulation and core cooling Abnormal operating instructions Introduction to emergency operating instructions	Power operations leading to reactor trips and recovery
Health physics review Radiation monitoring Radwaste disposal	Power operations with malfunctions leading to controlled shutdown
Condition II and III events Emergency operating instructions	Reactor trip and recovery with malfunctions
Condition II and III events Abnormal operating instructions Emergency operating instructions	Major steam plant failures; reactor coolant pump failures; partial and complete loss of flow
Condition II and III events Alternative cooling techniques Core recriticality	Major plant equipment failures; natural circulation cooldown
Condition IV events Loss-of-coolant accident Reactor coolant system leak	Power operations with condition IV faults
Condition IV events Steam generator tube leak/ rupture	Power operations with condition IV faults
Condition IV events and mitigation Extreme emergency operating instructions	Power operations with condition IV faults; main steam line break
Condition IV events and mitigation Inadvertent safety injection	Power operations with condition IV faults; anticipated transient without trip
Condition IV events and mitigation Loss of auxiliary feedwater	Power operations with condition IV faults; Three Mile Island accident

during simulated reactor coolant cold leg injection.

3. The centrifugal charging pump cold leg injection line throttling valves are properly positioned, and injection branch line flows and pump runout flowrates are verified.

4. The safety injection pump cold and hot leg injection line throttling valves are properly positioned, and injection branch line flows and pump runout flowrates are verified.

5. The boron injection tank inlet and outlet valves are operated under conditions of maximum differential pressure, and operation is verified.

6. Safety injection pump room cooler fan and safety injection pump interlocking is verified during pump operation.

D. Acceptance Criteria

1. SIS components respond to normal control and interlock signals and to simulated safety signals.

2. The centrifugal charging pumps, safety injection pumps, and their associated system performance characteristics are within design specifications.

3. Centrifugal charging pump and safety injection miniflowrates are within design specifications.

4. The centrifugal charging pump cold leg injection line throttling valves are positioned to provide branch line flows and pump runout flowrates within design specifications.

5. The safety injection pump cold and hot leg injection line throttling valves are positioned to provide branch line flows and pump runout flowrates within design specifications.

6. The time required for the centrifugal charging pumps and safety injection pumps to reach rated flow conditions is within design specifications.

7. Boron injection tank inlet and outlet valve response times are within design specifications.

8. Safety injection pump and room cooler fan interlock operates.

14.2.8.1.23 Safety Injection Check Valve Preoperational Test

A. Objectives

1. To demonstrate the operability of the various safeguard systems injection line check valves which are expected to be at higher than ambient temperature when the RCS is at normal operating temperature.

2. To demonstrate the integrity of the accumulator and safeguard systems injection line check valves by performing a backleakage check.

3. To demonstrate that each accumulator motor-operated isolation valve opens on reset of the pressurizer pressure (P-11) manual block.

B. Prerequisites

1. Required component testing, preoperational testing, and instrument calibrations are complete.

2. Required electrical power supplies and control circuits are energized and operational.

3. RCS pressure and temperature are established near the normal operating values, and hot functional testing is in progress. 7

C. Test Method

1. Flow from a safety injection pump is directed through the SIS test line to the RCS, and the accumulator and injection line check valve operability is verified.

2. SIS test line valves are aligned to provide a leakoff path from each of the accumulator and injection line primary and backup check valves, and valve backleakage is verified.

3. Accumulator motor-operated isolation valve opening is verified on reset of the pressurizer pressure (P-11) manual block.

C. Test Method

1. The ability of the emergency lighting system is verified by simulating a loss of the normal and essential lighting and observing that the emergency system automatically activates.

2. Illumination levels and operation times will be verified.

D. Acceptance Criteria

The performance of the emergency lighting system tested is in accordance with the design criteria and subsections 8.3.1 and 9.5.3.

14.2.8.1.78 Offsite Communication System Preoperational Test

A. Objective

To demonstrate operation of the offsite communication system.

B. Prerequisites

1. Construction acceptance testing is complete.

2. Support systems are available.

C. Test Method

1. Verify operation of the plant telephone branch exchange (PABX) system to provide adequate communication between onsite stations.

2. Verify operation of the PABX system in relation to the following offsite communication systems:

   a. Hotline to Georgia Power Company (GPC) general office production department.

   b. Southern Bell telephone system lines.

   c. Two telephone lines from GPC's Atlanta private branch exchange.

D. Acceptance Criteria

The offsite communication system operates as described in subsections 9.5.2 and 9.5.10 when using the above test methods.

14.2.8.1.79 Inplant Communication System Preoperational Test

A. Objectives

To demonstrate the adequacy of the inplant communication system to provide reliable communications between plant areas and to verify the operability of the emergency alarm system.

B. Prerequisites

1. Construction acceptance testing is complete.

2. Component testing and instrument calibration are complete.

3. Test instrumentation is available and calibrated.

4. Support system is available.

5. Plant equipment that contributes to the ambient noise level is in operation if possible.

C. Test Methods

1. Verify the telephone/page system operability.

2. Verify the sound-powered system operability.

3. Verify the tone generator operability.

D. Acceptance Criteria

The inplant communication system operates as described in subsection 9.5.2 when using the above test methods.

14.2.8.1.80 Heat Tracing System Preoperational Test

A. Objective 7

To demonstrate operation of the heat tracing system.

B. Prerequisites

1. Construction acceptance testing is complete.
2. Component testing and instrument calibration are complete.
3. Test instrumentation is available and calibrated.
4. Support systems are available.

C. Test Method

1. Verify the operability of the heat tracing circuits.
2. Verify alarms, indicating instruments, and status lights are functional.

D. Acceptance Criterion

The heat tracing system automatically controls the associated heat tracing circuits, in accordance with system operation requirements. 7

14.2.8.1.81 (Material deleted)

14.2.8.1.82 Plant Annunciator System Preoperational Test

A. Objectives

1. To demonstrate operation of the plant annunciator system.

2. To verify that the annunciator will transfer to the alternate power source upon loss of primary power source.

B. Prerequisites

1. Construction acceptance testing is complete.

2. Component testing and instrumentation calibration are complete.

3. Test instrumentation is available and calibrated.

4. Support systems are available.

C. Test Methods

1. Self-test features of the system shall be tested and verified to be operational.

2. Verify appropriate annunciator response to each retransmitting contact when it is actuated.

3. Transfer of power sources shall be tested and verified operational.

D. Acceptance Criteria

The plant annunciator system operates as described in chapter 18 when using the above test methods.

17.2.12 CONTROL OF MEASURING AND TEST EQUIPMENT

Measures for the control of measuring and test equipment are consistent with the position of Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation), as described in section 1.9.

Provisions for the control of applicable measuring and test equipment require that:

A. Procedures shall be established which describe the calibration technique, calibration frequency, maintenance and control of measuring and test instruments, tools, gauges, fixtures, reference standards, transfer standards, and nondestructive test equipment to be used in the measurement, inspection, and monitoring of safety-related components, systems, and structures.

B. Measurement and test equipment shall be uniquely identified and have traceability to calibration test data. (Contrary to American National Standards Institute N18.7-1976, paragraph 5.2.16, installed process instrumentation at VEGP will not be tagged or labeled with calibration due date.)

C. Measuring and test instruments shall be calibrated and maintained at specific intervals, based on the required accuracy, purpose, degree of usage, stability characteristics, and other conditions affecting the measurement.

D. Measuring and test equipment shall be calibrated on or before the designated due date.

E. When measuring and test equipment is found to be out of calibration, an investigation shall be conducted and documented to determine the validity of previous inspections performed and the acceptability of those items previously inspected.

F. Calibrating instruments shall have known, valid relationships to a nationally recognized standard. If no national standard exists, the basis of calibration will be documented and approved by the responsible department superintendent or an authorized level of management. 7

G. Records will be maintained which indicate the complete status of all items under the calibration system and reflect the last and future calibration dates or the last calibration date and frequency, if applicable.

H. Calibration facilities used for calibrating sensitive and close tolerance measuring and test equipment shall provide an environment that is sufficiently controlled to allow the measuring device to be evaluated and calibrated to its required accuracy.

Reference standards will have an uncertainty (error) requirement of no more than one-fourth of the tolerance of the measuring and test equipment being calibrated; a greater uncertainty will be acceptable when limited by the state of the art. Equipment and standards not meeting this requirement will be documented and approved by the superintendent of maintenance or by an authorized level of management. Comparison standards used in calibration of reference standards will have a tolerance smaller than the reference standard and will be traceable to the standards housed in the National Bureau of Standards and supported by certification reports and data sheets, when applicable. 7

The superintendent of maintenance is responsible to the plant manager for developing, approving, and implementing procedures and instructions to establish a control and calibration program. Effectiveness of the program is assured through periodic audits performed under the quality assurance audit system that is described in subsection 17.2.18.

17.2.15 NONCONFORMING MATERIALS, PARTS, OR COMPONENTS

Requirements for the control of nonconforming materials, parts, or components are consistent with the position of Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation); Regulatory Guide 1.38, Quality Assurance Requirements for Packing, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants; and Regulatory Guide 1.123, Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants, as described in section 1.9. Georgia Power Company and its contractors follow written requirements to identify, document, segregate, disposition, and report to the affected organization any nonconformance, deviation, or other conditions adversely affecting quality. Provisions for control of nonconforming materials, parts, or components require that:

A. Measures and procedures shall be established to control the identification, documentation, segregation, review, disposition, and notification of the affected organization of nonconformance of materials, parts, components, or services.

B. Documentation shall be provided which clearly identifies the nonconforming item, describes the nonconformance and disposition of the nonconformance inspection requirements, and includes signature approval of the disposition.

C. Those individuals or organizations responsible for disposition and approval of the nonconforming items shall be identified.

D. Nonconforming items are segregated from other acceptable items (where feasible) and uniquely identified as nonconforming until properly dispositioned. Items that are unique, identified, properly marked, and have their own specified storage location need not be segregated.

E. Acceptability of rework/repair of items by reinspection or testing of the item as originally performed or by a method which is equivalent to the original inspection and testing method shall be verified.

F. Nonconformance reports which are dispositioned "accept as is" or "repair" are made part of the quality verification records associated with the item.

G. Periodic analysis of these reports shall be performed and forwarded to management to show quality trends.

Approved procedures provide provisions for an independent review of nonconformances. The quality assurance audit system 7
(subsection 17.2.18) will verify compliance of each activity with the operations quality assurance program.

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430.71	8.3.1	Mar. 13, 1984	7
430.72	8.3.1	Mar. 13, 1984	7
430.73	8.3.1	Mar. 13, 1984	7
430.74	1.9, 8.3.1	Mar. 13, 1984	7
440.1	Misc.	Feb. 21, 1984	6
440.2	5.2.2	Feb. 21, 1984	6
440.3	5.2.2	Feb. 21, 1984	6
440.4	5.2.2	Feb. 21, 1984	6
440.5	5.2.2	Feb. 21, 1984	6
440.6	5.2.2	Feb. 21, 1984	6
440.7	5.2.2, 5.4.13	Feb. 21, 1984	6
440.8	5.2.2, 5.4.12, 6.3	Feb. 21, 1984	6
440.9	5.2.2	Feb. 21, 1984	6
440.10	5.2.2	Feb. 21, 1984	6
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440.12	5.2.2	Feb. 21, 1984	6
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440.23	5.4.7	Feb. 21, 1984	6
440.24	5.4.7	Feb. 21, 1984	6
440.25	5.4.7	Feb. 21, 1984	6
440.26	5.4.7, 10.3.1	Feb. 21, 1984	6
440.27	5.4.7	Feb. 21, 1984	6
440.28	5.4.7	Feb. 21, 1984	6
440.29	5.4.7, 10.3.2	Feb. 21, 1984	6
440.30	5.4.7	Feb. 21, 1984	6
440.31	5.4.7	Feb. 21, 1984	6
440.32	5.4.7	Feb. 21, 1984	6
440.33	5.4.7	Feb. 21, 1984	6
440.34	5.4.7	Feb. 21, 1984	6
440.35	5.4.7	Feb. 21, 1984	6

Question	Relative Section/ Subsection	Question Transmittal Date	Amendment
440.36	5.4.7	Feb. 21, 1984	6
440.37	5.4.7	Feb. 21, 1984	6
440.38	5.4.7	Feb. 21, 1984	6
440.39	5.4.7	Feb. 21, 1984	6
440.40	5.4.7	Feb. 21, 1984	6
440.41	5.4.7	Feb. 21, 1984	6
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440.43	5.4.7	Feb. 21, 1984	6
440.44	5.4.7	Feb. 21, 1984	6
440.45	5.4.7	Feb. 21, 1984	6
440.46	5.4.13	Feb. 21, 1984	6
440.47	5.1.2, 5.4.15	Feb. 21, 1984	6
440.48	5.2.2	Feb. 21, 1984	6
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460.1	10.4.2	Sept. 6, 1983	1
460.02	6.5.1	Jan. 23, 1984	5
460.03	6.5.1	Jan. 23, 1984	5
460.04	10.4.2, 10.4.3	Jan. 23, 1984	5
460.05	1.9, 11.2	Jan. 23, 1984	5
460.06	1.9, 11.3	Jan. 23, 1984	5
460.07	11.4.1	Jan. 23, 1984	5
460.08	11.5	Jan. 23, 1984	5
460.09	12.1.3	Jan. 23, 1984	5
471.1	12.5	Sept. 6, 1983	1
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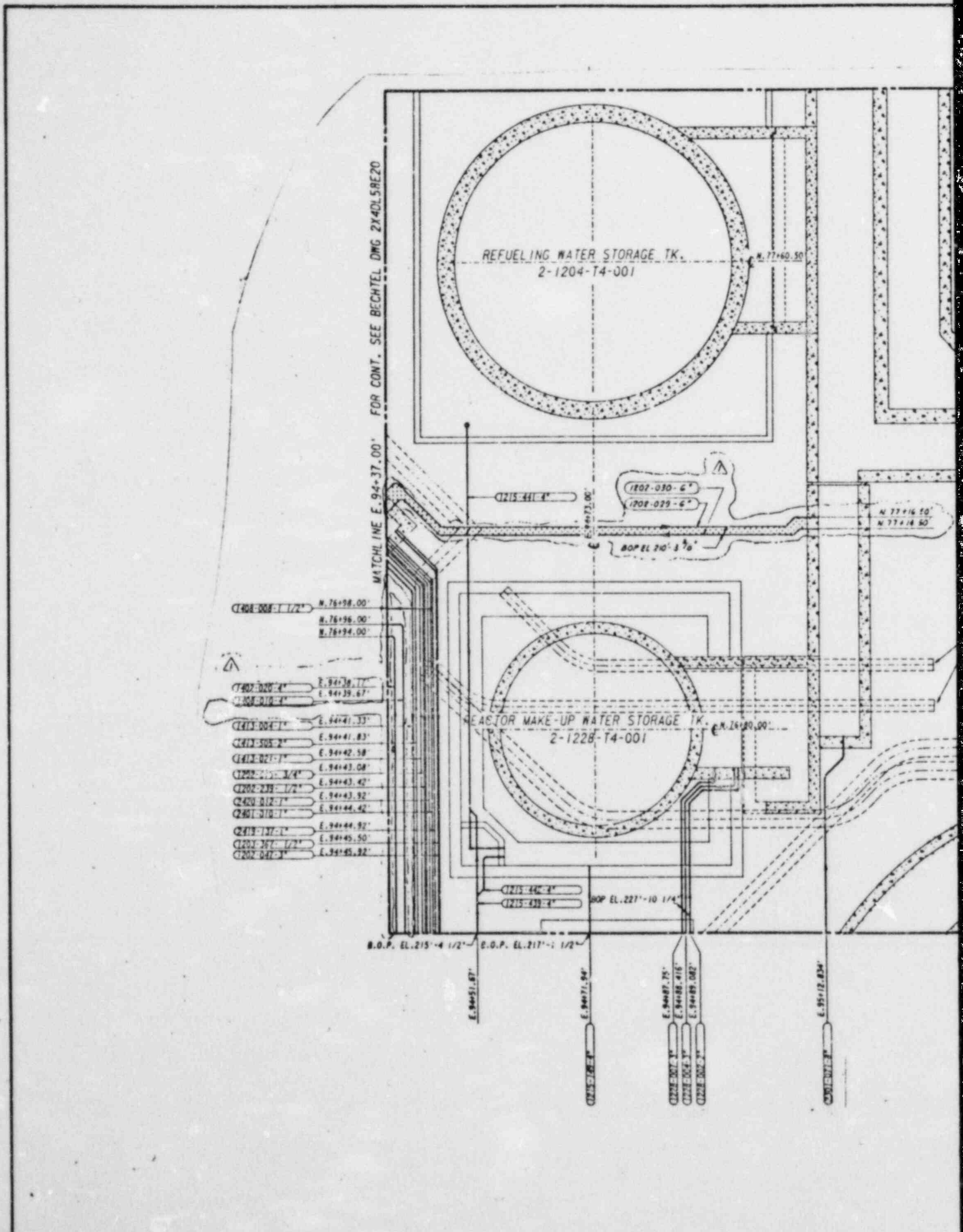
471.03	12.5.2	Dec. 13, 1983	4
471.04	12.5.1	Dec. 13, 1983	4
471.05	13.1	Dec. 13, 1983	4
471.06	13.1	Dec. 13, 1983	4
471.07	12.3.4	Dec. 13, 1983	4
471.08	13.2.2	Dec. 13, 1983	4
471.09	12.5.3	Dec. 13, 1983	4
471.10	12.1	Dec. 13, 1983	4
471.11	12.5.2	Dec. 13, 1983	4
471.12	12.5.3	Dec. 13, 1983	4
471.13	11.5.2, 12.3.4	Dec. 13, 1983	4
471.14	12.3.1	Dec. 13, 1983	4
471.15	12.3.1, 12.3.4	Dec. 13, 1983	4
471.16	12.4.1	Dec. 13, 1983	4
471.17	12.3.1	Dec. 13, 1983	4
480.1	6.2.1	Sept. 6, 1983	1
480.2	6.2.1	Sept. 6, 1983	1
480.3	6.2.1	Sept. 6, 1983	1
480.4	6.2.1	Sept. 6, 1983	1
480.5	6.2.2	Sept. 6, 1983	1
480.6	6.2.2	Sept. 6, 1983	1
480.7	6.2.4	Sept. 6, 1983	1

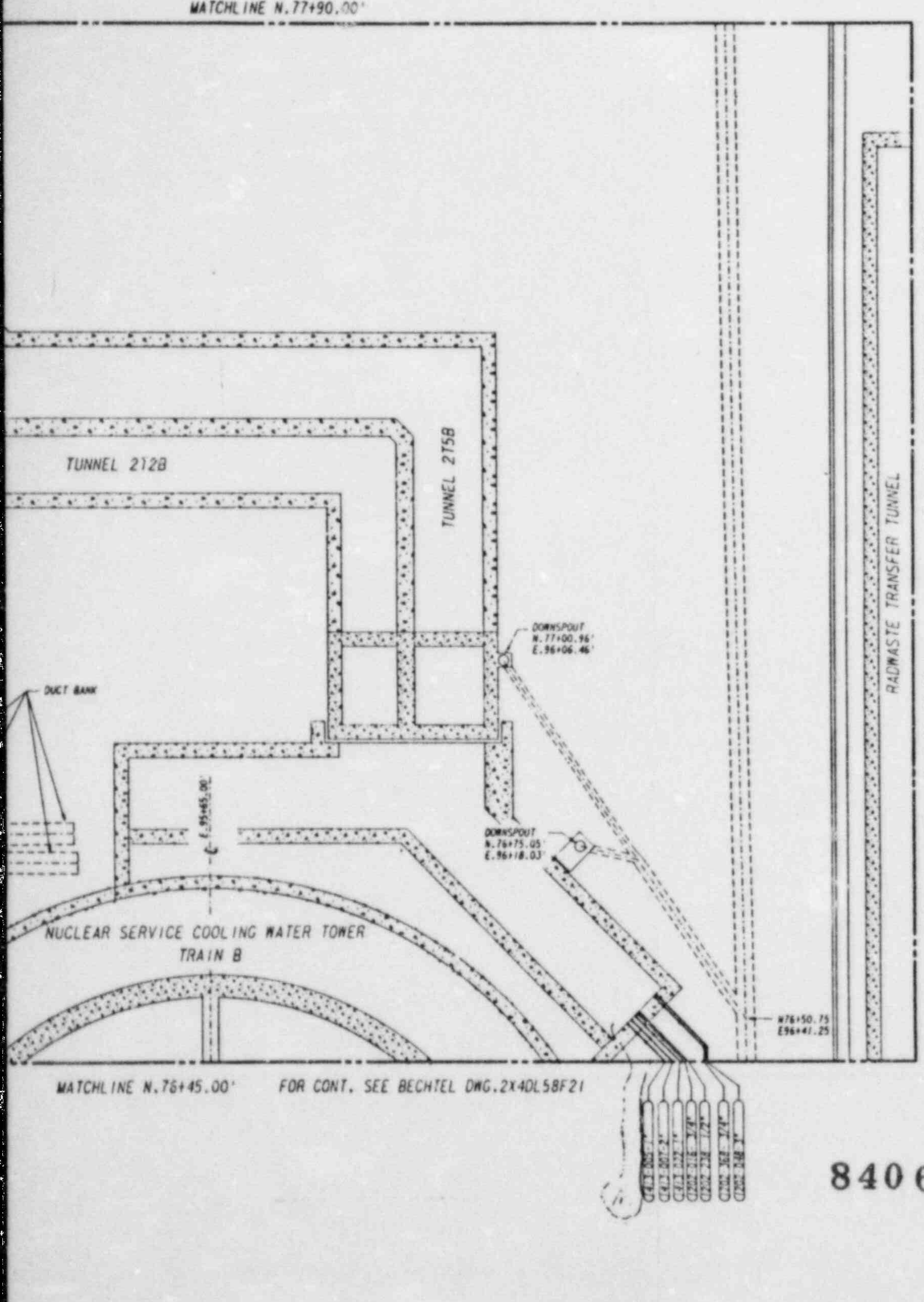
Question	Relative Section/ Subsection	Question Transmittal Date	Amendment
480.8	6.2.6	Sept. 6, 1983	1
491.1	4.3.2	Jan. 23, 1984	5
491.2	15.4.1	Jan. 23, 1984	5
630.1	13.1	Sept. 6, 1983	3
630.2	13.1.1	Sept. 6, 1983	1
630.3	13.2.2	Sept. 6, 1983	1
630.1	13.2.1	Dec. 13, 1983	4
630.2	13.2.1	Dec. 13, 1983	4
630.3	13.2.1	Dec. 13, 1983	4
630.4	13.2.1	Dec. 13, 1983	4
630.5	13.2.1	Dec. 13, 1983	4
630.6	13.2.1	Dec. 13, 1983	4
630.7	13.2.2	Dec. 13, 1983	4
630.8	13.2.2	Dec. 13, 1983	4
630.9	13.2.2	Dec. 13, 1983	4
630.10	9B	Dec. 13, 1983	4
630.11	9.5.1, 9B	Dec. 13, 1983	4
630.12	9B	Dec. 13, 1983	4
630.13	9B, 13.2.2	Dec. 13, 1983	4
630.14	9.5.1, 9B, 13.2.2	Dec. 13, 1983	4
630.15	9B	Dec. 13, 1983	4
630.16	9.5.1, 9B	Dec. 13, 1983	4
630.17	13.2.2	Dec. 13, 1983	4
630.18	13.2.2	Dec. 13, 1983	4
630.19	13.2.2	Dec. 13, 1983	4
630.20	13.2.1, 13.2.2	Dec. 13, 1983	4
640.1	14.2.8	Sept. 6, 1983	1
730.1	Misc.	Jan. 23, 1984	5



REFUELING WATER STORAGE TK.
2-1204-T4-001
REACTOR MAKE-UP WATER STORAGE TK.
2-1228-T4-001
MATCHLINE E.94+37.00' FOR CONT. SEE BECHTEL DWG 2X4DL5RE20

433-9

Also Available On
Aperture Card



TI APERTURE CARD

8406060006-12

MODIFIED FOR USE IN FSAR
2X4DL58F20 REV. 1

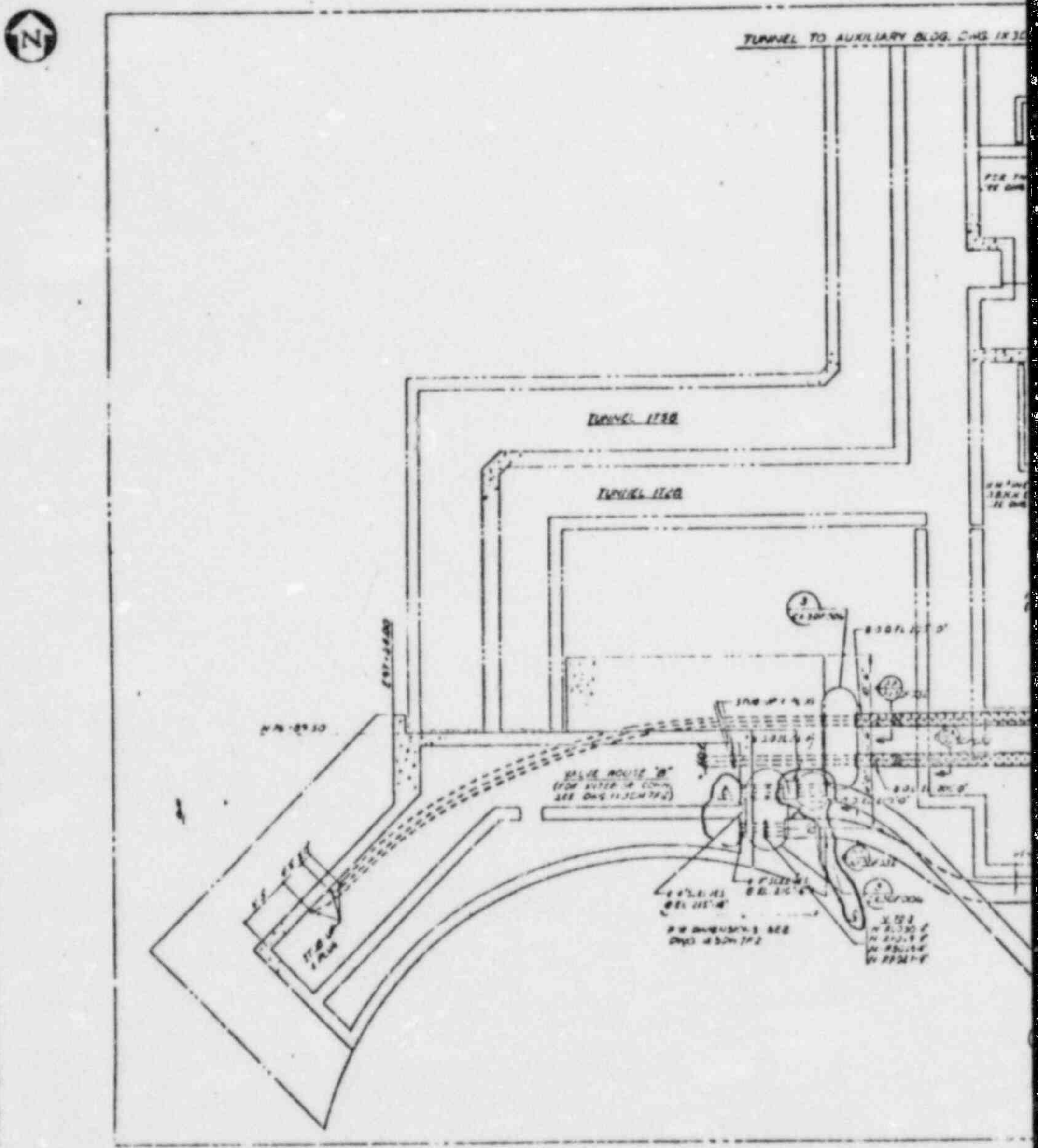
Amend. 7 5/84

Georgia Power

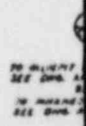
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

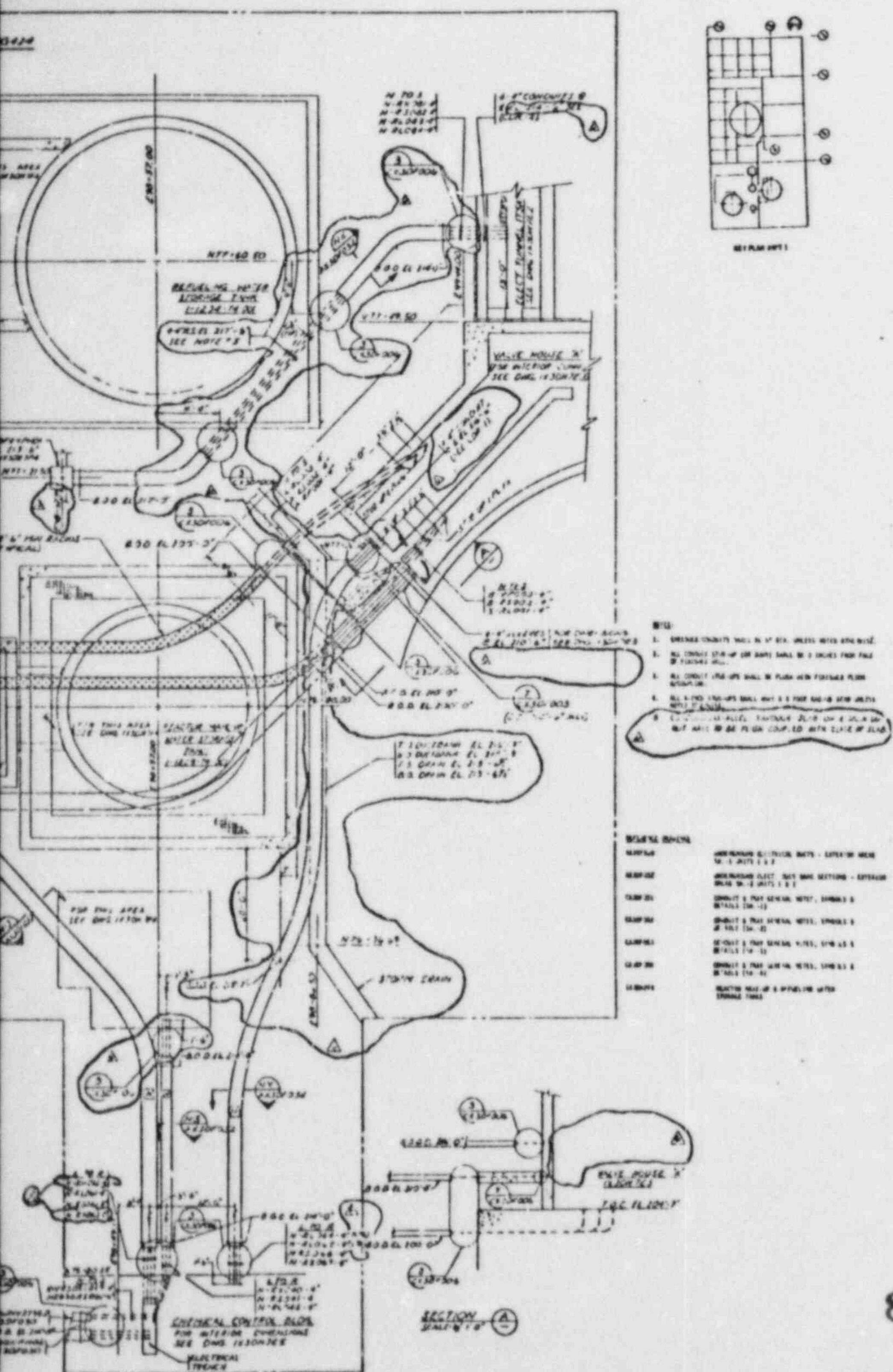
UNDERGROUND AND ABOVE GROUND
PERMANENT FACILITIES

FIGURE 241.2-6



PARTIAL SITE PLAN - DWG. AX3DF030





SAFETY RELATED PIPING

MODIFIED FOR USE IN FSAR
1X3DH7E6 REV. 6

Amend. 7 5/84

Georgia Power — VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	OUTDOOR AREAS NSCW DUCT BANK PARTIAL PLAN
	FIGURE 241.2-11

Question 241.12

Provide the input values to permit the staff to verify that you have used a consistent set of soil properties and soil profiles below plant grade in your finite-element and lumped parameter studies. Your description of techniques used to obtain the impedance functions for layered medium, provided in the appendix 3E of the FSAR, is inadequate. Give the depth of soil profile and values of soil parameters you considered while using this approach. Provide design assumptions and sufficient details of your calculative procedures and results to justify your proper use of soil stiffnesses and damping values for soil springs used in your lumped-parameter analysis.

Response

The soil properties and soil profiles, on the basis of which the finite-element soil-structure analyses of deeply embedded structures and the lumped parameter soil-structure analyses of shallowly embedded structures are performed, are provided in figure 241.12-1 attached. Appendix 3E will be revised in Amendment 8 to provide an expanded description of techniques used to obtain the impedance functions for layered medium. The soil layers and values of soil parameters considered while using this approach are also identified in the attached table. The design assumptions, details of calculative procedure, and results demonstrating the proper use of soil stiffnesses and damping values for soil springs used in the lumped parameter analyses will be provided in the structure design reports, which will be submitted by December 1, 1984. 7

NRC QUESTIONS AND RESPONSES
AMENDMENT 7, MAY 1984

Question	Relative Section/ Subsection	Keywords
240.7	2.4	Floodplain management (Executive Order 11988)
240.8	2.4	Radiological consequences of a liquid pathway release from a posulated core melt accident
281.12	9.3.2	Post-accident sampling system
430.1	8.3.1, 13.1.3	Training, education, and experience of personnel associated with the operation and maintenance of the emergency diesel generators
430.2	8.3.1	Surveillance testing of a standby diesel generator
430.3	1.9, 8.1, 8.3.1	Testing and test loading of an emergency diesel generator
430.4	8.3.1	Controls and monitoring instrumentation for an emergency diesel generator
430.5	9.5.3	Emergency lighting for the main control board and remote shutdown panels
430.6	3.2.2, 9.5.4	Components and piping systems for the diesel generator auxiliaries
430.7	9.5.4-9.5.8	High and moderate energy lines and systems in the diesel generator room
430.8	7.3.17, 8.3.1, 9.5.4-9.5.8	Instrumentation associated with the diesel generators
430.9	1.9, 9.5.4	Conformance of design of the fuel oil storage and transfer system to Regulatory Guide 1.137

Question	Relative Section/ Subsection	Keywords
430.10	9.5.4	Concrete wall barrier between the diesel generators
430.11	9.5.4	Fuel oil storage tank fill line
430.12	9.5.4	Valve house between the fuel oil storage tanks
430.13	9.5.4	Fuel oil day tank
430.14	3.2.2, 3.5, 3.7, 9.5.4	Seismic and missile protection design of the fuel oil valve house and transfer pump houses
430.15	9.5.4	Spurious actuation of the fire protection system
430.16	9.5.4	Adequate fuel oil storage capacity
430.17	9.5.4	Replenishment of fuel oil without interrupting operation of the diesel generator
430.18	9.5.4	Delivery of fuel oil to the site
430.19	9.5.4	Addition of biocides to fuel oil
430.20	9.5.4	Cathodic protection for the fuel oil storage tanks and transfer system
430.21	9.5.4	Nonsafety-related portions of the fuel oil storage and transfer system
430.22	9.5.4	Fuel oil transfer system alarms and indications
430.23	9.5.5	Diesel generator cooling water system jacket water exchanger
430.24	9.5.5	Diesel engine cooling water system chemical treatment
430.25	9.5.5	Filling of the diesel engine cooling water system

Question	Relative Section/ Subsection	Keywords
430.26	8.3.1, 9.5.5	Diesel generator operation at less than full load for extended periods
430.27	9.5.5	Diesel engine cooling water system standpipe
430.28	9.5.5	Jacket water leakage
430.29	9.5.5	Water spray onto the diesel engine electrical starting system
430.30	9.5.6	Air start system capability
430.31	9.5.4, 9.5.6	Air start system filters
430.32	9.5.6, 9.5.7	Air dryer design and operation
430.33	9.5.4, 9.5.7	Low lube oil pressure trip
430.34	9.5.4, 9.5.7	Lube oil keepwarm system
430.35	9.5.7	Adequate lube oil sump capacity for each diesel generator
430.36	9.5.7	Entry of deleterious materials into the engine lubrication oil system
430.37	9.5.7	Checking lube oil system
430.38	9.5.7	Crankcase vacuum system
430.39	9.5.7	Governor lube oil cooler assembly and turbocharger lubrication circuits
430.40	9.5.7	Design margin for the lube oil coolers
430.41	9.5.8	Combustion air intake filter, silencer, and piping
430.42	1.2.2, 9.5.8	Combustion air intake tornado missile protection
430.43	9.5.8	Diesel engine exhaust tornado missile protection

Question	Relative Section/ Subsection	Keywords
430.44	9.5.8	Effect of abnormal climatic conditions on the diesel engine combustion air intake and exhaust system
430.45	8.3.1, 9.4.5, 9.5.8	Deleterious accumulations on electrical equipment associated with the diesel generators
430.46	8.3.1, 9.5.5, 9.5.7, 9.5.8	Diesel generator performance under service conditions or weather disturbances
430.47	8.3.1, 9.4.5, 9.4.7, 9.5.4, 9.5.8	Diesel generator room ventilation system
430.48	10.2	Turbine speed control and overspeed protection systems
430.49	10.2	Failure of turbine speed control and overspeed protection system components
430.50	10.2	Testing and inservice inspection of the main steam stop and governor control valves, combined reheat stop and intercept valves, and steam extraction nonreturn valves
430.51	9.3.5, 10.2	Bulk hydrogen storage facility
430.52	10.2.2, 10.4.4	Turbine bypass valves and associated controls
430.53	10.2.2, 10.4.4	Turbine bypass system components and instrumentation
430.54	1.2.2, 8.1, 8.2.1	230- and 500-kV switchyard transmission lines
430.55	8.2.2	Loss of Unit 1 or 2 during 1989 peak conditions
430.56	8.2.1	Main stepup, auxiliary, and reserve auxiliary transformers

Question	Relative Section/ Subsection	Keywords
430.57	8.2.1, 8.3.2	Switchyard battery circuits
430.58	8.2	Control room instrumentation for monitoring offsite power circuits
430.59	8.3.1	Reserve auxiliary transformer
430.60	1.9, 8.3.1	Redundant Class 1E 4.16-kV circuit breakers
430.61	8.3.1	Class 1E and non-Class 1E 120-V ac power supplies
430.62	8.3.1	Non-Class 1E loads feed from Class 1E supplies
430.63	8.3.1	Shared Class 1E electrical loads
430.64	8.3.1	Use of thermal overloads in motor-operated valve circuits
430.65	7.1.2, 8.3.1	Class 1E circuit breakers and motor controllers testable during reactor operation
430.66	8.3.1	Underfrequency of overcurrent protection for the diesel generators
430.67	1.9, 3.10	Qualification of emergency diesel generators
430.68	8.3.1	Compliance with Branch Technical Position PSB-1
430.69	8.3.1	Load shedding and sequencing
430.70	8.3.1	Comparison of VEGP diesel generators with those previously used
430.71	8.3.1	Calculations on 80 percent starting rate
430.72	8.3.1	Centrifugal charging pumps horsepower

Question	Relative Section/ Subsection	Keywords
430.73	8.3.1	Motor-operated valves with power lockout
430.74	1.9, 8.3.1	Containment building electrical penetrations

Question 240.7

Definition (from Executive Order 11988, Floodplain Management) of floodplain: the lowland and relatively flat areas adjoining inland and coastal waters including flood-prone areas of offshore islands, including at a minimum that area subject to a 1 percent or greater chance of flooding in any given year.

A. Provide descriptions of the floodplains of all water bodies, including intermittent water courses, within or adjacent to the site. On a suitable scale map provide delineations of those areas that will be flooded during the 1 percent chance flood in the absence of plant effects (i.e., preconstruction floodplain).

B. Provide details of the methods used to determine the floodplains in response to item A above. Include your assumptions of and bases for the pertinent parameters used in the computation of the 1 percent flood flow and water elevation. If studies approved by Flood Insurance Administration (FIA), Housing and Urban Development (HUD), or the Corps of Engineers are available for the site or adjoining area, the details of analyses need not be supplied. You can instead provide the reports from which you obtained the floodplain information.

C. Identify, locate on a map, and describe all structures and topographic alterations in the floodplains.

D. Discuss the hydrologic effects of all items identified in item C above. Discuss the potential for altered flood flows and levels, both upstream and downstream. Include the potential effect of debris accumulating on the plant structures. Additionally, discuss the effects of debris generated from the site on downstream facilities.

E. Provide the details of your analysis used in response to item D above. The level of detail is similar to that identified in item B above.

F. The floodplain mapping should be of suitable quality for use in the environmental statement.

Response

The response for the request for additional information regarding Executive Order 11988, Floodplain Management, will be provided in section 2.4 of the Operating License Stage Environmental Report (Amendment 3).

Question 240.8

Calculate the radiological consequences of a liquid pathway release from a postulated core melt accident. The analysis should assume, unless otherwise justified, that there has been a penetration of the reactor basemat by the molten core mass and that a substantial portion of radioactivity contaminated sump water was released to the ground. Doses should be compared to those calculated for the Liquid Pathway Generic Study (NUREG-0440, 1978) land-based river site. Provide a summary of your analysis procedures and the values of parameters used (such as permeabilities, gradients, populations affected, water use).

Response

The radiological consequences of a liquid pathway release from a postulated core melt accident was provided in the Operating License Stage Environmental Report, appendix 7A (Amendment 1, February 1984).

Question 281.12

The information you provided on the post-accident sampling system (PASS) is inadequate to demonstrate compliance with NUREG-0737, item II.B.3. Provide information that satisfies the criteria listed below.

Criteria Guidelines

The PASS will be evaluated for compliance with the criteria from NUREG-0737, item II.B.3. These 11 items have been copied from NUREG-0737. The licensee's submittal should include information equivalent to that which is normally provided in an FSAR. System schematics with sufficient information to verify flow paths should be included, consistent with documentation requirements in NUREG-0737, with appropriate discussion so that the reviewer can determine whether the criteria have been met. Further information pertaining to the specific clarifications of NUREG-0737, which will be considered in the reviewer's evaluation are listed below. Technically justified alternatives to these criteria will be considered.

Criterion (1)

The licensee shall have the capability to promptly obtain reactor coolant samples and containment atmosphere samples. The combined time allotted for sampling and analysis should be 3 h or less from the time a decision is made to take a sample.

Clarification

Provide information on sampling(s) and analytical laboratories locations including a discussion of relative elevations, distances, and methods for sample transport. Responses to this item should also include a discussion of sample recirculation, sample handling, and analytical times to demonstrate that the 3-h time limit will be met (see criterion (6) below relative to radiation exposure). Also describe provisions for sampling during loss of offsite power (i.e., designate an alternative backup power source, not necessarily the vital (Class 1E) bus, that can be energized in sufficient time to meet the 3-h sampling and analysis time limit).

Criterion (2)

The licensee shall establish an onsite radiological and chemical analysis capability to provide, within the 3-h time frame established above, quantification of the following:

(a) Certain radionuclides in the reactor coolant and containment atmosphere that may be indicators of the degree of core damage (e.g., noble gases, iodines and cesiums, and nonvolatile isotopes).

(b) Hydrogen levels in the containment atmosphere.

(c) Dissolved gases (e.g., H_2), chloride (time allotted for analysis subject to discussion below), and boron concentration of liquids.

(d) Alternatively, have inline monitoring capabilities to perform all or part of the above analyses.

Clarification

(a) A discussion of the counting equipment capabilities is needed, including provisions to handle samples and reduce background radiation to minimize personnel radiation exposures (ALARA). Also a procedure is required for relating radionuclide concentrations to core damage. The procedure should include:

1. Monitoring for short and long lived volatile and nonvolatile radionuclides such as ^{133}Xe, ^{131}I, ^{137}Cs, ^{134}Cs, ^{85}Kr, ^{140}Ba, and ^{88}Kr (see Volume II, Part 2, pages 524-527 of Rogovin Report for further information).

2. Provisions to estimate the extent of core damage based on radionuclide concentrations and taking into consideration other physical parameters such as core temperature data and sample location.

(b) Show a capability to obtain a grab sample, transport, and analysis for hydrogen.

(c) Discuss the capabilities to sample and analyze for the accident sample species listed here and in Regulatory Guide 1.97, Revision 2.

(d) Provide a discussion of the reliability and maintenance information to demonstrate that the selected online instrument is appropriate for this application (see criteria (8) and (10) below relative to backup grab sample capability and instrument range and accuracy).

Criterion (3)

Reactor coolant and containment atmosphere sampling during post-accident conditions shall not require an isolated auxiliary system (e.g., the letdown system, reactor water cleanup system) to be placed in operation in order to use the sampling system.

Clarification

System schematics and discussions should clearly demonstrate that post-accident sampling, including recirculation, from each sample source is possible without use of an isolated auxiliary system. It should be verified that valves which are not accessible after an accident are environmentally qualified for the conditions in which they must operate.

Criterion (4)

Pressurized reactor coolant samples are not required if the licensee can quantify the amount of dissolved gases with unpressurized reactor coolant samples. The measurement of either total dissolved gases or H_2 gas in reactor coolant samples is considered adequate. Measuring the O_2 concentration is recommended but is not mandatory.

Clarification

Discuss the method whereby total dissolved gas or hydrogen and oxygen can be measured and related to reactor coolant system concentrations. Additionally, if chlorides exceed 0.15 ppm, verification that dissolved oxygen is less than 0.1 ppm is necessary. Verification that dissolved oxygen is < 0.1 ppm by measurement of a dissolved hydrogen residual of ≥ 10 cm^3/kg is acceptable for up to 30 days after the accident. Within 30 days, consistent with minimizing personnel radiation exposures (ALARA), direct monitoring for dissolved oxygen is recommended.

Criterion (5)

The time for a chloride analysis to be performed is dependent upon two factors: (a) if the plant's coolant water is seawater or brackish water and (b) if there is only a single barrier between primary containment systems and the cooling water. Under both of the above conditions the licensee shall provide for a chloride analysis within 24 h of the sample being taken. For all other cases, the licensee shall provide for the analysis to be completed within 4 days. The chloride analysis does not have to be done onsite.

Clarification

Boiling water reactors (BWRs) on sea or brackish water sites and plants which use sea or brackish water in essential heat exchangers (e.g., shutdown cooling) that have only single barrier protection between the reactor coolant are required to analyze chloride within 24 h. All other plants have 96 h to perform a chloride analysis. Samples diluted by up to a factor of 1000 are acceptable as initial scoping analysis for chloride, provided (1) the results are reported as ______ ppm Cl (the licensee should establish this value; the number in the blank should be no greater than 10.0 ppm Cl) in the reactor coolant system and (2) that dissolved oxygen can be verified at < 0.1 ppm, consistent with the guidelines above in clarification (4). Additionally, if chloride analysis is performed on a diluted sample, an undiluted sample need also be taken and retained for analysis within 30 days, consistent with ALARA.

Criterion (6)

The design basis for plant equipment for reactor coolant and containment atmosphere sampling and analysis must assume that it is possible to obtain and analyze a sample without radiation exposures to any individual exceeding the criteria of General Design Criterion 19 (Appendix A, 10 CFR Part 50) (i.e., 5 rem whole body, 75 rem extremities). (Note that the design and operational review criterion was changed from the operational limits of 10 CFR Part 20 (NUREG-0578) to the General Design Criterion 19 criterion (October 30, 1979, letter from H. R. Denton to all licensees)).

Clarification

Consistent with Regulatory Guide 1.3 or 1.4 source terms, provide information on the predicted personnel exposures based on person-motion for sampling, transport, and analysis of all required parameters.

Criterion (7)

The analysis of primary coolant samples for boron is required for pressurized water reactors (PWRs). (Note that Revision 2 of Regulatory Guide 1.97 specifies the need for primary coolant boron analysis capability at BWR plants.)

Clarification

PWRs need to perform boron analysis. The guidelines for BWRs are to have the capability to perform boron analysis, but they do not have to do so unless boron was injected.

Criterion (8)

If inline monitoring is used for any sampling and analytical capability specified herein, the licensee shall provide backup sampling through grab samples and shall demonstrate the capability of analyzing the samples. Established planning for analysis at offsite facilities is acceptable. Equipment provided for backup sampling shall be capable of providing at least one sample per day for 7 days following onset of the accident and at least one sample per week until the accident condition no longer exists.

Clarification

A capability to obtain both diluted and undiluted backup samples is required. Provisions to flush inline monitors to facilitate access for repair is desirable. If an offsite laboratory is to be relied on for the backup analysis, an explanation of the capability to ship and obtain analysis for one sample per week thereafter until accident condition no longer exists should be provided.

Criterion (9)

The licensee's radiological and chemical sample analysis capability shall include provisions to:

(a) Identify and quantify the isotopes of the nuclide categories discussed above to levels corresponding to the source terms given in Regulatory Guides 1.3 or 1.4 and 1.7. Where necessary and practicable, the ability to dilute samples to provide capability for measurement and reduction of personnel exposure should be provided. Sensitivity of onsite liquid sample analysis capability should be such as to permit measurement of nuclide concentration in the range from approximately 1 μCi/g to 10 Ci/g.

(b) Restrict background levels of radiation in the radiological and chemical analysis facility from sources such that the sample analysis will provide results with an acceptably small error (approximately a factor of 2). This can be accomplished through the use of sufficient shielding around samples and outside sources and by the use of a ventilation system design which will control the presence of airborne radioactivity.

Clarification

(a) Provide a discussion of the predicted activity in the samples to be taken and the methods of handling/ dilution that will be employed to reduce the activity sufficiently to perform the required analysis. Discuss the range of radionuclide concentration which can be analyzed for, including an assessment of, the amount of overlap between post-accident and normal sampling capabilities.

(b) State the predicted background radiation levels in the counting room, including the contribution from samples which are present. Also provide data demonstrating what the background radiation levels and radiation effect will be on a sample being counted to assure an accuracy within a factor of 2.

Criterion (10)

Accuracy, range, and sensitivity shall be adequate to provide pertinent data to the operator in order to describe radiological and chemical status of the reactor coolant systems.

Clarification

The recommended ranges for the required accident sample analyses are given in Regulatory Guide 1.97, Revision 2. The necessary accuracy within the recommended ranges are as follows:

- Gross activity, gamma spectrum: measured to estimate core damage; these analyses should be accurate within a factor of 2 across the entire range.

- Boron: measured to verify shutdown margin.

In general this analysis should be accurate within ±5 percent of the measured value (i.e., at 6000 ppm B, the tolerance is ±300 ppm, while at 1000 ppm B, the tolerance is ±50 ppm). For concentrations below 1000 ppm, the tolerance band should remain at ±50 ppm.

- Chloride: measured to determine coolant corrosion potential.

For concentrations between 0.5 and 20.0 ppm chloride, the analysis should be accurate within ±10 percent of the measured value. At concentrations below 0.5 ppm, the tolerance band remains at ±0.05 ppm.

- Hydrogen or total gas: monitored to estimate core degradation and corrosion potential of the coolant.

An accuracy of ±10 percent is desirable between 50 and 2000 cm^3/kg, but ±20 percent can be acceptable. For concentration below 50 cm^3/kg, the tolerance remains at ±5.0 cm^3/kg.

- Oxygen: monitored to assess coolant corrosion potential.

For concentrations between 0.5 and 20.0 ppm oxygen, the analysis should be accurate within ±10 percent of the measured value. At concentrations below 0.5 ppm, the tolerance band remains at ±0.05 ppm.

- pH: measured to access coolant corrosion potential.

Between a pH of 5 to 9, the reading should be accurate within ±0.3 pH units. For all other ranges, ±0.5 pH units is acceptable.

To demonstrate that the selected procedures and instrumentation will achieve the above listed accuracies, it is necessary to provide information demonstrating their applicability in the post-accident water chemistry and radiation environment. This can be accomplished by performing tests utilizing the standard test matrix provided below or by providing evidence that the selected procedure or instrument has been used successfully in a similar environment.

STANDARD TEST MATRIX FOR UNDILUTED REACTOR
COOLANT SAMPLES IN A POST-ACCIDENT ENVIRONMENT

Constituent	Nominal Concentration (ppm)	Added as (chemical salt)
I	40	Potassium iodide
Cs+	250	Cesium nitrate
Ba+2	10	Barium nitrate
La+3	5	Lanthanum chloride
Ce+4	5	Ammonium cerium nitrate
Cl-	10	-
B	2000	Boric acid
Li±	2	Lithium hydroxide
NO_3	150	-
NH_4	5	-
K+	20	-
Gamma radiation (induced field)	10^4 rad/g of reactor coolant	Adsorbed dose

NOTES:

1. Instrumentation and procedures which are applicable to diluted samples only should be tested with an equally diluted chemical test matrix. The induced radiation environment should be adjusted commensurate with the weight of actual reactor coolant in the sample being tested.

2. For PWRs, procedures which may be affected by spray additive chemicals must be tested in both the standard test matrix plus appropriate spray additives. Both procedures (with and without spray additives) are required to be available.

3. For BWRs, if procedures are verified with boron in the test matrix, they do not have to be tested without boron.

4. In lieu of conducting tests utilizing the standard test matrix for instruments and procedures, provide evidence that the selected instrument or procedure has been used successfully in a similar environment.

All equipment and procedures which are used for post-accident sampling and analyses should be calibrated or tested at a frequency which will ensure, to a high degree of reliability, that it will be available if required. Operators should receive initial and refresher training in post-accident sampling, analysis, and transport. A minimum frequency for the above efforts is considered to be every 6 months if indicated by testing. These provisions should be submitted in revised Technical Specifications in accordance with Enclosure 1 of NUREG-0737. The staff will provide model Technical Specifications at a later date.

Criterion (11)

In the design of the post-accident sampling and analysis capability, consideration should be given to the following items:

(a) Provisions for purging sample lines, for reducing plateout in sample lines, for minimizing sample loss or distortion, for preventing blockage of sample lines by loose material in the reactor coolant system or containment, for appropriate disposal of the samples, and for flow restrictions to limit reactor coolant loss from a rupture of the sample line. The post-accident reactor coolant and containment atmosphere samples should be representative of the reactor coolant in the core area and the containment atmosphere following a transient or accident. The sample lines should be as short as possible to minimize the volume of fluid to be taken from containment. The residues of sample collection should be returned to containment or to a closed system.

(b) The ventilation exhaust from the sampling station should be filtered with charcoal absorbers and high-efficiency particulate air (HEPA) filters.

Clarification

(a) A description of the provisions which address each of the items in criterion (11)(a) should be provided. Such items as heat tracing and purge velocities should be addressed. To demonstrate that samples are representative of core conditions, a discussion of mixing, both short and long term, is needed. If a given sample location can be rendered inaccurate due to the accident (i.e., sampling from a hot or cold leg loop which may have a steam or gas pocket), describe the backup sampling capabilities or address the maximum time that this condition can exist.

BWRs should specifically address samples which are taken from the core shroud area and demonstrate how they are representative of core conditions.

Passive flow restrictors in the sample lines may be replaced by redundant, environmentally qualified, remotely operated isolation valves to limit potential leakage from sampling lines. The automatic containment isolation valves should close on containment isolation or safety injection signals.

(b) A dedicated sample station filtration system is not required, provided a positive exhaust exists which is subsequently routed through charcoal absorbers and HEPA filters.

Response

The following responses correspond to the above listed criteria:

(1) As described in paragraph 9.3.2.2.5, the PASS is an inline system with the capability to remotely obtain and analyze the required samples. The PASS sampling panel is located on level A of the fuel handling building in a shielded enclosure adjacent to the spent fuel pool heat exchanger room, as shown in figure 1.2.2-19.

Grab samples are analyzed in the radiochemistry laboratory which is located on level 1 of the control building. Grab samples are transported from the PASS sampling panel to the radiochemistry laboratory in a shielded portable cask.

VEGP conforms with the 3-h time limit for sampling and analysis from the time a decision is made to take a sample. Conformance with the 3-h time limit is contingent on the fact that prior to the decision to take a sample, certain activities shall be completed to ensure adequate preparation for sampling, such as assembling chemistry and health physics personnel, energizing PASS and verifying status, selection of sample points, etc.

The PASS is not a safety-related system; therefore, the capability to sample during a loss of offsite power is not a design basis for the system.

(2) As described in subsection 9.3.2, the PASS consists of an inline monitoring system capable of performing the required analyses. Grab sampling capability is provided in addition to a radiochemical laboratory.

(a) The PASS radiation analysis panel is equipped with liquid nitrogen cooled germanium detectors, which separately monitor gaseous and liquid samples. A procedure for assessing core damage is being developed in accordance with the response to question 281.10.

(b) The PASS has the capability to obtain a containment atmosphere grab sample, to transport, and to analyze for hydrogen.

(c) As described in subsection 9.3.2, the PASS has the capability to sample and analyze the species identified in Regulatory Guide 1.97, Revision 2. In addition, the MCA based detection system is capable of monitoring the applicable nuclides.

(d) See the response to item (c) above.

(3) Figure 9.3.2-4 shows a schematic of PASS. The reactor coolant system (RCS) sample is taken from the normal RCS sample line upstream of the outer containment isolation valve. The containment atmosphere sample is taken from the hydrogen monitoring line downstream of the outer containment isolation valve, and the containment sump sample is taken from the residual heat removal (RHR) recirculation line downstream of the encapsulation vessel around the RHR emergency sump containment isolation valve. The location of the PASS takeoffs from the other systems allows the PASS to be operated without requiring the use of isolated auxiliary systems that would circulate post-accident

fluids outside containment. Principal PASS valves are environmentally qualified and are listed in table 281.12-1.

(4) The PASS can quantify both dissolved oxygen and dissolved hydrogen with unpressurized reactor coolant samples using a hydrogen gas chromatograph and an Orbisphere oxygen analyzer. Dissolved oxygen can be measured to less than 0.1 ppm.

(5) The VEGP cooling water is neither seawater nor brackish, and more than one barrier is provided between primary containment systems and the cooling water; therefore, chloride analysis will be performed within 4 days.

(6) The PASS is designed to permit inline analysis of the reactor coolant, emergency sumps, and containment atmosphere in accordance with the exposure criteria of General Design Criterion 19. Remote inline sampling is performed from the radiochemistry laboratory.

(7) As discussed in paragraph 9.3.2.2.5, the PASS has the capability to perform boron analysis.

(8) Inline monitoring is used as the primary method of performing the required analysis. The PASS has the capability to obtain both diluted and undiluted backup grab samples. In the event both inline monitoring and grab sampling analysis capability fail, arrangements have been made to send the samples to Oak Ridge National Laboratories in a licensed shipping cask.

Provisions for inline monitor flushing have been provided to reduce plateout, crud buildup, and radiation exposure of components, the panel tubing and monitors are flushed after every panel exercise.

(9) Concerning the radiological and chemical sample analysis capability:

(a) As discussed in paragraph 9.3.2.2.5, the PASS has the capability to identify and quantify radionuclides that are indicative of the degree of core damage. Post-accident source terms are discussed in paragraph 12.2.1.3. High activity samples can be diluted by 1000 to 1, and sample size is minimized to reduce the activity sufficiently to perform the required analysis. Radionuclide concentrations in the range of 10 uCi/ml to 10 Ci/ml can be analyzed.

(b) The predicted post-accident background radiation level in the PASS cubicle in the fuel handling building is 100 to 1000 R/h as shown in figure 12.3.1-2, sheet 13. The contribution to background radiation levels from samples which are present is small due to the extensive lead shielding which is provided around the sample.

Date demonstrating the accuracy of the PASS counting system are not available at this stage of the design. However, the "multiport cave" design of the radiation analysis panel allows the placement of properly conditioned samples into one of several shielded measurement ports. These ports provide a fixed counting geometry for both liquid and gaseous samples. High purity germanium detectors are provided with integral metal shields to minimize background effects on counting accuracy. In addition, the sampling area is ventilated to control the presence of airborne radioactivity.

(10) The Sentry PASS provided for VEGP is designed to provide accuracy, range, and sensitivity necessary to allow the operator to determine the radiological and chemical status of the sample. Evidence that equipment provided in the PASS has been successfully used in a similar environment can be provided on a case basis as requested. Numerous systems of this design have been provided for other nuclear power plants. Post-accident sampling procedures will be developed to ensure that sampling, analysis, and transport is in conformance with Nuclear Regulatory Commission guidelines.

(11) Design of the PASS follows the ANSI N13.1 sampling guide. The liquid and gas samples are purged at a rate of 1400 cm^3/min and 5600 cm^3/min, respectively, for five volume changeouts. Appropriate sample lines are thermostatically controlled and electric heat traced with insulation to maintain sample tube surface at 300°F. Piping design measures to minimize particle and iodine plateout include smallest practical bore for sample supply lines to achieve maximum sample velocity which also ensures total turbulent flow for representative sampling, minimum tube bend radii of 20 times tube bore, full bore valves without abrupt directional changes, and/or abrupt expansion/contraction.

To prevent blockage of sample lines by loose material in the reactor coolant system or containment, 3/8-in. tubing is used up to the PASS sample coolers. There is a filter before the valves which can filter particles larger than 140 microns. Block and bleed valves are provided to backflush the system.

To minimize sample loss, joints are welded. Any leakage within the PASS panel is detected by a radiation monitor. The residues of the liquid sample collection are returned back to the containment during accident condition. During normal condition, residues of the liquid sample collection are returned to the chemical and volume control system mixed bed demineralizer and eventually to the volume control tank. The gas sample is returned back to the containment.

