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MEMORANDUM FOR: Document Control Desk
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Division of Information Support Services
Office of Information Resources Management

FROM: Mark A. Cunningham, Chief
Probabilistic Risk Analysis Branch
Division of Safety Issue Resolution
Office of Nuclear Regulatory Research

SUBJECT: PLACEMENT OF RESEARCH REPORTS IN THE PUBLIC DOCUMENT ROOM

Enclosed is a copy of an unpublished, draft document which is used as a reference in a report (NUREG/CR-4832) being published by Sandia National Laboratories. This draft report would have been published as Volume 6 of NUREG/CR-4832, but has been dropped because the author is no longer available.

Please deposit this report in the Public Document Room. If you have any questions, please contact Harold VanderMolen at 492-3968.

Mark A. Cunningham

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Office of Nuclear Regulatory Research

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ROUTING AND TRANSMITTAL SLIP
(PLEASE ROUTE TO THE NEXT PERSON)

G. Burdick for dist. B 3/31/94	C. Ader SAIB CEAder 3/31/94	G. Mazetis 3/17/94 w/comment	Reviewer G. Burdick B 3/17/94
C. Serpan EIB	M. Cunningham PRAB		
R. Emrit	J. Murphy DSIR (Acting)	C. Ader SAIB	Reviewer G. Burdick

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SUBJECT: PRIORITIZATION OF GENERIC ISSUE 167

TITLE: Hydrogen Storage Facility Separation

PROGAM GUIDANCE:

The Commisson in RES Office Letter Number 1 stated that a priority list based on the potential signifigance of each [generic] issue will be established. In keeping with the Commission's goal, an evaluation of the safety priority of the subject issue is attached for purposes of obtaining reviews and comments, or concurrences. The RES Division that may be involved in the resolution is identified. Comments or concurrences by these RES Branches and Division Director should be returned to ____/RES within **FIFTEEN WORKING DAYS**. Issues requiring concurrence by NRR should be returned to ____/RES within **FIFTEEN WORKING DAYS**.

Comments on the technical accuracy and completeness of the issue evaluation may be noted on the attached copy. Generally, comments will be either incorporated into the evaluation or resolved with the commentator. If designated as a HIGH priority, the issue should be reviewed by DSIR to determine whether it should be a USI. Initialing this slip does not indicate unconditional approval, but instead indicates approval subject to all comments provided in this copy.

cc: ~~[illegible]~~ ~~[illegible]~~ ~~[illegible]~~ J. Jordan (AEOD)
I. Shao (DE) F. Gillespie (NRR/PMAS) [illegible] (RES/DRA)
~~[illegible]~~ ~~[illegible]~~

9/4/91 RCE

ENCLOSURE 1

PRIORITIZATION EVALUATION

Issue 167: Hydrogen Storage Facility Separation

ISSUE 167: HYDROGEN STORAGE FACILITY SEPARATION

DESCRIPTION

The safety question of concern with Generic Issue 167 is whether or not there is adequate physical separation between hydrogen storage facilities and buildings or structures housing systems important to safety at nuclear power generating stations.

Historical Background

In 1988, the U.S. Nuclear Regulatory Commission (NRC) completed the prioritization analysis of Generic Issue 106, "Piping and the Use of Highly Combustible Gases in Vital Areas". The issue was resolved in 1993 as described in Generic Letter 93-06, published October 25 of that year. In December 1993, the Office of Nuclear Reactor Research (RES) identified[1532] a new generic issue based on exclusions from Issue 106:

> The resolution of this issue [106] included evaluation of the risk from: (1) the storage and distribution of hydrogen for the volume control tank in PWRs and the main electric generator in BWRs and PWRs; (2) other sources of hydrogen such as battery rooms, the waste gas system in PWRs and the offgas system in BWRs; and (3) small, portable bottles of combustible gases used in maintenance, testing, and calibration. However, ... the potential risk from large hydrogen storage facilities outside the reactor, auxiliary, and turbine buildings was not addressed.

Studies during and subsequent to that for Issue 106 raised concern as to the magnitude of the previously excluded risk[1535,1534]. The issue was formally opened by Reference 1532.

Safety Significance

As reported in by Ballif et al. in SCIE-EGG-103-89[1535], <u>Draft Technical Evaluation Report on U.S. Commercial Power Reactor Hydrogen Tank Farms and Their Compliance with Separation Distance Safety Criteria</u>,

> ... [A]t the Trojan Nuclear Plant, April 17, 1989, [NRC] inspectors identified a potential safety problem concerning the storage of 32,000 standard cubic feet (scf) of hydrogen gas on the control room roof. The 32,000 scf was made up of four 8,000-scf tanks. This discovery raised concerns about possible similar hazards in the storage of hydrogen at other nuclear facilities. NRC issued Information Notice 89-44, "Hydrogen Storage on the Roof of the Control Room," on May 2, 1989. Each NRC regional office was to determine whether the nuclear plants in its region had similar safety-related concerns.

Ballif et al. reviewed the information compiled by the five NRC regional offices and issued preliminary report SCIE-EGG-103-89[1535]. The storage of gaseous or liquid hydrogen at 119 power plants was then investigated. Possible accident scenarios resulting from a fireball, explosion, or presence of unburned hydrogen gas in ventilation air intakes were examined. Explosion was identified as the scenario posing the greatest risk potential. As per Ballif et al., this analysis focuses on explosion, with all quantification performed relative to this accident only.

Ballif et al[1535]. assessed the status of the 119 power plants with respect to hydrogen tank farm separation guidelines as per the Electric Power Research Institute (EPRI) Report NP-5283-SR-A, Guidelines for Permanent BWR Hydrogen Water Chemistry Installations. Sixteen percent were found not to meet the separation guidance with respect to explosion hazard. For the current population of power plants (110), this translates into 18 LWRs not meeting the EPRI guidance.[1]

Ballif et al[1535]. reviewed nuclear power industry experience, data published by the hydrogen industry and related industries (such as liquified natural gas), and surveyed the hydrogen supply industry to estimate the frequency of a hydrogen tank explosion. They deemed the data from the nuclear power industry to be most suitable, and estimated a frequency of 0.001/tank farm-year for a hydrogen tank farm explosion. This admittedly conservative value[2] was reasonably comparable to published values of failure incidents from the liquified natural gas industry (0.0024/facility-year), which they expected to exhibit a higher rate than nuclear plant installations.

Possible Solutions

Possible solutions include relocation, or placement in pits, of storage facilities, buildings, equipment, and the construction of blast shields, or a combination of these. A resolution for this issue is assumed to be the construction of concrete enclosing walls around the hydrogen storage facility. This structure would serve as a blast shield in the event of an explosion, essentially eliminating the risk.

RISK ANALYSIS

Of the types of accidents analyzed in risk assessments, hydrogen tank farm explosions would seem most similar to those classified as "external events." Furthermore, since such explosions would cause large pressure forces, or possibly missiles, to be exerted upon building walls, they would appear most similar to tornadoes among the types of external events. However, unlike what is assumed for tornadoes, hydrogen tank farm explosions would not exert

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1 Note that the permanently shutdown Trojan PWR is no longer included among this population. Thus, the subsequent analysis does not address hydrogen storage tanks located atop the control room roof.

2 Limited response from the survey of the hydrogen supply industry yielded a rough estimate of 1E-5/tank-year for a "generic hydrogen tank" rupture.

pressure on all site buildings at one time. Thus, the consequences from hydrogen tank farm explosions are not expected to exceed those from tornadoes, although the risk could be greater due to higher incident frequencies (typical tornado frequencies are on the order of 1E-5/reactor-year [ry]).

A review of recently available risk assessments yielded the Individual Plant Examination (IPE) for Oconee 3[1533] as most amenable for the risk analysis in this prioritization analysis. A fairly detailed assessment of the tornado risk was performed, building on that from the earlier Oconee-3 risk assessment in 1984[889]. An overview of the tornado risk assessment from the Oconee-3 IPE is provided in the next section. An added advantage to the selection of Oconee 3 is that Ballif et al.[1535] provided a description of the Oconee plant 48,000-scf hydrogen tank farm, which they deemed as representative.

The tornado accident sequences from the Oconee-3 IPE[889] are discussed, then redefined, in the next sections to estimate the baseline risk from hydrogen tank farm explosions. The results yield a baseline core damage frequency of 6.25E-5/ry and a baseline risk of 2.94 person-rem/ry. Table 1 completes the calculations. Occupational dose calculations are summarized in Table 2.

OVERVIEW OF THE TORNADO RISK ASSESSMENT FROM THE OCONEE-3 IPE

Duke Power[1533] considered two categories of tornado events: (1) tornadoes whose winds impact on Oconee 3 and (2) tornados passing within 2,000 ft of Oconee 3, for the purpose of analyzing tornado-generated missiles. The latter category was subsequently dismissed when analysis showed the probability of core-melt due to tornado-generated missiles to be 100-1,000 times lower than that due to tornado wind loadings. Only the first category is addressed here.

Duke Power[1533] assumed that a tornado would render unavailable all offsite AC power sources, except for one underground path. Tornadoes of intensity F-1 or less (i.e., with wind speeds < 113 mph) were assumed not to cause sufficient wind damage to generate core-melt with a frequency similar to higher F-scale tornadoes (F-2 and above). Oconee 3 had been designed to withstand wind loadings of F-1 tornadoes.

The Turbine Building was assumed susceptible to wall damage from F-2 and stronger tornadoes. Wall damage could fail the 4160-volt (4KV) AC switchgear that powers safety equipment and/or the Upper Surge Tank (UST), the prime suction source for the emergency feedwater pumps. The Auxiliary Building was assumed susceptible to wall damage from F-4 and stronger tornadoes (wind speeds > 206 mph), particularly the exterior walls of the West and East Penetration Rooms (WPR and EPR). Damage to the WPR wall could fail piping and electrical penetrations, including those from the Standby Shutdown Facility (SSF). This could lead to Reactor Coolant Pump (RCP) seal LOCAs, loss of the SSF backup for RCP seal cooling, and loss of feedwater from the SSF. Damage to the EPR wall would cause similar failures, although the likelihood of piping failures there was judged to be about ten times less due to tornado shielding by the Reactor Building.[3]

Tornadoes falling within categories F-2 through F-5, resulted in accident sequences leading to various Plant Damage States (PDSs). The total core-damage frequency, the sum of the accident sequence frequencies is 9.74E-6/ry. However, after eliminationg the PDSs not resulting in offsite releases, the frequency was calculated to be 8.20E-6/ry

There were[1533] 17 possible release categories (RCs) associated with the PDSs. To each of the RCs was assigned a conditional probability of release. When multiplied by the the sequence frequency, each of these yielded the sequence frequency per RC (1/ry). Associated with each RC is a whole-body person-rem equivalent dose. The product of each RC frequency and its associated dose yields the individual RC risks which sum to the total RC risk, 9.11 person-rem/ry, which, together with the total RC frequency of 8.20E-6/ry, comprise the tornado results, which are next modified for hydrogen explosions.

RISK ANALYSIS FOR HYDROGEN STORAGE TANK EXPLOSIONS

The best available data from Ballif et al.[1535] indicated a frequency of 0.001/tank farm-year for a hydrogen storage tank explosion. They further stated:

> Some reactors may have multiple tank farms, and in other cases multiple reactors may share a single tank farm. It is assumed these cases have a general cancelling effect and there is an average of one tank farm per reactor. This assumption is believed to be reasonable ...

Therefore, the frequency of a hydrogen storage tank explosion is assumed to be:

(0.001/tank farm-year)(1 tank farm/reactor) = 0.001/ry.

To translate this into an initiator frequency analogous to that of a tornado, it is necessary to associate the blast force from an explosion to the severity of a tornado. This information is not readily available, although Ballif et al.[1535] reported that EPRI assumed the blast pressure to range from ~1.5 to ~4.5 psi, depending on the material and its equivalent mass of TNT explosive. This analysis assumes that the blast force is most likely to correspond to that from an F-2 tornado, in the nomenclature of the Oconee IPE[1533]. An initiator frequency of 0.001/ry is assigned to T(F2)[1533] to reflect this, decreasing the frequency by a factor of 10 for each increasing category of tornado severity (assumed to correspond to increasing blast forces), i.e., 1E-4/ry for T(F3)[1533], 1E-5/ry for T(F4)[1533], and 1E-6/ry for T(F5)[1533].

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[3] Other exterior components, such as the Borated Water Storage Tank, are also susceptible to failure from tornadoes. However, they did not appear in the listed cut sets for core damage, so have not been discussed here.

Unlike tornadoes, hydrogen tank farm explosions would not exert pressure on all site buildings at one time. Thus, multiple building wall failures are not expected as in the tornado accident sequences. To reflect this limitation, the cut sets of the tornado accident sequences have been reviewed and found nearly all to contain conditional failure of the Turbine Building wall. Associated with this are failures of the UST and/or 4KV-AC switchgear. Failures of the walls of the WPR and/or EPR are contained in less of the cut sets of the tornado accident sequences.

A hydrogen tank farm explosion is assumed to fail only the Turbine Building wall, resulting in failures of the UST and/or 4KV-AC switchgear. No failure of the WPR or EPR walls is assumed. This eliminates most of the T(F4) and T(F5) sequences. However, the higher initiator frequencies for T(F2) and T(F3) result in a total core-damage frequency from hydrogen tank explosion of 6.25E-5/ry, ~64% higher than Duke Power's assessment for tornadoes.

Using the same RC conditional probabilities and equivalent doses as for tornadoes, a total RC frequency of 6.20E-5/ry (again, less than the total core-damage frequency since not all accident sequences lead to offsite release) and a total RC risk of 2.94 person-rem/ry are obtained. Despite the higher core-damage and RC frequencies, the risk is less than that for tornadoes since the RCs associated with the PDSs of the T(F2) and T(F3) sequences are less consequential than those associated with T(F4) and T(F5).

TABLE 1. Public Risk Reduction

1. **Title and Identification Number of Safety Issue:**

   Hydrogen Storage Facility Separation (167)

2. **Affected Plants (N) and Average Remaining Lives (T):**

   As per Ballif et al.[1535], 16% of currently operating plants are assumed to not comply with EPRI standards for separation from explosion effects. Thus, (0.16)(110 LWRs) ≈ 18 LWRs with average remaining lives of ~23 yr are assumed affected.

3. **Selected Analysis Plant:**

   Oconee 3 (representative LWR)

4. **Base-Case Parameters, Values, Frequencies, and Public Risk:**

   The base-case core-damage frequency and public risk have been calculated to be:

Core-Damage Frequency	=	6.25E-5/ry
Public Risk	=	2.94 person-rem/ry

5. **Adjusted-Case Parameters, Values, Frequencies, and Public Risk:**

   Resolution is assumed to essentially eliminate the risk. Thus, all adjusted-case values are zero.

6. **Core-Damage Frequency Reduction (ΔF):**

   Base-case - Adjusted-case = 6.25E-5/ry - 0 = 6.25E-5/ry

7. **Per-Plant Public Risk Reduction (ΔW):**

   Base-case - Adjusted-case = 2.94 person-rem/ry - 0 = 2.94 person-rem/ry

8. **Total Public Risk Reduction [$(\Delta W)_{Total}$]:**

Best Estimate	=	(2.94 person-rem/ry)(18 reactors)(23 yr)
	=	1.22E+3 person-rem
Lower Bound	=	0
Upper Bound	=	3.65E+4 person-rem[4]

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[4]Standard calculation from NUREG/CR-2800, Appendix F.

TABLE 2. Occupational Dose

1. **Title and Identification Number of Safety Issue:**

   Hydrogen Storage Facility Separation (167)

2. **Affected Plants (N):**

   18 LWRs

3. **Average Remaining Lives of Affected Plants (T):**

   ~23 yr

4. **Per-Plant Occupational Dose Reduction Due to Accident Avoidance [$\Delta(FD_R)$]:**

   (1.99E+4 person-rem)[5](6.25E-5/ry) = 1.24 person-rem/ry

5. **Total Occupational Dose Reduction Due to Accident Avoidance (ΔU):**

Best Estimate	=	(1.24 person-rem/ry)(18 reactors)(23 yr)
	=	5.15E+2 person-rem
Lower Bound	=	0
Upper Bound	=	3.09E+3 person-rem[6]

6. **Utility Radiation Zone Labor and Occupational Dose Increase:**

   Since the enclosing structure would be constructed outside any radiation zone, no utility radiation zone labor or occupational dose increase is foreseen.

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[5]Standard value from Reference 64, Table D-2.

[6]Standard calculation, NUREG/CR-2800, Appendix F.

COST ANALYSIS

Ballif et al.[1535] reported that the 48,000-scf Oconee tank farm consists of six tanks with a footprint of 45 ft by 30 ft. It is surrounded by an exclusion fence and is always lighted. The concrete enclosure is assumed to have rectangular dimensions comparable to this footprint. From the manual 1993 Means Building Construction Cost Data, 51st Annual Edition, R. S. Means Co., Inc., Kingston, MA, 1993, the costs were obtained for thick, smooth gray architectural precast concrete 10-ft high and 6-in thick. For a 20-ft length, the cost was $\$14.95/ft^2$ (area); for a 30-ft length, the cost was $\$14.60/ft^2$. To form an enclosure at least 45 ft by 30 ft, one 20-ft and one 30-ft length would be needed for each long side and one 30-ft length for each short side. Ten feet should be sufficiently high to protect the surroundings from horizontal blast effects. However, a thickness comparable to that of site building walls (~18 in) would be desired. Thus, the total number of precast concrete wall panels becomes:

30-ft panels = (4 per perimeter)(3 at 6-in thickness each) = 12
20-ftpanels = (2 per perimeter)(3 at 6-in thickness each) = 6
Total = 18.

In footprint, the enclosure would be 50 ft by 30 ft, yielding a total wall panel area of:

$(2)(50\ ft + 30\ ft)(10\ ft)(3\ panels) = 4.80E+3\ ft^2$.

At ~$\$15/ft^2$, the cost of this enclosure becomes:

$(\$15/ft^2)(4.80E+3\ ft^2) = \$7.20E+4$.

In the previously cited manual, R.S. Means states that, "[if] the work is to be subcontracted, add the general contractor's markup, approximately 10%." In addition, the enclosure will have to be anchored in place and penetrated for piping and access. Combined with the general contractor's markup, these factors are assumed to increase the cost of the enclosure by ~50%, bringing the total cost to:

$(1.5)(\$7.20E+4) = \$1.08E+5$.

Any industry operation and maintenance activities associated with this resolution are assumed to be performed as part of activities already in place, such as standard inspection and reporting procedures. No industry labor or cost is foreseen for operation and maintenance. Table 3 summarizes the cost analysis, including that for NRC costs.

TABLE 3. Cost

1. **Title and Identification Number of Safety Issue:**

   Hydrogen Storage Facility Separation (167)

2. **Affected Plants (N):**

   18 LWRs

3. **Average Remaining Lives of Affected Plants (T):**

   ~23 yr

<u>Industry Costs (Steps 4 Through 12)</u>

4. **Per-Plant Industry Cost Savings Due to Accident Avoidance [Δ(FA)]:**

   (\$1.65E+9)[7](6.25E-5/ry) = \$1.03E+5/ry

5. **Total Industry Cost Savings Due to Accident Avoidance (ΔH):**

Best Estimate	=	(\$1.03E+5/ry)(18 reactors)(23 yr) = \$4.27E+7
Lower Bound	=	0
Upper Bound	=	\$2.56E+8

6. **Per-Plant Industry Resources and Cost (I) to Implement Resolution:**

   18 wall panels, twelve 30 ft x 10 ft x 6 in and six 20 ft x 10 ft x 6 in, covering a footprint 50 ft x 30 ft

   Wall Area (18-in thick) =

   (2)(50 ft + 30 ft)(10 ft)(3 panels) = 4.80E+3 ft^2

   Per-plant cost at \$15/ft^2 with 50% markup =

   (\$15/ft^2)(1.5)(4.80E+3 ft^2) = \$1.08E+5

7. **Total Industry Cost to Implement Resolution (NI):**

   (\$1.08E+5/LWR)(18 LWRs) = \$1.94E+6

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[7]Standard value from Reference 64, Appendix E-2.

TABLE 3. Cost (Cont'd)

8. **Industry Labor and Cost to Operate and Maintain Resolution:**

9. **Total Industry Cost (S_I):**

Best Estimate	=	\$1.94E+6
Lower Bound	=	\$0.97E+6[8]
Upper Bound	=	\$2.92E+6[9]

<u>NRC Costs (Steps 13 Through 21)</u>

10. **NRC Resources and Total Cost to Develop Resolution (C_D):**

    A level of effort analogous to that required to produce the technical reports by Ballif et al.[1535] and EG&G Idaho, Inc.[1534] is assumed necessary, with a total cost = \$1.0E+5.

11. **Per-Plant NRC Labor and Cost (C) to Support Implementation of Resolution:**

    Reference 961 listed the cost for a "typical uncomplicated technical specification change" to be \$1.1E+4 (1988 dollars). Assuming this applies to NRC support to assure utility compliance with the resolution, the following per-plant cost is estimated (with ~4%/yr inflation since 1988):

    $$(\$1.1E{+}4)(1.04)^5 = \$1.34E{+}4$$

12. **Total NRC Cost to Support Implementation of Resolution (NC):**

    (\$1.34E+4/LWR)(18 LWRs) = \$2.41E+5

13. **NRC Labor and Cost to Review Operation and Maintenance of Resolution:**

    Any industry operation and maintenance activities associated with this resolution are assumed to be performed as part of activities already in place, such as standard inspection and reporting procedures. No industry labor or cost is foreseen for operation and maintenance. Thus, no NRC labor or cost is foreseen for review.

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[8] Standard calculation from NUREG/CR-2800, Appendix F.

[9] Ibid.

Table 3. Cost (Cont'd)

13. **Total NRC Cost (S_N):**

Best Estimate=\$3.41E+5
Lower Bound =\$2.10E+5
Upper Bound=\$4.71E+5

Value/Impact Assessment

Using appropriate items from Tables 1, 2, and 3, the following differential values are obtained for entry into the Priority Ranking matrix of NUREG-0933, Revision 4, June 30, 1993:

Core-Melt/RY:	6.25E-5/RY
Core-Melt/Yr.:	1.13E-3/Yr.
Person-Rem/Reactor:	96.6 P-R/R
Person-Rem (Total, All Reactors:	1.74E+3 P-R
Person-Rem/\$M:	1.75E+3/1.94 (P-R/\$M)
	= 9.0E+2

Note that the dollars per person-rem averted is less that 1000. In fact, that quantity, when calculated, is negative because the cost savings due to accident avoidance exceeds the cost to implement the resolution.

Other Considerations

One important consideration must be noted. The number of plants affected was determined by those not conforming to the EPRI separation criteria, which are based on a hydrogen to TNT detonation equivalency. Had more stringent criteria been used, the number of plants affected would have been correspondingly larger. Reference 1534 concludes "...that the hydrogen to TNT detonation equivalency used in previous calculations should no longer be used." The reason given for this is that "...the separation distances results from previous calculations [including those of the EPRI criteria] can be either overconservative or unconservative depending upon the the set of hydrogen detonation parameters that are used."

Conclusion

Based upon the Value/Impact Assessment results, Generic Issue 167 is assigned a priority ranking of HIGH.

REFERENCES

1535. Ballif, J., et al., Draft Technical Evaluation Report on U.S. Commercial Power Reactor Hydrogen Tank Farms and Their Compliance with Separation Distance Safety Criteria, SCIE-EGG-103-89, SCIENTECH, Inc., Idaho Falls, Idaho, March, 1990.

1534. Technical Report: Improved Estimates of Separation Distances to Prevent Unacceptable Damage to Nuclear Power Plant Structures from Hydrogen Detonation for Gaseous Hydrogen Storage, EGG-SSRE-8747, EG&G Idaho, Inc., Idaho Falls, Idaho, November, 1993.

1532. Memorandum for C. Serpan from W. Minners, "Identification of New Generic Issue: Hydrogen Storage Facility Separation." December 16, 1993.

1533. Letter to the NRC from M. Tuckman (Duke Power Co.) Oconee Nuclear Station Unit 3 Probabilistic Risk Assessment. Charlotte, South Carolina, November 30, 1990.

889. NSAC-60, A Probabilistic Risk Assessment of Oconee Unit 3, Electric Power Research Institute (EPRI), Palo Alto, California, June 1984.

961. NUREG/CR-4627, Generic Cost Estimates, U.S. Nuclear Regulatory Commission, June 1986.

64. NUREG/CR-2800, Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development, U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

REFERENCES

1535. Ballif, J., et al., Draft Technical Evaluation Report on U.S. Commercial Power Reactor Hydrogen Tank Farms and Their Compliance with Separation Distance Safety Criteria, SCIE-EGG-103-89, SCIENTECH, Inc., Idaho Falls, Idaho, March, 1990.

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961. NUREG/CR-4627, Generic Cost Estimates, U.S. Nuclear Regulatory Commission, June 1986.

64. NUREG/CR-2800, Guidelines for Nuclear Power Plant Safety Issue Prioritization Information Development, U.S. Nuclear Regulatory Commission, February 1983, (Supplement 1) May 1983, (Supplement 2) December 1983, (Supplement 3) September 1985, (Supplement 4) July 1986.

NUREG/CR-4832/6 of 10
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ANALYSIS OF THE LASALLE UNIT 2 NUCLEAR POWER PLANT: RISK METHODS INTEGRATION AND EVALUATION PROGRAM (RMIEP)

Volume 6: System Descriptions and Fault Tree Definition

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ABSTRACT

This volume presents the results of the systems analysis task for the LaSalle Unit II nuclear power plant Level I PRA performed as part of the level III PRA being performed by Sandia National Laboratories for the Nuclear Regulatory Commission.

The systems analysis task included a through review of utility and A&E information on the design, construction, layout, and operation of all systems that could be used to mitigate the accident sequences, defined in volume 4 of this report on accident sequence delineation, and their support systems in order to construct fault trees for probabilistic evaluation of the accident sequence frequencies.

Because one of the major purposes of the LaSalle PRA was to integrate the external event analysis with the internal events analysis, additional components and information needed to be included directly in the fault trees or in associated data files. The system fault trees were expanded to directly include: 1) piping, 2) passive failures, 3) multiple spurious actuations, and 4) multiple diversion paths. The fault trees were expanded indirectly through the use of transformation equations on the basic events to include location information for all components, piping, and cabling. The results of these analyses for seismic, fire, and flood are presented in volumes 8, 9, and 10 of this report, respectively and include appendices with all of the associated location information listed.

Since the LaSalle analysis only used three accident sequence event trees, one each for loss of coolant, transient, and anticipated transient without scram accident classes, the effects of the specific initiators in each class on the systems and the different success criteria were handled by including the initiating events directly in the system fault trees. In this way, if an initiator failed or partially failed a system, then its specific effect on the system would be propagated up through the fault trees during the sequence evaluation and the final sequence cut sets would appear with that initiator as a basic event specifically failing the appropriate portion the system.

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FOREWORD

LaSalle Unit 2 Level III Probabilistic Risk Assessment

In recent years, applications of Probabilistic Risk Assessment (PRA) to nuclear power plants have experienced increasing acceptance and use, particularly in addressing regulatory issues. Although progress on the PRA front has been impressive, the usage of PRA methods and insights to address increasingly broader regulatory issues has resulted in the need for continued improvement in PRA methods to support the needs of the Nuclear Regulatory Commission (NRC).

Before the new methods can be considered suitable for routine use in the regulatory arena, they need to be integrated into the overall framework of a PRA, appropriate interfaces defined, and the utility of the methods evaluated. The LaSalle Unit 2, Level III PRA described in this and associated reports provides the framework for this integration and evaluation. It helps lay the bases for both the routine use of the methods and the preparation of procedures that will provide guidance for future PRAs used in addressing regulatory issues. These new methods, once integrated into the framework of a PRA and evaluated, lead to a more complete PRA analysis, a better understanding of the uncertainties in PRA results, and broader insights into the importance of plant design and operational characteristics to public risk.

In order to satisfy the needs described above, the LaSalle Unit 2, Level III PRA addresses the following broad objectives:

1) To develop and apply methods to integrate internal, external, and dependent failure risk methods to achieve greater efficiency, consistency, and completeness in the conduct of risk assessments;

2) To evaluate PRA technology developments and formulate improved PRA procedures;

3) To identify, evaluate, and effectively display the uncertainties in PRA risk predictions that stem from limitations in plant modeling, PRA methods, data, or physical processes that occur during the evolution of a severe accident;

4) To conduct a PRA on a BWR 5, Mark II nuclear power plant, ascertain the plants' dominant accident sequences, evaluate the core and containment response to accidents, calculate the consequences of the accidents, and assess overall risk; and finally

5) To formulate the results in such a manner as to allow the PRA to be easily updated and to allow testing of future improvements in methodology, data, and the treatment of phenomena.

The LaSalle Unit 2 PRA was performed for the NRC by Sandia National Laboratories (SNL) with substantial help from CECo and its contractors. Because of the size and scope of the PRA, various related programs were set up to conduct different aspects of the analysis. Additionally, existing programs had tasks added to perform some analyses for the LaSalle PRA. The responsibility for overall direction of the PRA was assigned to the Risk Methods Integration and Evaluation Program (RMIEP). RMIEP was specifically responsible for all aspects of the Level I analysis (i.e., the core damage analysis). The Phenomenology and Risk Uncertainty Evaluation Program (PRUEP) was responsible for the Level II/III analysis (i.e., the source term and consequence analysis). Other programs provided support in various areas or performed some of the subanalysis. These programs include the Seismic Safety Margins Research Program (SSMRP) at Lawrence Livermore National Laboratory (LLNL), which performed the seismic analysis; the Integrated Dependent Failure Analysis Program (IDFAP), which developed methods and analyzed data for dependent failure modeling; the MELCOR Program, which modified the MELCOR code in response to the PRA's modeling needs; the Fire Research Program, which performed the fire analysis; the PRA Methods Development Program (PRAMDP), which developed some of the new methods used in the PRA; and the Data Programs, which provided new and updated data for BWR plants similar to LaSalle. Commonwealth Edison (CECo) provided plant design and operational information and reviewed the analysis results.

The LaSalle PRA was begun before the NUREG-1150 analysis and the LaSalle program has supplied the NUREG-1150 program with simplified location analysis methods for integrated analysis of external events, insights on possible subtle interactions that come from the very detailed system models used in the LaSalle PRA, core vulnerable sequence resolution methods, methods for handling and propagating statistical uncertainties in an integrated way through the entire analysis, and BWR thermal-hydraulic models which were adapted for the Peach Bottom and Grand Gulf analyses.

The Level I results of the LaSalle Unit 2 PRA are presented in: "Analysis of the LaSalle Unit 2 Nuclear Power Plant: Risk Methods Integration and Evaluation Program (RMIEP)," NUREG/CR-4832, SAND87-7157, ten volumes and NUREG/CR-4831. The reports are organized as follows:

NUREG/CR-4831 - Analysis of the LaSalle Unit 2 Nuclear Power Plant: Risk Methods Integration and Evaluation Program (RMIEP), Executive Summary.

NUREG/CR-4832 - Volume 1: Summary Report.

NUREG/CR-4832 - Volume 2: Integrated Quantification and Uncertainty Analysis.

NUREG/CR-4832 - Volume 3: Internal Events Accident Sequence Quantification.

NUREG/CR-4832 - Volume 4: Initiating Events and Accident Sequence Delineation.

NUREG/CR-4832 - Volume 5: Parameter Estimation Analysis and Human Reliability Screening Analysis.

NUREG/CR-4832 - Volume 6: System Descriptions and Fault Tree Definition.

NUREG/CR-4832 - Volume 7: External Event Scoping Quantification.

NUREG/CR-4832 - Volume 8: Seismic Analysis.

NUREG/CR-4832 - Volume 9: Internal Fire Analysis.

NUREG/CR-4832 - Volume 10: Internal Flood Analysis.

Important associated reports have been issued by the Methods Development Program in NUREG/CR-4833 to 4839. The Level II/III results will be issued in a series of reports by PRUEP and other programs, including NUREG/CR-5032, 5168, 5174, 5253, 5262, 5380, 5444, 5445, 5455, and 5456.

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1.0 INTRODUCTION

Because of the extensive information collection and documentation needs, system notebooks were constructed by the system analysts to gather all of the information needed to construct the fault trees and to perform the location analysis in to one place. The procedure for construction and the types of information to be included in these notebooks is described in section 1.1. Once sufficient information has been gathered fault tree definition and construction can begin. Section 1.2 describes the general guidelines used in the construction of the LaSalle fault trees used in this analysis. Section 1.3 describes were certain supporting information pertaining to the fault tree analysis that is not included in the published documents can be obtained.

1.1 System Notebook Format

Each analyst kept a separate system notebook for each system analyzed. The notebook provided a filing system for all information gathered and all of the analysts notes. Organization of the notebook followed the suggested format for individual system fault tree development documentation. The following system notebook outline is essentially that presented in "Documentation Design for Probabilistic Risk Assessment"[1]. This format includes the guidelines presented in the "IREP Procedures Guide"[2]. No specific guidance on system notebooks is contained in the "PRA Procedures Guide"[3].

The system notebook format is as follows:

I. System Function

Describe the purpose of the system and its relationship to the overall plant performance of the critical safety functions.

II. System Description

II.1 General

Simple description of basic system configuration with one-line diagrams.

a) Detailed diagrams showing all connections, diversion paths, etc. Include plant P&IDs for piping and component layout.

b) Construct simplified diagrams showing only the components and flow paths to be considered in the fault tree models.

Include plant system training manual descriptions and appropriate portions of FSAR describing the system. Write brief descriptions of the major components modeled. Construct a table which includes: component identifier, component type, type of driver, power supply (specific electrical bus), component function, normal operating state, status on loss of power, applicable failure modes, and effect of component failure on system for each failure mode. Use system descriptions, discussions with plant and A&E personnel expert on the the system, plant operating procedures, and electrical drawings.

Construct table containing information needed for external events analysis. This should include: component identifier, component type, manufacture and/or model number, location of component (for extended components such as pipes or control or actuation circuits, the location of each subpart modeled), and any associated cables. Use general arrangement drawings, piping drawings, master electrical diagrams for cable identification, cable routing tables, cable routing point drawings, electrical drawings, and environmental and seismic qualification lists to determine major component locations, trace piping locations, determine cabling that is part of component control or actuation circuitry, determine cable path through plant, map path to locations, determine location of all electrical components such as relays, contacts, switches etc., and determine make and model number of all equipment.

II.2 Support System Interfaces

Identify and describe the support systems required for system and component operation.

Include an FMEA of the system identifying all of the support systems, the specific support system components that interface with the primary system, and their failure effects on the primary system. Construct a table which includes: specific subsystem component failure, primary system component(s) affected (identifier and type), primary system component(s) failure mode(s), detection or recovery potential for each affected component, primary system component(s) failure effect on subsystem that component(s) is (are) in, summary effect of support system failure on primary system. Flag potential special initiators for the initiating event analyst (i.e., events which might cause a plant trip and simultaneously degrade responding safety systems).

II.3 Instrumentation and Control

List Instrumentation available to monitor the performance of the system and describe its function.

Control logic associated with any of the components should be described. Actuation logic should be described.

Information should be provided concerning:

a) System initiation - the parameters and setpoints used for automatic system actuation should be described.

b) Component trips - the parameters and setpoints used to automatically inhibit component operation should be described.

c) System Isolation - the parameters and setpoints used to isolate the system should be described.

II.4 Test and Maintenance Procedures

a) Test

List all test procedures that affect the system. Describe the important general test procedures applicable to the system. Indicate whether or not and when testing can be overridden if the system is required during testing for an emergency. Review all relevant procedures to determine specific steps which, if incorrectly performed, would result in component failure or unavailability and identify all applicable secondary checks and operating tests or conditions which might catch the failures. Construct a table containing: procedure number, procedure title, test frequency, components affected, and affect on system operation. Construct a second table containing: component identifier and type, type of test, test procedure number, type of override, components aligned away from emergency position with no automatic return, test frequency, and test duration. Use master procedure list to identify all applicable test procedures. Obtain from procedural common mode analysis[4] any other procedures that might affect system. Identify all human actions, errors or otherwise, that could result in failure to restore the system or components to operability after the test, give these to the human factors analyst, and include in fault tree any that survive the screening rules[4].

b) Maintenance

There are two types of maintenance to be considered: scheduled and unscheduled (repair).

i. List and describe the general scheduled maintenance procedures applicable to the system.

ii. Determine all components for which maintenance will be modeled. From general maintenance procedures and discussions with plant maintenance personnel determine how maintenance will be performed for the component type and failure mode. Identify all secondary components which will be aligned away from normal positions and, if not realigned at end of maintenance, would result in component failure or unavailability. Determine all post maintenance checks and tests which would catch these misalignments. Give this information to the human factor analyst and include all actions that survive the screening analysis[4] on the fault tree.

Construct a table containing: component identifier and type, if scheduled maintenance include type and procedure number, other components which must be aligned away from emergency positions without automatic return, if allowed during plant operation, frequency, duration, and if staggered or not.

II.5 Technical Specification Limitations

Get all technical specifications applicable to the system. Write a short summary.

III. System Operation

Summarize the role of the operator in system performance, including manual actuation or control capabilities. List the operator tasks required. Discuss recovery actions available to the operator for major component or system failure modes. List and summarize all relevant normal, abnormal, and emergency operating procedures.

IV. System Performance During Accident Conditions

Summarize the system response to important accident scenarios, focusing on:

a) Success criteria for various initiators.

b) Physical impact of accident conditions on the ability of the system to perform its functions.

c) Impact of system failure on other safety-related systems.

V. System Operating Experience

List relevant operating experience from other similar plants. Information is available in "Nuclear Power Experience"[5]. Plants with BWR4 designs are Peach Bottom 2 and 3, and Brunswick 1 and 2. Plants with BWR5 designs are LaSalle 1 and Nine Mile Point. Grand Gulf is a BWR6 (HPCS is a BWR6 system).

VI. System Fault Tree

VI.1 Top Event Description

Define and describe the top events for which fault trees must be constructed.

VI.2 Assumptions

List all system specific assumptions used in the fault tree model.

VI.3 Fault Tree

Include all fault tree modules as developed.

It is suggested that a separate notebook be used for each system. Also, the notebook should be divided into major sections as described above for ease in locating relevant information by other analysts. All material used in developing the fault tree should be entered into the appropriate sections. This includes applicable FSAR pages, P&IDs, procedures, technical specifications, and other drawings. All personal notes and calculations should be included.

1.2 Fault Tree Development Guidelines

In general the IREP Procedures Guide[2] were used in the development of the system fault trees. Applicable sections of this report (pp. 43-58, 115-121) were used. Other sources included the PRA Procedures Guide[3] and the Fault Tree Handbook[6]. Please note the special guidelines listed on pages 115 and 116 of the IREP Procedures Guide[2] concerning:

a) System segment decomposition (nodalization),

b) Rule of thumb for neglecting diversion paths in fluid systems. This must be applied with caution,

c) I&C circuits.