Redundant, environmentally qualified, remotely operated isolation valves which close on containment isolation signals restrict flow to limit reactor coolant loss from a rupture of sample lines.

The PASS sample station area is provided with a positive exhaust filtration system equipped with charcoal and HEPA filters.

TABLE 281.12-1

ENVIRONMENTALLY QUALIFIED PASS VALVES

Valve Tag No.	Function
HV-8211	Containment isolation valve on PASS gas sample return to containment atmosphere
HV-8212	Containment isolation valve on PASS gas sample return to containment atmosphere
HV-8208	Containment isolation valve on PASS liquid sample return line to containment sump
HV-8209	Containment isolation valve on PASS liquid sample return line to containment sump
HV-8986A	Isolation valve on sample from RHR emergency sump
HV-8986B	Isolation valve on sample from RHR emergency sump
HV-8811A	Containment isolation valve on RHR emergency sump discharge line
HV-8811B	Containment isolation valve on RHR emergency sump discharge line
HV-3501	Isolation valve on sample from RCS hot leg loop 3
HV-3548	Containment isolation valve on sample from RCS hot leg
HV-8220	Containment isolation valve on sample from RCS hot leg
HV-3500	Isolation valve on sample from RCS hot leg loop 1
HV-2970A	Containment isolation valve on containment atmosphere sample
HV-2970B	Containment isolation valve on containment atmosphere sample
HV-2791A	Containment isolation valve on containment atmosphere sample
HV-8221	Isolation valve on containment atmosphere sample

Question 430.1

Provide a detailed description (or plan) of the level of training proposed for your operators, maintenance crew, quality assurance, and supervisory personnel responsible for the operation and maintenance of the emergency diesel generators. Identify the number and type of personnel that will be dedicated to the operations and maintenance of the emergency diesel generators and the number and type that will be assigned from your general plant operations and maintenance groups to assist when needed.

In your discussion identify the amount and kind of training that will be received by each of the above categories and the type of ongoing training program planned to assure optimum availability of the emergency generators.

Also discuss the level of education and minimum experience requirements for the various categories of operations and maintenance personnel associated with the emergency diesel generators.

Response

Formal training programs for the operation and maintenance of the emergency diesel generators will be developed by the VEGP training department. The manufacturer will be consulted for assistance in the development of the length, depth, and content of the courses. Operators and the operator's supervisors will receive training in the operational aspects of the diesel. Selected personnel in maintenance and quality control and supervisors in these areas will receive training in the maintenance aspects of the emergency diesels. Courses provided by the manufacturer or a qualified consulting company may be given in lieu of the formal schools given by the VEGP training department.

If major design or operational changes occur, they will be covered on an as required basis during requalification programs in the operations, maintenance, and quality control training.

One operations department operator will be immediately available for emergency diesel generator operations. Two maintenance crews will be assigned to the diesel generators as their primary (but not full time) responsibility. Each crew will consist of a foreman and six maintenance personnel. One crew will be assigned mechanical maintenance, the other crew electrical maintenance.

Two other operators are available as needed. Additional operators could be reassigned from other shifts if required. In addition to the two on-call maintenance crews, the other personnel in the maintenance department could be assigned to maintenance efforts if required.

All personnel will have a high school diploma or equivalent. The minimum educational and experience requirements for the aforementioned personnel are as specified in subsection 13.1.3.

Question 430.2

Operating experience of two nuclear power plants has shown that during periodic surveillance testing of a standby diesel generator, initiation of an emergency start signal (loss-of-coolant accident or loss of offsite power) resulted in the diesel failing to start and perform its function due to depletion of the starting air supply from repeated activation of the starting relay. This event occurred as the result of inadequate procedures and from a hangup in engine starting and control circuit logic failing to address a built-in time delay relay to assure the engine comes to a complete stop before attempting a restart. During the period that the relay was timing out, fuel to the engine was blocked, while the starting air was uninhibited. This condition, with repeated start attempts, depleted starting air and rendered the diesel generator unavailable until the air system could be repressurized.

Review procedures and control system logic to assure this event will not occur at your plant. Provide a detailed discussion of how your system design, supplemented by procedures, precludes the occurrence of this event. Should the diesel generator starting and control circuit logic and procedures require changes, provide a description of the proposed modifications.

Response

If the diesel generator set is intentionally shut down for periodic surveillance testing or shut down for any other reason, there will be a 90-s time delay initiated to permit the engine to come to a complete stop. During the 90-s time delay period, fuel to the engine is blocked, but starting air is available. However, if an emergency start signal is received at the control panel during the 90-s time delay period, the system will immediately switch to emergency mode bypassing the 90-s time delay, and the engine will start. The diesel will automatically start as long as 150 psig of air pressure remains in the starting air receivers. If the pressure becomes less than 150 psig, the starting air control valves on the engine will shut and will not open until manual start is initiated. This is to conserve air and prevent diesel failure due to depleted starting air. This means, if the pressure in the receivers is less than 150 psig, the engine cannot be started automatically but can be started manually. The engine will start manually with air pressure down to approximately 90 psig.

See the response to question 430.30 for air receiver pressure decay.

Operating procedures are being developed to preclude depletion of starting air during the 90-s time delay period. These procedures will be completed 6 months prior to fuel load.

Question 430.3

Periodic testing and test loading of an emergency diesel generator in a nuclear power plant is a necessary function to demonstrate the operability, capability, and availability of the unit on demand. Periodic testing coupled with good preventive maintenance practices will assure optimum equipment readiness and availability on demand. This is the desired goal.

To achieve this optimum equipment readiness status the following requirements should be met:

A. The equipment should be tested with a minimum loading of 25 percent of rated load. No load or light load operation will cause incomplete combustion of fuel resulting in the formation of gum and varnish deposits on the cylinder walls, intake and exhaust valves, pistons and piston rings, etc., and accumulation of unburned fuel in the turbocharger and exhaust system. The consequences of no load or light load operation are potential equipment failures due to the gum and varnish deposits and fire in the engine exhaust system.

B. Periodic surveillance testing should be performed in accordance with the applicable Nuclear Regulatory Commission (NRC) guidelines (Regulatory Guide 1.108) and with the recommendations of the engine manufacturer. Conflicts between any such recommendations and the NRC guidelines, particularly with respect to test frequency, loading, and duration, should be identified and justified.

C. Preventive maintenance should go beyond the normal routine adjustments, servicing, and repair of components when a malfunction occurs. Preventive maintenance should encompass investigative testing of components which have a history of repeated malfunctioning and require constant attention and repair. In such cases consideration should be given to replacement of those components with other products which have a record of demonstrated reliability, rather than repetitive repair and maintenance of the existing components. Testing of the unit after adjustments or repairs have been made only confirms that the equipment is operable and does not necessarily mean that the root cause of the problem has been eliminated or alleviated.

D. Upon completion of repairs or maintenance and prior to an actual start, run, and load test, a final equipment check should be made to assure that all electrical circuits are functional; i.e., fuses are in place, switches and circuit breakers are in their proper position, there are no loose wires, all test leads have been removed, and all valves are in the proper positions to permit a manual start of the equipment. After the unit has been satisfactorily started and load tested, return the unit to ready automatic standby service and under the control of the control room operator.

Provide a discussion of how the above requirements have been implemented in the emergency diesel generator system design and how they will be considered when the plant is in commercial operation, i.e., by what means will the above requirements be enforced.

Response

The following responses correspond to the above questions:

A. The diesel generator can be operated at no load at rated speed for periods up to 7 days. To reduce the possibility of accumulation of combustion and lube oil products in the exhaust system at low loads, the engine will be operated at 50 percent load for 1-h periods during each 24 h within 7 days, starting with the first hour of each 24-h period. Above the 30 percent load rating, the engine may be run continuously, as required.

   VEGP is in the process of developing diesel generator test procedures. The procedures will require the diesel generators to be tested to a minimum of 30 percent of rated load during surveillance testing.

B. VEGP is in conformance with Regulatory Guide 1.108. Refer to sections 1.9 and 8.1 for details.

C. Presently, preventive maintenance identified for the diesel generators incorporates the manufacturers recommendations. As a member of the Transamerica Delaval, Inc., (TDI) diesel generator owners group, project management will have access to investigative studies and history of repeated malfunctioning of components. The TDI diesel generator owners group is presently developing recommendations for preventive maintenance based on the investigative studies and history. Project management will review these recommendations for applicability at VEGP and in addition will review VEGP component failure history for trends.

D. Administrative procedures will be utilized to control the restoration of equipment upon the completion of repairs or maintenance.

Question 430.4

The availability on demand of an emergency diesel generator is dependent upon, among other things, the proper functioning of its controls and monitoring instrumentation. This equipment is generally panel mounted and in some instances the panels are mounted directly on the diesel generator skid. Major diesel engine damage has occurred at some operating plants from vibration-induced wear on skid-mounted control and monitoring instrumentation. This sensitive instrumentation is not made to withstand and function accurately for prolonged periods under continuous vibrational stresses normally encountered with internal combustion engines. Operation of sensitive instrumentation under this environment rapidly deteriorates calibration, accuracy, and control signal output.

Therefore, except for sensors and other equipment that must be directly mounted on the engine or associated piping, the controls and monitoring instrumentation should be installed on a free-standing floor-mounted panel separate from the engine skids and located on a vibration-free floor area. If the floor is not vibration free, the panel shall be equipped with vibration mounts.

Confirm your compliance with the above requirement or provide justification for noncompliance.

Response

Refer to paragraph 8.3.1.5.

Question 430.5

Expand paragraph 9.5.3.2.3 to provide the following additional information regarding emergency lighting for the main control board and remote shutdown panels. Your discussion should also include access routes to the control room.

A. List the illumination levels provided by each of the emergency lighting systems, and demonstrate that these illumination levels conform to the minimum recommendations of NUREG-0700. In your discussion of illumination levels, consider a single active failure of an emergency diesel generator.

B. Consider the design basis seismic event coincident with the loss of all nonseismic equipment, components, and systems (including offsite power). Show that adequate illumination will be provided in the control room to effect safe, cold shutdown of the reactor and to maintain cold shutdown for an extended period of time, or provide justification for not requiring control room lighting under these conditions.

Response

See table 430.5-1.

TABLE 430.5-1 (SHEET 1 OF 2)

ILLUMINATION LEVELS OF EMERGENCY LIGHTING FOR THE MAIN CONTROL BOARD AND REMOTE SHUTDOWN PANELS

Operating Conditions	Main Control Board[a][b]	Remote Shutdown Panels[a]	Access Routes to Control Room and Shutdown Rooms	Remarks
With offsite or onsite ac power available	50 fc (min) (panel lighting levels are adjustable)	30 fc (min)	10 fc (min)	Conforms with NUREG-0700 minimum requirements
With active failure of one emergency diesel generator	25 fc (min)[c]	15 fc (min)[c]	10 fc (min)[d]	Conforms with NUREG-0700 minimum requirements
Design basis earthquake coincident with loss of all non-seismic equipment (including offsite power)[e]	(f)	(g)	(g)	---

a. Vertical face of switchboards are 66 in. above floor level, facing operator.

b. Control room luminous ceiling also has additional 90-min rated battery-backed power systems to provide lighting during loss of ac conditions.

c. Lighting level will be more than minimum footcandles indicated, since the ceiling fixtures will be supplemented by 8-h self-contained sealed beam modular units.

d. Ten fc (min) for the first 8 h following loss of one emergency diesel generator; 5 fc (min) after 8 h following loss of one emergency diesel generator assuming offsite power is not restored.

TABLE 430.5-1 (SHEET 2 OF 2)

e. The emergency lighting power distribution system is Class 1E from the 4.16-kV to the 480-V level. Fully qualified Class 1E isolation transformers reduce the voltage to the 120-V level. Beyond the isolation transformers the system is non-Class 1E. All components including raceways, panelboards, and lighting fixtures have been mounted to Seismic Category 1 requirements. Due to the simple design of panels and fixtures, it is felt that should a fixture or breaker problem develop as a result of a design basis earthquake (DBE), repair could be performed (if required) within the same time frame as relamping could be accomplished.

It should be noted that in areas where emergency lighting is provided, fixtures are powered from alternate distribution systems; i.e., diversity in distribution is provided.

f. The main control room luminous ceiling is designed and qualified to Seismic Category 1 requirements. Lamps within the fixtures are not guaranteed to function during or following a DBE. Test results have shown that lamps remain functional, however. Should all lamps (including 8-h modular sealed beam units) fail during a DBE, the illumination levels can be restored by replacing the lamps, and/or portable dc units can be used until lighting is restored.

g. The lighting fixtures are not seismically qualified to function during or after a DBE. However, the fixtures are mounted in accordance with Seismic Category 1 requirements. Failed lamps within the fixtures (if any) can be replaced and/or portable dc units can be used until lighting is restored.

Question 430.6

The FSAR text and table 3.2-1 states that the components and piping systems for the diesel generator auxiliaries (fuel oil system cooling water, lubrication, air starting, and intake and combustion system) that are mounted on the auxiliary skids are designed Seismic Category 1 and are ASME Section III, Class 3 quality. The diesel engine and piping and valves within the engine boundary are Seismic Category 1 and are constructed to DEMA and manufacturer's standards, respectively. This is not in accordance with Regulatory Guide 1.26, which requires the entire diesel generator auxiliary systems be designed to ASME Section III Class 3 or Quality Group C. Therefore, provide the following:

A. The industry standards which were used by the diesel generator vendor in the design, manufacture, and inspection of the piping and components within the diesel engine boundary.

B. A revised piping and instrumentation diagram (figure 9.5.4-1) which shows all piping and components which are within the engine boundary and which are engine mounted. Identify the diesel engine interface and all locations where there is a change in piping classification. (The diesel engine interface is defined as the first connection off the engine block, either flanged, screwed, or welded.)

Response

The engine piping boundary and auxiliary module (skid) boundary are shown in figure 9.5.4-1. Safety-related piping and components within these boundaries are designed to Seismic Category 1 requirements and are furnished by the engine manufacturer.

Piping and components within the auxiliary module are designed to ASME Section III, Class 3 requirements.

Piping and components within the engine piping boundary are designed in accordance with the engine manufacturer's standards. Fabricated piping outside of the cast iron cylinder block and the cast steel cylinder heads is made from SA53 and A106 steel pipe, utilizing ASME qualified welders and procedures. Castings, such as block, heads, and pump casings, are pressure tested in accordance with the engine manufacturer's standards. The following types of connections are used in pressure connections to the engine: ANSI Standard NPT threaded;

150- and 300-lb raised face flange; and ASME-rated expansion couplings.

Locations where there is a change in piping classification are shown in figure 9.5.4-1. The piping classification system used for the VEGP is described in subsection 3.2.2.

Question 430.7

Identify all high and moderate energy lines and systems that will be installed in the diesel generator room. Discuss the measures that will be taken in the design of the diesel generator facility to protect the safety-related systems, piping, and components from the effects of high and moderate energy line failure to assure availability of the diesel generators when needed.

Response

There are no high energy lines in the diesel generator rooms. The only moderate energy lines are those associated with each diesel engine and its auxiliaries such as nuclear service cooling water, demineralized water, and fuel oil. There is complete separation between the train A and B diesel generators; therefore, a failure of a moderate energy line in one room would not affect the availability of the other diesel generator.

Question 430.8

Describe the instruments, controls, sensors, and alarms provided for monitoring the diesel engine fuel oil storage and transfer, cooling water, lubrication, air starting, and combustion air intake and exhaust systems, and describe their function. Discuss the testing and calibration necessary to maintain and assure a highly reliable instrumentation, controls, sensors, and alarm system, the frequency of such testing, and where the alarms are annunciated. Identify the temperature, pressure, and level sensors which alert the operator when these parameters exceed the ranges recommended by the engine manufacturer and describe what operator actions are required during alarm conditions to prevent harmful effects to the diesel engine. Discuss the system interlocks provided. If this information is provided in another section of the FSAR, provide a specific reference to that section.

Response

Instrumentation associated with the diesel generators is described in paragraphs 9.5.4.5, 9.5.5.5, 9.5.6.5, 9.5.7.5, 9.5.8.5, 8.3.1.1.3, and 7.3.17. Testing and calibration of instrumentation will be based on the manufacturer's recommendations.

Question 430.9

In FSAR section 1.9, you state that the design of the fuel oil storage and transfer system conforms to the requirements of Regulatory Guide 1.137, which endorses ANSI N-195. However, there is no reference to testing of fuel oil as discussed in Appendix B of ANSI N-195 and position C2 of Regulatory Guide 1.137. Revise your FSAR to include a discussion of your conformance to these requirements.

Response

A response will be provided by July 1984.

Question 430.10

The diesel generator structures are designed to seismic and tornado criteria and are isolated from one another by a reinforced concrete wall barrier. Describe the barrier (including openings) in more detail and its capability to withstand the effects of internally generated missiles resulting from a crankcase explosion, failure of one or all of the starting air receivers, or failure of any high or moderate energy line and initial flooding from the cooling system so that the assumed effects will not result in loss of an additional generator.

Response

The diesel generators are separated from each other by a 2-ft thick reinforced concrete wall barrier that extends the length of the building (111 ft) and is 33 ft high and supports the second floor slab. Figure 430.10-1 provides a plan view of the wall barrier, and figure 430.10-2 shows the penetrations in this barrier wall. Table 430.10-1 lists these penetrations and their associated function.

The crankcase is vented as described in response to question 430.38, and crankcase explosions are precluded by design.

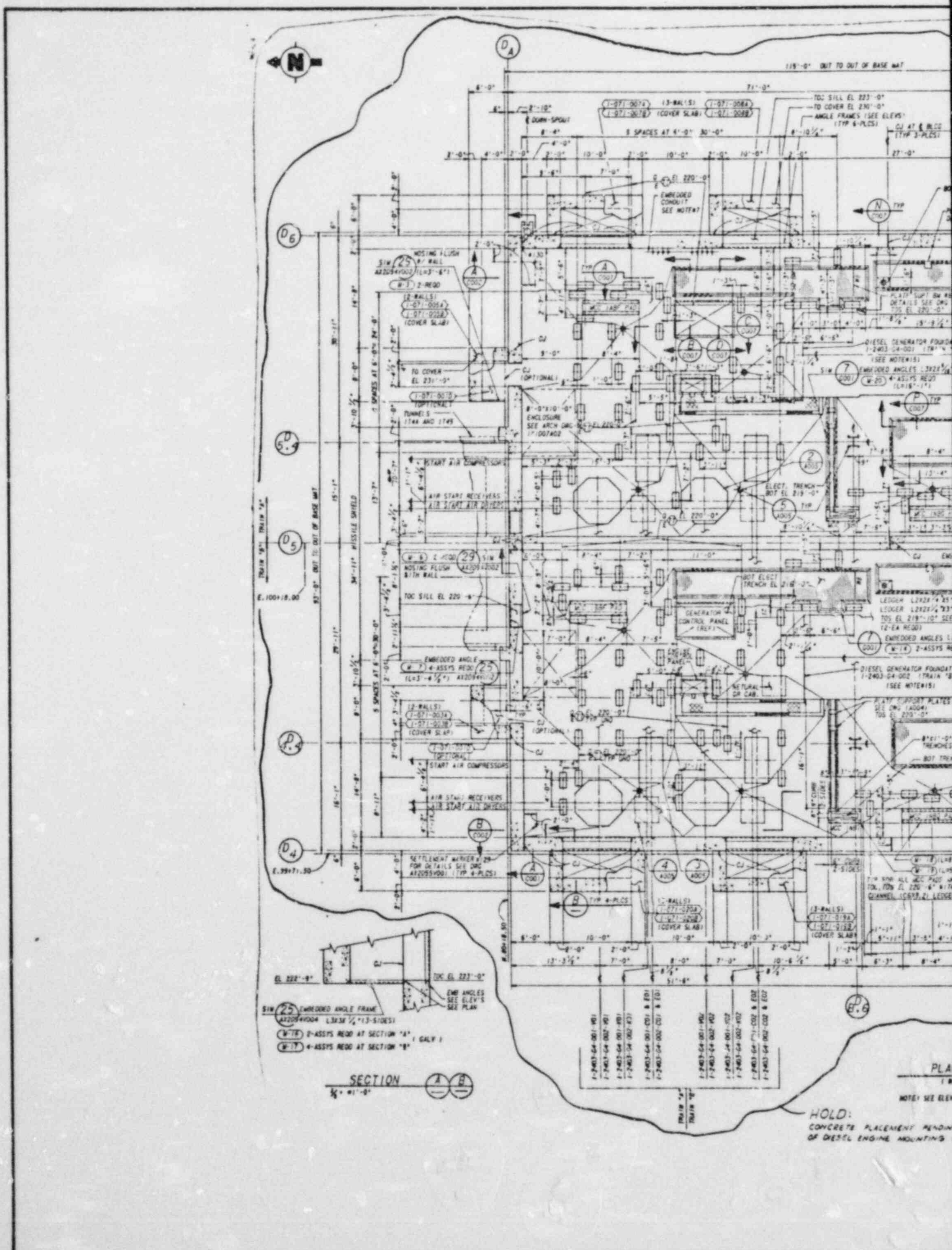
The starting air receivers are designed to Seismic Category 1, ASME Section III, Class 3 requirements. Overpressure protection is incorporated into the design. The maximum air pressure inside the receivers is limited to 250 psig and is not a high energy system. Therefore, missiles resulting from failure of the starting air receivers are not postulated.

There are no high energy lines in the diesel generator building. The only moderate energy lines are those associated with each diesel engine and its auxiliaries. None of these moderate energy lines are considered potential missile sources. Penetrations between rooms are located above the maximum postulated flood elevation; therefore, flooding of one room will not affect the other diesel engine.

TABLE 430.10-1

PENETRATIONS IN DIESEL GENERATOR BARRIER WALL

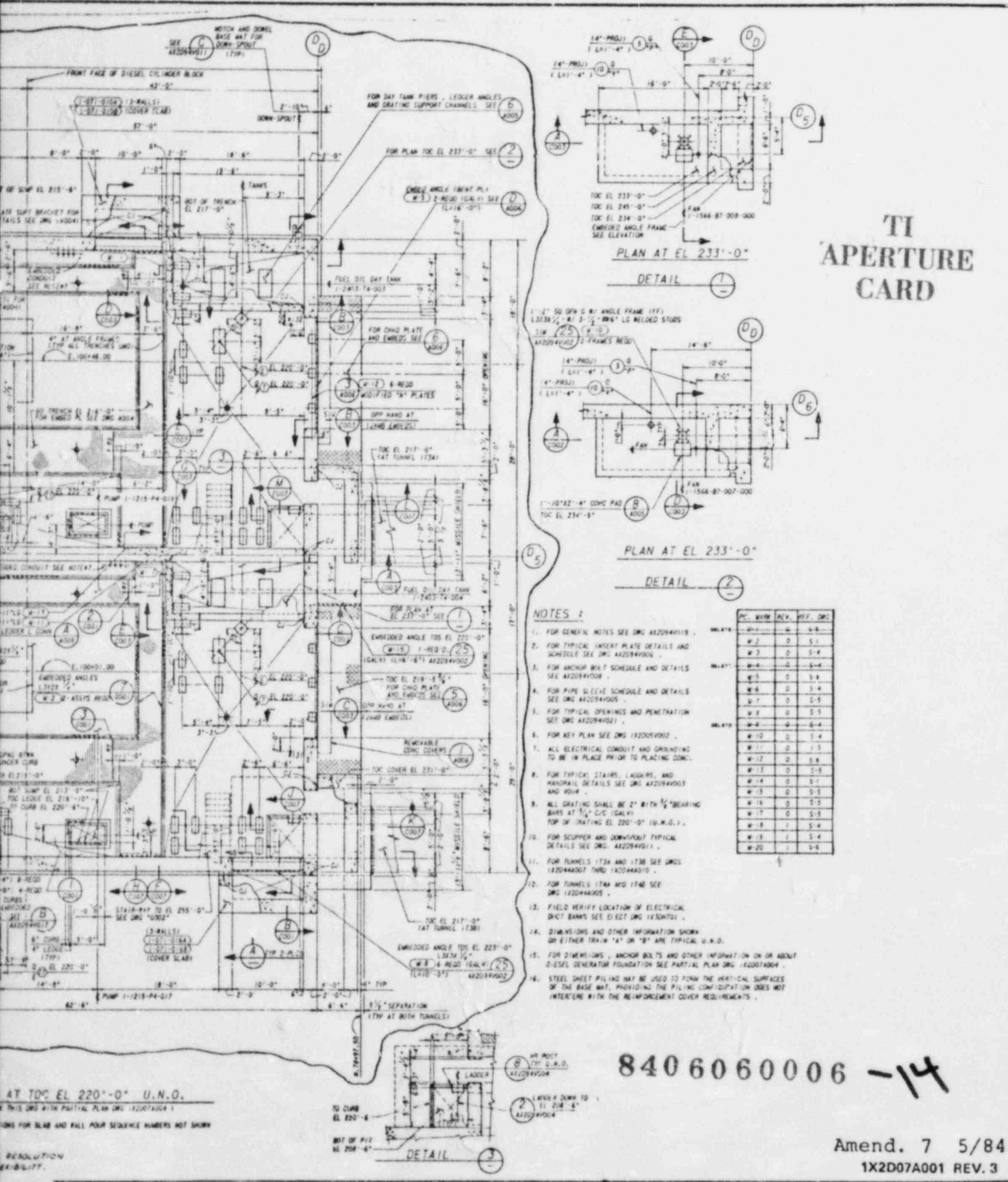
Description	Size	Elevation (centerline, at bottom of penetration)
Fire protection piping	6-in. diameter	229 ft
Fire protection piping	8-in. diameter	229 ft
Fire protection piping	10-in. diameter	229 ft
Fire protection piping	10-in. diameter	229 ft
Electrical opening	2 ft x 3 ft	248 ft 6 in.



115'-0" OUT TO OUT OF BASE MAT
71'-0"
5 SPACES AT 6'-0" 30'-0"
EMBEDDED CONDUIT SEE NOTE#7
START AIR COMPRESSORS
AIR START RECEIVERS
AIR START AIR DRYERS
MISSILE SHIELD
93'-0" OUT TO OUT OF BASE MAT
GENERATOR CONTROL PANEL (REF)
DIESEL GENERATOR FOUNDATION
TUNNELS 1744 AND 1745
SETTLEMENT MARKER
EMBEDDED ANGLE FRAME
SECTION
HOLD:
CONCRETE PLACEMENT PENDING
OF DIESEL ENGINE MOUNTING

Also Available On
Aperture Card

TI
APERTURE
CARD



NOTES :

1. FOR GENERAL NOTES SEE DWG AX2094V019 .
2. FOR TYPICAL INSERT PLATE DETAILS AND SCHEDULE SEE DWG AX2094V006 .
3. FOR ANCHOR BOLT SCHEDULE AND DETAILS SEE AX2094V008 .
4. FOR PIPE SLEEVE SCHEDULE AND DETAILS SEE DWG AX2094V005 .
5. FOR TYPICAL OPENINGS AND PENETRATION SEE DWG AX2094V021 .
6. FOR KEY PLAN SEE DWG 1X2D05V002 .
7. ALL ELECTRICAL CONDUIT AND GROUNDING TO BE IN PLACE PRIOR TO PLACING CONC.
8. FOR TYPICAL STAIRS, LADDERS, AND HANDRAIL DETAILS SEE DWG AX2094V003 AND V004 .
9. ALL GRATING SHALL BE 2" WITH 3/16" BEARING BARS AT 1 3/16" C/C (GALV) TOP OF GRATING EL 220'-0" (U.N.O.).
10. FOR SCUPPER AND DOWNSPOUT TYPICAL DETAILS SEE DWG. AX2094V011 .
11. FOR TUNNELS 1T3A AND 1T3B SEE DWGS 1X2D44A007 THRU 1X2D44A010 .
12. FOR TUNNELS 1T4A AND 1T4B SEE DWG 1X2D44A005 .
13. FIELD VERIFY LOCATION OF ELECTRICAL DUCT BANKS SEE ELECT DWG 1X3DH701 .
14. DIMENSIONS AND OTHER INFORMATION SHOWN ON EITHER TRAIN "A" OR "B" ARE TYPICAL U.N.O.
15. FOR DIMENSIONS , ANCHOR BOLTS AND OTHER INFORMATION ON OR ABOUT DIESEL GENERATOR FOUNDATION SEE PARTIAL PLAN DWG 1X2D07A004 .
16. STEEL SHEET PILING MAY BE USED TO FORM THE VERTICAL SURFACES OF THE BASE MAT, PROVIDING THE PILING CONFIGURATION DOES NOT INTERFERE WITH THE REINFORCEMENT COVER REQUIREMENTS .

	PC. MARK	REV.	REF. DWG
DELETED	~~W-1~~	~~0~~	~~S-6~~
	W-2	0	S-1
	W-3	0	S-4
DELETED	~~W-4~~	~~0~~	~~S-4~~
	W-5	0	S-4
	W-6	0	S-4
	W-7	0	S-5
	W-8	0	S-5
DELETED	~~W-9~~	~~0~~	~~S-4~~
	W-10	0	S-4
	W-11	0	S-5
	W-12	0	S-4
	W-13	0	S-5
	W-14	0	S-1
	W-15	0	S-5
	W-16	0	S-5
	W-17	0	S-5
	W-18	1	S-4
	W-19	1	S-4
	W-20	1	S-6

8406060006 -14

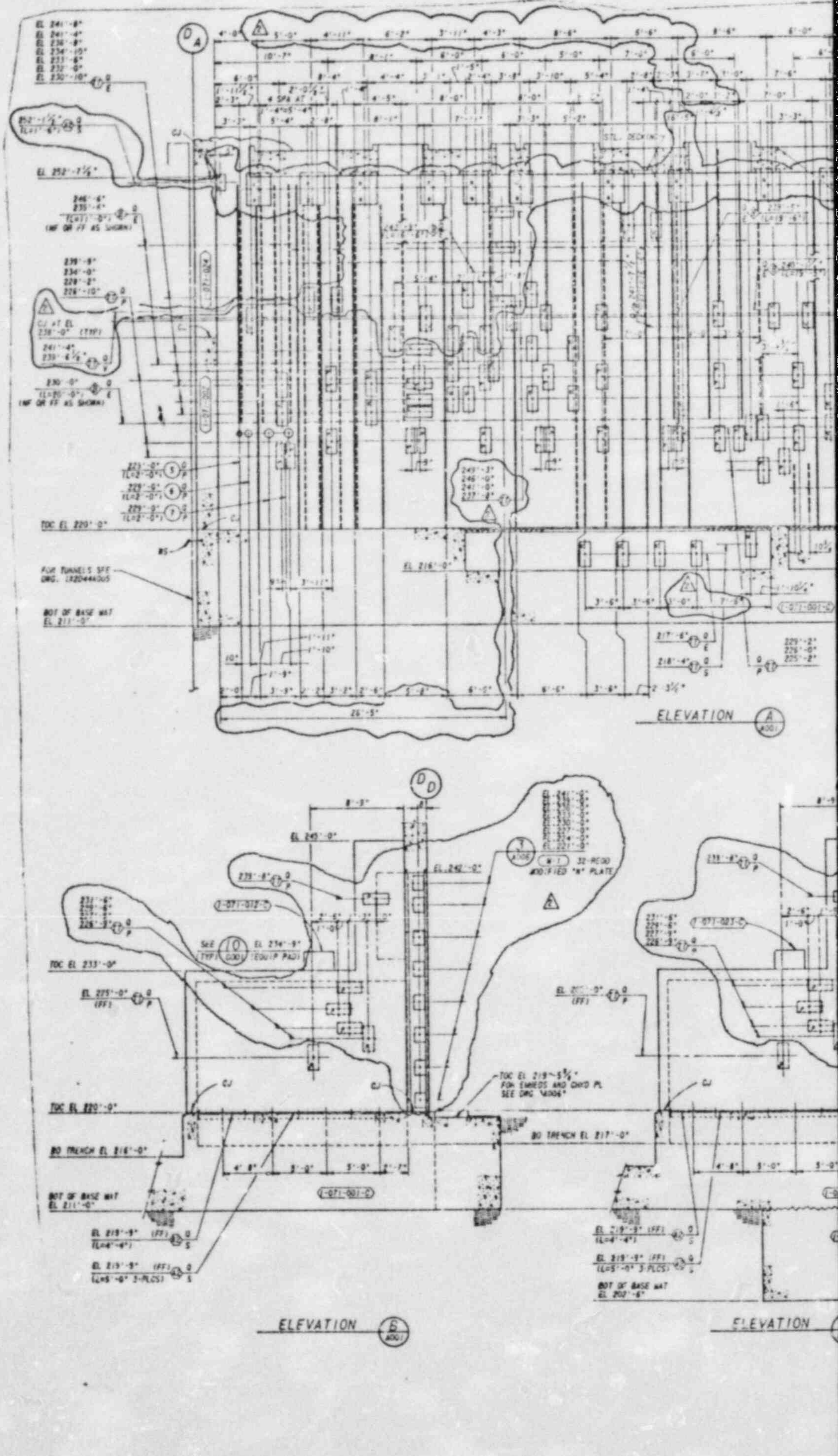
Amend. 7 5/84
1X2D07A001 REV. 3

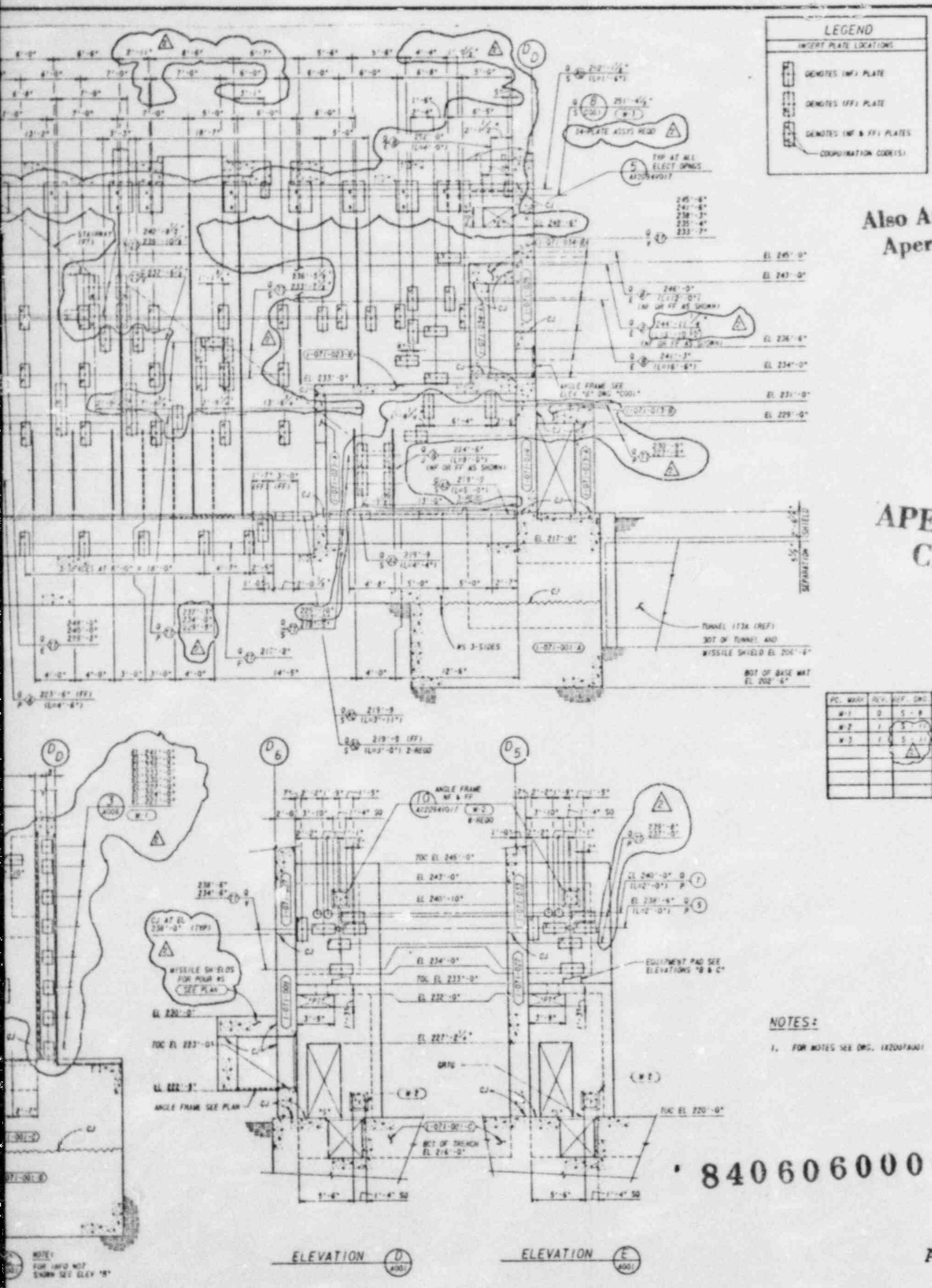
Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

DIESEL GENERATOR BUILDING
FORMING PLAN AT EL 220 FT

FIGURE 430.10-1


STL. DECKING
TOC EL 220'-0"
FOR TUNNELS SEE DWG. 1X2D444D05
BOT OF BASE MAT EL 211'-0"
EL 216'-0"
ELEVATION
TOC EL 233'-0"
TOC EL 220'-0"
BO TRENCH EL 216'-0"
BO TRENCH EL 217'-0"
BOT OF BASE MAT EL 211'-0"
ELEVATION
ELEVATION



Also Available On Aperture Card

TI APERTURE CARD

8406060006-15

Amend. 7 5/84

1X2D07C003 REV. 2

Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

DIESEL GENERATOR BUILDING WALL ELEVATION INSERTS AND PENETRATIONS

FIGURE 430.10-2

Question 430.11

Describe your design provisions made to protect the fuel oil storage tank fill line from damage by tornado missiles.

Response

The 4-in. fill line for the fuel oil storage tank extends approximately 5 in. from the outside wall surface of the valve house and is approximately 48 in. above grade. In the unlikely event that the fill line outside the valve house is damaged, the storage tank can be filled by opening the manway cover on the storage tank which is located in the missile-protected pump house. Since damage of the storage tank fill line does not preclude the addition of fuel oil into the storage tank via alternate means, there is no tornado missile protection for the fill line.

Question 430.12

In the FSAR, you state that the fuel oil storage tanks are vented to the "valve house" located between the storage tanks. Expand your FSAR to provide additional information on the design features of this "valve house" which ensure adequate ventilation of the structure so as to preclude a buildup of combustible gases and the provisions to prevent the ventilation capability being blocked as a consequence of any weather condition.

Response

Diesel fuel oil is a heavy distillate gas oil, which by virtue of its specification and chemical composition does not contain light petroleum distillate products such as propane, butane, and gasoline, which are volatile and can transform into readily combustible gases. Therefore, at room temperature it is highly unlikely for a combustible gas to build up, since the means for producing the combustible gases is not present.

Two 4-in., U-bend vents are provided on the roof of the valve house to provide redundancy in ventilation under the most adverse weather conditions. Similarly, two 4-in., U-bend vents are provided on the roof of each diesel fuel oil storage tank pump house.

Question 430.13

Expand the FSAR to include a discussion of where the fuel oil day tank is vented and what provisions are made to prevent a buildup of combustible gases.

Response

See revised paragraph 9.5.4.2.1.3.

Question 430.14

FSAR subsection 9.5.4 and table 3.2.2-1 do not address seismic and quality group classification for the fuel oil valve house and transfer pump houses. Tornado missile protection for these structures also is not addressed. Revise your FSAR to include a discussion of the seismic and missile protection design of these structures, or provide a specific reference to an FSAR section where the information may be found.

Response

The fuel oil valve house and transfer pump houses are integrated into a single structure designated as the diesel fuel oil storage tank pump house. The seismic and quality group classifications of this structure are provided in table 3.2.2-1. The missile protection of this structure is described in section 3.5. The seismic design of this structure is described in section 3.7.

Question 430.15

Expand your FSAR to show that a spurious actuation of the fire protection system as a consequence of a seismic event will not affect transfer pump operation and, consequently, diesel generator availability.

Response

See revised paragraph 9.5.4.2.1.2.

Question 430.16

Regulatory Guide 1.137 (and ANSI N-195) require fuel oil storage capacity which is adequate for 7 days of diesel generator operation at post-loss-of-coolant accident (post-LOCA) loads, with a 10 percent margin for diesel generator testing and maintenance. Provide a discussion of the post-LOCA diesel generator loading and fuel consumption which demonstrates that the 80,000-gal storage capacity is adequate for 7 days of operation for either diesel generator without refueling, assuming only 90 percent of the storage capacity is available at the start.

Response

The estimated 7-day post-LOCA load per diesel generator is 864,122 kWh. Fuel consumption is 0.0678 gal/kWh at engine rated (100 percent) load. This is equivalent to approximately 58,600 gal of fuel consumed for the 7-day period. The 7-day fuel consumption represents approximately 73 percent of the storage tank capacity. Therefore, the storage capacity is adequate for 7-day post-LOCA operation without refueling.

Question 430.17

Assume an unlikely event has occurred requiring operation of a diesel generator for a prolonged period that would require replenishment of fuel oil without interrupting operation of the diesel generator. What provision will be made in the design of the fuel oil storage fill system to minimize the creation of turbulence of the sediment in the bottom of the storage tank? Stirring of this sediment during addition of new fuel has the potential of causing the overall quality of the fuel to become unacceptable and could potentially lead to the degradation or failure of the diesel generator. In the response, refer to FSAR paragraph 9.5.4.2.1.1, and describe how a "full" tank, free of disturbed sediment, is obtained initially and how fuel oil is transferred from it to the day tanks.

Response

Piping layout between train A and train B provides the capability to transfer fuel oil in the following manner:

A. From train A storage tank to train A day tank (automatic operation).

B. From train A storage tank to train B day tank (manual operation).

C. From train B storage tank to train A day tank (manual operation).

D. From train B storage tank to train B day tank (automatic operation).

In the event that train A storage tank is being refilled, train A day tank will be replenished by train B storage tank via manual operation of the transfer pump and control valves.

The fill line is arranged in such a manner that fuel oil will be introduced to the bottom of the storage tank to minimize turbulence which may disturb any sediment collected at the bottom of the tank. A basket type strainer is provided in the truck fill line inside the valve house to prevent any sediment in the tanker truck from getting into the storage tank. A duplex fuel strainer and a duplex fuel filter are provided between the day tank and the engine to further prevent any sediment from reaching the engine. A 3-in. water drain is provided at the storage tank so that water and sediment can be removed periodically. A basket type strainer is provided in the fuel oil transfer pump discharge line which conveys fuel oil from the storage tank to the day tank.

The switching to a full fuel oil storage tank and the filling of a near-empty fuel oil storage tank are fully described in paragraph 9.5.4.2.1.1. Moreover, after a near-empty fuel oil tank has been filled, the operating procedure would require the fuel oil in the tank to be allowed to stand for 24 h, to ensure all the fine particles and sediments are settled out, prior to the storage tank being realigned and put back into service.

With the above provisions for ensuring clean fuel is delivered to the engine, the postulated interruption of the diesel generator operation is not anticipated.

Question 430.18

Expand your FSAR discussion on fuel oil resupply to include the method employed to deliver fuel oil to the site, how fuel oil can be transferred from the adjacent fuel oil fired steam turbine plant to the site, and how either can be accomplished under extremely unfavorable environmental conditions.

Response

See revised paragraph 9.5.4.2.2.

Question 430.19

Expand your FSAR discussion on biocides and "other additives." State what biocides and "other additives" will be utilized, and show that these materials comply with the diesel engine vendor's recommendation and are compatible with the fuel to be used at VEGP. Also, state how fuel oil temperature will be maintained above the cloud point, i.e., by locating below the frost line, by heat tracing, or both. Provide details, and state the minimum fuel oil cloud point allowable.

Response

This response will be provided by July 1984

Question 430.20

Provide justification for not providing cathodic protection for the fuel oil storage tanks and the underground portion of the fuel oil transfer system.

Response

As discussed in paragraph 9.5.4.2.1, the fuel oil storage tanks are coated both inside and outside for corrosion protection. The exterior of the fuel oil storage tanks is coated with one layer of coal tar epoxy with an average dry film thickness of 22 mils. These tanks are fabricated and coated in the field. Also, a 1/8-in. corrosion allowance is provided for the tanks. The fuel oil transfer piping is designed with 1/16-in. corrosion allowance. The buried portion is coated and wrapped for corrosion protection.

Question 430.21

In FSAR table 9.5.4-1, you include a heading of "nonsafety-related portion" under the title of Standby Diesel Generator Fuel Oil Storage and Transfer System. Describe what portions of this system are nonsafety-related, show these portions on the piping and instrumentation diagram, and describe their isolation from safety-related portions.

Response

The truck fill lines (from truck fill connection to the first valve connection) and the flame arresters for both the fuel oil storage and fuel oil day tanks are the nonsafety-related portions of the fuel oil storage and transfer system.

The nonsafety-related portions of the system are designated as project class 626 and are shown in figure 9.5.4-1. See revised table 9.5.4-1.

Question 430.22

FSAR subsection 9.5.4 and figure 9.5.4-1 do not agree with regard to fuel oil transfer system alarms and indications. (For example: (1) figure 9.5.4-1 shows high and low level alarms and (2) the FSAR text refers to pressure differential alarms on strainers and filters, but figure 9.5.4-1 shows indication, only). Revise the FSAR text and figure 9.5.4-1 to agree. Coordinate this response with the response to staff questions on overall system descriptions.

Response

Figure 9.5.4-1 will be revised by July 1984 to show the appropriate alarms. Table 9.5.4-3 has been revised accordingly.

Question 430.23

In subsection 9.5.5 of the FSAR, you indicate that the function of the diesel generator cooling water system is to dissipate the heat transferred through (1) engine jacket water, (2) lube oil cooler, and (3) combustion air aftercoolers. In table 9.5.5-1, you show the jacket water heat exchanger design duty as 21.02 x 10^6 Btu/h. Tabulate the maximum heat rejection to the cooling water system, and show that the jacket water heat exchanger is adequate for the intended service plus a design margin (excess capability), assuming the most severe design conditions for the plant.

Response

The cooling system is designed to handle a maximum heat load of 21.02 x 10^6 Btu/h from the engine water jackets, lube oil, and turbocharger air coolers. Tests performed on a similar engine have shown that the actual heat rejected from the diesel at 110 percent rated load (7700 kW) is just under 19.0 x 10^6 Btu/h which consists of 10.4 x 10^6 Btu/h from the engine jacket water, 2.9 x 10^6 Btu/h from the lube oil cooler, and 5.7 x 10^6 Btu/h from the turbocharger air cooler. Therefore, the jacket water heat exchanger has adequate margin for the intended service.

Question 430.24

You state in paragraph 9.5.5.2.2 the diesel engine cooling water is treated as appropriate to minimize corrosion. Provide additional details of your proposed diesel engine cooling water system chemical treatment, and discuss how your proposed treatment complies with the engine manufacturer's recommendations.

Response

The following paragraph is the recommended diesel engine cooling water treatment provided by the manufacturer in their instruction manual.

In accordance with the diesel engine manufacturer's recommendations, the pH value of the jacket water is maintained within a range of 8.25 and 9.75. The minimum pH value is necessary to prevent acid attack on the metallic surfaces, and the 9.75 maximum value prevents corrosion due to high alkaline content in the water. The manufacturer's suggested water treatment material for jacket water systems is sodium dichromate and a commercial boiler compound; however, the manufacturer recommends that a commercial water treatment company be consulted to ensure that local conditions are taken fully into account. Sodium dichromate is a source of alkaline chromate (CrO_4) which has been found to form a protective film on metallic surfaces that prevents attack by the corrosive elements found in the jacket water. Sodium dichromate is an acid compound which must have an alkaline compound such as boiler compound added to convert the dichromate to an effective alkaline chromate form. The manufacturer recommends that the alkaline chromate concentration be maintained between 700 and 1700 ppm. Less than 700 ppm can result in accelerated corrosion, while more than 1700 ppm serves no useful purpose and is a waste of material. The chloride content is not allowed to exceed 100 ppm as the effectiveness of alkaline chromate decreases and the chloride content increases. When initiating alkaline chromate water treatment for the first time, or after the system has been refilled, the manufacturer recommends testing the water daily for alkaline chromate concentration and for pH value. When the treatment becomes stable, the test interval can be extended to weekly tests. After each addition of chemicals, the water is circulated through the system, then tested to ensure that the required limits are met.

A cooling water treatment program which is based upon these recommendations of the engine manufacturer is being developed.

Question 430.25

Describe the provisions made in the design of the diesel engine cooling water system to assure that all components and piping are filled with water.

Response

The jacket water standpipe is a 30-in. diameter vertical cylindrical tank approximately 18 ft 10 in. in height. The standpipe is vented to the atmosphere at the top. The low level alarm is set at 37 in. below the top of the standpipe and is approximately 5 in. above the centerline of the 8-in. jacket water return line from the engine. This low level setting is to ensure the return line is below the water level in the standpipe, so that no air pocket will be created by the return jacket water. The standpipe normal water level is approximately 12 in. below the top to allow 12 in. for thermal expansion. The volume of water between the normal water level and the low level alarm is approximately 122 gal. The jacket water return line to the standpipe is above all other jacket water piping and other components to ensure the entire jacket water system is filled with water.

Question 430.26

The diesel generators are required to start automatically on loss of all offsite power and in the event of a loss-of-coolant accident (LOCA). The diesel generator sets should be capable of operation at less than full load for extended periods without degradation of performance or reliability. Should a LOCA occur with availability of offsite power, discuss the design provisions and other parameters that have been considered in the selection of the diesel generators to enable them to run unloaded (on standby) for extended periods without degradation of engine performance or reliability. Expand your FSAR to include and explicitly define the capability of your design with regard to this requirement.

Response

See revised paragraph 9.5.5.2.2.

Question 430.27

You state in paragraph 9.5.5.2 each diesel engine cooling water system is provided with a standpipe to provide for system expansion to absorb pump pressure variations and to provide makeup water. Demonstrate by analysis that the standpipe size will be adequate to provide for minor system leaks at pump shafts seals, valve stems, and other components and to maintain required net pump suction head on the system circulating pump and makeup water for 7 days continuous operation of the diesel engine at full rated load without makeup, or provide a Seismic Category 1, Safety Class 3 makeup water supply to the expansion tank.

Response

See the response to question 430.25 for a description of the standpipe. There are approximately 122 gal of water between the normal water level and the low level alarm. The 10-in. suction for the engine jacket water pump is located near the bottom of the standpipe. The approximate volume of water remaining in the standpipe between the low level alarm and the water level just above the pump suction nozzle is 650 gal. Minor system leakages and evaporation losses are not expected to exceed 10 gal/day; therefore, the volume above the low level alarm (122 gal) is adequate for 7-day continuous operation without makeup water.

Question 430.28

Recent licensee event reports have shown that tube leaks are being experienced in the heat exchangers of diesel engine jacket cooling water systems with resultant engine failure to start on demand. Provide a discussion of the means used to detect tube leakage and the corrective measures that will be taken. Include jacket water leakage into the lube oil system (standby mode), lube oil leakage into the jacket water (operating mode), and jacket water leakage into the engine air intake and governor systems (operating or standby mode). Provide the permissible inleakage or outleakage in each of the above conditions which can be tolerated without degrading engine performance or causing engine failure. The discussion should also include the effects of jacket water/service water systems leakage.

Response

Any leakage such as jacket water leaking into lube oil or lube oil leaking into jacket water will be detected by periodic examination of the jacket water and lube oil. Unusual amounts of jacket water or lube oil makeup required is an indication that the system should be checked for leakage.

Jacket standpipe water low level alarm is provided in the control room. Visual inspection of the jacket water in the standpipe will give some indication whether oil is present in the jacket water. A level sight gauge mounted on the standpipe can be used to check for any abnormal change of jacket water level in the standpipe. Also, the lube oil sump tank level gauge can be used to check lube oil level for abnormal changes.

The rise in water level with a corresponding drop in oil level, or vice versa, will indicate leakage has taken place, and corrective action would be initiated.

Question 430.29

Operating experience indicates that diesel engines have failed to start on demand due to water spraying on locally mounted electronic/electrical components in the diesel engine starting system. Describe what measures have been incorporated in the diesel engine electrical starting system to protect such electronic/electrical components from such potential environment.

Response

Two potential sources of water spray onto the diesel engine electrical starting system are from a jacket water system line leak and fire protection sprinklers.

The only electrical starting components which could come into contact with water spray resulting from a jacket water line leak are the four starting air solenoid valves mounted on the engine. The rest of the starting electrical system is mounted inside the engine control panel which is located approximately 16 ft away from the engine. The starting air solenoid valves are sealed units, and electrical wiring to these units is enclosed in sealed electrical conduits. Therefore, water spray from a jacket water pipe leak will not affect the engine starting capability.

The fire protection system for the diesel generator building is a preaction system. The main water supply valve is normally closed and the sprinkler piping is dry. Both the main supply valve and sprinkler must malfunction before water spray can be generated from the fire protection system. In addition, the engine control panel acts as a barrier between the spraying water and the engine electrical starting components mounted inside the panel. Therefore, water spray from the fire protection system is not considered a potential problem.

Question 430.30

In FSAR paragraph 9.5.6.3, you state that each air start system contains sufficient air for five consecutive starts of its associated diesel engine, commencing with the air receiver pressure at the low-pressure alarm point and without recharging from the air compressor. Expand subsection 9.5.6 of the FSAR to clarify your position regarding air start system capability and provide the following:

A. Define a diesel engine start cycle; i.e., engine cranking for a predetermined time, engine cranking until a predetermined rpm is reached, engine cranking for a predetermined number of engine revolutions, etc.

B. Describe the sequence of events when an emergency start signal exists. State whether the diesel engine cranks until all compressed air is exhausted or cranking stops after a preset time to conserve the diesel starting air supply.

C. Provide a tabulation of receiver pressure at the beginning and end of each of the five diesel engine starts, starting at the receiver pressure at the low pressure alarm point and without recharging.

Response

The following responses correspond to the above questions:

A. A diesel engine start cycle is defined in paragraph 9.5.6.3.B. Each starting air receiver tank holds approximately 305 ft^3 of air under a normal operating pressure range of 225 to 250 psig. The low pressure starting air alarm is set at 210 psig.

B. See revised paragraph 9.5.6.2.2.

C. The following is a typical air receiver pressure decay based on actual tests of similar engines using a 305-ft^3 air receiver:

Start Attempt	Initial Pressure (psig)	End Pressure (psig)
1	238	202
2	202	174
3	174	155
4	155	138
5	138	125
6	125	114
7	114	104
8	104	96
9	96	88

A greater quantity of air is consumed during starts at high receiver pressures due to greater leakage at the higher pressure through rings and valves.

Question 430.31

In FSAR paragraph 9.5.6.1, you state that filters are included as part of the air start system. There are no air start systems filters shown on figure 9.5.4-1. Revise your text and figure 9.5.4-1 to include a discussion of the filters provided and where they are located, or justify not having filters.

Response

The filters mentioned in paragraph 9.5.6.2 are the air compressor intake air filter and the strainer mounted on the engine starting air header upstream of the starting air valves.

The air compressor intake filter is part of the air compressor skid which is shown in figure 9.5.4-1. The engine starting air header strainer is also shown in figure 9.5.4-1.

Question 430.32

A recommendation in NUREG/CR-0660 states that the dewpoint in a compressed air starting system for diesel generators should be maintained at a minimum of 10°F below the lowest ambient temperature in the space housing the system (diesel generator room). In FSAR subsection 9.5.6, you state the design dewpoint for the starting air system is 50°F, while in FSAR subsection 9.5.7, you state that the minimum diesel generator room temperature will be 50°F, also. Your design does not conform to the recommendations of NUREG/CR-0660. Expand the FSAR to provide a detailed discussion of the air dryer design and operation, including provisions to ensure that the compressed air dewpoint is being maintained at or below the 50°F design.

Response

Refer to paragraph 9.5.6.2.2.

IMAGE EVALUATION
TEST TARGET (MT-3)

150mm

6

Question 430.33

In FSAR paragraph 9.5.7.5 you briefly discuss the low lube oil pressure trip. Expand your FSAR to provide additional information on this trip function, including more details on the pressure switches (manufacturer, model, etc.), the location of these switches on the diesel generator, and identification of these switches on the piping and instrumentation diagram (figure 9.5.4-1).

Response

The low pressure lube oil trip function is provided for the automatic safe shutdown of the engine during both normal and emergency operations. It is a two out of three logic (see paragraph 9.5.7.2.2). This means that there are three oil sensors installed on the engine lube oil inlet header. The lube oil pressure sensors are set to trip open at 30 psig decaying pressure. Their operation is similar to mechanical valves which are closed when pressure is above 30 psig and trip open on decreasing pressure. These sensors are monitored by a series of pneumatic logic circuits mounted inside the engine control panel. In the event that any two of the sensors are tripped open, they vent 60 psi pressure from an alarm/shutdown circuit in the pneumatic safety system. When venting occurs, a control air pressure extends the fuel rack shutdown cylinder at the engine. The cylinder moves the fuel racks to the no fuel position, and the engine stops due to fuel starvation. At the same time, a pressure switch in the engine control panel indicates to the electrical system that a malfunction has occurred in the lube oil system.

The oil pressure sensors are manufactured by California Controls Company (model B-4400), and the pressure switch is manufactured by Barksdale Controls Division, Transamerica Delaval, Inc. (model E15-M90).

The oil pressure sensors and switches are furnished by the engine manufacturer as integral parts of the engine and control panel. They are shown on engine pneumatic schematic and engine control panel schematic drawings furnished by the vendor. Therefore, they are not shown on the piping and instrumentation diagram.

Question 430.34

In FSAR paragraph 9.5.7.3, you discuss the lube oil keepwarm system, which is shown in part in figure 9.5.4-1. In the FSAR, you state that the keepwarm lube oil pump circulates heated lube oil throughout the diesel engine during standby. Continual prelubrication to certain parts of a diesel engine, such as the valve train and the turbochargers, may have a harmful effect; i.e., it may cause a hydraulic cylinder lock due to lube oil leaking through valve guides, or it could cause turbocharger fires due to oil leaking past seals and into the diesel engine exhaust. Confirm that these problems do not exist for your diesel generator design. Also, revise the FSAR to explicitly define the design provisions which preclude the above conditions from occurring.

Response

To prevent the problems described above, the diesel generator manufacturer has incorporated the following into their design of the lube oil keepwarm system:

A. An orifice is installed in a line from the lube oil keepwarm pump to limit the flow to the turbocharger during standby. Also, recently, the manufacturer has recommended that a manual valve be installed to preclude sending keepwarm lube oil to the turbocharger and recommended that this valve be opened to provide positive lubrication of the turbocharger bearings for 2 min just before a manual start. The manufacturer's recommendation is being evaluated. When the engine starts and the keepwarm pump is shutdown, the turbocharger receives oil from the main oil pump.

B. Keepwarm lube oil is precluded from reaching the rocker arms when the keepwarm pump is running. Therefore, oil leaks into the cylinder via the valve guides are prevented by design.

Question 430.35

Assume an unlikely event has occurred requiring operation of the diesel generators for a prolonged period of time. Demonstrate that there is adequate lube oil in each of the diesel generator sumps for a minimum of 7 days of operation at post-loss-of-coolant accident (post-LOCA) loads without the necessity of replenishing and without encountering abnormal lube oil temperatures, assuming the lube oil level is at the lowest permissible point of the start of operation. In the event the sump capacity is not adequate for 7 days operation and lube oil must be added, provide the following:

A. What provisions have been made in the design of the lube oil system to add lube oil to the sump. These provisions shall include procedures or instructions available to the operator on the proper addition of lube oil to the diesel generator as follows:

   1. How and where lube oil can be added while the equipment is on standby service.

   2. How and where lube oil can be added while the equipment is in operation.

   3. Particular assurance that the wrong kind of oil is not inadvertently added to the lubricating oil systems.

   4. That the expected rise in level occurs and is verified for each unit of lube oil added.

B. Verification that these operating procedures or instructions will be posted locally in the diesel generator rooms.

C. Verification that personnel responsible for the operation and maintenance of the diesel are trained in the use of these procedures. Verification of the ability of the personnel on the use of the procedures shall be demonstrated during preoperation tests and during operator requalification.

D. Verification that the color coded, or otherwise marked, lines associated with the diesel generator are correctly identified and that the line or point for adding lube oil (when the engine is on standby or in operation) has been clearly identified.

E. Where and how lube oil is stored onsite and quantity stored for each diesel generator.

Response

The following responses correspond to the above questions:

A. The normal operating level of engine lube oil in the lube oil sump is approximately 31 in. above the bottom. A level switch is set to alarm at a decreasing level of approximately 26 in. above the sump bottom. However, if the engine is operating, the heater is not required and the oil level can drop below the alarm level. The top of the engine lube oil suction line is approximately 14 in. above the sump bottom; i.e., there is a vertical height difference of 12 in. (14 in. to 26 in.) between the low lube oil level alarm and the top of the lube oil pump suction. The equivalent volume between these two levels is approximately 144 gal.

The estimated oil consumption rate given by the engine manufacturer is approximately 1 gal per 7000 kW/h. The safety-related post-LOCA load on the diesel generator is under 6000 kW. Using 6000 kW as the load, the engine would theoretically consume 144 gal of lube oil in 7 days. Therefore, under the hypothetical situation given for minimum lube oil level at the beginning of a 7-day completely unattended operating period, the engine would be able to operate for the full 7 days with post-LOCA Loads.