The fault trees from other BWR PRAs which are similar to the LaSalle system being analyzed were reviewed. Specific PRAs reviewed included Millstone-1 (IREP), Browns Ferry-1 (IREP), and Shoreham (utility). The analysts also looked at Limerick, and Kuosheng, although this information was proprietary and could not be used directly in the analysis.

After reviewing other similar fault trees and collecting the basic data for the system notebook an initial one-line diagram showing all components to be included in the fault tree was drawn. This was iterated on as the fault tree was developed.

The IREP component naming scheme was used for all basic events in the fault trees. This naming scheme is described in the Modular Fault Tree Analysis Procedures Guide[7]. The IREP modular logic fault trees were used for constructing the fault trees and the method for their use is described in that document. Modifications were made to the modular modules for the LaSalle analysis and two computer programs were written to help in the fault tree construction. Since the modules were not easy to edit, a computer program called MODEDIT was written to allow the analysts to call up the appropriate module, edit the module for his ystem, check for entry errors, and then store the module. The second program called INDEX reads in the modules for a single fault tree , checks that they link correctly, and prints out any top events and undeveloped events. This allows the analyst to determine if the appropriate transfers to support systems are the only undeveloped events left in the tree and if the only unlinked top events are those for which the tree was developed. Both of these programs are documented Reference 8 along with any corrections or changes to the modular logic modules that were made as a result of the LaSalle analysis.

The SETS code[9,10] was used to evaluate the system fault trees. In order to improve the efficiency with which the solution is obtained, the following considerations needed to be kept in mind while constructing the trees: 1) do not use special gates or complementary events, 2) develop the tree so "AND" gates are limited to two inputs at any level, and 3) move nodal points up to higher levels in the tree. Special gates can not be processed and removed or rearranged by many SETS algorithms and, therefore, do not allow maximum use of SETS capabilities. Complementary events also increase the computing time and/or efficiency of the processing. If possible, a complementary events should be named similarly but different to its base event and noted. The combinations can be removed later in the cut sets by using the DELETRM option in SETS. This can be more efficient in practice than trying to have SETS implement the correct Boolean algebra reduction as the solution is being obtained. In cases where the use of the modular logic method resulted in very deep fault trees (i.e., fault trees with many levels), the efficiency of the solution was greatly improved by identifying nodal points where multiple branches of the system joined together. An example would be in the main feedwater system where the use of the modular logic directly resulted in a fault tree where two injection paths joined together then split into two heat exchanger paths which rejoined then split into three pump paths which rejoined then split into four condensate booster pump paths which rejoined then split into four condensate pump paths and finally rejoined to the condenser. Without modification the fault tree solution would have taken, for example, the three feedwater pump paths and input all four condensate booster pump paths. In order to see the effects of this modeling consider the following simplified example. Let X1, X2, and X3 be the feedwater paths and Y1, Y2, Y3, and Y4 be the booster pump paths. In failure space, feedwater failure would need all three feedwater pumps to fail or all four condensate booster pumps to fail. This can be represented as X1*X2*X3 + Y1*Y2*Y3*Y4. However, if these events are developed linearly using the modular logic without modification the representation that SETS would try to solve is (X1 + Y1*Y2*Y3*Y4)*(X2 + Y1*Y2*Y3*Y4)*(X3 + Y1*Y2*Y3*Y4). As can be seen, event if one has SETS evaluate the Ys and Xs separately first, this second representation will produce many more intermediate cut sets then the first and , in fact, may be impossible to evaluate.

I&C circuits were modeled as single events representing extended components. Standard designs were determined for quantification purposes. All new circuits were compared with the standard set and it was augmented if necessary. For the location analysis, all component locations and all cables comprising the circuit were assigned to this super event.

Events representing spurious actuation of components needed to be modeled. Normally these kinds of events are of sufficiently low probability for most internal event scenarios that they do not need to be modeled; however, in the fire analysis, the ability of a fire to cause short circuits in one or more components control and/or actuation circuits at the same time is not a low probability event. In fact, not only did we need to consider single spurious actuations but we had to consider multiple spurious actuations as well. We included in the model multiple spurious actuations resulting in diversion paths of sufficient size to fail the system.

Events representing the effects of piping failure on the system had to be modeled in order to accurately model the effects of seismic events and internal pipe breaks on system components and system response. Events representing the pipe segments were included in the system fault trees at the appropriate place in the tree so that the direct effect of the pipe failure on the system operation was represented. The secondary effect of the internal flood on other systems was evaluated using the flood propagation zones and component locations in the internal flood analysis[7]. These pipe segments were treated as extended components and had multiple locations. All piping that could have a significant effect on the system operation was traced. Piping in a system that would not directly affect the system but could result in an internal flood with indirect effects was also traced but was lumped in with balance of plant piping[11].

After a system fault tree was constructed, the individual fault tree was solved using the SETS code and the cut sets were checked by the system analysts and a second reviewer to make sure that the fault tree was producing cut sets that correctly represented the system response to the failures. The review also included checking the fault tree logic, the event naming scheme, the level of modeling detail, and the fault tree assumptions. This was done to assure that a component that might appear in several systems was named the same in each and that the level of modeling detail was similar for all systems.

Finally, the front-line systems appearing in the accident sequence event trees were merged with their support systems and solved. The resulting cut sets were again reviewed by the front-line and support system analysts to assure that the effects of the support systems were propagating correctly through the interface and were producing legitimate cut sets.

1.3 Location of Supporting Information

The fault trees constructed for the LaSalle analysis are very large. It was not convenient to plot the trees on standard size paper for printing in this document and the number of pages would have been very large (several thousand). In order for the analyst to be able to examine the fault tree visually and check the tree for errors, large plots of major portions of the fault trees were made and put on aperture cards. The complete fault tree could then be automatically divided up and plotted on the aperture cards. Hard copy was then be made from printers and a complete version of the fault tree was available to the analyst.

The LaSalle fault trees are plotted on 158 aperture cards. Users needing a copy of the fault trees can obtain a set of aperture cards from Sandia; however, because of the limited number of sets made, they will have to copy the set and return the original cards. Hard copy can then be made using an appropriate printer. Also, the fault trees, in SETS computer code format, are available on floppy disk in ASCII format.

1.4 References

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2.0 HIGH PRESSURE INJECTION SYSTEMS

2.1 Main Feedwater System (MFW)

2.1.1 System Function

The purpose of the Feedwater System is to deliver condensate from the condensate booster system to the reactor vessel in order to maintain the desired water level. The Feedwater System is not a safe shutdown system but can be used to bring the reactor to a safe condition following a transient or LOCA initiator.

2.1.2 System Description

2.1.2.1 General Design

A simplified schematic of the Feedwater System is shown in Figure 2.1-1.

Flow Path

The Condensate System described in Section 3.1 provides condensate at the required NPSH to the feedwater pump suction. Two turbine-driven reactor feedwater pumps and one motor-driven reactor feedwater pump are provided to increase the condensate pressure for injection into the reactor vessel. Two high pressure feedwater heaters increase the feedwater temperature to 420F. The Feedwater System separates into two lines before penetrating the containment. Once inside the containment, each line splits into three lines, each of which penetrates the vessel to supply a section of the feedwater sparger.

Locations

The Feedwater System is located in the turbine building, the auxiliary building, the reactor building, and the primary containment.

Component Descriptions

The two turbine-driven reactor feedwater pumps are horizontally mounted, single stage, double suction centrifugal pumps. Each pump has the capability of operating at 68% of reactor rated steam flow corresponding to a rated flow of 8.58×10^6 lbm/hr.

Each of the turbine-driven reactor feed pumps is driven by a separate steam turbine. The turbine drives are the dual-admission type, each equipped with two sets of main stop and control valves. One set of valves regulates low-pressure steam flow extracted from the main turbine crossover piping. The other set regulates high-pressure steam flow from the main steam supply. During normal operation, the turbine drives run on the low-pressure crossover steam. Main steam is used during plant startup, low load, or transient conditions when crossover steam either is not available or is of insufficient pressure. The turbine drives exhaust steam to the main condenser.

Turbine speed is varied to control the flow rate of each pump. The turbine speed is controlled by the turbine control valve that is regulated by the Reactor Water Level Control System (RWLCS).

Steam shut-off valves allow each turbine drive to be removed individually from service while maintaining system operability with the remaining reactor feed pumps.

Bearing oil for the feed pump turbine is supplied by the Main Turbine Lube Oil System at about 25 psig. A turbine turning gear disengages at less than 1 RPM to prevent rotor bowing.

The Turbine Gland Sealing System provides clean sealing steam for the turbine-driven pump turbines to prevent leakage of radioactive steam The Gland Water System provides water to the turbine-driven pumps to prevent air-inleakage and to prevent loss of feedwater.

A 40%-capacity, motor-driven reactor feed pump is also supplied for startup convenience and service during an outage of a turbine-driven reactor feed pump. The pump is a two stage, horizontal centrifugal pump driven by a 6.9 KV, 6000 HP induction motor. Its rated capacity is 10,300 gpm (approximately 33% of required rated flow). A shaft-driven oil pump provides lubrication of its bearings. During startup and shutdown, an auxiliary oil pump provides lubrication for the motor-driven feed pump bearings. The auxiliary oil pump auto starts on low bearing oil pressure.

A bypass line around the motor-driven pump containing a motor-operated valve (2FW022) allows the condensate booster pumps to supply feedwater directly to the reactor vessel when the reactor is depressurized.

Flow from the motor-driven reactor feedwater pump is controlled by a feedwater control valve (2FW015). This valve is a 16-inch globe valve requiring air for opening and is designed to spring close. The position of this valve is controlled by the RWLCS.

Shut-off valves allow each reactor feed pump to be removed individually from service while maintaining system operability with the remaining reactor feed pumps.

Controlled feedwater recirculation is provided from the discharge side of each reactor feed pump directly to the main condenser hotwell. This provision ensures that the minimum required flow is maintained through each reactor feed pump during operation.

Two 50% capacity high pressure heaters are provided to help increase the thermal efficiency of the heat cycle. The heaters are horizontal, U-tube heat exchangers with feedwater on the tube side and extraction steam on the shell side. A 50% bypass line is also provided.

A 16-inch feedwater flushing line located downstream of the feedwater heater is provided to recirculate feedwater to the main condenser during startup. This line allows the condensate polishers to clean up the condenser water prior to admitting it to the reactor. Two closed motor-operated valves are provided in series for isolation of this line during power operation.

Motor-operated stop valves are provided on both feedwater lines penetrating the containment for long-term isolation purposes. The valves are remote manually operated from the control room and are not actuated by Primary Containment Isolation System signals. In-line check valves on both sides of the containment wall also provide for containment isolation in the event of a feedwater line break.

2.1.2.2 System Interfaces

A failure modes and effects analysis of the Feedwater System indicating the required support system interfaces is shown in Table 2.1-1. The support system interfaces are discussed below.

Shared Components

Operation of the turbine-driven reactor feedwater pumps requires steam from the main steam equalizing header. The main steam equalizing header is included in the Power Conversion System.

With the exception of the turbine-driven feedwater pump trains, the entire feedwater flow path to the reactor vessel is required for the low pressure injection of feedwater by the Condensate System.

Electrical

The only component requiring motive power for operation in the Feedwater System is the motor-driven reactor feedwater pump (2FW01PC). This pump is powered from 6900 VAC Bus 252.

Actuation

Actuation of the motor-driven reactor feedwater pump requires control power from 125 VDC Buses 212X, 211X, and 211Y.

Control

Control of feedwater flow is provided only by the reactor water level signals using the RWLCS while in the single element control mode. Power for this system is provided from 480 VAC MCC 235X-3 through a step-down transformer. Control of the turbine-driven feedwater pumps also requires operation of the Main Turbine Lube Oil System. Specifically, operation of the auxiliary oil pump (2TO11P) is required following a main turbine trip. This pump requires power from 480 VAC MCC 236Y-3.

Component Cooling

The turbine-driven reactor feedwater pumps require lubrication oil from the Main Turbine Lube Oil System. During normal power operation, lube oil is provided to the pumps through operation of a main turbine shaft-driven pump. Backup electric motor-driven pumps are used when the main turbine shaft-driven pump is unavailable. In this study, two electric driven pumps were modeled: the turning gear oil pump (2T010P) and the emergency bearing oil pump (2T009P). These pumps require power from 480 VAC MCC 236Y-3 and 250 VDC MCC 221X, respectively.

Heat removal from the Main Turbine Lube Oil System is accomplished through two redundant oil coolers. During normal operation only one cooler is in service with oil flowing through the shell side and service water through the tube side.

The motor-driven reactor feedwater pump has its own shaft-driven lube oil system. Cooling for the oil is provided by the Turbine Building Closed Cooling Water System.

Room Cooling

The Feedwater System does not require room cooling.

2.1.2.3 Instrumentation and Control

System Actuation

During normal power operations, the Feedwater System is configured with both turbine-driven feedwater pumps operating and the motor-driven pump in standby. The motor-driven pump will automatically start when both turbine-driven feedwater pump turbines trip. A simplified logic diagram of the motor-driven pump actuation logic is shown in Figure 2.1-2. Supporting actuation logic is shown in Figure 2.1-3. The feedwater turbines will trip if any of the following conditions occur:

a)	Turbine overspeed	105% - 6070 RPM 60
b)	Low condenser vacuum	17 inch HG vacuum
c)	High thrust bearing wear	
d)	Low bearing oil pressure	4 psig
e)	Low suction pressure	250 psig
f)	Reactor vesse' high level (Level 8)	54.4 inches
g)	Remote trip f m control room	
h)	Local trip at turbine	

The motor-driven feedwater pump will trip when any of the following conditions exist:

1)	High reactor water level	54.5 inches
2)	Low feedwater pump suction pressure	250 psig
3)	Low pump lube oil pressure	5 psig

4) Bus undervoltage
5) Phase overcurrent
6) Neutral overcurrent
7) Control switch in trip position

Upon a main turbine trip, the shaft-driven lube oil pump will coastdown and the oil pressure will decrease. The turning gear oil pump and the auxiliary oil pump will automatically start when the shaft-driven plump discharge pressure drops to 190 psi. The emergency bearing oil pump will automatically start if the shaft-driven oil pump discharge pressure drops below 180 psi and the turning gear oil pump discharge pressure is below 10 psi.

Component Control

The Reactor Water Level Control System (RWLCS) maintains the water level in the reactor vessel by controlling the amount of feedwater entering the vessel. The system accomplishes this by controlling the speed of the turbine-driven feedwater pumps (RFP) and/or the position of the feedwater control valve (FCV). A simplified block diagram of the RWLCS is shown in Figure 2.1-4.

The feedwater turbines and control valve can be operated manually from the control room at their individual M/A stations or automatically by RWLCS signals. There are two modes of automatic operation available to the operator.

1) Single-Element Control - In this mode, only the reactor vessel water level is used to automatically maintain the proper vessel level. Single-element control is normally used for startup and low power operations. Only one component at a time can be controlled by the single-element controller. An actuator selector switch is used to select the component to be controlled.

2) Three-Element Control - Commonly referred to as the automatic mode, control of the feedwater flow is based on a combination of feedwater flow signals, steam line flow signals, and reactor water level signals. Feedwater operation above 30% is normally accomplished in three-element control. Only two components can be in three-element control at the same time.

Following trip of both turbine-driven feedwater pumps, the motor-driven feedwater pump flow is determined by the single-element controller when the actuator selector switch is set for the feedwater control valve and if the M/A station is in "manual". If the turbine feedwater pumps do not trip following a reactor trip, both pumps will continue to operate on three-element control.

Instrumentation

The following instrumentation in the control room indicate the status of the Feedwater System:

1) Reactor feedwater pump suction pressure - indicator

2) Reactor feedwater pump discharge pressure - indicator

3) Motor-driven feedwater pump motor amps - indicator

4) Turbine-driven feedwater pump hydraulic oil pressure - indicator

5) Turbine-driven feedwater pump control oil pressure - indicator

6) Feedwater pump turbine lube oil pressure - indicator

7) Turbine-driven feedwater pump lube oil pressure - indicator

8) Feedwater pump turbine speed - indicator

9) Feedwater turbine control valve position - indicator

10) Feedwater turbine high pressure stop valve position - indicator

12) Motor-driven feedwater pump flow - indicator

13) Turbine-driven feedwater pump flow - recorder

14) Turbine-driven feedwater pump flow - recorder

15) Total feedwater flow - recorder

In addition, the following control room alarms exist:

1) Low feedwater discharge header pressure - 850 psig

2) Low feedwater pump suction pressure - 250 psig

3) High feedwater pump suction strainer differential pressure - 10 psid

4) Feedwater pump recirculation valve full open

5) Motor-driven feedwater pump bypass valve not closed

6) Feedwater flush valve leakage - 850 psig

7) Feedwater pump low bearing oil pressure - 5.5 psig

8) Turbine-driven feedwater pump high lube oil temperature - [illegible]°F

9) Turbine-driven feedwater pump low thrust bearing oil pressure - 40 psig

10) Turbine-driven feedwater pump low hydraulic oil pressure - 130 psig

11) Feedwater pump tripped

12) High reactor water level (level 7) feedwater control - 40.5 inches

13) Turbine-driven feedwater pump control signal failure - 106% or -6%

14) Reactor water level feedwater control trip (level 8) - 54.5 inches

15) Feedwater control valve signal failure - 106% or -6%

16) Turbine-driven feedwater · mp not ready

17) Low reactor water level (level 4) feedwater control - 31.5 inches

2.1.2.4 Operator Actions

During normal reactor operations, the Feedwater System is normally placed in the automatic mode of operation (three-element control). The operator can, however, manually control the feedwater flow from the control room.

For some transients, a high reactor vessel level (level 8) signal will trip the turbine-driven feedwater pumps and prevent automatic startup of the motor-driven pump. To re-initiate feedwater flow, the operator must reset the level 8 trip once it has cleared and manually initiate any of the three feedwater pumps. He must also align the pump for single-element control.

For other transients such as an MSIV closure event, the turbine-driven pumps will coast down but not actually trip. The motor-driven pump will not automatically initiate. To restart feedwater flow, the operator must either reestablish a turbine-driven pump (by opening the MSIVs in the case of MSIV closure for example) or by manually starting the motor-driven pump. In either case he must establish the component on single-element control.

Technical Specifications

The only technical specifications applicable to the Feedwater System pertain to the feedwater/main turbine trip system actuation instrumentation.

Limiting Control for Operation

The feedwater/main turbine trip system actuation instrumentation is provided to initiate the Feedwater System/main turbine trip system in the event of reactor vessel water level equal to or greater than the level 8 setpoint associated with a feedwater controller failure to prevent overfilling the reactor vessel which may result in high pressure liquid discharge through the safety/relief valve discharge lines.

Technical specification 3.3.8 states that the reactor vessel water level instrumentation channels must be operable with their trip setpoints at 55.5

inches (level 8). If the channel setpoint is less than the allowable value of 56.0 inches, the channel must be tripped or the channel be declared inoperable. If there are only two operable channel must be restored within 7 days or the plant must be placed in startup mode within the next 6 hours.

If only one channel is operable per trip system actuation instrumentation channels must be demonstrated operable by performing the following tests at the designated frequency:

1) Channel check - at least once per 12 hours

2) Channel functional tests - at least once per 31 days

3) Channel calibration - at least once per 18 months

4) Logic system functional tests - at least once per 18 months

2.1.2.6 Test

The scheduled tests that can affect the operability of the Feedwater System during normal plant operation are summarized in Table 2.1-2. These tests are related to the reactor vessel narrow range level instrumentation used in the Reactor Water Level Control System and for the level 8 feedwater pump trip system.

2.1.2.7 Maintenance

No scheduled maintenance which disables components while the plant is at power is planned. However, unscheduled maintenance is allowed within the technical specification limitations and due to the redundant nature of the system.

A summary of unscheduled maintenance which can be performed on the portions of the Feedwater System of interest is summarized in Table 2.1-3. Although allowed, unscheduled maintenance on check valves and manual valves is not listed on the table because of the significantly lower frequencies of occurrence when compared to motor-operated valves.

2.1.3 System Operation

2.1.3.1 Normal Operation

During normal plant operation, the Feedwater System is providing feedwater to the reactor vessel. The two turbine-driven feedwater pumps are normally operating in three-element control. The feedwater is pumped to the reactor vessel through the two high pressure heaters and the two feedwater injection lines.

2.1.3.2 Abnormal Operation

Following a transient, the Feedwater System can be in one of three conditions:

1) The transient doesn't effect the turbine-driven feedwater pump operation and they continue to provide feedwater to the reactor vessel. The motor-driven pump remains in standby condition.

2) The transient results in a reactor vessel level 8 signal which trips the turbine-driven pumps and prevents startup of the motor-driven pump. Any one of the pumps can be restarted once the level 8 signal clears and is reset.

3) The transient results in loss of steam to the turbine-driven pumps resulting in their coastdown. The motor-driven pump does not start automatically since the turbine-driven pumps did not actually trip. The motor-driven pump can be initiated by manually tripping the turbine-driven pumps or by manually initiating the pump directly. The turbine-driven pumps can be restarted by reestablishing steam flow to the turbines.

Following a reactor trip, only one feedwater pump is required to provide flow to the reactor. A flow path through one high pressure heater or bypass line and one feedwater injection line is required.

2.1.4 System Fault Tree

2.1.4.1 Description

The fault tree for the Feedwater System includes the Condensate System fault tree discussed in Section 3.1. A portion of the Feedwater System fault tree is also required by the Condensate System when used as a low pressure injection system. This portion deals with the failure of the high pressure feedwater heater lines, the injection lines to the vessel, and the motor-driven pump flow path.

A simplified diagram of the Feedwater System indicating only the mechanical components included in the fault trees is shown in Figure 2.1-5.

2.1.4.2 Success/Failure Criteria

Successful operation of the Feedwater System following a transient will be defined in this analysis as requiring that the Condensate System provide the necessary NPSH to the feedwater pump suction, that one feedwater pump be operable, and that one flow path through a high pressure heater and an injection line to the reactor vessel be available. Failure of the Feedwater System will, therefore, occur if one of the following occurs:

1) The Condensate System fails to provide flow and the required NPSH to the feedwater pump suction.

2) All three feedwater pumps fail.

3) Both high pressure heater lines fail closed and the heater bypass line is unavailable.

4) Both injection lines to the vessel fail to remain open.

The top event of the feedwater fault tree is:

"FAILURE OF THE FEEDWATER SYSTEM TO PROVIDE FEEDWATER TO THE REACTOR VESSEL"

2.1.4.3 Assumptions

In addition to the general assumptions regarding fault tree development (listed at the beginning of this volume), the following assumptions specific to the LPCS system were made:

1) A rupture of any of the main Feedwater System piping including the pump recirculation lines was assumed to result in eventual depletion of the condensate supply and subsequent failure of the Feedwater System.

2) No credit was taken for manually controlling the feedwater control valve or the turbine-driven feedwater pump turbine speed. Single-element control is assumed to be required. The reactor vessel Level A instrumentation was assumed to be aligned to the single-element controller. No credit was taken for the redundant Level B instrumentation since it requires operator action to switch.

3) The actuator selector switch used for selecting the component used in single-element control was assumed to be in its normal standby position (VALVE). The turbine-driven pumps were thus assumed to be in three-element control.

4) The Turbine Gland Sealing System and the Gland Water System were assumed not required for emergency turbine-driven pump operation.

5) The auxiliary oil pump of the main turbine lube oil system was assumed required to operate in order to supply oil to the turbine-driven reactor feedwater pumps control oil systems. The main shaft oil pump was assumed unavailable. Also, the turning gear oil pump and the emergency bearing oil pump were assumed to be the only pumps available to provide lubricating and cooling oil to the turbine-driven feedwater pump bearings.

6) No credit was taken for the redundant turbine oil cooler in the main turbine lube oil system. Manual actions would be required to initiate the standby cooler.

7) Credit is only taken for the low pressure steam admission to the turbine-driven reactor feedwater pumps.

8) Failure of the pump recirculation lines was assumed not to result in a significant diversion path since the lines are designed to be fully open at 25% pump flow.

9) Unscheduled maintenance on the turbine-driven feedwater pumps was not modeled due to the redundant motor-driven pump. Unscheduled maintenance was included on the standby motor-driven pump.

10) No credit was taken for the high pressure heater bypass line since it requires remote manual opening from the control room.

2.1.5 References

1) FSAR

System description	Section 10.4.7
Instrumentation	Section 7.7.1.4
Technical Specifications	Limiting Conditions for Operation, Section 3.3.8 Surveillance Requirements, Section 4.3.8.1, 4.3.8.2 Bases, Section 3/4.3.8

2) Operator Training Manual — Chapters 24, 19, and 31

3) Drawings

P&IDs	M-118, M-116, M-131
I&C	IE-2-4200AD, IE-2-4208AA - IE-2-4208ZG, IE-2-4203AN - IE-2-4203BJ
General Arrangement	M-204, M-206, M-310, M-310, M-314, M-316, M-368, M-376, M-379, M-382, M-398, M-406, M-408, M-545, M-548, M-562, M-565, M-5851, M-584
I&C Details	M2057 Sh1

4) Procedures — LIS-FW-201
LIS-FW-401

Table 2.1-1 Feedwater System Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
Instrument Air	2FW011B	Air operated valve	Open	Indicator light, alarm	Turbine feed pump 2B recirculation valve to main condenser fully open	Decrease in feedwater flow to reactor due to recirculation back to the condenser
	2FW011A	Air operated valve	"	"	Turbine feed pump 2A recirculation valve to main condenser fully open	"
	2FW008	Air operated valve	"	"	Motor feed pump 2C recirculation valve to main condenser fully open	"
	2FW005	"	Closed	"	Motor feed pump 2C control valve fails closed	No injection from motor feedwater pump
120 Vac MCC 233B-1	2FSV-FW008A and 2FSV-FW008B	Solenoid operated valve	Deenergized	Valve indicator lights, alarm	Loss of air to turbine feed pump 2B recirculation valve to main condenser valve fails open	"
120 Vac MCC 231B-2	2FSV-FW003A and 2FSV-FW003B	Solenoid operated valve	"	"	Loss of air to turbine feed pump 2A recirculation valve to main condenser valve fails open	"
120 Vac 232B-3	2FSV-FW012A and 2FSV-FW012B	Solenoid operated valve	"	"	Loss of air to motor feed pump 2C recirculation valve to main condenser valve fails open	"
Main turbine lube oil	2FW01PA	Turbine feed pump 2A	Pump stops	Alarms - low oil pressure feed pump trip	Turbine feed pump 2A unavailable for operation	Loss of both turbine driven feed pumps 2A and 2B
	2FW01PB	Turbine feed pump 2B	"	"	Turbine feed pump 2B unavailable for operation	"

Table 2.1-1 Feedwater System Support Systems Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
High pressure steam	2FW01PA	Turbine feed pump 2A	Will not fail pump if L.P. steam available	H.P. stop valve position indication	Loss of one of two steam sources to turbine	No eifect unless lost in conjunction with L.P. steam
High pressure steam	2FW01PB	Turbine feed pump 2B	Will not fail pump if L.P. steam available	H.P. stop valve position indication	Loss of one of two steam sources to turbine	No effect unless lost in conjunction with L.P. steam
Low pressure steam	2FW01PA	Turbine feed pump 2A	Will not fail pump if H.P. steam available	L.P. stop valve position indication	"	No effect unless lost in conjunction with H.P. steam
Low pressure steam	2FW01PB	Turbine feed pump 2B	"	"	"	"
480 Vac MCC 232B-1	2FW010A	Motor operated valve	Fail as is	Control panel alarm, breaker position	Normally open, no effect	No effect
6900 Vac SWGR 252	2FW01PC	Motor feed pump 2C	Pump stops, pump will not start	Flow indication, breaker position	Fails motor feed pump 2C	Fail motor feed pump 2C
125 Vdc Bus 212X	2FW01PC	Motor feed pump 2C	Pump will not start	Breaker position loss of pump indicating lights	"	"
480 Vac MCC 235X-3	2FW01PC	Motor feed pump 2C	Pump will not automatically start	Loss of instrumentation indication	Loss of auto start capability for MDFP	Loss of auto start capability for MDFP, manual start still possible
MDFP lube oil system	2FW01PC	Motor feed pump 2C	Trips pump	Bearing oil pressure low alarm	Fail motor driven feed pump 2C	Fail motor driven feed pump 2C
480 Vac MCC 231B-3	2FW022	Motor operated valve	Fail as is	Control panel alarm, breaker position	(Normally closed) Fail condensate bypass line of feed pumps	Fail condensate bypass line of feed pumps. Flowpath though MDFP still available

Table 2.1-1 Feedwater System Support Systems Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
Reactor water level control system	2FW005	Hydraulic valve	Fail as is	Control signal failure alarm, reactor water level indication	Possible blockage of motor driven feed pump discharge line	Possible loss of automatic feedwater flow control
	2FW01PA	Turbine feed pump 2A	Can trip pump	Control signal failure alarm	Possible pump trip	"
	2FW01PB	Turbine feed pump 2B	"	"	"	"
480 Vac MCC 232B-1	2FW013	Motor operated valve	Fail as is	Control panel alarm, breaker position	Block H.P. feedwater heater bypass line (normally closed)	Block one of three 50% feed flow paths
	2FW014A	Motor operated valve	"	"	Normally open valve, no effect	No effect
	2FW015A	Motor operated valve	"	"	"	"
480 Vac MCC 232Y-2	2FW014B	Motor operated valve	"	"	"	"
	2FW015B	Motor operated valve	"	"	"	"
	2FW010B	Motor operated valve	"	"	"	"
	2FW026	Motor operated valve	"	"	Normally shut valve, blocks flush line to condenser	"

Table 2.1-1 Feedwater System Support Systems Interface FMEA (Concluded)

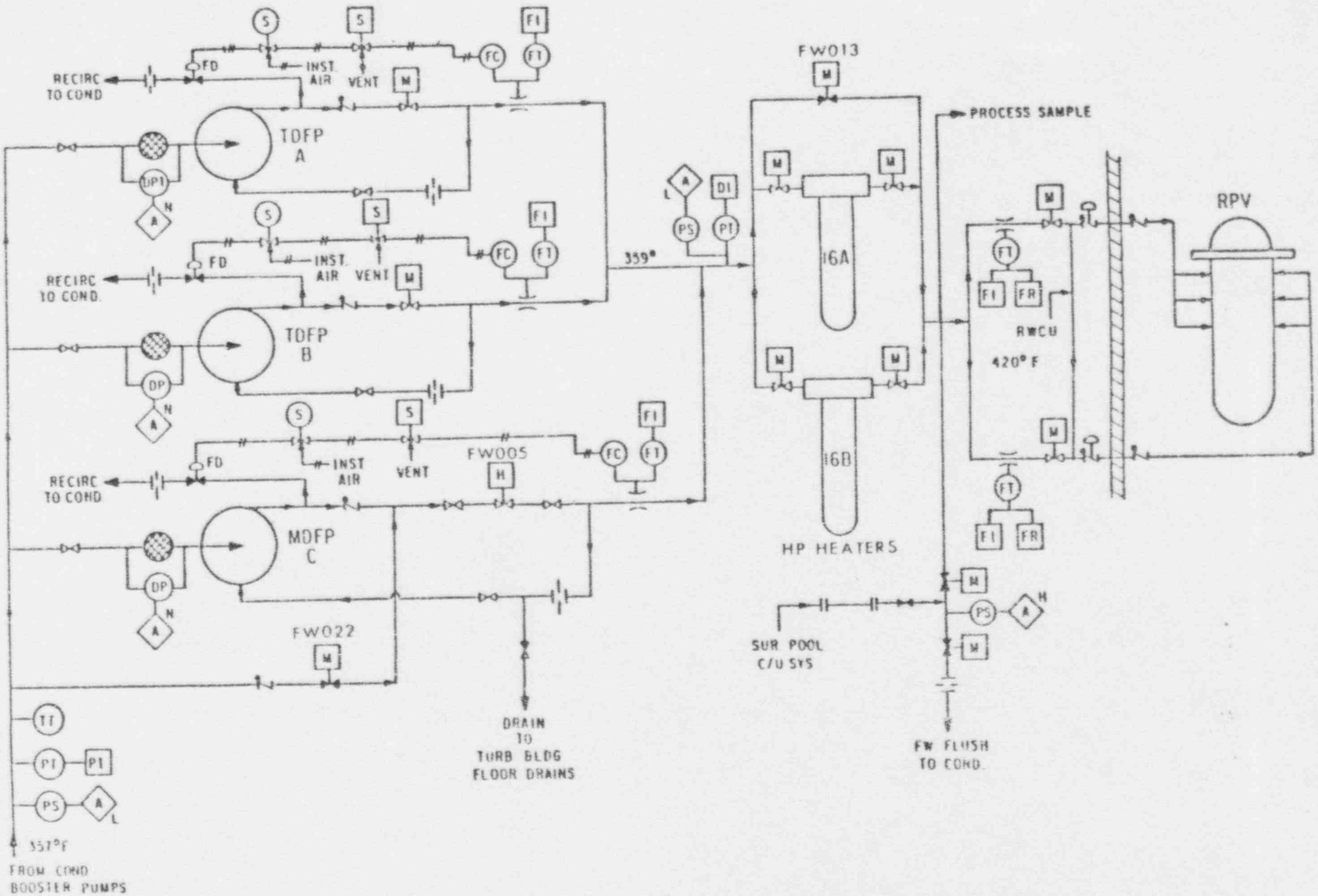
Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
480 Vac MCC 232Y-2	2FW018	Motor operated valve	Fail as is	Control panel alarm, breaker position	Normally shut valve, blocks flush line to condenser	No effect
480 Vac MCC 235X-3	2B21 F065B	Motor operated valve	"	"	Normally open valve, no effect	"
480 Vac MCC 235Y-1	2B21 F065A	Motor operated valve	"	"	"	"
TBCCW	2FW01PC	Motor feed pump 2C	Fail seals, or overheat pump	TBCCW temp., pressure alarms and indications	Fail motor feed pump 2C	Fail motor feed pump 2C
Service Water	2FW01PA	Turbine feed pump 2A	Overheat pump	Low pressure alarm, high pressure temp.	Fail turbine feed pump 2A	Fail turbine feed pumps 2A and 2B
	2FW01PB	Turbine feed pump 2B	Overheat pump	Low pressure alarm, high pump temp.	Fail turbine feed pump 2B	Fail turbine feed pumps 2A and 2B

Table 2.1-2 Feedwater System Component/Subsystem Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
LIS FW-201	Calibration	2C34-N004A 2C34-N004B 2C34-N004C	Differential Pressure Transmitter	Feedwater Trip System	No	18 months	-	Shiftly
LIS FW-401	Functional test	2C34-N004A 2C34-N004B 2C34-N004C	Differential Pressure Transmitter	Feedwater Trip System	No	31 days	-	Shiftly

Table 2.1-3 Feedwater System Unscheduled Maintenance Summary

Component/ Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2FW01PA	Pump	Mechanical	2FW010A 2CB003A	Yes			None
2FW01PB	"	"	2FW010B 2CB003B	"			"
2FW01PC	"	"	2FW003 2CB008	"			"
		Electrical	Pump circuit breaker				
2FW005	Pneumatic Valve	Mechanical	2FW003 2FW004	"			Shiftly
2T011P	Pump	Mechanical		"			
		Electrical	Pump circuit breaker	"			Shiftly
2T009P	"	"		"			
			"	"			"
2T010P	"	"		"			
			"	"			"


RECIRC TO COND
TDFP A
INST. AIR
VENT
FD
RECIRC TO COND.
TDFP B
MDFP C
FW005
FW022
339°
FW013
PROCESS SAMPLE
16A
16B
HP HEATERS
RWCU
420° F
RPV
SUR POOL C/U SYS
FW FLUSH TO COND.
DRAIN TO TURB BLDG FLOOR DRAINS
357°F
FROM COND BOOSTER PUMPS

B.X-1

Figure 2.1-1 Simplified Schematic of Main Feedwater System

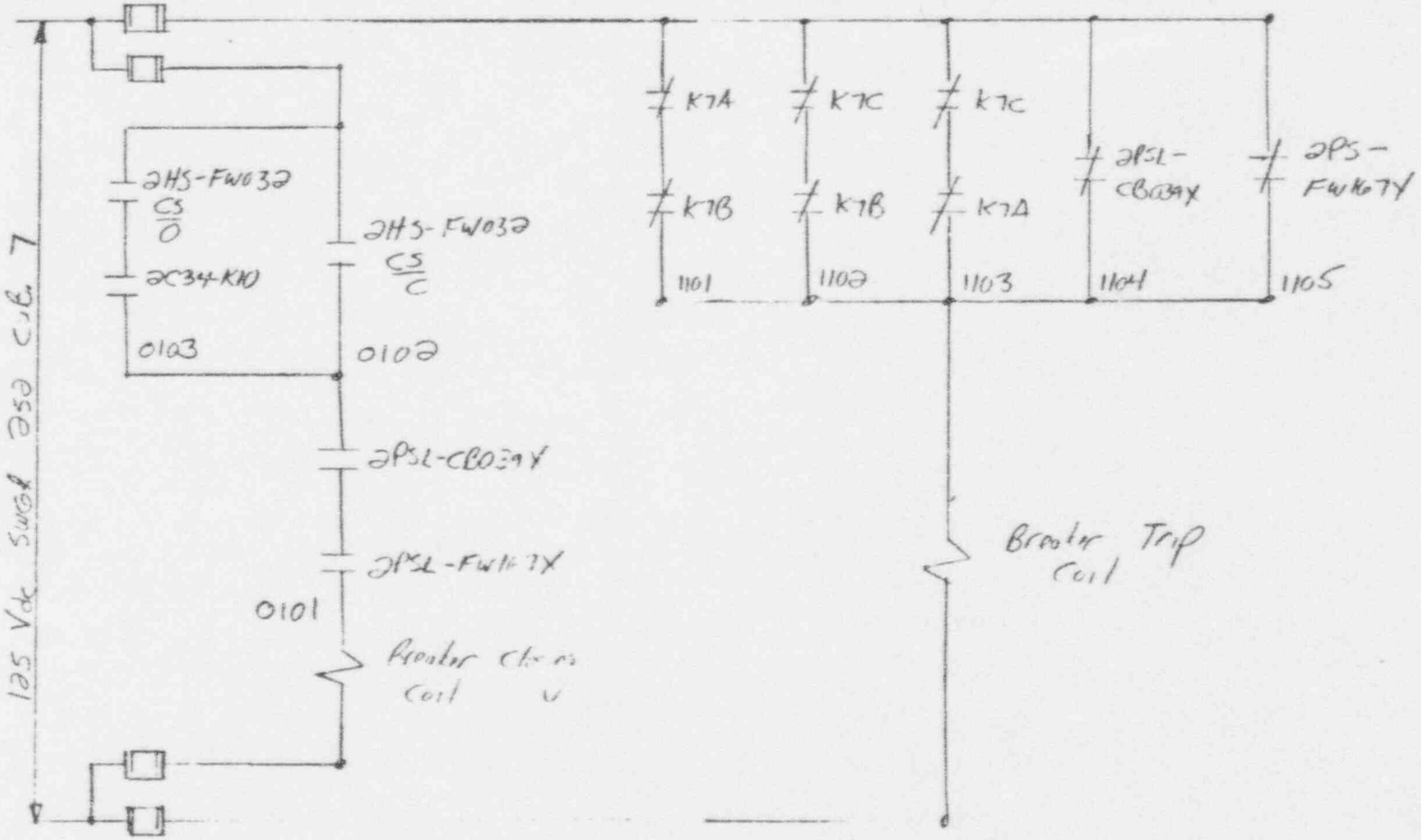
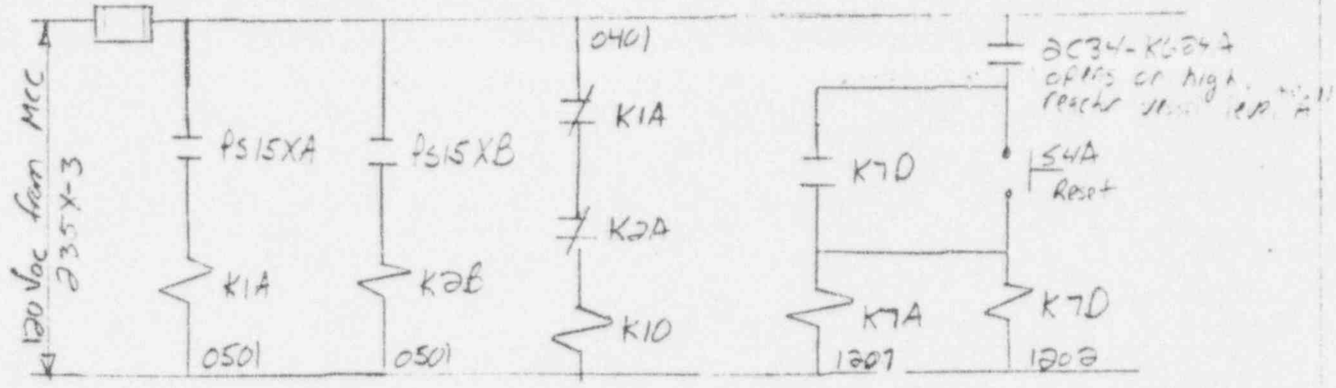
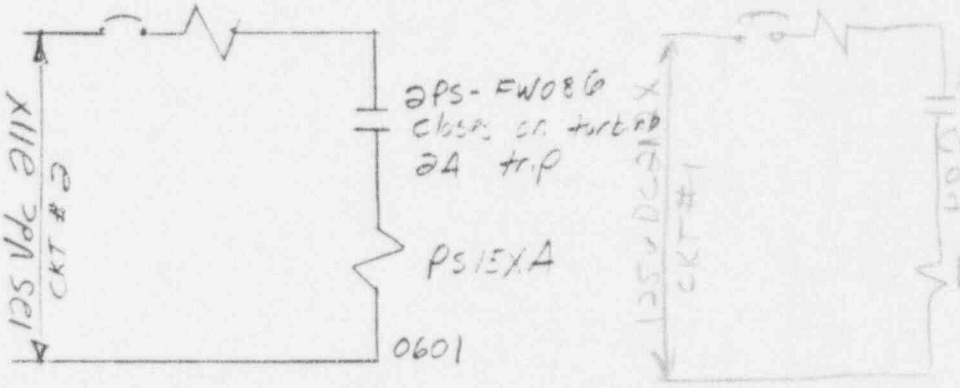


Fig. B.X.2 Motor-driven feedwater pump actuation logic.