There are two methods by which lube oil can be added:

1. There is a 2-in. NPT (normally capped) connection provided on the lube oil sump for the addition of oil by manual means.

2. There is a 3-in., 150-lb flange (normally blind flanged) connection provided on the lube oil piping for the addition of oil by means of a power-driven pump or other pressurized equipment.

Either method will permit the addition of lube oil to the system during either standby or operating modes.

Small amounts of added oil (5 to 10 gal) would not be shown by the sump level indicator on the engine control panel, and verification of oil level would be obtained by using a calibrated dip stick inserted through the 2-in. NPT connection. Gauging will be performed while the engine is in standby or in operation. However, there will be a difference in the readings because a certain volume of oil is removed from the sump tank to fill the engine passages when the main oil pump is operating.

The addition of lube oil to the lubricating oil system will be controlled administratively by plant procedures. These procedures will include verification that the expected change in lube oil level occurs for the volume of added oil.

B. The procedures for operating the diesel, i.e., prelube or barring over and shutdown, will be available locally in the diesel generator room.

C. Refer to the response to question 430.1 for training of personnel responsible for the operation and maintenance of the emergency diesel generators.

D. Georgia Power Company will add markings on the diesel generator, especially the lube oil lines, to ensure lube oil is added at the correct location.

E. VEGP procedures to address where and how lube oil will be stored onsite, if applicable, and the quantity to be stored are being developed.

Question 430.36

What measures have been taken to prevent entry of deleterious materials into the engine lubrication oil system due to operator error during recharging of lubricating oil or normal operation?

Response

A response will be provided by July 1984.

Question 430.37

In FSAR paragraph 9.5.7.4 you state that to ensure quality lube oil is present in the lube oil system and that it is within manufacturer's specifications, the lube oil will be "checked routinely." Define routinely.

Response

To ensure lube oil quality and that it is within the manufacturer's specifications, the lube oil will be checked as specified by the engine manufacturer. Refer to revised paragraph 9.5.7.4.

Question 430.38

In FSAR paragraph 9.5.7.2 a brief description of the crankcase vacuum system is given. Provide a more detailed description of the system including operating modes and power sources. If this system is necessary during normal operation of the diesel engine (prevention of crankcase explosion) we require that the mechanical portions of this system be designed to Seismic Category 1, ASME Section III, Class 3 (Quality Group C) requirements and the electrical systems (if any) to Class 1E requirements. The portion of the system extending outside the diesel generator building shall be tornado missile protected.

Response

The crankcase ventilating fans are arranged to receive electrical power from a non-Class 1E electric source provided through the engine control panel. They are set to turn on automatically when the engine receives a start signal.

If the fans do not operate for any reason, the only effect will be that the crankcase pressure will increase to a positive pressure level of 1/2 to 1 in. of water column. This will not affect the engine, except there will be some increase in visible oil leakage from side covers, etc., due to the higher than atmospheric pressure.

The 6-in. crankcase vent line is designed to Seismic Category 1, ASME Section III, Class 3 requirements. The short portion of the line outside the diesel generator building is tornado missile protected.

In the event that the crankcase vent fan is not operating, the fan case will still allow some venting capability for the engine crankcase, and crankcase explosion is precluded.

Question 430.39

In accordance with 10 CFR 21 requirements, Transamerica Delaval, Inc., has reported potential problems in the governor lube oil cooler assembly and turbocharger lubrication circuits which could result in diesel generator nonavailability or degraded performance. Transamerica Delaval has recommended modifications be made to the DSRV diesel engines to preclude occurrence of these problems. State whether these modifications have been made to the diesel generators at VEGP and, if not, when the modifications will be made.

Response

The governor lube oil cooler is installed correctly for the VEGP engines, and no modification will be required. As for the turbocharger thrust bearing lubrication system, modification will be in accordance with the recommended corrective action specified by the engine manufacturer. The recommended corrective action will be made as part of the overall modification program for VEGP diesels to be completed prior to fuel loading.

Question 430.40

Provide a discussion of the design margin (excess heat removal capability) included in the design of the lube oil coolers for the diesel generators.

Response

The lube oil coolers are designed with a capacity of 3.2×10^6 Btu/h. At a design load of 6000 kW, the engine will dissipate an expected heat load of 2.4×10^6 Btu/h, providing a margin of 27 percent.

At the unit rated load of 7000 kW, the engine will dissipate an expected heat load of 2.6×10^6 Btu/h, and the margin is 22 percent.

At rated overload of 10 percent for 2 h, the engine will dissipate 2.9×10^6 Btu/h, with a margin of 14 percent.

Question 430.41

In FSAR table 9.5.8-1, you list the combustion air intake filter, silencer, and flexible connections as being designed to "manufacturer's standard." In addition, the diesel engine exhaust silencer, exhaust piping, and flexible connections are listed as being designed to "manufacturer's standard" or an ASTM standard. This is not acceptable without further justification. The staff normally requires the entire diesel engine combustion air intake and exhaust system to be designed, fabricated, and installed in accordance with ASME Section III, Class 3 requirements. Provide justification for noncompliance.

Response

The combustion air intake piping is designed to Seismic Category 1, ASME Section III, Class 3 requirements. However, due to the high operating temperature of the engine exhaust, there are no acceptable materials available that will meet both ASME Section III, Class 3 requirements and the operating temperature requirements. Therefore, the exhaust piping is designed in accordance with ANSI B31.1 with stress allowables in accordance with ASME Section III. Except for the temperature limits the exhaust piping meets ASME Section III, Class 3 requirements. Also, the exhaust piping is designed to Seismic Category 1 requirements.

The combustion air filters and silencers and the exhaust silencer meet or exceed the manufacturer's standard. This means that some materials are heavier than for commercial applications and that the units are strengthened with extra welding, etc.

To ensure that these components are adequate for the service, they are qualified seismically by analysis to determine that stress levels do not exceed allowable limits during postulated seismic events.

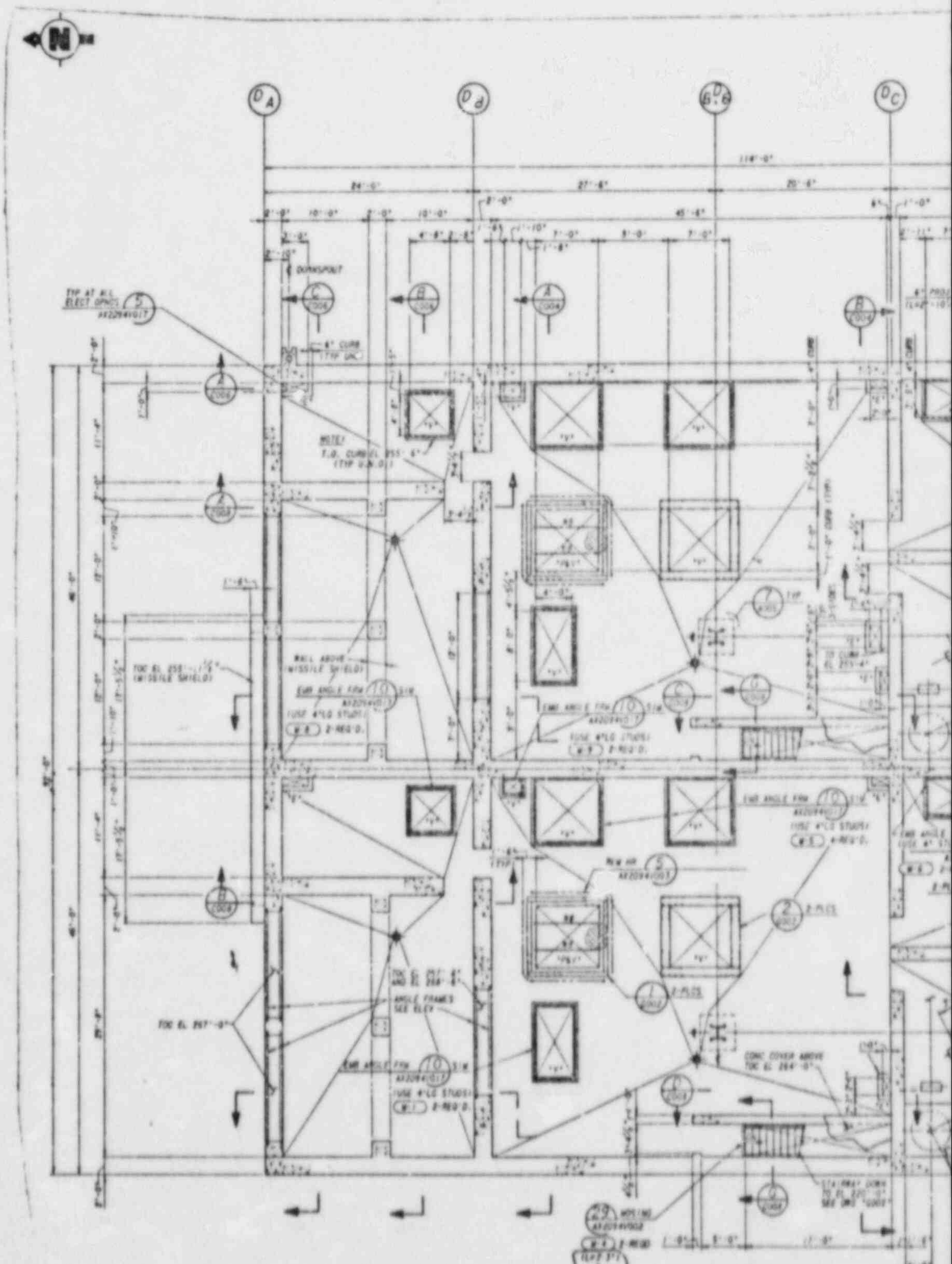
Due to the low operating pressures for the combustion air intake and exhaust systems, the requirements to design these systems to completely meet ASME Section III, Class 3 requirements do not add to the reliability of these systems.

Question 430.42

FSAR subsection 9.5.8 and figure 1.2.2-28 do not provide adequate information or details, respectively, to determine how tornado missile protection is provided for the combustion air intake. Provide additional information, including drawings, as required, which will clearly show how tornado missile protection is designed.

Response

The combustion air intakes are located in the south wall of the diesel generator building, along column line D_D and to the west of column lines D_6 and D_5, as shown in figure 430.42-1. Missile protection for the air intake filters is provided by the 2-ft thick reinforced concrete walls and roof slabs shown in sections E and F of figure 430.42-2 and section C of figure 430.42-3.



PLAN AT TOC EL 255'-0" U.N.O.

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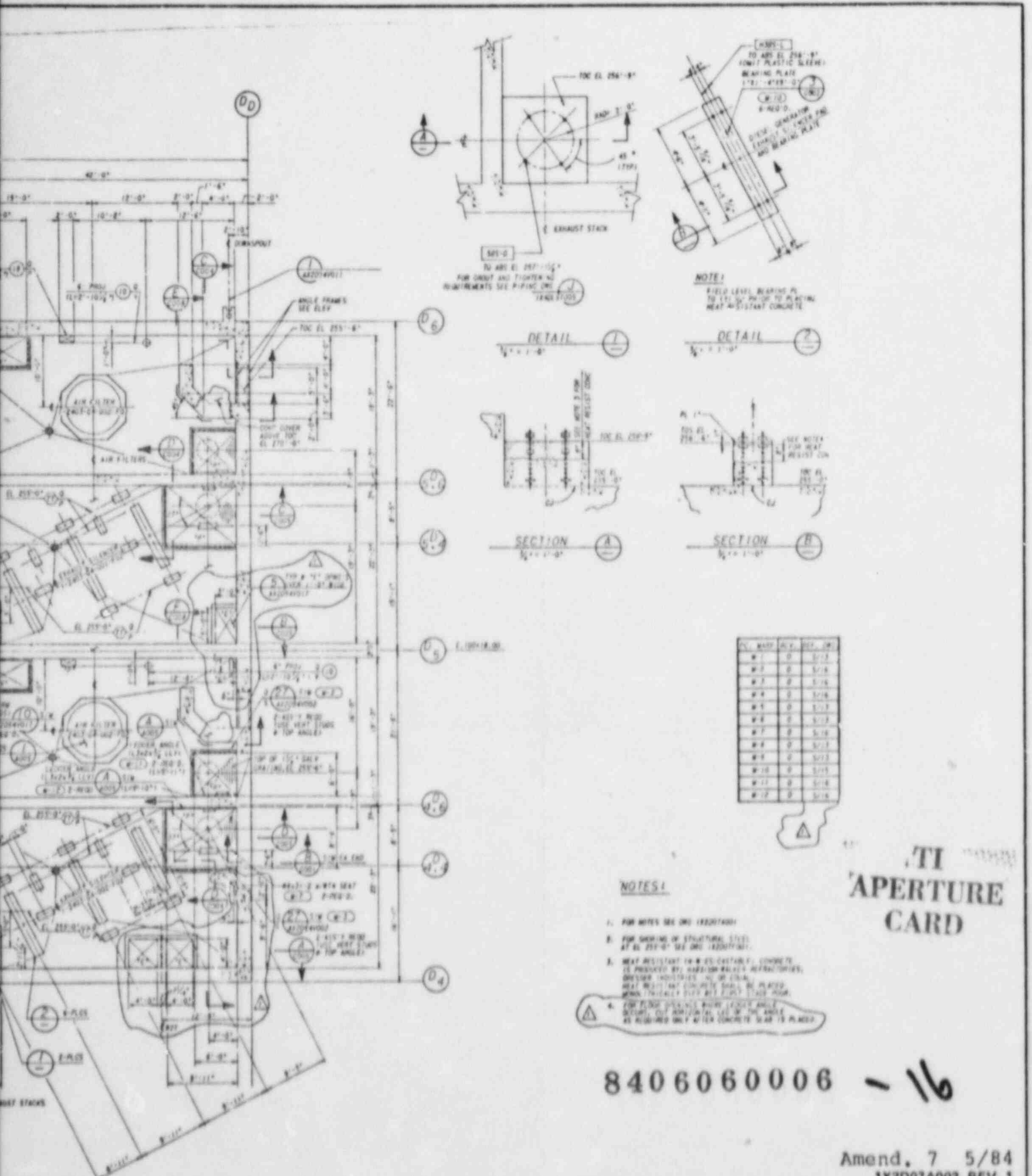
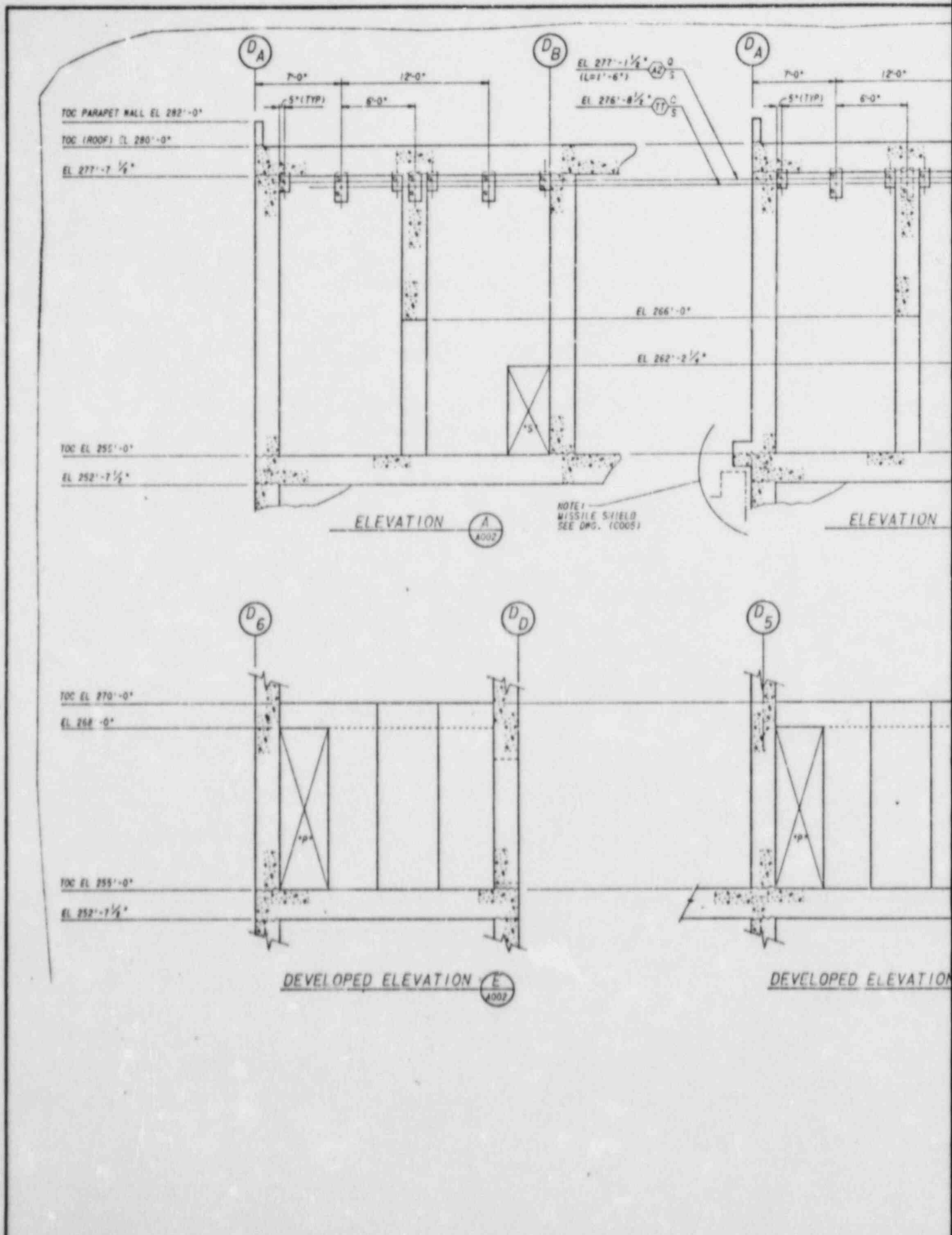
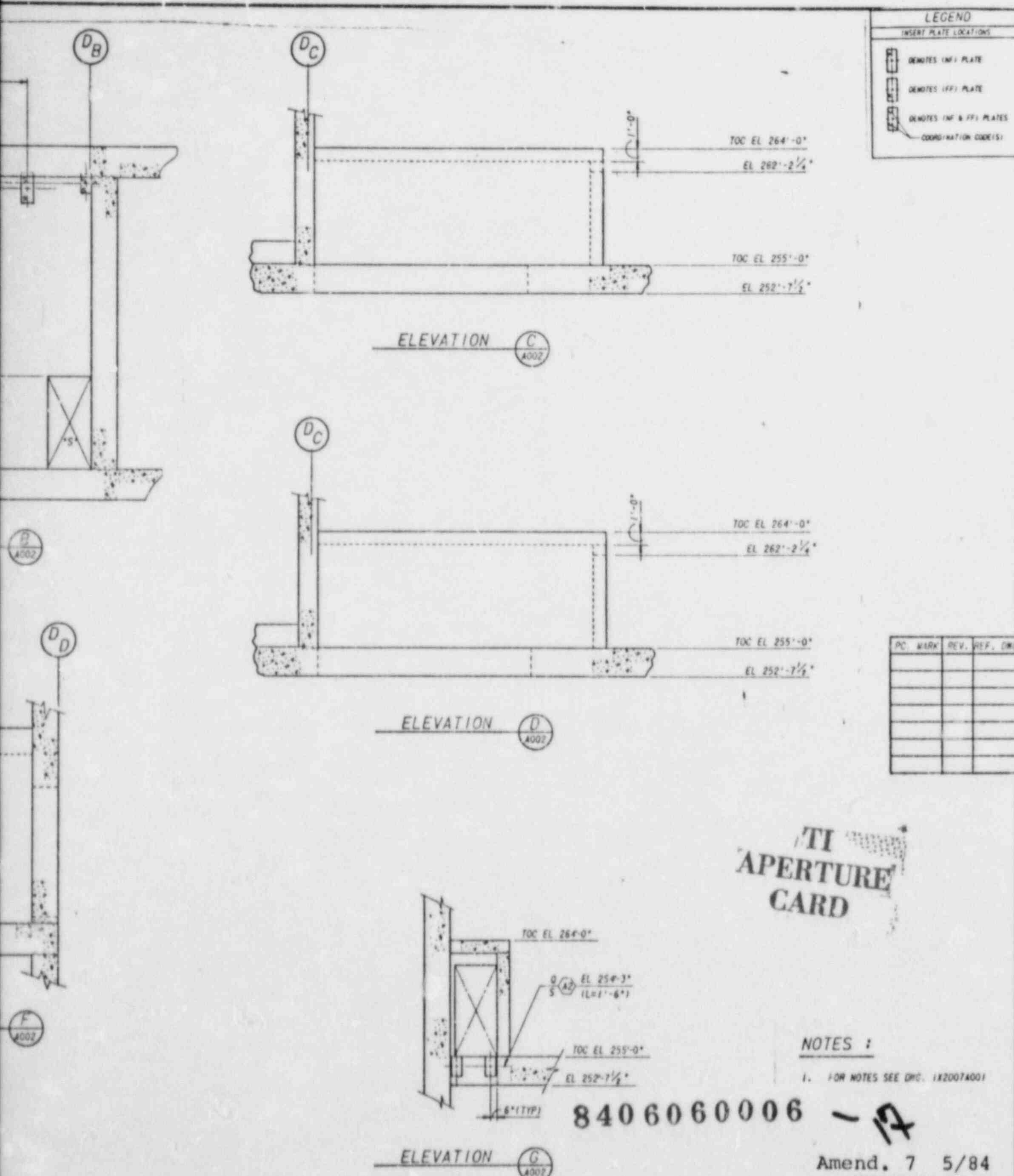


Amend. 7 5/84
1X2D07A002 REV. 1

Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	DIESEL GENERATOR BUILDING FORMING PLAN AT EL 255 FT
		FIGURE 430.42-1


DA
DB
DA
7'-0"
12'-0"
5"(TYP)
6'-0"
TOC PARAPET WALL EL 282'-0"
TOC (ROOF) EL 280'-0"
EL 277'-7 1/4"
EL 277'-1 1/8" (L=1'-6")
EL 276'-8 1/2"
EL 266'-0"
EL 262'-2 1/4"
"S"
TOC EL 255'-0"
EL 252'-7 1/2"
NOTE: MISSILE SHIELD SEE DWG. (C005)
ELEVATION A A002
ELEVATION
D6
DD
D5
TOC EL 270'-0"
EL 258'-0"
"P"
TOC EL 255'-0"
EL 252'-7 1/2"
DEVELOPED ELEVATION E A002
DEVELOPED ELEVATION

Also Available On
Aperture Card



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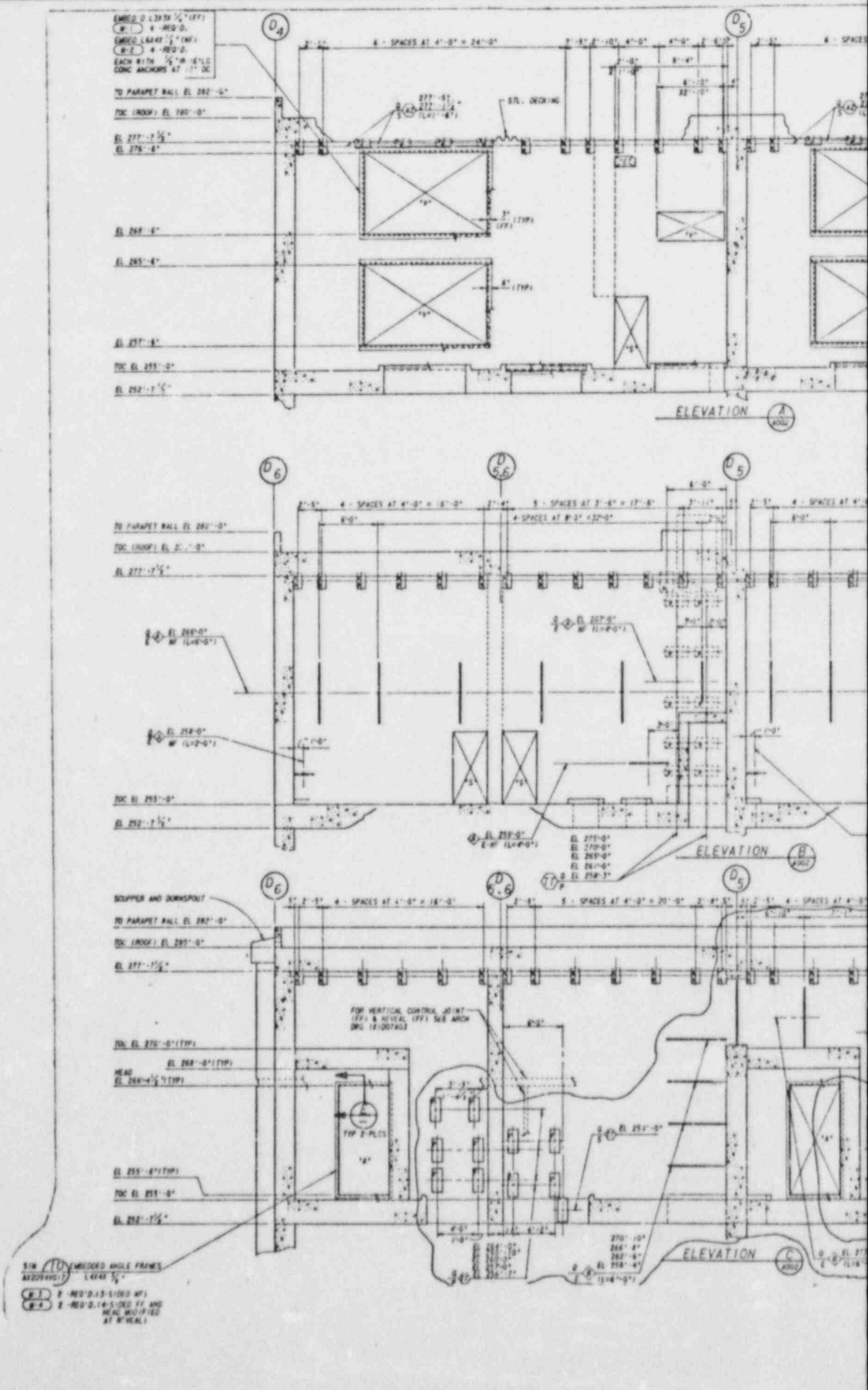
Amend. 7 5/84
1X2D07C008 REV. 0

Georgia Power
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

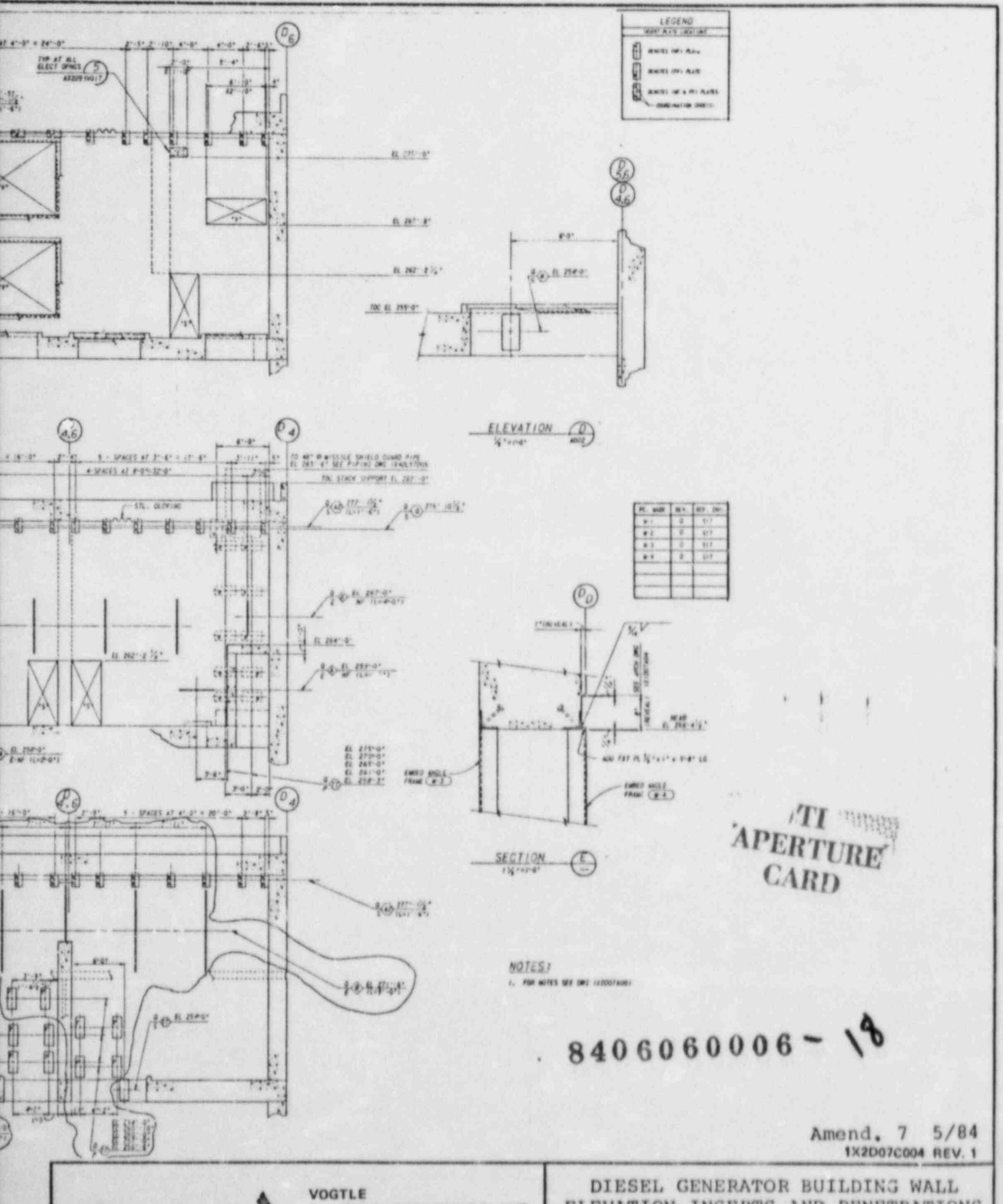
DIESEL GENERATOR BUILDING WALL
ELEVATION INSERTS AND PENETRATIONS

FIGURE 430.42-2



ELEVATION A
ELEVATION B
ELEVATION C
TO PARAPET WALL EL 282'-0"
TOC (ROOF) EL 280'-0"
TOC EL 255'-0"
STL. DECKING
SCUPPER AND DOWNSPOUT
FOR VERTICAL CONTROL JOINT (FF) & REVEAL (FF) SEE ARCH DWG
EMBEDDED ANGLE FRAMES
TYP 2-PLCS

Also Available On
Aperture Card



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Amend. 7 5/84
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Georgia Power — VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	DIESEL GENERATOR BUILDING WALL ELEVATION INSERTS AND PENETRATIONS
	FIGURE 430.42-3

Question 430.43

Provide a discussion in the FSAR on how tornado missile protection is provided for the diesel engine exhausts. Include such drawings as may be required.

Response

The design for tornado missile protection of the diesel engine exhausts will not be completed until September 1, 1984. Drawings showing the design will be provided at that time.

Question 430.44

Discuss the provisions made in your design of the diesel engine combustion air intake and exhaust system to prevent possible clogging, during standby and in operation, from abnormal climatic conditions (heavy rain, freezing rain, dust storms, ice, and snow) that could prevent operation of the diesel generator on demand.

Response

The engine combustion air intake system, including the air intake filter, is installed indoors. The air intake filter is installed in a separate room located on the second level of the diesel generator building. Air is drawn from the outside through a louvered/screened opening into the air filter room. The intake air filter is an oil bath type with self-cleaning features. Therefore, the engine combustion air intake system is protected from the abnormal climatic conditions. The exhaust system is also installed indoors, except a short section of the exhaust pipe which projects above the roof top of the diesel generator building. This portion of the exhaust pipe above the roof is tornado missile protected. A 2-in. drain is provided for a sump at the bottom of the vertical section of the 42-in. exhaust pipe to remove any rain water that enters the exhaust pipe. The end of the exhaust pipe is approximately 63 ft above grade. This location of the exhaust pipe opening to atmosphere will minimize the amount of dust entering the exhaust, which could prevent operation of the diesel generator. Any freezing rain or snow entering the exhaust pipe will melt after reaching the exhaust pipe sump due to the room temperature (50°F minimum), and the resulting liquid will drain out through the 2-in. drain. During engine operation, any rain, freezing rain, dust, ice and snow entering the exhaust pipe will be either blown out and/or melted by the exhaust gas. The abnormal climatic conditions mentioned will not clog the engine exhaust and prevent operation of the diesel generator.

Question 430.45

Experience at some operating plants has shown that diesel engines have failed to start due to accumulation of dust and other deleterious material on electrical equipment associated with starting of the diesel generators (e.g., auxiliary relay contacts, control switch, etc.). Describe the provisions that have been made in your diesel generator building design, electrical starting system, and combustion air and ventilation air intake design(s) to preclude this condition to assure availability of the diesel generator on demand.

Also describe under normal plant operation what procedure(s) will be used to minimize accumulation of dust in the diesel generator room; specifically address concrete dust control. In your response also consider the condition when Unit 1 is in operation and Unit 2 is under construction (abnormal generation of dust).

Response

Refer to paragraphs 8.3.1.1.3.K and 9.4.5.8. The Unit 1 diesel generator building is separated from the Unit 2 diesel generator building by a distance of approximately 600 ft. Therefore, dust generation during Unit 2 construction will not affect the operation of Unit 1 diesel generators. See the response to question 430.44 for combustion air dust control.

Question 430.46

Diesel generators for nuclear power plants should be capable of operating at maximum rated output under various service conditions. Under no load and light load operations, the diesel generator may not be capable of operating for extended periods of time under extreme service conditions or weather disturbances without serious degradation of the engine performance. This could result in the inability of the diesel engine to accept full load or fail to perform on demand. Provide the following:

A. The environmental service conditions for which your diesel generator is designed to deliver rated load including the following:

   1. Ambient air intake temperature range (°F).

   2. Maximum humidity (percent).

B. Assurance that the diesel generator can provide full rated load under the following weather disturbances:

   1. A tornado pressure transient causing an atmospheric pressure reduction of 3 psi in 1.5 s followed by a rise to normal pressure in 1.5 s.

   2. A low pressure storm such as a hurricane resulting in ambient pressure of not less than 26 in. Hg for a minimum duration of 2 h followed by a pressure of no less than 26 to 27 in. Hg for an extended period of time (approximately 12 h).

C. Discuss the effects low ambient temperature will have on engine standby and operation and effect on its output particularly at no load and light load operation. Will air preheating be required to maintain engine performance? Provide a curve or table which shows performance versus ambient temperature for your diesel generator at normal rated load, light load, and no load conditions. Also provide assurance that the engine jacket water and lube oil preheat systems have the capacity to maintain the diesel engine at manufacturer's recommended standby temperatures with minimum expected ambient conditions. If the engine jacket water and lube oil preheat systems' capacity is not sufficient to do the above, discuss how this equipment will be maintained at ready standby status with minimum ambient temperature.

D. Provide the manufacturer's design data for ambient pressure versus engine derating.

E. Discuss the effects any other service and weather conditions will have on engine operation and output, i.e., dust storm, air restrictions, etc.

Response

The following responses correspond to the above questions:

A. The diesel generators for Units 1 and 2 are designed to deliver rated load at:

1. Ambient air intake temperature of 17°F to 120°F.

2. Maximum humidity of 95 percent.

B. Concerning the following weather disturbances:

1. The engines will operate at 100 percent rated load under a tornado pressure transient condition. The heavy rotating parts of the engine together with its flywheel will provide a large moment of inertia, which will ride through the transient condition due to momentary depressurization and its immediate recovery. The diesel generator manufacturer has verified this by operating an engine under simulated tornado conditions with no adverse results. The atmospheric reduction of 3 psi is equivalent to operating the diesel engine at an elevation of 6500 ft above sea level; the engine performance will not be derated, because the diesel generator manufacturer states that the engine performance would only be derated if the engine is installed above 10,000 ft in altitude. However, under the above conditions, the engine will not provide any overload capability.

2. The engine will operate at 100 percent rated load during a low pressure storm such as a hurricane with an ambient pressure of 26 in. Hg, which is equivalent to having the engine installed at an elevation of 4000 ft in altitude. The engine performance will not be derated, because the diesel generator manufacturer states that engine performance would only be derated if the engine is installed above 10,000 ft in altitude. Prolonged engine operation under the depressurized atmospheric condition would cause temperatures to rise, and the exhaust will become more dense due to lack of oxygen and the rich fuel/air mixture.

However, the diesel engine will continue to operate, but the engine will not provide any overload capability.

C. With an assumed "low temperature" of 17°F, air preheating will not be required for the engines' benefit because the air aftercooler will effectively be serving as an air heater. It utilizes engine jacket water which is thermostatically controlled so that if the heat load is low or nonexistent, there will be no waterflow to the jacket water cooler. As the engine heats up, heat will be rejected to the incoming air by the jacket water. The low ambient temperatures do not affect the design or rated load capability of the engine, so no curve is applicable. In fact, the reverse is actually true wherein the engine can actually produce more power at low temperatures because of the higher density of air and increased oxygen.

The standby heating system for the engine is provided on the basis that the engine room will be maintained at 50°F. At this temperature, the engine could actually be started even though the on-engine heaters and pumps failed.

The diesel generator manufacturer has started similar cold engines in ambient temperatures as low as 45°F. However, at lower temperatures, jacket water would have a tendency to freeze, and lube oil is very viscous at 30°F to 40°F levels; so the pumps and heaters are to be used below the 50°F level in any situation.

D. The diesel generators are derated only for installations above 10,000 ft in altitude and/or where sufficient aftercooler water is not available to maintain proper air manifold temperatures. No derating would be applicable to the engines for the VEGP conditions.

E. See the response to question 430.44.

Question 430.47

In FSAR subsection 9.5.4 you state that in the event of a loss of offsite power, the diesel generator engineered safety features (ESF) room ventilation system must be manually connected to the bus. The diesel generator room ventilation system provides cooling to the diesel generator and its auxiliary equipment during diesel generator operation. Failure to start the ESF ventilation system to operating condition within a reasonable amount of time will result in diesel generator room temperatures exceeding the 120°F design ambient temperature specified in subsection 9.5.4. Provide the following:

A. The means that are provided to the control room operator that tells him the ESF ventilation system needs to be manually connected to the bus in the event of a loss of offsite power.

B. How and from where will manual connection be performed?

C. The time period that will be required to manually connect the ventilation system to the bus. This should include all startup and operator recognition that diesel room ventilation system has to be turned on as a result of room temperature alarm, procedures, or other indication and other contingencies or actions that the operator must take as a result of the accident.

D. A room temperature versus time profile for the worst case outside ambient air temperature conditions for the following events:

   1. Diesel generator started, ventilation system automatically reenergized.

   2. Diesel generator started, ventilation system manually reenergized in the time specified in item C above.

   3. Diesel generator started, ventilation system not energized.

E. Assuming that the diesel room ESF ventilation system is not energized for whatever reason, verify that the diesel generator and its associated equipment (electrical and mechanical) is qualified to operate in the maximum room temperature environment specified in item D.3 above and will be able to operate in this environment for a minimum of 7 days of diesel generator operation.

F. If the diesel generator and its associated equipment (electrical and mechanical) cannot operate in the maximum room temperature environment of item D.3 above, state the maximum allowable room temperature in which the diesel generator and its associated equipment can operate, and provide a list of diesel generator components whose environmental operating temperatures are less than the maximum room temperature specified in item D.3 above and their operating temperatures. Discuss how the listed diesel generator components will be upgraded to qualify and operate in the maximum environmental room temperature or will be protected during these conditions, so that the diesel generator can perform its design safety function, or provide assurance to the staff that the ventilation system will be reenergized prior to reaching the maximum environmental room temperature so that the diesel generator and the above listed equipment can perform its design safety function.

Response

The diesel generator ESF room ventilation system is automatically started following starting of the diesel generator. A second ESF ventilation unit is started should the diesel generator building reach 90°F. Subsection 9.4.7 has been revised.

Question 430.48

Expand your discussion of the turbine speed control and overspeed protection systems. Provide a schematic drawing for the electrohydraulic control system which shows all system components and circuits in sufficient detail to permit following any speed control and/or turbine trip action from initiation to completion of the action. Describe the sequence of events associated with all turbine speed control and/or turbine trip actions. Show all test components and describe their function during turbine operation. Provide identification for all system components and refer to this identification in your description of system operation. Coordinate the system schematic with figures 10.2.2-2 and 10.2.2-3.

Response

This response will be provided by July 1984.

Question 430.49

Provide the results of an analysis which demonstrates that any failure of a turbine speed control and overspeed protection system components and/or power supply will disable in a safe manner the turbine speed control and overspeed protection from functioning.

Response

As stated in paragraph 10.2.2.3.1.1, the speed control unit uses two redundant channels, a primary and a backup. In the event that both channels are lost, the turbine will trip. As stated in paragraph 10.2.2.3.1.5, there is also an emergency overspeed protection system which will operate if the normal overspeed protection should fail. Figure 10.2.2-2 shows the redundant paths of the overspeed protection system. Paragraph 10.2.2.3.1.5 lists the component redundancies used to guard against overspeed.

Question 430.50

Describe your program for periodic testing and inservice inspection of the main steam stop and governor control valves, the combined reheat stop and intercept valves, and the steam extraction nonreturn valves.

Response

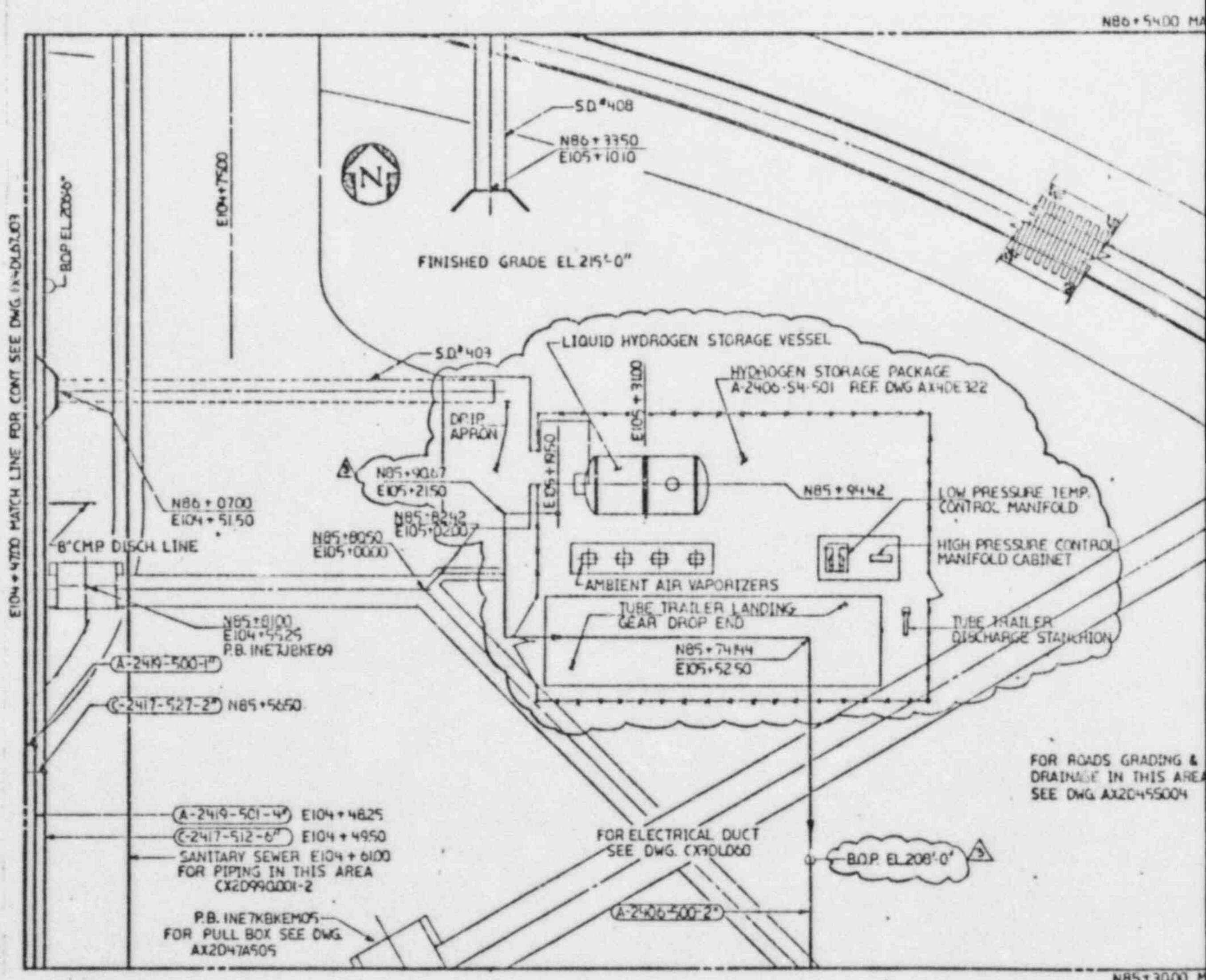
Periodic testing and inservice inspection of the main steam stop valves, control valves, and combined intercept valves will be as specified in the VEGP Technical Specifications. Visual inspection of all of these valves will be a part of the VEGP preventive maintenance program.

Question 430.51

Describe, with the aid of drawings, the bulk hydrogen storage facility, including its location and distribution system. Include the protective measures considered in the design to prevent fires and explosions during operations such as filling and purging the generator, as well as during normal operations.

Response

The VEGP generators are cooled with gaseous hydrogen provided by the auxiliary gas system. Liquid hydrogen is stored in a cryogenic vessel, and ambient air vaporizers turn this liquid into gas. Gas pressure is regulated to the house supply lines by means of a pressure-temperature-excess flow control manifold. Pressure relief devices are located throughout the piping system and anywhere liquid hydrogen can be trapped between isolation valves. A fire control valve located downstream of the storage vessel is designed to close via instrument air whenever hydrogen ignition occurs. A storage vessel vent stack is provided with carbon dioxide connections to extinguish any potential vent stack ignitions. House lines to the distribution system contain National Fire Protection Association-rated ball valves to prevent leakage of gaseous hydrogen. A removable pipe spool piece is located in each generator distribution system, so a blanking flange can be installed to prevent gas leakage during generator servicing. The hydrogen storage facility is shown in figure 430.51-1. This location is approximately 1000 ft from the centerline of the Unit 1 containment structure and even further from the Unit 2 containment structure. The outside facility is anchored to a concrete slab and enclosed by a fence to restrict the entry of unauthorized personnel. The hydrogen equipment layout is depicted in figure 430.51-2. The storage flow diagram is shown in figure 9.3.5-1. The distribution system is shown in figure 10.2.2-1. House lines are schedule 80 carbon steel. Vendor lines are thick-walled copper tubing or carbon steel.



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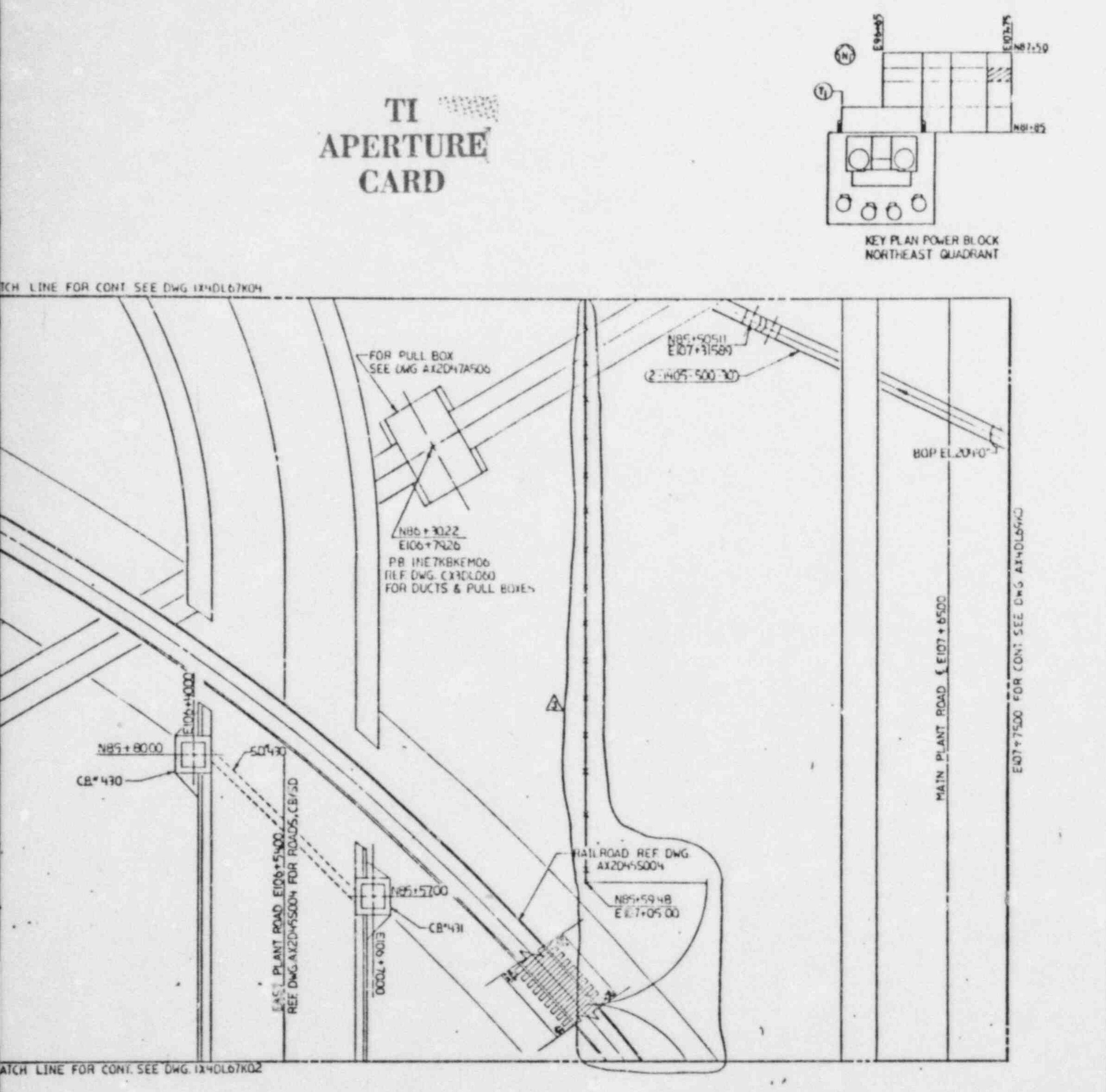


NOTE:
1. SECURITY DUCTS NOT SHOWN ON THESE DRAWINGS. DETAILS OF THESE DUCTS WILL BE ISSUED BY GPCo. POWER GENERATION DEPARTMENT.

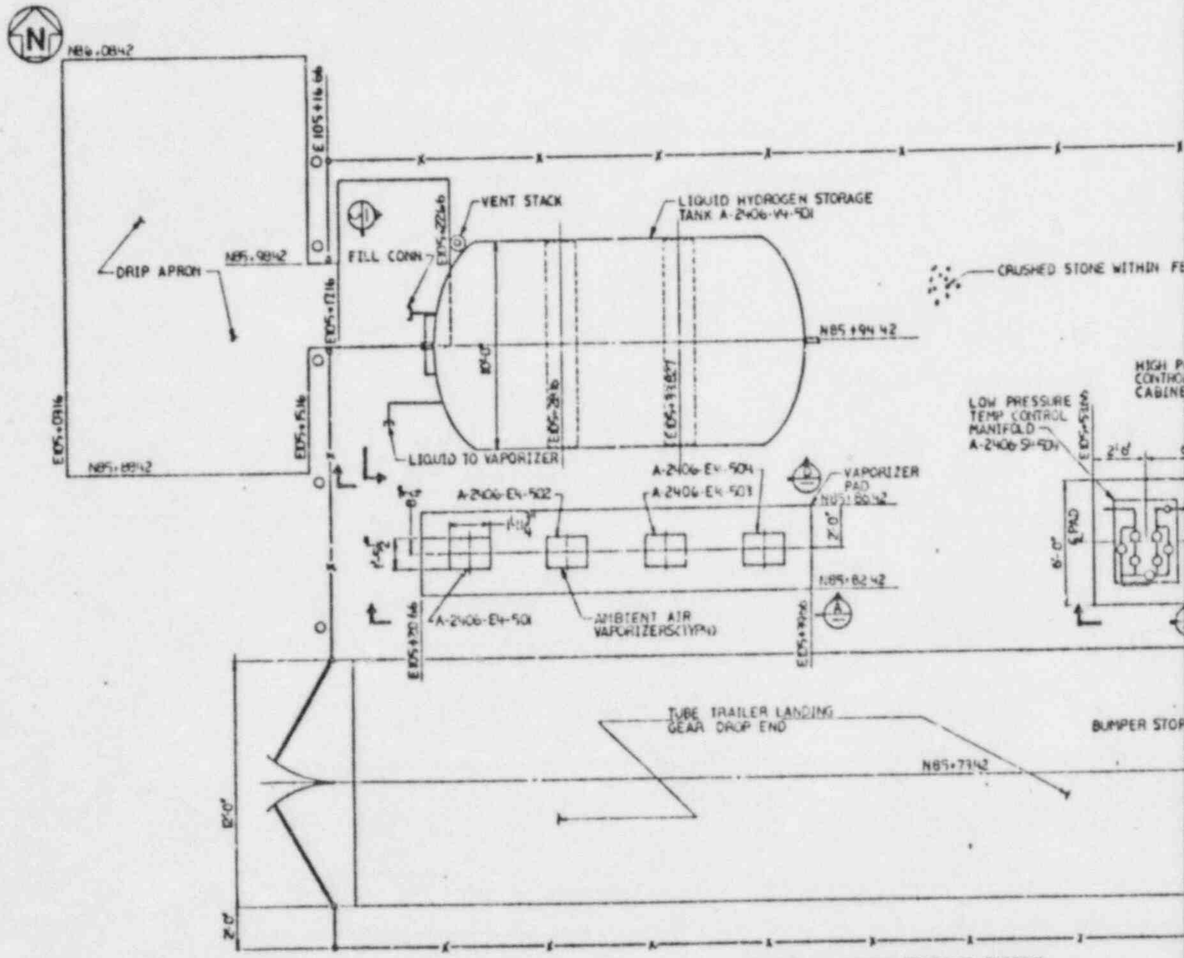
Amend. 7 5/84
1X4DL67K03 REV 3

Georgia Power

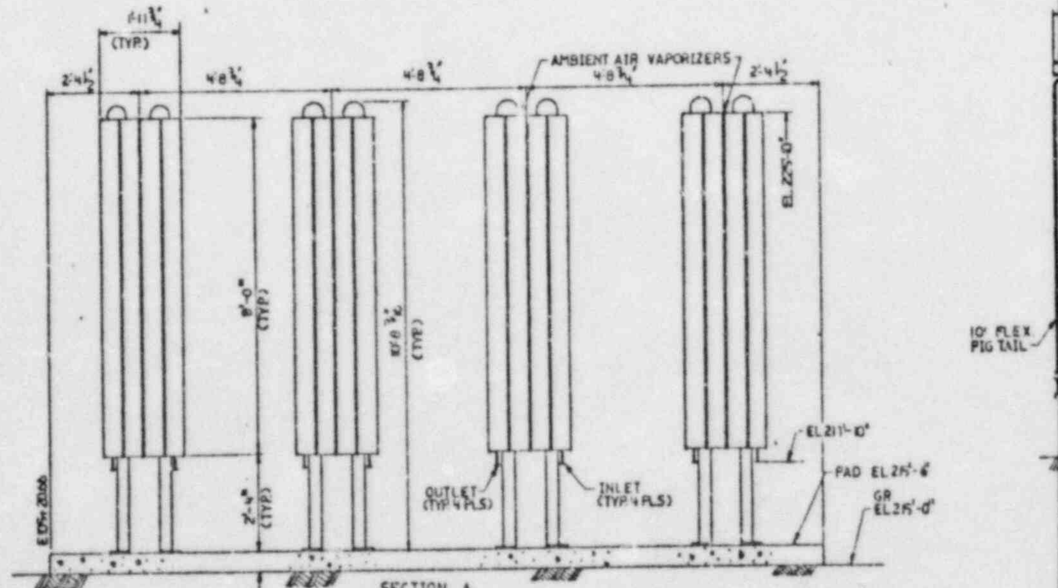
VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2

OUTDOOR AREA 7K PIPING

FIGURE 430.51-1



LIQUID HYDROGEN STORAGE SYSTEM
SCALE 1/8"=1'-0"



SECTION A
SCALE 1/4"=1'-0"

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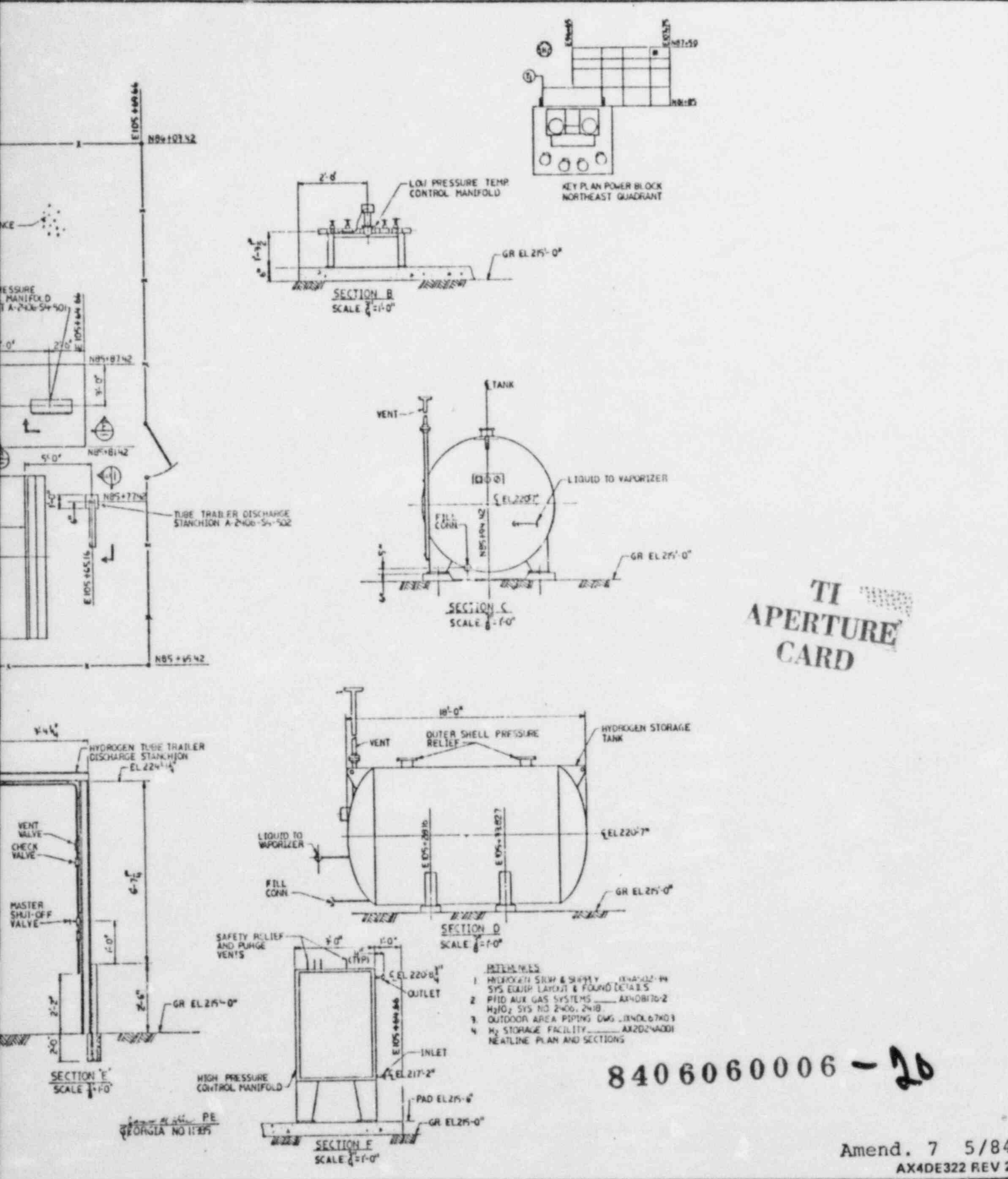

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Amend. 7 5/84

AX4DE322 REV 2

Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	LIQUID HYDROGEN STORAGE FACILITY EQUIPMENT LOCATION PLAN
		FIGURE 430.51-2

Question 430.52

Provide additional description (with the aid of drawings) of the turbine bypass valves and associated controls. In your discussion include the number, size, principle of operation, construction, setpoints, and capacity of each valve and the malfunctions and/or modes of failure considered in the design of the turbine bypass system.

Response

The turbine bypass valves are 6-in , 900-lb carbon steel globe valves. The seats are made of type 316 stainless steel. Each valve was sized to pass 800,000 lb/h at an inlet pressure of 1200 psia. Each valve has a spring-mounted diaphragm actuator with side-mounted handwheel. The arrangement of the turbine bypass valves and associated controls is shown in figure 10.2.2-1 (sheet 1 of 9).

The number of valves is given in paragraph 10.4.4.2.1. The principle of operation is described in paragraph 10.4.4.2.2 and 10.4.4.2.3. The malfunctions and/or modes of failure are discussed in paragraph 10.4.4.2.3. Setpoints will be provided in the Technical Specifications.

Question 430.53

Provide a piping and instrumentation diagram (P&ID) for the turbine bypass system showing system components and all instrumentation.

Response

Refer to figure 10.2.2-1 (sheet 1 of 9) for a P&ID showing the turbine bypass system.

Question 430.54

Regarding the transmission lines connected to the VEGP 230- and 500-kV switchyards:

A. FSAR paragraph 8.2.1.1 states that the lines approach the plant site on at least two rights-of-way, from the northwest and south. Figures 1.2.2-1 and 8.1-1 seem to indicate there are more than two rights-of-way, and the figures are not consistent with each other. Clarify these discrepancies and provide a drawing in chapter 8 similar to figure 8.1-1 which identifies the right-of-way approaches to the plant and the lines which exist on those rights-of-way.

B. Table 8.2.1-1 indicates that the Wilson combustion turbine line is not finalized, but figure 8.1-1 indicates that the VEGP to Plant Wilson line is existing. Clarify this discrepancy.

Response

The following responses correspond to the above questions:

A. Figure 8.1-1, sheet 2 of 2, is the single-line drawing showing the 230- and 500-kV transmission line approach to the plant site on five rights-of-way. Figure 1.2.2-1 will be modified by July 1984 to reflect the current plans.

B. The line from VEGP to Plant Wilson is scheduled for October 1984. Figure 8.1-1, sheet 2 of 2, has been revised accordingly.

Question 430.55

FSAR paragraph 8.2.2.1 states that the loss of either VEGP Unit 1 or 2 during a 1989 peak condition will not result in a loss of offsite power to the safety-related loads at the plant site. Provide the results of a study for the simultaneous loss of both VEGP Units 1 and 2 during the same type of 1989 peak condition.

Response

A study simulating 1989 peak conditions has been made to determine the effect of the loss of both Units 1 and 2 and the ability of the offsite source to supply emergency and safety related loads at VEGP. It was found that the offsite transmission is adequate. The voltage at the 230-kV bus is above 98 percent under any normal planning criteria. The 230-kV bus is the offsite supply source for both Unit 1 and 2 safety-related loads.

Question 430.56

In figure 8.2.1-2 or another FSAR figure identify the location on the main stepup transformers, the unit auxiliary transformers, and the reserve auxiliary transformers.

Response

Figure 8.2.1-2 has been revised to identify the main stepup transformers, the unit auxiliary transformers, and the reserve auxiliary transformers.

Question 430.57

FSAR paragraph 8.2.1.2 and table 8.2.1-2 indicate that the two switchyard battery circuits are divided between the primary-secondary relaying, trip coils, and closing coils of the various 230-kV switchyard circuit breakers; however, paragraph 8.3.2.1.3 indicates that one battery circuit serves one switchyard (Unit 1) and the other battery circuit serves the other switchyard (Unit 2). Clarify this apparent discrepancy, and describe the dc power supply to the 500-kV switchyard and the periodic maintenance which will be performed on all switchyard batteries. Also describe the physical separation between the switchyard circuit breaker control circuits of the two offsite sources. If they are not separated, show compliance with General Design Criterion 17 by verifying the plant can remain in a safe condition until at least one offsite circuit can be returned to service, given a failure at the point where the circuits are not separated.

Response

Paragraph 8.3.2.1.3 has been revised to correctly describe the switchyard battery circuits. The switchyard battery circuits are divided as described in paragraph 8.2.1.2 and illustrated in tables 8.2.1-2 and 8.2.1-3. The switchyard battery periodic maintenance will comply with IEEE 450-1975 as stated in paragraph 8.2.2.5.

In response to the question concerning separation of control circuits, each of the two offsite sources can be energized through either or both of the two switchyard circuit breakers. The high voltage switchyard raceway network consists of a system of concrete trenches with concrete lids. Control cables to the four circuit breakers are routed through the trenches in such a way that lengthy trench sections do not include circuits to all four offsite source breakers. Control cables to the plant control room for these breakers are routed outdoors in conduit within a reinforced concrete duct run and within the plant in cable tray. These cables are arranged within these raceways in such a manner that no two breakers from different offsite sources are in a common raceway. Areas in which circuits to all four breakers are common in this duct run are limited to the three pull boxes. Areas in which circuits to all four breakers are routed in a common trench are limited to some areas of the switch house interior and a small area of the trench adjacent to the switch house.

In these areas, the trench is protected by location or adjacent structure (i.e., switch house) and additional separation is not practical. All cable is fire retardant (in accordance with IEEE 383-1974), and no oil containment equipment is located in the vicinity of the cable trench.

The switchyard is not a Class 1E system and, therefore, is not designed to be protected from such things as missiles, tornadoes, aircraft impact, etc. In the case of such an event, onsite diesel generators would be used until offsite power could be restored. Similarly, in the case of the extremely unlikely failure of the control circuits to all four breakers, the onsite diesels would provide temporary power until the offsite source could be energized by manually closing appropriate high voltage breakers.

Question 430.58

Describe the instrumentation provided in the control room to monitor the status of the offsite power circuits including the switchyard. Also describe the controls provided in the main control room to operate the switchyard circuit breakers.

Response

The switchyard can be controlled either from the main control room or the switchyard control house. The power circuit breakers (PCBs) adjacent to the main stepup transformer and reserve auxiliary transformer buses can be controlled from only one location at a time depending on the position of the main stepup transformer motor-operated disconnect switches and reserve auxiliary transformer circuit switchers. If a main stepup transformer or reserve auxiliary transformer bus is isolated from the Georgia Power Company system, using the associated disconnect switches or circuit switches, control of the two corresponding PCBs resides in the switchyard house. If a main stepup transformer or reserve auxiliary transformer bus is connected, control of these PCBs resides in the main control room. The main stepup transformer motor-operated switches are controlled only at the switches themselves in the low voltage switchyard. The reserve auxiliary transformer circuit switchers are controlled only from the main control room. All other PCBs in the high voltage switchyard can be controlled simultaneously from either location at all times by the use of rotary solenoid-driven control switches mounted on the switchyard control house console that are slaved to the control switches in the main control room.

The switchyard is controlled either totally or partially from three locations: main control board in the main control room; electrical auxiliary board in the main control room; and switchyard control console in the switchyard.

A. Main Control Board in Main Control Room

A mimic bus of the one 230-kV substation bay (three breakers) containing the Unit 1 main stepup transformer is incorporated on the lower right hand corner of section 1B2. Similarly, a portion of the Unit 2 main control board has been dedicated for a mimic bus of the one 500-kV switchyard bay (three breakers) containing the Unit 2 generator stepup transformer. The purpose for segregating these controls from the other substation controls is to present to the operator only that information and control essential for placing the generating unit online and to present this information in a location immediately adjacent to the generating unit controls.

Instrumentation mounted on the main control board is as follows:

1. Volts and frequency selector switch.

2. 230-kV (500-kV) system voltmeter.

3. 230-kV (500-kV) system frequency meter.

4. 230-kV (500-kV) synchroscope.

5. Two lights for synchronizing.

6. White lights indicating presence of bus voltage.

7. Synchronizing switches.

8. Main generator breaker control siwtches with red (closed), green (open), and amber (breaker nonoperator trip) lights.

9. Pushbutton switches (used for synchronizing and tripping main generator breaker).

10. Red and green lights for each disconnect switch.

11. Red lights (indicate generator breaker ready to close) for auto synchroverifier.

B. Electrical Auxiliary Board in Main Control Room

230-kV substation controls occupy the entire section 1B. Similarly, a section of the Unit 2 electrical auxiliary board has been dedicated to 500-kV substation controls. Collectively, these two boards constitute a complete mimic bus of the entire high voltage switchyard. The purpose for these boards is to place general control of the substation within the main control room and to fulfill the requirements that the main control room operator have immediate access to the control of the offsite sources.

Instrumentation mounted on the electrical auxiliary board is as follows:

1. Preferred and alternate incoming supply breakers monitoring equipment for each 4.16-kV Class 1E system:

a. Ammeter.

b. Breaker control switch with red, green, and amber lights.

c. Synchronizing switch.

d. Two white lights to monitor incoming voltage.

2. 230-kV electrically operated switchers for each reserve auxiliary transformer: control switch with red and green switcher position lights.

3. Switchyard portion:

   a. Switchyard breaker control switches with red, green, and amber lights, except main generator breaker, switches which are located on the main control board. Only red, green, and amber lights for main generator breakers are located on the electrical auxiliary board.

   b. Ammeters.

   c. Varmeters.

   d. Wattmeters.

   e. Voltmeter switches.

   f. 230-kV (500-kV) voltmeter.

   g. 230-kV (500-kV) synchroscope.

   h. 230-kV (500-kV) frequency meter.

   i. Synchronizing switches.

   j. White lights to monitor phase voltages.

   k. Red and green lights for each disconnect switch position indication.

   l. 230-kV system annunciator test, reset, and acknowledge pushbuttons.

The design also includes a temporary indication panel mounted on the Unit 1 side of the main control room for monitoring the status of the 500-kV switchyard during the period before the Unit 2 electrical auxiliary board is operational. Potential indication for the 500-kV circuit elements and status of the 500-kV PCBs and motor-operated switches is presented on this panel in the form of a mimic bus and indicating lights. Control of the 500-kV PCBs and monitoring of watts, vars, and amps for the 500-kV lines will not be available in the main control room until the Unit 2 electrical auxiliary board is operational.

C. Switchyard Control Console in Switchyard House

The design incorporates a conventional slant board console and mimic bus utilizing electroswitch type CSR control switch relays slaved to the control switches on the electrical auxiliary board. Regular control switches are used for the PCBs adjacent to the generator stepup transformers and are operable only when the unit motor-operated disconnect switches are open. Regular control switches are also used for the PCBs adjacent to the reserve auxiliary transformer buses and are operable only when both reserve auxiliary transformer circuit switchers are open. The design incorporates manual controls for all PCBs and motor-operated switches in the switchyard, including the line reactor circuit switchers. Instrumentation features of the console include:

1. A complete mimic bus of the entire 230- and 500-kV switchyard in one place.

2. Position indicating lamps for all PCBs, motor-operated switches, and circuit switchers in the switchyard.

3. Potential lamps for all bus, line, and transformer elements.

4. Continuous metering of watts, vars, three-phase amps, and three-phase volts for all circuit elements. This information is available to the operator through the single act of looking.

5. Annunciation for all switchyard alarms presented on 2-in. x 3-in. windows with generous verbage to describe the problem.

Question 430.59

FSAR paragraph 8.3.1.1.2 states that each reserve auxiliary transformer has the capacity to supply all connected non-Class 1E running loads and to start and run the loads of one Class 1E train. Justify the capability to start and run only one Class 1E train from each offsite source. Is this capability limited by the capacity of the "Y" transformer winding or by the total transformer capacity? Following a loss of one preferred power supply to a Class 1E bus, do you intend that the diesel generator will supply the bus for the entire length of time allowed under this limiting condition for operation? Identify the loading on the diesel for this condition, and justify its operation at that light load for that extended period.

Response

The normal configuration of the onsite auxiliary power system is subdivided into two groups of equipment, each of which is powered from a separate reserve auxiliary transformer (RAT). Each group of equipment consists of one 4.16-kV Class 1E train, one or more nonsafety-related 4.16-kV buses, and one 13.8-kV nonsafety-related bus. The electrical connections from the offsite source to the RATs and from the RATs to the Class 1E buses are designed in accordance with the requirements of General Design Criterion 17. Each of these sources of preferred power has immediate access to the offsite power sources. IEEE 308-1974, as endorsed by Regulatory Guide 1.32, requires a minimum of one offsite source per train which shall normally be available during operation and accident conditions. The VEGP design has two sources of preferred power, each of which is sized for the normally connected load and has access to all transmission system power sources. The statement in the FSAR addresses the normal configuration of the auxiliary power distribution at the 4.16-kV level. Under the conditions discussed in paragraph 8.3.1.1.2.D (which requires that the transfer be made to the alternate source only if the normal preferred power source, the standby power source, and the redundant Class 1E 4.16-kV bus were all lost simultaneously), the system can be reconfigured to allow access to the alternate preferred power source at the 4.16-kV level. Under the conditions identified in paragraph 8.3.1.1.2.D, only one Class 1E train would be available; therefore, there is no possibility of overloading the alternate source RAT.

The capability of a RAT is limited by the capacity of the "Y" transformer winding, in that this winding is sized to provide power to one Class 1E train in addition to the connected non-Class 1E loads (approximately one-half of the non-Class 1E loads per unit). Following a loss of one preferred power source, the associated diesel generator would start, accelerate, accept load, and be expected to provide power to the affected bus. The diesel generator has been tested and successfully demonstrated to be capable of 7 days operation at no load with subsequent loading to 100 percent. This exceeds the limiting condition for operation for this condition. For additional information on diesel generator light load operation, see the response to question 430.26.

If circumstances should arise which would require the operation of both Class 1E trains from the same RAT, the non-Class 1E loads associated with the RAT would be administratively shed. Having isolated the non-Class 1E loads, each RAT has the capacity to provide power to both Class 1E trains.

Question 430.60

FSAR paragraphs 8.3.1.1.2.D and 8.3.1.1.3.D indicate that only one circuit breaker is provided for the two cubicles available at each Class 1E 4.16-kV bus for connection to the normal or alternate offsite power source. Paragraph 1.9.6.2 seems to indicate that the arrangement may also be used to interconnect the redundant 4.16-kV safety buses when operating from the standby source (diesel generators). Interlocks should exist which preclude the manual closing of both interconnecting circuit breakers. This will prevent overloading of a preferred power source and interconnection of the redundant safety buses. Discuss your compliance.

Response

Paragraph 1.9.6.2 states that provision has been made for manually connecting redundant Class 1E trains together. This is only done under administrative control if the normal preferred power source, the standby power source, and the redundant Class 1E 4.16-kV bus were all lost simultaneously, as discussed in paragraph 8.3.1.1.2.D, by removing the normal Class 1E 4.16-kV breaker from its cubicle and installing it in the alternate (empty) cubicle. The normal preferred source Class 1E 4.16-kV breaker should not be removed from its cubicle and installed in the alternate cubicle when operating from the standby source. Should this inadvertently occur, interlocks have been provided so that when the diesel generator breaker is closed, neither of the incoming preferred source breakers can be closed locally at the switchgear. Should circumstances arise which would require the closing of a preferred source breaker in parallel with the associated diesel generator breaker, it can only be done administratively from the main control room by synchronizing the incoming preferred power source and the diesel generator. At least three manual actions must be performed to reconfigure the system in this manner: physical relocation of the 4.16-kV breaker; obtaining a handle for the synchronizing switch and closing the synchronizing switch for the alternate source voltage; and turning of the alternate breaker control switch to "close" after synchronizing the two voltages. These basic steps must be followed whether or not voltage is present from the preferred source. Ammeters are mounted in the control room to monitor the current drawn from each power source to avoid overload. Considering the failures that must have occurred and the administrative steps that would have to be followed to reconfigure the system, credit is taken for the operator monitoring the load on each power source. Information will be provided to the operator concerning the maximum permissible load which can be drawn from the RATs and the standby diesel generator.

Question 430.61

Regarding the Class 1E and non-Class 1E 120-V ac power supplies shown in figures 8.3.1-4 and 8.3.1-6:

A. Some of the inverter systems shown in these figures have one 125-V dc input while others have the dc input plus an additional 480-V ac input, although in every other respect they appear identical. Describe the function of the second input and give the design criteria used in specifying one type of system over the other. Also, provide a one-line diagram showing the interconnections between the inputs and outputs within the inverter system block.

B. The General Electric UPS in figure 8.3.1-6 shows only one input from a 480-V/120-V regulated transformer. This is a little unusual since the ac regulated input associated with an UPS is normally a backup or maintenance supply to the loads. Describe and provide a functional one-line block diagram showing the major components of the UPS and identify any power inputs from other supplies. Also identify the loads this UPS feeds.

C. Figure 8.3.1-6 shows several manual 120-V ac load transfers between non-Class 1E power supplies which are ultimately fed from redundant 4160-V ac Class 1E buses. The configuration of the transfer circuits is such that a single failure of an open circuit breaker or transfer switch could potentially affect the redundant Class 1E buses. In light of the fact Standard Review Plan section 8.3.1.III.2.b does not allow this configuration for connection of Class 1E loads to redundant Class 1E supplies, justify the acceptability of this configuration for non-Class 1E loads which are not vital to plant safety. The transfers in question are those shown in figure 8.3.1-6 between the regulated transformer and the inverter system to the Westinghouse computer, between regulated instrument buses 1NYS and 1NYR, and between the two regulated transformers to regulated instrument bus 1NYRS. Also identify all other non-Class 1E transfers or interconnections which are connected to redundant Class 1E power supplies.

Response

The following responses correspond to the above questions:

A. The inverter system supplied are designed to have 480-V ac input as the normal source of power, with an automatic backup from a 125-V dc battery-backed bus. For the Class 1E systems, these 480-V ac inputs were eliminated on the Channel III and IV inverters to avoid train separation/isolation problems. The design has been recently revised to show that these inputs are not connected on the 7.5-kVa Channel I and II inverters also.

The ac input to the 10-kVa inverters is required for initial startup of the inverter. These breakers are to be opened after this is accomplished to isolate the ac source. This action was taken in response to Nuclear Regulatory Commission IE Circular 79-02 and the inability to clearly establish that the inverters are capable of withstanding momentary ac overvoltages. Paragraph 8.3.2.2.C and figure 8.3.1-4 have been revised accordingly.

Block diagrams are provided as follows: figure 430.61-1, 7.5-kVa inverter; and figure 430.61-2, 10-kVa inverter.

B. Attached is the UPS vendor's description of the static switch used in conjunction with the UPS (figure 430.61-3). This information indicates there is a bypass switch that allows the 120-V supply to be fed directly to the load (the electrohydraulic control cabinet), leaving the UPS available for maintenance. The only load supplied by this UPS is the main turbine electrohydraulic control system.

The UPS is used primarily to furnish a clean, noise-free ac supply to the electrohydraulic control system.

C. As discussed in paragraph 8.3.1.1.2.E, there is a Class 1E circuit breaker in each 4.16-kV Class 1E bus which feeds a non-Class 1E load center. These load centers are identified as buses NB01 and NB10. These load centers feed motor control centers NBS and NBR, respectively, which in turn generally feed regulating transformers providing power to the loads in question. Final connection to the 120-V distribution panels is made via mechanically interlocked molded case incoming power circuit breakers. For the inverter providing power to the plant computer, the power inputs are interlocked by a static switch and isolated through the inverter and rectifier subassemblies within the inverter.

Under accident conditions, the 4.16-kV circuit breakers are tripped by a safety grade signal generated from the safety features sequencer. These breakers act as redundant isolation devices in accordance with the requirements of Regulatory Guide 1.75. Hypothetically, if a failure occurred in the mechanical interlock in the distribution panels discussed above or within the inverter, the redundant sources could be tied together at these voltage levels under nonaccident conditions. With the VEGP design, such a tie could not exist between the redundant Class 1E 4.16-kV buses under accident conditions, even assuming a single failure of the Class 1E 4.16-kV isolation breakers to trip. Since these breakers are intentionally tripped under accident conditions, Standard Review Plan section 8.3.1.III.2.b is not applicable to these connections.

The concern about this condition is further mitigated by the fact that the regulating transformers act as very effective isolation devices. Postulated failures on the secondary side of such a transformer do not result in unacceptable effects on the primary side. Postulated failures in the transformer secondary circuit result in the following changes in the primary circuit:

1. Secondary short circuit - primary current reduces to approximately 90 percent of rated full load current.

2. Secondary hot short - inadvertent application to the seondary circuit of voltages higher than 120-V ac due to shorts involving other circuits operating at 480-V ac nominal (or less) or out of phase voltages.

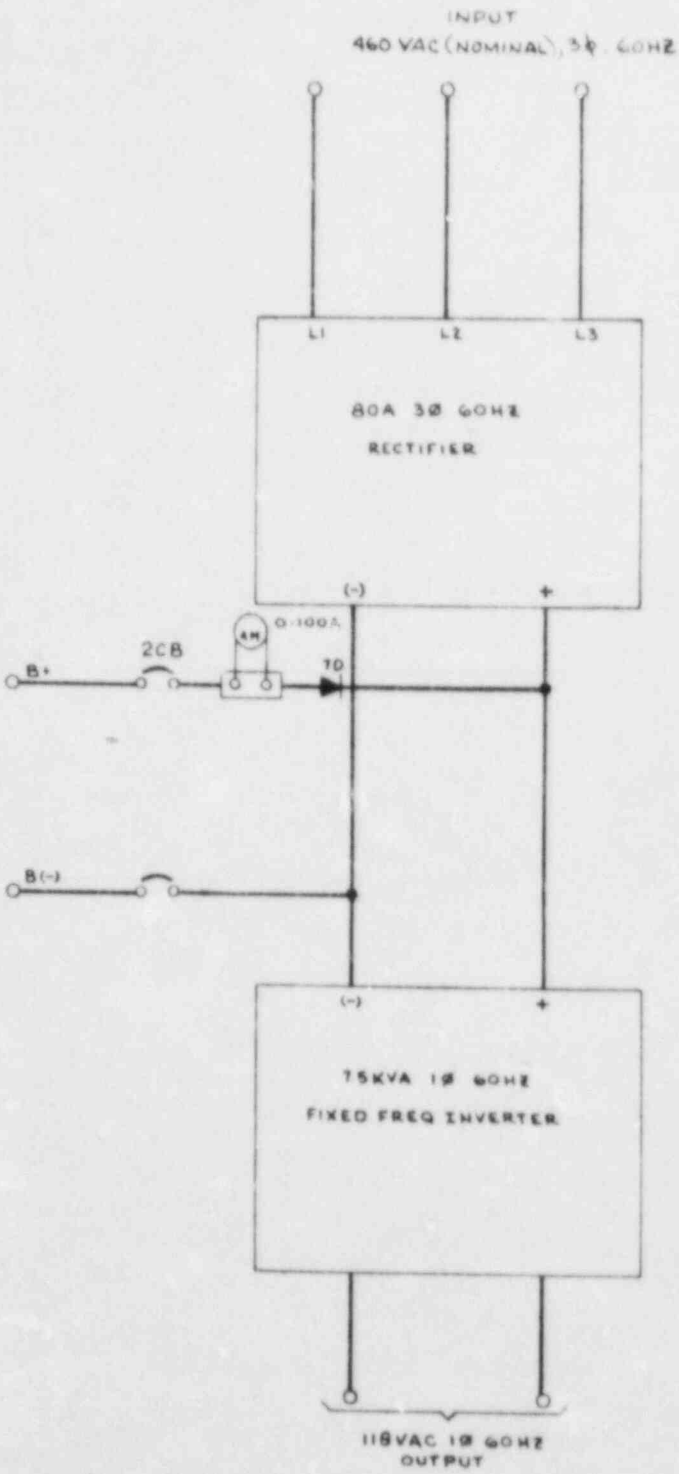
   The cables connected to the seondary side of the regulating transformers are routed only in raceways with cables operating at 480-V ac nominal or less. Should a hot short occur, results similar to that identified in item 1 above would be obtained with no degrading effect on the primary side of the transformers. The insulation between the primary and secondary windings is rated at 1500 V ac.

   A hot short is considered an extremely unlikely event since all cables which could come in contact with transformer secondary circuits are fully Class 1E qualified for the life of the plant, whether they are used in Class 1E applications or not.

Also, cables exposed to a fire or subjected to a fault sustained for a sufficient length of time to allow cable failure to the extent necessary to achieve a hot short would require the failure of the associated circuit breakers to open under fault conditions.

This is based on the fact that the conductors in a given circuit would short together prior to the cable degrading to the point where they could come in contact with conductors of another circuit.

Distribution panel NYC2 (non-Class 1E) is used to provide power to the control rod position indication system powered directly from redundant Class 1E motor control centers via Class 1E regulating transformers used as isolation devices. Mechanically interlocked power input circuit breakers are provided on this panel.



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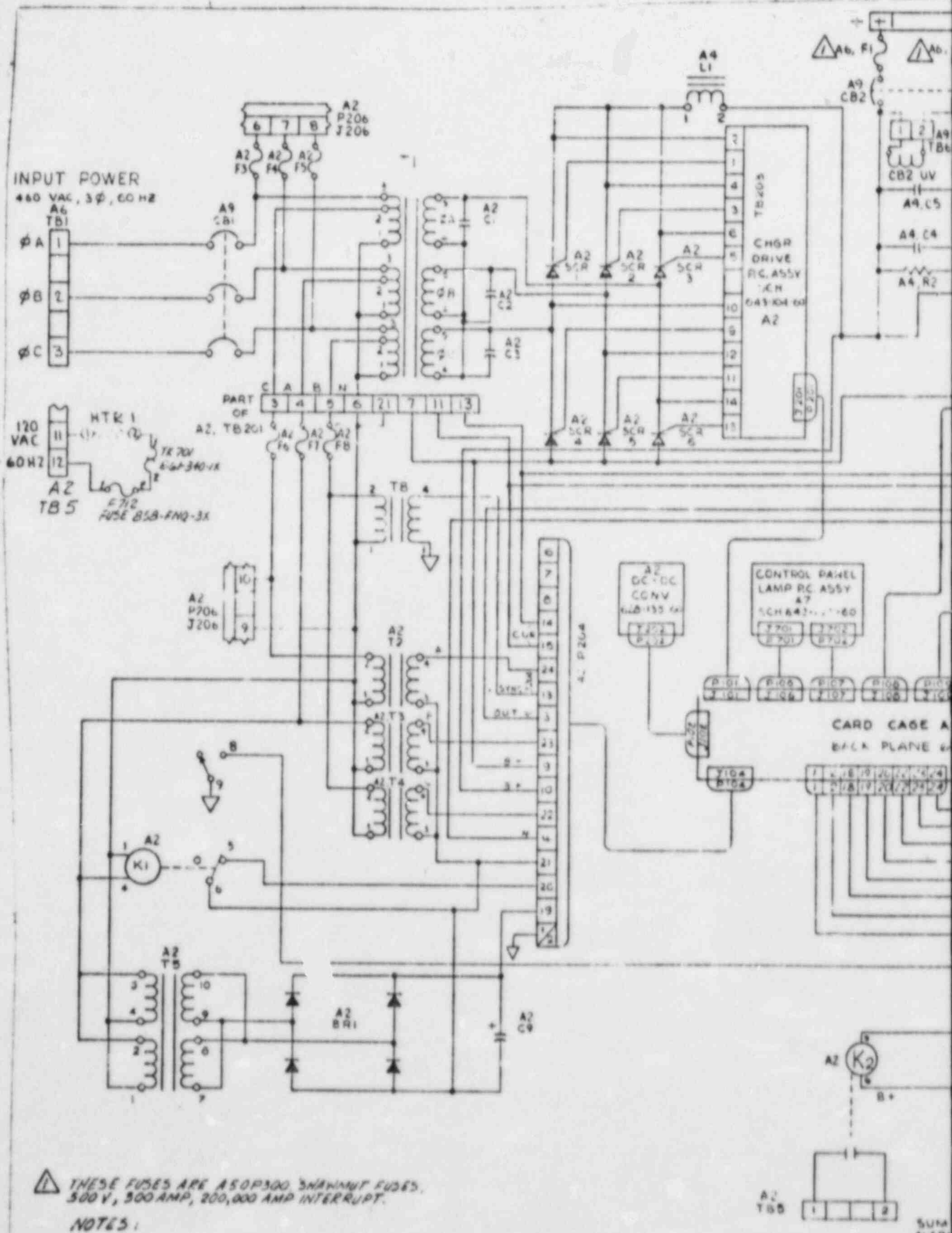
Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

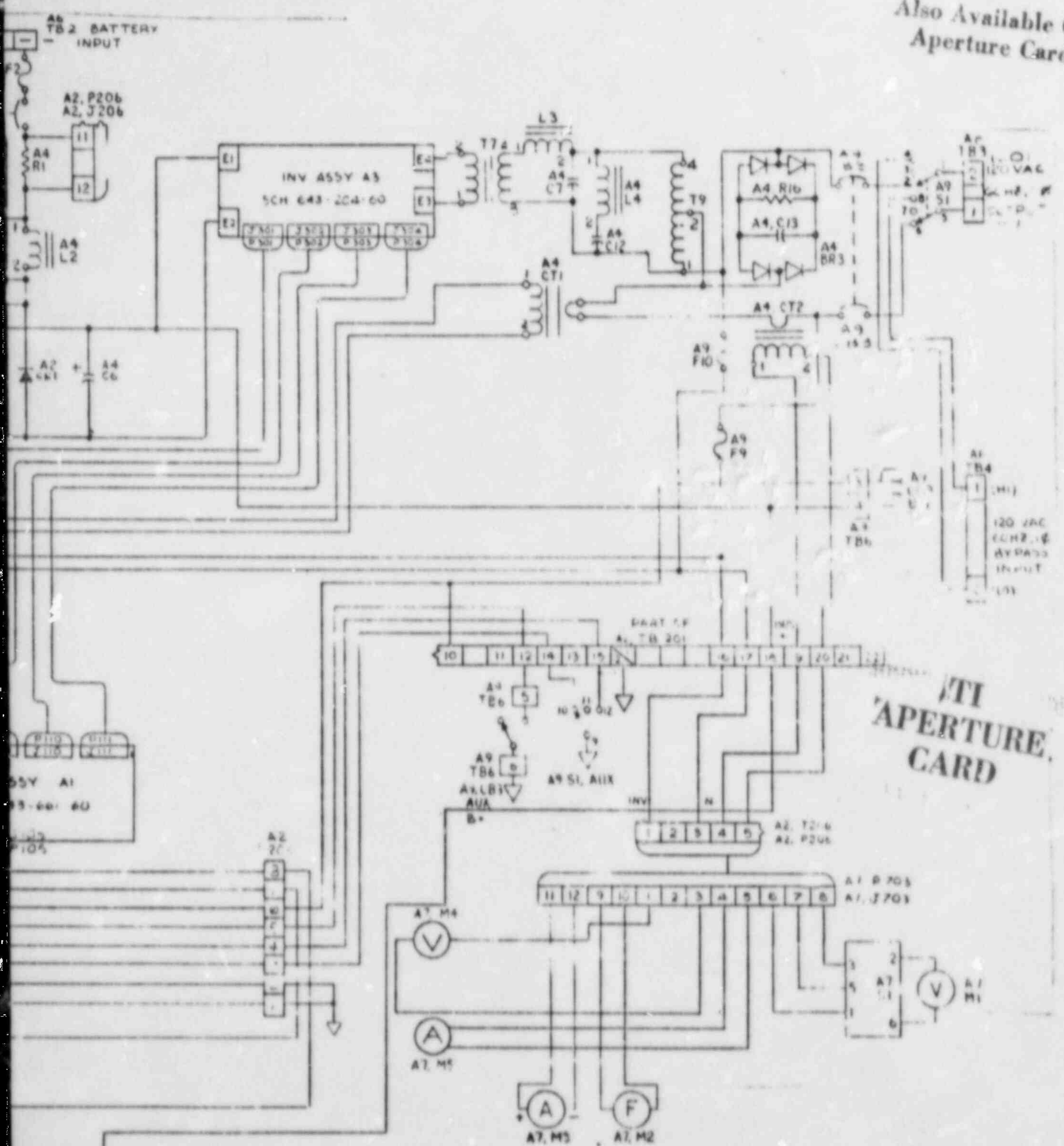
7.5 KVA F.F STATIC INVERTER
SYSTEM BLOCK DIAGRAM

FIGURE 430.61-1



THESE FUSES ARE A50P300 SHAWMUT FUSES. 300 V, 300 AMP, 200,000 AMP INTERRUPT.

NOTES:



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Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	OVERALL SCHEMATIC UPS 103-1-185
		FIGURE 430.61-2

SECTION I
DESCRIPTION

1-1. INTRODUCTION

1-2. This instruction manual has been prepared for use with the Elgar SBS 03-1 Static Bypass Switch. The information it contains concerns the description, installation, operation, and theory of operation. Also provided is maintenance information, schematics, and a parts list to aid in maintaining the SBS 03-1 at optimum performance.

1-3. GENERAL DESCRIPTION

1-4. The Elgar Model SBS 03-1 is an automatic, solid state, self contained static bypass switch designed specifically for use with Elgar AC Uninterruptible Power Sources UPS 102-1, 501-1, and 252-1. The SBS 03-1 increases the reliability of the UPS by providing a switching time of 2-4 milliseconds when changing from UPS power to a bypass power source.

1-5. The front panel controls includes an ON/OFF Circuit Breaker Switch, a Critical Load on UPS Indicator Switch, and a Critical Load on Bypass Indicator Switch. The rear panel of the SBS features seven connectors for interconnecting the SBS 03-1 to the UPS, remote alarm and sensing capabilities are also available.

1-6. ELECTRICAL DESCRIPTION

1-7. The SBS 03-1 operates from 95 to 130 VAC, 57-63 Hz, single-phase input AC line power. The output voltage generated by the SBS 03-1, for use by the UPS, is the same as the input power required by the associated UPS.

1-8. The internal circuitry of the SBS features three sensing circuits which continually monitor the associated UPS for a failure or condition that would require a reverse transfer. Once sensed, the SBS will automatically remove the critical load from UPS power and connect it to bypass power. These three sensing circuits are described fully in Section IV of this instruction manual.

1-9. BLOCK DIAGRAM DESCRIPTION

1-10. A block diagram of a SBS 03-1 being used with an Elgar UPS is shown in Figure 1-1. The SBS operates from the AC input line power and provides the UPS with its necessary input power; the UPS in turn provides the critical load with its required power. In the event of a failure within the UPS the sensing circuits of the SBS will automatically initiate a reverse transfer at which time power to the critical load will be provided directly from the AC input line rather than from the UPS.

1-11. PHYSICAL DESCRIPTION

1-12. The SBS 03-1 is housed in an all-metal enclosure. The front panel features screw holes for either mounting the unit in a standard 19 inch equipment rack or in a cabinet. All connectors and cables necessary for installation are included with the SBS.

1-13. PERFORMANCE SPECIFICATIONS

1-14. The performance specifications for the SBS 03-1 appear in Table 1-1.

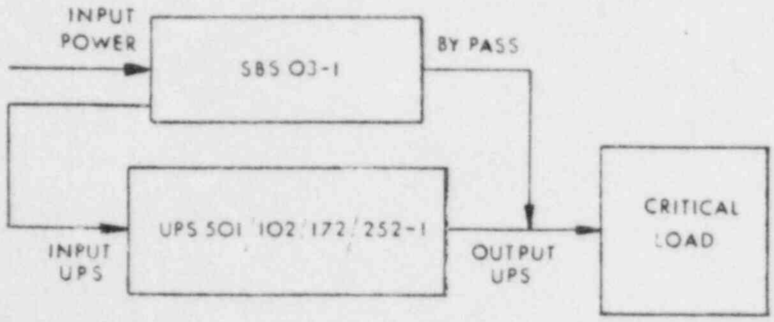
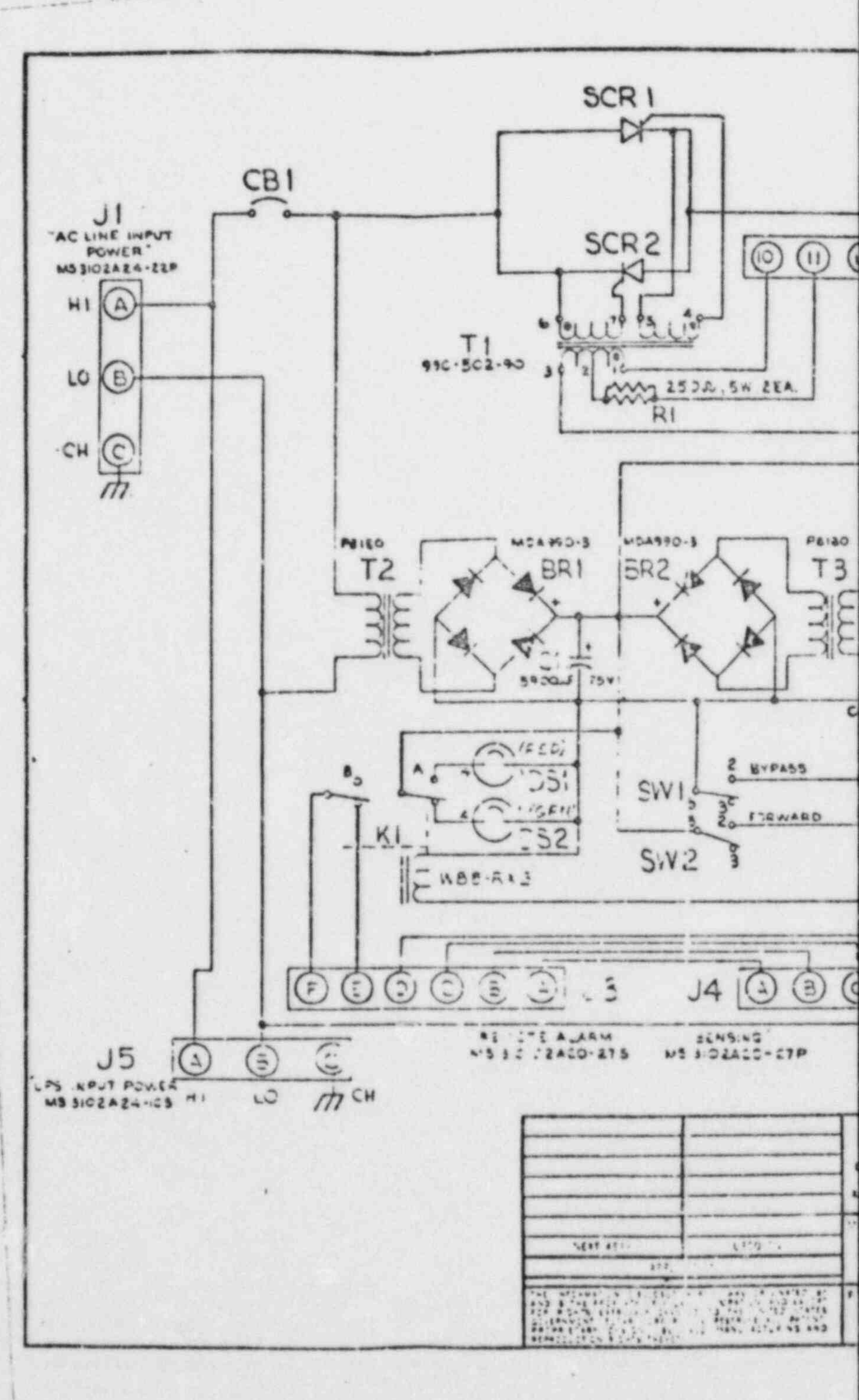


Figure 1-1. Block Diagram.

Table 1-1. Performance Specifications.

INPUT POWER	
AC Input	95-130 VAC, single-phase
Frequency	57-63 Hz
Protection	Input ON/OFF Circuit Breaker
Switching Time	2-4 milliseconds
OUTPUT POWER	
Power	2.5 KVA
AC Volts	115 VAC ±2%
Power Factor	±0.7
Frequency	60 Hz ±0.25%
FRONT PANEL INDICATORS	
Critical load on Bypass	Red light
Critical load on UPS	Green light
PHYSICAL DIMENSIONS	Height 3.5 inches Width 19.0 inches Depth 12 inches Weight 20 lbs (Approximately)


SCR 1
SCR 2
CB1
J1
"AC LINE INPUT POWER"
MS3102A24-22P
H1
LO
CH
T1
T2
T3
BR1
BR2
R1
SW1
SW2
BYPASS
FORWARD
K1
DS1
DS2
J4
SENSING
J5
UPS INPUT POWER
HI
LO
CH

MODEL SBS 03-1

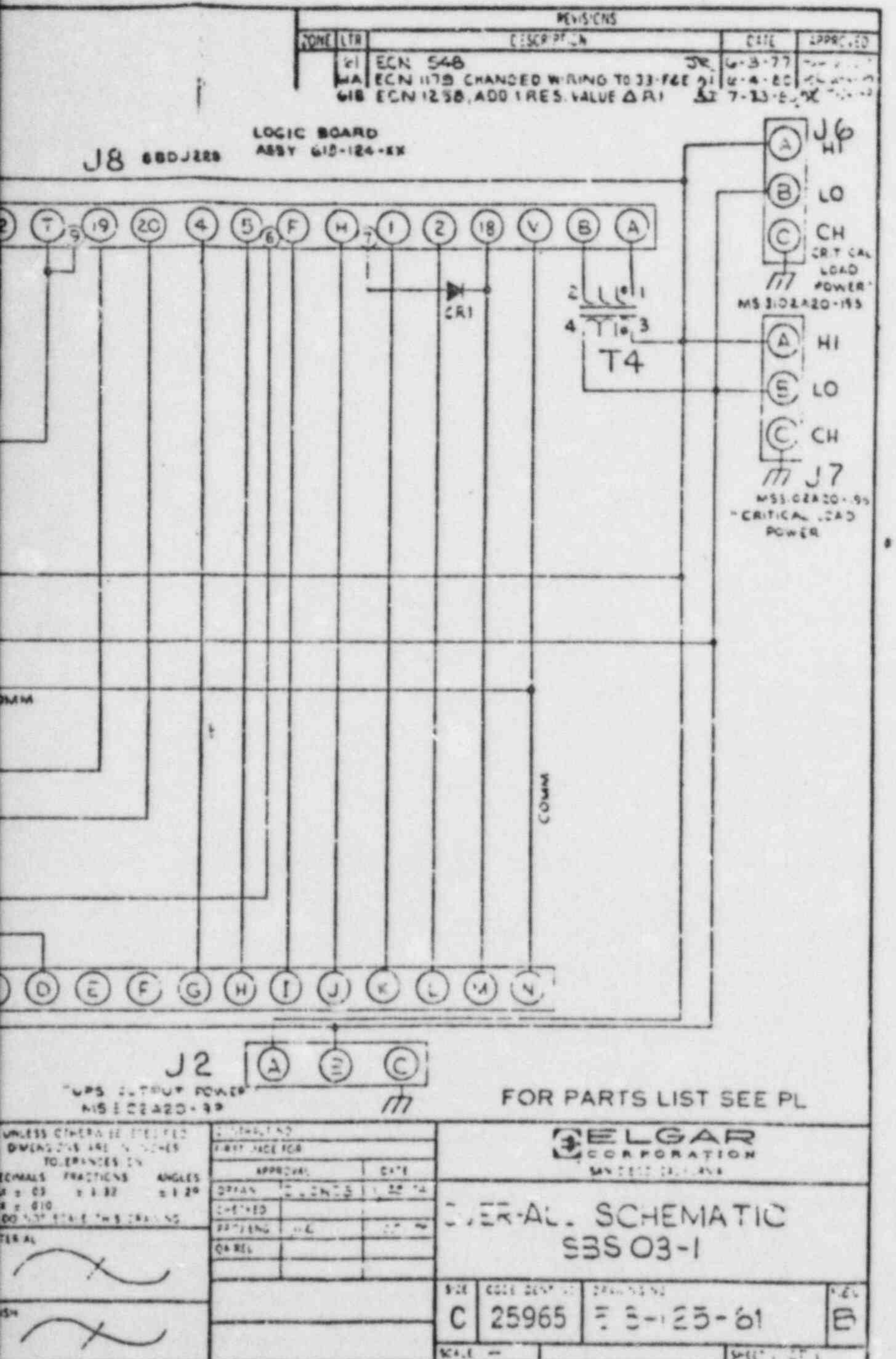


Figure 7-1. Overall Schematic SBS 03-1.

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Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	STATIC BYPASS SWITCH DESCRIPTION, SPECIFICATIONS, AND SCHEMATIC FIGURE 430.61-3 (SHEET 3 OF 3)

Question 430.62

FSAR paragraph 8.3.1.1.2.E and figure 8.3.1-1 identify switchgear 1NB01, 1NB10, 2NB01, and 2NB10 as non-Class 1E loads fed from Class 1E supplies. Identify any other ac or dc non-Class 1E loads fed from Class 1E supplies. Also identify the isolation device which is used between the 1E and non-1E systems in accordance with Regulatory Guide 1.75.

Response

In addition to switchgear NB01 and NB10, non-Class 1E emergency lighting panels NLP29, 32, 47, and 50 are powered from Class 1E 480-V ac motor control centers via Class 1E regulated transformers which act as isolation devices due to their inherent current limiting characteristics. See the response to question 430.61 concerning isolation characteristics of the regulating transformers.

Motor space heaters in Class 1E motors are powered from 120-V ac distribution panels located in Class 1E motor control centers of the same train as the motor. Cables used to power these heaters are qualified and are treated as Class 1E and are physically routed solely with other cables of the same train under the requirements of Regulatory Guide 1.75. Isolation from the 480-V bus is provided by two circuit breakers in series (the distribution panel branch breaker and the distribution panel main breaker).

Monitor light boxes located on the main control board have not been qualified as Class 1E. These monitor light boxes are powered via 120/24-V ac transformers from circuit breakers located in Class 1E 120-V ac distribution panels. As such, they are considered control level circuits. These circuits are protected by fuses in the secondary of the transformers. Cables associated with the monitor light boxes are qualified and are treated as Class 1E and are physically routed solely with other cables of the same train under the requirements of Regulatory Guide 1.75.

Question 430.63

Identify all the common Class 1E electrical loads shared between Units 1 and 2. Also identify their power sources, and, if any of the loads have the capability of being supplied from either unit, describe these connections and the interlocks which exist to preclude paralleling the Unit 1 and Unit 2 Class 1E supplies.

Response

The following Class 1E loads are common to Unit 1 and 2. They are powered from Class 1E sources associated with Unit 1 only and have no provision for connection to Unit 2 power supplies.

Load	Source
Fuel Handling Building Post-Accident Unit Heater	
A-1542-N7-001-H01	1ABA10
A-1542-N7-002-H01	1BBA10
Fuel Handling Building Post-Accident Exhaust Fan	
A-1542-N7-001-M01	1ABA08
A-1542-N7-002-M01	1BBA08
Fuel Handling Building Radiation Monitor	
ARX-2532	1AY2A06
ARX-2533	1BY2B06

Question 430.64

FSAR paragraph 8.3.1.1.2.K.5 states that molded case circuit breakers for motor circuits are equipped with instantaneous trip only and motor overload protection is provided by thermal trip units in the motor controller. It also states that during startup and periodic testing all starters for motor-operated valves (MOVs) are equipped with thermal overloads (TOLs) but prior to core loading and during plant operation the TOL contacts for all Class 1E valves are permanently bypassed with jumpers. In this regard the staff would like to point out that it is not the intent of Regulatory Guide 1.106 to totally eliminate the use of TOLs or MOVs. It is intended to assure that under accident conditions the valve will not be hindered from performing its safety function by a spurious overload trip condition. For the majority of valve operations such as during valve test or operation during nonaccident conditions, the use of TOLs in MOV circuits is a prudent operational practice to minimize motor damage due to overload conditions. Though the proposed approach resolves concern relating to inadvertent operations of TOL under accident conditions, the staff does not recommend the virtual elimination of TOLs from MOV circuits by permanent bypass. Address the following comments relative to the above:

A. For the Class 1E MOV circuits that have the overloads jumpered out describe how your design protects the cables to the valve motors against sustained locked rotor currents or high impedance faults such that the cable will not fail and affect other Class 1E loads.

B. Describe how the settings of the circuit breaker instantaneous trips for the Class 1E MOVs satisfy the above concern as well as providing coordination while avoiding spurious operation during normal motor starting transients.

C. Continuous bypassing of Class 1E MOV overloads (except during periodic or maintenance testing) is not the only option offered by Regulatory Guide 1.106. However, if it is used, it must comply with the sections of IEEE 279 which are designated as requirements in Regulatory Guide 1.106. The use of jumpers to bypass the thermal overloads to Class 1E MOVs does not comply with section 4.13 of IEEE 279. The requirement is that the bypass (or in this case lack of a bypass) be continuously indicated in the control room. Please address this issue.

Response

The following responses correspond to the above questions:

A. The smallest conductor size used for any power circuit is No. 12 AWG. Cables are protected by the magnetic only trip circuit breakers as indicated in figure 8.3.1-7, sheet 1.

B. Magnetic only trip circuit breakers are set to operate at two times the locked-rotor current of the MOV but not to exceed 13 times the motor full load current. The lowest setting on the next larger size breaker is used where this criterion cannot be met.

C. Section 4.13 of IEEE 279 and Regulatory Guide 1.47 require continuous monitoring of a component of a protection system being bypassed or deliberately rendered inoperative. The VEGP design is such that, when an MOV is moved away from the safe position, it is monitored at the system bypass status panel. Bypassing the TOL is bypassing an overcurrent protective device, not bypassing a protective system component as defined by IEEE 279. It should be noted that the overload heater itself in the power circuit is not bypassed, only the trip contact in the control circuit. During plant operation an MOV motor overload condition is annunciated in the control room as "equipment trouble alarm" using a second independent contact in the overload relay.

Regulatory Guide 1.106 states that acceptable methods of implementing the Regulatory Guide requirements are either (1) to continuously bypass the TOL and place the TOL in service only when the valve motors are undergoing periodic or maintenance testing or (2) to automatically bypass the TOL under accident conditions. The VEGP design conforms with method 1. The Regulatory Guide 1.106 requirements relative to IEEE 279-1971 address issues associated with method 2 concerning the design of the bypass initiation system circuitry. Because the VEGP design implements the use of manually installed jumpers (method 1), there is no bypass initiation system circuitry.

The Technical Specifications will explicitly identify those MOVs which are required to have TOL bypass jumpers in place during plant power operation. Since jumpers are categorically installed on all MOVs identified on this list in accordance with administrative procedures developed to ensure conformance with the Technical Specifications, the presence (or the lack of) a jumper need not be continuously monitored in the main control room.

Question 430.65

FSAR paragraph 8.3.1.1.2.L states that all Class 1E circuit breakers and motor controllers are testable during reactor operation, except for the electric equipment associated with those Class 1E loads identified in chapter 7. Identify the loads referred to in chapter 7 and provide the justification for not testing, or reference the specific sections in chapter 7 where the justification is provided.

Response

The referenced loads listed on page 7.1.2-14 are as follows:

A. Manual actuation switches for reactor trip system and engineered safety features actuation system.

B. Turbine trip system.

C. Main steam line isolation valves (close).

D. Main feedwater isolation valves (close).

E. Feedwater control valves (close).

F. Main feedwater pump trip solenoids.

G. Reactor coolant pump auxiliary component cooling water isolation valves (close).

H. Reactor coolant pump seal water return valves (close).

The justification for not testing is provided in paragraph 7.1.2.5.

Question 430.66

FSAR paragraphs 8.1.4.2.C and 8.3.1.1.3.C state that underfrequency protection is provided to safely separate the diesel generators from the preferred source during an underfrequency condition. It is not clear that this feature can also be relied upon to open the diesel generator breaker when parallel with the preferred power supply and preferred power is subsequently lost. Will the underfrequency or overcurrent protection operate to open the diesel generator breaker first?

Response

In the event the diesel generator is operating in parallel with the preferred power supply and preferred power is lost one of two cases occurs:

A. Case 1

Due to a faulted condition downstream of the preferred source breaker, the preferred power supply 186 lockout relay is actuated, causing the preferred power supply breaker and the diesel generator breaker to trip. A manual reset of the 186 device would be required to allow reenergization of the bus after a determination is made as to the cause of the lockout and that it is safe to reenergize.

B. Case 2

Due to any reason other than fault, depending upon the resultant load condition on the diesel generator and the position of the preferred source breaker, a trip and/or a lockout of the diesel generator breaker could be effected by either the underfrequency or the voltage restrained overcurrent relays. Under nonaccident conditions this lockout would require a manual reset of the associated 186 relay prior to restarting of the diesel generator and reenergization of the bus. The reset would be carried out by the operators involved with the monitoring of the parallel operation of the diesel generator with the preferred source.

Should an accident occur with this lockout in effect, safety-grade signals are automatically generated which override this lockout and initiate automatic starting of the diesel generator and loading of the accident loads as required by system logic design as if no lockout existed.

Question 430.67

In your discussion of conformance with Regulatory Guide 1.9 in FSAR section 1.9 you state that the diesels are qualified in accordance with IEEE 344-1971. Section 3.10.B, however, states that electrical equipment is qualified in accordance with IEEE 344-1975. Correct this discrepancy, and, if the diesels are qualified in accordance with the 1971 version of IEEE 344, state that fact in section 3.10.B.

Response

The emergency diesel generators are qualified in accordance with IEEE 344-1975. Paragraph 1.9.9.2 has been revised accordingly.

Question 430.68

Regarding your compliance with Branch Technical Position PSB-1 in appendix 8A of the Standard Review Plan:

A. Verify that the degraded voltage protection equipment is Class 1E qualified and is physically located at and electrically connected to the Class 1E switchgear.

B. Paragraph 8.3.1.1.3.H states that studies have been performed which indicate that at the degraded voltage setpoint of 86.5 percent the permanently connected Class 1E motor loads will not be damaged and there is adequate voltage to start the Class 1E loads. Verify that, at the setpoint of 86.5 percent, no Class 1E loads will be damaged, including all motor and nonmotor loads down to the 120-V level. Verify that all these loads will start and operate satisfactorily and no overcurrent devices (overloads, fuses, circuit breakers, etc.) will be tripped as a result of that degraded voltage. Provide the results of your studies which show the worst case transient and steady state terminal voltage at each voltage level relative to the 86.5 percent relay setpoint.

C. Provide the results of your analysis used to select the voltage tap settings of the offsite power transformers in accordance with position B.3 of the Branch Technical Position.

D. Discuss your compliance with position B.4 of the Branch Technical Position.

Response

The following responses correspond to the above questions:

A. The degraded voltage protection equipment is fully Class 1E qualified in accordance with IEEE 323-1974 and 344-1975. The equipment consists of solid state undervoltage devices, as described in paragraph 8.3.1.1.3.F, which are physically located in the safety features sequencers. Potential transformers are located in each Class 1E 4.16-kV switchgear which provide voltage signals to the undervoltage sensors in the associated sequencer. Although the undervoltage devices are located in the sequencer cabinet, they are "front end" devices which generate the loss of or degraded voltage signals which the sequencer accepts as an input to initiate sequencing.

B. As stated in paragraph 8.3.1.1.3.F, an analysis has been performed which justifies that no Class 1E loads, including motor and nonmotor loads, down to the 120-V level, will be damaged when the Class 1E 4.16-kV buses are subjected to a degraded voltage condition. The analysis was actually performed at slightly above (0.866 per unit) the relay setpoint (0.865 per unit, bus base), since tripping would occur in 30 s at the relay setpoint. Overcurrent protection trip setpoints are selected considering worst case voltage conditions to preclude overload tripping when the voltage is within design ranges.

The results of the voltage analyses for the worst case portion of the distribution system are as follows:

	Steady State (per unit)	Transient* (during motor start)
4.16-kV bus**	0.866	--
4.16-kV load terminal***	0.898	0.888
4.80-V load center bus	0.873	--
4.80-V load center load terminal	0.892****	0.820
4.80-V motor control center bus	0.863	--
4.80-V motor control center load terminal	0.901	0.863
1.20-V load terminal	0.853*****	0.828

*Transient voltages assume steady state voltage of 0.866 at 4.16-kV bus prior to the starting of the largest load at each voltage level.

**Bus voltages are given on bus base.

***Load terminal voltages are given on motor base (4.0 kV, 460 V, 115 V).

****The motor thermal damage curve for this worst case motor indicates that this motor can operate indefinitely at the load current corresponding to this voltage.

*****Reduced space heater power output under degraded voltage conditions is not considered to have a degrading effect on performance of safety-related equipment.

All Class 1E loads have been specified to operate at 0.9 per unit (motor base) and start at 0.75 per unit (motor base), except those loads specified to start at 0.8 per unit (motor base) as discussed in question 430.71. Because degraded voltage conditions are abnormal conditions, justifiable deviations from specified operating conditions have been allowed.

C. The analysis to determine tap setpoints for the reserve auxiliary transformer and for the load center transformers considered (1) the most heavily loaded plant distribution system concurrent with the minimum switchyard voltage and (2) the postulated light load condition during switchyard maximum voltage. The tap setpoints selected to achieve a balance between these conditions are 0.975 for the reserve auxiliary transformers and 0.95 for the load center transformers. The resultant voltages under the heavily loaded condition are those voltages given in item B above. The light load condition per unit voltages (motor base) are as follows:

4.16-kV Class 1E bus	1.066
480-V Class 1E load center bus	1.096
480-V Class 1E motor control center bus	1.089

Loads have been specified to operate at 1.1 per unit (motor base).

D. VEGP will conform to position B.4 of Branch Technical Position PSB-1. Refer to subsection 14.2.8 for further information on preoperational testing.

Question 430.69

Regarding the load shedding and load sequencing:

A. Describe what provisions are taken to allow decay of motor residual voltage when a loss of offsite power occurs following a loss-of-coolant accident and the diesel generators are running in standby.

B. FSAR paragraph 8.3.1.1.3.F states that logic has been provided that prevents more than three undervoltage conditions from being recognized within a 2-h period in order to prevent automatically exceeding the manufacturer's recommendations concerning motor start capability of two successive starts within a 2-h period. Does the manufacturer's limitation on motor starting apply to both motor-operated valve motors and pump motors? Does the logic count the number of undervoltage conditions when operating on offsite and onsite power? What is the purpose of requiring manual opening of the diesel generators breaker to reinstate sequencing following the block? Provide a more detailed discussion of the logic associated with this system, and discuss the safety benefit, if any, derived from it.

C. Describe the load sequencer logic, circuitry, and components. Because the emergency loads are sequenced on both offsite and onsite power sources, we require that you either provide a separate sequencer for offsite and onsite power (per electrical division) or a detailed analysis to demonstrate that there are no credible sneak circuits or common failure modes in the sequencer design that could render both onsite and offsite power sources unavailable. In addition provide information concerning the reliability of your sequencer and reference design detailed drawings.

Response

The following responses correspond to the above questions:

A. Considering a loss-of-coolant accident (LOCA) with the diesel generators operating in standby with a subsequent loss of offsite power, there is a time delay of approximately 1.4 s before the first motor load is applied to the output of the diesel generators. This is sufficient time delay to allow residual motor voltages to decay to a low enough level to preclude damage to the motors upon reenergization.

B. Manufacturers of large motors impose motor starting limitations relative to the number of starts within a certain time frame and under particular operating conditions. These limitations are typically imposed only on large motors due to the excessive heat internally generated in the motor during starting with corresponding potential reductions in the life of the motor. No such limitations have been imposed by the manufacturers on motor-operated valves.

The logic system senses undervoltage on the Class 1E 4.16-kV bus and therefore does not distinguish whether the undervoltage is due to loss of offsite or onsite power. The logic is designed such that the third undervoltage condition within a 2-h period initiates a load shed but does not trip the diesel generator breaker. The design has been recently changed such that, instead of opening the generator, a pushbutton has been provided at the sequencer which resets the counter in the logic system to zero, thereby allowing three more undervoltage conditions to be recognized. The intent of this system is to address the start limitations imposed by the motor manufacturer and attempts to prevent repetitively automatically starting large motors due to an intermittent undervoltage condition on the 4.16-kV bus. The intermittent undervoltage condition is considered credible only due to a defect in the excitation system of the diesel generator, and under this condition an automatic stopping or resequencing is justified in order to allow inspection and correction, as required, of the exciter prior to continuation of operation. Subsection 8.3.1 has been revised.

C. There is no requirement to provide a separate sequencer for offsite and onsite power sources because both sources are supplying power to common buses AA02 for train A and BA03 for train B. On each bus are four potential transformers to monitor the phase-to-phase voltages with the potential transformer secondary output fed to the sequencer.

There is no sneak circuit in the design that could render both onsite and offsite power sources unavailable for the following reasons:

1. No circuit from either the offsite power source or onsite power source circuit is directly interlocked to the sequencer logic circuit.

2. The only association of either the offsite or the onsite power source to the sequencer is through the four potential transformers on the bus (common bus to both sources) which sense the bus voltage.

3. Except for output relays which are electromechanical, all components are solid state devices of high reliability.

The sequencer supplier, Consolidated Controls Corporation, is an experienced designer and manufacturer of reactor protective equipment using high quality components. A test prototype of the sequencer was subjected to seismic tests and environmental qualification tests (aging) with an indicated qualified life of 41 years in accordance with IEEE 323-1974 and 344-1975. The same samples were used in a comprehensive functional test and the sequencer operated successfully in accordance with design logic.

The sequencer is provided with two manually actuated testing modes, the system mode and sequencer mode. The system mode includes the starting of the diesel generator. In the sequencer mode indicating lights which indicate actuation of each step (illuminating at its assigned step) will demonstrate that the step logic is functioning properly. During tests all sequencer output relays are blocked.

In addition to the manual testing system, the sequencer has a built-in automatic test insertion (ATI) feature. The automatic testing feature provides a continuous surveillance of the system operations from the input to output circuits. A failure of any circuitry will stop the ATI operation, and ATI failure is indicated and alarmed.

With the above features of the sequencer, any malfunction of the circuitry is sensed immediately, thereby ensuring proper opration of the sequencer when needed. Since the sequencer components are essentially all solid state, the failure rate of the sequencer is considered extremely low.

A description of the load sequencer logic, circuitry, and components is provided in the following excerpt from the instruction manual for the sequencer.