Supporting logic as shown on B.X.3

Figure 2.1-2 Simplified Diagram of Motor-Driven Pump Actuation Logic





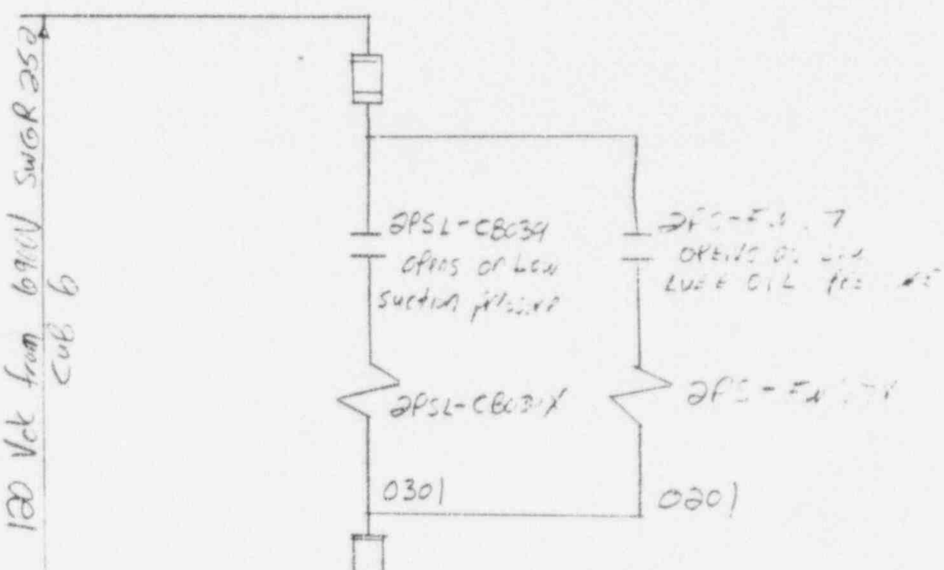


Figure B.X-3 Motor-driven feedwater pump

Figure 2.1-3 Supporting Logic for Motor-Driven Pump Actuation

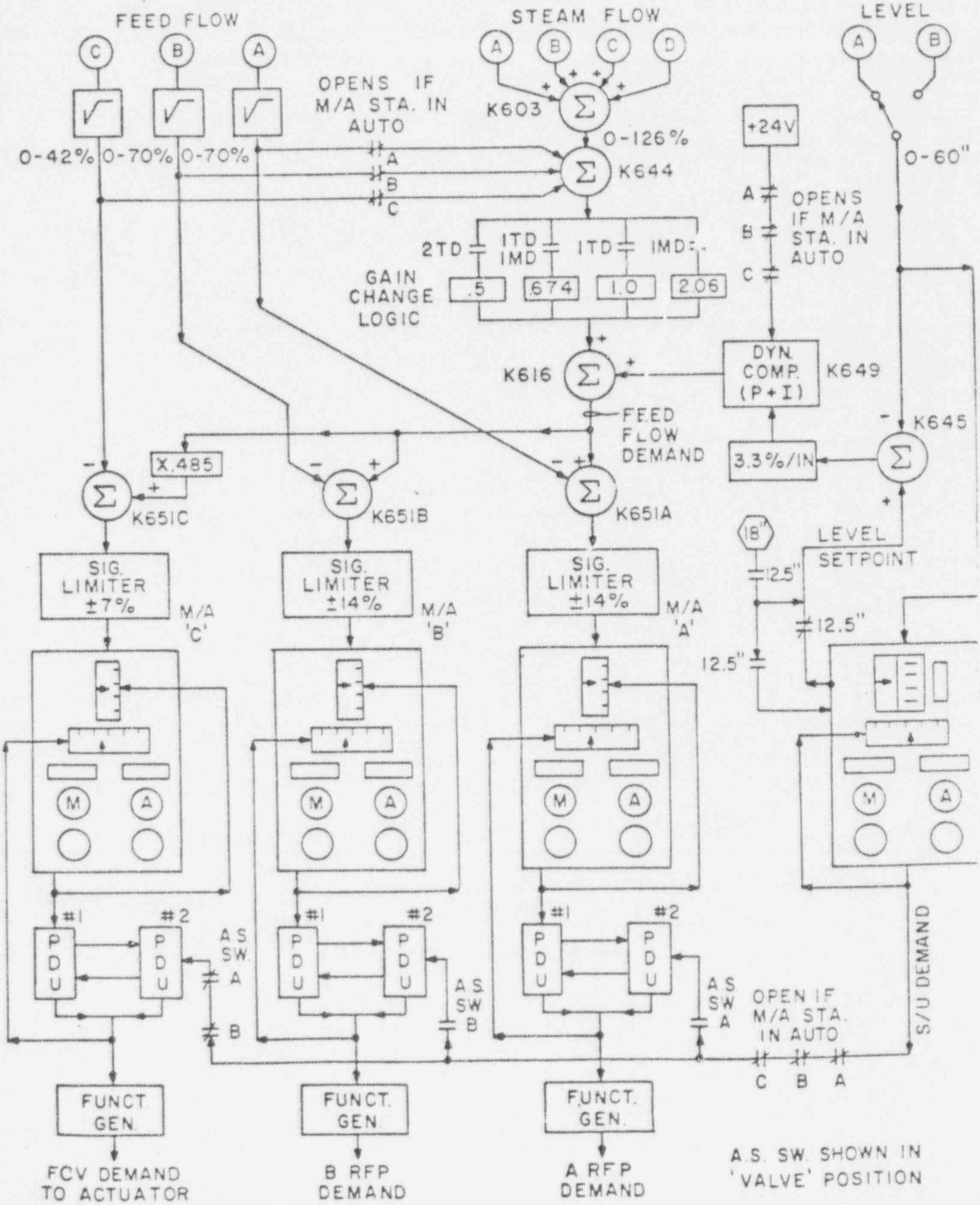
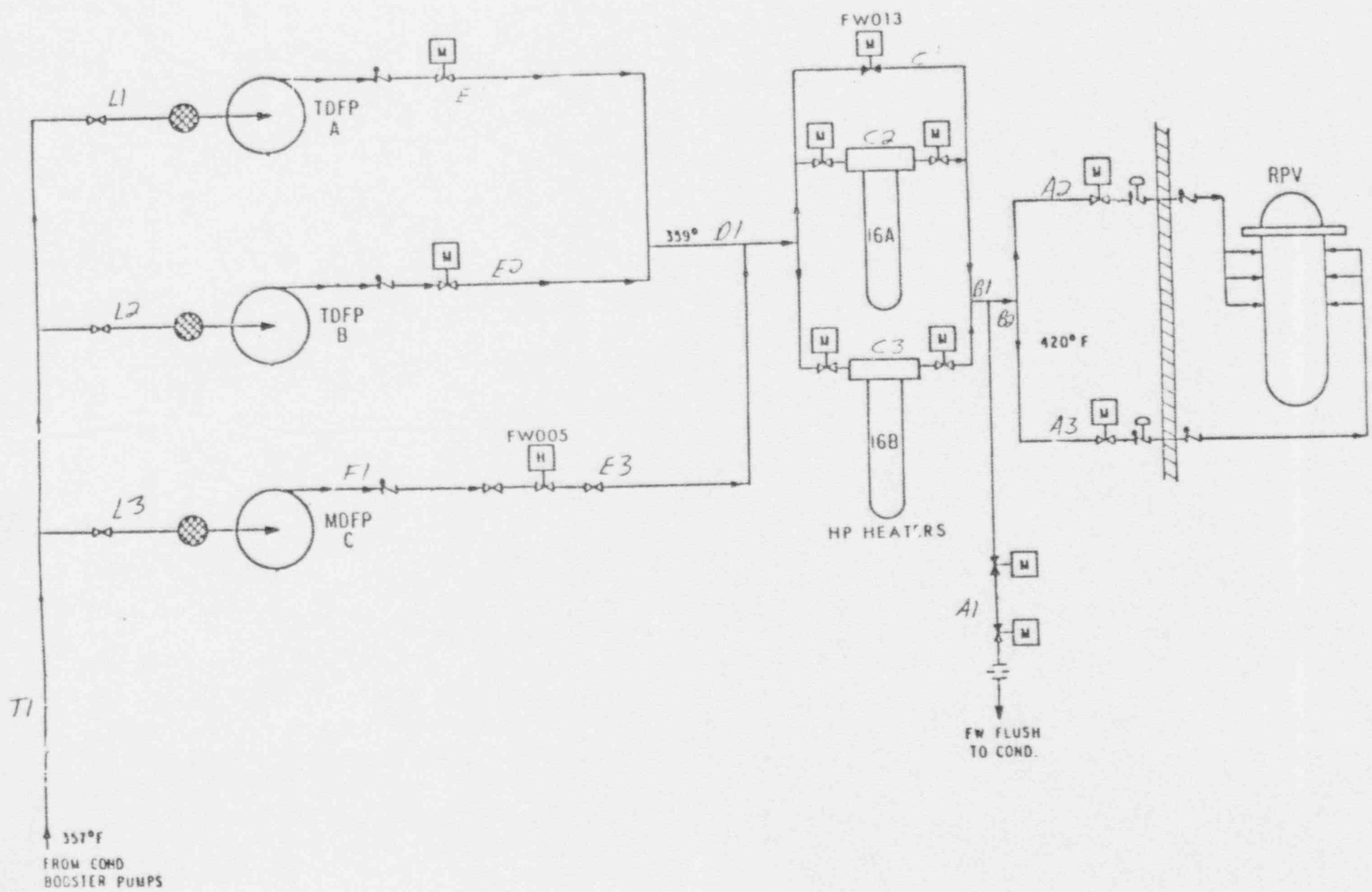

FEED FLOW
C
B
A
STEAM FLOW
A
B
C
D
LEVEL
A
B
OPENS IF M/A STA. IN AUTO
K603
0-126%
K644
0-42%
0-70%
0-70%
+24V
0-60"
A
B
C
OPENS IF M/A STA. IN AUTO
2TD
ITD IMD
ITD
IMD
GAIN CHANGE LOGIC
.5
.674
1.0
2.06
K616
DYN. COMP. (P+I)
K649
FEED FLOW DEMAND
K645
X.485
3.3%/IN
K651C
K651B
K651A
18"
LEVEL SETPOINT
12.5"
SIG. LIMITER ±7%
SIG. LIMITER ±14%
SIG. LIMITER ±14%
M/A 'C'
M/A 'B'
M/A 'A'
M
A
#1
#2
PDU
A.S. SW. A
A.S. SW. B
OPEN IF M/A STA. IN AUTO
S/U DEMAND
FUNCT. GEN.
FCV DEMAND TO ACTUATOR
B RFP DEMAND
A RFP DEMAND
A.S. SW. SHOWN IN 'VALVE' POSITION

Figure B.X-4

Figure 2.1-4 Simplified Block Diagram of Reactor Water Level Control System


FW013
TDFP
A
TDFP
B
MDFP
C
FW005
L1
L2
L3
T1
E2
E3
F1
339°
D1
C2
C3
16A
16B
HP HEATERS
B1
B2
A1
A2
A3
420° F
RPV
FW FLUSH
TO COND.
357°F
FROM COND
BOOSTER PUMPS

B.X-5

Figure 2.1-5 Simplified Diagram of Main Feedwater System for Fault Tree Construction

2.2 High Pressure Core Spray System (HPCS)

2.2.1 System Function

The purpose of the HPCS system is to provide sufficient water spray to the fuel bundles in the core to prevent excessive fuel cladding temperatures and to depressurize the reactor vessel during small break LOCAs, which do not result in rapid depressurization of the reactor vessel. However, the HPCS system is capable of maintaining the reactor vessel water level throughout the full range of breaks up to and including a DBA. The HPCS system also serves as a back up to the Reactor Core Isolation Cooling (RCIC) system should the RCIC system fail to maintain the reactor vessel water level following a reactor vessel isolation.

2.2.2 System Description

2.2.2.1 General Design

The HPCS system injects water from either the suppression pool or CST into the reactor vessel through a single injection line. The system consists of one motor driven pump, a flow distribution sparger mounted directly over the reactor core, and associated piping, valves, instrumentation, and controls. Figure 2.2-1 is a simplified P&ID of the HPCS system.

Flow Path

The HPCS system is normally lined up to draw water from the CST through the normally open MOV 2E22-F001. Should the CST become depleted or the suppression pool level become too high, the HPCS pump suction automatically shifts to the suppression pool by opening normally closed MOV 2E22-F015 and closing 2E22-F001. The HPCS pump discharge is directed to the reactor vessel through the normally closed injection MOV 2E22-F004 or diverted for full flow tests to the CST through normally closed MOVs 2E22-F010 and 2E22-F011, or the suppression pool through normally closed MOV 2E22-F023. When the pump discharge is directed to the reactor vessel through 2E22-F004 the flow penetrates the containment, passes through a testable check valve 2E22-F005 and a locked open manual isolation valve 2E22-F038. Flow then enters the reactor vessel where it splits into two two semi-circular spargers which distribute the flow to the fuel bundles.

Locations

The majority of the HPCS system components are located in the southwest corner of the reactor building basement. Two valves, 2E22-F005 and 2E22-F038, are located inside the primary containment. The condensate storage tank is located outside of the southwest corner of the turbine building.

Component Descriptions

The HPCS pump is a vertically mounted centrifugal pump located in the reactor building basement SE cubicle. The pump will deliver 1650 gpm against full reactor pressure (1110 psig), reaching its rated flow of 6250 gpm at 370 psid between the containment and the reactor vessel. The pump is driven by a 3000 HP, 1780 RPM, 4160 VAC air cooled motor which is powered from bus 243.

The HPCS pump suction header is supplied by two 24-inch lines. There are two major valves in each suction line. The CST suction valve 2E22-F001 is a normally open 14-inch 480 VAC motor operated gate valve which isolates the HPCS suction header from the CST. A 24-inch check valve, 2E22-F002, in the CST suction line prevents suppression pool water from entering the CST. The suppression pool suction valve, 2E22-F015, is a normally closed 18-inch, 480 VAC motor operated gate valve which isolates the suppression pool from the HPCS suction header. A 24-inch check valve 2E22-F016 in the suppression pool suction line prevents the CST water from entering the suppression pool.

The condensate storage tank is a 350,000 gallon cylindrical tank. Penetrations in the tank for systems other than HPCS and RCIC are located above the tank bottom to provide 135,000 gallons of reserve capacity for HPCS and RCIC.

The suppression pool suction line is fitted with a strainer inside the suppression pool. The strainer is above the bottom of the suppression pool to prevent clogging from sedimentation. The strainer is oversized to provide the minimum required NPSH should 50% of the strainer surface become plugged.

A 16-inch check valve, 2E22-F024, on the HPCS pump discharge prevents backflow through the HPCS pump.

The motor operated injection valve, 2E22-F004, separating the HPCS pump discharge from the injection sparger is a 12-inch valve.* This normally closed valve opens upon HPCS initiation and attainment of rated pressure.

The HPCS testable check valve, 2E22-F005, is located inside containment in the injection header between the motor operated injection valve and the locked open manual isolation valve. This check valve seats with reactor pressure and isolates the reactor vessel should a HPCS injection line break occur outside of the containment. For test purposes, to enable verification of valve operability, a pneumatic actuator is attached to the valve disc pivot arm. The air actuator cannot prohibit disc opening. By energizing a solenoid-controlled air supply to the actuator, the valve can be forced to lift off its seat. A light on the HPCS display on the 1H13-P601 panel verifies the operability of the stem indicating that the shaft is not broken.

A 12-inch locked open manual gate valve, 2E22-F038, between the testable check valve (F005) and the reactor vessel can be used during shutdown to isolate the HPCS system from the vessel for maintenance.

The HPCS minimum flow valve 2E22-F012 is a 4 inch motor operated gate valve which is normally closed to prevent the condensate storage tank from draining into the suppression pool when the system is in the Standby Mode. The valve automatically opens when pump flow is less than 1000 gpm and the pump discharge pressure is greater than 120 psig.

The 14-inch HPCS full flow test line is used to verify the technical specification flow requirements of the HPCS system. The line splits into two 14 inch lines, one going to the CST, the other to the suppression pool. The CST return line contains two normally closed isolation valves, 2E22-F010 and 2E22-F011. Both valves are 10 inch 480 VAC motor operated globe valves.

The suppression pool return line contains one normally closed isolation valve, 2E22-F023, which is a 12-inch 480 VAC motor operated globe valve.

To ensure that the HPCS system discharge piping is full of water, a water leg pump is used to keep the discharge piping full of water. The pump takes suction from the HPCS suction line and discharges to the HPCS discharge header. The water filled lines help prevent water hammer when the pump starts and ensures that water will reach the core sooner.

HPCS flow is distributed over the core by the HPCS sparger. The 12-inch HPCS discharge line is reduced to 10" and penetrates the reactor vessel. There it divides into two 6-inch pipes extending in both directions half way around the outside of the core shroud. Each 6-inch header then penetrates the shroud and divides forming the sparger which encircles the core with 128 spray nozzles. The spray nozzles rise are tilted down toward the vertical centerline of the reactor to give optimum spray distribution to all fuel bundles.

The HPCS system will auto initiate on low low water level (Level 2) or high drywell pressure. The instrumentation contacts for either initiating parameter are arranged in a one of two taken twice logic. Upon initiation, the HPCS pump starts, the injection valve F004 opens, and the full flow test return valves F023, F011, and F010 will close if open. When a high water level condition (Level 8) is established while the system is operating, the F004 valve closes and the minimum flow bypass valve, F012, opens.

2.2.2.2 System Interfaces

A failure modes and effects analysis of the High Pressure Core Spray System indicating the required support system interfaces is shown in Table 2.2-1. The support system interfaces are discussed below.

<u>Electrical</u>

The plant electrical distribution system provides power to the HPCS system for operation of the pump motor, system MOVs, and system instrumentation and controls. The HPCS pump motor is supplied by the 4160 VAC distribution system from bus 243. Two sources of power are available to this bus. The normal feed is through the system auxiliary transformer (SAT). The alternate supply is from the HPCS diesel generator. The HPCS motor operated valves are powered from the 480 VAC distribution system through MCC 243-1. The 125 VDC distribution system , DC bus 213, supplies power to the HPCS initiation relay logic circuits and control power for the HPCS pump motor. System instrumentation is powered by the 120 VAC from MCC 243-1.

Component Cooling

The core standby cooling system (CSCS) provides cooling to the HPCS pump room HVAC system to maintain area temperatures within normal operating limits during system operation. The CSCS system also provides cooling water for the HPCS diesel generator.

2.2.2.3 Instrumentation and Control

System Actuation

The HPCS system may be initiated either manually, at panel 1H13-P601, or automatically by a low low reactor vessel water level, Level 2 (-50 inches), or high drywell pressure (+1.69). Both automatic signals seal in and must be reset with the reset pushbutton. HPCS will shut down following a reset if the reactor vessel water level has been restored regardless of the state of the drywell pressure signal. The system will auto-restart following a reset if the reactor vessel level once again decreases to Level 2. The drywell pressure signal can cause a restart only if it has cleared and been reset.

Four reactor vessel water level instruments, 2B21-N031A thru 2B21-N031D, provide the Level 2 HPCS initiate signal. Contacts for each of these four instruments are arranged in a one of two taken twice logic. This arrangement prevents single failures from causing or preventing an initiation, and allows single element testing of the initiation logic during plant operations.

Four drywell pressure sensing elements, 2B21-N047A, thru 2B21-N047D provide the HPCS high drywell pressure initiate signal. The signal contacts from these instruments are arranged in a one of two taken twice logic like the reactor vessel water level signal contacts.

Startup and flow alignment of the HPCS system is initiated and controlled by three relays (K3, K9, and KX9) that are energized by the initiation signals.

The K3 relay initiates closing of full flow test return valves 2E22-F010 and 2E22-F023, starts the HPCS pump, and generates a permissive signal for starting of the HPCS diesel generator.

The K9 relay initiates opening of the HPCS injection valve 2E22-F004, the CST suction valve 2E22-F001, closing of the full flow test return valve 2E22-F011 and seals in the initiation signals.

The KX9 relay bypasses the thermal overloads on HPCS system MOVs (2E22-F001, 004, 010, 011, 012, 023).

Component Control

a) HPCS Motor Operated Injection Valve Control (2E22-F004)

The normally closed motor operated injection valve will open when an initiation signal is present if the following permissives are satisfied:

1) The manual override function is not in use
2) The reactor vessel level is below -50"
3) The valve position limit switch indicates that the valve is not in the fully open position
4) The closing relay is not energized.

The valve will stay open until the reactor level high trip (+55.5") comes into effect or the control switch is put in the close position causing it to shut. A close signal is locked in until either: a) the reactor high level trip signal clears and the high level reset push button is pressed or 2) the reactor high level trip signal clears and a low low level signal Level 2 is received.

b) Minimum Flow Bypass Valve

In automatic operation, the minimum flow bypass valve opens when the HPCS pump discharge pressure is equal to or greater than 120 psig and flow is less than 1000 gpm. The valve shuts when the flow exceeds 1000 gpm or discharge pressure decreases to less than 120 psig.

c) Cycled Condensate Storage Tank Suction Isolation Valve (2E22-F001)

The valve is normally open with the control switch in the Auto position. If the valve is closed, it will open when the control switch is placed in the open position or when an HPCS initiation signal is present if the suppression pool suction valve is not full open. The valve automatically shuts when the suction valve from the suppression pool is opened or it can be manually shut with the Control Room switch.

d) Suppression Pool Suction Valve (2E22-F015)

This valve opens automatically when the Condensate Storage Tank level is low (5'1" actual, 3'1" indicated) or the suppression pool level is 2" above normal level or it may be manually opened by the control switch in the Control Room if the test valves to the condensate storage tank are shut.

e) CST Full Flow Test Return Valves (2E22-F010 & 2E22-F011)

These normally closed valves are open only during full flow tests to the CST. Both valves will close automatically, if open, when a HPCS system initiation signal occurs or when the suppression suction valve 2E22-F015 is opened.

f) Suppression Pool Full Flow Test Return Valve (2E22-F023)

This normally closed valve is opened for full flow testing to the suppression pool. It will automatically close, if open, when a HPCS initiate signal occurs.

Instrumentation

a) HPCS Pump Discharge Pressure

The discharge pressure of the HPCS pump is used to evaluate the performance of the HPCS pump and provide a signal for the HPCS Minimum Flow Bypass Valve operation logic.

The instrumentation consists of a pressure transmitter and pressure switch located between the HPCS pump and the downstream check valve. The pressure transmitter provides a readout on the HPCS portion of the 1H13-P601 panel in the control room. The pressure switch closes at a pressure of 120 psig.

b) HPCS System Flow

Flow in the HPCS system is sensed by an orifice-type flow element installed between the HPCS pump discharge check valve and the HPCS injection valve. A flow transmitter provides indication of system flow on the HPCS portion of the 1H13-P601 panel in the Control Room. A flow switch closes at a flow of 1000 gpm providing a signal for the Minimum Flow Bypass Valve control logic.

c) HPCS Injection Header Break Detector

A pressure differential indicating switch is used to confirm the integrity of the HPCS piping inside the vessel. If the core spray piping should break between the vessel and the shroud, the sensed pressure difference will change causing an alarm in the Control Room.

d) HPCS Testable Check Valve Leak Detection

A 3/4" pipe detects packing leakoff on the operating mechanism side of the testable check valve 2E22-F005 utilizing a temperature recorder and a high temperature alarm. When a temperature of 250F is sensed, an alarm will sound in the Control Room. The temperature recorder located on the back panels is then used to determine if the leakage is increasing or decreasing.

Alarms

Annunciator P601 Panel	Set Point
HPCS Pump Breaker Trip	
Reactor Vessel Water Level 8 Hi	+55.5"
4KV Bus 243 Bkr Auto Trip	
HPCS Pump Breaker 2 Closed	
HPCS System Actuated	
HPCS Spray Hdr Top Core Plate Diff Press Hi	5 psid
HPCS Pump Over Current	
Reactor Vessel Water Level 2 Lo	-50"
HPCS 125Vdc System Trouble	
4KV Bus 243 Main Feeder Bkr Lockout Trip	
HPCS Prot Relay Power Failure	
HPCS Pump Suction Press Hi/Lo	Hi > 100 psi Lo < 4 psi
HPCS CNDS Storage Tank Level Lo	715' 7" (3' 1" indicated)
Suppression Chamber Level Hi	700' 1" (2" indicated)
HPCS System Ground Trouble	
4KV Bus 243/243-1 Under Voltage	
HPCS Discharge Flow Hi	1000 gpm
HPCS Header Pressure Hi	120 psi
HPCS Pump Cubicle Temp Hi	
HPCS Manual Initiation PB Armed	
LD Valve Stem RHR LPCS HPCS LKG Temp Hi	250F

2.2.2.4 Operator Actions

The HPCS system is designed to automatically start and function, when required, without operator actions. The primary responsibility of the operator is to verify system operability on a regular basis and proper operation following an initiation. Should portions of the initiation or control circuitry malfunction during system operation the operator can take manual control of the components that are operating improperly.

2.2.2.5 Technical Specification Limitations

The limiting conditions for operation in the LaSalle technical specifications require the HPCS system and its actuation instrumentation to be operable during operational conditions 1, 2, and 3. The system is considered operable when it is capable of transferring water from the suppression pool, through the sparger, into the reactor vessel at rated flow and pressure. The actuation instrumentation is considered operable when the minimum number of operable channels, trip setpoints, and time response requirements of Section 3.3.3 of the technical specifications are satisfied. When the system is declared inoperable it must be restored to operable status within 14 days or the plant must be placed in a cold shutdown condition within the next 36 hours.

During plant operation the HPCS keep filled alarm instrument, the header dP instrumentation, and watertight door must be operable. If the keep filled alarm is inoperable, the system must be verified full every 24 hours by venting through the high point vent. The header dP must be determined locally every 12 hours if the instrument becomes inoperable. If the HPCS room watertight door in inoperable, the door must be returned to operable status within 14 days or the plant placed in a cold shutdown condition within 36 hours.

The HPCS system and the actuating instrumentation is determined to be operable by meeting the following surveillance requirements:

1) Every 31 days, by verifying the system is filled with water by venting at the high point vents, that each valve in the flow path that is not secured in position is in its correct position, and that each ECCS corner room watertight door is closed, and performing a channel functional test of the discharge line "keep filled" pressure alarm instrumentation, and header delta P instrumentation.

2) Once every 18 months, by performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position, and performing a channel calibration of the:

   a) Discharge line "keep filled" pressure alarm instrumentation, verifying the low pressure setpoint to be > 63 psig. Verifying the setpoint of the header delta P instrumentation to be 5 $\pm$ 2.0 psid greater than normal.

   b) Verifying that the pump suction automatically transfers from the CST to the suppression chamber on a CST low water level signal and on a suppression chamber high water level signal.

   c) Visually inspecting the HPCS cubicle watertight door seals and room penetration seals and verifying no abnormal degradation, damage, or obstructions.

Each actuation instrumentation channel shall be demonstrated operable by the performance of the channel check, channel functional test, and channel calibration operations for the operational conditions at the frequencies shown in Table 4.3.3.1-1 of the Technical Specifications.

Logic system functional tests and simulated automatic operation of all channels shall be performed at least once per 18 months.

The response time of each trip function shown in Table 3.3.3-3 of the Technical Specifications shall be demonstrated to be within the limit at least once per 18 months.

2.2.2.6 Tests

The HPCS system tests which affect the system availability are summarized in Table 2.2-2. Component operability is verified monthly for MOVs by stroke time testing and quarterly for the system with a full flow test.

2.2.2.7 Maintenance

Scheduled routine maintenance is not performed on the HPCS system during plant operation. Unscheduled maintenance (replacement, repair or adjustment) is permitted on system components providing applicable safety and radiological administrative controls can be satisfied. If a component malfunction renders the HPCS system inoperable, all maintenance activities for restoring the system operability must be completed within 14 days or the plant must be placed in a cold shutdown condition (Technical Specification 3.5.1). Possible unscheduled maintenance activities during plant operation include:

1) Replacement or repair of actuation and control circuitry

2) Mechanical maintenance on MOVs and pumps that do not require breaching the system boundary unless double isolation from all high pressure, high temperature sources can be achieved.

3) Electrical maintenance on motor driven components.

A summary of possible maintenance activities during plant operations is given in Table 2.2-3.

2.2.3 System Operations

2.2.3.1 Normal Operation

During normal plant operation, the HPCS system is in standby with the water leg pump operating to keep the system discharge piping filled.

2.2.3.2 Abnormal Operation

When a HPCS system actuation signal, either manual or automatic, is received the HPCS pump 2E22-C001 starts and the HPCS injection valve 2E22-F004 opens. Only these two components are required to start or change state from a normal standby lineup to inject water into the reactor vessel. If the system is in an abnormal lineup from surveillance tests those valves out of their normal operating position will automatically return to the desired position without operator action. During system operation if the normal suction path from the CST becomes depleted or if the suppression pool level increases to 2" above normal, the HPCS suction will automatically shift to the suppression pool. If the reactor vessel water level increases to Level 8 (+55.5 inches) during system operation, the HPCS injection valve 2E22-F004 will close and the minimum flow bypass valve

2E22-F012 will open. If the water level subsequently drops to Level 2, the injection valve will reopen and the minimum flow bypass valve will close re-establishing flow to the reactor vessel.

2.2.4 System Fault Tree

2.2.4.1 Fault Tree Description

A simplified diagram of the HPCS system used for fault tree modeling is shown in Figure 2.2-2. The system has been divided into labeled segments for modeling. Component control and actuation system diagrams developed for system modeling are shown in Figures 2.2-3 through 2.2-6.

The fault tree contains one top event labeled: "Failure of the HPCS System to Provide Coolant With 1 of 1 Pumps." There are four developed events in the fault tree where the HPCS system interfaces with electrical power distribution system.

2.2.4.2 Success/Failure Criteria

Successful operation of the HPCS system occurs when the system delivers flow to the core against full reactor pressure. System failure occurs when design flow to the core is disrupted. Events resulting in failure of the system include:

1) Failure of the HPCS pump.

2) Failure of the injection valve to open or remain open.

3) Diversion of flow through one of the system full flow test return lines.

4) Failure of the HPCS suction to successfully transfer to the suppression pool upon receipt of a CST low level indication.

2.2.4.3 Major Assumptions

In constructing the fault tree for the HPCS system, the following assumptions were made in addition to the general assumptions given at the beginning of this volume:

1) Operator errors resulting in MOV misposition faults were neglected because:

   a) HPCS MOVs receive an initiation signal to go to their safe position.

   b) If an MOV or its breaker is out of position, there will either be a Wrong Position Indication or No Position Indication in the control during the shift turnover check.

2) The minimum flow recirculation line was neglected as a diversion path because it is orificed to limit flow through the line.

3) No immediate operator actions were modeled except for failure of the operator to actuate HPCS and failure to shift HPCS suction if the automatic shift fails.

4) Failures of the water leg pump were neglected because:

   a) The pump discharge pressure is alarmed in the control room

   b) During periods of unavailability, the water leg must be verified full every 24 hours (Technical Specification 3.5.1). The pump discharge line is designed to withstand the water hammer resulting from a pump start.