EXCERPT FROM INSTRUCTION MANUAL FOR
SAFETY FEATURE SEQUENCER BOARD

1.0 GENERAL

The safety features sequencer subsystem (SFSS) monitors bus voltage and the safety injection signal (SIS). When required, the SFSS will automatically shed bus loads, start a diesel generator, and sequentially reconnect applicable loads to the voltage bus. The status of the SFSS is displayed on a manual test panel. In addition, the SFSS is continuously tested automatically by an automatic test insertion (ATI) subsystem. This subsystem ensures that the SFSS will be ready to function in the event of an SIS or bus undervoltage condition.

The logic diagram (figure 430.69-1) describes the operation of the SFSS. In normal plant operation all status equipment input contacts are open, and indicator lamps on the manual test panel are extinguished. When using the logic diagram, it is assumed that a logic 1 is the energizing or energized condition, while a logic 0 is the deenergizing or deenergized condition.

The plant loads are normally connected to a voltage bus through contacts of energized control relays in the termination cabinets. If the control relay contacts are closed, the load is connected; if the contacts are opened, the load is disconnected. When a disconnected load is to be connected, a control relay is energized by the operation of the sequencer.

1.1 LOSS OF OFFSITE POWER (LOP)

The SFSS monitors the four bus voltage inputs. The two out of four (2/4) logic contains the bistable modules that detect the loss of voltage and the actuation modules that will provide activation if at least two bistables detect the loss of power.

Three sets of four bistables (see sheet 1 of figure 430.69-1) are used; one set is adjusted to detect a voltage loss of 88.5 percent (third-level voltage), the second set is adjusted to detect a voltage level of 86.5 percent (second-level voltage), and the third set is adjusted to detect a voltage level of 70 percent (first-level voltage). Any single third-level voltage detection that is present for at least 5 s provides a system alarm and activates the local UNDERVOLTAGE lamp on the manual test panel. Likewise, any single first-level voltage detection immediately activates the alarms. Any 2/4 actuation due to a second-level or first-level voltage detection provides a logic 1 2/4 active signal which is applied through an inverter to the TEST MANUAL pushbutton five-input AND gate (see sheet 2 of figure 430.69-1). With the 2/4 active signal at logic 1, the AND gate is disabled and no test functions are possible.

If a second-level voltage is present for at least 20 s and the diesel generator breaker is not closed (logic 0), a logic 1 is applied through an OR gate to set a memory latch. Likewise, if a first-level voltage is present for 0.75 s, the memory latch is set. With the memory latch set, a logic 1 is present at the M output. This logic 1 is applied through an OR gate to an AND gate whose second input is a logic 1, since no test functions can be activated. (The logic 0 from the TEST BLOCK D-G ENGINE AND gate is logic 0 which is inverted to logic 1.) The AND gate is enabled, providing the diesel generator start signal. The output of the memory latch AND gate is also applied as a logic 1 to one input of a three-input AND gate.

The logic 1 from the memory latch is also applied to energize undervoltage (U/V) relays for external use, lighting the U/V lamp on the manual test panel. The logic 1 from the memory latch is also applied to an AND gate, through two delay circuits. The AND gate is enabled 0.2 s after the memory latch is set and remains enabled for 1 s, providing the logic 1 to output relays to trip the 1E and non-1E breakers, thus shedding the loads from the bus (4.16-kV motors, 480-V 1E motors, and 1E load center secondary breakers including the non-1E diesel backed load center secondary breakers).

The logic 1 from the memory latch is applied, after a 10 ms delay through an OR gate to several logic circuits:

A. An AND gate, whose second input is derived from the SIS detection circuit. With no SIS condition present, the second input to the AND gate is logic 1, resulting in the AND gate being enabled 10 ms after the memory latch is set. The logic 1 output from the AND gate is inverted to logic 0, thus disabling all of the step 1-9 and 1B-9B logic, preventing the activation of any 1-9 or 1B-9B output relay.

B. An AND gate whose second input is the U/V signal from the memory latch AND gate, delayed 0.5 s. After the delay, the AND gate is enabled, providing the logic 1 diesel generator breaker auto closure permissive signal, allowing the diesel generator breaker to be closed when ready.

C. An AND gate whose second input is an SIS signal. With no SIS condition present, this AND gate is disabled.

D. An AND gate, through an inverter which applies a logic 0, disabling the gate.

E. To the TEST U/V pushbutton logic, which is disabled as previously described.

The logic 1 output of the AND gate of item A above is also applied to one AND date directly and to one AND gate after a 0.5-s delay. These two AND gates will be enabled after the diesel generator breaker is closed. With the breaker closed, the 2/4 logic is disabled, and the AND gates are enabled, providing a logic 1 after the 0.5-s delay to the step timing bus, activating the sequencer to provide logic 1 to energize relays 1A-9A and 1C-9C steps. The activation of the 1A-9A relays sequentially is applied to a flashing AND gate (see the logic associated with steps 5A and 5C on the logic diagram), enabling the gate to flash the associated SEQ STEPS INDICATION lamp of the manual test panel. Each output step of the sequencer is maintained as long as the sequencer is active. The output relays associated with steps 1A-9A are therefore maintained energized, maintaining the 1A-9A lamps flashing. The output relays associated with 1C-9C are activated for only 1 s, since the delay circuit at the input to the relay drive AND gate will be disabled by the inverted logic 1 when the 1-s delay timer times out. The outputs of the C relays are applied through an OR gate-AND gate latch that maintains the 1C-9C lamps flashing even when the relay is deenergized.

The three-input AND gate that provides the block auto/manual signal is enabled for 36 s. One input is the logic 1 diesel generator start signal. A second input is always logic 1 if a U/V and SIS condition are not present simultaneously. The third input is logic 1, derived from the memory latch AND gate, for 36 s after the diesel generator breaker is closed. The result of the logic is that any test mode is prevented from being activated at least 36 s after the U/V condition is detected, a period greater than that required to complete the sequencer operation.

At the end of the sequencer (last step) and 1.2 s later, the delayed logic 1 from the last step timer is applied to reset the memory latch, thus removing the logic 1 from the M output of the memory latch, removing the U/V level signal, thus disabling the step timing bus, resetting the sequencer, deenergizing the output relays, and extinguishing the SEQ STEPS INDICATION lamps.

1.2 SAFETY INJECTION CONDITION (LOCA)

When an SIS is present from either train A or train B, the sequencer operates in essentially the same manner as for a U/V condition with several notable differences:

A. The SIS applied through the two-input OR gate and the two-input AND gate turns on the diesel generator as in a U/V condition. However, with no U/V condition, the diesel generator breaker auto closure permissive signal is not generated and the diesel generator is not placed online.

B. The SIS lights the SI SIGNAL lamp on the manual test panel and activates the SI maintained relays. The SI momentary relays are energized and then deenergized 1 s after activation when the 1.0-s timer times out, thus disabling the SI momentary AND gate.

C. The SIS logic 1 signal is applied, after a 90-ms delay, to an AND gate whose second input is logic 1 when no U/V condition is present. The resultant logic 1 from this AND gate is applied, after a 0.5-s delay, to the step timing bus. With no U/V condition, the step 1-9 and 1B-9B relays are no longer blocked. When the step timing bus is activated by the SIS, all output relays are energized sequentially, providing the flashing SEQ STEPS INDICATION lamps 1-9, 1A-9A, 1B-9B, 1C-9C, in the same manner as described for the U/V condition. At the end of the sequence the logic 1 from the last step delay is delayed 2 s, then inverted to logic 0, thus removing the enabling logic 1 from the flashing AND gates for SEQ STEPS INDICATION lamps 1B-9B and 1C-9C, thus extinguishing the lamps. As long as the SIS condition is present, the step timing bus is energized, holding all 1-9 and 1A-9A relays energized and maintaining the corresponding SEQ STEPS INDICATION lamps flashing. When the SIS condition is removed, the step timing bus is disabled, the sequencer resets, and the output relays are deenergized, thus extinguishing all flashing lamps.

1.3 LOP AND SUBSEQUENT LOCA

This is similar to "LOP only" operation except:

A. If a LOCA occurs during sequencing, the sequencer will reset for 0.8 s and restart to sequence all LOP plus LOCA loads until the sequence is completed.

B. If a LOCA occurs after the sequencer is timed out and the sequencer is reset, the sequencer will restart by the SIS and sequence those loads required for LOCA. No load shed will occur (because voltage is present at the 4.16-kV bus).

NOTE: This conforms with the NRC requirement that no load shed is allowed when loads are already connected to the diesel generator bus.

1.4 LOCA AND SUBSEQUENT LOP

A. After receiving the SIS:

1. Start diesel generator.

1. Start sequencing (0.1-s delay).

B. If during sequencing an LOP occurs:

1. The sequencer resets immediately and sheds all loads then sends a second signal to start the diesel generator (even through the diesel generator is already running from item A.1 above).

2. Trips preferred incoming breakers and closes diesel generator breaker:

   a. The sequencer resets immediately and sheds all loads; sends a second signal to start diesel generator (even though the diesel generator is already running from item A.1 above).

   b. Trips preferred incoming breakers and closes diesel generator breaker.

   c. Starts sequencing (0.8-s delay minimum) (all output relays will be energized).

   d. Resets the undervoltage signal (after 36 s).

3. If LOP occurs after the sequence is completed, the sequencer operates as paragraph 1.4.B above.

1.5 TEST CONDITIONS

The manual test panel can simulate a U/V or SIS condition and test either the sequencer only or the plant system. For any test, the TEST MANUAL pushbutton is depressed before any other test selection can be made. Referring to sheet 2 of figure 430.69-1, the five-input AND gate associated with the TEST MANUAL pushbutton is enabled when no manual reset is in effect, no real SIS or U/V condition is present, no active 2/4 first- or second-level voltage is detected, and the pushbutton is depressed. With the AND gate enabled, it is latched through an OR gate feedback and the TEST MANUAL lamp is lighted. With the AND gate latched, a logic 1 conditioning level is applied to the other test pushbutton AND gates. The latched AND gate also provides a blocking signal that blocks the activation of all output relays. With all relays blocked, the resultant logic 0 from the 18-input OR gate is inverted, lighting the OUTPUT RELAYS BLOCKED lamp on the manual test panel. In the system test mode, the block signal is removed from selected relays and load activation will take place.

1.5.1 TEST SEQUENCER MODE

To test the sequencer only, the TEST MODE switch is set to the SEQ position, lighting the SEQ lamp. In the SEQ position, a logic 1 is applied to a two-input AND gate whose second input is a logic 1 from the test manual AND gate, thus enabling the gate. With this AND gate enabled the resultant logic 1 is applied to a series of AND gates (two gates shown typically in figure 430.69-1) that will be enabled when the specific sequencer step is activated, providing a steadily lighted SEQ STEPS INDICATION lamp, signifying that a test sequencer mode test is in effect. The logic 1 from the SEQ position of the TEST MODE switch is also applied as a conditioning input to two AND gates associated with the TEST U/V and TEST SI pushbutton switches.

1.5.1.1 Sequencer Mode U/V Test

Depressing the TEST U/V pushbutton enables the sequencer mode AND gate, providing a logic 1 through an OR gate to a three-input AND gate. With the test manual AND gate latched and no U/V or SIS condition present, the AND gate is enabled and latched through an OR gate. The latched logic 1 lights the TEST U/V and U/V SIGNAL lamps and is also applied to an AND gate whose second input is a logic 1 when the sequencer is not in the test system mode. The resultant logic 1 is delayed 0.1 s and applied to the U/V AND resultant logic 1 is delayed 0.1 s and applied to the U/V AND gate. When the TEST D-G BRKR CLOSE pushbotton is depressed, its associated AND gate is enabled and latched, lighting the TEST D-G BRKR CLOSE lamp, providing a diesel generator breaker closed signal through an OR gate, and setting up the U/V operation of the sequencer as described in paragraph 1.1. The SEQ STEPS INDICATION lamps are steadily lighted instead of flashing, as the sequencer operates, with the output relays blocked as described in paragraph 1.3.

At the end of the sequence, the last step logic 1 is inverted and applied as a logic 0 to the test manual AND gate. A logic 0 applied to the AND gate unlatches the gate, thus removing the logic 1 from the U/V sequencer AND gate, removing the test U/V condition, and extinguishing the 1A-9A and 1C-9C SEQ STEPS INDICATION lamps.

1.5.1.2 Sequencer Mode SIS Test

Depressing the TEST SI switch enables logic circuitry similar to that for the TEST U/V condition described in paragraph 1.3.1.1. In this case the TEST SI lamp and SI SIGNAL lamp are lighted. The logic 1 output of the TEST SI sequencer AND gate is applied through an OR gate as the SI-A signal to activate the step timing bus, energizing the sequencer, providing the steadily lighted SEQ STEPS INDICATION lamps. When the sequence is complete the TEST MANUAL AND gate is deenergized as described in paragraph 1.3.1.1, removing the SIS test condition, and all lamps are extinguished.

1.5.2 TEST SYSTEM MODE

During any system test mode, selected output relays are energized and all output relays become unblocked. Any activated relay will activate the corresponding plant load. This possible activation of plant loads is indicated by the flashing SYS lamp and the flashing of any selected SEQ STEPS INDICATION lamp/relay.

With the TEST MODE switch in the SYS position, no active U/V or SIS condition detected, and the TEST MANUAL pushbutton depressed, the three-input AND gate associated with the SYS position is enabled and latched, providing a conditioning logic 1 to the system mode TEST SI and TEST U/V AND gates, a conditioning logic 1 to no pairs of TEST OUTPUT SWITCHES, and logic 1 through an OR gate and an inverter as the block output relay signal.

1.5.2.1 System Mode U/V Tests

In the system mode, when the TEST U/V pushbutton is depressed, the system mode AND gate is enabled, and the resultant logic 1 latches the subsequent AND gate for 0.2 s. The resultant logic 1 sets the memory latch, providing a logic 1 through an OR gate to latch the TEST U/V AND gate, providing a logic 1 to an AND gate whose second input is the test U/V AND gate, providing a logic 1 to an AND gate whose second input is the test U/V system signal. The logic 1 from the memory latch will generate the start diesel generator signal unless blocked by the activation of the TEST BLOCK D-G ENGINE pushbutton switch.

After the 0.2-s pulse from the TEST U/V pushbutton is complete, the second input to this test U/V AND gate is logic 1, enabling the gate, providing the U/V level to activate the step timing bus and block the activation of relays 1-9 and 1B-9B as previously described for the normal U/V condition. The completion of the 0.2-s test U/V system pulse (logic 0) is inverted and applied through an enabled AND gate and an OR gate to reset the memory latch, preventing load shed.

With the step timing bus enabled, the sequencer begins its operation. With the block output relay logic 0 in effect, the only step AND gates that can be enabled are those whose second input is derived from one of the 1A-9A or 1C-9C TEST OUTPUT SWITCHES. The enabled AND gate activates the flashing logic to flash the selected SEQ STEPS INDICATION lamp. At the end of the sequencer operation, the TEST MANUAL AND gate, is unlatched, thus disabling all test mode AND gates, and the selected relays are deenergized and all flashing lamps are extinguished.

1.5.2.2 System Mode SI Tests

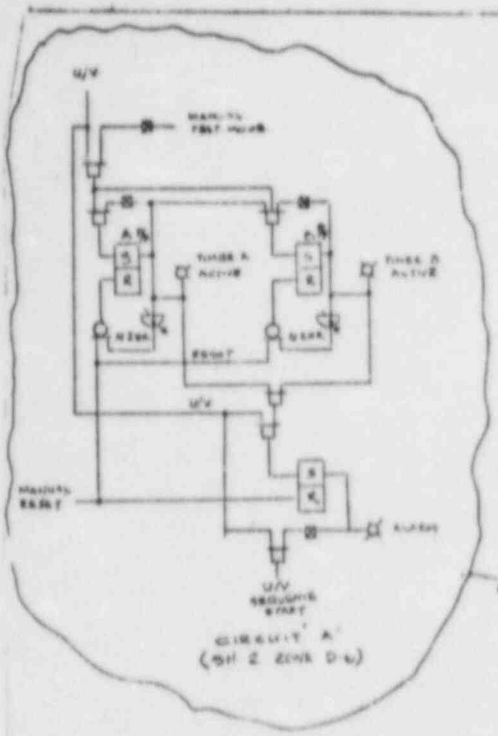
The operation of the logic for the SI system test mode is essentially the same as that of the U/V system test mode. The SI system test signal is generated by depressing the TEST SI pushbutton, eventually latching the TEST SI system AND gate to enable the step timing bus. The U/V timing bus is also enabled since no U/V condition is in effect. The only relays and associated lamps that are activated are those selected by the activation of the corresponding TEST OUTPUT SWITCHES. For the system mode SI tests, all TEST OUTPUT SWITCHES may be activated.

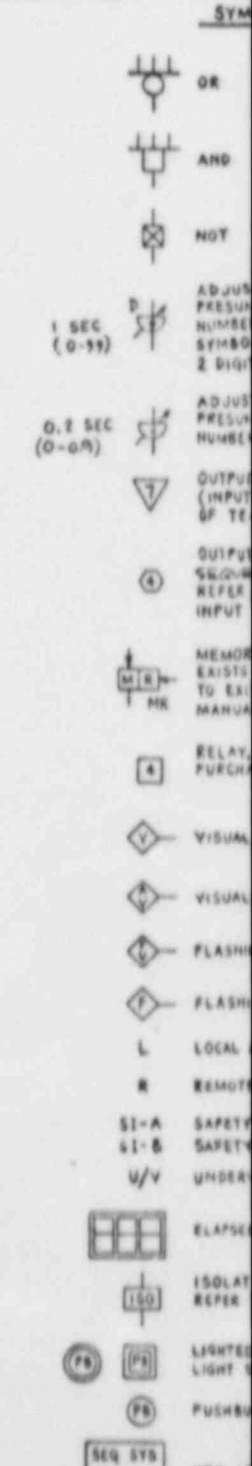
1.6 FUNCTIONAL DESCRIPTION OF ATI OPERATION

The ATI consists of three wire-wrap modules, 6N362-1, 6N363-2, and 6N364-3. It is powered by a 5-V dc, 3-ampere power supply which is located on the mounting frame in logic cabinet 2. The ATI simulates field input signals generated from an input table PROM. Figure 430.69-2 is a functional block diagram of the ATI subsystem. The 10-Hz clock starts a counter which generates the proper addresses for the input table PROM, the timing PROM, and the output table PROM. Signals from the input table PROM are "ORed" with the actual signals from the logic modules. The timing or clock signal for the input table PROM is generated by the same 1000-Hz crystal oscillator used in the logic circuits. The signal is divided down to 10 Hz which is the system clock for the ATI. The 10-Hz clock also goes to an ATI strobe generator, which generates a 2-ms pulse every 100 ms. This 2-ms signal pulses the output of the logic (input to the relay drivers) by "ANDing" the 2-ms pulse with the output signal which has been generated due to the simulated input signal from the input table PROM. This output 2-ms signal is not sufficiently long to activate the output relays. This output signal also is applied to a comparator circuit, where it is compared to an output signal generated by the output table PROM. if the signal output from the output table PROM and the simulated output signal from the logic output are not equal, an ATI FAILURE signal is generated.

The ATI FAILURE signal resets the logic modules and stops the ATI clock which stops the ATI. This signal also stops the ATI DISPLAY at the step number corresponding to the failure occurrence, and the display is continuously on. The step number at which the ATI display stops will be an indication of where in the circuitry the failure has occurred. At the end of the ATI test sequence, the timing counters, the PROMs, and the ATI display are momentarily reset and the ATI test sequence begins again.

If an undervoltage or SIS condition trip signal comes into the sequencer, the ATI is turned off by these signals. A momentary reset is applied to all the logic modules to reset the counters, timers, and shift registers. The ATI strobe generator output goes to a maintained high signal (logic 1) which is "ANDed" with the real output signal from the logic modules to activate the relay driver and, subsequently, the output relay. When the active signal is removed, the ATI may be started again by depressing the ATI RESET switch.


U/V
MANUAL TEST MODE
TIMER A ACTIVE
TIMER B ACTIVE
RESET
U/V
MANUAL RESET
ALARM
U/V SEQUENCE START
CIRCUIT 'A'
(SH 2 ZONE D-6)


OR
AND
NOT
1 SEC (0-99)
0.2 SEC (0-0.9)
L LOCAL
R REMOTE
SI-A
SI-B
U/V
SEQ SYS
INPUT

Also Available On
Aperture Card

BOLS & ABBREVIATIONS

ABLE TIME DELAY "ON." FIRST NUMBER INDICATES
ABLE SET VALUE OF SECONDS OF DELAY.
S IN PARENTHESES INDICATE TIME RANGE.
, WITH LETTER "D" INDICATES TIME DELAY WITH
ADJUSTMENTS.

ABLE TIME DELAY "OFF." FIRST NUMBER INDICATES
ABLE SET VALUE OF SECONDS OF DELAY.
S IN PARENTHESES INDICATE TIME RANGE.

FROM THE SAFETY FEATURES SEQUENCER SYSTEM
TO PURCHASER; REFER TO PARAGRAPH 3.4.4
HNICAL PROVISION FOR OUTPUT IDENTIFICATION.

FROM THE PURCHASER SYSTEM (INPUT TO SAFETY FEATURES
NCER SYS.) ONLY ONE CONTACT WILL BE FURNISHED.
TO PARAGRAPH 3.4.3 OF TECHNICAL PROVISION FOR
IDENTIFICATION.

Y ELEMENT – MEMORY OUTPUT
WHEN THE MEMORY INPUT IS PRESENT AND CONTINUES
T UNTIL THE RESET INPUT IS PRESENT. "MR" INDICATES
RESET. "ER" INDICATES ELECTRICAL R...T.

NUMBER INDICATES SPDT CONTACTS AVAILABLE FOR
SER'S USE.

INDICATION

AND AUDIBLE ALARM

G AND STEADY VISUAL INDICATION

G LIGHT

T THE SAFETY FEATURES SEQUENCER BOARD.

AT THE CONTROL ROOM. (ELECTRICAL AUXILIARY BOARD)

INJECTION SIGNAL. TRAIN (A)
INJECTION SIGNAL TRAIN (B)
OLTAGE SIGNAL

TIME METER

ON DEVICE
O PARAGRAPH 4.1.2.1 OF TECHNICAL PROVISION.

PUSHBUTTONS (MOMENTARY)
TAYS "ON" AFTER PUSHBUTTON IS RELEASED.

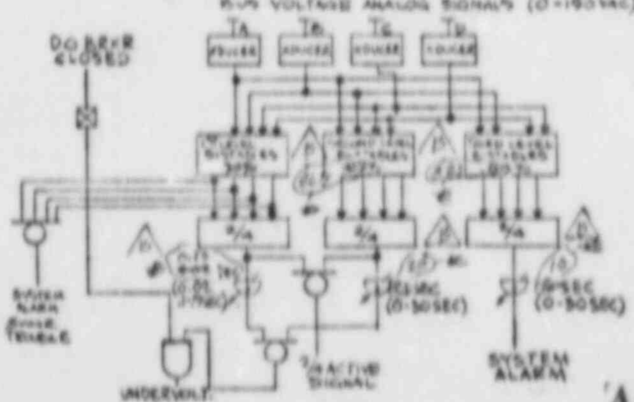
TON (MOMENTARY WITHOUT INDICATING LIGHT).

CKED CONTROL SWITCH

TO COMPUTER

NOTES:

1. TIME DELAY USED ONLY FOR STEP TIMING BUS RESET
2. DIAGRAM SHOWS ONLY THE LOGIC FUNCTIONS. IT IS NOT INTENDED TO REPRESENT THE ACTUAL HARDWARE IMPLEMENTATION.
3. ALL EXTERNAL CIRCUITS ENTERING OR LEAVING THE SAFETY FEATURES SEQUENCER BOARD ARE PROVIDED WITH ISOLATION DEVICES
4. APPROXIMATELY 9.5 SECONDS ARE REQUIRED FOR THE DIESEL GENERATOR TO START AND COME UP TO SPEED AND VOLTAGE.
5. UNIT 1 TRAIN "A" SAFETY FEATURES SEQUENCER BOARD (1182IU3001) LOGIC IS SHOWN. UNIT 1 TRAIN "B", UNIT 2 TRAINS "A" & "B" SAFETY FEATURES SEQUENCER BOARD LOGICS ARE ALSO SIMILAR.
6. KEY OPERATED SELECTOR SWITCH (KEY REMOVABLE IN "SEQUENCER" MODE POSITION ONLY).
7. "BLOCK AUTO/MANUAL SIGNAL" HAS THE FOLLOWING INTERLOCKING TIME DURATIONS: DURING "SI" = 16 SECS; DURING "UNDERVOLTAGE" CONDITION = 36 SECS.
8. LOGIC WITHIN DASHED LINES ARE IMPLEMENTED WITH RELAY CONTACTS. THE OUTPUTS "B", "C" & "D" TERMINATE AT THE SAME TERMINAL BLOCKS USED FOR THE INCOMING PURCHASER'S S.I. AND "D-G BRKR CLOSED" SIGNALS, AS SHOWN.
9. FIRST LOAD STEP (STEP 1 & 2) IS 0.5 SEC AFTER DIESEL GEN BRKR IS CLOSED OR AFTER SI SIGNAL IS RECEIVED AT THE SF SEQUENCER.
10. THESE OUTPUT CONTACTS HAVE AN ISOLATION DEVICE FOR INPUT TO NON-CLASS 1E CIRCUITS.
11. ALL CIRCUITS WILL RESTART FROM TIME ZERO WHENEVER THE SEQUENCER IS RESET.
12. UNDERVOLTAGE LOGIC.
BUS VOLTAGE ANALOG SIGNALS (0-150 VAC)



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APERTURE
CARD

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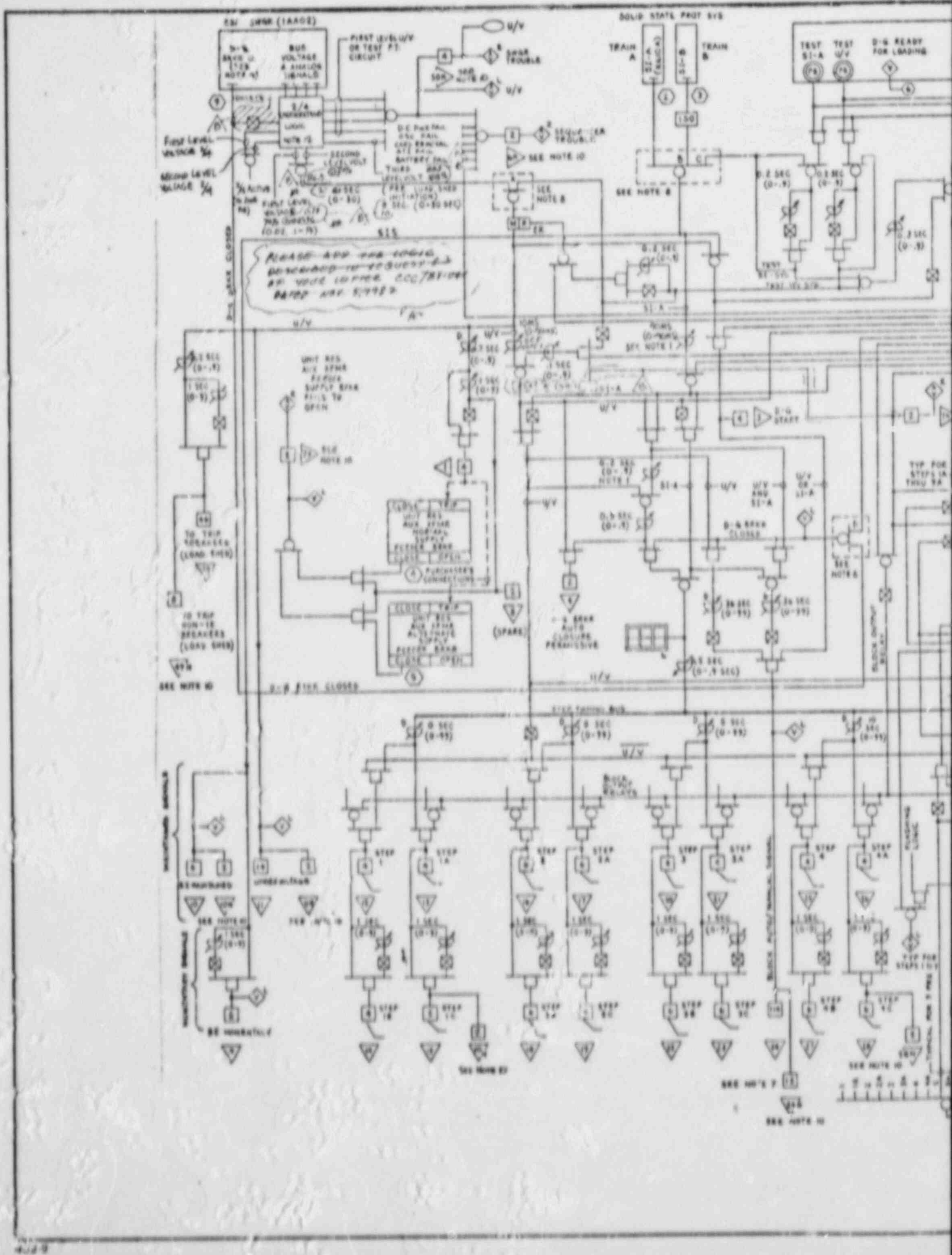
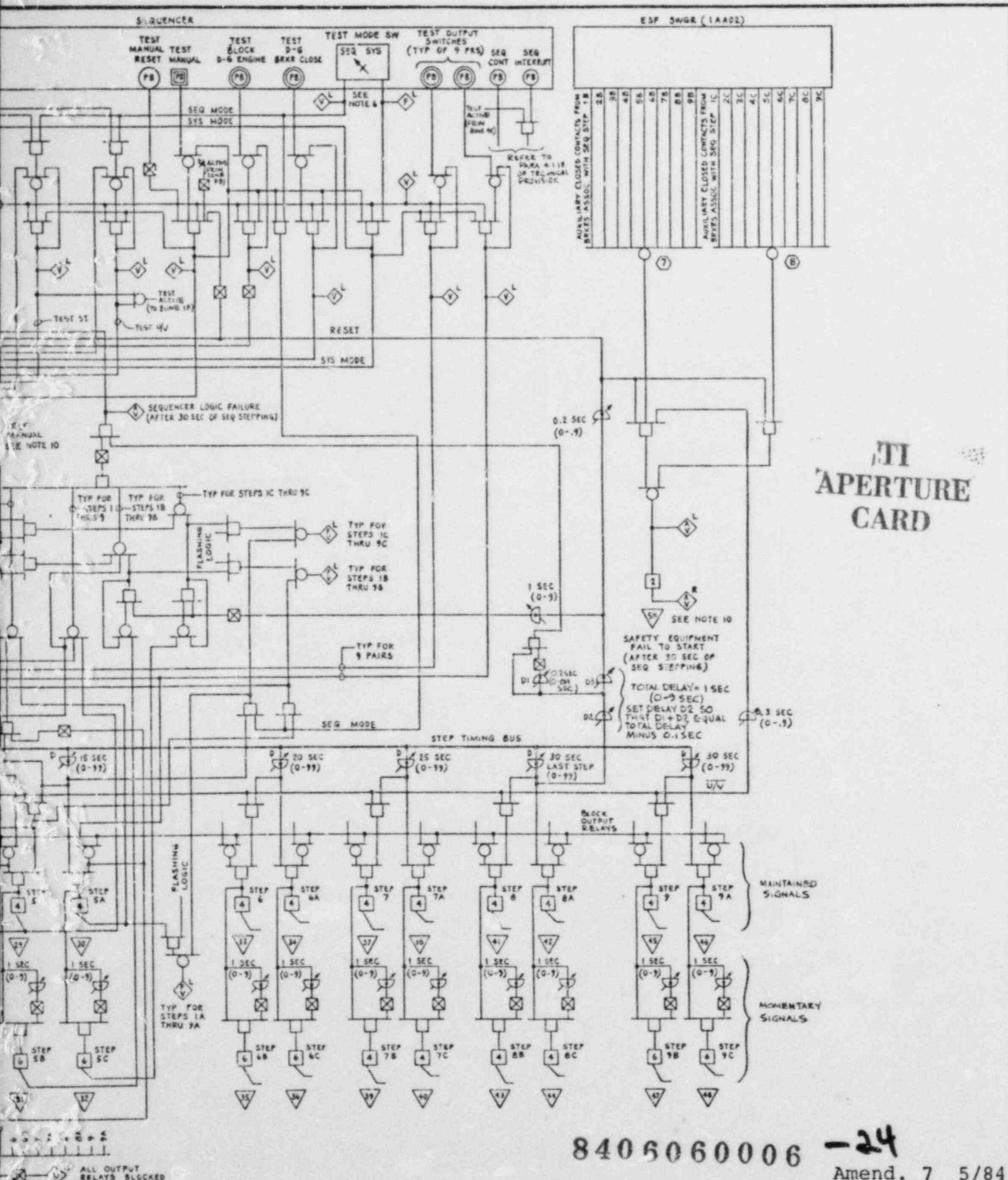
Amend. 7 5/84

Georgia Power	ALVIN W. VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	LOGIC DIAGRAM SAFETY FEATURES SEQUENCER BOARD
		FIGURE 430.69-1 (SHEET 1 OF 2)



SOLID STATE PROT SYS
TRAIN A
TRAIN B
TEST SI-A
TEST U/V
D-G READY FOR LOADING
FIRST LEVEL U/V OR TEST P.T. CIRCUIT
BUS VOLTAGE & ANALOG SIGNALS
SWGR TROUBLE
SEQUENCER TROUBLE
SEE NOTE 10
SEE NOTE 8
FIRST LEVEL VOLTAGE 3/4
SECOND LEVEL VOLTAGE 3/4
U/V
SIS
UNIT RES. AUX SPHR
TO TRIP BREAKERS (LOAD SHED)
TO TRIP NON-1E BREAKERS (LOAD SHED)
D-G BRKR CLOSED
D-G BRKR AUTO CLOSURE PERMISSIVE
D-G START
(SPARE)
PURCHASER'S CONNECTIONS
D-G BRKR CLOSED
BLOCK OUTPUT RELAY
TYP FOR STEPS 1A THRU 9A
STEP 1
STEP 1A
STEP 2
STEP 2A
STEP 3
STEP 3A
STEP 4
STEP 4A
1 SEC (0-9)
SEE NOTE 7
SEE NOTE 10
SEE NOTE 10

Also Available On
Aperture Card



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CARD

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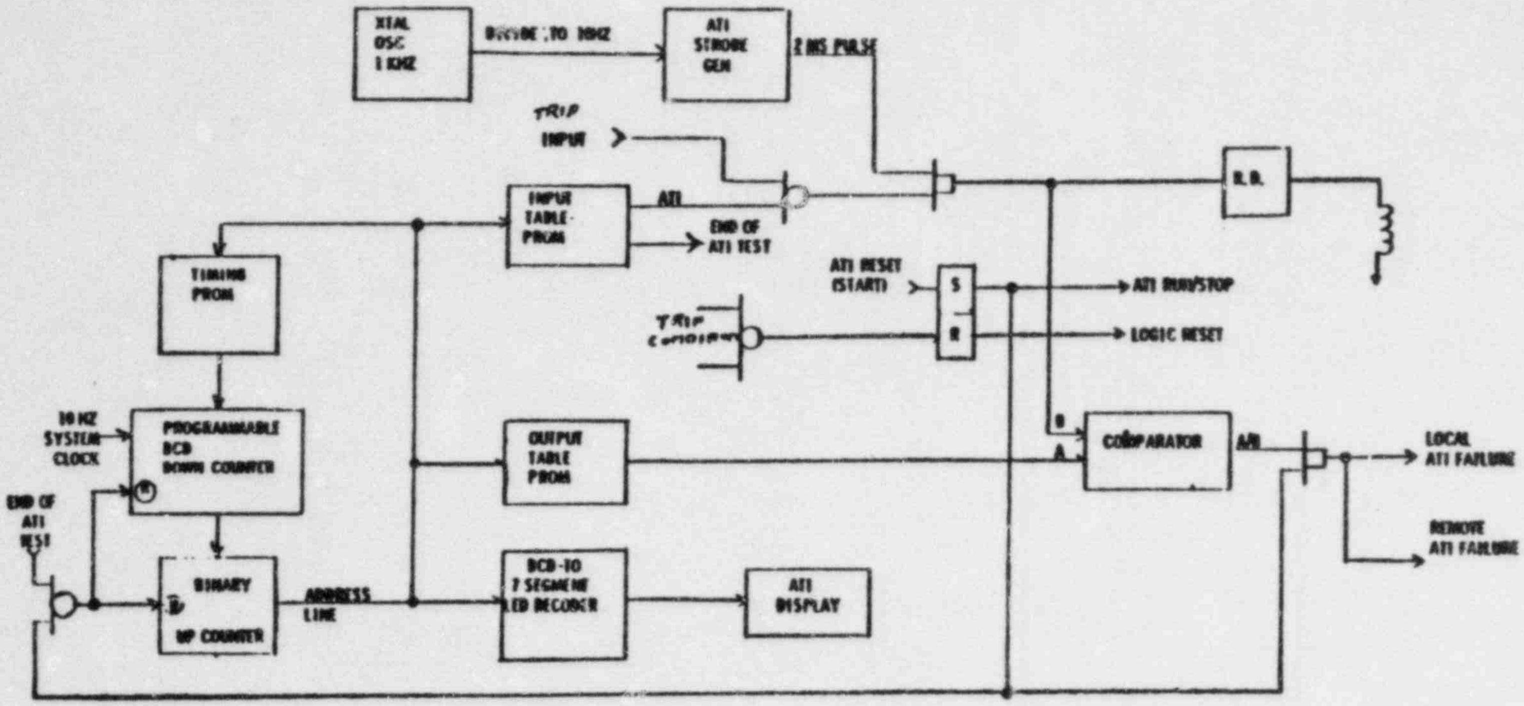
Georgia Power

ALVIN W. VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

LOGIC DIAGRAM
SAFETY FEATURES
SEQUENCER BOARD

FIGURE 430.69-1 (SHEET 2 OF 2)



3-9

TM9N57

Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ATI FUNCTIONAL BLOCK DIAGRAM

FIGURE 430.69-2

Amend. 7 5/84

433-9

Question 430.70

FSAR paragraph 8.3.1.1.3.H states that the diesel generators are of the type and size that have been previously used as standby emergency power sources in other nuclear power plants. Identify the other nuclear power plants referred to and provide a comparison of the two machines which address the requirements given in sections 5.4.2, 5.4.3, and 5.4.4 of IEEE 387-1977. If there are any differences between the two machines provide the additional tests and/or analyses required by these sections of the IEEE standard.

Response

The following is a list of selected Transamerica Delaval, Inc., (TDI) engines, model DSRV-16-4, which have been or are being used in nuclear standby service. Of this list, the installations noted with asterisks have been or are in the process of being qualified. The Nuclear Regulatory Commission-Power Systems Branch should have documentation on these installations, since several of these facilities are ahead of VEGP in the licensing process.

Owner	Installation	TDI Engines	Rated kW	Rated hp at 450 rpm
Mississippi Power & Light	Grand Gulf	*74033-36	7000	9755
Carolina Power & Light	Shearon Harris	74046-49	6500	9075
Duke Power	Catawba	*75017-20	7000	9755
TVA	Bellefonte	*75080-83	7000	9734
WPPSS	Unit 1	75084/85	6300	8742
Texas Utilities	Commanche Peak	*76001-4	7000	9754
Georgia Power	VEGP	76021-2871 76022-2872 76023-2873 76024-2874	7000	9700

*One or more engines at these installations has been operated. Generators for engines 74033 through 77035 are manufactured by NEI-Parsons Peebles of Cleveland, Ohio. All are frame size 190.

The VEGP diesel generators also are model DSRV-16-4 with a full load rating of 9700 bhp at 450 rpm. The generator is manufactured by Parsons Peebles, frame size 190. There are no major differences between the VEGP and Grand Gulf diesel generators. Field performance/acceptance testing of the diesel generators is described in section 1.9 and paragraph 8.3.1.1.3.H.

Question 430.71

In FSAR paragraph 8.3.1.1.8.B you reference calculations that have been made which indicate that motors rated to start at 80 percent of their nameplate voltages will not be provided power at less than their capabilities. Provide the results of those calculations when the 80 percent motors are started on the diesel generators and when they are started on the offsite sources. For the offsite power calculations assume the 4.16-kV bus voltage is at the setpoint of the degraded voltage relays prior to motor starting.

Response

The motors identified in the referenced paragraph of the FSAR are all small (< 20 hp) motors fed from motor control centers. As indicated in the response to question 430.68, with the 4.16-kV bus at 0.866 per unit (bus base), which is the degraded voltage relay setpoint, the worst case voltage at the motor control center load level under starting conditions is 0.863 per unit (on motor base) which is 0.063 higher than the 0.80 required by those motors for successful starting.

Since these motors are connected to motor control centers, these loads are energized at the 0.5-s sequencer step as indicated in figure 8.3.1-2. Table 8.3.1-2 indicates that the voltage at the diesel generator terminals (which for all intents and purposes is the same voltage as at the 4.16-kV bus) is at least 0.899 per unit (bus base) at the 0.5-s step. Since this voltage is 0.033 per unit higher than that analyzed under degraded offsite voltage conditions, proper motor starting capabilities are substantiated.

Question 430.72

For the centrifugal charging pumps you state that the pump brake horsepower exceeds the nameplate rating of the motor (670 hp and 600 hp, respectively) but is within the capability of the motors which have a service factor of 1.15. The service factor applied to a motor allows it to deliver greater than rated horsepower without damaging its insulation system when operating at its nameplate voltage. It is not, however, capable of delivering this same horsepower at reduced voltages. Therefore, justify operation of this motor at reduced voltages down to the settings of the degraded voltage relays.

Response

In accordance with NEMA MG-1, the motors of the centrifugal charging pumps will function continuously at 90 percent voltage (degraded voltage relay setting).

Question 430.73

Regarding motor-operated valves with power lockout:

A. Provide or reference motor control schematic drawings for the valves listed in FSAR paragraph 8.3.1.1.11.A which show the power lockout capability at the main control board. Describe the technique used to lock the power out, and describe the redundant valve position indication and their power supplies provided for each valve.

B. Clarify that the power is locked out to the accumulator isolation valves identified in paragraph 8.3.1.1.11.B by drawing the circuit breaker from the motor control center during startup and maintaining it in the racked out position during reactor power operation.

C. Identify how the accumulator isolation valve circuits comply with each position given in Branch Technical Position ICSB-4 (PSB) and provide or reference motor control schematic drawings for the valves. Identify the redundant power supplies provided to the position indicators of each valve.

Response

The following elementary diagrams detail the circuitry associated with the valves listed in section 8.3.1.1.11.A:

A. Emergency core cooling system (ECCS) valves and relative figure numbers are listed below:

HV-8806	Figure 430.73-1
HV-8835	Figure 430.73-2
HV-8802A	Figure 430.73-3
HV-8802B	Figure 430.73-4
HV-8840	Figure 430.73-5
HV-8809A	Figure 430.73-6
HV-8809B	Figure 430.73-7
HV-8813	Figure 430.73-8

Power lockout for the ECCS valves is attained at the main control board through the use of a lockout switch.

Redundant indication is provided at indicator light boxes ZLB6 and ZLB7 which are mounted on the main control board. The power supplies for these light boxes are from termination cabinets which are supplied power from 120-V distribution panels located in Class 1E motor control centers (one per train). The termination cabinet is not powered from a motor control center providing main power to any valve listed above. The second position indication is powered from the motor-operated valve control circuit.

B. Paragraph 8.3.1.1.11 has been revised to indicate that the circuit breakers will be disengaged from the bus, thereby attaining power lockout for the accumulator isolation valves during reactor power operations.

C. The accumulator isolation valve circuits conform with Branch Technical Position ICSB-4 (PSB) by virtue of:

1. K621 and K603 relays for automatic valve opening.

2. Handswitch indicator lights for visual valve indication.

3. Critical function alarm with periodic reflash for independent audible and visual alarm.

4. Relay K603 automatic prevention of valve closure.

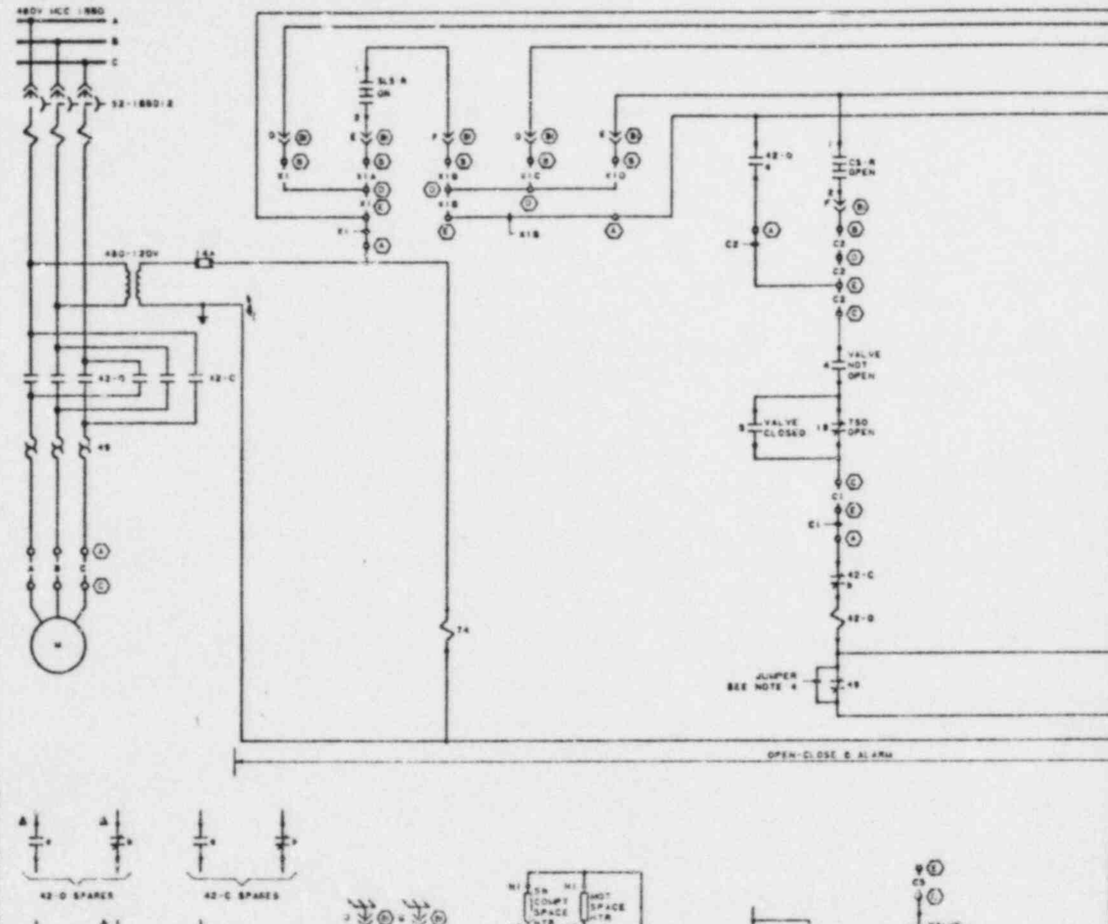
Motor control schematic drawings and drawings for the critical function alarm have been provided in figures 430.73-9 through 430.73-12.

Redundant indication and power supply provided to the position indicators of valves are:

1. Motor-operated valve control handswitch indication light, feed from control circuit.

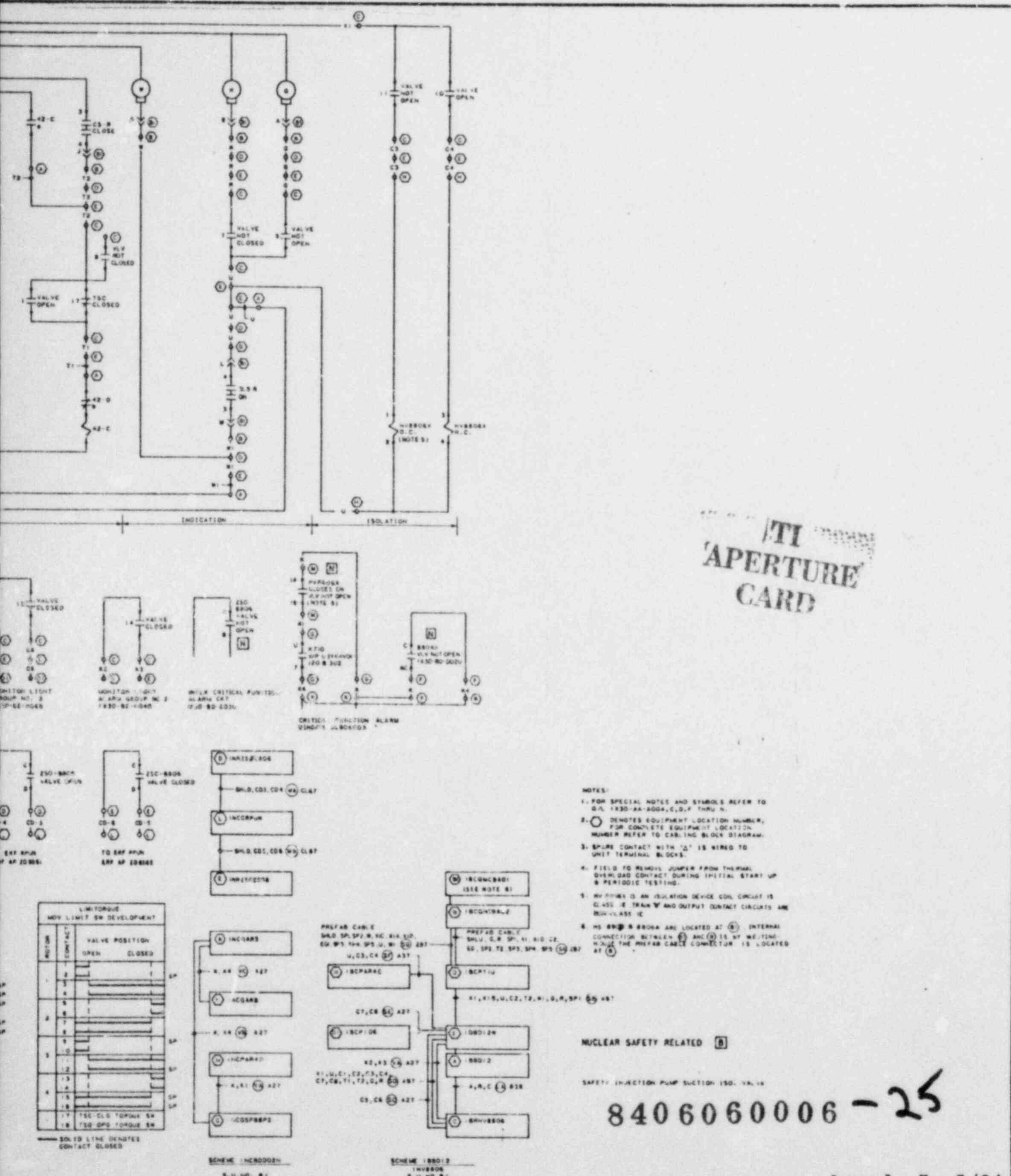
2. Monitor light (on main lighting board), fed from termination cabinet.

3. Critical function alarm (periodic reflash), fed from annunciator panel (dc and diesel generator-backed ac powered).



OPEN-CLOSE & ALARM
42-O SPARES
42-C SPARES
JUMPER SEE NOTE 4
VALVE CLOSED
VALVE NOT OPEN
SYSTEM STATUS MONITOR PANEL
STEM MOUNTED LIMIT SWITCH DEVELOPMENT
VALVE POSITION
OPEN
CLOSED
SOLID LINE DENOTES CONTACT CLOSED
CONTACTS
CLOSE
OPEN
LOCKOUT
ON
MAINTAINED
SPRING RETURN TO NORMAL

Also Available On
Aperture Card



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CARD

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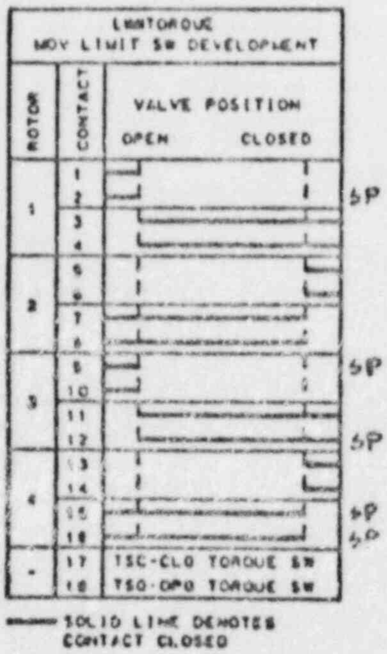
Amend. 7 5/84

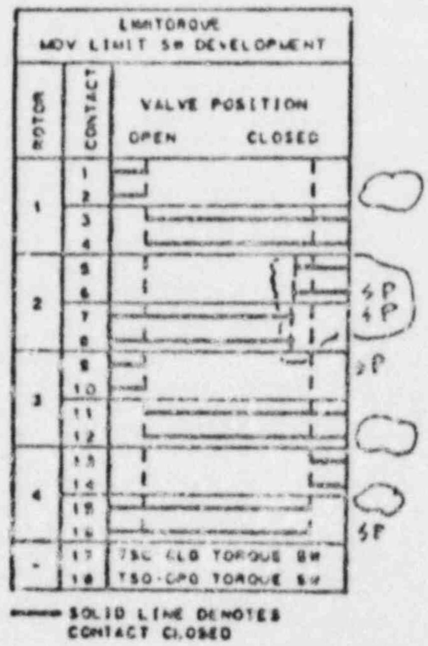
Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	ELEMENTARY DIAGRAM SAFETY INJECTION SYSTEM 1HV-8806
		FIGURE 430.73-1 (SHEET 1 OF 2)

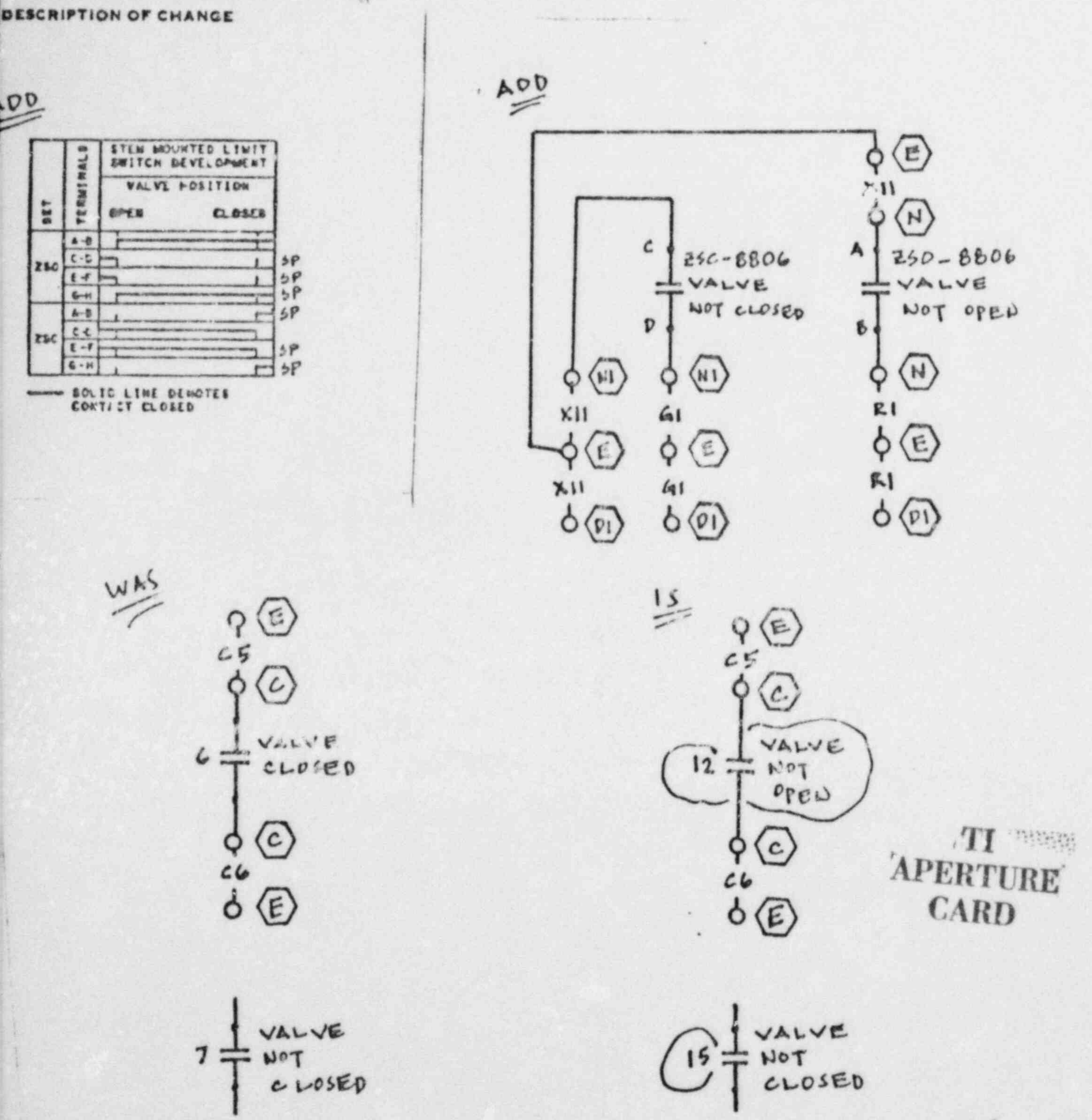
DESCRIPTION OF CHANGE

WAS



NOW





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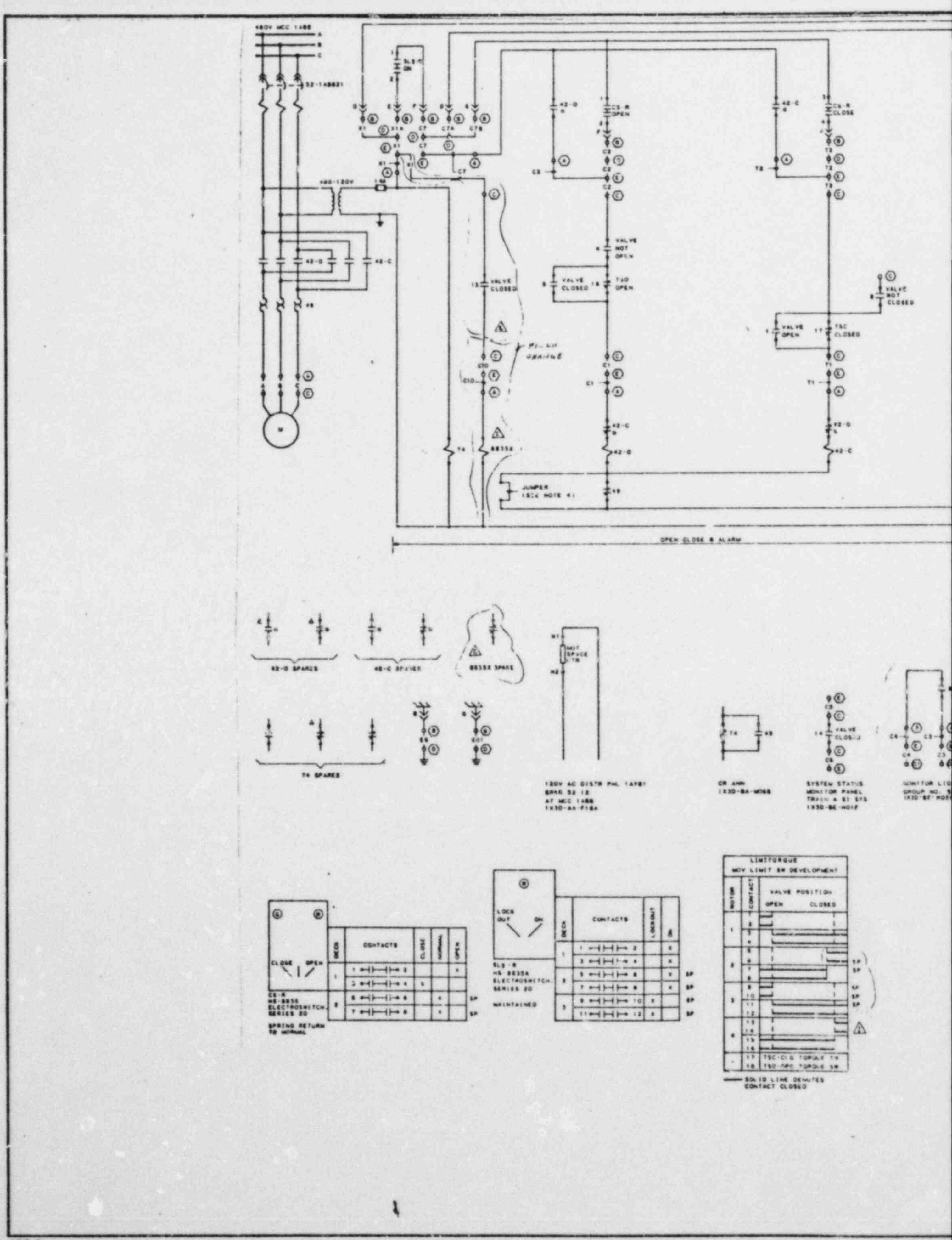
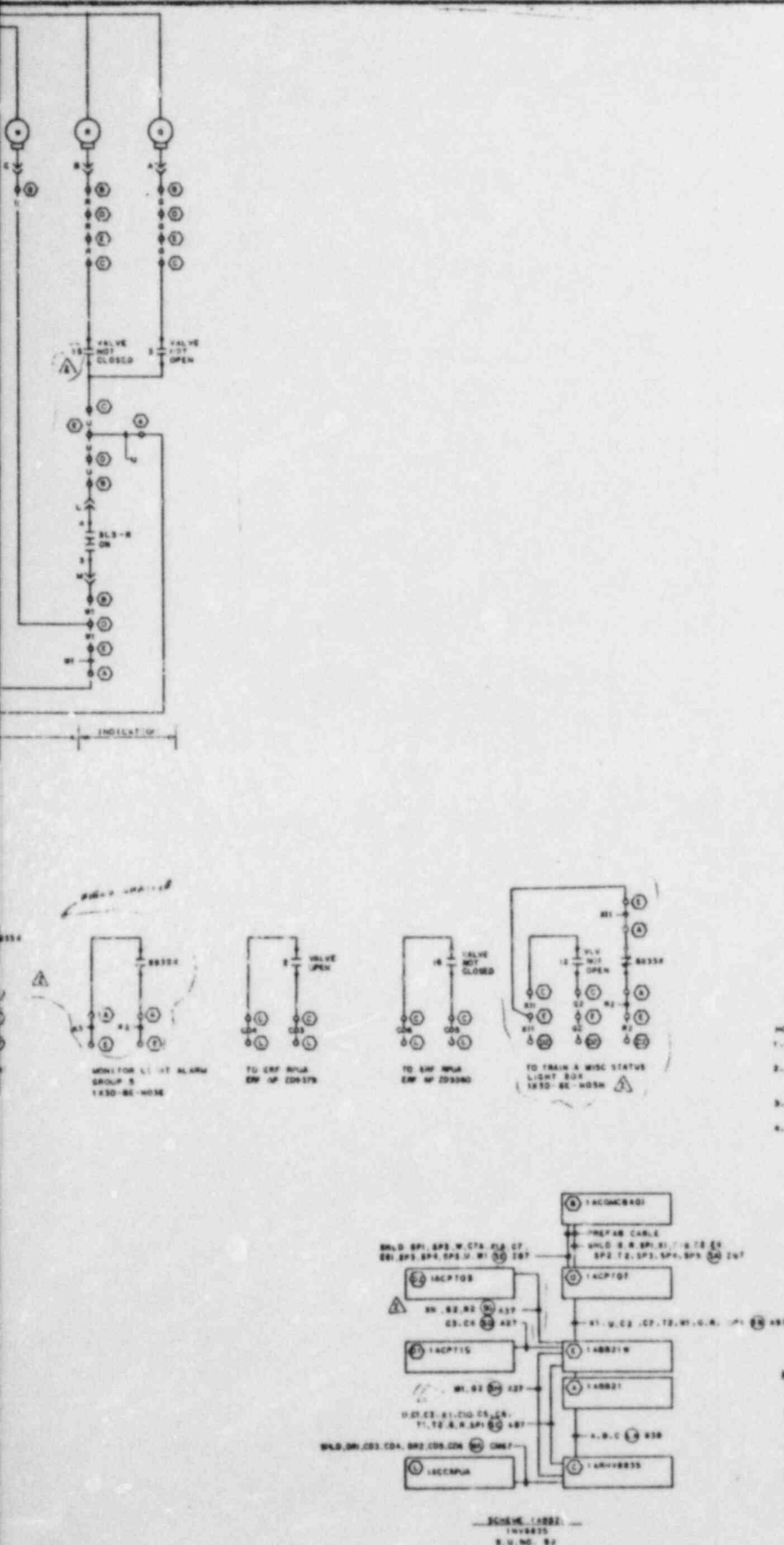
Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8806

FIGURE 430.73-1 (SHEET 2 OF 2)


480V MCC 1AB8
480-120V
JUMPER (SEE NOTE 4)
OPEN CLOSE & ALARM
42-O SPARES
42-C SPARES
T4 SPARES
120V AC DISTR PNL 1AYB1
CR ANN
SYSTEM STATUS MONITOR PANEL
CLOSE
OPEN
CONTACTS
DECK
NORMAL
CS-R
ELECTROSWITCH SERIES 20
SPRING RETURN TO NORMAL
LOCK OUT
ON
LOCKOUT
SLS-R
MAINTAINED
LIMITORQUE
MOV LIMIT SW DEVELOPMENT
ROTOR
CONTACT
VALVE POSITION
CLOSED
SOLID LINE DENOTES CONTACT CLOSED



NOTES:

1. FOR SPECIAL NOTES AND SYMBOLS REFER TO G/L 1X3D-AA-A00A,C,D,F THRU H.
2. ◯ DENOTES EQUIPMENT LOCATION NUMBER. FOR COMPLETE EQUIPMENT LOCATION NUMBER REFER TO CABLING BLOCK DIAGRAM.
3. SPARE CONTACT WITH "⚠" IS WIRED TO UNIT TERMINAL BLOCKS.
4. FIELD TO REMOVE JUMPER FROM THERMAL OVERLOAD CONTACT DURING INITIAL START-UP & PERIODIC TESTING.

NUCLEAR SAFETY RELATED [A]

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Georgia Power

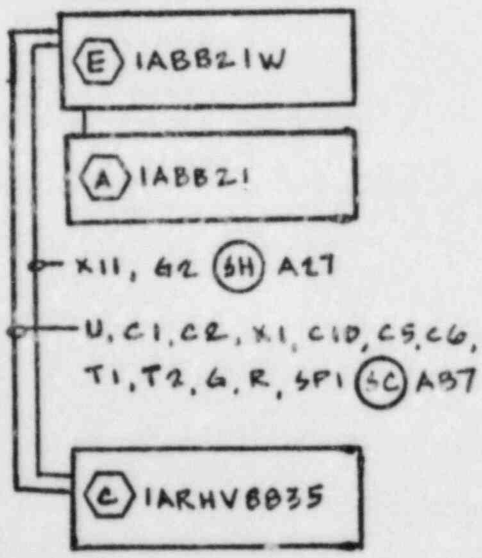
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8835

FIGURE 430.73-2 (SHEET 1 OF 3)

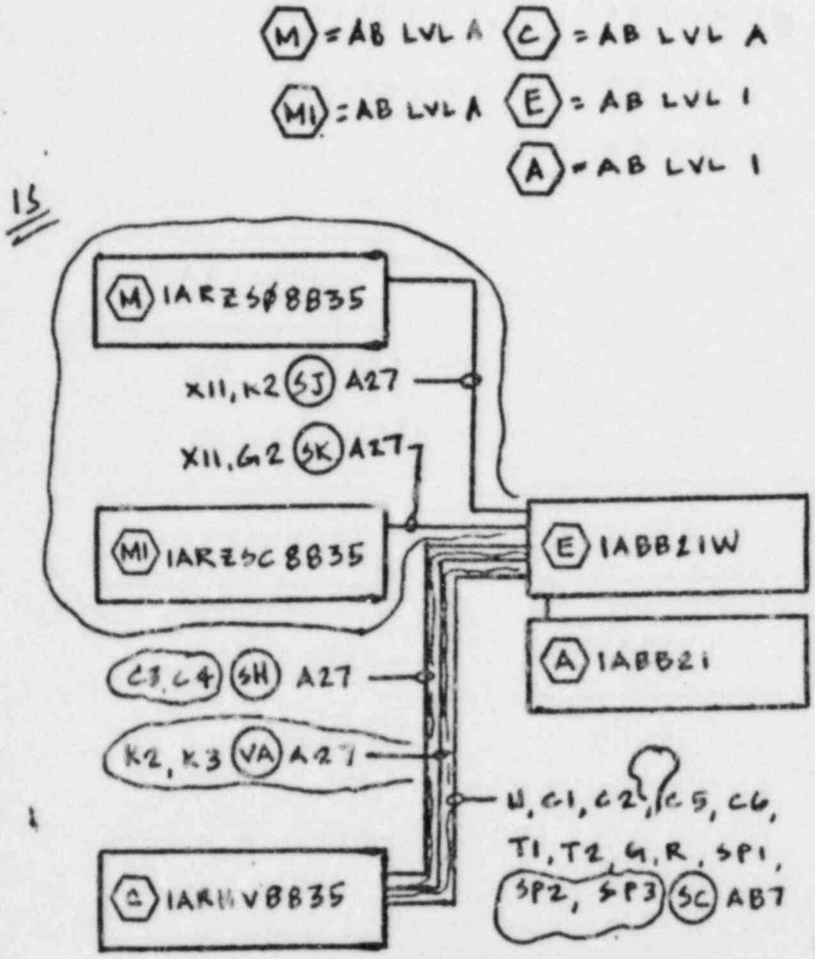
DESCRIPTION OF CHANGE

WAS



SCHEME 1ABB21
1HV8835
S.U. NO. BJ

IS



SCHEME 1ABB21
1HV8835
S.U. NO. BJ

84060_U_06

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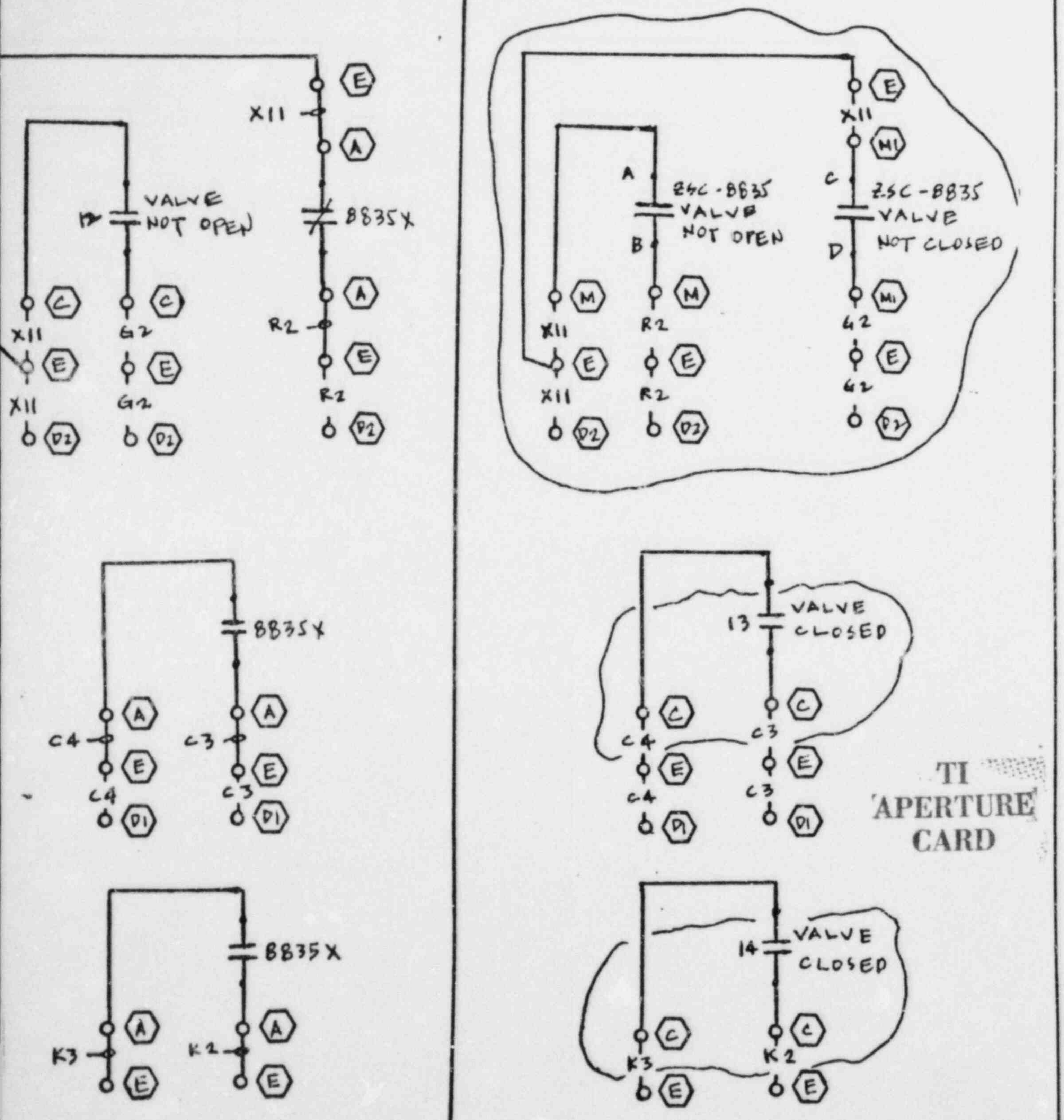
Also Available On Aperture Card

ESCRIPTION OF CHANGE



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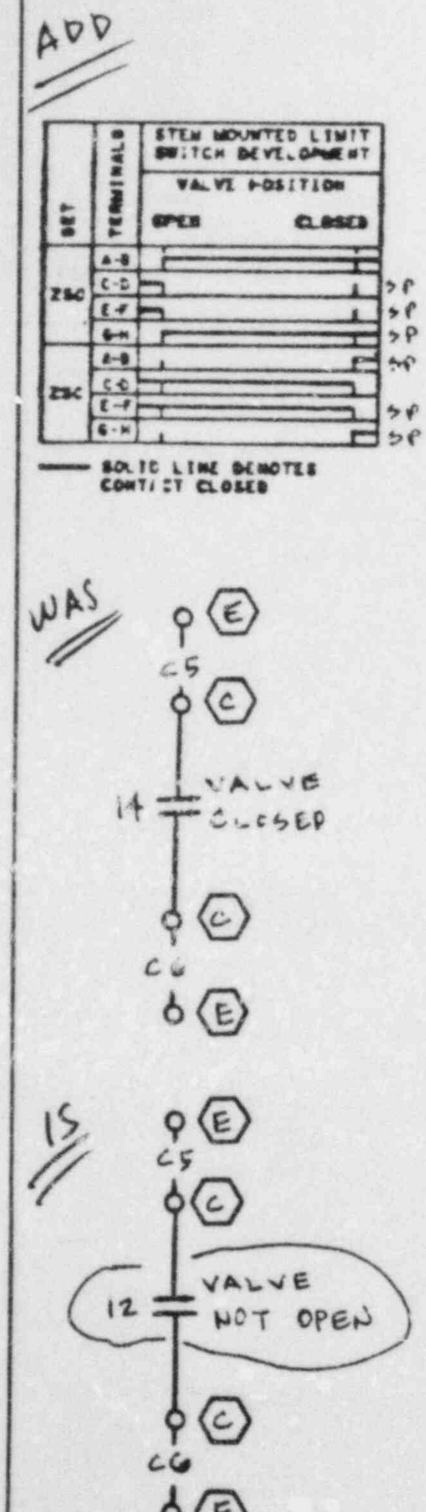
Georgia Power

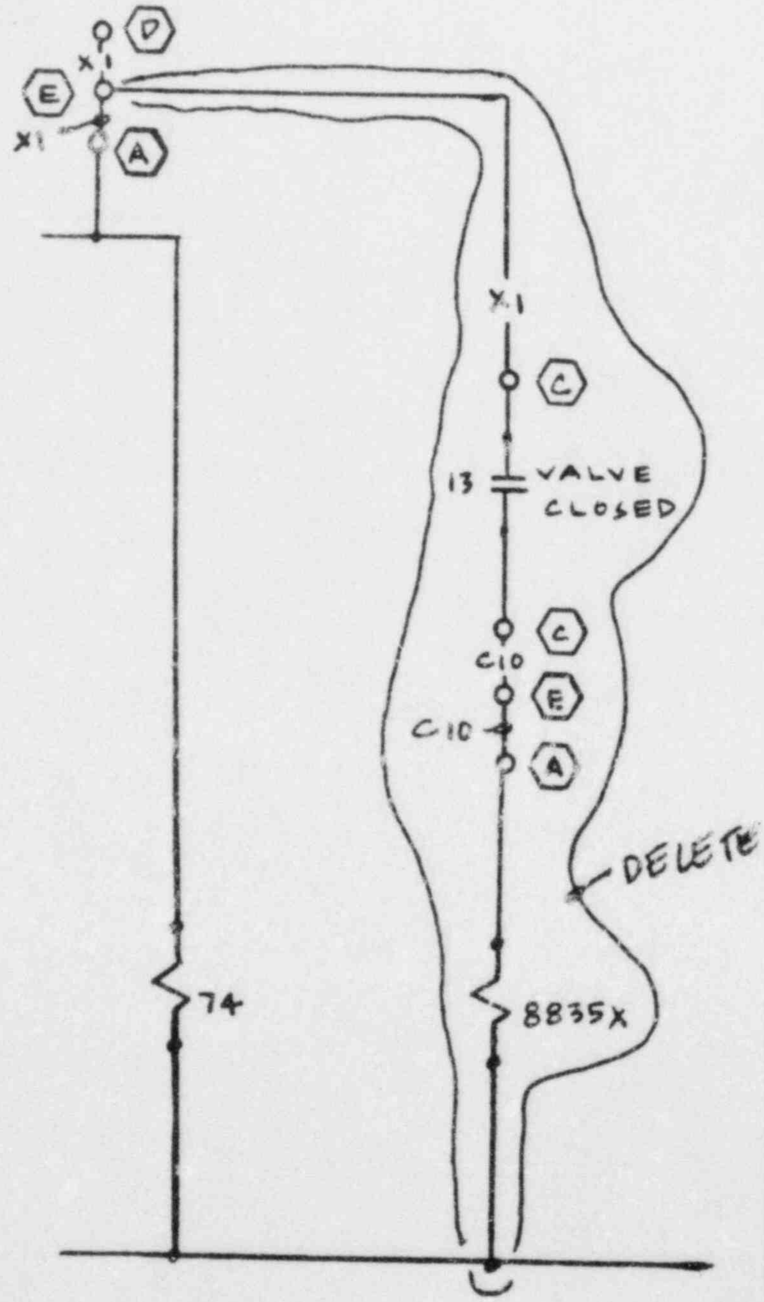
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8835

FIGURE 430.73-2 (SHEET 2 OF 3)

DESCRIPTION OF CHANGE





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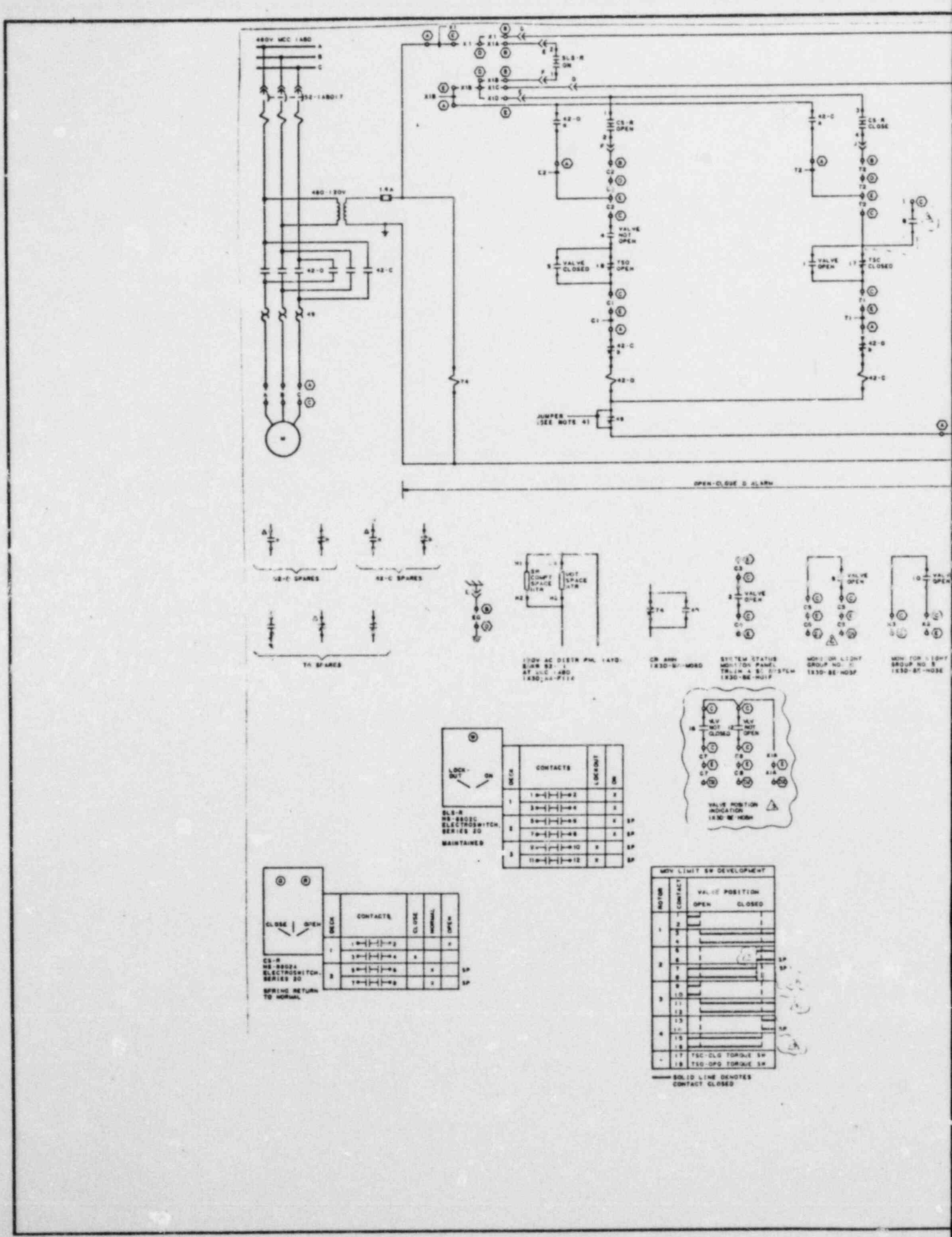
Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

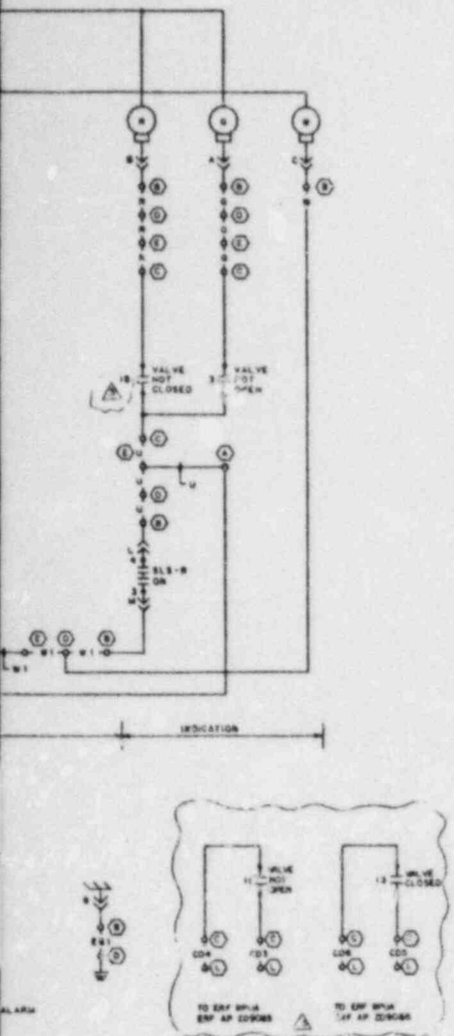
ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8835

FIGURE 430.73-2 (SHEET 3 OF 3)

433-9


480V MCC 1ABD
480-120V
VALVE NOT OPEN
VALVE CLOSED
VALVE OPEN
TSC CLOSED
JUMPER (SEE NOTE 4)
OPEN-CLOSE D ALARM
42-C SPARES
TA SPARES
CONTACTS
LOCKOUT
MAINTAINED
CLOSE
OPEN
SPRING RETURN TO NORMAL
VALVE POSITION INDICATION
MOV LIMIT SW DEVELOPMENT
VALVE POSITION
SOLID LINE DENOTES CONTACT CLOSED

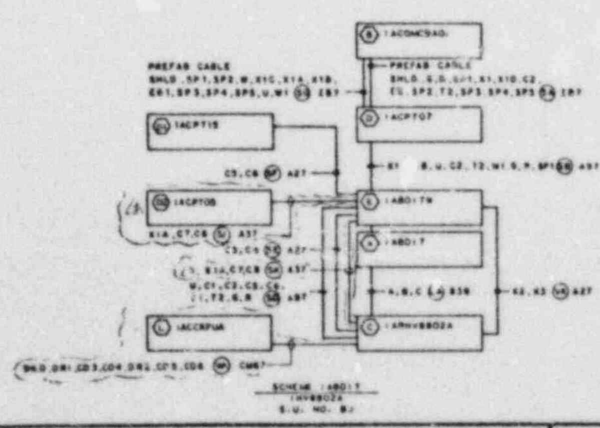
Also Available On
Aperture Card



TI
APERTURE
CARD

NOTES:

1. FOR SPECIAL NOTES AND SYMBOLS REFER TO D/L 1X3D-AA-A00A,C,D,F THRU R.
2. ◯ DENOTES EQUIPMENT LOCATION NUMBER. FOR COMPLETE EQUIPMENT LOCATION NUMBER REFER TO CABLING BLOCK DIAGRAM.
3. SPARE CONTACT WITH 'Δ' IS WIRED TO UNIT TERMINAL BLOCKS.
4. FIELD TO REMOVE JUMPER FROM THERMAL OVERLOAD CONTACT DURING INITIAL START-UP & PERIODIC TESTING.



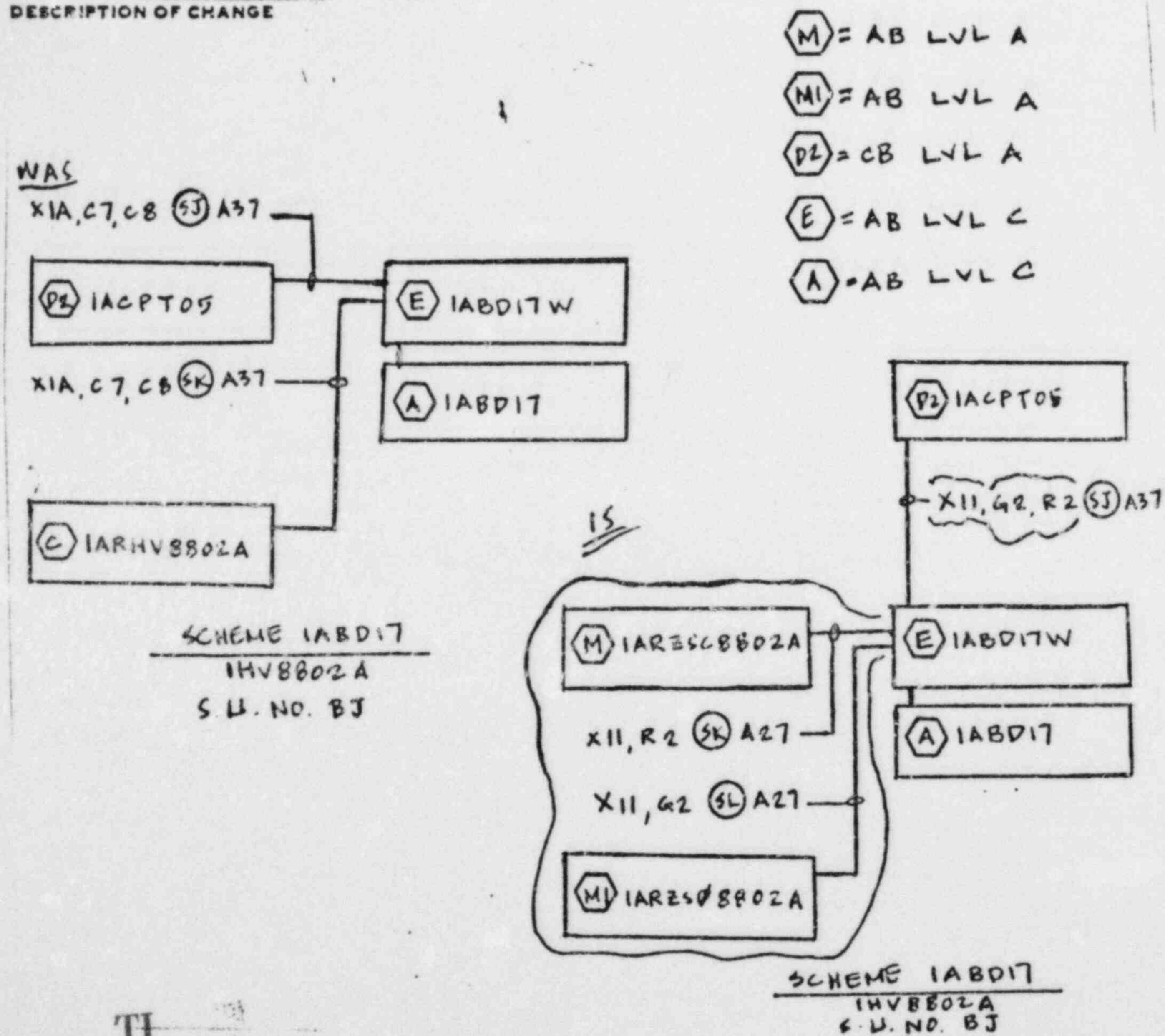
NUCLEAR SAFETY RELATED

8406060006 -29

Amend. 7 5/84

Georgia Power — ALVIN W. VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	ELEMENTARY DIAGRAM SAFETY INJECTION SYSTEM 1HV-8802A
	FIGURE 430.73-3 (SHEET 1 OF 2)

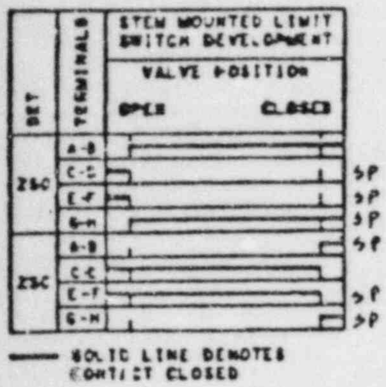
DESCRIPTION OF CHANGE

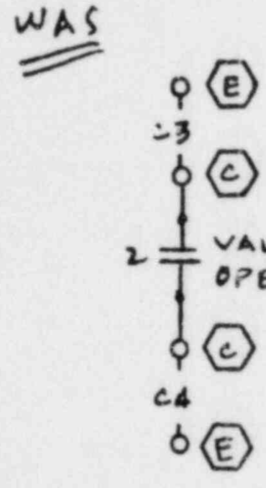


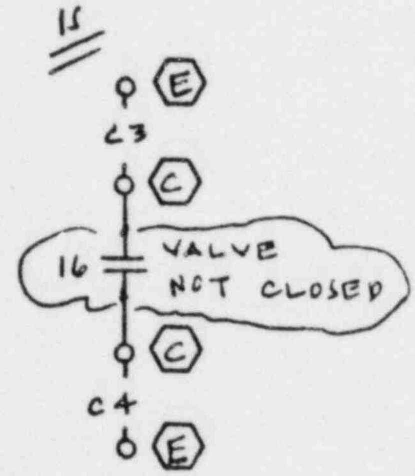
TI
APERTURE
CARD

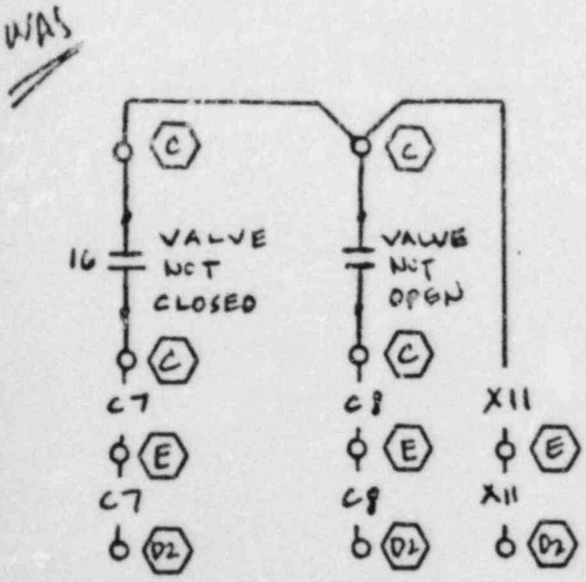
Also Available On
Aperture Card

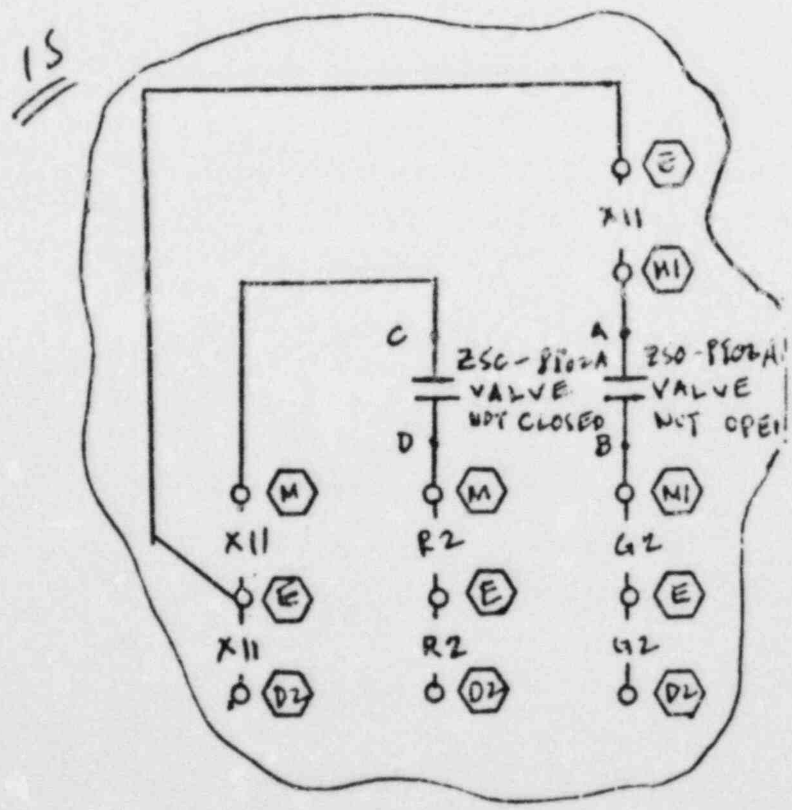
ESCRIPTION OF CHANGE







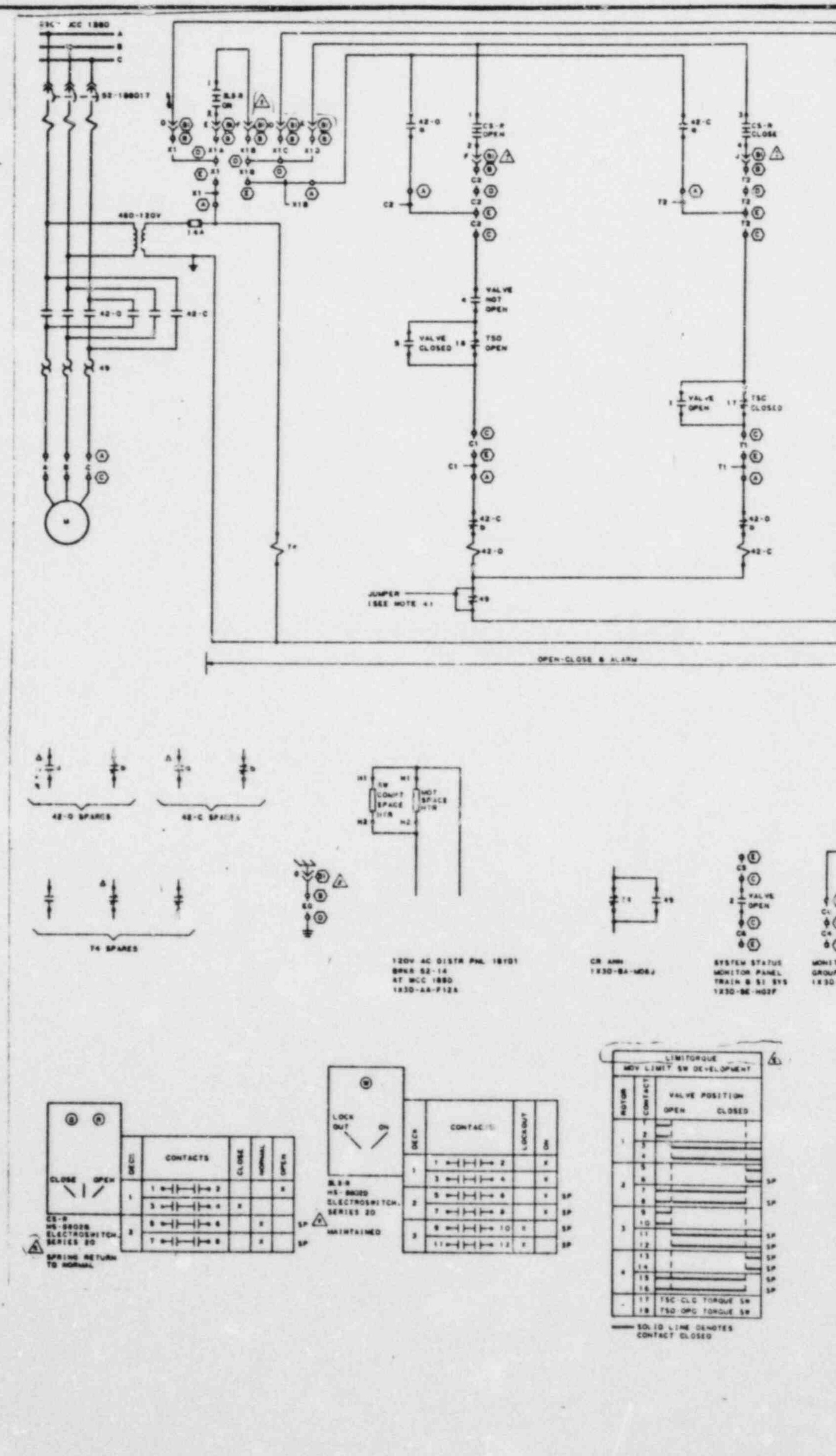




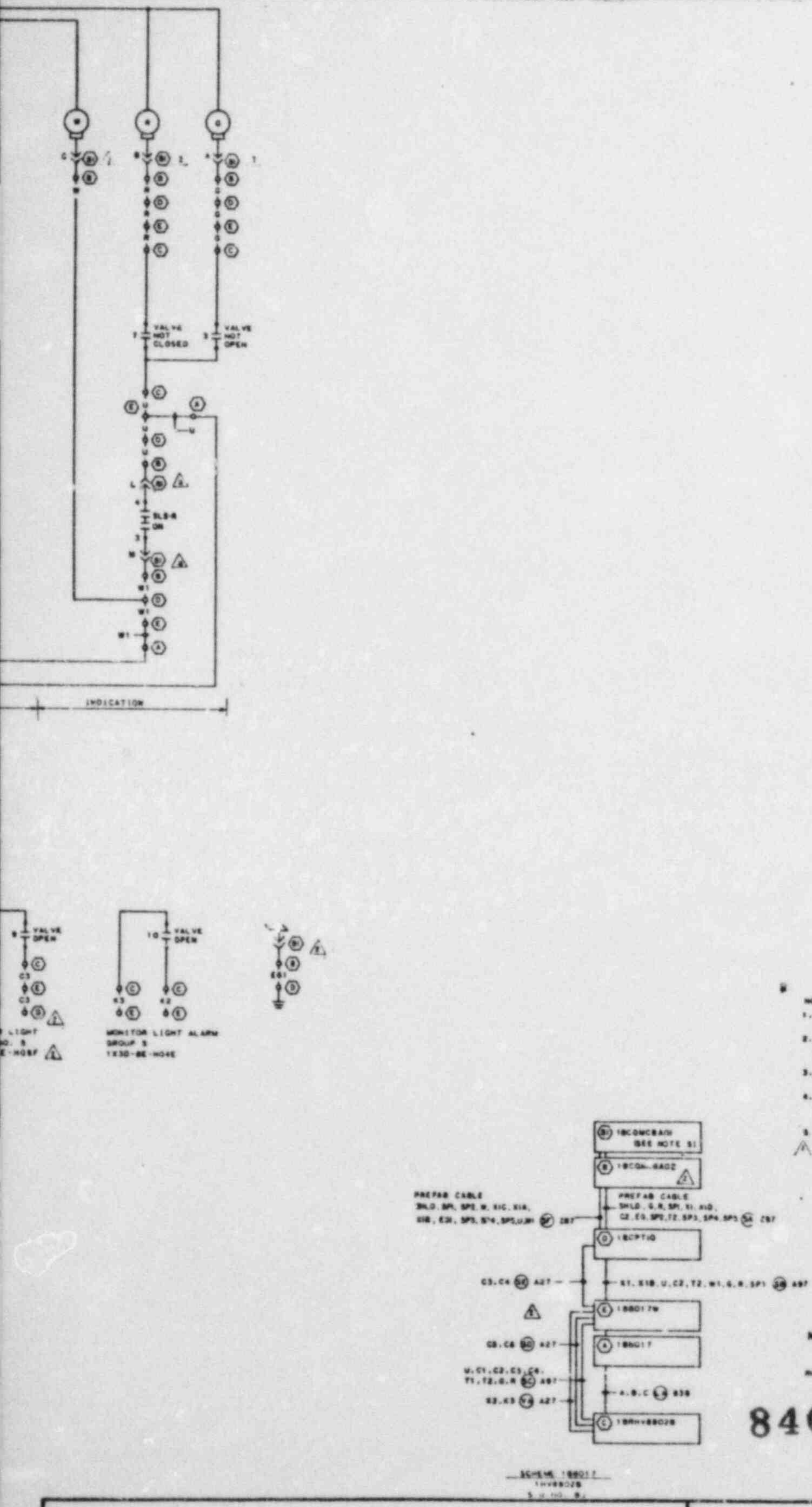
8406060006 -30

Amend. 7 5/84

Georgia Power — VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	ELEMENTARY DIAGRAM SAFETY INJECTION SYSTEM 1HV-8802A
	FIGURE 430.73-3 (SHEET 2 OF 2)



480-120V
42-O
42-C
CS-R OPEN
CS-R CLOSE
VALVE NOT OPEN
VALVE CLOSED
TSO OPEN
VALVE OPEN
TSC CLOSED
JUMPER (SEE NOTE 4)
OPEN-CLOSE & ALARM
42-O SPARES
42-C SPARES
T4 SPARES
120V AC DISTR PNL
SYSTEM STATUS MONITOR PANEL
LIMITORQUE MOV LIMIT SW DEVELOPMENT
VALVE POSITION
OPEN
CLOSED
ROTOR
CONTACT
TSC CLG TORQUE SW
TSO OPG TORQUE SW
SOLID LINE DENOTES CONTACT CLOSED
CONTACTS
DECK
CLOSE
NORMAL
OPEN
CS-R
ELECTROSWITCH SERIES 20
SPRING RETURN TO NORMAL
LOCK OUT
ON
LOCKOUT
ELECTROSWITCH SERIES 20
MAINTAINED



NOTES:

1. FOR SPECIAL NOTES AND SYMBOLS REFER TO D/A 1X3G-AA-A00A,C,D,F THRU N.
2. ◯ DENOTES EQUIPMENT LOCATION NUMBER. FOR COMPLETE EQUIPMENT LOCATION NUMBER REFER TO CABLING BLOCK DIAGRAM.
3. SPARE CONTACT WITH "△" IS WIRED TO UNIT TERMINAL BLOCKS.
4. FIELD TO REMOVE JUMPER FROM THERMAL OVERLOAD CONTACT DURING INITIAL START-UP & PERIODIC TESTING.
5. HS-8802B IS LOCATED AT (B1). INTERNAL CONNECTION BETWEEN (B1) AND (B) IS BY WESTINGHOUSE. THE PREFAB CABLE CONNECTOR IS LOCATED AT (B).

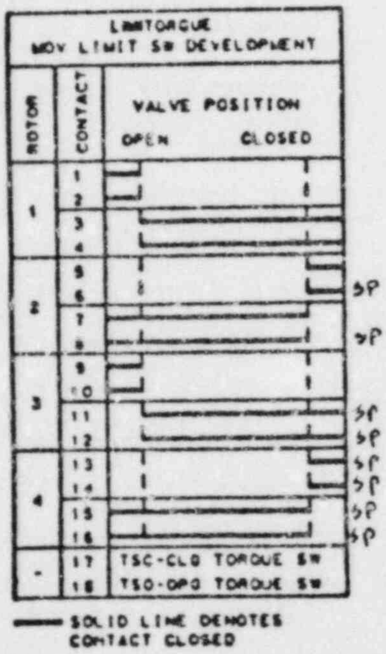
NUCLEAR SAFETY RELATED [B]

Amend. 7 5/84

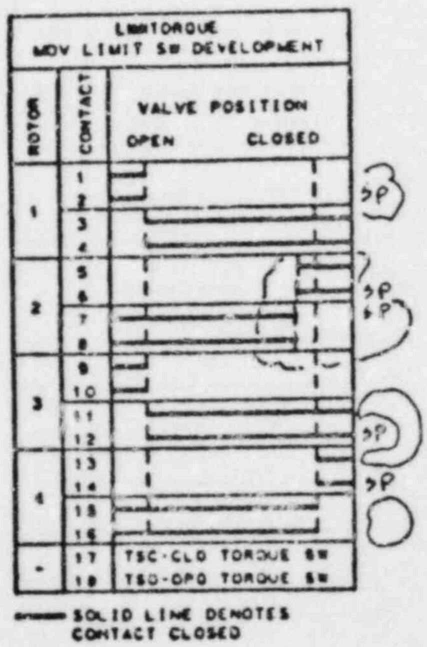
Georgia Power VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	ELEMENTARY DIAGRAM SAFETY INJECTION SYSTEM 1HV-8802B
	FIGURE 430.73-4 (SHEET 1 OF 3)

DESCRIPTION OF CHANGE

WAS



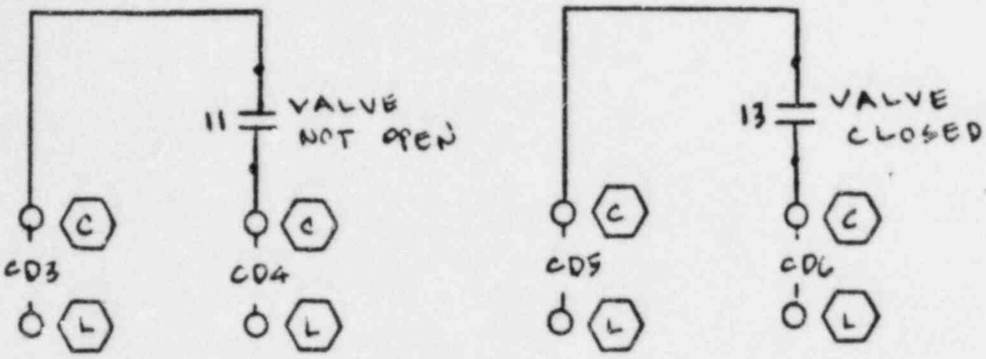
NOW

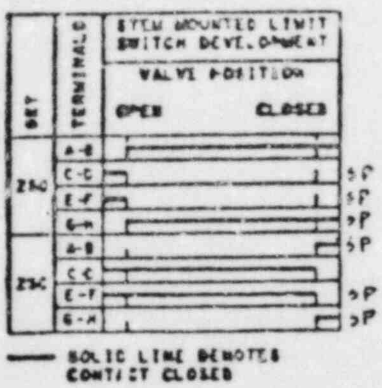


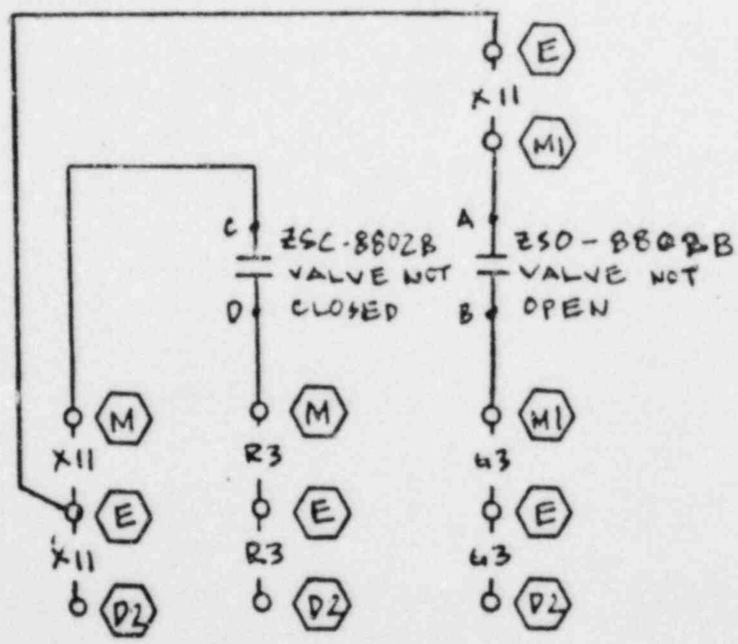
Also Available On
Aperture Card

DESCRIPTION OF CHANGE

ADD







8406060006 -32

Amend. 7 5/84

Georgia Power

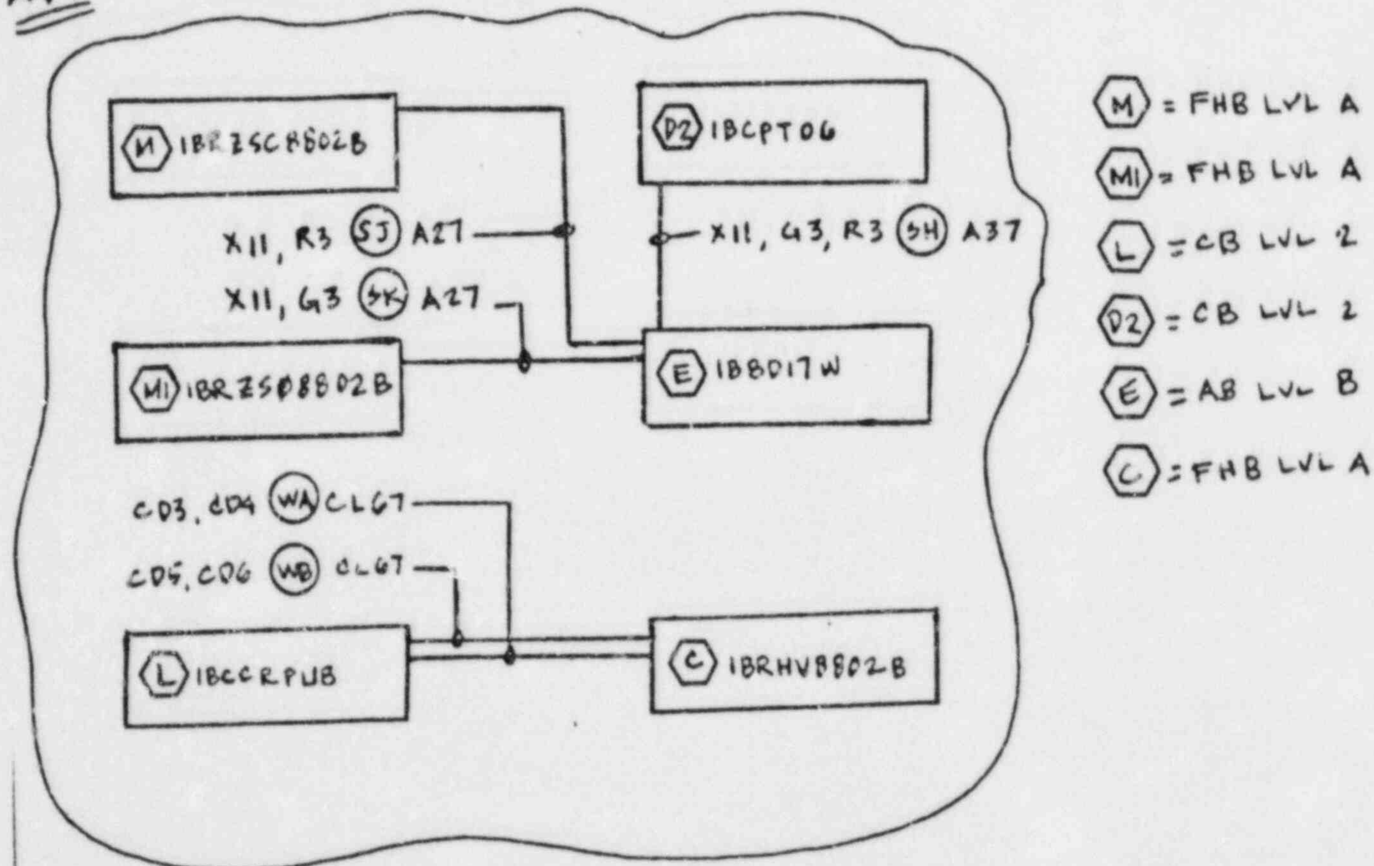
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8802B

FIGURE 430.73-4 (SHEET 2 OF 3)

DESCRIPTION OF CHANGE

ADD

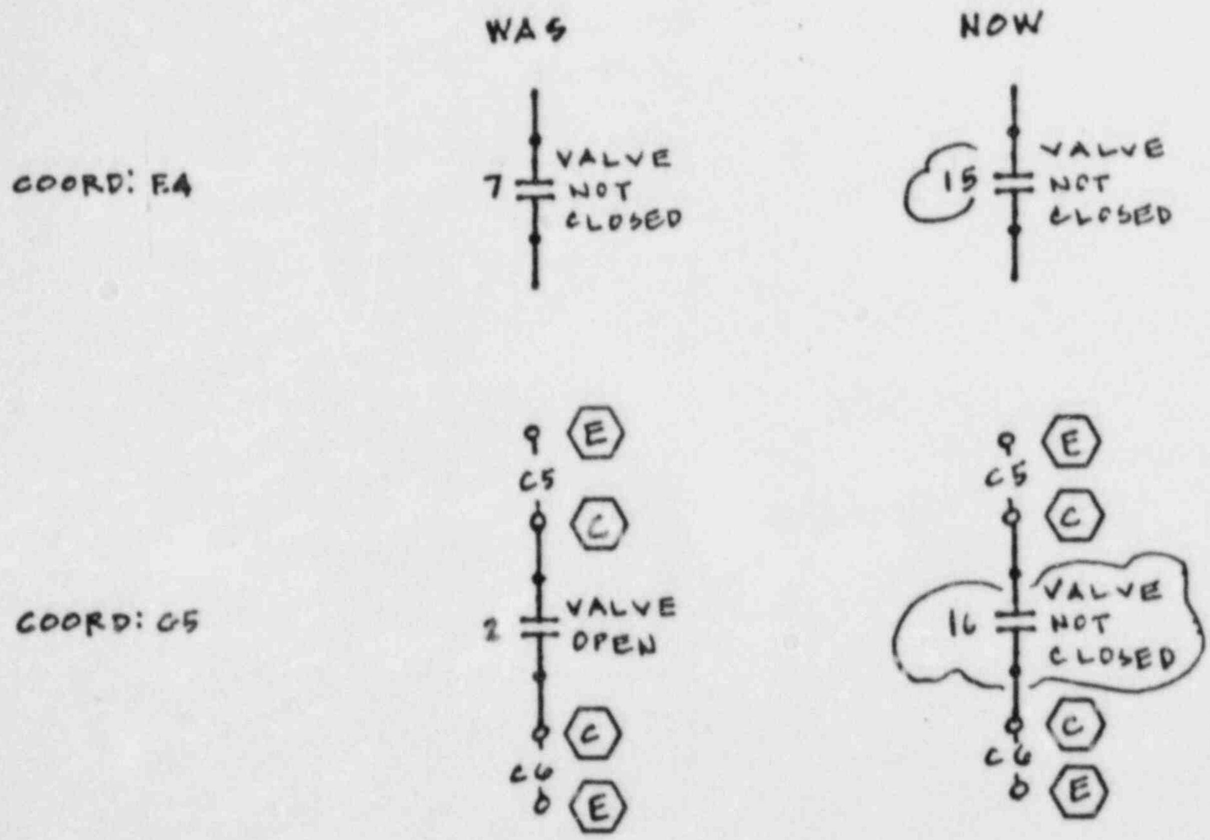


SCHEME 1BBD17

1HV8802B

S.U. NO. BJ

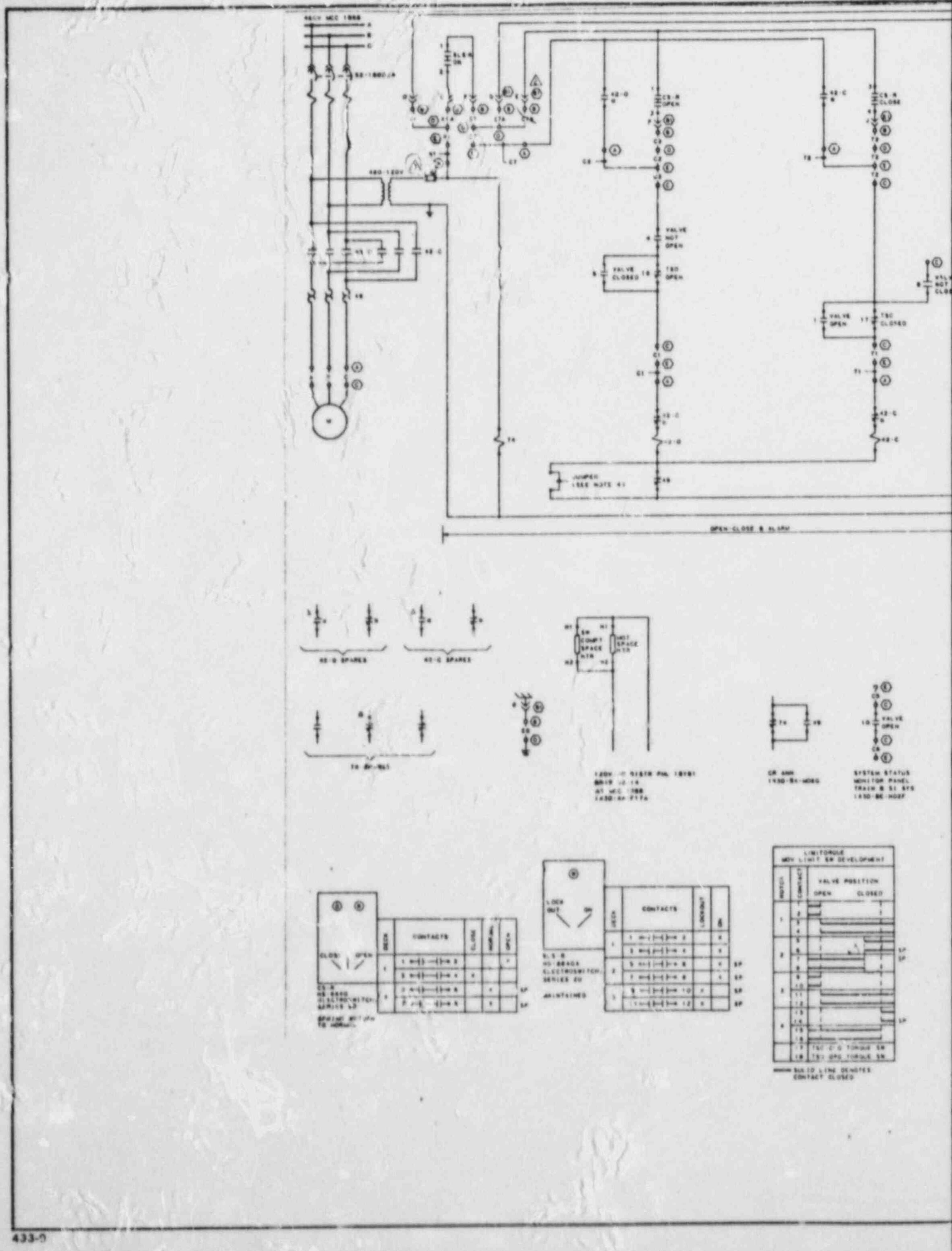
DESCRIPTION OF CHANGE



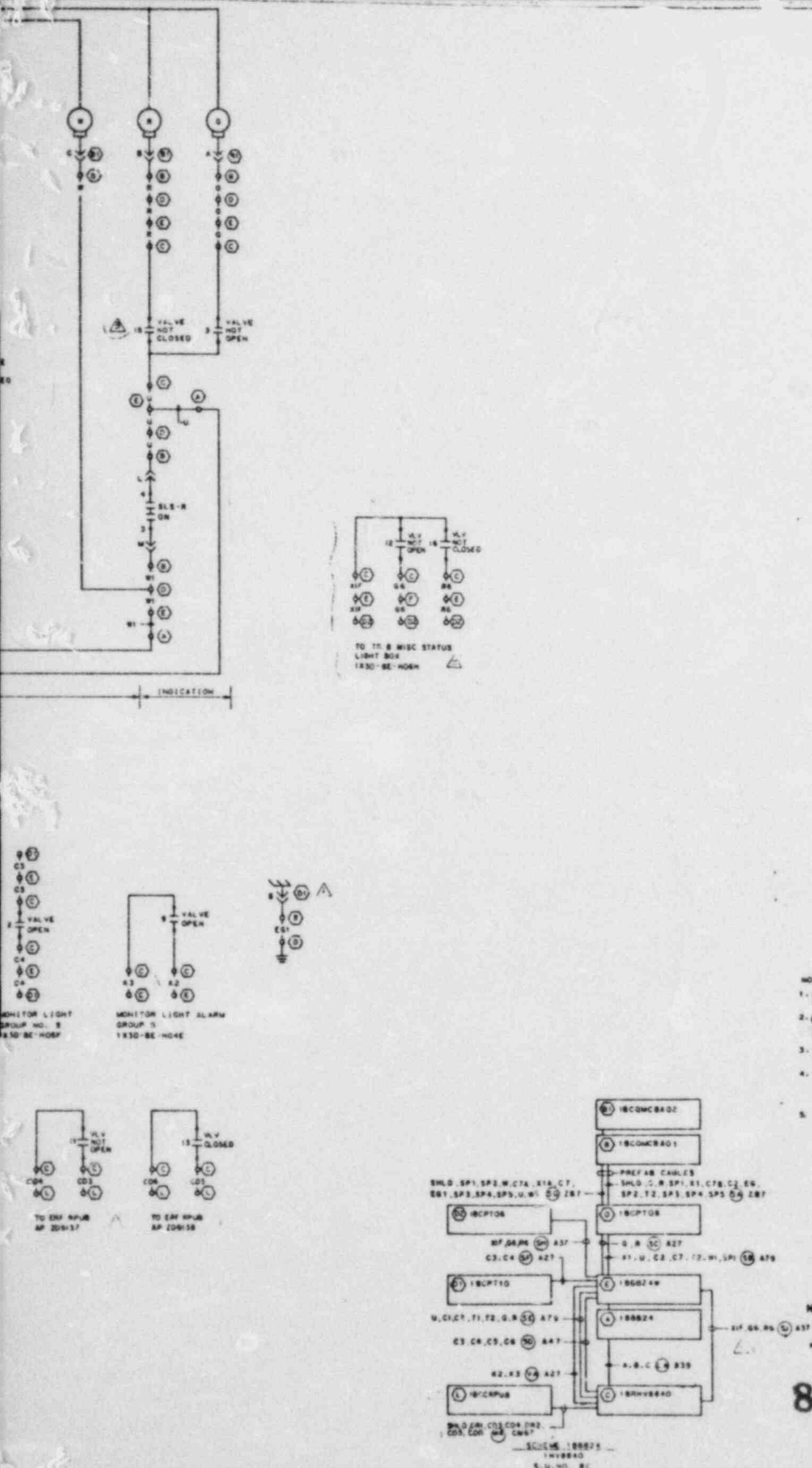
8406060006 - 37

Amend. 7 5/84

Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	ELEMENTARY DIAGRAM SAFETY INJECTION SYSTEM 1HV-8802B
		FIGURE 430.73-4 (SHEET 3 OF 3)


480-120V
VALVE NOT OPEN
VALVE CLOSED
TSO OPEN
VALVE OPEN
TSC CLOSED
JUMPER (SEE NOTE 4)
OPEN-CLOSE & ALARM
42-O SPARES
42-C SPARES
SYSTEM STATUS MONITOR PANEL
CONTACTS
VALVE POSITION
OPEN
CLOSED
SOLID LINE DENOTES CONTACT CLOSED

Also Available On
Aperture Card



NOTES:

1. FOR SPECIAL NOTES AND SYMBOLS REFER TO D/L 1X30-AA-A00A,C,D,F THRU R, L.
2. ◯ DENOTES EQUIPMENT LOCATION NUMBER. FOR COMPLETE EQUIPMENT LOCATION NUMBER REFER TO CABLING BLOCK DIAGRAM.
3. SPARE CONTACT WITH "△" IS WIRED TO UNIT TERMINAL BLOCKS.
4. FIELD TO REMOVE JUMPER FROM THERMAL OVERLOAD CONTACT DURING INITIAL START-UP & PERIODIC TESTING.
5. HS-8840 IS LOCATED AT (B1). INTERNAL CONNECTION BETWEEN (B1) AND (B) IS BY WESTINGHOUSE. THE PREFAB CABLE CONNECTOR IS LOCATED AT (B).