Table 2.2-1 High Pressure Core Spray System Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
ECCS Cooling	HPCS Area Cooling		HPCS failure	CR Alarm	Degradation of HPCS pump motor immediate failure not likely	Loss of area cooling resulting in area high temperature leading to long term degradation of the HPCS pump motor
4160VAC Bus 243 Div. 3	C001	Pump	Deenergized	CR Alarm	Loss of pump	Loss of system function if bus damaged or feeders to bus are lost.
480VAC Bus 243-1 from 4160 VAC Bus 243	C001	Pump	Deenergized	CR Alarm	Water hammer during system start	Potential water hammer damage to system or vessel components.
	F004	MOV	Closed	CR Alarm	Failure of injection path	System failure due to blockage of injection path
	F012	MOV	Closed	CR Indica-tion	No minimum flow for pump	Long term, HPCS pump damage if other discharge paths also shut off and pump left running
	F015	MOV	Closed	CR Indica-tion	Unable to switch suction to suppression pool on a low level in CST	Loss of system function if EST becomes depleted.
125VDC Bus 213	System initiation logic		Deenergized	Loss of valve position indicators	System will not initiate	Loss of system function
120VAC 243-1	F005	check valve	Loss of capability	Unable to test	No operational effect	None

Table 2.2-2 High Pressure Core Spray Component/Subsystem Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency (Mo)	Test Outage (Hr)	Component/Subsystem Alignment/Operability Verification Frequency
LTS-900-10	Isolation Valve Leak Test	2E22-C001	HPCS Pump	Yes (Pump Control in Pull to Lock)	No	18	8-10	Shiftly
		2E22-F004	MOV	Yes	No	18	8-10	Shiftly
		2E22-F015	MOV	No	No	18	8-10	Shiftly
		2E22-F012	MOV	No	No	18	8-10	Shiftly
		2E22-F001	MOV	Yes	No	18	8-10	Shiftly
		2E22-F023	MOV	No	No	18	8-10	Shiftly
		2E22-F011	MOV	No	No	18	8-10	Shiftly
		2E22-F308	Manual Valve	Yes	No	18	8-10	Shiftly
		2E22-F017	Manual Valve	Yes	No	18	8-10	Shiftly
LOS-HP-M1	System Operability (Alignment)	All motor-operated valves required for HPCS operation		No	No	1	0	Shiftly
		HPCS Water Leg Pump		No	No	1	0	Monthly
LOS-HP-Q1	Full Flow Test to CST	2E22-F011	MOV	Yes	Yes	3	0.5	Shiftly
LOS-HP-R1	Full Flow Test to Supp. Pool	2E22-F015	MOV	Yes	Yes	18	0.5	Shiftly
		2E22-F023	MOV	Yes	Yes	18	0.5	Shiftly

Table 2.2-3 High Pressure Core Spray System Component/Subsystem Maintenance Summary

Component Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E22-F001	MOV	Mechanical Electrical I&C	None	Yes			Shiftly
2E22-F002	Ck Valve	None					
2E22-F015	MOV	Mechanical Electrical I&C	None	Yes			Shiftly
2E22-F016	Ck Valve	None					
2E22-C001	Pump	Mechanical Electrical I&C	F015,F001,F004 None None	Yes Yes Yes			Shiftly
2E22-F024	Pump	Ck Valve	None				
2E22-F004	MOV	Mechanical Electrical I&C	None None None	Yes Yes Yes			Shiftly
2E22-F005	Ck Valve	None					
2E22-F038	Manual Valve	None					
2E22-F010	MOV	Mechanical Electrical I&C	None None None	Yes Yes Yes			Shiftly
2E22-F011	MOV	Mechanical Electrical I&C	None None None	Yes Yes Yes			Shiftly
2E22-F022	MOV	Mechanical Electrical I&C	None None None	Yes Yes Yes			Shiftly
Actuation Relay logic	I&C	Electrical I&C	None None	Yes Yes			NA

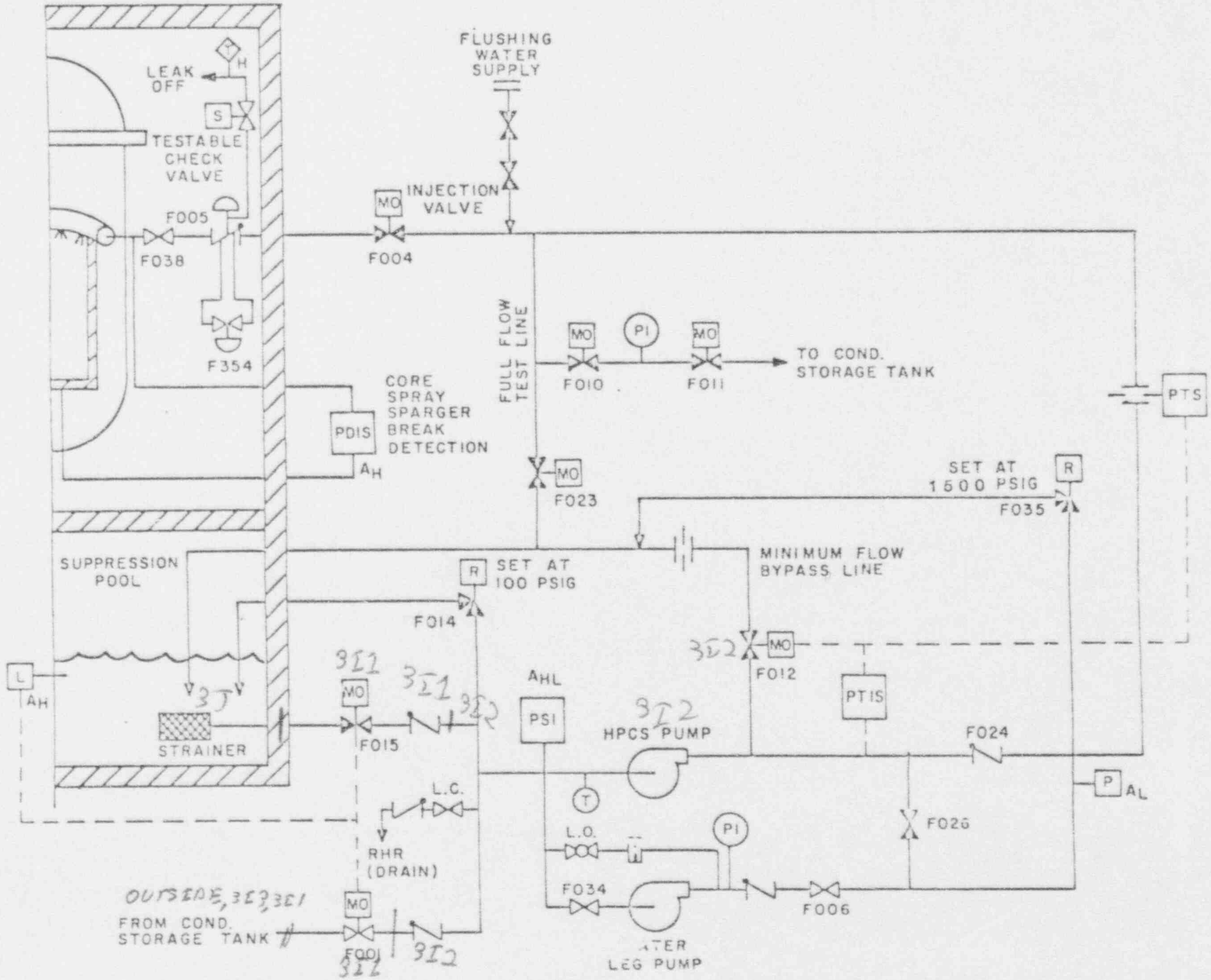


FIGURE B.X.1 HIGH PRESSURE CORE SPRAY SYSTEM SIMPLIFIED DRAWING

Figure 2.2-1 Simplified Schematic of High Pressure Core Spray System

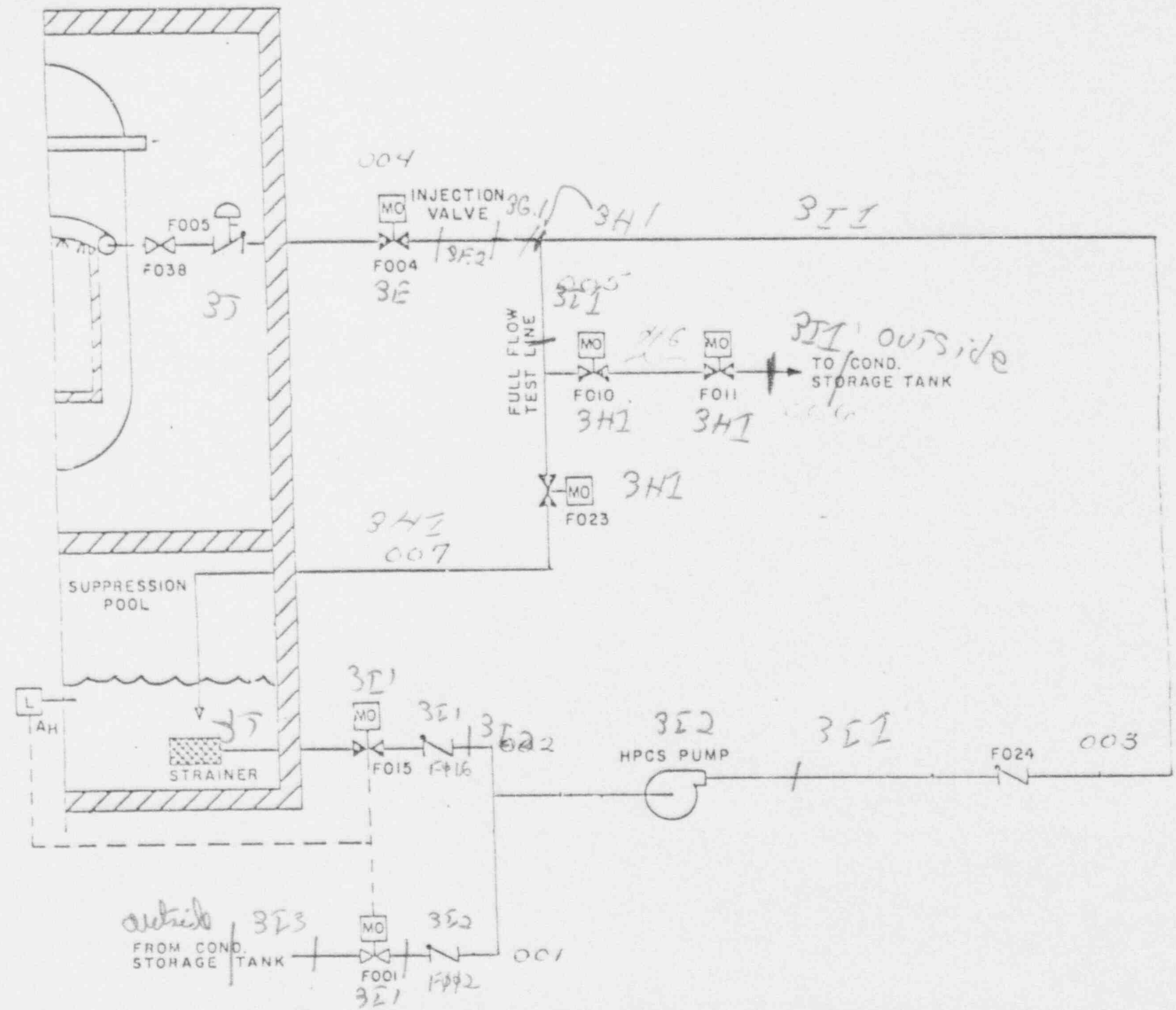


FIGURE B.1-2 HIGH PRESSURE CORE SPRAY SYSTEM SIMPLIFIED DRAWING

Figure 2.2-2 Simplified Diagram of High Pressure Core Spray system for Fault Tree Construction

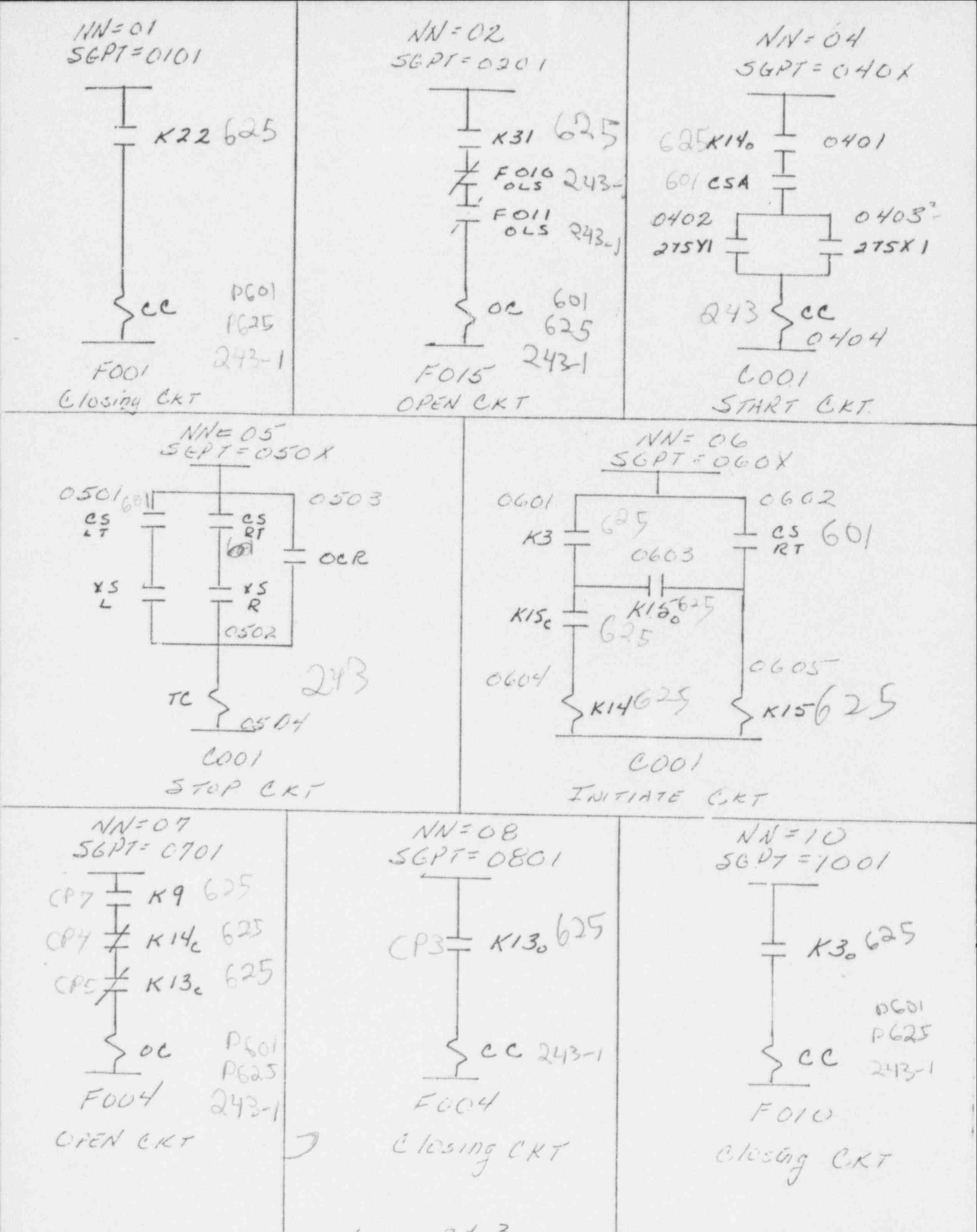


Figure B.X.3

Composite Contact Circuits

Figure 2.2-3 Component Control Circuits

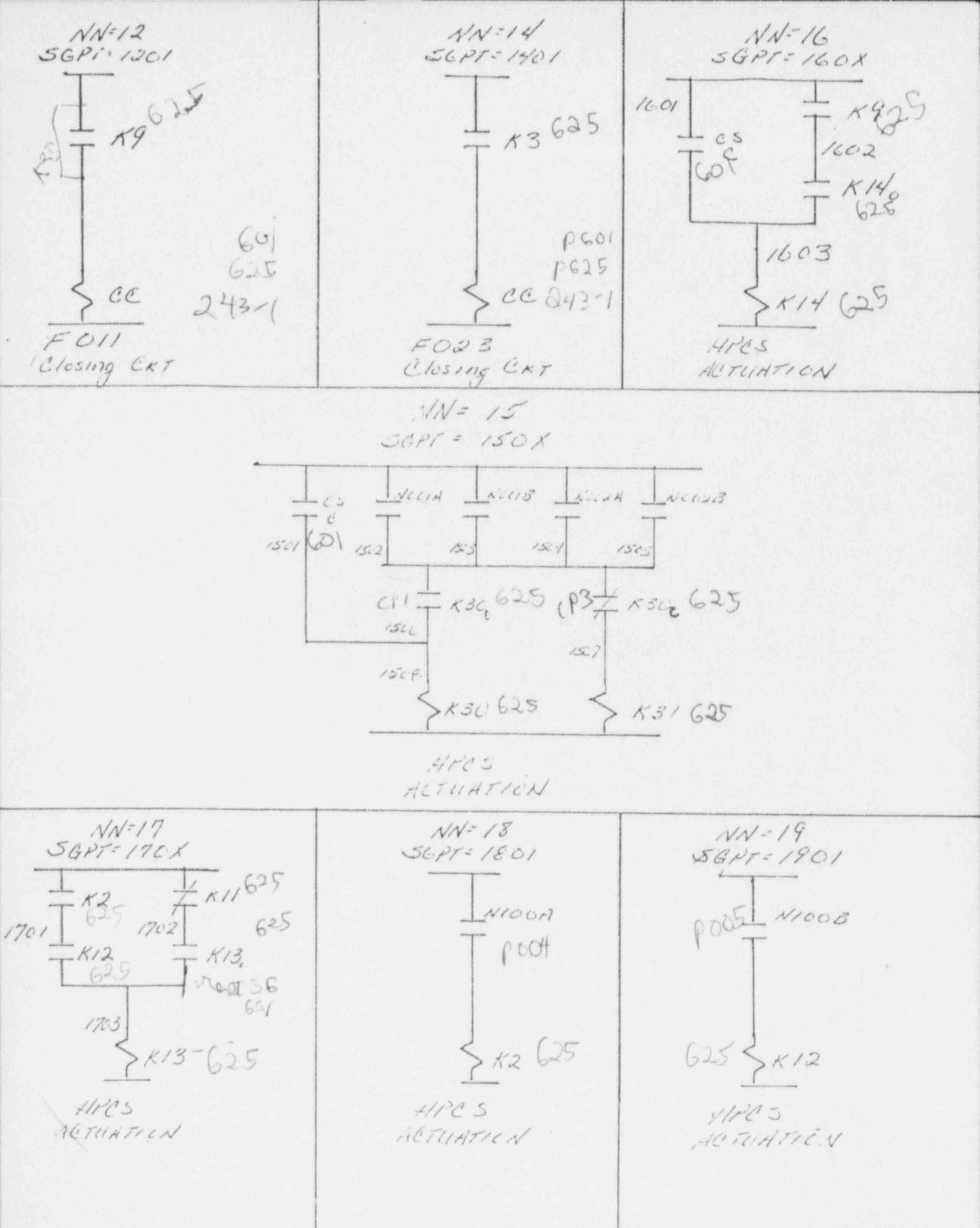


Figure B.X.4
Actuation & Control Ckt

Figure 2.2-4 Component Control and Actuation Circuits

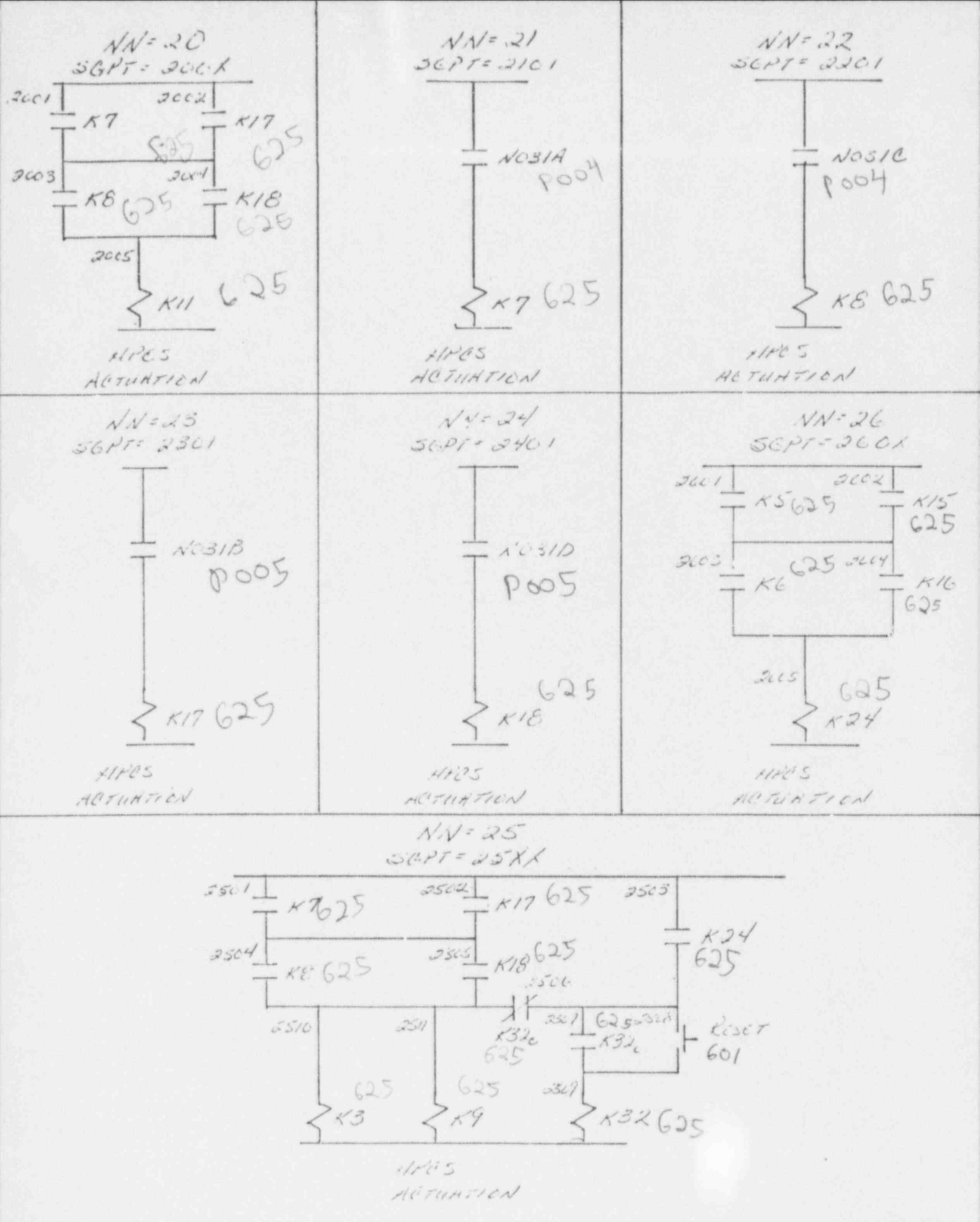


Figure B. X. 5
Actuation & Control Ckts

Figure 2.2-5 Component Actuation Circuits-2

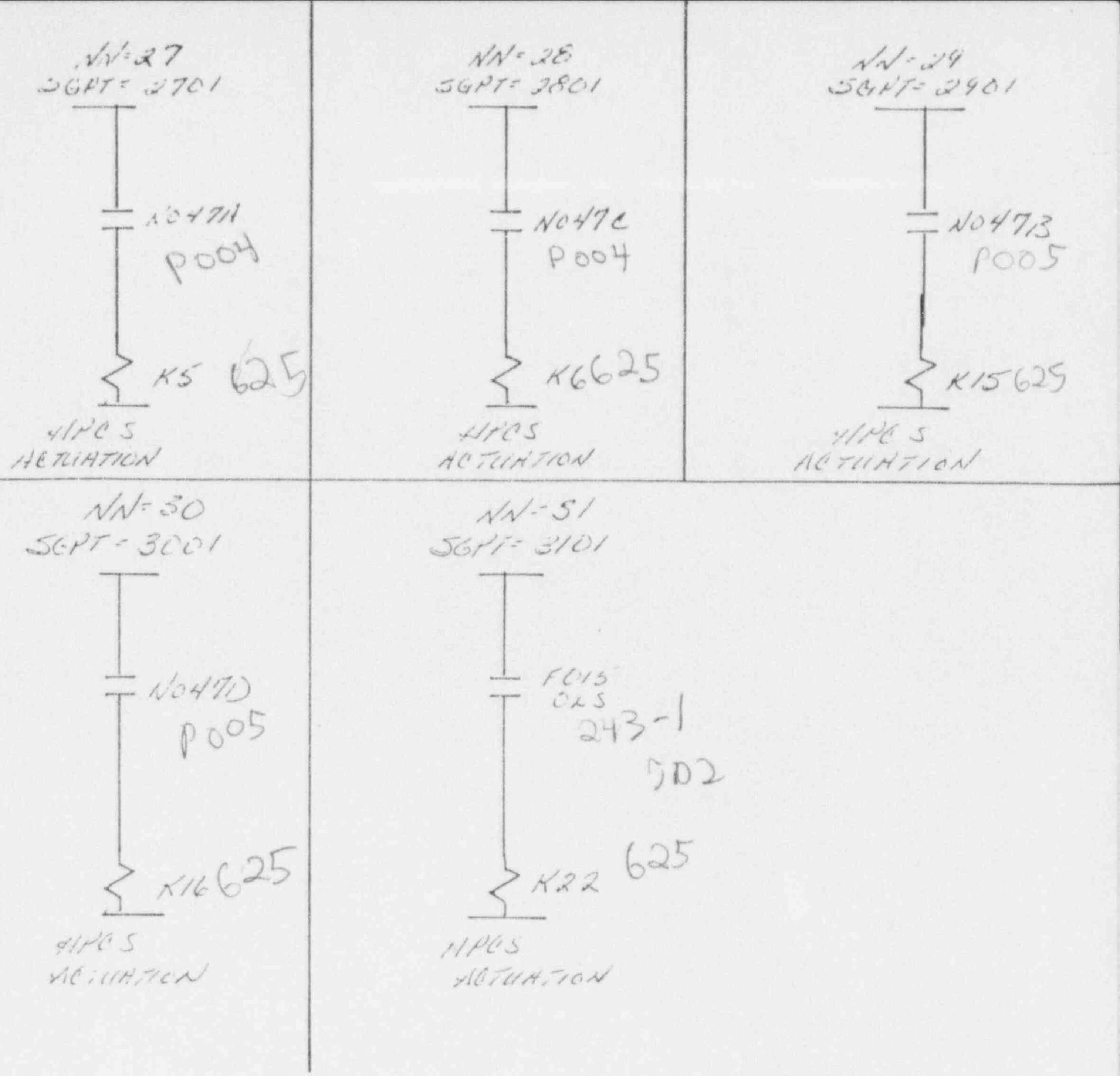


Figure B.X.6

Actuation & Control Circuits

Figure 2.2-6 Component Actuation Circuits-3

2.3 Reactor Core Isolation Cooling System (RCIC)

2.3.1 System Function

The RCIC system cools the core and reduces reactor vessel pressure following a reactor shutdown when it is isolated from its normal coolant source. Reactor vessel water is maintained or supplemented by RCIC:

a) When the reactor vessel is isolated and maintained in the hot standby condition.

b) When the reactor vessel is isolated and accompanied by a loss of normal coolant flow from the reactor feedwater system.

c) When a complete plant shutdown, following a loss of normal feedwater, is started before the reactor is depressurized enough to allow operation of the reactor shutdown cooling mode of RHR.

The RCIC system may also be used to backup the HPCS system or operate in conjunction with other ECCS systems if desired.

2.3.2 System Description

2.3.2.1 General Design

The RCIC turbine driven pump operates on steam generated by decay heat and injects water from either the suppression pool or CST into the reactor vessel through a single injection line. The pump can also be aligned to take a suction on the RHR heat exchanger for shutdown cooling. The system consists of one turbine driven pump discharging to the head spray nozzle inside the reactor vessel, and associated piping, valves, instrumentation and controls. Figure 2.3-1 is a simplified P&ID of the RCIC system.

Flow Path

a) Water

The RCIC system is normally lined up to draw water from the CST through normally open MOV 2E51-F010. Should the CST become depleted, the RCIC pump suction automatically shifts to the suppression pool by opening normally closed MOV 2E51-F031 and closing 2E51-F010. The RCIC pump discharge is directed to the reactor vessel through the normally closed injection MOV 2E51-F013 or diverted for full flow tests to the CST through normally closed MOVs 2E51-F022 and 2E51-F059. When the pump discharge is directed to the reactor vessel through 2E51-F013, the flow passes through a testable check valve 2E51-F065, penetrates the containment, then passes through another testable check valve 2E51-F066. Flow then enters the reactor vessel through the head spray nozzle. In the Hot Standby Mode, the water suction may be from either the RHR heat exchangers or the Condensate Storage Tank.

b) Steam

Steam is drawn off the reactor vessel from the "B" MSL, through 2E51-F063, penetrates the containment, then passes through 2E51-F008 to the RCIC turbine steam supply stop valve F045. From the steam supply stop valve, it is routed through the turbine stop and governor valves into the turbine. The turbine exhaust is directed to the suppression pool.

Locations

The majority of the RCIC system components are located in the northeast corner cubicle in the reactor building basement. Valve 2E51-F066 is located inside the drywell. The condensate storage tank is located outside of the southwest corner of the turbine building.

Component Descriptions

a) Water Side

The RCIC pump is a 4 stage centrifugal pump that is capable of delivering 625 gpm over a reactor pressure range of 150 to 1150 psig. The pump utilizes submerged type bearings that have no forced lubrication. Their cooling is supplied from the pump's discharge. In order to ensure adequate NPSH for the pump when the suction is aligned to the suppression pool, the pump has been located low in the Reactor Building.

The RCIC pump suction is an 8 inch line supplied by 3 sources, the CST, the suppression pool and RHR.

The Cycled Condensate Storage Tank Suction Valve 2E51-F010 is an 8-inch 250 VDC motor operated gate valve that is normally open. An 8-inch check valve 2E51-F011 prevents back-flow to the CST from the other suction sources.

The Suppression Pool Suction Valve 2E51-F031 is an 8-inch 250 VDC motor operated gate valve that is normally closed. An 8-inch check valve 2E51-F030 in series with F031 prevents back flow from the other suction sources.

The normally closed RHR suction is used only in the steam condensing (hot standby) mode of operation.

The condensate storage tank is a 350,000 gallon cylindrical tank. Penetrations in the tank for systems other than HPCS and RCIC are located above the tank bottom to provide 135,000 gallons of reserve capacity for the HPCS and RCIC systems.

The suppression pool suction line is fitted with a strainer inside the suppression pool. The strainer is above the bottom of the suppression pool to prevent clogging from sedimentation. The strainer is oversized to provide the minimum required NPSH if 50% of the strainer surface becomes plugged.

Two locked open manual isolation valves, 2E51-F016 in the RCIC pump suction line and 2E51-F012 in the pump discharge line, isolate the RCIC pump for maintenance. 2E51-F016 is an 8-inch gate valve, 2E51-F012 is a 6-inch gate valve.

The RCIC Injection Valve 2E51-F013 is a normally closed 6-inch gate valve operated by a 250 VDC motor. F013 opens on system initiation and shuts on any signal that trips the turbine.

Two testable check valves, 2E51-F065 and 2E51-F066, are located in the injection header between the injection valve and the head spray nozzle. These valves seat with reactor pressure isolating the reactor vessel should a RCIC injection line break occur. To enable verification of valve operability, a pneumatic actuator is attached to each valve disc pivot arm. The air actuator cannot prohibit disc opening. By energizing a solenoid controlled air supply to the actuator, the valve can be forced to lift off its seat. A light on the RCIC portion of the 1H13-P601 panel verifies the operability of the stem.

The minimum flow bypass valve, 2E51-F019, is a normally closed 2-inch 250 VDC motor operated globe valve. 2E51-F019 provides a minimum flow return to the suppression pool by opening when the RCIC pump is operating and other discharge paths are closed. A 2-inch check valve, 2E51-F021, in series with 2E51-F019 prevents back flow from the suppression pool.

Two DC motor operated valves in the RCIC pump discharge line allow a full flow testing of the system, routing the water back to the cycled condensate storage tank. 2E51-F022 is a normally closed 4-inch 250 VDC motor operated gate valve used to throttle the flow. 2E51-F059 is a normally closed 4-inch 250 VDC motor operated gate valve used as an isolation valve.

b) Steam Side

The RCIC turbine is a Terry Water Wheel Turbine which is not affected by water shagging. It is capable of starting and delivering rated pump flow within 30 seconds of an actuation signal. The turbine's bearings are supplied oil by a shaft driven oil pump. The turbine oil system provides lubrication to the turbine bearings and actuating oil for the turbine control valve. The oil pressure is developed by a shaft driven oil pump. Water tapped off the discharge side of the RCIC pump is routed to the turbine lube oil cooler. The discharge of the cooler is then routed to the barometric condenser where it is used as spray to condense the steam that is exhausted by the turbines seals and the leakage from the governor and stop valve stems. 2E51-F046 is a 2-inch 250 VDC motor operated throttling valve in the cooling water supply line. When the system is not operating this valve is shut to prevent draining water from the cycled condensate storage tank through the pump to the barometric condenser.

Two normally open steam line isolation valves, 2E51-F063 the inboard isolation valve and 2E51-F008 the outboard isolation valve, are 480 VAC motor operated valves. 2E51-F063 is a 10-inch gate valve, 2E51-F008 is a 4-inch gate valve.

The turbine steam supply stop valve, 2E51-F045, is a 250 VDC 4-inch motor operated globe valve. It is the only valve in the steam supply line that is closed when the system is in the standby mode. It is designed to open against full reactor pressure (1140 psig) within fifteen seconds.

A drain pot preventing condensation from building up in the steam supply line drains to the main condenser. The drain control valves close when F045 opens.

The turbine trip and throttle valve (stop valve) is a normally open 250 VDC motor operated 3-inch gate valve controlled from the P601 panel. The valve interrupts steam supply to the turbine upon receipt of a turbine trip signal.

The turbine control (governor) valve is a hydraulically operated throttling valve that controls the steam flow to the turbine for turbine speed control.

The RCIC turbine exhausts through a 10-inch line to an underwater sparger in the suppression pool. Two rupture diaphragms installed in series in a 6-inch line connected to the turbine exhaust line provide overpressure protection for the turbine casing. The diaphragms rupture at 150 psig. The space between the diaphragms is vented to the atmosphere through a restricting orifice. A high pressure of 10 psig in the space between the two diaphragms will cause a system isolation and turbine trip.

Primary containment isolation valve 2E51-F068 in the turbine exhaust line is a 10-inch 250 VDC motor operated gate valve. A 10-inch check valve 2E51-F040 in series with 2E51-F068 prevents suppression pool water from entering the turbine exhaust line while the system is secured. A 2-inch vacuum breaker line taps into the exhaust line downstream of the exhaust line isolation valve. This line prevents water from being drawn back into the exhaust line following RCIC operation. Two normally open 2-inch motor operated globe valves, 2E51-F080 and 2E51-F086, isolate this line.

2.3.2.2 System Interfaces

A failure modes and effects analysis of the Reactor Core Cooling System indicating the required support system interfaces is shown in Table 2.2-1. The support system interfaces are discussed below.

Electrical

The plant electrical distribution system provides power to the RCIC system for control of the turbine driven pump, operation of system MOVs, and system instrumentation and controls. Turbine controls and the initiation relay logic are supplied power from 125 VDC distribution panel 211Y. The RCIC isolation logic is supplied from 125 VDC distribution panel 212Y. All system DC operated MOVs are powered from 250 VDC Bus 221Y. AC operated MOVs 2E51-F063 and 2E51-F086 are powered from 480 VAC Bus 236Y-2. The RCIC steam supply outboard isolation valve 2E51-F008 is supplied from 480 VAC Bus 235X-1.

RHR

The RCIC pump suction may be aligned to the RHR Heat Exchanger for operation in the steam condensing mode (Hot Standby). The condensate from the RHR heat exchanger is returned to the reactor vessel by the RCIC pump. The RHR steam supply to the RHR heat exchangers taps off of the RCIC steam line between the containment and the RCIC outboard isolation valve 2E51-F008.

The core standby cooling system (CSCS) provides cooling to the RCIC room HVAC to maintain area temperatures within normal operating limits during system operation.

2.3.2.3 Instrumentation and Control

System Actuation

The RCIC system may be initiated either manually, at Panel 2H13-P601, or automatically by a low low reactor vessel water level, Level 2 (-50 inches). The initiate signal seals in and must be manually reset before the system can be secured.

Four reactor vessel water level instruments, 2B21-N037A through 2B21-N037D, provide the Level 2 RCIC initiate signal. Contacts for each of these four instruments are arranged in a one of two taken twice logic. This arrangement prevents single failures from causing or preventing an initiation, and allows single element testing of the initiation logic during plant operations.

Startup and flow alignment of the RCIC system is initiated and controlled by four relays (K2, K3, K5 and KX5) that are energized by the initiate signal.

The K2 relay opens the turbine steam supply valve 2E51-F045 and the turbine cooling water supply valve 2E51-F046.

The K3 relay controls the CST suction valve 2E51-F010 and the full flow test return isolation valve 2E51-F059.

The K5 relay closes the full flow test return throttling valve 2E51-F022 and opens the RCIC injection valve 2E51-F013.

The KX5 relay bypasses the RCIC system MOV thermal overloads.

Component Control

a) RCIC Motor Operated Injection Valve (2E51-F013)

The normally closed motor operated injection valve opens when an initiation signal is present if the following permissives are satisfied.

1) The turbine exhaust valve 2E51-F068 is open.
2) The reactor vessel high water level (+55.5 inches) signal is not present.

The valve will stay open until manually closed after the reactor vessel water level has increased above Level 2 or either the turbine trip and throttle valve or the turbine steam supply (F045) close.

b) Minimum flow Bypass Valve (2E52-F029)

A low flow signal of 60 gpm and greater than 125 psig discharge pressure will cause F019 to open and route flow to the suppression pool. F019 will close when flow has increased to 90 gpm.

c) CST suction isolation valve (2E51-F010)

The CST suction valve is a normally open motor operated valve. The valve will open upon a RCIC initiation if shut and the suppression pool isolation valve 2E51-F031 is not open. The CST isolation valve will shut automatically if the suppression pool isolation valve is opened.

d) Suppression pool suction isolation valve (2E51-F031)

The suppression pool isolation valve opens during system operation when the CST level decreases below 5'1". The valve can only be closed with the manual control switch.

e) Full Flow Test Return Valves (2E51-F022 and 2E51-F059)

Both valves are normally closed MOVs that must be opened with the manual control switch. When open both valves will automatically shut upon a RCIC initiation or if the suppression pool isolation valve is opened.

f) Turbine Cooling Water Supply Valve (2E51-F046)

The cooling water supply valve automatically opens upon a RCIC initiation. The valve must be manually closed with its control switch.

g) Inboard Steam Line Isolation Valve (2E51-F063)

The inboard steam isolation valve is a normally open MOV that closes upon indication of a steam leak (both upstream and downstream of the valve), low steam supply pressure, or failure of a turbine exhaust rupture diaphragm.

h) Outboard Steam Line Isolation Valve (2E51-F008)

The outboard isolation valve is a normally open MOV that automatically closes upon indication of a steam leak downstream of the valve, low steam supply pressure or failure of the turbine exhaust rupture diaphragm.

i) Turbine Steam Supply Valve (2E51-F045)

The turbine steam supply valve is a normally closed MOV that opens upon RCIC initiate to admit steam to the RCIC turbine. After opening, the valve can be closed manually with the control switch or automatically if the reactor vessel water level increases to +55.5 inches.

j) Turbine Trip and Throttle Valve (Stop Valve)

The turbine trip and throttle valve is a normally open MOV with the valve stem latched to the operator. If the valve is unlatched from the operator spring pressure will drive it closed. The following signals will cause the latch mechanism to disengage from the operator.

1) Remote pushbutton depressed.

2) Local manual trip lever pushed.

3) RCIC turbine overspeed.
   a. 110% electronic (4950 RPM).
   b. 125% mechanical (5625 RPM).

4) High reactor water level (Level 8, +55.5') - prevents carryover.

5) High turbine exhaust pressure (25 psig) - prevents damage to turbine casing and exhaust lines.

6) Low RCIC pump suction pressure (20" Hg Vac) - prevents damage to RCIC pump.

7) Any isolation signal.

To reopen the valve after it has tripped, the valve must be driven to the full close position to relatch the trip device. The valve can then be reopened. The valve may be reset from the control room, by driving the motor operator to the full shut position, or locally by manual operation of the handwheel. If the valve trips on mechanical overspeed or local manual, it must be reset locally. The remote reset function is disabled when the mechanical trip device is tripped.

k) Turbine Control Valve (Governor Valve)

The control valve is hydraulically operated by pressure provided by the turbines control oil system via the shaft driven oil pump. The position of the control valve is controlled by a flow controller that compares actual turbine speed to desired speed producing a speed signal that controls oil pressure to the governor valve, controlling turbine speed. The flow controller may be operated in automatic or manual with the operator setting the desired flow. When the turbine is shut down (no oil pressure), the control valve is fully opened.

During system startup, the RCIC turbine speed is controlled by ramp generator. When 2E51-F045 opens, it energizes the ramp generator. In approximately 12 seconds the ramp generator signal will bring the turbine to rated speed.

When the turbine is shut down or is tripped by a trip signal other than mechanical overspeed, the 2E51-F045 valve must be closed to reset the ramp generator. On mechanical overspeed the ramp generator must be reset by locally resetting the mechanical overspeed trip device.

l) Turbine Exhaust Isolation Valve (2E51-F008)

The turbine exhaust valve is a normally open MOV. The valve position is indicated and controlled by the control switch in the control room.

m) Vacuum Breaker Isolation Valves (2E51-F080 and 2E51-F086)

The Vacuum breaker isolation valves are normally open. They close to isolate the Vacuum breaker line on a containment isolation.

Instrumentation

The following instrumentation is associated with the RCIC system:

Parameter	Condition	Setpoint	Indicator Location
RCIC Steam Supply Pressure	Low	57 psig	Control Room
RCIC Steam line Diff Press Hi	High	117"/191"	Control Room
RCIC Turbine Exhaust Pressure	High	25 psig	Control Room

RCIC Turbine Exhaust Diaphragm Pressure	High	10 psig	Control Room
RCIC Pump Discharge Flow	Low	<60 gpm & F045 open	Control Room
RCIC Pump Suction Pressure	High	85 psig	Control Room
RCIC Pump Suction Pressure	Low	20" Hg Vac	Control Room
Leak Detection Valve Stem Leakage Stem Leakage Temp Hi	High	250F	Control Room
RCIC Barometric Condenser Level	Low/High	5 1/4/14 3/4"	Control Room
RCIC Vacuum Tank Pressure	High	3" Vac	Control Room
RCIC Turbine Stm Line Drain Pot Level	High	Reference 0"	Control Room
RCIC Turbine Trip	trip relay energized		Control Room
RCIC Steam line Isolation	isolation relay energized		Control Room
Manual Init. P.B.	Armed		Control Room
Bar. Condenser Vac Pump Disch. Valve	Not Open	F069 not fully open	Control Room
RCIC Steam Supply Valve F076	Open	Warming valve is open	Control Room
RCIC Turbine L.O. Pressure	Low	2-4 psig	Control Room
RCIC Turbine Bearing Temp.	High	180	Control Room
Main/Feedwater Turb RCIC Trip Bypass	Armed	Control Switch In Test	Control Room

RCIC Oil Filter Diff. Press Hi	High	5-7 psig	Control Room
RCIC Cond Storage Tank Level Lo	Low	3'1"	Control Room
RCIC Pipe Routing Equip. Area Temp. Hi Div I & Div II	High	Multiple	Control Room
RCIC Vacuum Breaker Isolation Valve F080 or F086 Not Full Open		Not Full Open	Control Room

2.3.2.4 Operator Actions

The RCIC system is designed to automatically start and function when required without operator actions. The primary responsibility of the operator is to verify system operability on a regular basis and proper operation following an initiation. Should portions of the initiation or control circuitry malfunction during system operation the operator can take manual control of the components that are operating improperly.

2.3.2.5 Technical Specification Limitations

The LaSalle technical specifications require the reactor core isolation cooling (RCIC) system and its actuation instrumentation to be operable during operational conditions 1, 2, and 3 with reactor steam dome pressure greater than 150 psig. The system is considered operable when it is capable of taking suction from the suppression pool and transferring the water to the reactor vessel. The actuation instrumentation is considered operable when the minimum number of operable channels, trip setpoints, and time response requirements of section 3.3.5 are satisfied. If the RCIC system becomes inoperable plant operation may continue for 14 days provided the HPCS system is operable. If the RCIC system is not restored within this period, the plant must be placed in hot shutdown within the next 12 hours and reactor steam dome pressure reduced to 150 psig within the following 24 hours.

During plant operations with a RCIC discharge line, "keep filled" pressure alarm instrumentation channel inoperable, the system must be verified full by venting though the high point vent at least once per 24 hours.

Surveillance Requirements

The RCIC system must be demonstrated operable at the following time intervals:

1) Every 31 days by:

a) Verifying the system is filled with water by venting at the high point vents.

b) Performing of a channel functional test of the discharge line "keep filled" pressure alarm instrumentation.

c) Verifying that each valve in the flow path that is not secured in position, is in its correct position.

d) Verifying that the pump flow controller is in the correct position.

2) Every 92 days by verifying that the RCIC pump develops a flow greater than or equal to 600 gpm in the test flow path.

3) Every 18 months by:

a) Performing a system functional test which includes simulated automatic actuation and verifying that each automatic valve in the flow path actuates to its correct position.

b) Verifying that the system is capable of providing a flow of greater than or equal to 600 gpm to the reactor vessel when steam is supplied to the turbine at a pressure of 150 $\pm$ 15 psig using the test flow path.

c) Performing a Channel Calibration of the discharge line "keep filled" pressure alarm instrumentation and verifying the low pressure setpoint to be > 62 psig.

5) Power to the RCIC system must also be verified available by demonstrating that MCC 221Y, the 250-volt battery, and the charger are operable at the following time intervals.

a) Every 7 days:

MCC-221Y is energized with correct breaker alignment and power available from the charger and battery.

The electrolyte level of each pilot cell is above the plates, and the cell specific gravity is greater than or equal to 1.200, and

The overall battery voltage is greater than or equal to 250 volts.

b) Every 92 days:

The voltage of each connected battery is greater than or equal to 250 volts under float charge and has not decreased more than 12 volts from the value observed during the original test, The specific gravity of each connected cell is greater than or equal to 1.195 and has not decreased more than 0.05 from the value observed during the previous test, and

The electrolyte level of each connected cell is above the plates.

c) Every 18 months:

The battery shows no visual indication of physical damage or abnormal deterioration, and

Battery terminal connections are clean, tight, free of corrosion and coated with anticorrosion material.

6) Each RCIC actuation instrumentation channel must be demonstrated operable by performing the channel checks, functional tests, and calibrations at the frequencies given in Table 4.3.5.1-1 of the technical specifications.

2.3.2.6 Tests

The RCIC system tests which affect the system availability are summarized in Table 2.3-2. Component operability is verified monthly for MOVs by stroke time testing, and quarterly for the system with a full flow test.

2.3.2.7 Maintenance

Scheduled routine maintenance is not performed on the RCIC system during plant operation. A summary of expected unscheduled maintenance activities during plant operations is given in Table 2.3-3.

2.3.3 System Operations

2.3.3.1 Normal Operation

During normal plant operation, the RCIC system is in standby with the water leg pump operating to keep the system piping filled.

2.3.3.2 Abnormal Operation

When a RCIC system initiation signal is received, either manual or automatic, the 2E51-F045 valve opens admitting steam to the RCIC pump turbine. At the same time, the RCIC injection valve opens aligning the pump discharge to the reactor vessel and the cooling water supply valve, 2E51-F046, opens to provide cooling for the turbine lube oil and condensing spray to the barometric condenser. These components are the only ones in the RCIC system required to change state for system operation when the system is in a normal standby lineup. If the system is in an abnormal lineup from surveillance tests, those valves out of their normal operating position will automatically return to their normal position without operator action. If the CST level is depleted during system operation, the RCIC suction will automatically shift to the suppression pool. If the reactor vessel water level increases above +55.5 inches, the steam supply valve 2E51-F045, the turbine trip and throttle valve, and the injection valve 2E51-F013 will close securing the system. The initiation signal seal in must be reset before the system can reinitiate on low low reactor vessel water level.

2.3.4 System Fault Tree

2.3.4.1 Fault Tree Description

A simplified diagram of the RCIC system used for fault tree modeling is shown in Figure 2.3-2. The system has been divided into labeled segments for modeling. Component control and actuation system diagrams developed for system modeling are shown in Figures 2.3.3 through 2.3.11.

The fault tree contains one top event labeled "Failure of the RCIC System to Inject Coolant With One of One Pumps." There are 6 developed events in the fault tree where the RCIC system interfaces with the electrical power distribution system.

2.3.4.2 Success/Failure Criteria

Successful operation of the RCIC system occurs when the system provides flow to the core following a vessel isolation. System failure occurs when design flow to the core is disrupted. Events resulting a failure of the system include:

1) Failure of the RCIC pump

2) Failure of the injection valve to open

3) Failure of the turbine steam supply valve to open

4) Diversion of flow through the full flow test return line to the CST

5) Failure of the RCIC suction to successfully transfer to the suppression pool on a CST low level.

2.3.4.3 Major Assu ptions

In constructing tne fault tree for the RCIC system, the following assumptions were m de in addition to the general assumpti ven at the beginning of this olume:

1) Operator rrors resulting in MOV misposition faults were neglected because:

a) RCIC MOVs receive an initiation signal to go to their safe position.

b) If an MOV or its breaker is out of position, there will either be a Wrong Position Indication or No Position Indication in the control room which will be detected by the operator during the shift turnover check.

2) The minimum flow recirculation line was neglected as a diversion path because it is an orificed line with an effective diameter 1/3 of the injection line.

3) No immediate operator actions were modeled except for failure of the operator to actuate RCIC and failure to shift the pump suction from the CST to the suppression pool if the automatic shift fails.

4) Failures of the water leg pump were neglected because:

a) The pump discharge pressure is alarmed in the control room

b) During periods of unavailability, the water leg must be verified full every 24 hours (Tech Spec 3.5.1)

c) The pump discharge line is designed to withstand the water hammer resulting from a pump start.

2.3.5 References

1) FSAR

System description	Section 5.4.6
Instrumentation	Sections 7.1.2.18 and 7.4.1.3
Technical Specifications	Limiting Condition for Operation: Sections 3.7.3, 3.3.5 Surveillance Requirements: Sections 4.7.3 and 4.3.5 Basis: Section 3/4.7.3

2) Operator Training Manual — Chapter 41

3) Drawings

P&ID M-147
I&C IE-2-4226AA - BF
General Arrangement
M-312
M-314
M-316
M-207
M-223

M-231
M-206
Master Diagrams
RI01 - RI37
Cable Tabulation
2RI01 - 2RI29

4) Procedures	LIS-RI-10 Rev.3
	LOS-RI-10 Rev.3
	LOS-RI-10 Rev.6
	LOS-RI-10 Rev.7
	LOS-RI-10 Rev.3
	LOS-RI-10 Rev.1
	LOS-RI-10 Rev.7
	LOP-RI-10 Rev.5
	LOP-RI-10 Rev.3
	LOP-RI-05 Rev.7

Table 2.3-1 Reactor Core Cooling System Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
250 VDC MCC 221Y	F031	RCIC pump suction to suppression pool	Fail to open	Valve status lights in CR	Inability to switch RCIC suction to suppression pool CST low level resulting in a loss of RCIC	
	Pump	Barometric Condenser Vacuum Pump	Not running (deenergized)	CR Alarm	Loss of barometric condenser vacuum Leakage of reactor steam to the LPCS room. Little or no short term affect on RCIC operation. Long term affects high activity in the LPCS room and excessive humidity with attendant electrical circuit affects, or an area high temperature alarm or isolation.	Failure of the 250 VDC MCC 221Y electrical supply will disable RCIC and prevent initiation of the system when required. Loss of this bus while RCIC is operating will cause a loss of system control from the control room which will probably result in a system shutdown.
	Pump	Barometric Condenser Condensate Pump	Not running (deenergized)	CR Alarm	Same as above	
	F046	Turbine lube oil cooler water supply valve	Fail to open	High bearing temperature in control room	Loss of lube oil cooling and barometric condenser sprays resulting in a high RCIC lube oil temperature leading to turbine damage or failure and loss of RCIC	
	F019	Minimum flow bypass to suppression pool	Fail to open	Pump flow instrument in control room	Potential pump damage if all other pump discharge paths also remain closed. This would take a while to develop.	

Table 2.3-1 Reactor Core Cooling System Interface FMEA (Concluded)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
	F045	RCIC turbine isolation valve	Fail to open	CR status lights	Loss of RCIC Turbine	
480 VAC MCC 235Y-2	C003	RCIC water leg pump	Not running (deenergized)	CR alarm	Failure to keep water leg full with potential for water hammer during RCIC system start. Water hammer could damage RCIC & RPV system components.	Failure of this system will not prevent RCIC from operating when required.
480 VAC MCC 235X-1	F008	Steam supply valve	Fail as is	CR status light	Valve is normally open should not affect system operation	None
480 VAC MCC 236Y-2	F063	Steam supply valve	Fail as is	Status light in CR	Valve is normally open should not affect system operation	None
ECCS Cooling	High temperature in equipment room or pipe routing area		System Isolation	Alarm in CR	Loss of RCIC injection	Failure of the LPCS room cooler (cooling water or fan) will result in a RCIC isolation and loss of the system function.

Table 2.3-2 Reactor Core Cooling System Component/ Subsystem Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation?	Test Frequency (Mo)	Test Outage (Hr)	Component/Subsystem Alignment/Operability Verification Frequency
LIS-RI-10	Valve Response Time	2E51-F008	MOV	Yes	No	Cal 18	2	Shift
		2E51-F063	MOV	Yes	No	Ft 1	2	
LOS-RI-R1	Turbine Overspeed	Turbine	Turbine	Yes	No	18	12	Quarterly

Table 2.3-3 Reactor Core Cooling System Component/Subsystem Maintenance Summary

Component Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E51-F059	MOV	Mechanical Electrical I&C	None	Yes			Shift
2E51-F046	MOV	Mechanical Electrical I&C	None None None	Yes Yes Yes			Shift
2E51-F013	MOV	Mechanical Electrical I&C	None None None	Yes Yes Yes			Shift
2E51-F045	MOV	Mechanical Electrical I&C	None None None	Yes Yes Yes			Shift
2E51-C001	Turbine	Mechanical Electrical I&C	F045,F008 None None	Yes Yes Yes			Shift
2E51-C001	Pump	Mechanical	F013,F012 F016	Yes			Shift
2E51-F068	MOV	Mechanical Electrical I&C	F045,F008 None None	Yes Yes Yes			Shift
2E51-F080	MOV	Mechanical Electrical I&C	F045,F008 None None	Yes Yes Yes			Shift
2E51-F008	MOV	Mechanical Electrical I&C	None None None	Yes Yes Yes			Shift
2E51-F063	MOV	Mechanical Electrical I&C	None None None	Yes Yes Yes			Shift
2E51-F016	Manual Valve	Mechanical	F013,F012	Yes			Shift

Table 2.3-3 Reactor Core Cooling System Component/Subsystem Maintenance Summary (Concluded)

Component Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E51-F012	Manual Valve	Mechanical	None	Yes			
2E51-F030	Check Valve	Mechanical	F016,F012	Yes			
2E51-F011	Check Valve	Mechanical	F016,F012	Yes			
2E51-F065	Check Valve	Mechanical	None	No			
2E51-F066	Check Valve	Mechanical	None	No			
2E51-F040	Check Valve	Mechanical	F045,F008	Yes			

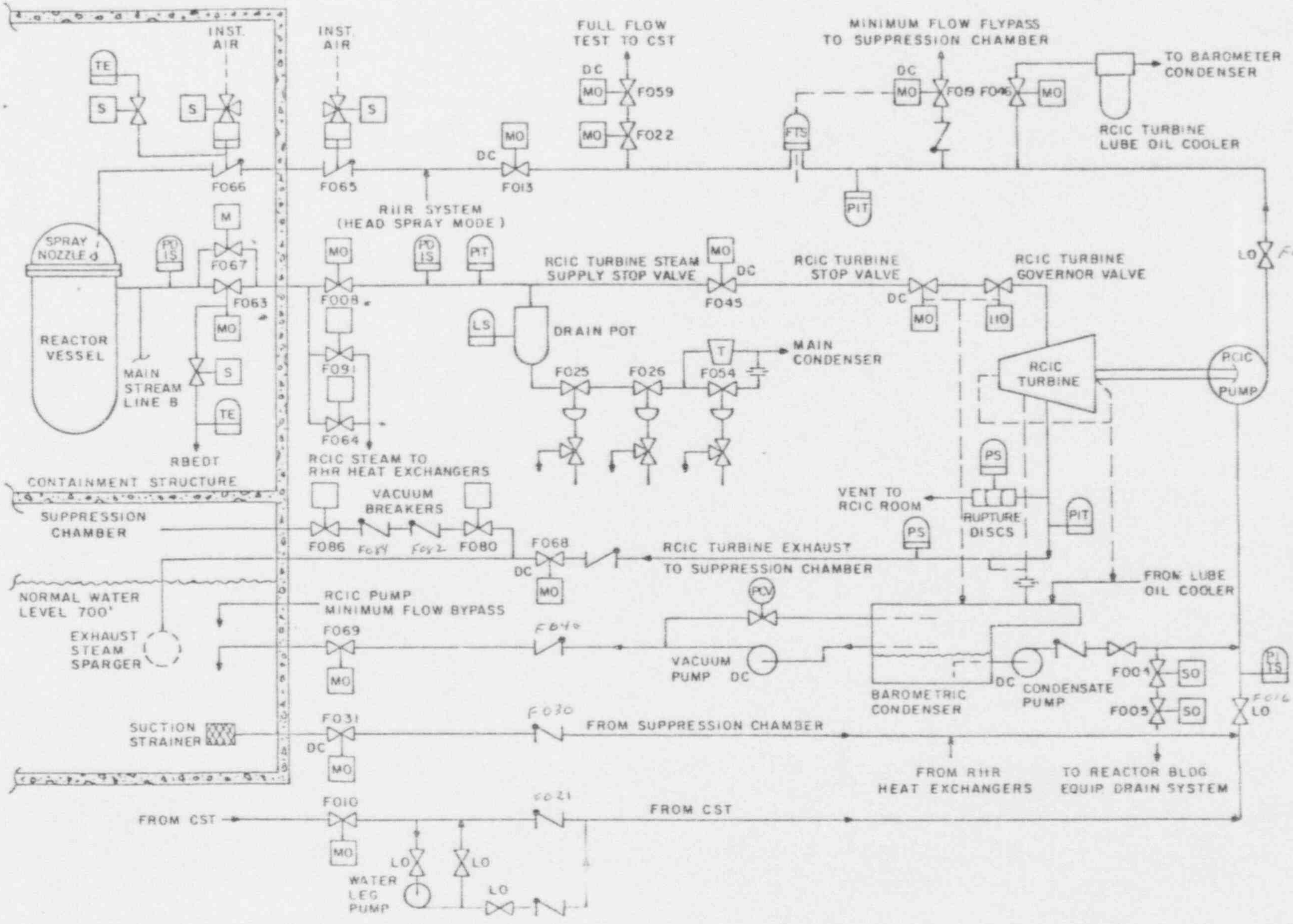


FIGURE B.X.1 REACTOR CORE ISOLATION COOLING SYSTEM SIMPLIFIED DRAWING

Figure 2.3-1 Simplified Schematic of Reactor Core Isolation Cooling System

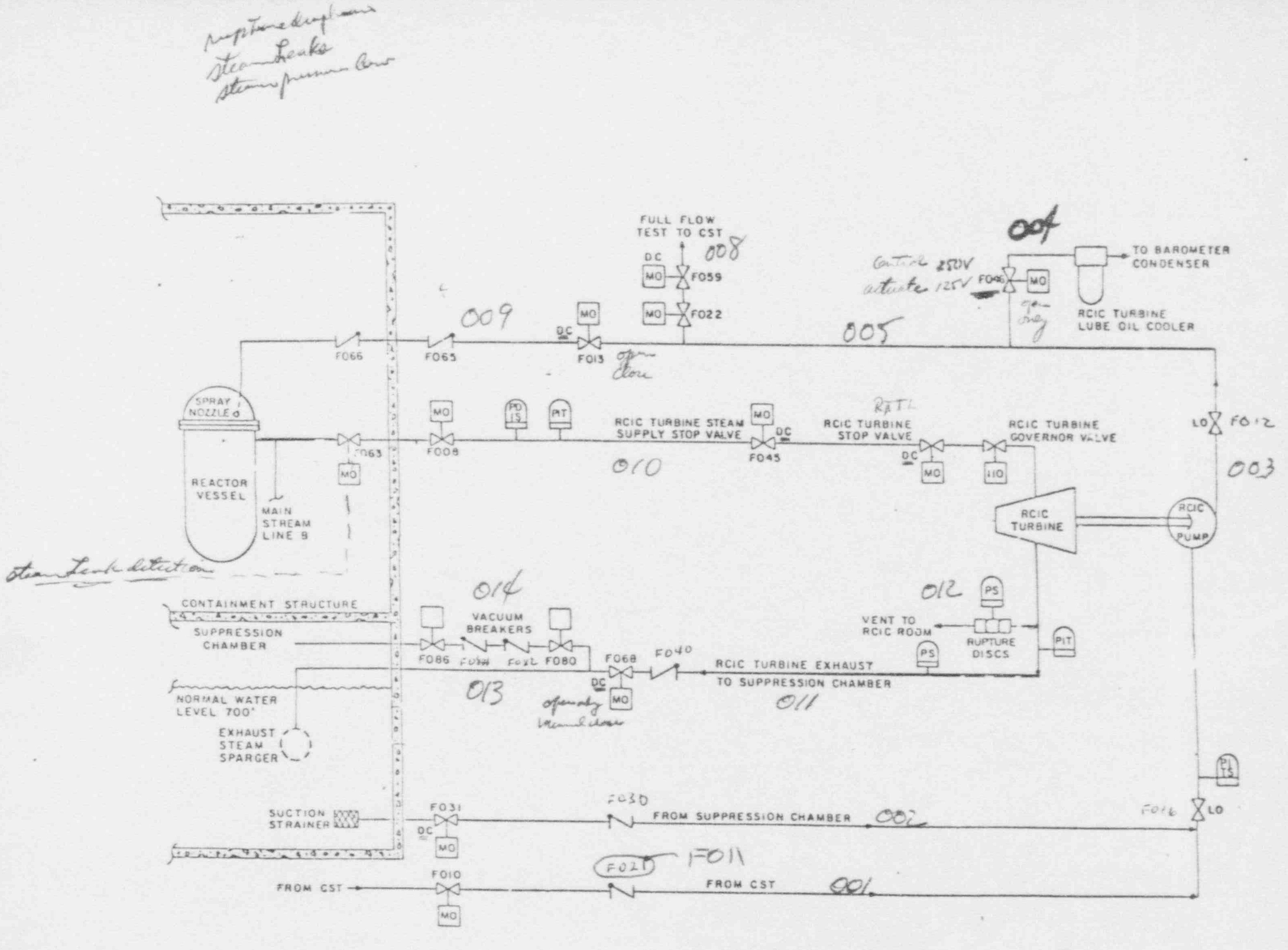


FIGURE 8.K.2 REACTOR CORE ISOLATION COOLING SYSTEM SIMPLIFIED DRAWING

Figure 2.3-2 Simplified Diagram of Reactor Core Isolation Cooling System for Fault Tree Construction

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Idaho Falls, Idaho 83402

CALCULATION / WORK SHEET

SHEET ________ OF ________

CLIENT:	PROJECT:			
COMPONENT/SYSTEM	PREPARED BY:	DATE:	CHECKED BY:	DATE:

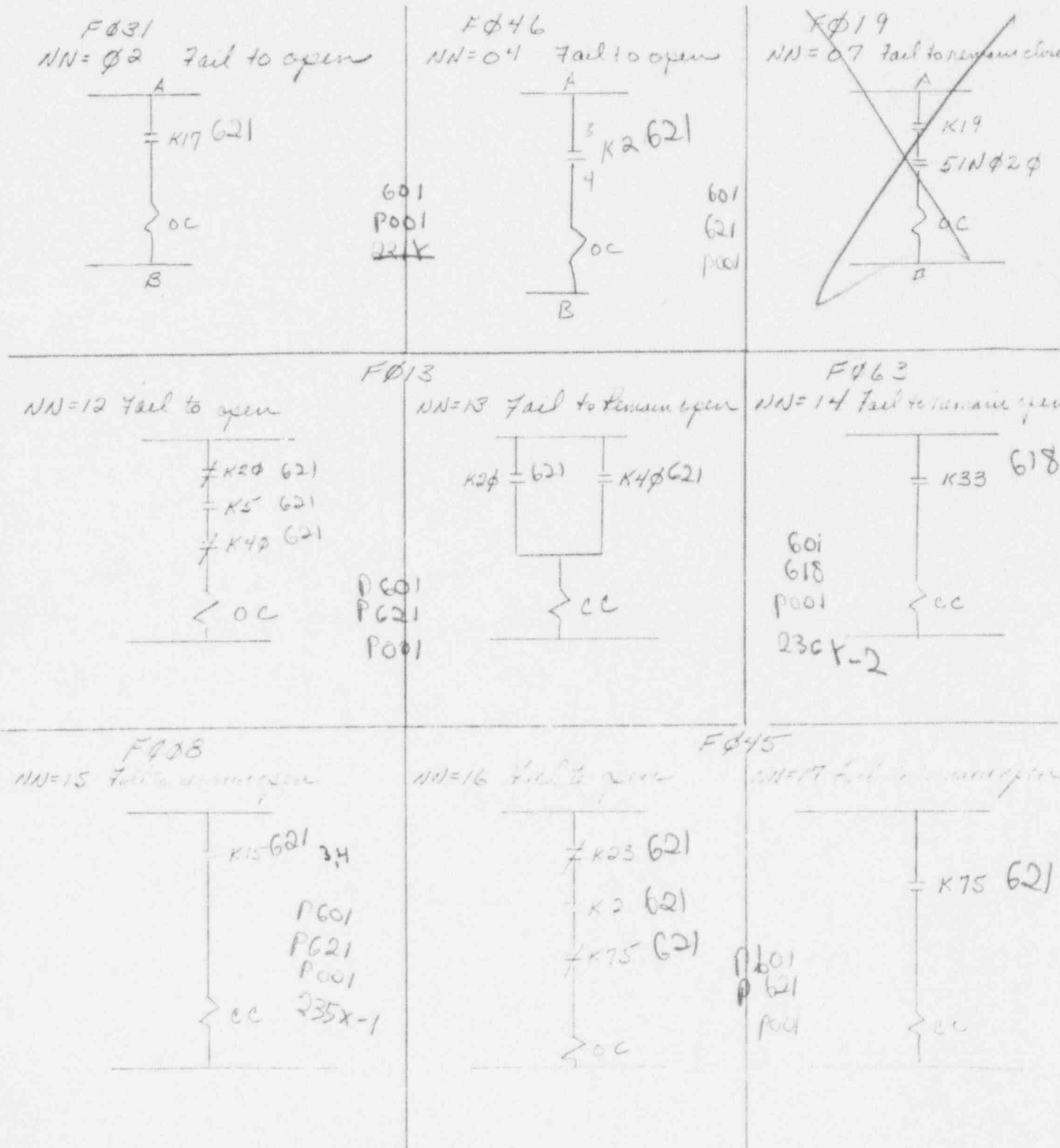

Figure B.X. 3

Figure 2.3-3 RCIC Valve Control Circuits-1

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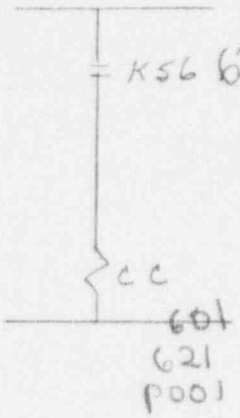
CALCULATION / WORK SHEET

SHEET ________ OF ________

CLIENT:		PROJECT:		
COMPONENT SYSTEM	PREPARED BY:	DATE:	CHECKED BY:	DATE:

FØ8Ø
NN=19 Fail to remain open



FØ86
NN=2Ø Fail to remain open

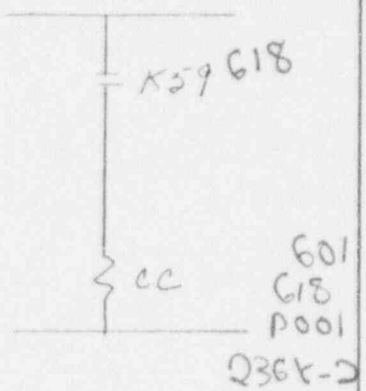
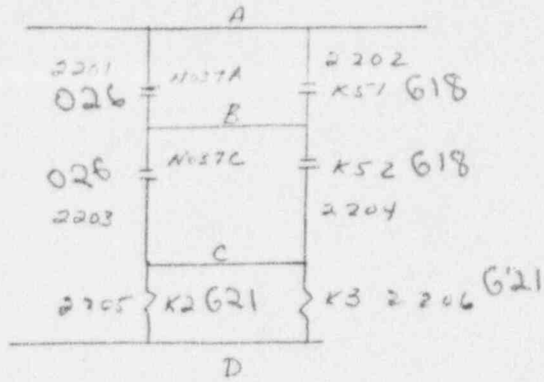


Figure B.X.4

Figure 2.3-4 RCIC Valve Control Circuits-2

ACTUATION

K2 & K3 NN = 22 Fail to Energize



N037A = RACN037A
K51 = RACTK510
K52 = RACTK520
N037C = RACN037C
K2 = RACTK2
K3 = RACTK3.

K2 = 217A

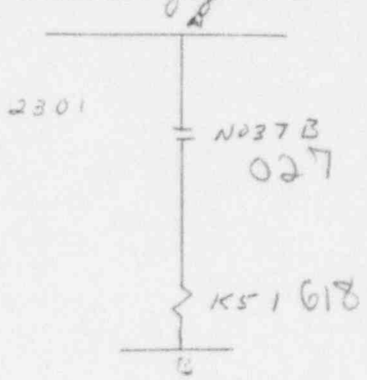
K3 = 217

Boolean K2 (contacts open)
D = 2205 + C

Boolean K3 (contacts open)
D = 2206 + C

common to K2 & K3
C = 2203 + 2204 + B
B = 2201 + 2202
power unavailable

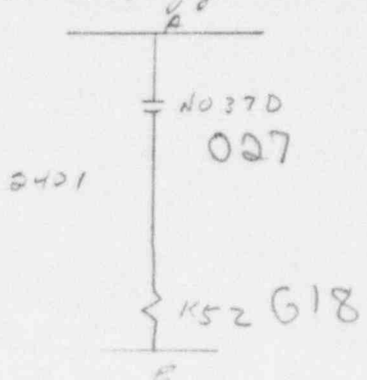
K51 Fail to Energize NN = 23



N037B = RAC N037B
K51 = RACTK51
Boolean (contacts open)
B = 2301
power unavailable

303

K52 Fail to Energize NN = 24



N037D = RACN037D
K52 = RACTK52
Boolean (contacts open)
B = 2401
power unavailable

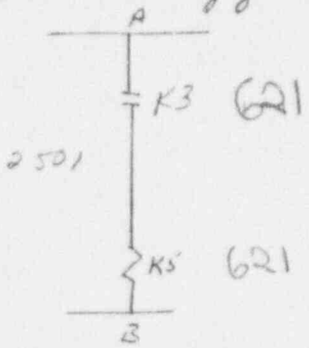
307

Figure B.X.5

Figure 2.3-5 RCIC Actuation Circuitry-1

ACTUATION

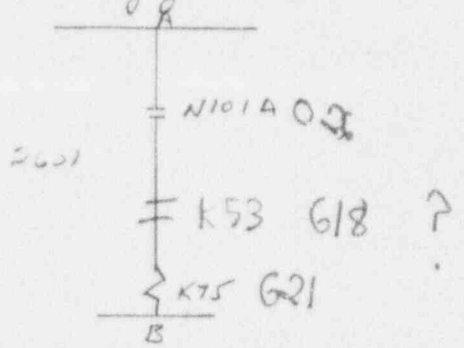
K5 Fail to Energize NN=25



K3 = RACTK30
K5 = RACTK5
Boolean (contacts open)
B=2501
power unavailable

204 X

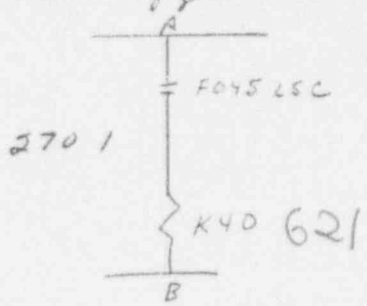
K75 Fails Energized NN=26



N101A = RACN101A
K75 = RACT K75
Boolean (contacts close)
B = 2601
power available

270

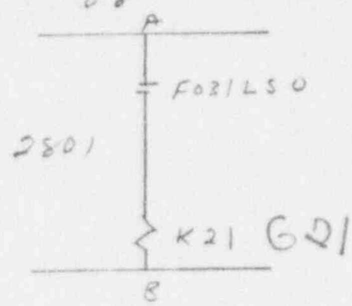
K40 Fails Energized NN=27



F045LSC = RF45LSC
K40 = RACTK40
Boolean (contacts close.
B=2701

209 X

K21 Fails to Energize NN=28.



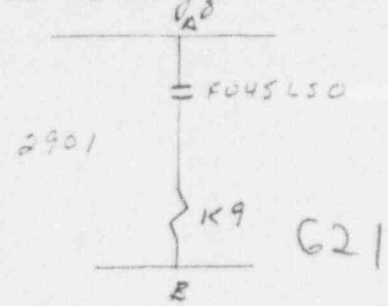
F031LSO = RF31LSO
K21 = RACTK31
B[illegible] ([illegible])
B = 2801

212

Figure B.X.6

Figure 2.3-6 RCIC Actuation Circuitry-2

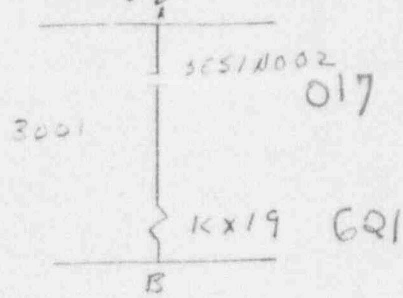
K9 Fail To Energize NN = 29



F045LS0 = RF45LS0
K9 = RACTK9
Boolean (contacts open)
B = 2901
power unavailable

231

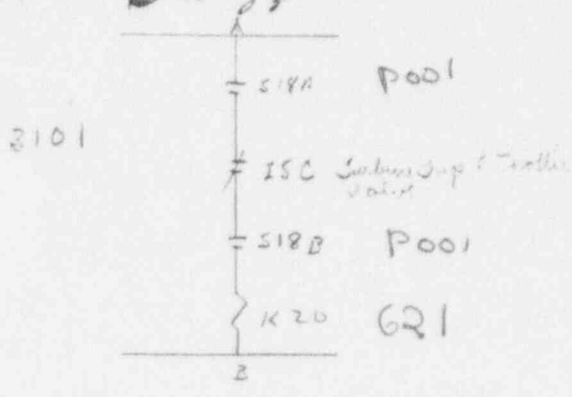
KX19 Fail to Energize NN = 30



2ES1N002 = RACN~~00~~20
KX19 = RACTKX19
Boolean (contacts open)
B = 3001
power unavailable

227

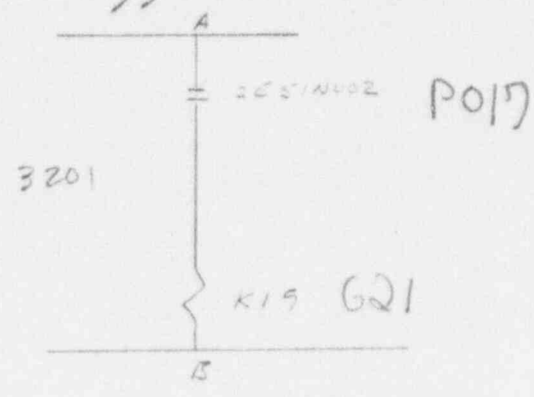
K20 Fail to Energize NN = 31



S18A = RACTS18A
S18B = RACTS18B
LSC = KTTTLSC
K20 = RACTK20
Boolean (contacts open)
B = 3101

200 X

K19 Fails Energized NN = 32



2ES1N002 = RACN002C
K19 = RACTK19
Boolean (contacts closed)
C = 3201
power available.

235

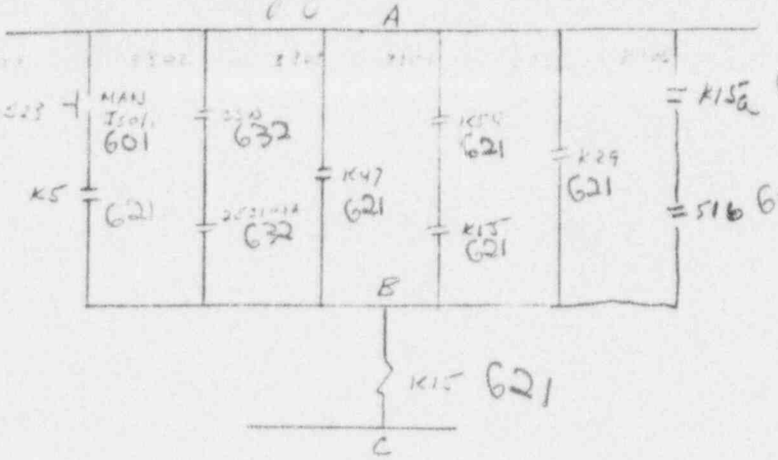
Figure B.X.7

Figure 2.3-7 RCIC Actuation Circuitry-3

22-141 50 SHEETS
22-142 100 SHEETS
22-144 200 SHEETS

ACTUATION

K15 Fails Energized NN = 33



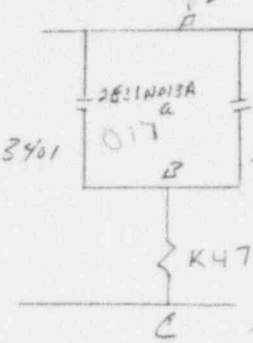
272

K5 = RACT K5 0
CSN = RACT CSN
2E31K2A = 2E31K2A
K47 = RACT K47 0
523 = RACT 523 0

K54 = RACT K54 0
K55 = RACT K55 0
K29 = RACT K29 0
K15a = RACT K15 0
516 = RACT 516 0

Boolean (contact closed)
B = 3301 + 3302 + 3303 + 3304 + 3306
power available.

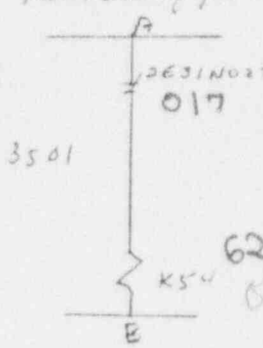
K47 Fails Energized NN = 34



327

2E31N013A = 31N013AA
2E31N013A = 31N013AB
Boolean (contacts closed)
B = 3401 + 3402
power available

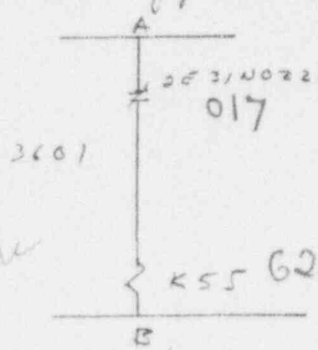
K54 Fails Energized NN = 35



2E31N022C = 31N022CC
K54 = RACT K54
Boolean (contacts closed)
B = 3501
power available

319

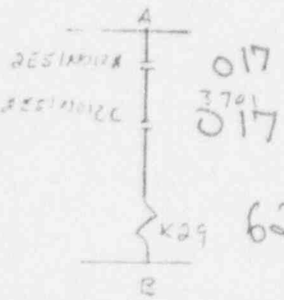
K55 Fails Energized NN = 36



2E31N022A = 31N022AC
K55 = RACT K55
Boolean (contacts closed)
B = 3601
power available.