NUCLEAR SAFETY RELATED [B]

RHRS HOT LEG INJECTION CROSSOVER ISO.

8406060006 - 34

Amend. 7 5/84

Georgia Power

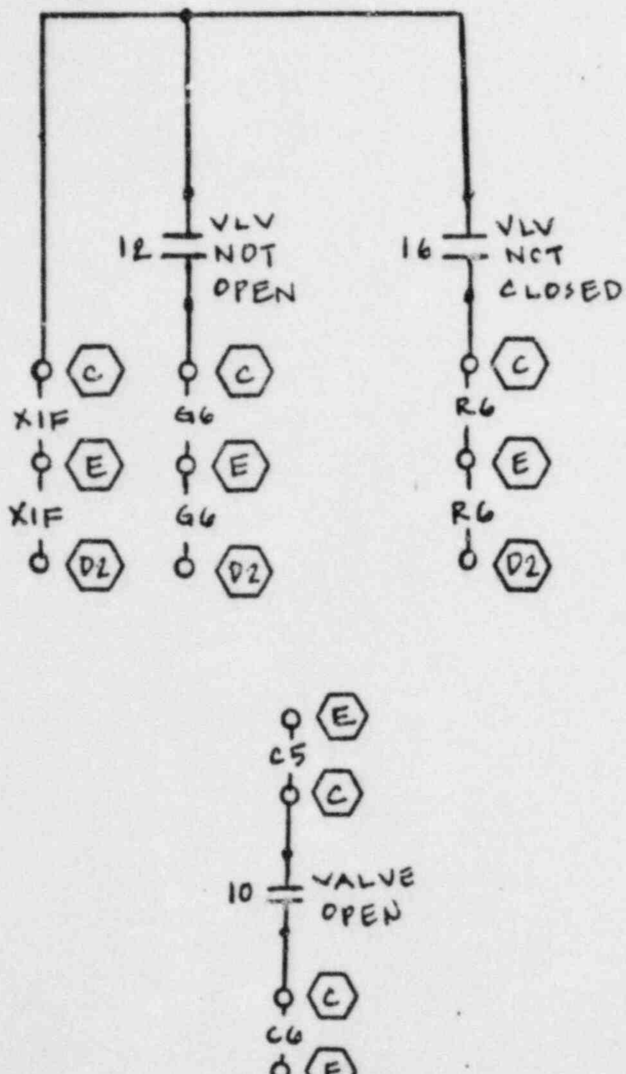
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8840

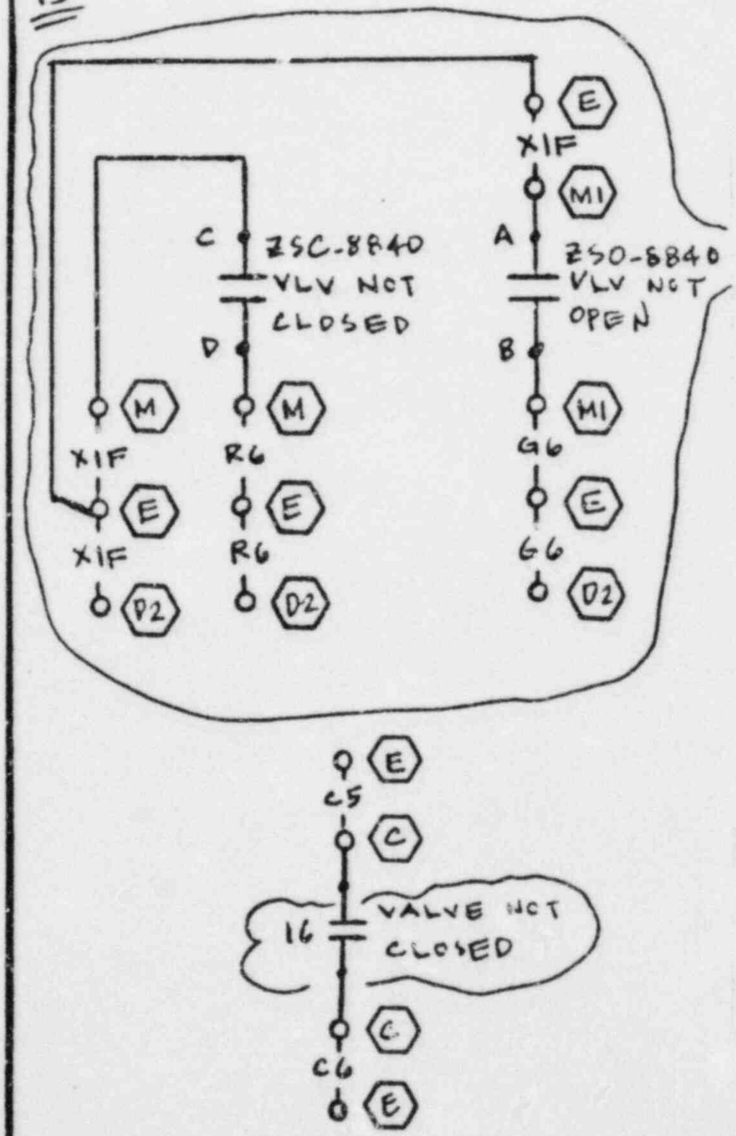
FIGURE 430.73-5 (SHEET 1 OF 2)

DESCRIPTION OF CHANGE

WAS

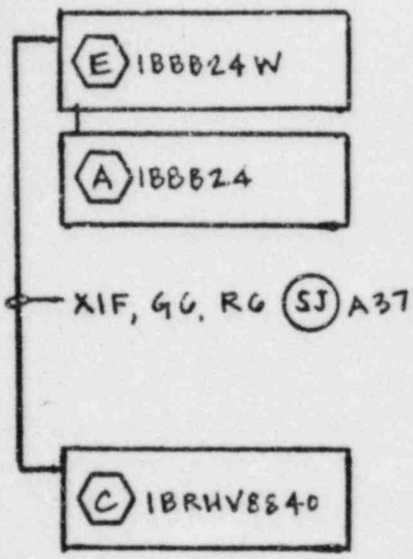


IS



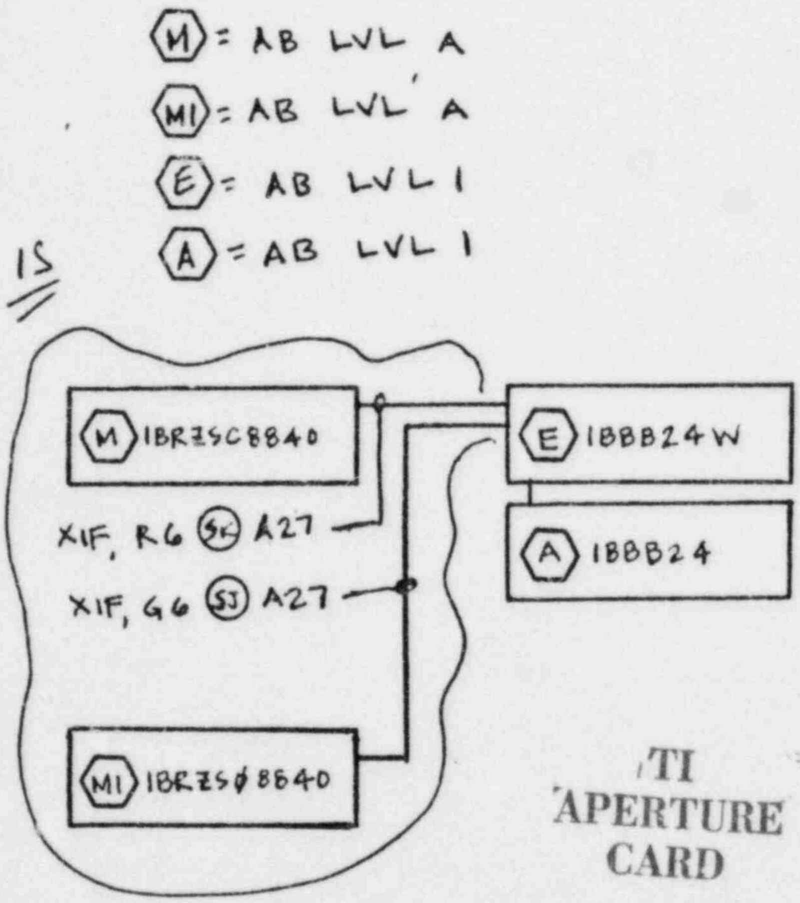
DESCRIPTION OF CHANGE

WAS



SCHEME 1BBB24
1HV8840
S.U. NO. BC

IS

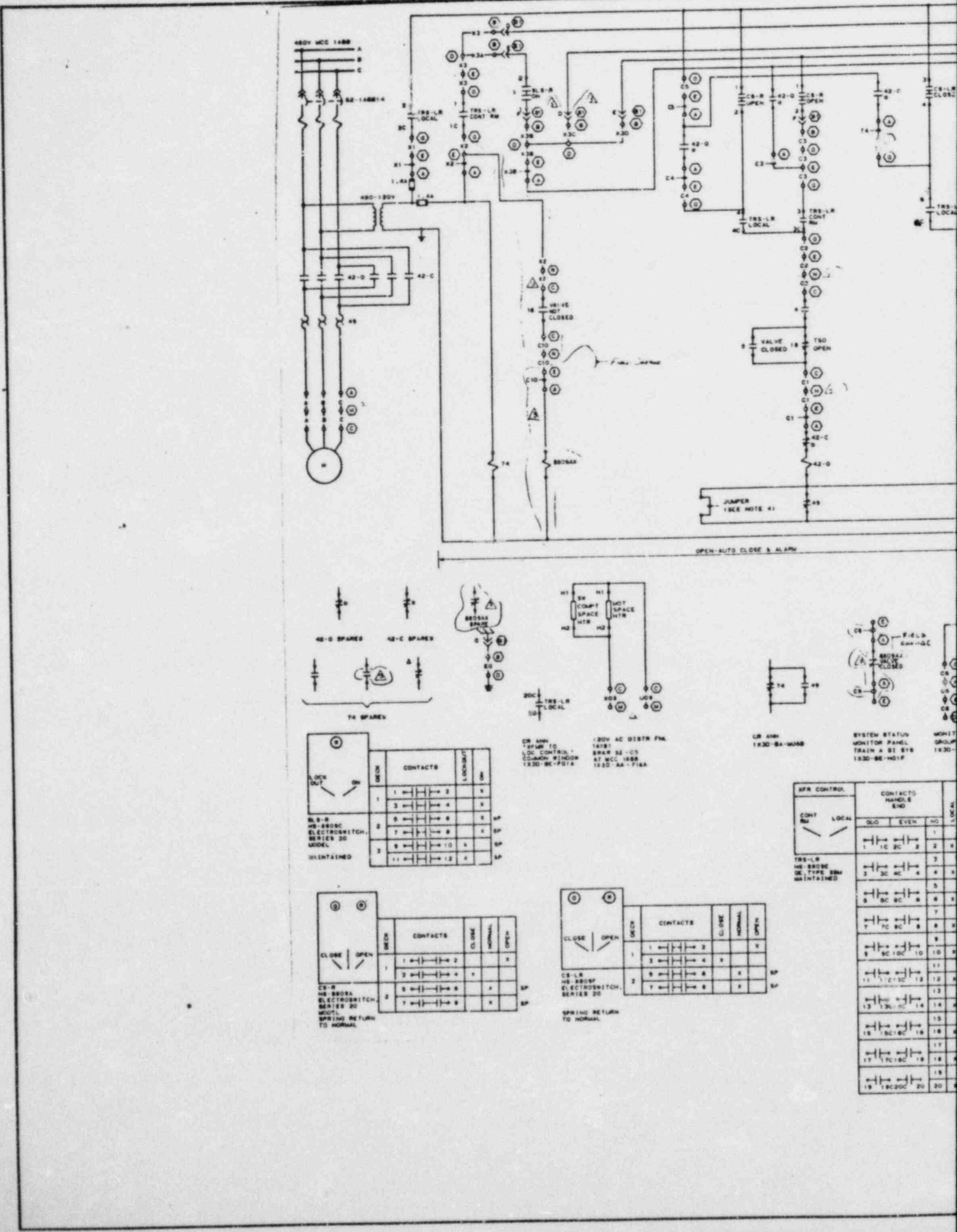


SCHEME 1BBB24
1HV8840
S.U. NO. BC

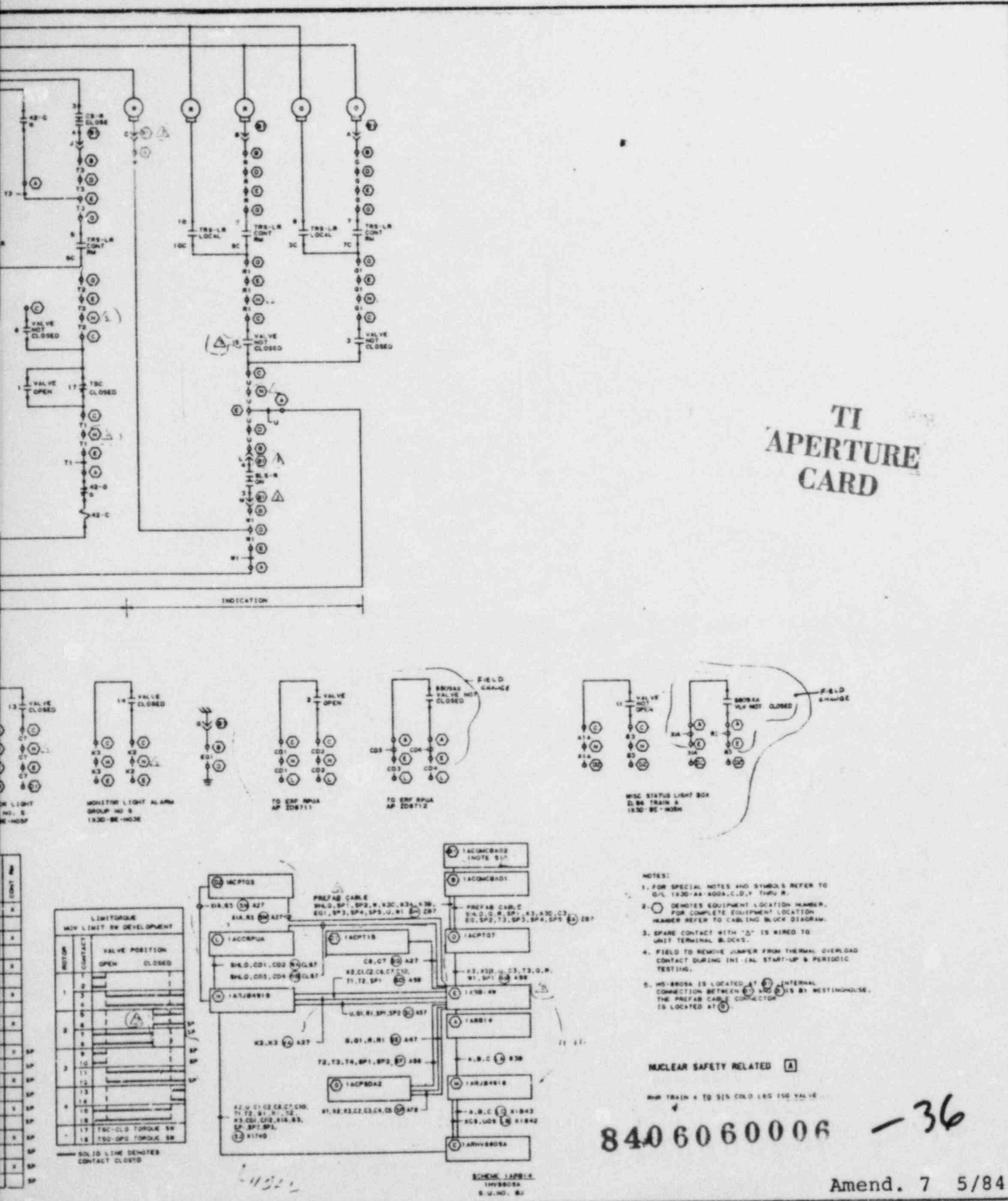
8406060006 - 35

Amend. 7 5/84

Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	ELEMENTARY DIAGRAM SAFETY INJECTION SYSTEM 1HV-8840
		FIGURE 430.73-5 (SHEET 2 OF 2)


480V MCC 1AB8
480-120V
42-O
42-C
VALVE NOT CLOSED
VALVE CLOSED
TSO OPEN
JUMPER (SEE NOTE 4)
OPEN-AUTO CLOSE & ALARM
42-O SPARES
42-C SPARES
T4 SPARES
TRS-LR LOCAL
CS-R OPEN
CS-R CLOSE
CONTACTS
DECK
LOCKOUT
CLOSE
NORMAL
OPEN
CLOSE
OPEN
SPRING RETURN TO NORMAL
XFR CONTROL
TRS-LR

Also Available On
Aperture Card



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APERTURE
CARD

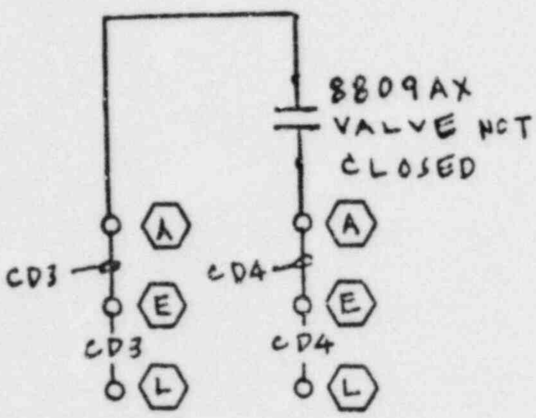
8406060006 -36

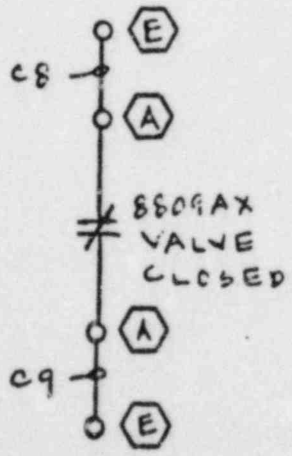
Amend. 7 5/84

Georgia Power — VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	ELEMENTARY DIAGRAM SAFETY INJECTION SYSTEM 1HV-8809A
	FIGURE 430.73-6 (SHEET 1 OF 3)

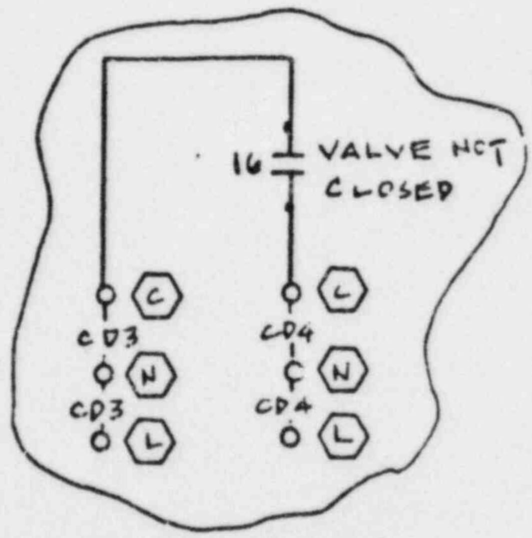
DESCRIPTION OF CHANGE

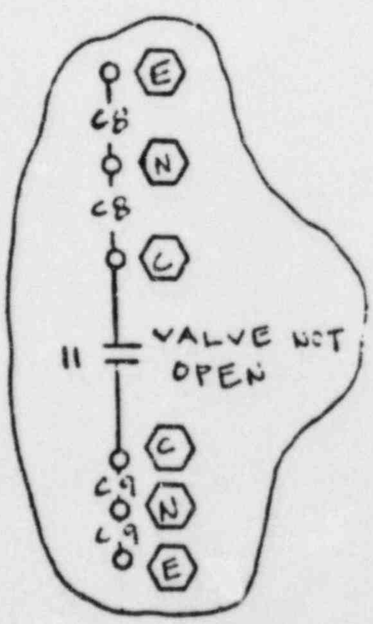
WAS





IS

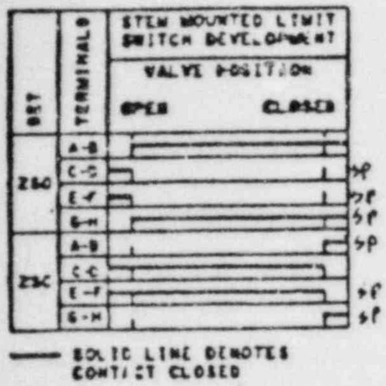


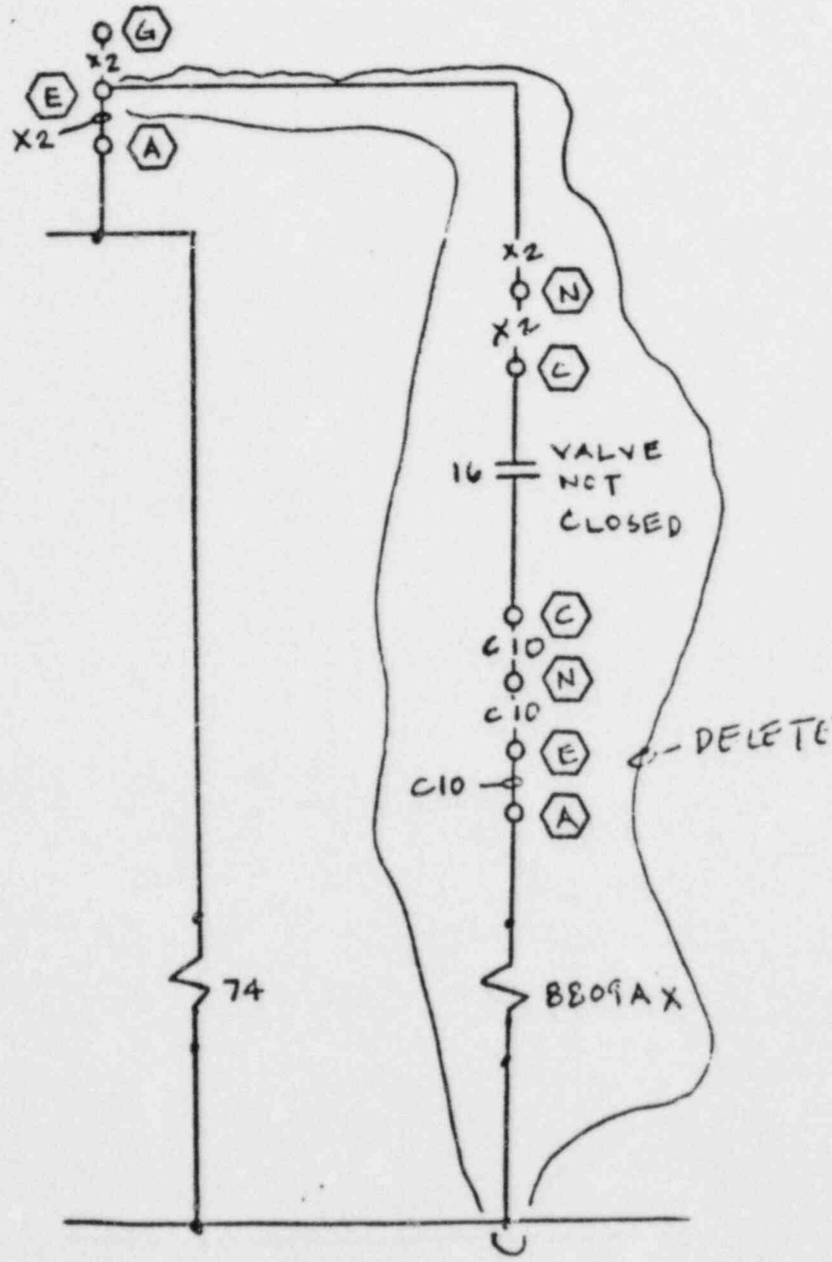


Also Available On
Aperture Card

DESCRIPTION OF CHANGE

ADD





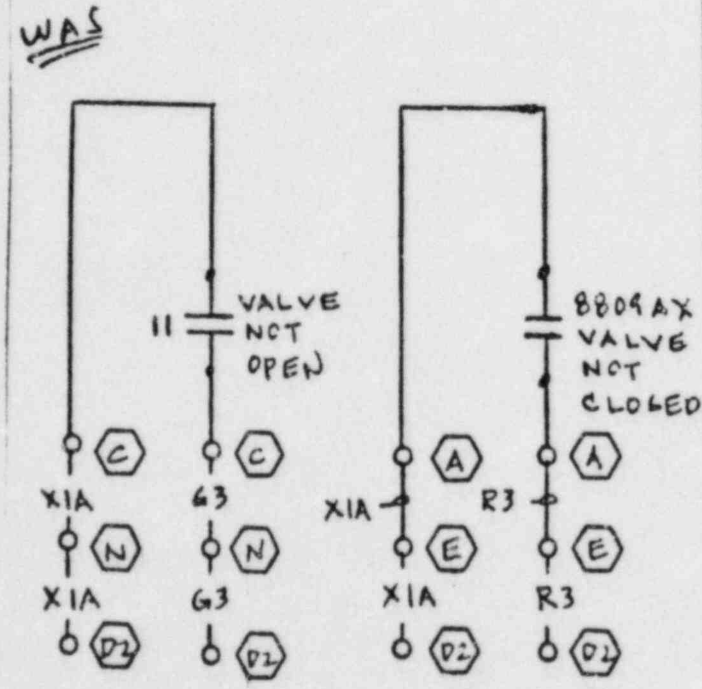
TI
APERTURE
CARD

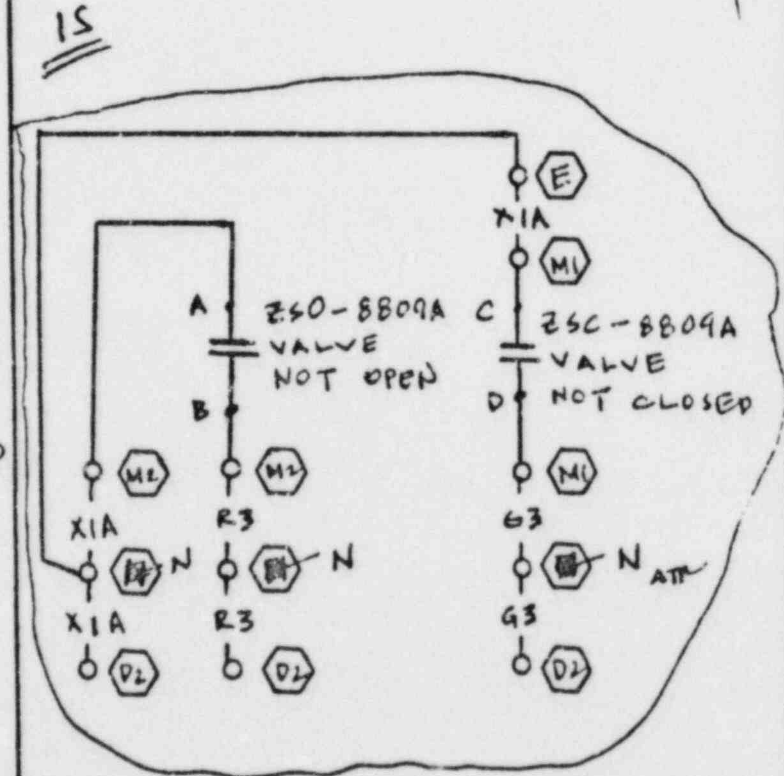
8406060006 - 37

Amend. 7 5/84

Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	ELEMENTARY DIAGRAM SAFETY INJECTION SYSTEM 1HV-8809A
		FIGURE 430.73-6 (SHEET 2 OF 3)

DESCRIPTION OF CHANGE



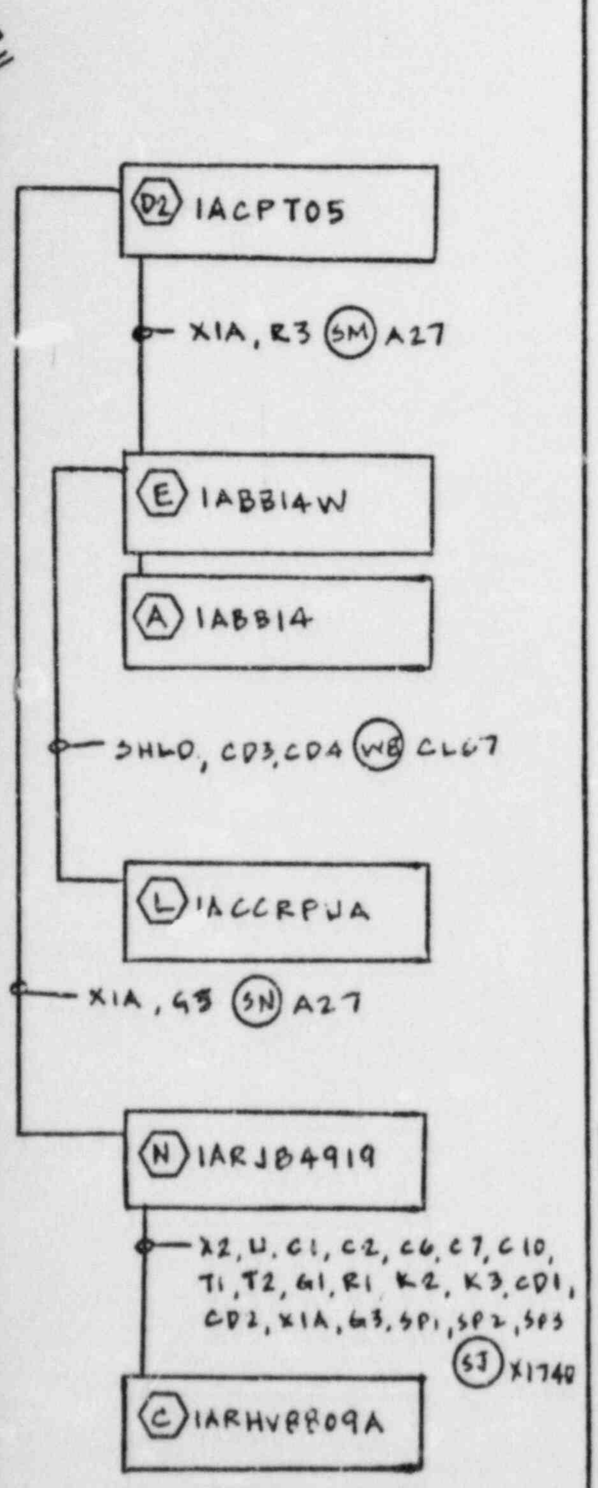


TI APERTURE CARD

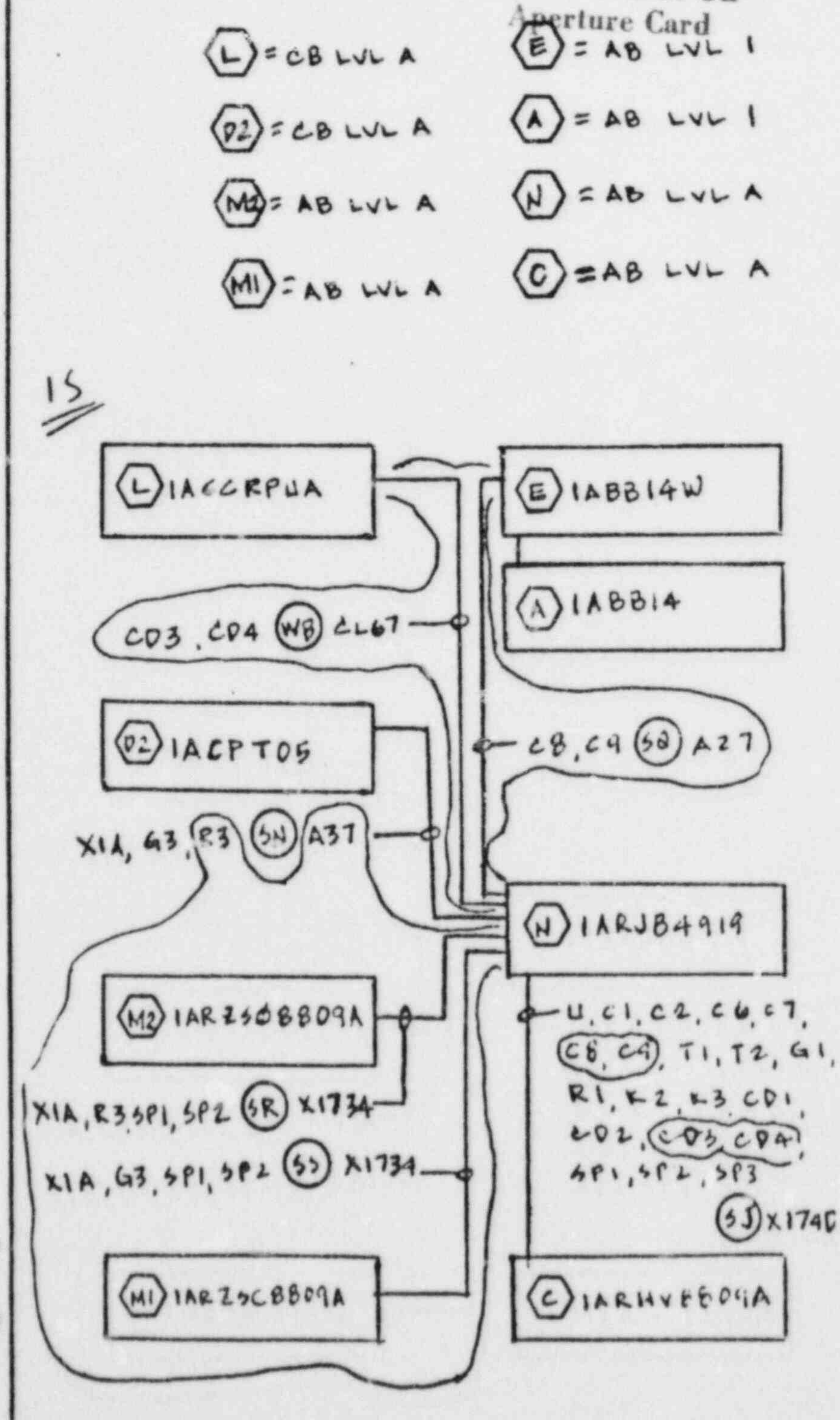
8406060006 -38

DESCRIPTION OF CHANGE

Also Available On Aperture Card



SCHEME 1ABB14
1HV8809A
S U NO BJ



SCHEME 1ABB14
1HV8809A
S U NO. BJ

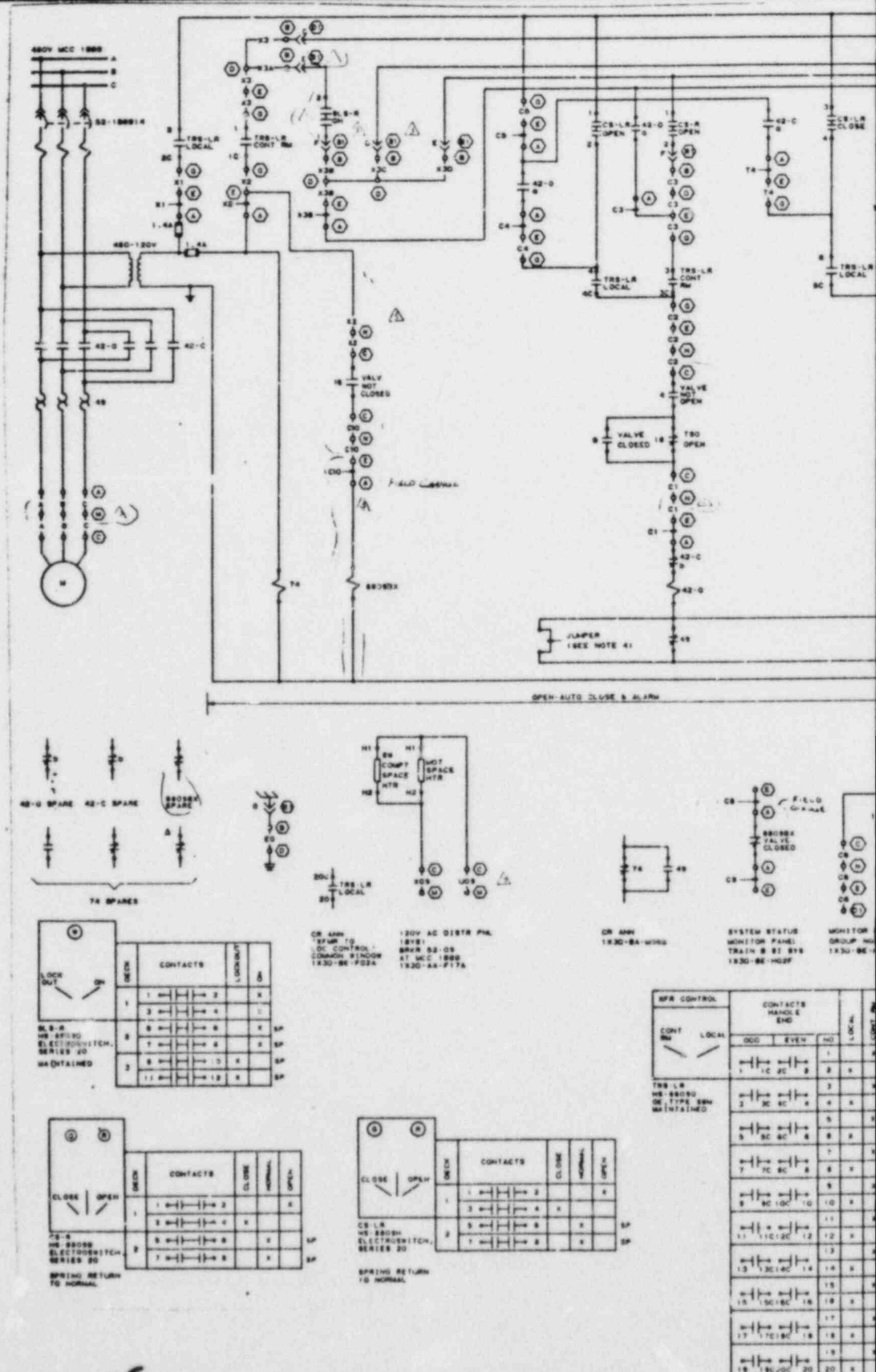
Amend. 7 5/84

Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

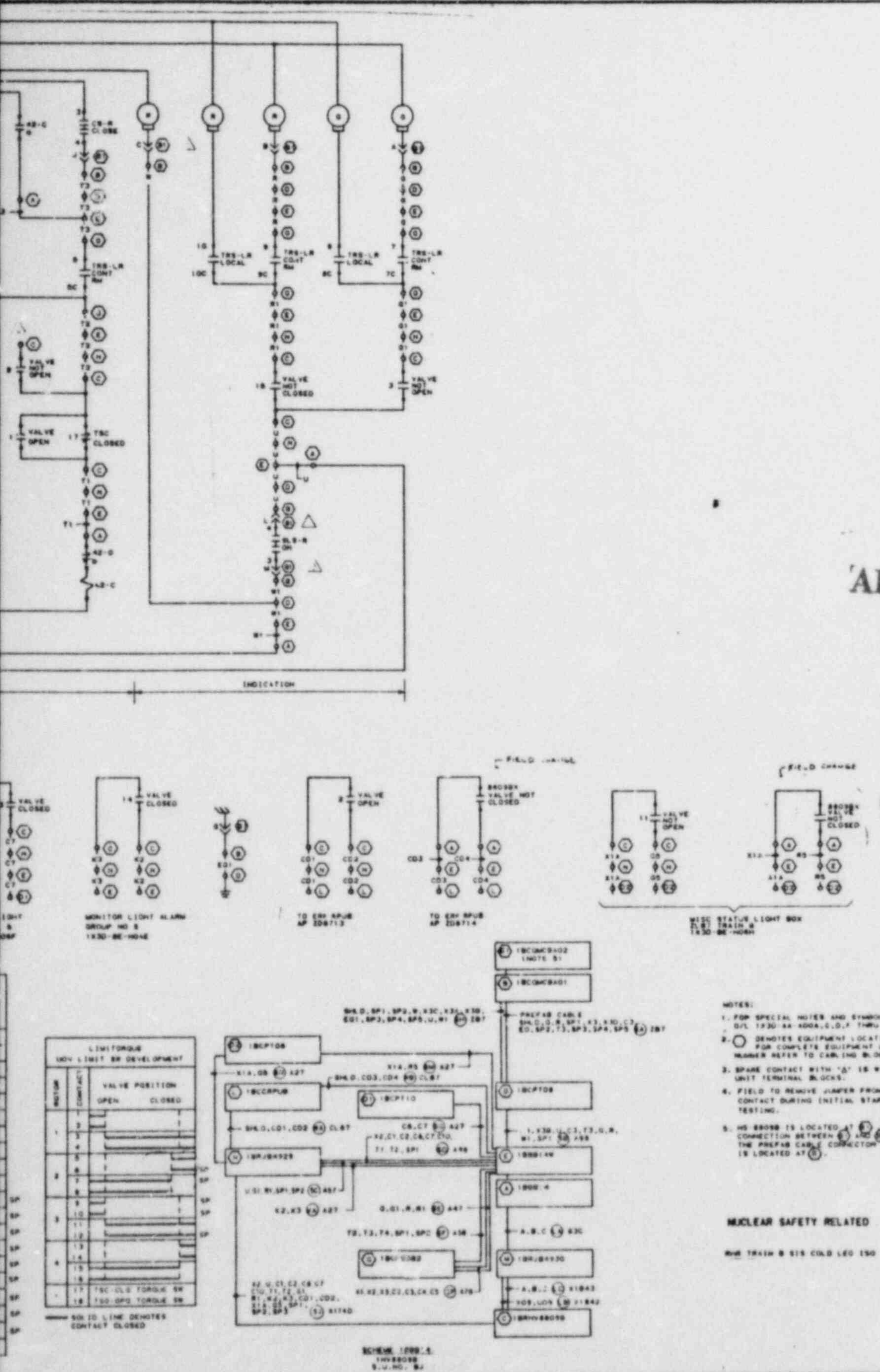
ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8809A

FIGURE 430.73-6 (SHEET 3 OF 3)



8406060006-39

Also Available On
Aperture Card



TI
APERTURE
CARD

NOTES:

1. FOR SPECIAL NOTES AND SYMBOLS REFER TO D/L 1X3D-AA-A00A,C,D,F THRU R.
2. ○ DENOTES EQUIPMENT LOCATION NUMBER. FOR COMPLETE EQUIPMENT LOCATION NUMBER REFER TO CABLING BLOCK DIAGRAM.
3. SPARE CONTACT WITH "Δ" IS WIRED TO UNIT TERMINAL BLOCKS.
4. FIELD TO REMOVE JUMPER FROM THERMAL OVERLOAD CONTACT DURING INITIAL START-UP & PERIODIC TESTING.
5. HS 8809B IS LOCATED AT ⓑ. INTERNAL CONNECTION BETWEEN ⓑ AND ⓑ IS BY WESTINGHOUSE. THE PREFAB CABLE CONNECTOR IS LOCATED AT ⓑ.

NUCLEAR SAFETY RELATED [B]

RHR TRAIN B SIS COLD LEG ISO

Amend. 7 5/84

Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

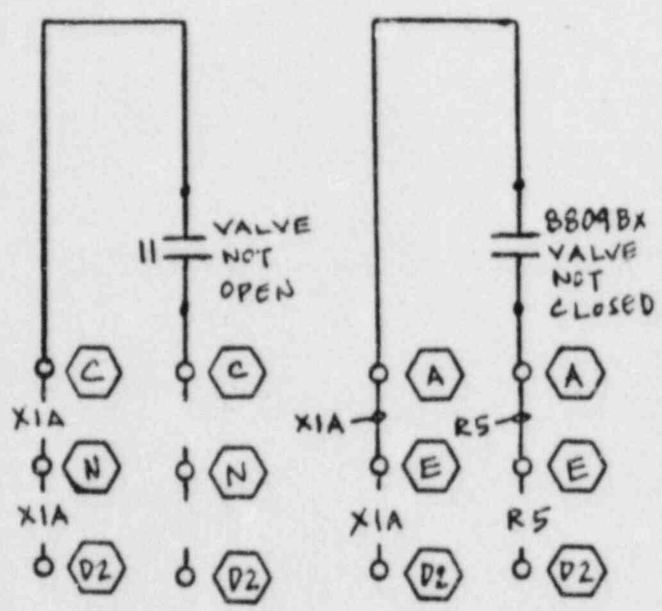
ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8809B

FIGURE 430.73-7 (SHEET 1 OF 3)

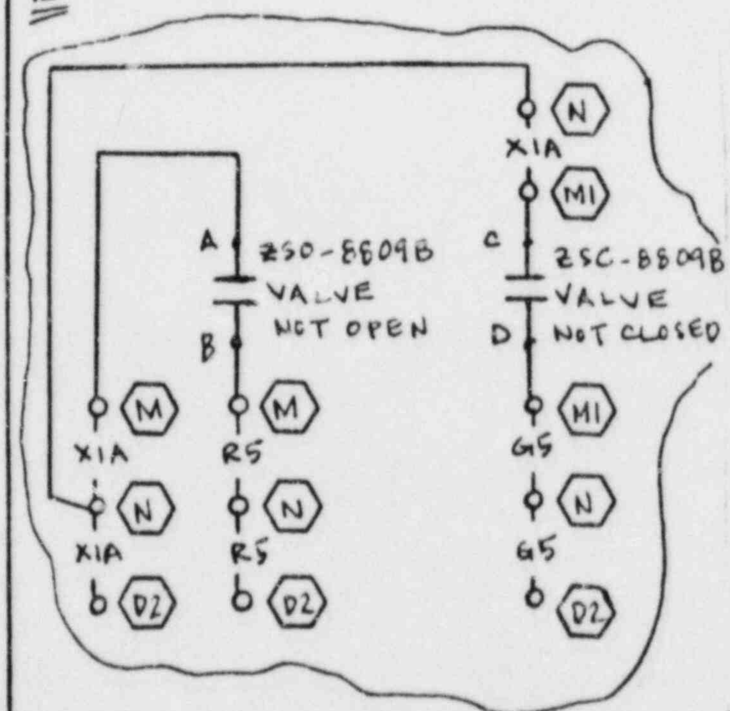
Also Available On
Aperture Card

DESCRIPTION OF CHANGE

WAS



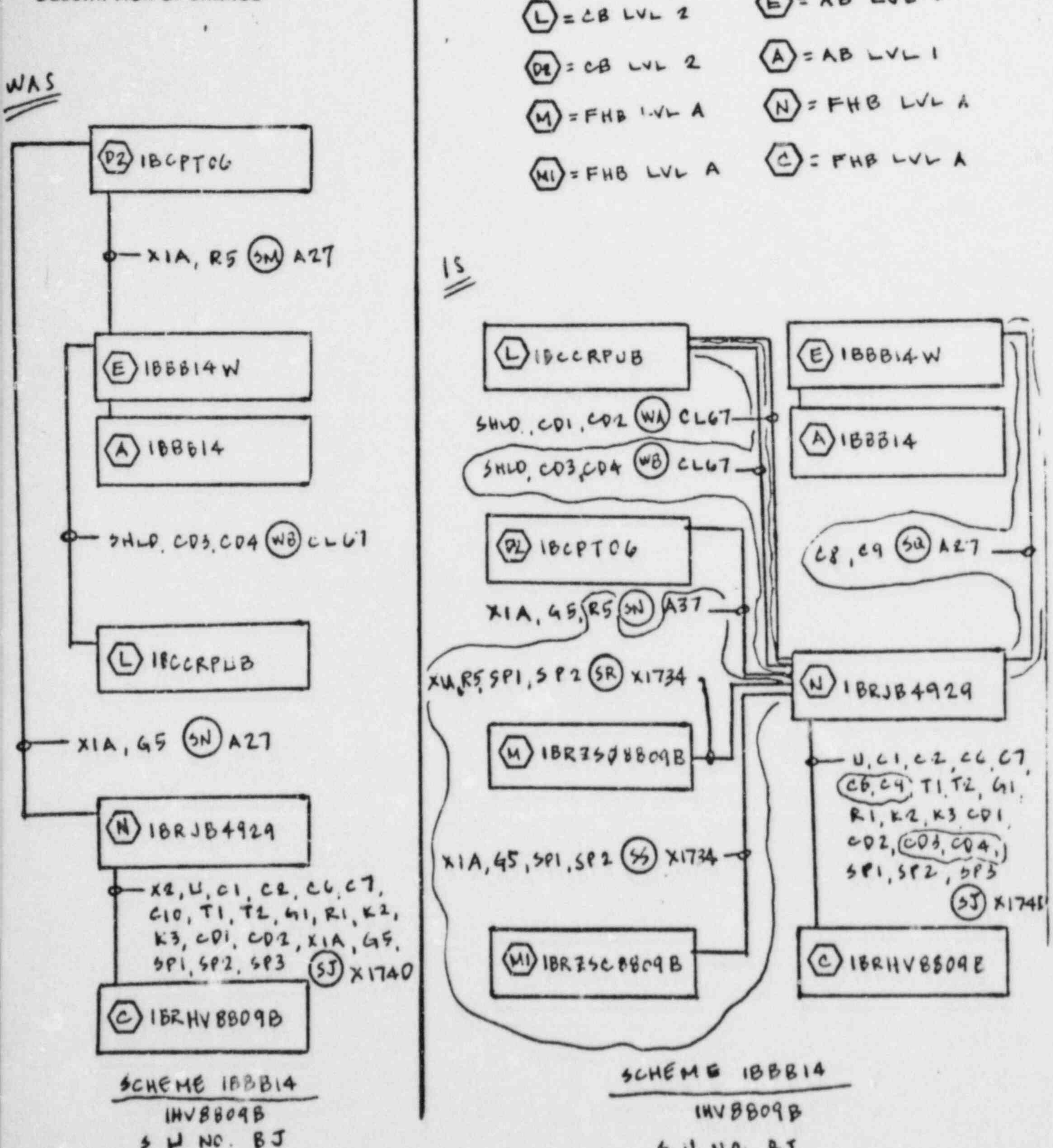
IS



TI
APERTURE
CARD

8406060006 -41

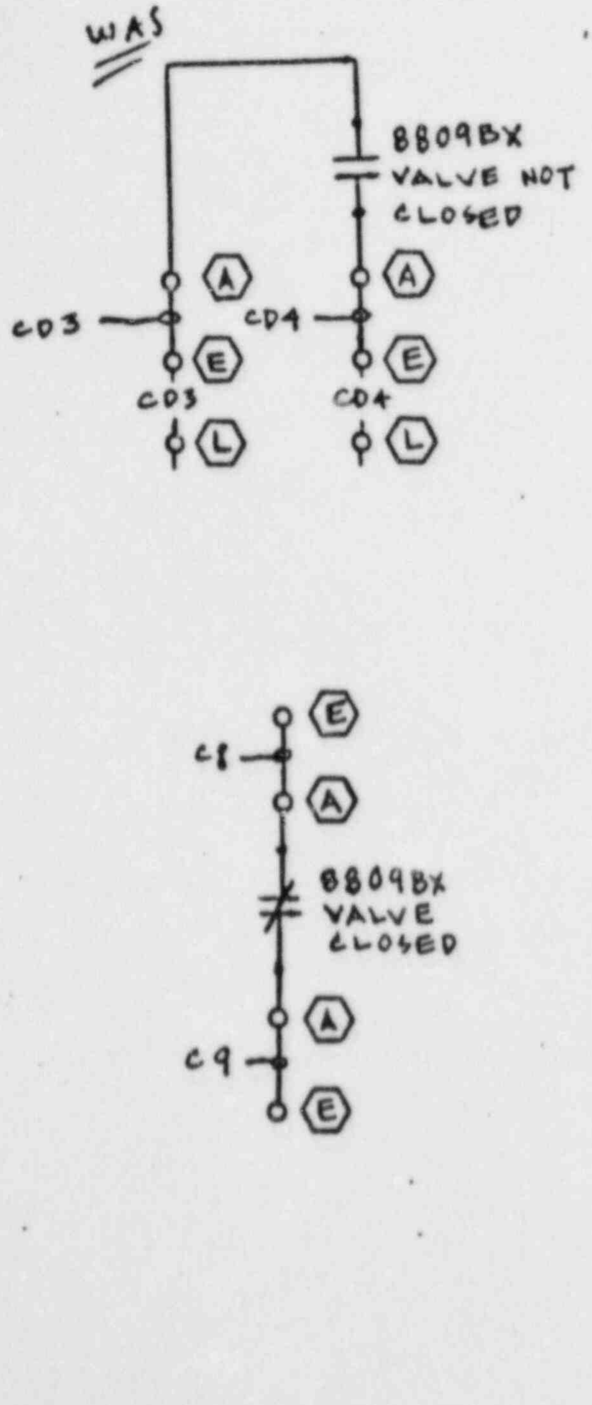
DESCRIPTION OF CHANGE

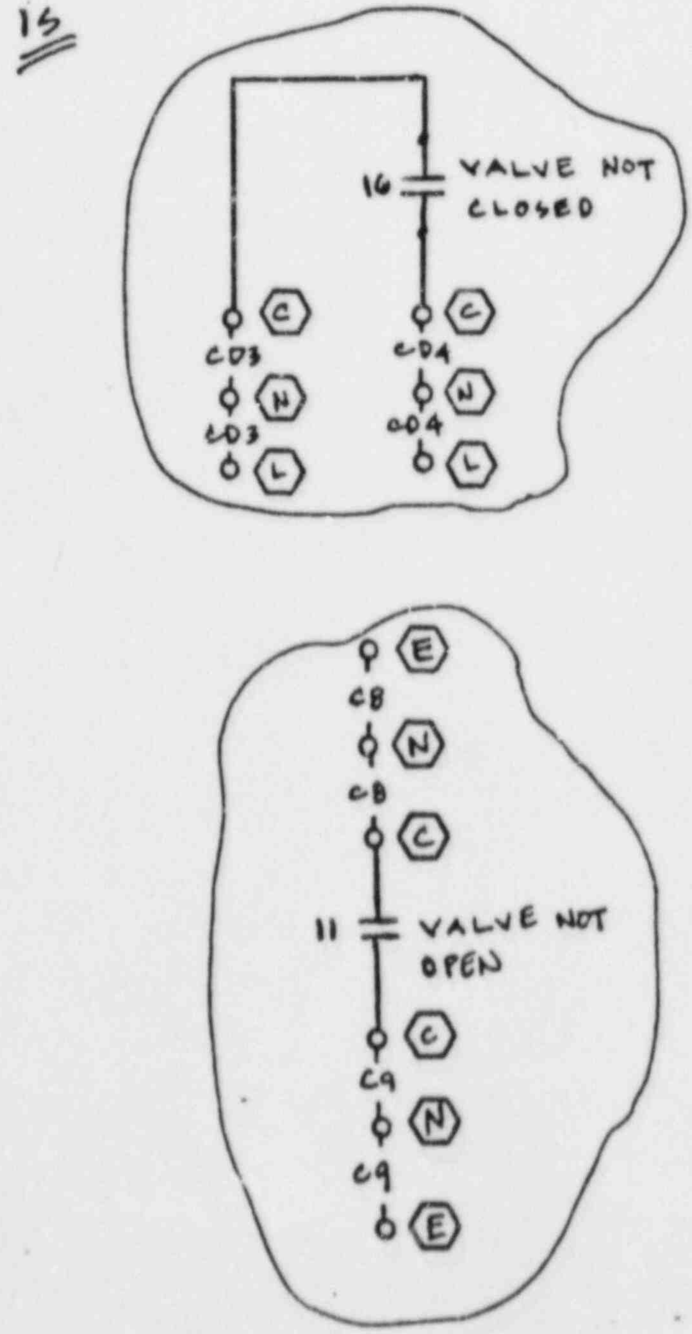


Amend. 7 5/84

Georgia Power	VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2	ELEMENTARY DIAGRAM SAFETY INJECTION SYSTEM 1HV-8809B
		FIGURE 430.73-7 (SHEET 2 OF 3)