321

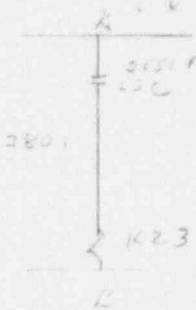
K29 Fails Energized NN = 37



330

2E31N013A = 31N013AD
2E31N022C = 31N022CD
Boolean (contacts closed)
B = 3701
power available

K23 Fails Energized NN = 38



265

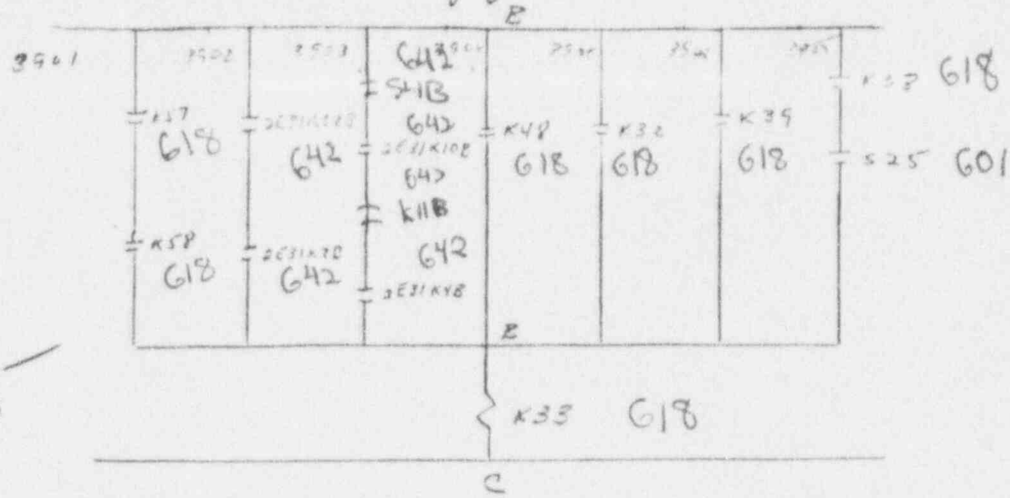
2E51F0LSC = F6XLSC
K23 = RACT K23
Boolean (contacts open)
B = 3801
power available

Figure B.X.8

Figure 2.3-8 RCIC Actuation Circuitry-4

ACTUATION

K33 Fails Energized NN = 39



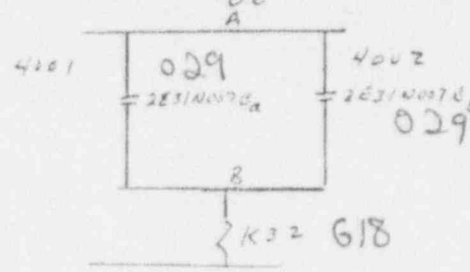
285

K57 = RACT K570
K58 = RACT K580
2E31K2B = 31K2B0
2E31K2D = 31K2D0
2E31K10B = 31K10B0

2E31K48 = 31K4B0
K48 = RACT K480
K32 = RACT K320
K39 = RACT K390
S25 = RACT S250

Boolean (contacts closed)
B = 3901 + 3902 + 3903 + 3904 + 3905 + 3906 + 3907
power available

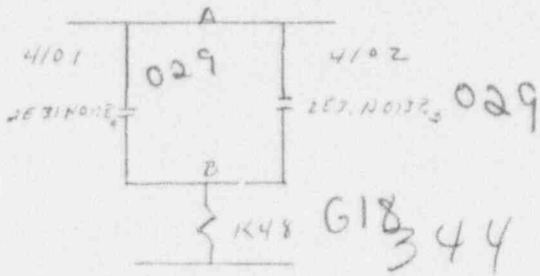
K32 Fails Energized NN = 40



347

2E31N007Ba = 31N007BA
2E31N007Bb = 31N007BB
Boolean (contacts close)
B = 4001 + 4002
power available

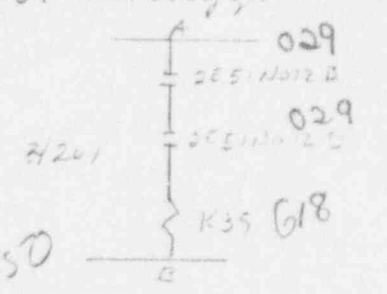
K48 Fails Energized NN = 41



344

2E31N013Ba = 31N013BA
2E31N013Bb = 31N013BB
Boolean (contacts close)
B = 4101 + 4102
power available

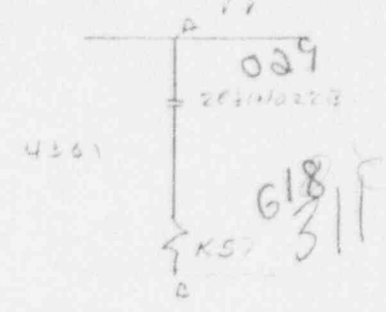
K39 Fails Energized NN = 42



350

2E51N012B = 51N012B0
2E51N012D = 51N012D0
Boolean (contacts close)
B = 4201
power available

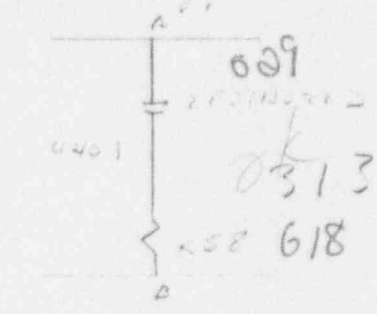
K57 Fails Energized NN = 43



311

2E31N022B = 31N022B0
Boolean (contacts close)
B = 4301
power available

K58 Fails Energized NN = 44



313

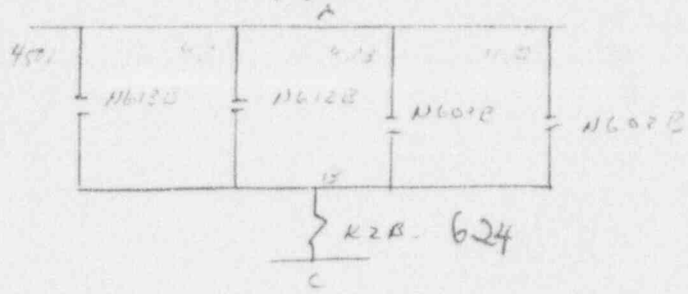
2E31N022D = [illegible]
Boolean (contacts close)
C = 4401
power available

Figure B.X.9

Figure 2.3-9 RCIC Actuation Circuitry-5

ACTUATION

2E31K2B Fails Energized. NN = 45



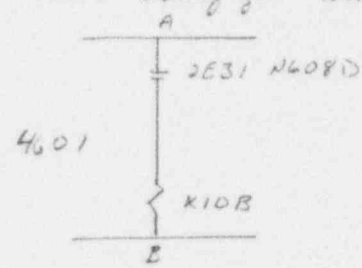
624

332

N613B = 31N613BO
N612B = 31N612BO
N603B = 31N603BO
N607B = 31N607BO

Boolean (contacts close)
B = 4501 + 4502 + 4503 + 4504
power available

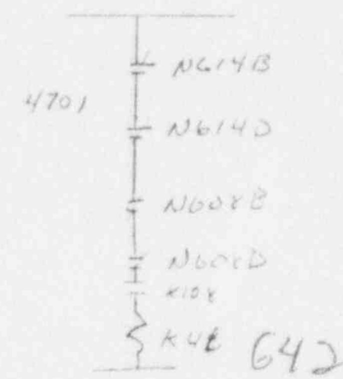
2E31K10B Fails Energized NN 46



2E31N608D = 31N608DO
Boolean (contacts close)
B = 4601
power available

337

2E31K4B Fails deenergized NN = 47



642

N614B = 31N614BC
N614D = 31N614DC
N608B = 31N608BC
N608D = 31N608DC
K10B = 31K10BO
K4B = 31K4B
Boolean Contacts open
B = 4701
power unavailable

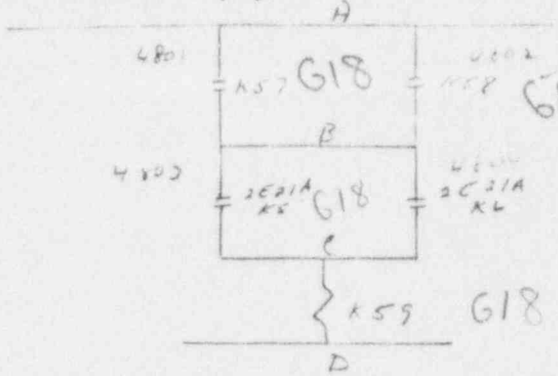
339

Figure B. X110

Figure 2.3-10 RCIC Actuation Circuitry-6

Actuation

K59 Fails Energized NN = 48

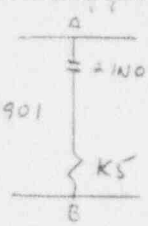


247

K57 = RACTK570
K58 = RACTK580
2E22AK5 = 22AK50
2E22AK6 = 22AK6 0
K59 = RACTK59

Boolean (contacts closed)
C = [4803 + 4804] E
E = 4801 + 4802
power available

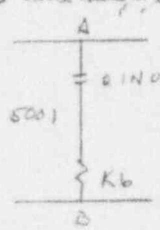
2E12K5 Fails Energized NN = 49



21N048B = 21N048B0
Boolean (contacts closed)
B = 4901
power available

315

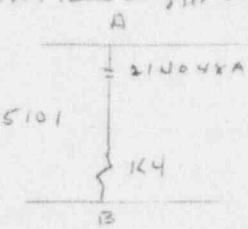
2E12K6 Fails Energized NN = 50



21N048D = 21N048D0
Boolean (CC)
B = 5001
power available

317

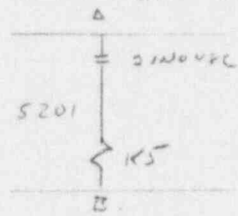
2E21K4 Fails Energized NN = 51



21N048A = 21N048A0
Boolean (CC)
B = 5101
power available

323

2E21K5 Fails Energized NN = 52

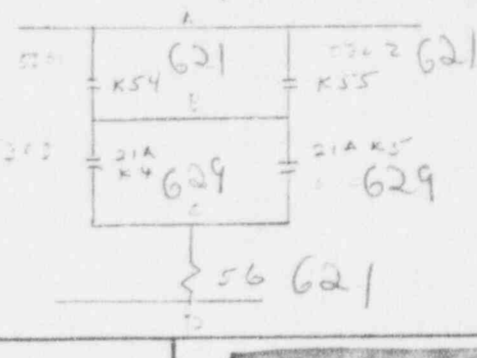


21N048C = 21N048C0
Boolean (CC)
B = 5201
power available

325

K56 Fails Energized NN = 53

K54 = RACTK540
K55 = RACTK550
21AK4 = 21AK40
21AK5 = 21AK50



Boolean (CC)
C = [ ] E
E = 5301 + 5302

256

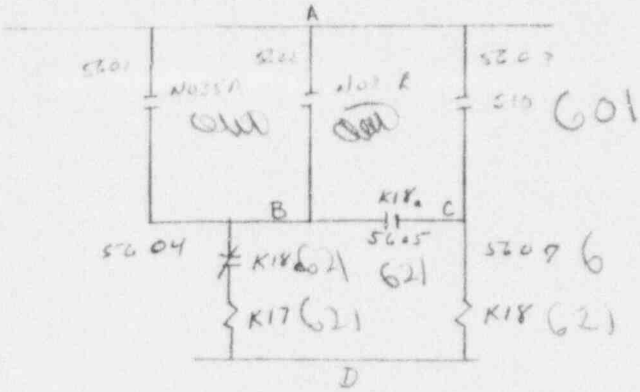
[redacted]

[redacted]

Figure B.X.11

ACTUATION

K17 Fails to Energize NN = 56



N035A = RAN035A0
N035B = RAN035B0
S10 = RF31510Ø0
$K18_o$ = RACTK180
$K18_c$ = RACTK18C

Boolean
D = 5604 + B + C
B = 5601 * 5602
C = [B' * 5605] + 5603
power unavailable

237

Figure B.K.12

Figure 2.3-11 RCIC Actuation Circuitry-7

2.4 CONTROL ROD DRIVE SYSTEM (CRD)

2.2.1 System Function

2.2.2 System Description

2.2.2.1 General Design

Flow Path

Locations

Component Descriptions

2.2.2.2 System Interfaces

Electrical

Component Cooling

2.2.2.3 Instrumentation and Control

System Actuation

Component Control

Instrumentation

2.2.2.4 Operator Actions

2.2.2.5 Technical Specification Limitations

2.2.2.6 Tests

2.2.2.7 Maintenance

2.2.3 System Operations

2.2.3.1 Normal Operation

2.2.3.2 Abnormal Operation

2.2.4 System Fault Tree

2.2.4.1 Fault Tree Description

2.2.4.2 Success/Failure Criteria

2.2.4.3 Major Assumptions

Table 2.4-1 Control Rod Drive System Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)

Table 2.4-2 Control Rod Drive Component/Subsystem Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency (Mo)	Test Outage (Hr)	Component/Subsystem Alignment/Operability Verification Frequency

Table 2.4-3 Control Rod Drive System Component/Subsystem Maintenance Summary

Component Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification

Figure 2.4-1 Simplified Schematic of Control Rod Drive System

Figure 2.4-2 Simplified Diagram of Control Rod Drive System for Fault Tree Construction

Figure 2.4-3 Component Control Circuits

Figure 2.4-4 Component Actuation Circuits-1

Figure 2.2-5 Component Actuation Circuits-2

3.0 MEDIUM/LOW PRESSURE INJECTION SYSTEMS

3.1 Condensate System

3.1.1 System Function

The purpose of the Condensate System is to provide a means of purifying and transferring water from the condenser hotwell to the suction of the reactor feedwater pumps. In addition, the flow of condensate serves as the cooling r 'um for the steam jet air ejector condensers, the gland exhaust :ser, and the off-gas condensers. In terms of the PRA, the Condensate s, a function is to provide condensate to the feedwater pumps or to act as a low pressure injection system.

3.1.2 System Description

3.1.2.1 Ger 1 Design

The Condens ystem transfers condensate from the condenser hotwell to the feedwater pumps through the path shown in Figure 3.1-1. The system consists of four condensate pumps, two steam jet air ejectors, two gland seal condensers, two off-gas condensers, seven condensate polishers, four condensate booster pumps, and three strings of low pressure heaters each containing five heaters.

Flow Path

During nor operation, three of four condensate pumps (one spare) take suction from the condenser hotwell and discharge to a common header. The condensate pump outlet flows through one steam jet air ejector and one gland seal exhauster. The redundant components are normally isolated and not in service. The outlet flow from the gland seal exhauster splits and passes through two off-gas condensers. The condensate then reconverges into a common condensate polisher header. Excess water in the condenser is rejected to the condensate storage tank through a line connected to this header.

The condensate flows from the polisher header through six of seven parallel polishers and reconverges in another header from which the condensate booster pumps take suction. A normally closed line is available to bypass the polishers. During normal operation, three of four condensate booster pumps are in operation with one as a spare. Controlled condensate recirculation to the condenser is provided downstream of each condensate booster pump. This provision ensures that a minimum safe flow is provided through all the Condensate System components.

The flow from the condensate booster pumps converges into a common header which feeds all three low pressure feedwater heater strings. The outlet flow from the heaters feeds the feedwater pump suction header. A 33% bypass line around the heaters is also available.

The flow path from the feedwater pumps to the reactor vessel is discussed in Section 2.1, Feedwater System. An alternate flow path through the feedwater bypass line to the reactor vessel can be used when the reactor vessel pressure is below the condensate booster pump shutoff head. The path is parallel to the motor-driven feedwater pump and utilizes the feedwater flow path discussed in Section 2.1.

Normal condensate makeup is provided to the condenser hotwell from the condensate storage tank (CST) by vacuum dragging. Emergency condensate makeup is provided from the CST to the condenser hotwell via one-of-two pump loops.

Locations

The majority of the Condensate System is located in the Turbine Building. A portion of the system (the interface with the Feedwater ' 'stem) is located in the Auxiliary Building.

Component Descriptions

The main condenser is a single pass, twin bank, divided water box, surface condenser. Each bank of tubes has upper and lower tube bundles. It is divided into three latitudinal compartments by two divided plates or tube sheets.

The condensing capacity of each compartment depends upon the difference in temperature between the steam in the shell and the circulating water in the tubes. With a uniform steam temperature entering each compartment, the section at the circulating water inlet (cold end) has the greatest condensing capacity (100%). The middle (intermediate) section condenses 99%. The last compartment is called the warm end. It typically condenses 97%-98% of the steam entering it. The excess steam is used for deaeration and reheat purposes. Since each compartment operates independently, the condenser operates at three different pressures.

Steam exhausted from the low pressure turbine flows over the tubes and is condensed. The condensate draining from the tubes of the upper bundles is collected in rain trays directly below the upper tube bundles. The condensate is drained away from the lower tube bundles through openings in the rain trays. The condensate then flows through rain tray ducts where it falls to the condenser floor. This protects the lower tube bundles from oversaturation by the condensate and helps the lower bundles retain their steam condensing efficiency.

The condensate falling to the condenser floor is admitted to the hotwell. Condensate from the intermediate and cold compartments flows through perforated plates to the hotwell. Condensate from the warm compartment flows into the hotwell through rectangular openings at the sides of the floor. Uncondensed steam from the warm compartment enters the hotwell through the same openings. Water streams, flowing through perforated plates from the intermediate and cold compartments, condense this steam. This "reheating" of the condensate deaerates it and any non-condensibles are vented back to the warm compartment to the air offtake pipes.

During low load operation, all the steam in the warm compartment condenses, leaving no steam for deaeration. In this situation, low load steam reheat lines in the hotwell are used to supply reheat steam. Main steam from the equalizing header supplies six reheat lines in the hotwell. The reheat lines are perforated and extend the length of the hotwell.

Once in the hotwell, condensate is forced to flow around baffle plates to the hotwell sump. These baffles provide approximately a two minute holdup time to allow for decay of N16. Storage space for about 96,000 gallons is provided.

Condensate then flows into the hotwell sump header and into outlet pipes leading to the condensate pumps. The hotwell sump is provided with a 4" dam around it to prevent foreign matter from being carried into the condensate pump suction line.

The condensate makeup subsystem adds condensate storage tank water to the main condenser hotwell. The normal method is vacuum dragging water from the CST via the normal makeup valve. A further hotwell level decrease will cause the emergency makeup valve to open and start the condensate makeup pumps. The CST contains 350,000 gallons and is designed so that at least 135,000 gallons will always be available for the RCIC system requirements. In addition, one 200,000 gallon demineralized storage tank is available for normal makeup use.

The four condensate pumps, each with a 33% capacity, are located in the condensate pump room, below the condenser hotwell. The pumps have a design flow rate of 7270 gpm at 150 psig The pump is an 1800 rpm centrifugal pump that shares a motor, via the shaft speed changer, with the condensate booster pump and the main shaft lube oil pump. The condensate pump is water sealed and is installed at an elevation that allows operation at low condensate levels in the main condenser hotwell.

Three pumps are required for full power operation. The other pump is kept in a standby condition. Shutoff valves allow each condensate pump to be removed from service individually while system operability is maintained with the remaining condensate pumps.

The two steam jet air ejector condensers are each 100% capacity but both are normally open on the condensate side. Water (condensate) flows through the tubes, and the steam is exhausted in the shell side.

The two gland seal exhauster condensers are each 100% capacity (both are normally valved in on the condensate side). Condensate water flows through the tubes while steam is exhausted into the shell side.

There are two off-gas condensers. Each have 100% capacity. Condensate is supplied to the tube side while the superheated steam is discharged from the recombiner. This condenser reduces the volume of off-gas exhausted from the reactor building stack and helps heat the condensate.

The seven condensate polishers each have a 16.6% capacity (six are necessary for rated flow). The polishers maintain the purity of the reactor feedwater system by removing corrosion products, dissolved solids, chlorides, and other chemical impurities to prevent or reduce damage to components due to chemical and corrosive attach, fouling of heat transfer surfaces, impurities available for activation, and the consequences of a condenser tube leak.

The polishers, located behind shield walls on the 710 foot level of the turbine building, are deep-bed types that utilize cation and anion resin beds.

The four condensate booster pumps, each having a 33% capacity, provide NPSH for the reactor feed pumps. The booster pumps are driven by the same motor that drives the respective condensate pump via the shaft speed changer. The booster pump speed is 3600 RPM with a flow of 7270 gpm at 410 psig. The pump has water seals. Shutoff valves allow each condensate booster pump to be removed from service individually while system operability is maintained with the remaining pumps.

Controlled condensate recirculation to the main condenser is provided downstream of the condensate booster pumps. This provision ensures the maintenance during operation of the minimum safe flow through the condensate and condensate booster pumps, steam jet air ejector, and steam packing exhauster. The recirculation lines are designed to open when the condensate flow is less than 1500 gpm in each line. The recirculation lines are also designed to fail open upon loss of control signals, air, or power.

Each condensate and condensate booster pump has an associated lube oil system consisting of a main shaft-driven oil pump, an auxiliary motor-driven oil pump, a filter, cooler, and oil reservoir.

The feedwater heaters are arranged in three parallel strings. The first-stage and second-stage feedwater heaters are located in the necks of the three exhaust hoods of the main condenser. Drain cooling is provided at all stages of feedwater heating except at the third stage. Drain-cooling sections are integral with the feedwater heaters. Deaeration of the pumped-forward drains is provided by the third-stage feedwater heaters to limit the oxygen content in the pumped-forward drain flow.

Each feedwater heater and drain cooler is a closed type, installed at an elevation that allows proper shell drainage at all loads. Each feedwater heater uses U-tube construction. All feedwater heater and drain-cooler tubes are made of stainless steel.

Shutoff valves and bypasses allow the feedwater heaters and the drain coolers of one of the parallel groups to be removed from service. System operability is maintained with the remaining feedwater heaters and drain coolers.

The startup and operating vents from the steam side of the feedwater heaters are piped directly to the main condenser. Discharges from shell relief valves on the steam side of the feedwater heaters are piped directly to the main condenser.

The heater drain tank receives deaerated drains from the shells of the third-stage feedwater heaters and provides reservoir capacity for drain pumping. The heater drain tank is installed beneath the third-stage feedwater heaters at an elevation that allows the heaters to drain freely by gravity flow. Level controls permit draining the tank when required. Remote tank level indication is also provided.

The drain tank system is capable of diverting incoming drains to the main condenser. Four heater drain pumps (one spare) operate in parallel, with each taking suction from the heater drain tank and discharging to the feedwater stream immediately before the fourth-stage heater. Each pump is a motor-driven, vertical, multistage, centrifugal-type pump located below the heater drain tank and designed for the available suction conditions.

3.1.2.2 System Interfaces

A failure modes and effects analysis of the Condensate System indicating the required support system interfaces is shown in Table 3.1-1. The support system interfaces are discussed below.

Shared Components

The Condensate System requires that the condenser hotwell contain condensate. The Power Conversion System requires operation of the condenser for condensing steam.

The use of the Condensate System as a low pressure injection system requires the availability of the majority of the feedwater injection path.

Electrical

The Condensate System uses both trains of the normal electrical power system. The motors for condensate/condensate booster pumps 2CD01PA/2CB01PA and 2CD01PC/2CB01PC require power from 6900 VAC bus 251. Control power for these motors is provided by 125 VDC bus 211X. The motors for condensate/condensate booster pumps 2CD01PB/2CB01PB and 2CD01PD/2CB01PD require power from 6900 VAC bus 252. Control power for these motors is provided by 125 VDC bus 212X. Control power is only required when the pump is started.

Power to condensate makeup pumps 2CY02PA and 2CY02PB is provided from 480 VAC MCCs 231B-1 and 232B-3, respectively.

Actuation

Actuation logic will start the idle condensate/condensate booster pump motor when the feedwater pump NPSH is low. Power for this actuation logic is provided from 480 VAC MCC 232B-3 through a step-down transformer.

Control

Automatic opening of the emergency makeup valve (2CD023) and startup of the condensate makeup pumps occurs when the condenser level drops to 38 inches. If the condenser level rises to 46 inches, the emergency overflow valve (2CD015) opens to reject water to the CST. Both valves require instrument air for valve control.

Control of the condensate flow is provided by the condensate booster pump recirculation valves. These valves require air from the instrument air system for valve control.

Component Cooling

The condensate/condensate booster pump/motor trains require operation of the corresponding lube oil systems. The lube oil in each train is cooled by the Turbine Building Closed Cooling Water System.

Room Cooling

The Condensate System does not require room cooling.

3.1.2.3 Instrumentation and Control

System Actuation

The Condensate System is normally operating. The Condensate System contains redundant components some of which will automatically actuate when required. The redundant condensate/condensate booster train will start upon a low feedwater pump NPSH signal. The actuation logic for the standby pumps is shown in Figure 3.1-2.

The redundant steam jet air ejector and gland seal exhauster are normally isolated by manual valves. Use of these components thus require manual actions.

The normally closed condensate polisher and low pressure heater bypass lines can be remotely opened from the control room.

Component Control

The condensate booster pump recirculation flow is initiated when the pump flow is less than 1500 gpm. This feature ensures that a minimum safe flow is maintained through the Condensate System components.

The condenser level is maintained at a prescribed range by both a makeup and reject system. If the condenser level drops to 38 inches, the emergency makeup system initiates to provide makeup. If the condenser level rises to 46 inches, the emergency overflow valve opens to reject condensate flow back to the CST.

Instrumentation

The following instrumentation in the control room indicates the status of the Condensate System:

1) Main condenser hotwell level (2LT-CD031) - recorder
2) Normal condenser makeup flow (2FE-CD032) - recorder
3) Emergency condenser makeup flow (2FE-CD033) - recorder
4) Condensate pump discharge header pressure - indicator
5) Condensate booster pump (2CB01PA) discharge flow (2FE-CB065A) - indicator
6) Condensate booster pump (2CB01PB) discharge flow (2FE-CB065B) - indicator
7) Condensate booster pump (2CB01PC) discharge flow (2FE-CB065C) - indicator
8) Condensate booster pump (2CB01PD) discharge flow (2FE-CB065D) - indicator
9) Condensate booster pump (2CB01PA) suction pressure (2PI-CD013) - indicator
10) Condensate booster pump (2CB01PB) suction pressure (2PI- CD012) - indicator
11) Condensate booster pump (2CB01PC) suction pressure (2PI- CD011) - indicator
12) Condensate booster pump (2CB01PD) suction pressure (2PI- CD010) - indicator
13) Condensate booster pump discharge header pressure - indicator
14) Condensate polisher differential pressure (2PDR-CD006) - recorder
15) Condensate normal reject flow (2FE-CD112) - recorder
16) Condensate/condensate booster pump motor current (4) - indicator

In addition, the following control room alarms are available:

1) Condenser hotwell level high - 45 inches
2) Condenser hotwell level low - 38 inches
3) Condensate pump strainer differential pressure high (4) - 10 psid
4) Condensate pump discharge header pressure low - 100 psig
5) Condensate booster pump suction header pressure low - 100 psig
6) Condensate booster pump strainer differential pressure high (4) - 10 psid

7) Condensate/condensate booster pump lube oil pressure low (4) - 12 psig
8) Condenser emergency makeup valve full open
9) Condenser emergency overflow valve not fully closed
10) Condensate/condensate booster pump auto trip
11) Condensate/condensate booster pump not in standby
12) Condensate polisher control panel trouble
13) Condensate makeup pump auto trip
14) Condensate emergency overflow valve not full closed
15) Low condenser vacuum - 24 inches vacuum

3.1.2.4 Operator Actions

The operation of the Condensate System is automatic and requires no operator action. However, the redundant steam air ejector and gland seal exhauster can be placed into service by manually opening the isolation valves locally. Also, the normally closed condensate polisher and low pressure heater bypass lines can be opened by the operator in the control room.

3.1.2.5 Technical Specifications

There are no technical specifications pertaining to the Condensate System.

3.1.2.6 Test

No test procedures were identified for the Condensate System which would disable any portion of the system.

3.1.2.7 Maintenance

No scheduled maintenance which disables components in the Condensate System was identified. However, due to the redundant nature of the Condensate System, unscheduled maintenance can be performed during normal plant operation.

The unscheduled maintenance which can be performed on the portions of the Condensate System of interest is summarized in Table 3.1-2. Although allowed, unscheduled maintenance on check valves and manual valves is not listed on the table because of the significantly lower frequencies of occurrence when compared to motor-operated valves.

3.1.3 System Operation

3.1.3.1 Normal Operation

During normal plant operation, the Condensate System is providing condensate to the feedwater pump suction. Three condensate pumps, one steam jet air ejector, one gland seal exhauster, one off gas condenser, six condensate polishers, and three condensate booster pumps are normally in operation.

3.1.3.2 Abnormal Operation

Following a reactor trip, the Condensate System would continue to operate with excess condensate recycled to the condenser via the individual pump recirculation lines. Adequate water can be provided to the reactor vessel by one condensate/condensate booster pump train. A flow path through one low-pressure heater, one steam jet air ejector, one gland seal exhauster, one off gas condenser, and two condensate polishers is required.

The condensate must be delivered to the reactor feedwater pumps for injection into reactor vessel if the reactor pressure is high. If the reactor vessel pressure is low, the Condensate System can inject into the reactor vessel without the operation of a feedwater pump. However, in this mode, control of the condensate flow can only be achieved by passing the flow through the feedwater control valve (2FW005).

3.1.4 System Fault Tree

3.1.4.1 Description

Two fault trees of the Condensate System were constructed. One was for failure of the Condensate System to provide flow to the reactor feedwater pumps for high pressure injection. The other was for failure of the Condensate System to operate as a low pressure injection system. Operation in this mode requires the logic developed in the prior fault tree and also failure to control the condensate flow through the feedwater control valve.

A simplified diagram of the Condensate System indicating only the mechanical components included in the fault tree model is shown in Figure 3.1-3.

3.1.4.2 Success/Failure Criteria

Successful operation of the Condensate System in providing flow to the feedwater pump suction requires that one condensate and condensate booster pump operate. In addition a flow path must be available from the condenser through one low pressure heater string, one steam jet air ejector, one gland seal exhauster, one off gas condenser, and two condensate polishers.

Successful operation of the Condensate System as a low pressure injection system requires the same success criteria stated above. In addition, a flow path through the feedwater control valve to the reactor vessel must also be available.

Failure of the Condensate System to provide flow to the feedwater pump suction header will occur if one of the following occur:

1) All four condensate or condensate booster pumps fail to operate.
2) All three low pressure heater strings and the heater bypass line are unavailable.
3) Both steam jet air ejector lines are unavailable.
4) Both gland seal exhauster lines are unavailable.
5) Both off gas condenser lines are unavailable.
6) Six of the seven condensate polisher lines and the bypass line are unavailable.
7) Insufficient condensate is available in the condenser.

The top event of the fault tree is:

"FAILURE OF THE CONDENSATE SYSTEM TO PROVIDE CONDENSATE TO FEEDWATER PUMP SUCTION HEADER"

Failure of the Condensate System to operate as a low pressure injection system will occur if any of the above occur and also if:

1) A flow path through the feedwater control valve is not available.
2) A flow path to the reactor vessel through the Feedwater System is not available.

The top event of this fault tree is the following:

"FAILURE OF THE CONDENSATE SYSTEM TO PROVIDE CONDENSATE TO THE REACTOR VESSEL"

3.1.4.3 Assumptions

In addition to the general assumptions regarding fault tree development (listed at the beginning of this volume), the following assumptions specific to the LPCS system were made:

1) A rupture of any of the main Condensate System piping was assumed to result in condensate depletion and subsequent Condensate System failure. However, ruptures in some locations can be isolated (a recovery action).

2) Unscheduled maintenance on the low pressure heater lines was not included in the model since the heater bypass line would be used in such a situation. No credit was taken for use of the heater bypass line since it requires manual actions to open it.

3) Credit for all four condensate and condensate booster pumps was taken since the standby pumps would start automatically on low feedwater pump NPSH. Unscheduled maintenance was assumed only for the standby pumps and associated equipment (lube oil system, recirculation line, etc).

4) Complete opening of a condensate booster pump recirculation line was assumed not to be a significant diversion path since the lines are designed to open on low flow.

5) No credit was taken for the electric-driven auxiliary lube oil pump in each of the operating condensate/condensate booster pump lube oil systems. These pumps are only required until the shaft-driven lube oil pumps come up to speed. The auxiliary lube oil pump is required for startup of the standby condensate/condensate booster pumps.

6) The normal condensate reject line was considered too small to be a significant diversion path and was not modeled. However, the emergency condensate reject line was modeled as a diversion path.

7) Unscheduled maintenance on the condensate polishers was not modeled since a standby condensate polisher line and a bypass line are available. No credit was taken for use of the standby condensate polisher line or the condensate polisher bypass line.

8) No unscheduled maintenance was modeled for the steam jet air ejector or steam packing exhauster flow paths due to the existence of redundant flow paths. No credit was taken for the redundant flow paths available in the system.

9) Emergency condensate makeup to the condenser is assumed required if the PCS is unavailable to condense steam. Flow from an emergency condensate makeup pump through the emergency condensate makeup valve was assumed required.

3.1.5 References

1) FSAR System description	Section 10.4.7
2) Operator Training Manual	Chapters 27 & 28
3) Drawings	P&ID M-119 through M121 and M-127 General Arrangement M-376, M-385, M-543, M-544, M-546 - M-548, M-560, M-563, M-564, M-566-M-568, M-582, M-583, M-585, M-596, M-597, and M-599 I&C IE-2-4012ZD P&ID/C&I Details M-2119

Table 3.1-1 Condensate System Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
480 VAC MCC 231A-1	2CD033	Motor operated valve	Fail as is	Loss of valve indication lights	Normally shut, prevent bypass of demineralizers	Loss of redundant flow path
	2CD035C	Motor operated valve	"	"	Normally open, no effect	No effect
	2CD036C	Motor operated valve	"	"	"	"
	2CD035B	Motor operated valve	"	"	"	"
	2CD036B	Motor operated valve	"	"	"	"
	2CD035A	Motor operated valve	"	"	"	"
	2CD036A	Motor operated valve	"	"	"	"
480 VAC MCC 232A-1	2CD035G	Motor operated valve	"	"	Assumed to be normally closed prevent use of demineralizer string 'G'	Loss of redundant flow path
	2CD036G	Motor operated valve	"	"	"	"
	2CD035F	Motor operated valve	"	"	Normally open, no effect	No effect

Table 3.1-1 Condensate System Support Systems Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifiar	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
	2CD036F	Motor operated valve	"	"	"	"
	2CD035E	Motor operated valve	"	"	"	"
	2CD036E	Motor operated valve	Fail as is	Loss of valve indication lights	Normally open, no effect	No effect
	2CD035D	Motor operated valve	"	"	"	"
	2CD036D	Motor operated valve	"	"	"	"
6900 VAC SWGR 252	2CD01PD	Condensate Pump 2D valve	Pump stops, pump will	Current flow indication	Fails one of four condensate pumps	Fails two of four condensate and condensate booster pumps
	2CD01PB	Condensate Pump 2B	"	"	"	"
	2CB01PB	Condensate Booster Pump 2B	"	"	Fails one of four condensate booster pumps	"
	2CB01PD	Condensate Booster Pump 2D	"	"	"	"

Table 3.1-1 Condensate System Support Systems Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
125 VDC 212X	2CD01PD	Condensate Pump 2D	"	Breaker, current flow indication	Fails one of four condensate pumps (if pump not running)	Fails two of four condensate and condensate booster pumps (if pumps are not running
	2CD01PB	Condensate Pump 2B	"	"	"	"
	2CB01PB	Condensate Booster Pump 2B	Pump will not start	Breaker current flow indication	Fails one of four condensate booster pumps (if pump is not running	Fails two of four condensate and condensate booster pumps (if pumps
	2CB01PD	Condensate Booster Pump 2D	"	"	"	"
6900 Vac SWGR 251	2CD01PC	Condensate Pump 2C	"	Current, flow indication	Fails one of four condensate pumps	"
	2CD01PA	Condensate Pump 2A	"	"	"	"
	2CB01PA	Condensate Booster Pump 2A	"	"	Fails one of four condensate booster pumps	
	2CB01PC	Condensate Booster Pump 2C	"	"	"	"
125 VDC 211X	2CD01PA	Condensate Pump 2A	Pump will not start	Breaker, current, flow indication	Fails one of four condensate pumps (if pump not running)	Fails two of four condensate and condensate booster pumps (if pumps are not running)
	2CB01PC	Condensate Pump 2C Pump 2C	"	"	"	"

Table 3.1-1 Condensate System Support Systems Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
	2CB01PA	Condensate Booster Pump 2A	"	"	Fails one of four condensate booster pumps (pump not running	"
	2CD01PC	Condensate Booster Pump 2C	"	"	"	"
125VDC 211X	2CD01PC	Condensate Booster Pump 2C	"	"	"	"
Condensate Pump 2D lube oil	2CD01PD	Condensate Pump 2D	Pump stops, pump will not start	Low lube oil pressure alarm	Fails one of four condensate	Fails two of four condensate and condensate booster pumps
	2CB01PD	Condensate Booster Pump 2D	"	"	Fails one of four condensate booster pumps	"
Condensate Pump 2C lube oil	2CD01PC	Condensate Pump 2C	"	"	Fails one of four condensate pumps	"
	2CB01PC	Condensate Booster Pump 2C	"	"	Fails one of four condensate booster pumps	"
Condensate Pump 2B lube oil	2CB01PB	Condensate Pump 2B	"	"	Fails one of four condensate pumps	
	2CB01PB	Condensate Booster Pump 2B	"	"	Fails one of four condensate booster pumps	"

Table 3.1-1 Condensate System Support Systems Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
Condensate Pump 2A lube oil	2CB01PA	Condensate Booster Pump 2A	"	"	"	"
	2CD01PA	Condensate Pump 2A	"	"	Fails one of four condensate pumps	"
480 VAC MCC 232B-3	2CB005C	Motor Operated Valve	Fails as is	Loss of valve indication lights	Normally open, no effect	"
	2CB006C	Motor Operated Valve	"	"	"	Fails makeup source to the main condenser
480 VAC MCC 231B-2	2CB005B	Motor Operated Valve	"	"	"	No effect
480 VAC MCC 231B-2	2CB006B	Motor Operated Valve	Fails as is	Loss of valve indication lights	Normally open, no effect	No effect
	2CB005A	Motor Operated Valve	"	"	"	"
	2CB006A	Motor Operated Valve	"	"	"	"
	2CB007	Motor Operated Valve	"	"	Normally shut, prevent bypass of L.P. heaters	Loss of redundant flow path
Instrument Air	2CB018D	Air Operated Valve	Fails open	Position indicator	Bypass flow from pump 2CB01PD to main condenser	Bypass flow from all condensate booster pumps to condenser

Table 3.1-1 Condensate System Support Systems Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
	2CB018C	Air Operated Valve	"	"	Bypass flow from pump 2CB01PC to main condenser	"
	2CB018B	Air Operated Valve	"	"	Bypass flow from pump 2CB01PB to main condenser	"
	2CB018A	Air Operated Valve	"	"	Bypass flow from pump 2CB01PA to main condenser	"
	2CD023	Air Operated Valve	Fails shut	"	Block one path of makeup water to main condenser	Loss of condensate makeup to condenser
	2CD026	Air Operated Valve	"	"	"	"
	2CD015	Air Operated Valve	Fails open	"	Bypass condensate to CST	Bypass condensate to CST
	2CD018	Air Operated Valve	"	"	"	"
TBCCW	2CB01PD	Condensate Booster Pump 2D	Overheat pump	TBCCW temp., pressure alarms and indications	Fail one of four condensate booster pumps	Fail all condensate and condensate booster pumps
	2CB01PC	Condensate Booster Pump 2C	"	"	"	"
	2CB01PB	Condensate Booster Pump 2B	"	"	"	"

Table 3.1-1 Condensate System Support Systems Interface FMEA (Concluded)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
	2CB01PA	Condensate Booster Pump 2B	"	"	"	"
	2CD01PA	Condensate Pump 2A	"	"	"	"
	2CD01PB	Condensate Pump 2B	"	"	"	"
	2CD01PC	Condensate Pump 2C	"	"	"	"
	2CD01PD	Condensate Pump 2D	"	"	"	"

Table 3.1-2 Condensate System Unscheduled Maintenance Summary

Component/ Subsystem	Type	Type of Maintenance[1]	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation:	Frequency	Outage	Frequency of Alignment/ Operability Verification
2CB01AA 2CB02AA 2CB03AA 2CB04AA 2CB05AA	Low Pressure Heaters	Mechanical "	2CB005A 2CB006A	Yes			None
2CB01AB 2CB02AB 2CB03AB 2CB04AB 2CB04AB	Low Pressure Heaters	Mechanical "	2CB005B 2CB006B	Yes			None
2CB007	Motor-operated Valve	Mechanical Electrical	- circuit breaker	Yes			None
2CB01PA	Pump	Mechanical	2CB002A 2CD013A	Yes			None
2CB01PB	Pump	Mechanical	2CB002B 2CD013B	Yes			None
2CB01PC	Pump	Mechanical	2CB002C 2CD013C	Yes			None
2CB01PD	Pump	Mechanical	2CB002D 2CD013D	Yes			None
2CD01PA	Pump	Mechanical	2CD001A 2CD002B	Yes			None
2CD01PB	Pump	Mechanical	2CD001B 2CD002B	Yes			None
2CD01PC	Pump	Mechanical	2CD001C 2CD002C	Yes			None

Table 3.1-2 Condensate System Unscheduled Maintenance Summary (Continued)

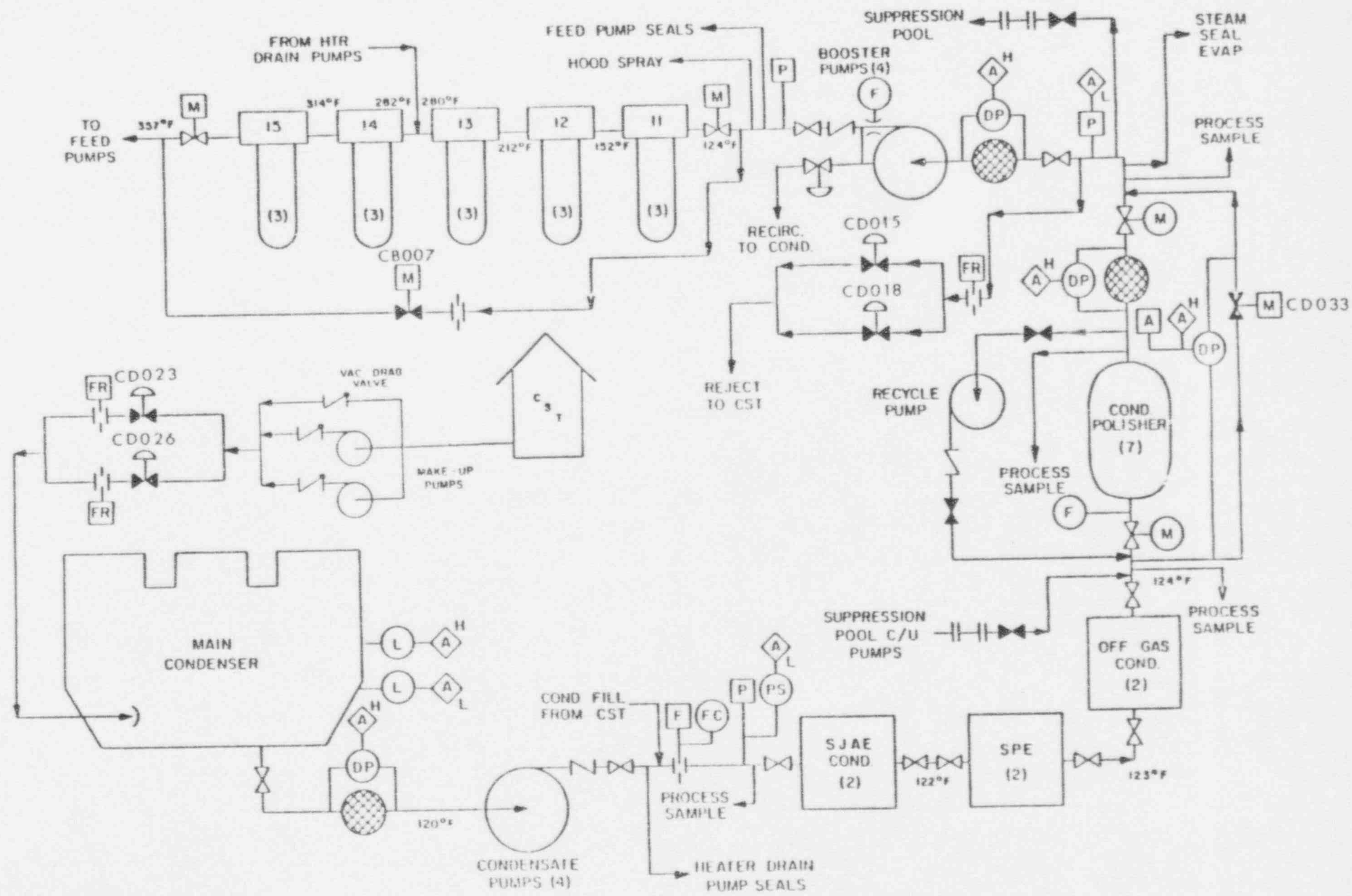
Component/ Subsystem	Type	Type of Maintenance[1]	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation:	Frequency	Outage	Frequency of Alignment/ Operability Verification
2CB01PA	Pump	Mechanical	2CD001D 2CD002D	Yes			None
2CB01PA/ 2CD01PA	Pump motor	Electrical	Pump circuit breaker	Yes			None
2CB01PB/ 2CD01PB	Pump motor	Electrical	Pump circuit breaker	Yes			None
2CB01PC/ 2CD01PC	Pump motor	Electrical	Pump circuit breaker	Yes			None
2CB01PD/ 2CD01PD	Pump motor	Electrical	Pump circuit breaker	Yes			None
2CB018A	Pneumatic valve	Mechanical	2CB019A 2CB002A 2CD013A	Yes			None
2CB018B	Pneumatic valve	Mechanical	2CB019B 2CB002B 2CD013B	Yes			None
2CB018C	Pneumatic valve	Mechanical	2CB019C 2CB002C 2CD013C	Yes			None
2CB018D	Pneumatic valve	Mechanical	2CB019D 2CB002D 2CD013D	Yes			None
2CP01DA or PDSAH-3A	Demineralizer Strainer	Mechanical	2CC035A 2CD036A	Yes			None
2CP01DB or PDSAH-3B	Demineralizer Strainer	Mechanical	2CD035B 2CD036B	Yes			None

Table 3.1-2 Condensate System Unscheduled Maintenance Summary (Continued)

Component/ Subsystem	Type	Type of Maintenance[1]	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation:	Frequency	Outage	Frequency of Alignment/ Operability Verification
2CP01DC or PDSAH-3C	Demineralizer Strainer	Mechanical	2CD035C 2CD036C	Yes			None
2CP01DD or PDSAH-3D	Demineralizer Strainer	Mechanical	2CD025D 2CD036D	Yes			None
2CP01DE or PDSAH-3E	Demineralizer Strainer	Mechanical	2CD035E 2CD036E	Yes			None
2CP01DF or PDSAH-3F	Demineralizer Strainer	Mechanical	2CD035F 2CD036F	Yes			None
2CP01DG or PDSAH-3G	Demineralizer Strainer	Mechanical	2CD035G 2CD036G	Yes			None
2CD033	Motor-operated valve	Electrical	Valve circuit breaker	Yes			None
2CD01CA	Steam jet air ejector	Mechanical	2CD006A 2CD007A	Yes			None
2CD01CB	Steam jet air ejector	Mechanical	2CD006B	Yes			None
2CD01SA	Steam packing exhauster	Mechanical	2CD008A 2CD009A	Yes			None
2CD01SB	Steam packing exhauster	Mechanical	2CD008B 2CD009B	Yes			None
2N62-B002A	Off gas condenser	Mechanical	2CD011A 2CD012A	Yes			None
2N62-B002B	Off gas condenser	Mechanical	2CD011B 2CD012B	Yes			None

Table 3.1-2 Condensate System Unscheduled Maintenance Summary (Concluded)

Component/ Subsystem	Type	Type of Maintenance[1]	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation:	Frequency	Outage	Frequency of Alignment/ Operability Verification
2CD023	Pneumatic valve	Mechanical	2CD022 2CD024	Yes			None
2CD015	Pneumatic valve	Mechanical	2CD014 2CD016	Yes			None
2CY02PA	Pump	Mechanical/ Electrical	2CY012A 2CY014A Pump circuit breaker	Yes			None
2CY02PB	Pump	Mechanical/ Electrical	2CY012B 2CY014B Pump circuit breaker	Yes			None

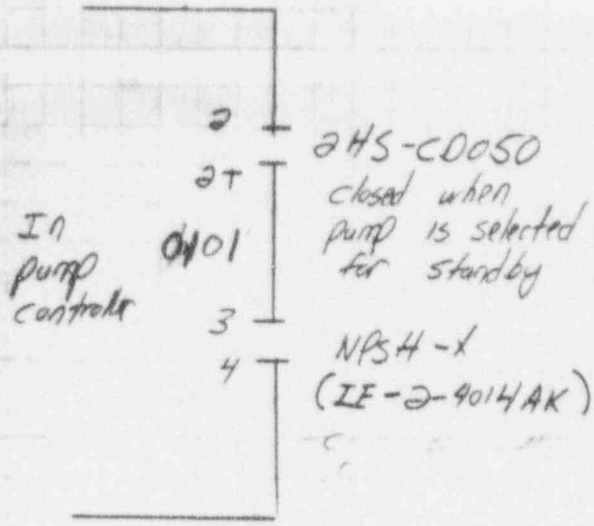


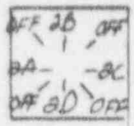
TO FEED PUMPS
357°F
M
15
314°F
14
282°F
280°F
13
212°F
12
152°F
11
124°F
(3)
FROM HTR DRAIN PUMPS
FEED PUMP SEALS
HOOD SPRAY
CB007
P
BOOSTER PUMPS (4)
F
SUPPRESSION POOL
DP
STEAM SEAL EVAP
PROCESS SAMPLE
RECIRC. TO COND.
CD015
CD018
FR
REJECT TO CST
RECYCLE PUMP
COND POLISHER (7)
CD033
124°F
SUPPRESSION POOL C/U PUMPS
OFF GAS COND. (2)
CD023
CD026
VAC DRAG VALVE
MAKE-UP PUMPS
CST
MAIN CONDENSER
L
A
H
120°F
CONDENSATE PUMPS (4)
COND FILL FROM CST
FC
PS
SJAE COND (2)
122°F
SPE (2)
123°F
HEATER DRAIN PUMP SEALS

B.X-1

Figure 3.1-1 Simplified Schematic of the Condensate System

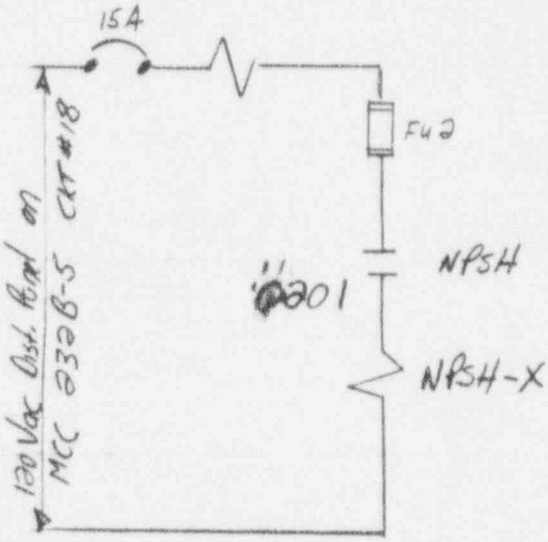
IE-2-4014AD





2HS-CD050
Condensate and Booster Pump Selector Switch

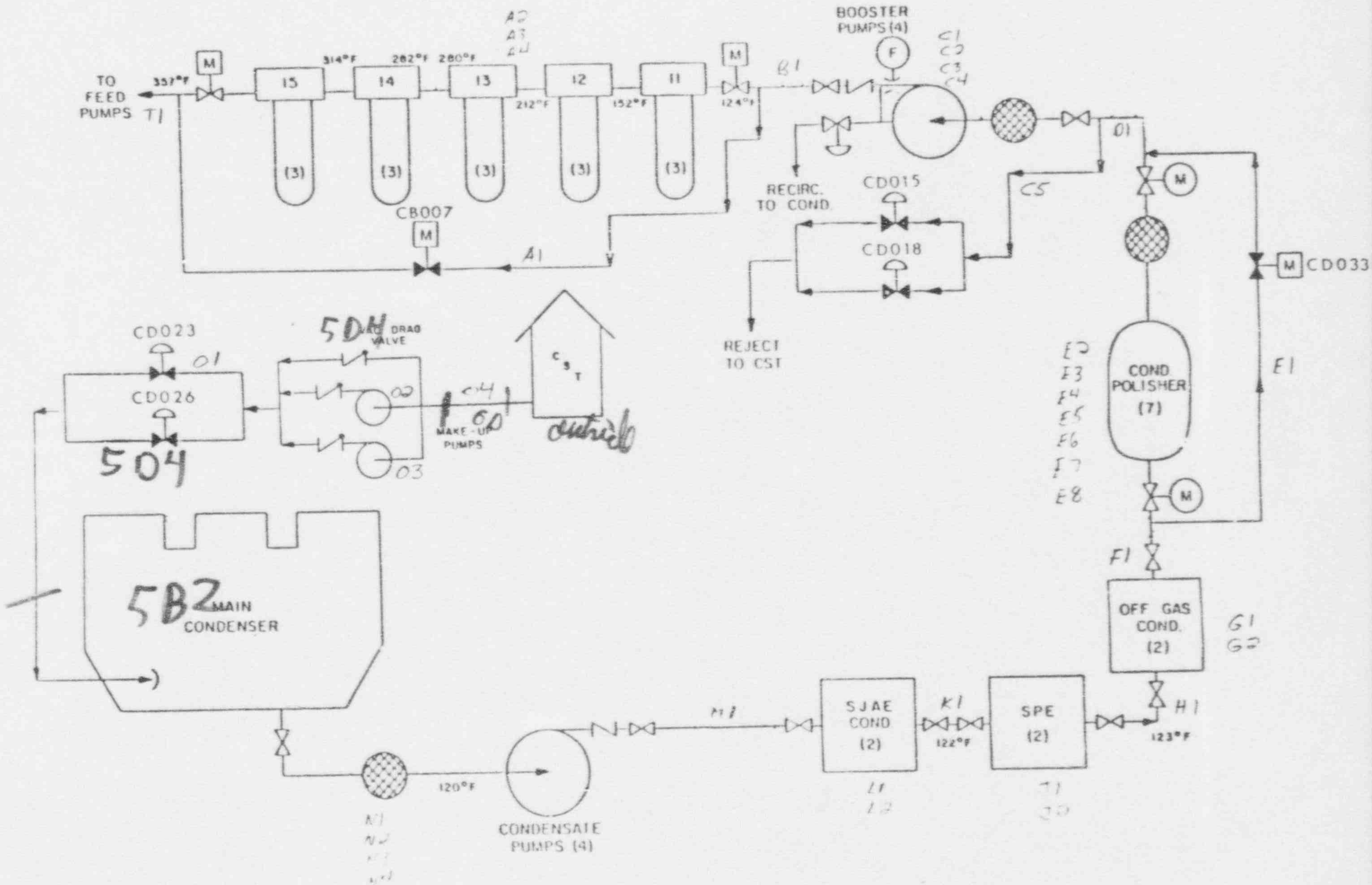
IE-2-4014AK



NPSH closes on low feedwater pump suction pressure

Figure BIX-2 Standby Condensate and Booster Pump Actuation Logic.

Figure 3.1-2 Standby Condensate and Booster Pump Actuation Logic



TO FEED PUMPS
T1
357°F
M
15
14
13
12
11
314°F
282°F
280°F
212°F
152°F
124°F
(3)
A2
A3
A4
CB007
A1
B1
BOOSTER PUMPS (4)
F
C1
C2
C3
C4
D1
RECIRC. TO COND.
CD015
CD018
C5
REJECT TO CST
CD033
E1
E2
E3
E4
E5
E6
E7
E8
COND POLISHER (7)
F1
OFF GAS COND. (2)
G1
G2
H1
123°F
SPE (2)
J1
J2
K1
122°F
SJAE COND (2)
L1
L2
M1
CONDENSATE PUMPS (4)
120°F
N1
N2
MAIN CONDENSER
5B2
CD023
CD026
01
504
5D4
DRAG VALVE
02
03
MAKE-UP PUMPS
C S T

Figure 3.1-3 Simplified Diagram of the Condensate system for Fault Tree Construction

3.2 Low Pressure Core Spray System (LPCS)

3.2.1 System Function

The Low Pressure Core Spray system (LPCS) is a low pressure ESF system designed to inject water directly onto the top of the core. It is similar to, but independent of, the HPCS system. This low pressure system is designed to provide core protection in case of larger breaks which could rapidly depressurize the reactor vessel. The LPCS system limits the maximum fuel cladding temperature and cools the core by direct spray with subsequent reflooding of the core. This protection also extends to a small break in which the high pressure injection system (HPCS and RCIC) have failed and the ADS system has operated to lower the reactor vessel pressure to the operating range of the LPCS.

3.2.2 System Description

3.2.2.1 General Design

The LPCS system is a single independent core spray loop consisting of a centrifugal pump that is powered from the safety AC power system, a spray sparger in the reactor vessel above the core (separate from the HPCS sparger), piping and valves to convey water from the suppression pool to the sparger, and associated controls and instrumentation. A detailed one-line diagram of the LPCS system is shown in Figure 3.2-1.

Flow Path

The LPCS system is correctly aligned and held in standby status during normal plant operation.

Upon receipt of a LOCA signal, the LPCS pump starts and the test return line MOV is directed to close, if not not already closed. The injection MOV does not open until the RPV pressure is less than 500 psig, so initially a portion of pump discharge is routed back to the suppression pool through a minimum flow bypass line. When reactor pressure has dropped sufficiently the LPCS injection MOV opens automatically and the pump conveys water from the suppression pool to the LPCS sparger.

Locations

Most of the LPCS components (including the pump and the suction MOV) are located in the northeast corner of the reactor building sub-basement. The injection MOV is at the 776' elevation and the injection line penetrates the primary containment at about 800' elevation. A testable check valve and a locked-open manual valve are inside the drywell in the LPCS injection line.

Component Descriptions

The LPCS pump (2E21-C001) is a five-stage vertical centrifugal pump with a 6350 gpm capacity against a reactor vessel back pressure of 290 psi above suppression pool pressure. The pump is located low in the reactor building such that a least 24 ft. of pump suction head is provided, at rated suction conditions of 212F water, with atmospheric pressure in the suppression pool. The normal shutoff head of the pump is 440 psi. The pump seals are self-cooled. The LPCS pump motor is 1500 HP, 1780 RPM and is powered from 4160 VAC emergency bus 241Y. Cooling water from the CSCS Equipment Cooling Water System flows through tubes adjacent to the stator windings to remove motor heat during pump operation.

The pump is provided with a minimum flow bypass line to prevent a 'dead-head' condition when the discharge flow path has not yet been established. The four-inch line contains a locked-open manual valve, a flow-actuated motor-operated valve, and a flow restrictor sized to pass 750 gpm flow. The minimum flow bypass MOV (2E21-F011) opens to direct a portion of pump discharge back to the suppression pool whenever LPCS flow is less than 750 gpm. When flow downstream of the pump exceeds the specified minimum, the minimum flow valve automatically closes.

The 24-inch pump suction line contains an MOV (2E21-F001) used to isolate the line from the suppression pool. The MOV is a 24-inch, 480 VAC motor-operated gate valve. The valve is manually operated from the control room using a keylock switch, and is normally locked open.

The suction line within the suppression pool is provided with a stainless steel, 1/8" mesh screen strainer to prevent debris from being drawn into the LPCS pump which may clog the core spray nozzles. The strainer is located 5 ft above the bottom of the suppression pool and is sized such that adequate pump NPSH is maintained even when the strainer is 50% clogged.

The 16-inch pump discharge line is water-filled during normal operation. A check valve (2E21-F003) downstream of the LPCS pump prevents the discharge line from emptying into the suppression pool. Some backflow and leakage is expected, so the lines are kept full by a water-leg pump. This pump, 2E21-C002, draws water from the LPCS suction line below the suppression pool water level and keeps the LPCS and LPCI train A discharge lines full. By maintaining the pump discharge line in a filled condition, the time between LPCS initiation and flow into the RPV is reduced and the possibility of water-hammer damage to the LPCS line is minimized.

The LPCS injection valve (2E21-F005) is 12-inch motor-operated gate valve. The valve is normally closed and opens automatically upon the following conditions:

a) Reactor vessel pressure, pressure downstream of the injection valve, decreases to less than 500 psig,

b) Initiation signals are present: 1.69 psig in the drywell and -129" reactor vessel water level (level 1), and

c) No undervoltage exists on bus 241Y (for LPCS pump).

The LPCS injection valve can be opened manually when the pressure downstream of the valve is less than 500 psig, the low pressure interlock, and if the DP across it is less than 100 psid. The injection valve can be manually closed at any time. The valve will not reopen automatically after it is manually closed even with automatic initiation conditions present. It must be manually reset.

An air-operated testable check valve (2E21-F006) is provided inside the drywell in the LPCS injection line. This check valve prevents back-flow into the low pressure LPCS lines and protects against LOCAs due to breaks in the line. The pneumatic operator permits verification of valve operability and valve position indicator lights are provided in the control room. The air actuator cannot prohibit the valve from opening, nor can the actuator open or hold the valve open against any significant differential pressure across it. The check valve will shut automatically on the following Group II isolation signals:

a) -50" reactor vessel water level
b) 1.69 psig in the drywell
c) Manual pushbutton (B and/or D)

A 12-inch manually operated, locked open gate valve (2E21-F051) between the RPV and the testable check valve in the LPCS line isolates the loop from the reactor vessel during shutdown maintenance periods, if required.

A 14-inch return line to the suppression pool is provided downstream of the LPCS pump. This test line is used to verify the technical specification flow requirements of the LPCS system. The test return line contains a normally closed, motor-operated globe valve (2E21-F012) that also receives a close signal upon LPCS initiation.

The signals that auto initiate LPCS are 1.69 psig sensed in the drywell or -129" reactor vessel water level. LPCI A initiation logic is common with the LPCS system and is separated from the initiation logic for LPCI B and LPCI C. Each set of initiation logic uses the same one-out-of-two taken twice form; however, one trip system uses only Division 1 sensors (LPCI A, LPCS), and the other trip system uses only Division 2 sensors (LPCI B, LPCI C). See Section 3.3, the LPCI system description, for figures showing the LPCI/LPCS actuation logic.

3.2.2.2 System Interfaces

A failure modes and effects analysis (FMEA) of LPCS support system interfaces is shown in Table 3.2-1. The support system interfaces are discussed below.

Shared Components

The LPCS initiation logic is shared by LPCI train A. During standby operation the LPCS water leg pump (2E21-C002) is used to keep both the LPCS and LPCI A pump discharge lines filled.

Electrical

Division 1 of the Class 1E electrical system provides power to the LPCS system for operation of the system pump, water leg pump, system MOVs, and system instrumentation and controls. The LPCS pump mot · is supplied by the 4160 VAC distribution system from bus 241Y. The system MOVs and the water leg pump are powered by the 480 VAC MCC 235Y-2 off the 142Y bus. Control power for the MOVs is provided by a 480/120 VAC transformer for each valve.

The 125 VDC distribution system (Div. 1) supplies power to the LPCS initiation (actuation) and interlock logic circuits and control power for the LPCS pump motor.

Component Cooling

The CSCS Equipment Cooling Water System cools the LPCS pump motor via tubes adjacent to the stator windings. The pump seals are self-cooled.

Room Cooling

The LPCS pump motor has a dedicated water cooling system. there are also instrumentation and control components located in the LPCS/RCIC pump cubicle which are air cooled. Analysis indicates that the pump cubicle temperature will reach 240F in about the one hour following loss of room cooling if both the LPCS and RCIC pumps are operating. Electrical components are typically qualified to temperatures considerably lower than this, so room cooling is judged to be a necessary support system to LPCS, at least in the long-term (i.e., for operating times greater than one hour).

3.2.2.3 Instrumentation and Control

System Actuation

The LPCS system may be initiated either manually, at panel 2H13-P601, or automatically by high drywell pressure (+1.69 psig) or - 129" reactor vessel water level. After an initiation signal is received by the LPCS control circuitry, the signal is sealed in until manually reset.

Drywell pressure sensing elements 2B21-N048A and 2B21-N048C provide the LPCI A and LPCS high drywell initiation signal. Reactor water level sensors 2B21-N037A and 2B21-N037C provide the low water level signals for these systems. The trip system consists of the two level switches and the two high pressure switches connected into a one-out-of-two twice configuration.

Once a LPCS initiation signal is received the following actions occur:

1) Under normal auxiliary power the LPCS pump starts immediately. When the 241Y bus is energized from its associated standby diesel generator, pump start is delayed five seconds.

2) Test return MOV (F012) closes if it is not already closed.

3) Injection valve F005 is interlocked to open once the reactor vessel pressure and pressure immediately downstream of the valve drop below 500 psig. Power must also be available on bus 241Y supplying the LPCS pump.

4) When LPCS flow is greater than 750 gpm, the minimum flow MOV closes.

Detailed diagrams of the LPCS system actuation and component control logic are given in Section 3.3, the LPCI system description, with which they are intimately associated. This is so that all the diagrams will be in one place and the inter-connections can be followed more easily. To manually initiate LPCS a pushbutton in the control room labeled "RHR A/LPCS Manual Initiation" is armed and depressed.

Component Control

LPCS Pump Control (2E21-C001)

Given the actuation of this pump as described above, the pump continues to operate at full capacity until it is manually shut down. The LPCS pump trips on the following:

1. Placing the control switch in the STOP position (even with initiation signal present). When the switch is allowed to return to the AUTO position, the initiation signal is still blocked out.

2. Placing the control switch in pull-to-lock.

3. Auto trips on:

    a. 241Y undervoltage

    b. Overcurrent (phases or neutral).

LPCS Injection MOV Control (2E21-F005)

The normally closed LPCS injection valve opens automatically upon receiving an initiation signal if the following permissives are satisfied:

1) Reactor vessel pressure and pressure downstream of the injection valve decrease to less than 500 psig and

2) No undervoltage exists on bus 241Y.

The LPCS injection valve can be opened manually at any time the pressure downstream of the injection valve is less than 500 psig and the DP across it is less than 100 psid. The injection valve can be manually closed at any time. It will not reopen automatically once it is manually closed even with automatic initiation conditions present.

Minimum Flow Bypass MOV for the LPCS Pumps (2E21-F011)

The normally open motor-operated valve in the minimum flow bypass line receives an 'open' signal upon sensing low flow in the discharge line from the LPCS pump when the pump is running. The valve automatically closes when the flow from the LPCS pump is above 750 gpm. Flow indications are derived from a flow switch that senses the pressure differential across a flow element in the pump discharge line. This feature serves to protect the main system pump from overheating at low flow rates.

ECCS Water Leg Pump (2E21-C002)

When the LPCS pump is inactive its associated discharge line is kept water-filled through use of a check valve near the pump discharge and a continually operating water leg pump that replaces any backflow through the check valve. The power supply to the water leg pump is classified as essential when the main LPCS pump is deactivated. Indication is provided in the control room as to whether the water leg pump is operating, and ESF system status lights indicate low injection (discharge) line pressure.

<u>Instrumentation</u>

Valves

All motor-operated valves in the LPCS system have lighted position indicators in the control room. In addition, control room position indicators are provided for the testable check valve and the manual maintenance valve in the LPCS injection line located within the drywell containment.

LPCS Pump

Indicators in the control room show whether the LPCS pump is on, off, or in pull-to-lock. The current being drawn by the pump is also indicated. Two pressure switches are installed in the pump discharge pipeline and linked to control room indicators to verify that the pump is operating following an initiation signal. (The pressure signal is also used by the automatic depressurization system to verify availability of low-pressure core cooling.) A pressure indicator is also provided in the suction line of the

LPCS pump. The pump and motor bearing temperatures can be monitored using the plant process computer during pump operation.

LPCS System Flow

Flow in the LPCS System is sensed by an orifice-type flow element in the pump discharge line. Indication of system flow is provided by meters on the RHR panel in the control room. The pump minimum flow bypass valve is positioned according to the indication received from this flow sensor.

LPCS Injection Line Integrity Monitor

A pressure differential indicating switch is used to confirm the integrity of the LPCS line within the reactor vessel. Should a break occur between the reactor core and the outer annulus the pressure difference will cause an alarm to trip in the control room.

LPCS Testable Check Valve Leak Detection

A pipe connected to the operating mechanism side of the testable check valve (2E21-F006) in the LPCS injection line detects packing leakage. When high temperature is detected an alarm is tripped in the control room.

Control Room Monitors

1. LPCS Pump

a.	Discharge piping pressure	0-400 psi
b.	Pump flow (Loop)	1-10,000 gpm
c.	Pump Amps	0-150 amps

2. LPCS Pump Room Temperature

a.	Duct	0-300F
b.	Area	0.300F

3. Reactor Water Level Fuel Zone -111" to -311"

Major Alarms

a. LPCS System Actuated - Drywell pressure 1.69 psig or Rx Water Level -129".

b. LPCS Pump Auto Trip

c. LPCS Pump Breaker Closed

d. LPCS Pump Discharge Pressure Hi/Low -475/55 psig.

e. LPCS Pump Flow Above Min (> 750 gpm) - closes LPCS minimum flow.

f. LPCS-RCIC Pump Cubicle Cooler Fan Auto Trip - Overload.

g. LPCS-RCIC Pump Cubicle Temp High - 108F.

h. LPCS Injection Valve Reactor Press Low - 500 psig.

i. RHR "A"-LPCS Line Integrity Monitor - 1.0 psid above or below zero. This is indicative of a leak in the LPCS/RHR "A" injection lines.

j. LD Valve Stem RHR/HPCS/LPCS Leakage Temp High - 250±6F.

k. LPCS Manual Initiation Pushbutton Armed.

Failure of the LPCS logic power supply will result in an alarm at the ESF Status Display Panel.

3.2.2.4 Operator Actions

LPCS initiation is completely automatic. The primary responsibility of the operator is to verify system operation on a regular basis following an initiation. The LPCS system can be shut down when it is determined that vessel water level can be maintained after the LPCS pump is stopped. LPCS does not shut down automatically.

3.2.2.5 Technical Specification Limitations

The following excerpts from the LaSalle Unit 2 technical specifications apply to the LPCS system during operational conditions 1, 2 and 3.

Limiting Condition for Operation

3.5.1 ECCS divisions 1, 2 and 3 shall be OPERABLE with:

a. ECCS division 1 consisting of:

1. The OPERABLE low pressure core spray (LPCS) system with a flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

2. The OPERABLE low pressure coolant injection (LPCI) subsystem "A" of the RHR system with a flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

3. At least 6 OPERABLE ADS valves.

b. ECCS division 2 consisting of:

1. The OPERABLE low pressure coolant injection (LPCI) subsystems "B" and "C" of the RHR system, each with a flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

2. At least 6 OPERABLE ADS valves.

c. ECCS division 3 consisting of the OPERABLE high pressure core spray (HPCS) system with a flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

Action

a. For ECCS division 1, provided that ECCS division 2 and 3 are OPERABLE:

1. With the LPCS system inoperable, restore the inoperable LPCS system to OPERABLE status within 7 days.

3. With the LPCS system inoperable and LPCI subsystem "A" inoperable, restore at least the inoperable LPCI subsystem "A" or the inoperable LPCS system to OPERABLE status within 72 hours.

4. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.*

d. For ECCS divisions 1 and 2, provided that ECCS division 3 is OPERABLE:

2. With the LPCS system inoperable and either LPCI subsystems "B" or "C" inoperable, restore at least the inoperable LPCS system or inoperable LPCI sub- system "B" or "C" to OPERABLE status within 72 hours.

3. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours*.

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* Whenever two or more RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

f. With an ECCS discharge line "keep filled" pressure alarm instrumentation channel inoperable, perform Surveillance Requirement 4.5.1.a.1 at least once per 24 hours.

g. With an ECCS header delta P instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 72 hours or determine ECCS header delta P locally at least once per 12 hours otherwise, declare the associated ECCS inoperable.

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o
o

f. With one or more ECCS corner room watertight doors inoperable, restore all the inoperable ECCS corner room watertight doors to OPERABLE status within 14 days, otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

Surveillance Requirements

4.5.1 ECCS division 1, 2, and 3 shall be demonstrated OPERABLE by:

a. At least once per 31 days for the LPCS, LPCI, and HPCS systems:

1. Verifying by venting at the high point vents that the system piping from the pump discharge valve to the system isolation valve is filled with water.

2. Performance of a CHANNEL FUNCTIONAL TEST of the:

a) Discharge line "keep filled" pressure alarm instrumentation, and

b) Header delta P instrumentation.

3. Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

4. Verifying that each ECCS corner room watertight door is closed, except during entry to and exit from the room.

b. Verifying that, when tested pursuant to Specification 4.0.5, each:

1. LPCS pump develops a flow of at least 6350 gpm against a test line pressure greater than or equal to 290 psig.

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c. For the LPCS, LPCI and HPCS systems, at least once per 18 months:

1. Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

2. Performing a CHANNEL CALIBRATION of the:

a) Discharge line "keep filled" pressure alarm instrumentation and verifying the:

1) High pressure setpoint and the low pressure setpoint of the:

a) LPCS system to be $\leq$500 psig and $\geq$55 psig respectively

o
o
o

b) Header delta P instrumentation and verifying the setpoint of the:

1) LPCS system and LPCI subsystems to be $\pm$ 1 psid.

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o
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4. Visually inspecting the ECCS corner room watertight door seals and room penetration seals and verifying no abnormal degradation, damage, or obstructions.

In addition, the suppression chamber must contain sufficient water for the LPCS system to operate successfully. The following excerpts from the technical specifications apply to the suppression chamber as it relates to the LPCS system.

<u>Limiting Condition for Operation</u>

3.5.3 The suppression chamber shall be OPERABLE:

a. In OPERATIONAL CONDITION 1, 2, or 3 with a contained water volume of at least 128,800 ft^3, equivalent to the level of 26 ft 1 1/2 in.

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o

o

Action

a. In OPERATIONAL CONDITION 1, 2, or 3 with the suppression chamber water level less than the above limit, restore the water level to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

o

o

o

c. With one suppression chamber water level instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 7 days or verify the suppression chamber water level to be greater than or equal to 26 ft 2 1/2 or 14 ft 0 in., as applicable, at least once per 12 hours by local indication.

d. With both suppression chamber water level instrumentation channels inoperable, restore at least one inoperable channel to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours and verify the suppression chamber water level to be greater than or equal to 25 ft 2 1/2 in. or 14 ft 0 in., as applicable, at least once per 12 hours by local indication.

Surveillance Requirements

4.5.3.1 The suppression chamber shall be determined OPERABLE by verifying:

a. The water level to be greater than or equal to, as applicable:

1. 26 ft. 2 1/2 in. at least once per 24 hours.

2. 14 ft. 0 in. at least once per 12 hours.

b. Two suppression chamber water level instrumentation channels OPERABLE by performance of a:

1. CHANNEL CHECK at least once per 24 hours,

2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and

3. CHANNEL CALIBRATION at least once per 18 months, with the low water level alarm setpoint at greater than or equal to 26 ft. 4 in.

3.2.2.6 Tests

The major tests of the LPCS system are summarized in Table 3.2-2. Operability of MOVs is verified quarterly via stroke testing and a full flow test is also performed quarterly.

Although it is not a test, shiftly surveillance verifies the condition of the LPCS pump, the position of the drywell manual valves in the LPCS injection line, and the alignment of MOVs essential to correct system operation.

3.2.2.7 Maintenance

No scheduled maintenance is planned which disables LPCS components while the plant is at power. Unscheduled maintenance is permitted on system components provided applicable safety and radiological administrative controls are satisfied. Unscheduled maintenance activities possible during plant operation include:

- Replacement or repair of actuation and control circuitry

- Electrical maintenance on motor driven components

- MOV and pump mechanical maintenance that does not result in a breech of the LPCS system fluid boundary.

- MOV and pump mechanical maintenance that breeches the system boundary when double isolation from reactor pressure/temperature can be achieved. Isolation here is taken to mean an accessible manual valve or a motor-operated valve that can be racked out. It is assumed that check valves do not provide a secure means of isolation.

Section 3.2.2.5 indicates the period of time that the LPCS system may be inoperable due to unscheduled maintenance. In summary, with just one of the low pressure reflood systems (LPCS and three LPCI trains) inoperable, the subsystem must be restored within seven days. With two of the low pressure reflood subsystems inoperable, one of the subsystems must be restored to operability within 72 hours. Otherwise the plant must be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

A summary of unscheduled maintenance acts allowed on the LPCS system while the plant is in full power operation is given in Table 3.2-3. The following notes pertain to this table:

- o Although permitted, unscheduled maintenance on check valves and manual valves is not listed on the table because of the significantly lower frequencies of occurrence when compared to MOVs.

- o The manual maintenance isolation valve in the drywell (F051) is assumed to be inaccessible during full power operation, and hence cannot be used to achieve LPCS line double isolation except during shutdown conditions.

- o Since the drywell maintenance isolation valve is inaccessible and there is no manual maintenance valve downstream of the LPCS pump, the only LPCS system component that can be double isolated for 'destructive' mechanical maintenance is the water leg pump (2E21-C002). It is assumed that the LPCS pump will be racked out when the water leg pump is taken out for maintenance.

- o Each of the system MOVs and the pump has a feed circuit breaker in the power supply lines in its associated MCC. In addition to the maintenance activity shown in Table 3.2-3, unscheduled electrical maintenance on these circuit breakers is anticipated. This activity is only of interest for components that must change state and it is assumed that no other system components are impacted. Failure to restore the breaker after maintenance is not considered likely because the component indicator lights in the control room receive power through this breaker.

3.2.3 System Operation

3.2.3.1 Normal Operation

During the normal plant operation, the LPCS system is in standby. One water leg pump operates continuously to keep the LPCS and LPCI A pump discharge lines filled. The suppression chamber must also be operable with its level between 26' 10" and 26' 2 1/2" and its temperature at or below 100F.

3.2.3.2 Abnormal Operation

LPCS operation is automatic when either the low reactor water level (-129") or the high drywell pressure (1.60 psig) signal is received or when the manual pushbutton is depressed. When LPCS initiation occurs, the following events take place and should be verified by the operator.

a. If normal auxiliary power is available, the LPCS pump will start without delay. When on Standby Diesel generator power, the LPCS pump starts after a five second delay.

b. The emergency LPCS/RCIC pump cubicle cooling systems actuate and continue to operate until the pumps are shut down and room temperature falls below 104F.

c. The LPCS injection valve (F005) will open when reactor pressure and pressure downstream of the injection valve decreases to less than 500 psig, and power is available to the LPCS pump. Coolant will be injected into the vessel when pressure drops below the pump discharge pressure and the check valve opens.

d. The test return line MOV (F012) closes automatically if it is not already closed.

e. The LPCS system can be manually shut down when it is determined that the reactor vessel water level can be maintained without the LPCS pump operating.

3.2.4 System Fault Tree

3.2.4.1 Description

A simplified diagram of the LPCS system showing the mechanical components included in the fault tree model is shown in Figure 3.2-2.

The water leg pump (2E21-C002) appears in the fault tree only as a contributor to LPCS system unavailability due to component maintenance that breeches the LPCS system boundary and requires closure of the injection MOV to achieve double isolation. Since this component is not modeled as essential to LPCS success, it has been omitted from the simplified diagram.

There are seven developed events in the LPCS fault tree. Three are transfers from the electric power fault trees: the 4160 VAC bus 241Y, the 480 VAC MCC 235Y-2, and the 125 VDC bus 211Y. One developed event represents the LPCS/RCIC pump cubicle cooling system and is developed in the ECCS Equipment Area Cooling System fault trees. Another developed event represents CSCS cooling water supplied to the LPCS pump motor. LOCA logic for LPCS initiation is the same as that for LPCI Train A and is developed there. The undervoltage trip for the LPCS pump is also developed in the LPCI A fault tree.