DESCRIPTION OF CHANGE



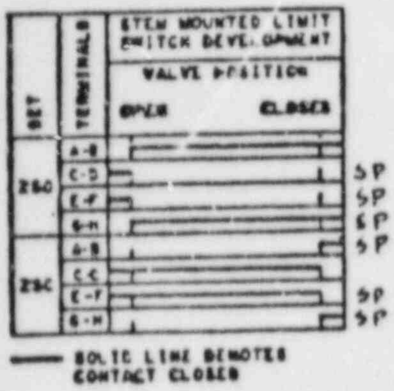


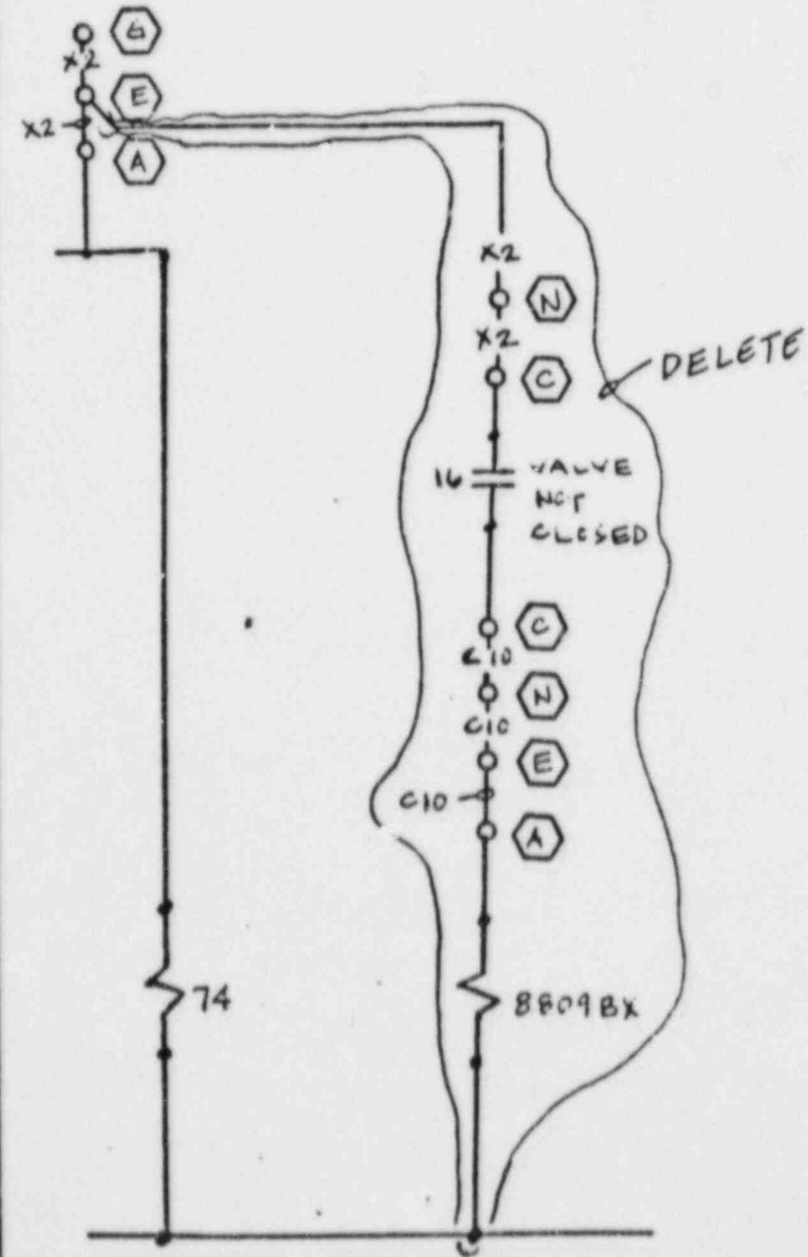
8406060006 -41

Also Available On Aperture Card

DESCRIPTION OF CHANGE

ADD





TI APERTURE CARD

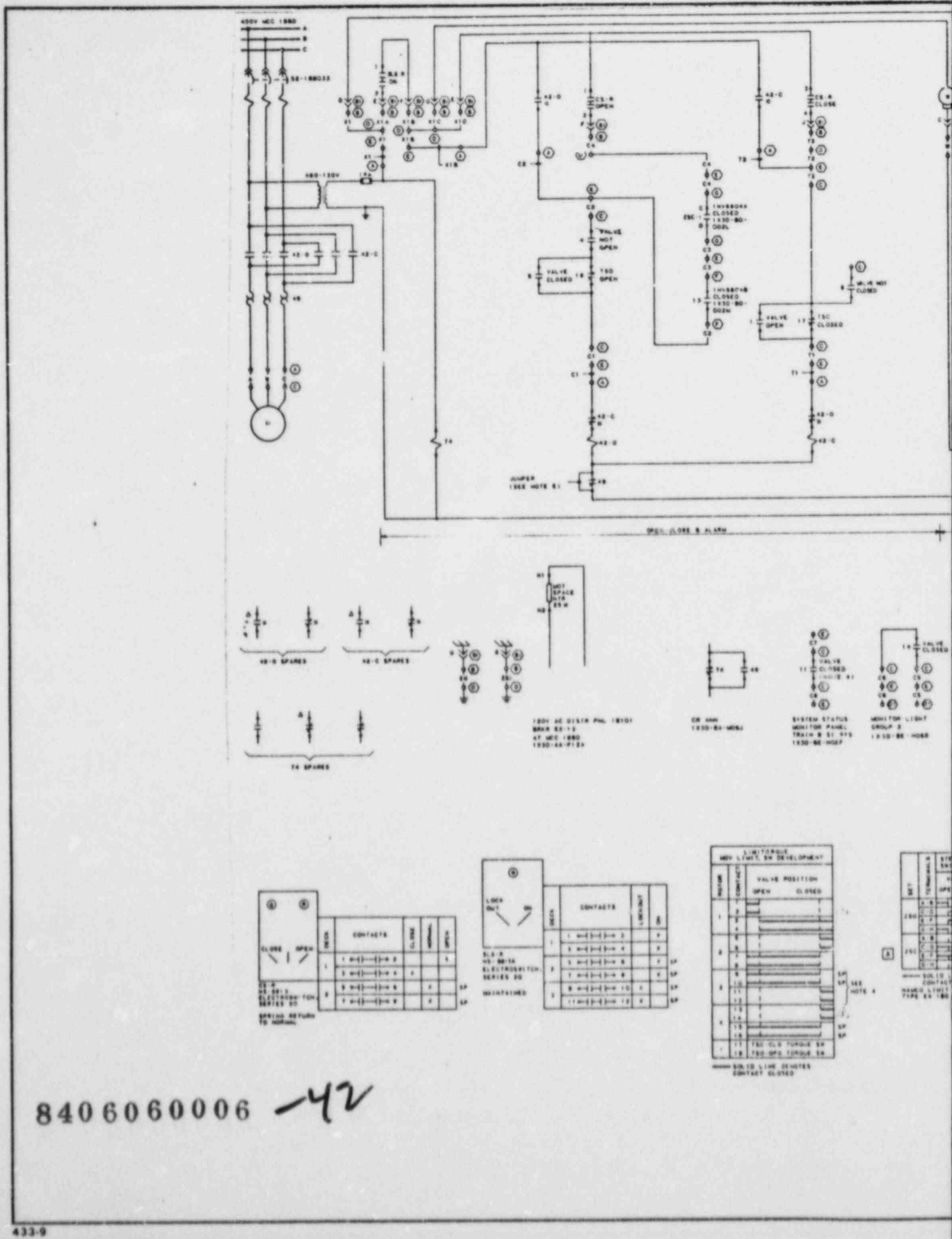
Amend. 7 5/84

Georgia Power

VOGTLE ELECTRIC GENERATING PLANT UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8809B

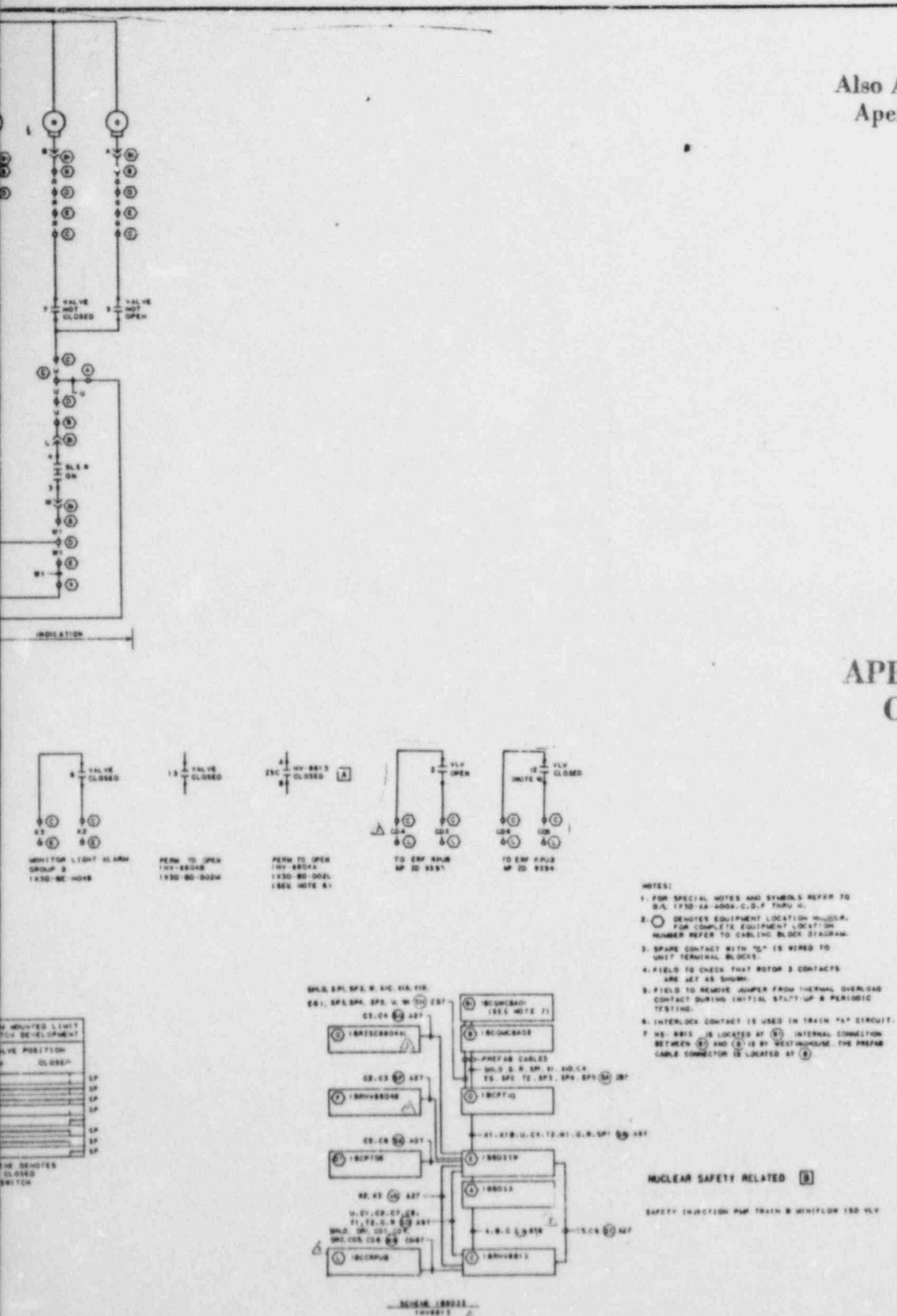
FIGURE 430.73-7 (SHEET 3 : 3)



8406060006 -42

433-9

Also Available On
Aperture Card



TI
APERTURE
CARD

Amend. 7 5/84

Georgia Power

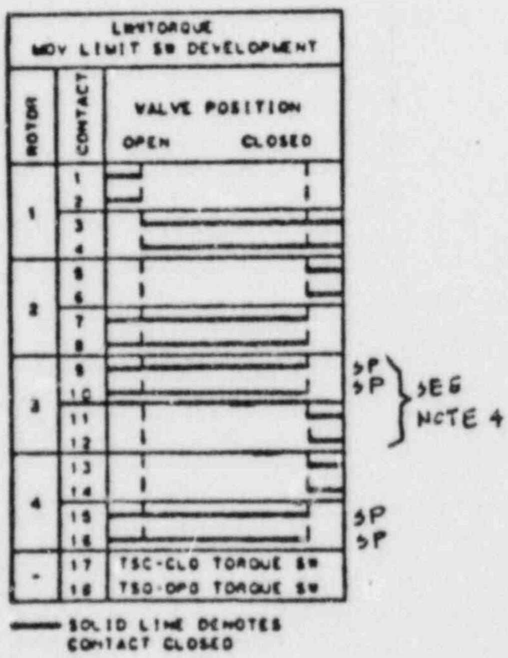
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8813

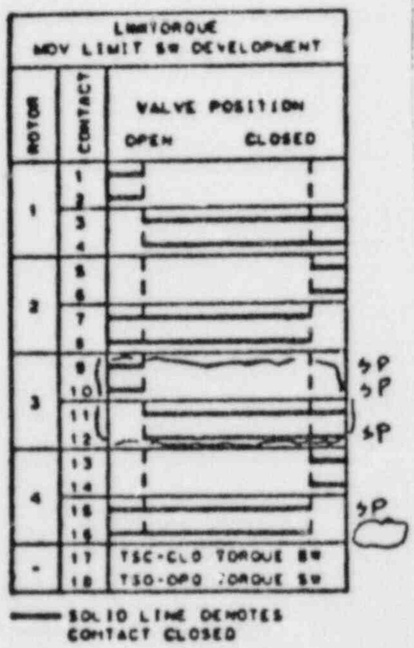
FIGURE 430.73-8 (SHEET 1 OF 3)

DESCRIPTION OF CHANGE

WAS



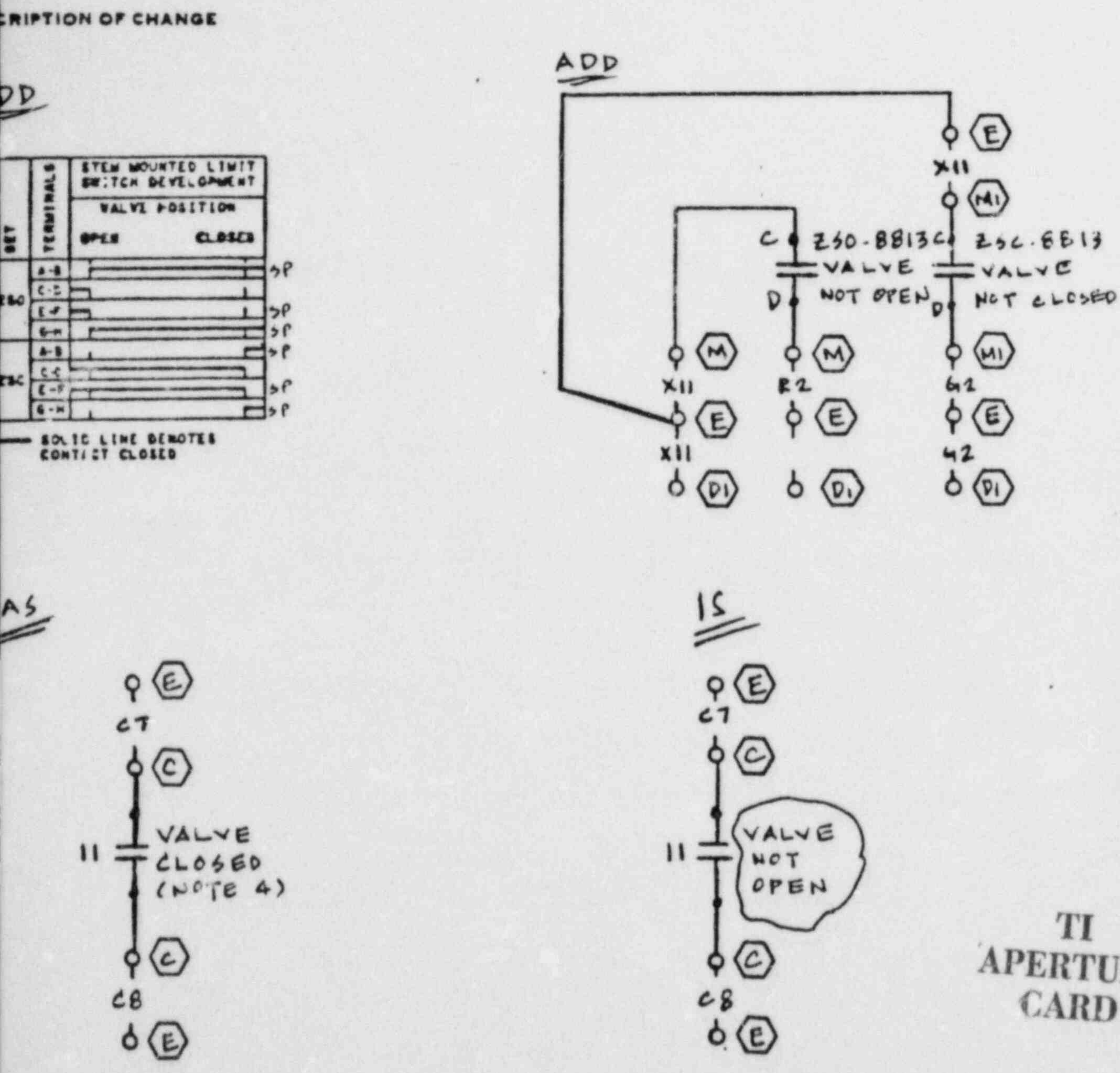
NOW



8406060006 -43

433-9

Also Available On
Aperture Card



TI
APERTURE
CARD

Amend. 7 5/84

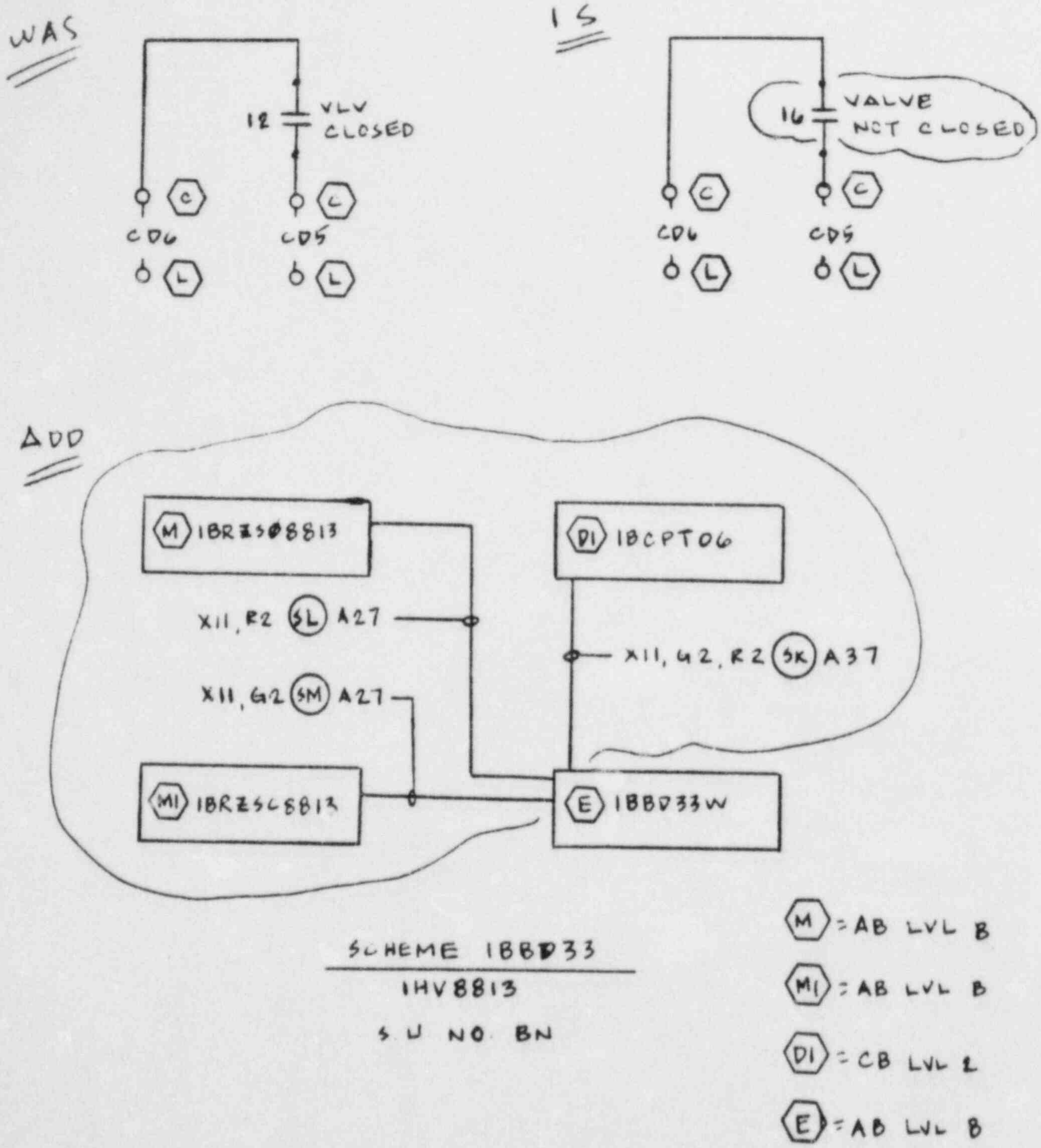
Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8813

FIGURE 430.73-8 (SHEET 2 OF 3)

DESCRIPTION OF CHANGE



Amend. 7 5/84

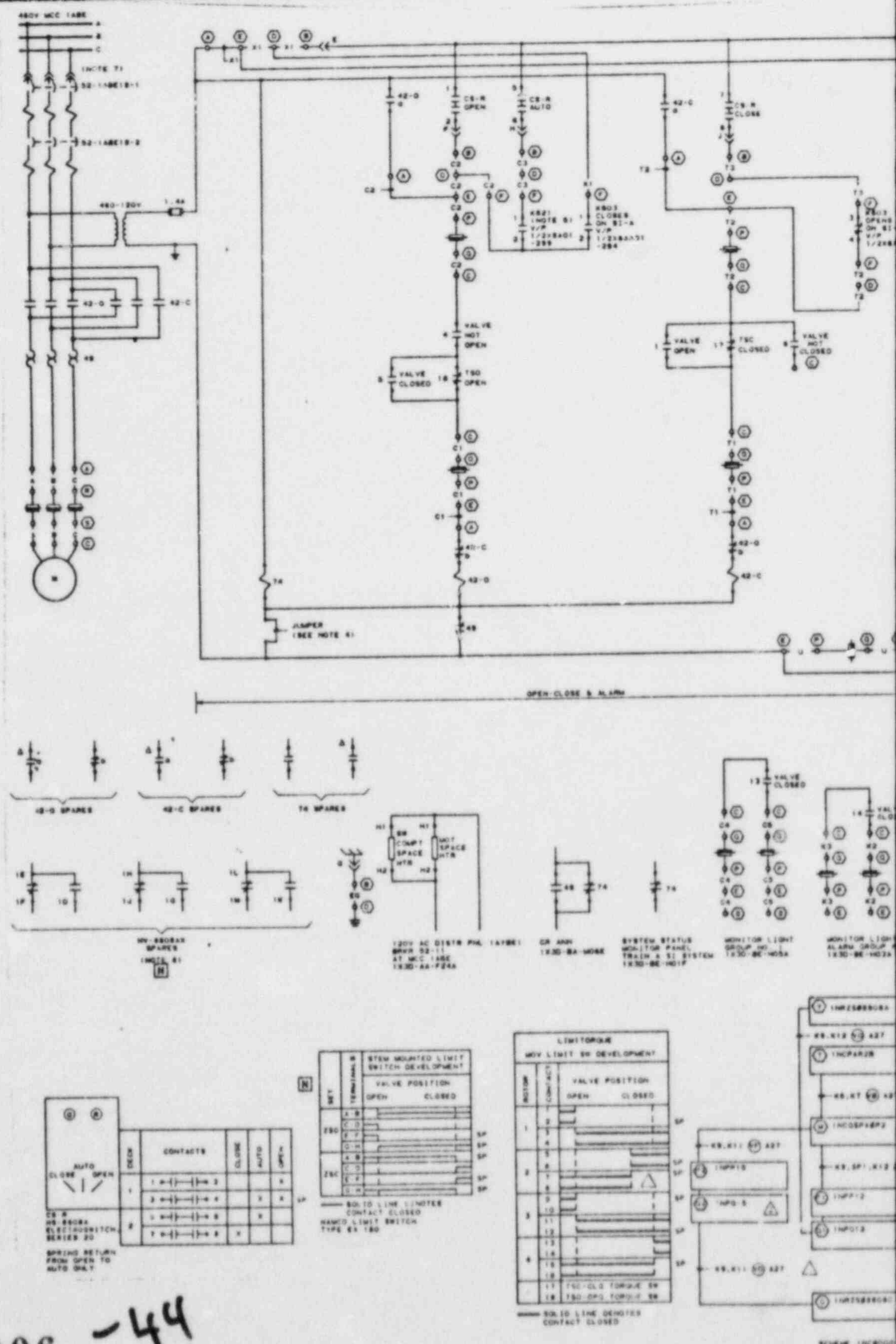
Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8813

FIGURE 430.73-8 (SHEET 3 OF 3)

433-9



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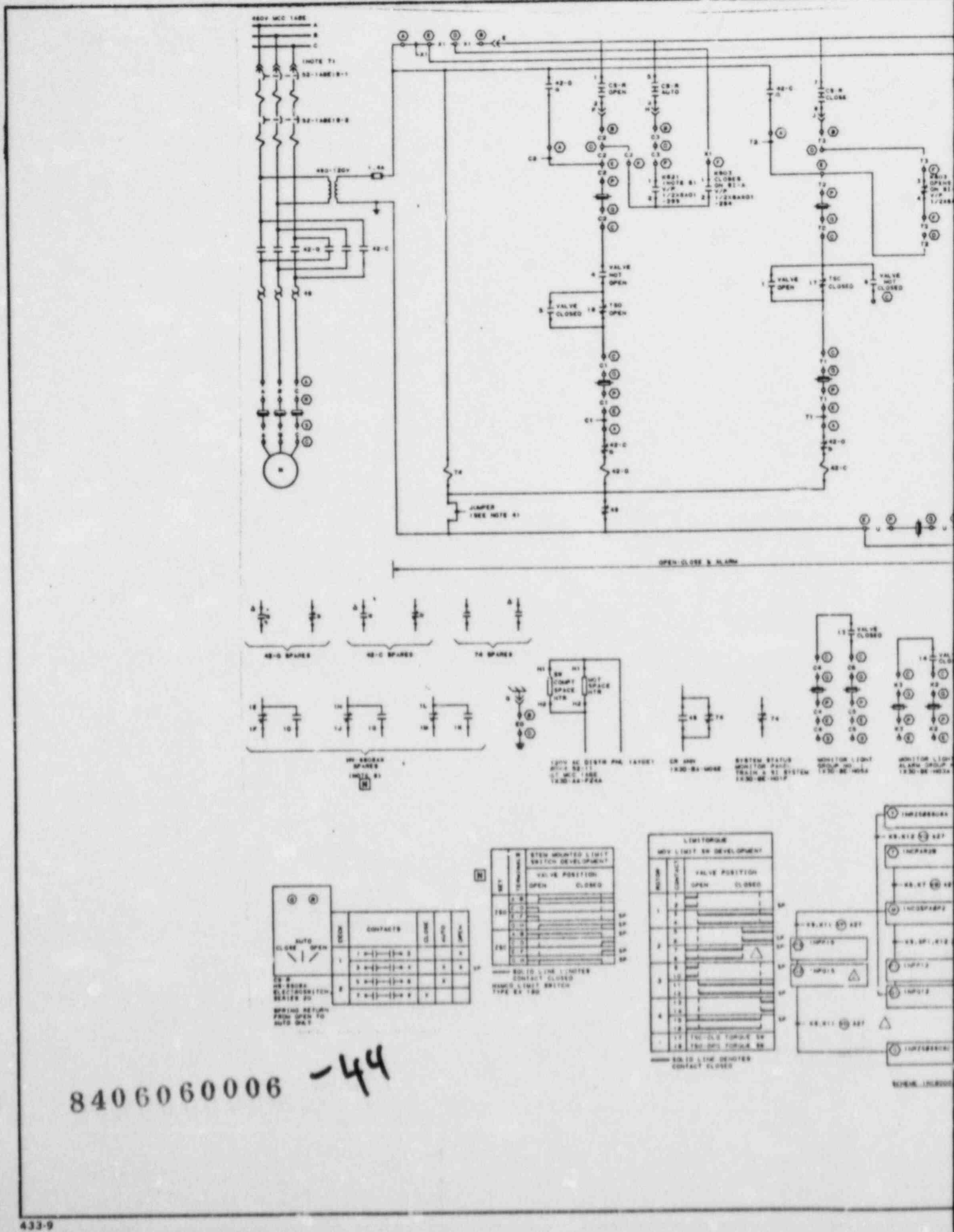

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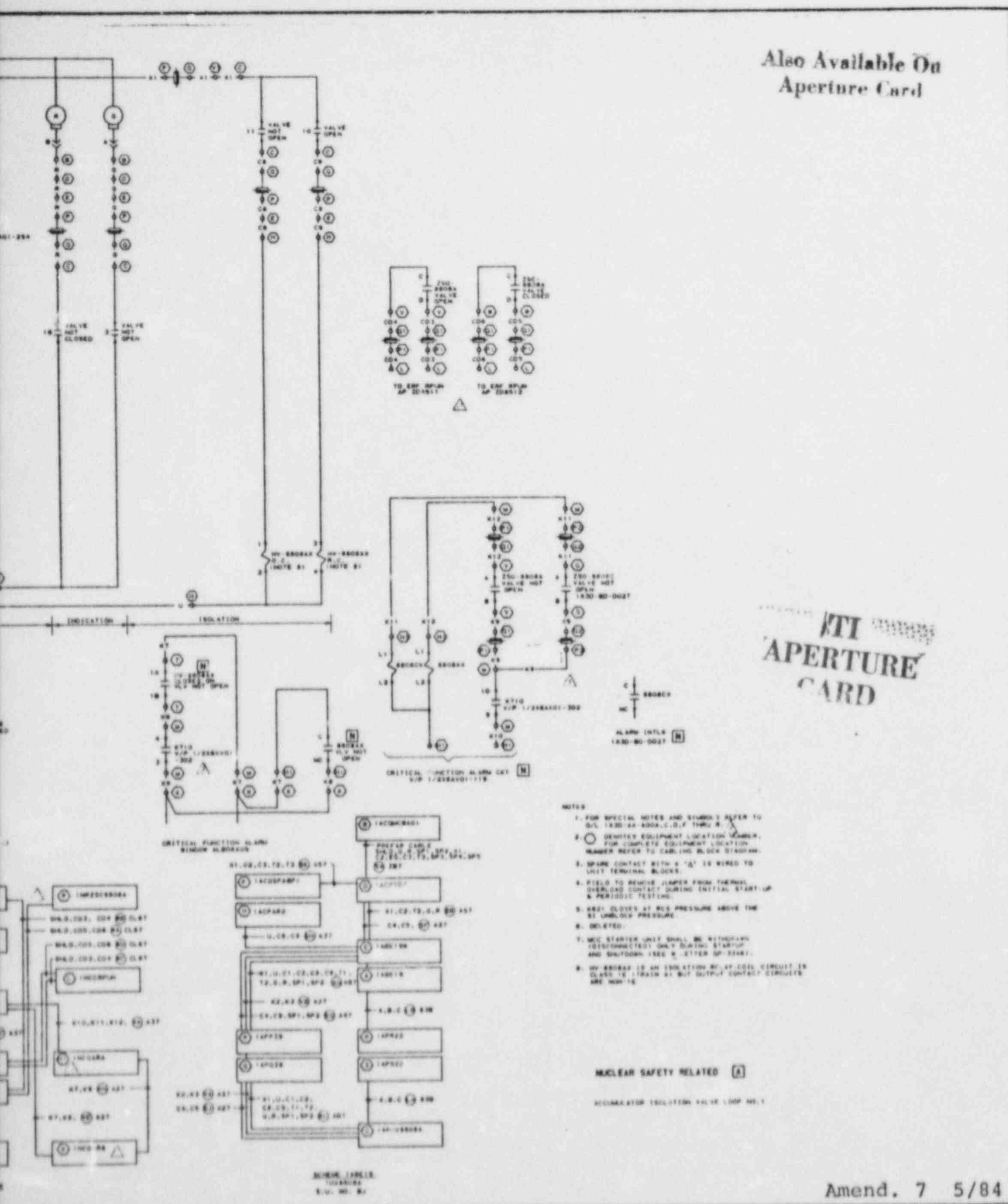
Also Available On
Aperture Card



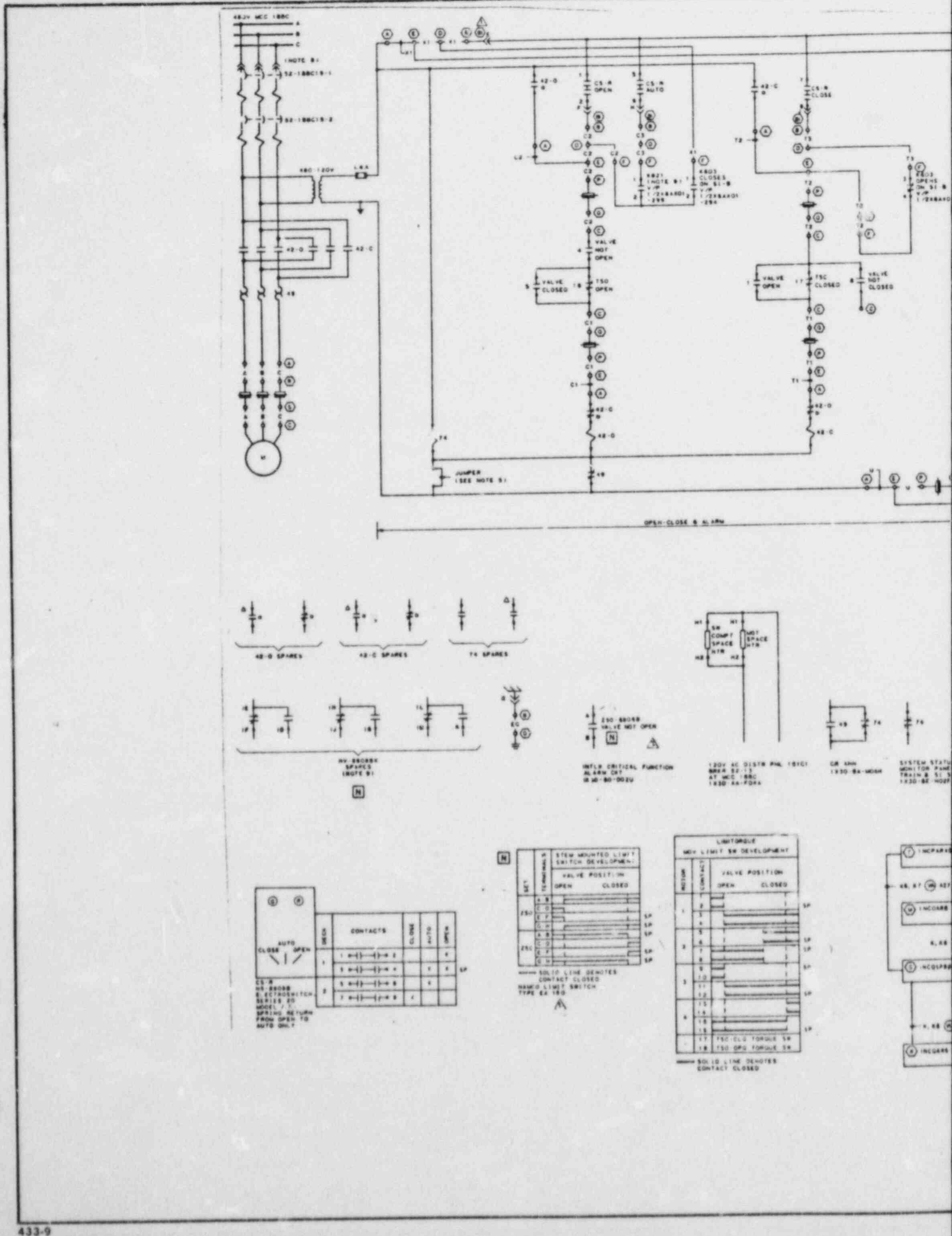
Amend. 7 5/84

Georgia Power

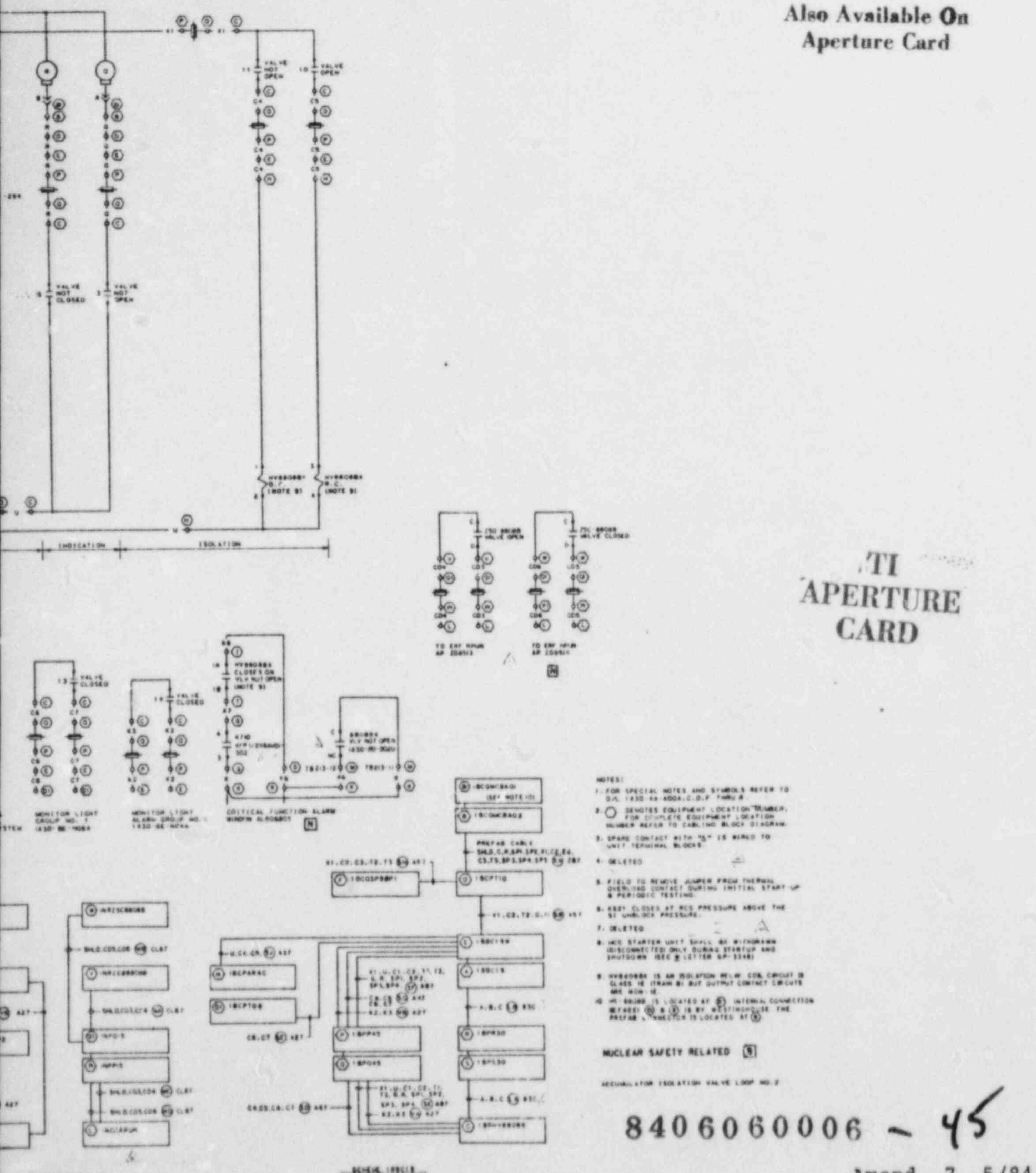
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8806A

FIGURE 430.73-9


480V MCC 1BBC
OPEN-CLOSE & ALARM
42-O SPARES
42-C SPARES
74 SPARES
JUMPER (SEE NOTE 5)
VALVE NOT OPEN
VALVE CLOSED
VALVE OPEN
TSO OPEN
TSC CLOSED
CS-R OPEN
CS-R AUTO
CS-R CLOSE
INTLK CRITICAL FUNCTION ALARM CKT
STEM MOUNTED LIMIT SWITCH DEVELOPMENT
VALVE POSITION
OPEN
CLOSED
SOLID LINE DENOTES CONTACT CLOSED
NAMCO LIMIT SWITCH TYPE EA 180
LIMITORQUE
MOV LIMIT SW DEVELOPMENT
TSC CLG TORQUE SW
TSO OPG TORQUE SW
CONTACTS
CLOSE
AUTO
OPEN
DECK
SPRING RETURN FROM OPEN TO AUTO ONLY

Also Available On Aperture Card



TI APERTURE CARD

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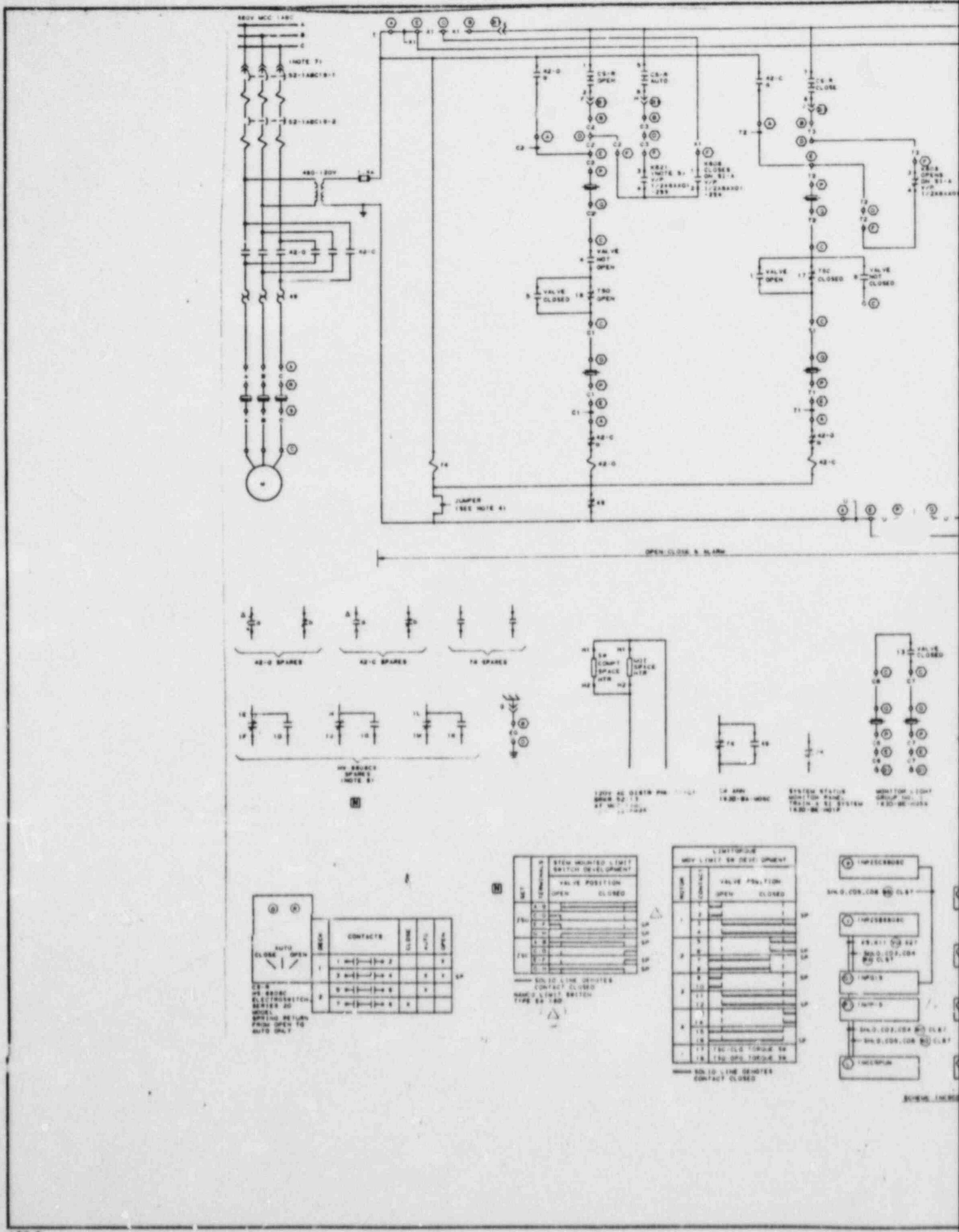
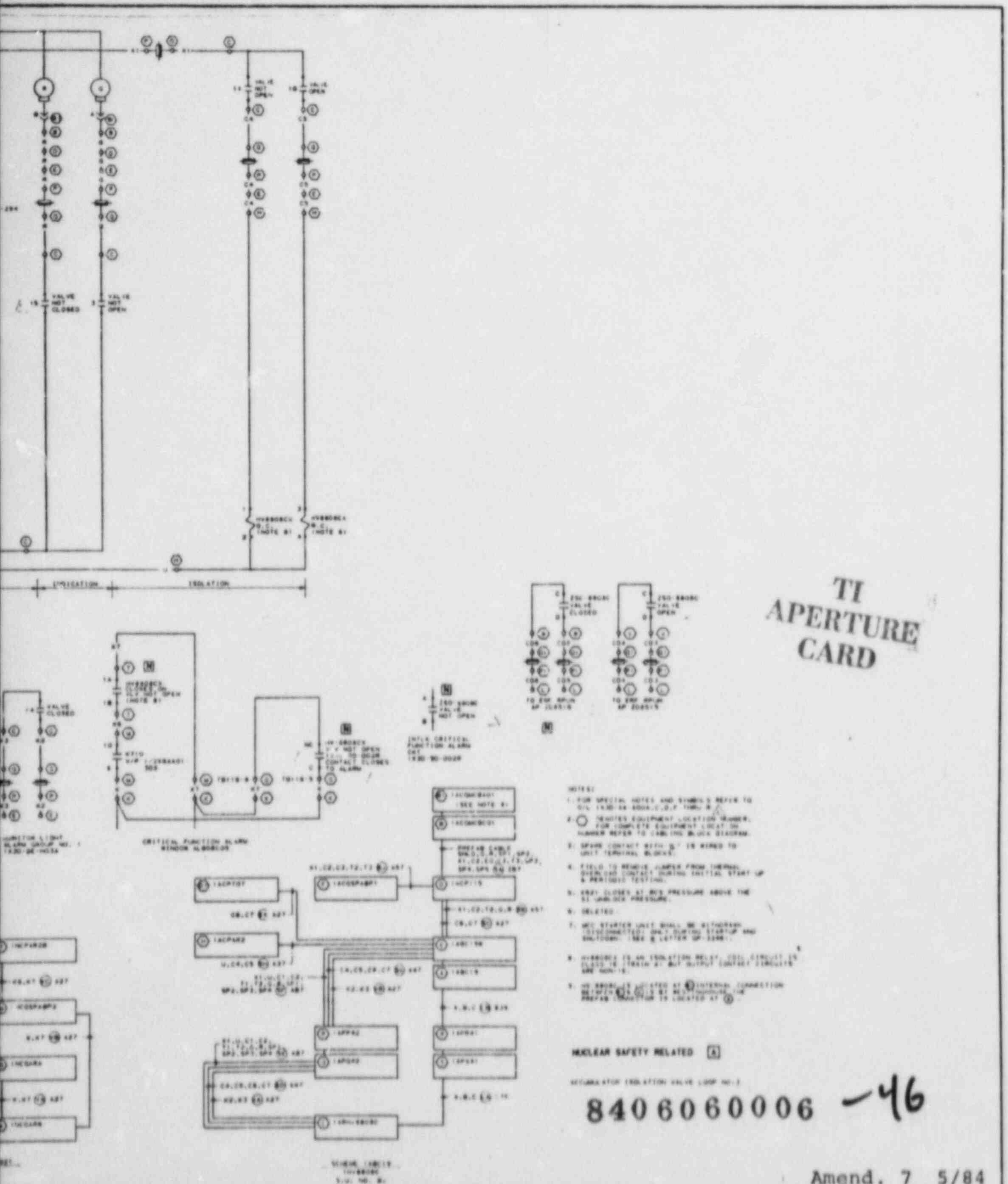
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8808B

FIGURE 430.73-10





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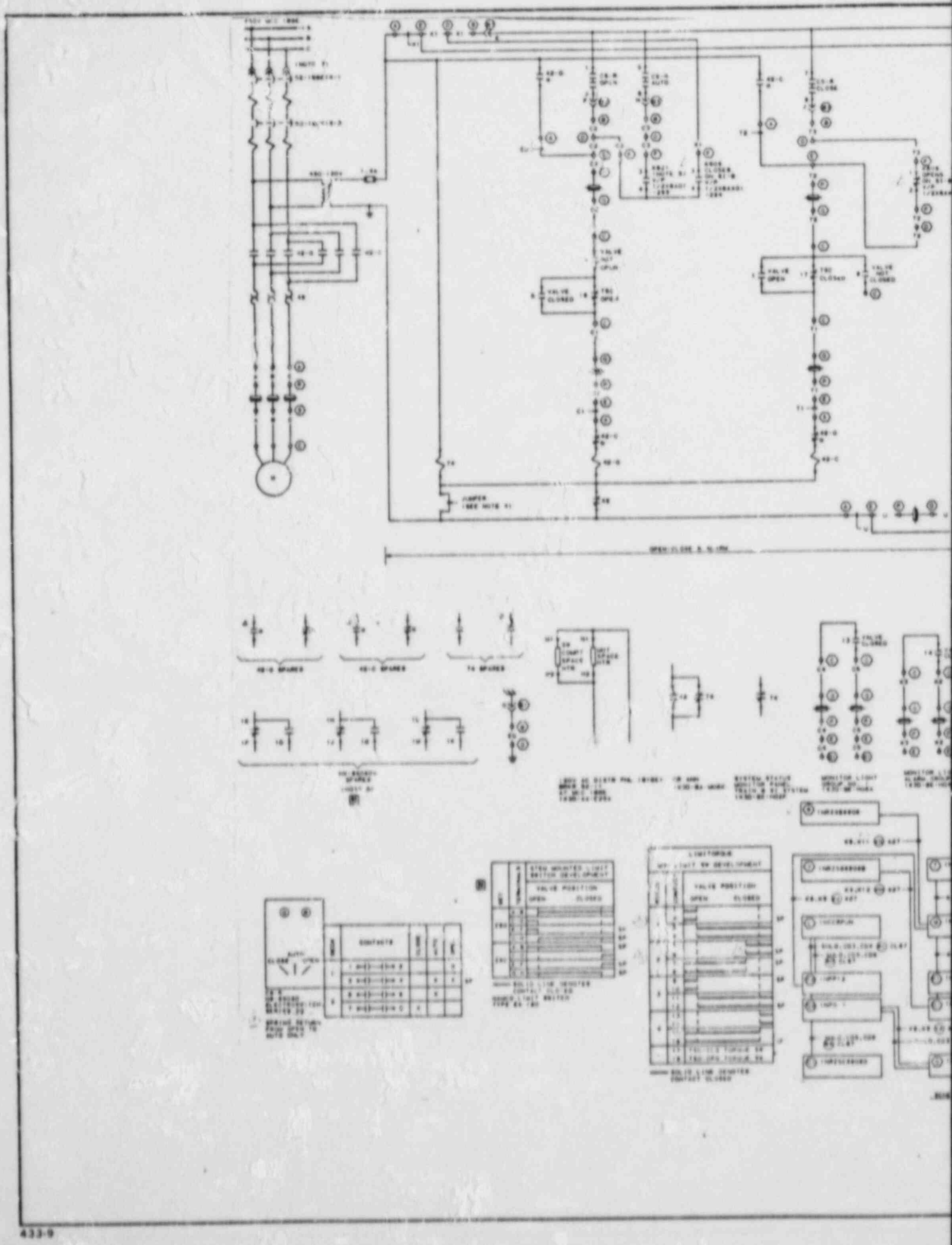
Georgia Power

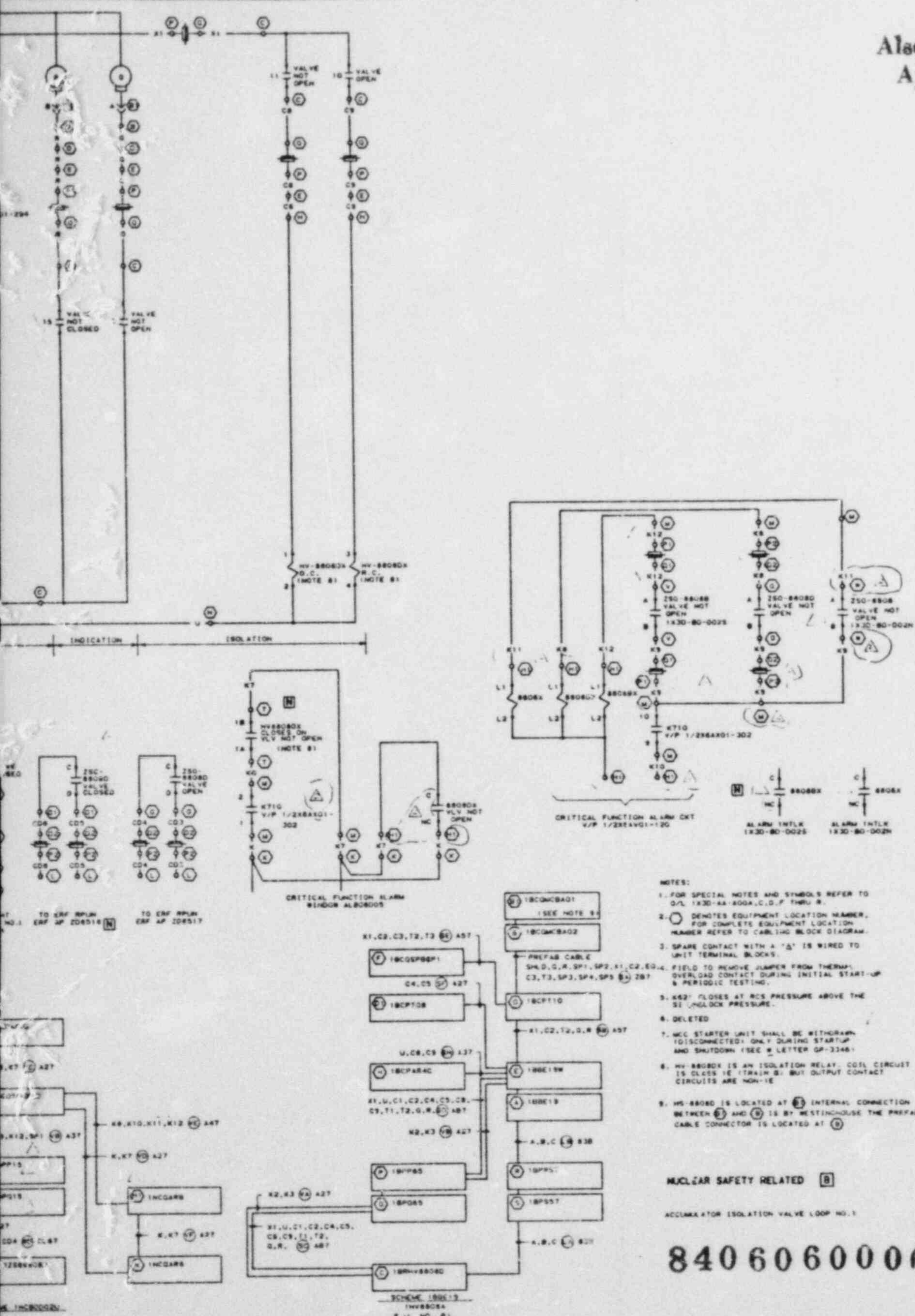
VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8808C

FIGURE 430.73-11



Also Available On
Aperture Card



TI
APERTURE
CARD

NOTES:

1. FOR SPECIAL NOTES AND SYMBOLS REFER TO D/L 1X3D-AA-A00A,C,D,F THRU R.
2. ◯ DENOTES EQUIPMENT LOCATION NUMBER. FOR COMPLETE EQUIPMENT LOCATION NUMBER REFER TO CABLING BLOCK DIAGRAM.
3. SPARE CONTACT WITH A "Δ" IS WIRED TO UNIT TERMINAL BLOCKS.
4. FIELD TO REMOVE JUMPER FROM THERMAL OVERLOAD CONTACT DURING INITIAL START-UP & PERIODIC TESTING.
5. K621 CLOSES AT RCS PRESSURE ABOVE THE SI UNBLOCK PRESSURE.
6. DELETED
7. MCC STARTER UNIT SHALL BE WITHDRAWN (DISCONNECTED) ONLY DURING STARTUP AND SHUTDOWN (SEE W LETTER GP-3346)
8. HV-8808DX IS AN ISOLATION RELAY. COIL CIRCUIT IS CLASS 1E (TRAIN B) BUT OUTPUT CONTACT CIRCUITS ARE NON-1E
9. HS-8808D IS LOCATED AT B1 INTERNAL CONNECTION BETWEEN B1 AND B IS BY WESTINGHOUSE THE PREFAB CABLE CONNECTOR IS LOCATED AT B

NUCLEAR SAFETY RELATED [B]

ACCUMULATOR ISOLATION VALVE LOOP NO.1

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Georgia Power

VOGTLE
ELECTRIC GENERATING PLANT
UNIT 1 AND UNIT 2

ELEMENTARY DIAGRAM
SAFETY INJECTION SYSTEM
1HV-8808D

FIGURE 430.73-12

Question 430.74

Regarding the containment building electrical penetrations:

A. In FSAR paragraph 1.9.63.2 you state that the fault current in low energy level control circuits and instrument circuits is limited and does not need backup overload protection. The fault currents in question should be limited to a value which is less than the continuous rating of the penetration (to maintain mechanical integrity). If the currents are limited by transformer impedances, the transformers should be capable of carrying that value of the fault current indefinitely. Verify that the above is the case.

B. Provide a single-line diagram of the penetration protection circuits associated with the protection curves given in sheets 1, 2, and 3 of figure 8.3.1-7. Show the primary and backup penetration overcurrent protection devices in these diagrams.

C. The I^2t curves shown in figure 8.3.1-7 are identified as penetration conductors. The curves used should be the actual thermal capability curves of the penetration itself (to maintain mechanical integrity). Verify that this is the case or else provide these curves. Also identify how the curves were derived.

D. The table given on sheet 1 of figure 8.3.1-7 lists a 10-amp circuit breaker, but the protection curves show a 15-amp circuit breaker. Clarify this discrepancy.

E. Sheet 5 of figure 8.3.1-7 shows fuses used as backup overcurrent protection for the load center motor feeders. Assuming a circuit breaker failure and a single line-to-ground fault, one fuse will open and clear the fault, leaving the motor operating in a single-phase condition. It is not clear from the curves shown on this figure that the remaining fuses will open before penetration integrity is lost. Address this concern. Also clarify what the maximum available fault current is for these circuits.

F. The single-line diagram on sheet 6 of figure 8.3.1-7 shows a No. 3/0 AWG penetration, but the thermal capability curve is labeled as No. 2/0 AWG. Clarify this discrepancy.

G. For sheet 8 of figure 8.3.1-7 clarify what the maximum available fault current is at the penetration.

H. The 25-amp magnetic-only circuit breaker shown on sheet 12 of figure 8.3.1-7 does not provide redundant protection over the entire range of the thermal capability curves for the No. 8 and No. 6 penetration conductors. Correct this deficiency. Also identify the maximum available fault currents at the penetrations for the circuits shown in this drawing.

Response

The following responses correspond to the above questions:

A. The analysis of the control and instrument level circuits which are connected to containment penetrations has determined the maximum fault current avalable at the penetration for each type of control circuit. Backup overload protection has been provided for each circuit that has a fault current of a magnitude which could damage the penetration. Where backup overload protection has not been provided due to circuit impedance characteristics, the resultant fault current can be carried by the penetration conductors indefinitely with no degrading effects on the penetration mechanical pressure boundary integrity.

Where fault currents are limited by circuit impedance, including transformer impedances, the transformer has not been demonstrated to be capable of carrying that magnitude of fault current indefinitely. However, the sequence of events and conditions that would be required to allow the fault current to increase to a damaging level should the transformer fail are not considered credible. Assuming the circuit protective fuse failed to clear the fault, the necessary events and conditions include the following:

1. As the fault current causes the transformer to fail by overheating, the primary winding would have to fail first by turn-to-turn shorts which could increase the volts per turn. As long as the secondary winding does not short in a similar manner or open up completely, the result could be an increasing fault current above the maximum calculated value based on transformer impedance.

2. That increasing fault current must be large enough and last long enough to damage the penetration.

3. That increasing fault current must stay small enough such that it does not open the upstream load breakers before it damages the penetration.

4. Transformer core saturation must have no limiting effect on the fault current.

5. Cables transmitting the fault current to the penetration must not fail.

B. Figure 8.3.1-7 has been revised. This revision provides the single-line diagrams showing primary and backup penetration protective devices and maximum fault currents. Various discrepancies which existed in this figure have also been eliminated.

C. The curves in figure 8.3.1-7 represent the actual thermal capability of the penetration itself to maintain pressure boundary mechanical integrity based on the heating characteristics of the identified conductor(s). The curves were generated by the penetration manufacturer on the basis that two or three conductors acting as a circuit were carrying the indicated current while all other conductors in the penetration feedthrough were carrying rated current concurrent with an ambient temperature within the penetration enclosure of 400°F (exceeds maximum temperature reached within the enclosure during an accident).

D. See item B above. The 15-amp circuit breaker is the correct value.

E. The load centers feeding motors inside containment which utilize fuses as backup protective devices operate as ungrounded 480-V ac distribution. This is shown by note 2 of figure 8.3.1-1. Therefore a single line-to-ground fault does not result in an overcurrent condition on the affected phase. This figure has been revised to more clearly demonstrate that the fuses protect the penetration conductor under any operating condition.

F. See item B above. A No. 2/0 AWG penetration conductor is the correct size.

G. See item B above.

H. The minimum postulated fault for this circuit is 306 amps. This value exceeds the area where the overlap exists (less than 190) as shown in figure 8.3.1-7, sheet 2; therefore, no correction is warranted. The maximum fault currents have been provided.

Question 430.74

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A. In FSAR paragraph 1.9.63.2 you state that the fault current in low energy level control circuits and instrument circuits is limited and does not need backup overload protection. The fault currents in question should be limited to a value which is less than the continuous rating of the penetration (to maintain mechanical integrity). If the currents are limited by transformer impedances, the transformers should be capable of carrying that value of the fault current indefinitely. Verify that the above is the case.

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   Where fault currents are limited by circuit impedance, including transformer impedances, the transformer has not been demonstrated to be capable of carrying that magnitude of fault current indefinitely. However, the sequence of events and conditions that would be required to allow the fault current to increase to a damaging level should the transformer fail are not considered credible. Assuming the circuit protective fuse failed to clear the fault, the necessary events and conditions include the following:

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   2. That increasing fault current must be large enough and last long enough to damage the penetration.

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