3.2.4.2 Success/Failure Criteria

The LPCS system is successful when the loop operates at near rated capacity conveying water from the suppression pool and injecting it above the reactor core for the time interval in which it is required. LPCS failure occurs upon one of the following:

1) Division 1 normal and emergency electrical power is lost.

2) AC Bus 241Y (4160V), or MCC 235Y-2, or DC bus 211Y is lost,

3) ECCS Equipment Area Cooling is lost for the NE cubicle

4) CSCS cooling water to the LPCS pump motor is lost.

5) The LPCS pump or injection MOV fail to actuate/operate.

6) The test return MOV inadvertently opens resulting in a diversion path.

7) Pipe rupture occurs in the LPCS loop.

8) LPCS is unavailable due to unscheduled maintenance.

9) Suction strainer in the suppression pool is greater than 50% clogged.

The top event of the LPCS system fault tree is:

FAILURE OF LCS SYST TO INJECT COOLANT WITH 1-OF-1 INJ PATH AND 1-OF-1 PUMPS

3.2.4.3 Assumptions

In addition to the general assumptions regarding fault tree development (listed at the beginning of this volume), the following assumptions specific to the LPCS system were made:

1) There is a large branch line to the RHR A suction line. It is sealed by a blind flange during normal operation. It is highly unlikely that such a line could be inadvertently left open and not detected during the various start-up procedures. Therefore this line is not modeled as a diversion path.

2. There are two safety relief valve lines associated with the LPCS system. The relief line near the injection valve is four inches in diameter, hence it cannot act as a significant diversion for flow in the 16-inch LPCS pipe. An inadvertently opened safety/relief valve in the one-inch line off the LPCS pump suction does not create a large enough path to significantly degrade pump NPSH.

3) The minimum flow bypass line protects the LPCS pump from overheating when a discharge path has not been established yet. The usual sequence for LPCS operation has the pump start upon receiving a LOCA initiation signal and the LPCS injection valve opening when reactor pressure drops below 500 psig. In certain postulated accident sequences, some time may elapse before the injection MOV opens. During this time the pump would be 'dead-headed' if the minimum flow MOV failed closed.

   The LPCS pump manufacturer indicates, however, that the pump will operate 30 to 60 minutes under no-flow conditions before it overheats. (The exact time-to-failure is dependent on the pump cubicle environment.) Even taking the minimum time-to-failure of 1/2 hour, it is highly likely that either RPV pressure will have dropped such that the LPCS injection valve opens, or various control room indicators will have warned the operator of a problem with LPCS pump flow. Control room indicators include a position indicator for the minimum flow bypass MOV, pump discharge pressure and alarm (475 psig), LPCS line flow indicator, and a pump bearing temperature recorder. For these reasons failure of the pump discharge bypass line to provide minimum flow after pump initiation is not considered a significant contributor to pump failure.

4) The eight-inch minimum flow bypass line at the discharge of the LPCS pump contains a four-inch diameter flow restrictor. It is therefore too small to act as a significant diversion path should the minimum flow bypass MOV remain open when LPCS flow is required.

5) The LPCS pump motor is cooled by water supplied by a branch line of the CSCS system. The pump itself has self-cooled seals. Though it is likely that the pump by itself could operate satisfactorily without room cooling, LPCS control and actuation components in the pump cubicle probably could not. (Analysis indicates that without the ECCS Equipment Area Cooling System operating, the LPCS/RCIC pump cubicle temperature reaches 240F within one hour. Hence it is assumed the room cooling is required for sequences where LPCS operation for more than one-hour would be required.

6) The possibility of water hammer failure of the pump discharge line due to failure of the water leg fill subsystem is neglected. The water leg pump operates continuously to maintain the LPCS/LPCI A lines in a filled condition and it is indicated in the control and checked shiftly. In addition, the LPCS pump discharge line pressure is indicated and alarmed in the control room, so failures of the water leg fill system are readily detected. When the water leg fill system is out of service the LPCS line can be manually filled via the Flushing Water Supply line. Even in the event that the LPCS line is not water filled when the LPCS pump starts, the design of the pump discharge line is such that pipe rupture due to water hammer is unlikely (i.e., the low pressure piping is actually the same as the high pressure piping at LaSalle).

Table 3.2-1 LPCS Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
4160V BUS 241Y	2E21-C001	Motor-driven pump	FTS/FTR	Loss of all LPCS MOV position lights in control room	Loss of LPCS	Fails LPCS
480VAC MCC 235Y-2	2E21-F005	MOV	FTO	Loss of position lights in control room	Loss of LPCS automatic and remote injection	
	2E21-F011	MOV	FTO/FTC	Loss of position lights in control room (If FTO, various pump/flow indications in control room	If FTO: LPCS pump may be dead-headed, overheat in 30-60 min. if no flow is established If FTC: About 10 percent of LPCS flow diverts to suppression pool	Action must be taken to prevent pump from overheating OR small portion of LPCS flow is diverted
125VDC Power Dist Pnl 211Y	2E21-C001	Motor-driven pump	FTS/FTR	Loss of pump indication lights in control room	LPCS pump inoperable	Fails LPCS
	Initiation and interlock logic for LPCS/LPCI A		Inoperable	Alarmed in control room	No LPCS initiation on LOCA	Fails LPCS
CSCS Equipment Cooling Water system RHR Service Water System (Div. 1)	2E21-C001	Motor-driven pump	Fails pump motor	Operation of service water pumps indicated in control room. Various temp indications in service water train for associated DG	Loss of LPCS after some time	Pump motor overheats - Fails LPCS

Table 3.2-1 LPCS Support Systems Interface FMEA (Concluded)

Support (Sub) System Failure	System Component Affected Identifier Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
<u>ECCS Equipment Cooling System</u>					
NE Cubicle Cooling	Pump and MOV Instrumentation and Control (I&C) in cubicle	Inoperable	Cubicle temperature indicated in control room. HVAC fan indicated in control room	After about 12 minutes cubicle temp reaches 212°F. I&C circuitry is assessed to fail resulting in loss of LPCS.	Fail LPCS

Table 3.2-2. LPCS System Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
LOS-RH-M1	System Operability (Alignment)	All motor-operated valves required for SCS operation and the drywell manual isolation valves		No	---	Monthly	---	Alignment: Shiftly Operability: Quarterly
		LPCI/LPCS Water Leg Pump		No	---	Monthly	---	Monthly
LOS-LP-Q1	Pump Inservice	2E21-C001	Pump	No	---	Quarterly	---	Alignment: Shiftly Operability: Quarterly
		2E21-F011	MOV	No	---	Quarterly	---	" "
		2E21-F012	MOV	Yes	Yes	"	---	" "
LOS-LP-Q2	Value Exercise	2E21-F001	MOV	Yes	No	Quarterly	---	Alignment: Shiftly Operability: Quarterly
		2E21-C001	Pump	Yes[1]	No	"	---	" "
		2E21-F011	MOV	Yes[2]	No	Quarterly	---	Indication: Shiftly
LIS-PC-203	LPCS Activation	PS-2B21-N048 A/B/C/D	Switch/ Initiation Logic	Yes	No	Quarterly	---	Indication: Shiftly Operability: Quarterly
LIS-NB-204	LPCS Activation	DPIS-2B21-N037B/D	Switch/ Initiation Logic	Yes	No	18 Months	---	Indication: Shiftly Operability: 18 Months

1) LPCS pump is placed in "Pull-to-Lock" while F001 valve is tested.
2) Valve is out of alignment only briefly.

Table 3.2-3 Low Pressure Core Spray Unscheduled Maintenance Summary

Component Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E21-C001	Motor-driven pump	Mechanical[1] electrical	2E12-F006A/B	Yes			Alignment: Shiftly Operability: Quarterly
2E21-F005	MOV	Mechanical[1]	Valve circuit breaker	Yes			" "
2E21-C002	Motor-driven pump	Mechanical[2]	LPCS pump circuit breaker	Yes			" "

1) Maintenance not involving a breach of LPCS system boundary.
2) Maintenance involving breaching the LPCS system boundary and requiring double isolation from reactor pressure.

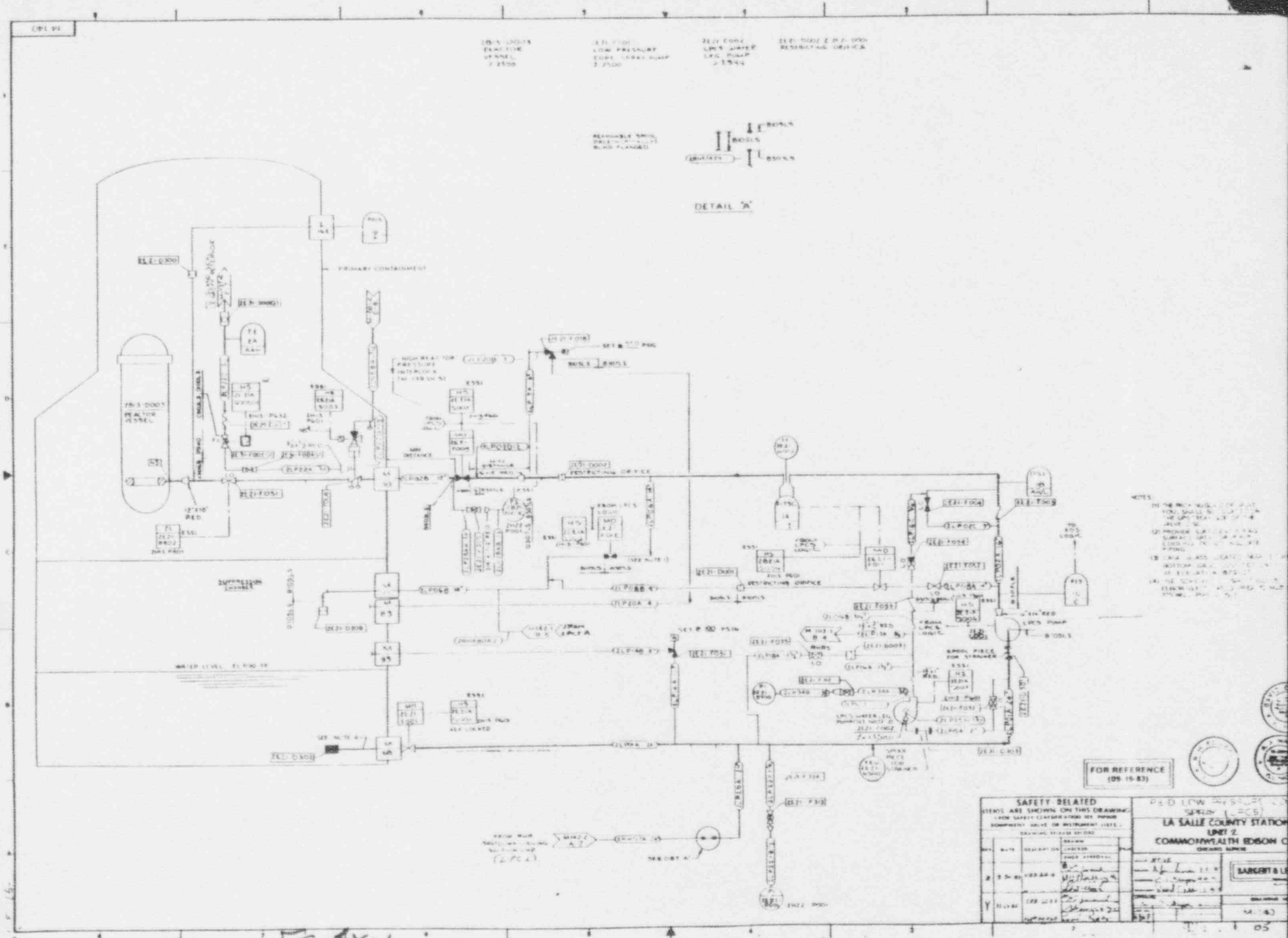
DETAIL 'A'
PRIMARY CONTAINMENT
REACTOR VESSEL
SUPPRESSION CHAMBER
RESTRICTING ORIFICE
LPCS PUMP
FOR REFERENCE
(09-15-83)
SAFETY RELATED
ITEMS ARE SHOWN ON THIS DRAWING
LA SALLE COUNTY STATION
UNIT 2
COMMONWEALTH EDISON C
SARGENT & L

Fig BX-1.

Figure 3.2-1 Simplified Diagram of the Low Pressure Core Spray System

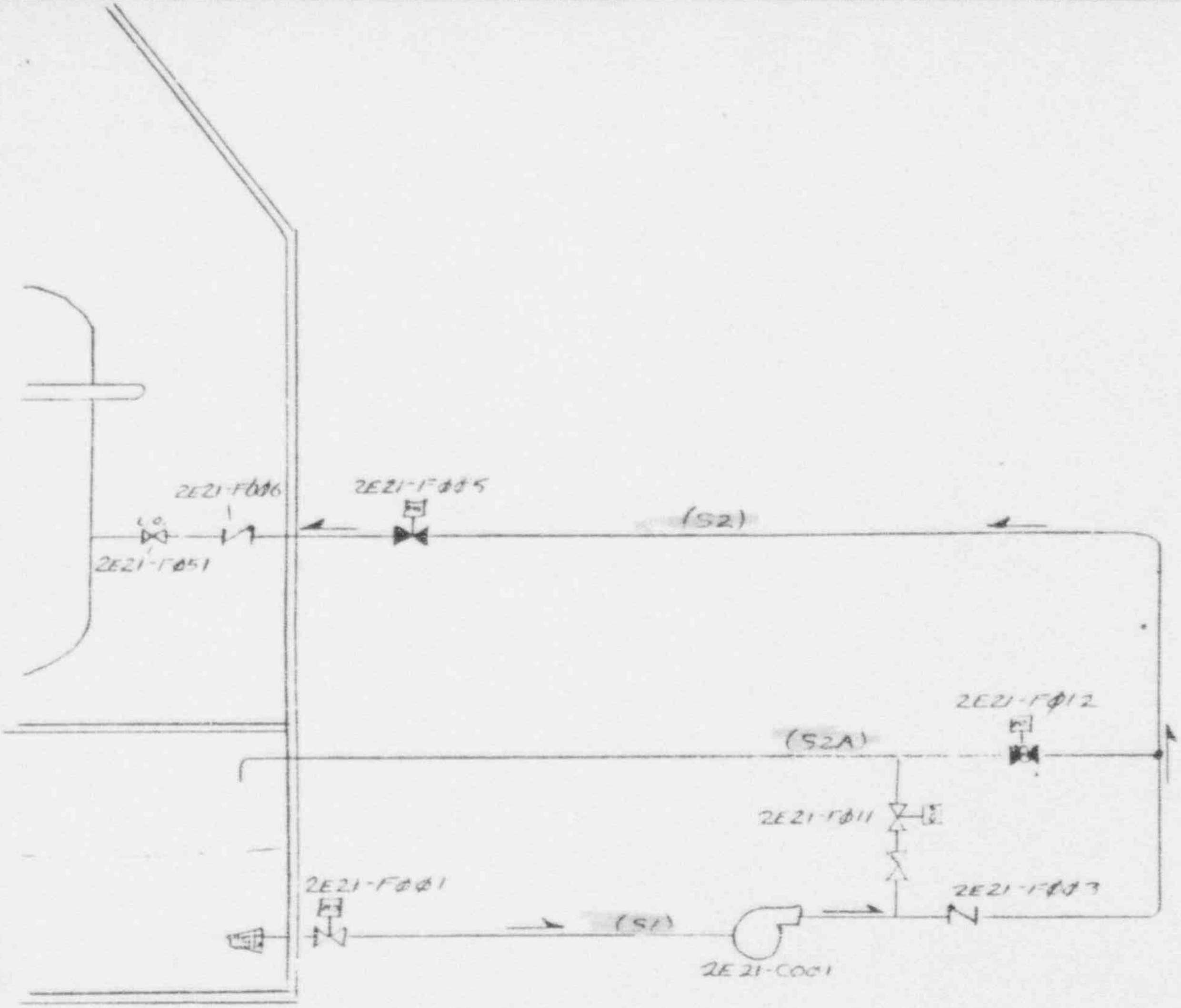

FIGURE B.X-4 Low Pressure Core Spray Simplified Piping Diagram

Figure 3.2-2 Simplified Diagram of the Low Pressure Core Spray System for Fault Tree Construction

3.3 Low Pressure Coolant Injection System (LPCI)

3.3.1 System Function

The Low-Pressure Coolant Injection system (LPCI) is one of the independent operating subsystems of the RHR system. It operates to restore and, if necessary, maintain the coolant inventory in the reactor vessel after a loss-of-coolant accident. LPCI operation provides protection to the core for a large break in the reactor coolant pressure boundary and also extends protection to cover a small break in which the HPCS and RCIC have failed and ADS has reduced the reactor vessel pressure to the LPCI operating range. LPCI is a low-head, high-flow system that delivers flow to the reactor vessel when the differential pressure between the vessel and drywell is less than 225 psid. LPCI is designed to reflood the reactor vessel to at least two-thirds core height and to maintain this level.

3.3.2 System Description

3.3.2.1 General Design

The LPCI subsystem consists of three independent fluid trains that convey water from the suppression pool and inject it into the reactor vessel via three separate nozzles. Two of the LPCI trains are configured from RHR pumps, valves and piping that may also be used in other RHR modes. The third train is used only in LPCI mode and contains no components common to the other subsystems. Detailed one-line diagrams of the three LPCI trains are shown in Figures 3.3-1 through 3.3-4.

Flow Path

The RHR System is lined up for LPCI operation and in standby during normal plant operation.

Immediately following a LOCA, the RHR system is directed to the LPCI mode, if it is not already in that condition. The three RHR pumps take suction from the suppression pool and route it to the reactor vessel via three separate flow paths. The injection MOV in each flow path does not open until reactor pressure is less than 500 psig, so a portion of pump discharge is routed back to the suppression pool through a minimum flow line until the reactor is sufficiently depressurized.

Two of the LPCI trains (A and B) contain RHR heat exchangers in their flow paths but the bypass lines around them are open for at least the initial stages of LPCI operation. Heat rejection from the containment is not needed during reactor reflooding.

Locations

Most of the LPCI train A components are located in the northwest corner of the reactor building basement. The injection line penetrates the primary containment at the 775' elevation about midway up the reactor vessel. A testable check valve and a locked-open manual maintenance valve are inside the drywell as part of the train A injection line.

The LPCI trains B and C components are predominantly located in the southeast corner of the reactor building basement. Similar to the A train, each of these trains has an injection line that penetrates the primary containment at an elevation about midway up the reactor vessel. The LPCI train B and C injection lines also contain a check valve and manual maintenance valve located inside the drywell.

Component Descriptions

The RHR pumps (2E12-C002A/B/C) are three stage vertical centrifugal pumps with a 7450 gpm capacity against a 280 ft. head. The pumps are sized to meet a required flowrate of 7200 gpm against 120 psid between the reactor vessel and the suppression pool. The pump motors are 800 HP, 1780 RPM powered from 4160 VAC emergency busses 241Y (train A) and 242Y (trains B and C), and are air-cooled. Pump seals are cooled by the RHR service water system. Pump seal cooling must be in operation to prevent seal failure (and subsequent leaking) whenever pumped water temperature exceeds 160F.

Each of the pumps is provided with a minimum flow bypass line to prevent a 'dead-head' condition when the pump discharge flow path has not yet been established. The 8-inch lines contain 4-inch diameter flow restrictors. The minimum flow MOV (2E12- F064 A/B/C) within each line directs a portion of the pump discharge back to the suppression pool whenever flow through its pump is less than 1010 gpm. When flow downstream of the pump exceeds the specified minimum, the minimum flow valve automatically closes.

The 24-inch pump suction lines each contain a MOV used to isolate the lines from the suppression pool. The 2E12-F004 A/B/C MOVs are 24-inch, 480 VAC motor operated gate valves. They are normally open and may be manually operated from the control room. An interlock is provided to prevent opening the F004 A/B valves if their respective shutdown cooling suction line valves (2E12-F006 A/B) are open.

The suction lines within the suppression pool for each of the LPCI trains are fitted with strainers to prevent debris from being drawn into the RHR pumps. The suction lines are located approximately three feet above the bottom of the suppression pool. The strainer screen is sized such that adequate pump NPSH is maintained even when the strainer is 50% clogged.

The 18-inch pump discharge lines are water-filled during normal operation. A check valve downstream of each RHR pump (2E12- F031A/B/C) prevents the discharge line from emptying into the suppression pool. Some back flow or system leakage is expected, so the lines are kept full by a water leg pump - one for each ECCS division. The 2E12-C003 pump draws water from the LPCI train C suction line and keeps the LPCI trains B and C discharge lines full. The 2E21-C002 pump draws water from the LPCS suction line and keeps the LPCS and LPCI train A discharge lines full. By maintaining the RHR pump discharge lines in a filled condition, the time between LPCI initiation and flow into the RPV is reduced and the possibility of water-hammer damage to the LPCI lines is minimized.

Each RHR pump discharge line also contains an 18-inch manual gate valve (2E12-F098 A/B/C) downstream of the pump check valve. These manual valves are used to provide maintenance isolation. They are normally locked open and no indication is provided in the control room.

The A and B LPCI trains contain inverted U-tube heat exchangers in their flow paths. Heat rejection from the containment is not required during reactor reflood so 18-inch bypass lines around the heat exchangers are provided. The bypass lines each contain an 18-inch motor-operated globe valve (2E12-F048 A/B) that can operate in a throttling mode. These valves are normally open in standby, receive an open signal upon LPCI initiation, and cannot be manually closed for ten minutes following LPCI initiation.

The 18-inch motor-operated gate valves at the inlet (2E12-F047 A/B) and outlet (2E12-F003 A/B) of the heat exchangers are normally open, but can be manually closed from the control room at any time.

The LPCI injection valves (2E12-F042 A/B/C) are 12-inch motor-operated gate valves. The valves are normally closed and open automatically upon the following conditions:

a) Reactor vessel pressure and pressure downstream of the injection valve decreases to less than 500 psig,

b) Initiation signals are present: 1.69 psig in the drywell and -129" reactor vessel water evel (level 1), and

c) No undervoltage on bus 241Y (for RHR pump A) or 242Y (for RHR pump B and C).

The LPCI injection valves can be opened manually when the pressure downstream of the valve is less than 500 psig. The injection valves can be manually closed at any time. The valves will not reopen automatically if they are manually closed even with automatic initiation conditions present.

Air-operated testable check valves (2E12-F041A/B/C) are provided inside the drywell in the LPCI injection lines. The check valves prevent back flow into the low pressure LPCI lines and protect against LOCAs due to breaks in the lines. The pneumatic operator permits verification of valve operability and valve position indicator lights are provided in the control room. The air actuator cannot prohibit the valve from opening, nor can the actuator open or hold the valve open against any significant differential pressure across it.

A 12-inch manually operated, locked open gate valve (2E12-F092 A/B/C) between the RPV and the testable check valve in each LPCI line isolates the LPCI train from the reactor vessel during shutdown maintenance periods.

An 18-inch return line to the suppression pool is provided for each LPCI train downstream of its RHR pump. The line is used to verify the technical specification flow requirements of the LPCI system and in trains A and B also provides return flow to the suppression pool when operating in the suppression pool cooling mode. Each of the return lines contains a normally closed, motor-operated globe valve (2E12-F024 A/B and 2E12-F021, train C). Each test return valve receives a close signal upon LPCI initiation. In addition, the test return MOVs are interlocked such that, given a LOCA signal, they cannot be opened until their respective LPCI injection valves are closed.

The signals that auto initiate LPCI are 1.69 psig sensed in the drywell or -129" reactor vessel water level. LPCI A initiation logic is common to the LPCS and is separated from the initiation logic for LPCI B and LPCI C. Each set of initiation logic uses the same one-out-of-two taken twice form: however, one trip system uses only Division 1 sensors (LPCI A), and the other trip system uses only Division 2 sensors (LPCI B, LPCI C).

3.3.2.2 System Interfaces

A failure modes and effects analysis (FMEA) of LPCI support system interfaces is shown in Table 3.3-1. The support system interfaces are discussed below.

Shared Components

Most of the components in trains A and B of the LPCI are also used in other RHR configurations - Shutdown Cooling, Suppression Pool Cooling, Containment Spray, and Steam Condensing. The same RHR pumps, heat exchangers and flow paths are used except that the pump suction, heat exchanger flow control, and injection MOVs for the various modes may be positioned differently.

As noted above, LPCI A initiation logic is common to the LPCS system and is separated from the initiation logic for the LPCI B and LPCI C trains. In addition, during standby operation, the same water leg pump is used to keep the LPCI A and LPCS lines filled, while another pump is dedicated to keeping the LPCI B and C lines water filled. Figures 3.3-5 through 3.3-15 show the control circuit and actuation logic circuits not only for the components in the three LPCI trains but also for the components used in the SDC, SPC, and CSS modes of operation and for the LPCS system components which use the LPCI A actuation circuits. All of this logic is shown together in this system description so that the interconnections can be traced more easily.

Electrical

Both divisions of the Class 1E electrical system provide power to the LPCI trains for operation of the RHR pumps, system MOVs, and system instrumentation and controls. The RHR A pump motor is supplied by the 4160 VAC distribution system from bus 241Y. Train A MOVs are powered by the 480 VAC MCC 235Y-2 off bus 241Y. The only exception is the pump minimum flow bypass valve which is powered by MCC 235Y-1.

The RHR B and C pump motors are supplied by the 4160 VAC distribution system from bus 242Y. The train B MOVs are powered by the 480 VAC MCC 236Y-1 off bus 242Y. Train C MOVs (with the exception of the test return valve, F021) are powered by the 480 VAC MCC 236Y-2. The 2E12-F021 valve is powered by MCC 236Y-1.

The 125 VDC distribution system (Div. 1) supplies power to the LPCI A initiation and interlock logic circuits and control power for the RHR A pump motor. The Division 2 125 VDC distribution system supplies power to the LPCI B and C initiation and interlock logic circuits and also provides control power for the RHR B and RHR C pump motors. Electrical power for actuation of MOVs is provided by a 480/120 VAC transformer for each valve.

Component Cooling

The RHR Service Water System provides cooling for the train A and B RHR heat exchangers. Over the long term this is an essential support system for removing decay heat from the containment. However, only the short term LPCI mission of RPV reflood is being modeled here so RHR Service Water is not considered a necessary support system.

The RHR Service Water System also cools the RHR pump seals. It must be in operation whenever pumped water temperature exceeds 160F or the seals may fail in as little as 20 seconds. However, failure of the pump seals is not judged to be a fault that prevents the RHR pumps from functioning adequately for the purposes of LPCI.

The RHR pump motors are air-cooled and depend on the ECCS Equipment Area Cooling System to keep the pump cubicle temperature within their qualification temperature limits (212F).

Room Cooling

The three RHR pump motors are air-cooled and depend on the ECCS Equipment Area Cooling System to maintain pump cubicle temperatures within qualification limits. There is an ECCS Equipment Area Cooling System dedicated to cooling the NW cubicle (which contains the RHR A pump) and a separate system dedicated to SE cubicle cooling (RHR B and C pumps).

3.3.2.3 Instrumentation and Control

System Actuation

The LPCI system may be initiated either manually, at panel 2H13- P601, or automatically by high drywell pressure (+1.69 psig) or - 129" reactor vessel water level. Reactor vessel low water level or drywell high pressure also stops other modes of RHR system operation so that LPCI is not inhibited. After an initiation signal is received by the LPCI control circuitry, the signal is sealed in until manually reset.

Drywell pressure sensing elements 2B21-N048A and 2B21-N048C provide the LPCI A and LPCS high drywell initiation signal. Reactor water level sensors 2B21-N037A and 2B21-N037C provide the low water level signals for these systems. The trip system consists of the two level switches and the two high pressure switches connected into a one-out-of-two twice configuration.

For LPCI trains B and C, drywell pressure sensing elements 2B21-N048B and 2B21-N048D provide the high pressure initiation signal while the water level sensors 2B21-N037B and 2B21-N037D provide the low reactor water level signals. Again, the trip system consists of the pressure switches and level switches arranged in a one-out-of-two twice configuration.

When a LPCI initiation signal is received the following actions occur:

1) RHR pump C will start immediately. RHR A and B pump starts are each time delayed for five seconds if their respective buses 241Y/242Y are energized from their associated standby diesel generators.

2) RHR Heat Exchanger A and B bypass MOVs receive an open signal and are interlocked to stay open for ten minutes. This ensures the maximum amount of water flow will be available for injection in to the vessel.

3) Injection valves F042, A, B and C are interlocked to open once the reactor vessel pressure and pressure immediately downstream of the injection valve reach 500 psig and power is available on their associated pump supplies 241Y/242Y (i.e., no undervoltage exists).

4) The following valves isolate:

    a) RHR Heat Exchanger flow to RCIC (F026 A/B)
    b) RHR Heat Exchanger flow to the Suppression Pool F011 A/B)
    c) RHR Test Return (F024 and F021)
    d) Suppression Pool Spray Valves (F027A/B)
    e) RHR Steam Pressure Reducing Valves (F051 A/B)
    f) RHR Discharge to RCIC and Suppression Pool F065 A/B)
    g) Heat Exchanger Steam Reducer Bypass (F087 A/B)
    h) RHR Steam Line Isolation Valve (F052 A/B)

To manually initiate RHR loops B and C in the LPCI mode a pushbutton in the control room labeled "RHR B/C Manual Initiation" must be armed and depressed. Similarly a pushbutton labeled "RHR A/LPCS Manual Initiation" will initiate LPCI A and LPCS. As mentioned previously, the LPCI and LPCS control and actuation circuitry is shown in Figures 3.3-5 through 3.3-15. In addition, the control and actuation circuitry of the associated SDC, SPC, and CSS mode of operation is also shown here.

Component Control

RHR A, B and C Pump Control (2E12-C002A/B/C)

The actuation of these pumps is described above. Once actuated the pumps continue to operate at full capacity until they are manually shut down. The RHR pumps trip on the following:

1) a) Undervoltage on respective power supply.

   b) Overcurrent (phase or neutral).

2) Loss of suction flow path:

   a) For RHR pumps A/B this occurs if F004 A/B is closed and either F006 A/B, F008, or F009 close.

   b) For RHR pump C, this occurs if F004C is closed.

3) Placing control switch to stop or pull-to-lock.

LPCI Injection MOV Control (2E12-F042 A/B/C)

The normally closed LPCI injection valves open automatically upon receiving an initiation signal if the following permissives are satisfied:

1) Reactor vessel pressure and pressure downstream of the injection valve decrease to less than 500 psig.

2) No undervoltage exists on bus 241Y (for RHR pump A) or 242Y (for RHR pumps B and C).

The LPCI injection valves can be opened manually at any time the pressure downstream of the injection valve is less than 500 psig. The injection valves can be manually closed at any time. They will not reopen automatically once they are manually closed if the automatic initiation conditions are still present. Once the automatic initiation conditions are removed, the injection valves will reopen automatically if the conditions reappear.

Heat Exchanger Bypass MOV Control (2E12-F048 A/B)

The normally open MOVs in the heat exchanger bypass lines receive an open signal upon LPCI initiation and a timer is activated which prevents the valves from being manually closed for ten minutes. This ensures that maximum flow is delivered to the reactor vessels in the shortest possible time.

Minimum Flow Bypass MOVs for the RHR Pumps (2E12-F064 A/B/C)

The normally open motor-operated valve in the minimum flow bypass line receives an 'open' signal upon sensing low flow in the discharge lines from its associated A pump (if the pump is running). The valve automatically closes when the flow from the RHR pump is above the low flow setting (>1010 gpm). Flow indications are derived from flow switches that sense the pressure differential across a flow element in the pump discharge lines. This feature serves to protect the main system pumps from overheating at low flow rates.

ECCS Water Leg Pumps (2E21-C002, 2E12-C003)

When the RHR pumps are inactive their associated discharge lines are kept water-filled through use of a check valve near each pump discharge and water leg pumps that operate continually to replace any backflow through the check valves or other system leakage. The power supply to these pumps is classified as essential when the main RHR pumps are deactivated. Indication is provided in the control room as to whether the water leg pumps are operating, and ESF system status lights indicate low discharge line pressure.

Instrumentation

Valves

All motor-operated valves in all three RHR trains have lighted position indicators in the control room. In addition control room position indicators are provided for the testable check valve and the manual maintenance valve in each LPCI injection line located within drywell containment.

RHR Pumps

Indicators for each RHR pump in the control room show whether the pump is on, off, or in pull-to-lock. The current being drawn by the pump is also indicated. Two pressure switches are installed in each pump discharge pipeline and linked to control room indicators to verify that pumps are operating following an initiation signal. (The pressure signal is also used in the automatic depressurization system to verify availability of low- pressure core cooling.) A pressure indicator is also provided in the suction line of each RHR pump. The RHR pump and motor bearing temperatures can and should be monitored using the plant process computer during pump operation.

LPCI System Flow

Flow in each LPCI train is sensed by an orifice-type flow element in the pump discharge lines. Indication of system flow for each train is provided by meters on the RHR panel in the control room. The pump minimum flow bypass valve is positioned according to the indication received from this flow sensor.

RHR Injection Line Integrity Monitor

A pressure differential indicating switch is used to confirm the integrity of the LPCI lines within the reactor vessel. Should a break occur between the reactor core and the outer annulus the pressure difference will cause an alarm to trip in the control room.

LPCI Testable Check Valve Leak Detection

A pipe connected to the operating mechanism side of the testable check valve (2E12-F041 A/B/C) in each LPCI injection line detects packing leakage. When high temperature is detected an alarm is tripped in the control room.

Control Room Monitors

1. RHR Pump
   a. RHR Discharge piping pressure 0-400 psi
   b. RHR Pump flow (Loop) 0-10,000 gpm
   c. RHR Pump Amps 0-150 amps

2. RHR Pump Room Temperature
   a. Duct 0-300F
   b. Area 0-300F

3. Reactor Water Level Fuel Zone -111" to -311"

Major Alarms

a. RHR Pump Cubicle Temp Hi - 149F
b. RHR Pump Breaker Closed - Breaker Closed
c. RHR Pump A, B or C Flow Above Minimum (550 gpm) - Alarm at 1500 gpm increasing, resets at 1010 gpm decreasing.
d. RHR Pump A/B/C Disch Press Hi/Low - 400/55 psig
e. RHR Pump Auto Trip - multiple
f. RHR Pump Cubicle Cooler Fan Auto Trip - Overload
g. LPCI System Actuated - Drywell pressure 1.69 psig, Rx Level - 129".
h. RHR Valves F006 - F064 Open - (Valves open simultaneously - drains reactor vessel)

i. RHR B/D (A/C) Drywell Press Hi - 1.69 psig
j. RHR B/D (A/C) Reactor Level 1 Low - -129"
k. RHR System Injection Valve Reactor Press Low - 500 psig
l. RHR Line Integrity Monitor - 1.0 psid above or below zero (Indicative of a leak in the RHR/LPCS injection lines)
m. RHR Equip Area Diff Temp or Ambient Temp Hi (Area - 130 ± 2F. Diff temp - 30 ± 2F)
n. LPCI Manual Initiation Pushbutton Armed - PB Armed

3.3.2.4 Operator Actions

The initiation of the three LPCI trains is completely automatic. No operator action is assumed for at least ten minutes after initiation. The primary responsibility of the operator is to verify system operability and proper operation on a regular basis following an initiation.

When the reactor water level is at least two-thirds of the normal level, two of the RHR pumps can be shut off manually, or used for other purposes. The LPCI system does not shut down automatically. Ten minutes after initiation a timer permits manual closing of the heat exchanger bypass valves in LPCI trains A and B. The operator may wish to direct a portion of LPCI flow through the heat exchanger(s) in order to begin residual heat removal.

3.3.2.5 <u>Technical Specification Limitations</u>

The following excerpts from the LaSalle Unit 2 technical specifications apply to the LPCI system during operational conditions 1, 2 and 3.

<u>Limiting Condition for Operation</u>

3.5.1 ECCS divisions 1, 2 and 3 shall be OPERABLE with:

a. ECCS division 1 consisting of:

   1. The OPERABLE low pressure core spray (LPCS) system with a flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

   2. The OPERABLE low pressure coolant injection (LPCI) subsystem "A" of the RHR system with a flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

   3. At least 6 OPERABLE ADS valves.

b. ECCS division 2 consisting of:

1. The OPERABLE low pressure coolant injection (LPCI) subsystems "B" and "C" of the RHR system, each with a flow path capable of taking suction from the suppression chamber and transferring the water to the reactor vessel.

2. At least 6 OPERABLE ADS valves.

c. ECCS division 3 consisting of the OPERABLE high pressure core spray (HPCS) system with a flow path capable of taking suction from the suppression chamber and transferring the water through the spray sparger to the reactor vessel.

Action

a. For ECCS division 1, provided that ECCS divisions 2 and 3 are OPERABLE:

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2. With LPCI subsystem "A" inoperable, restore the inoperable LPCI subsystem "A" to OPERABLE status within 7 days.

3. With the LPCS system inoperable and LPCI subsystem "A" inoperable, restore at least the inoperable LPCI subsystem "A" or the inoperable LPCS system to OPERABLE status within 72 hours.

4. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. For ECCS division 2, provided that ECCS divisions 1 and 3 are OPERABLE:

1. With either LPCI subsystem "B" or "C" inoperable, restore the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 7 days.

2. With both LPCI subsystems "B" and "C" inoperable, restore at least the inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

3. Otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours*.

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*Whenever two or more RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

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d. For ECCS divisions 1 and 2, provided that ECCS division 3 is OPERABLE:

   1. With LPCI subsystem "A" and either LPCI subsystem "B" or "C" inoperable, restore at least the inoperable LPCI subsystem "A" or inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

   2. With the LPCS system inoperable and either LPCI subsystems "B" or "C" inoperable, restore at least the inoperable LPCS system or inoperable LPCI subsystem "B" or "C" to OPERABLE status within 72 hours.

   3. Other wise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours*.

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f. With an ECCS discharge line "keep filled" pressure alarm instrumentation channel inoperable, perform Surveillance Requirement 4.5.1.a.1 at least once per 24 hours.

g. With an ECCS header delta P instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 72 hours or determine ECCS header delta P locally at least once per 12 hours otherwise, declare the associated ECCS inoperable.

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j. With one or more ECCS corner room watertight doors inoperable, restore all the inoperable ECCS corner room watertight doors to OPERABLE status within 14 days, otherwise, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

<u>Surveillance Requirements</u>

4.5.1 ECCS divisions 1, 2, and 3 shall be demonstrated OPERABLE by:

a. At least once per 31 days for the LPCS, LPCI, and HPCS systems:

1. Verifying by venting at the high point vents that the system piping from the pump discharge valve to the system isolation valve is filled with water.

2. Performance of a CHANNEL FUNCTIONAL TEST of the:

   a) Discharge line "keep filled" pressure alarm instrumentation, and

   b) Header delta P instrumentation.

3. Verifying that each valve (manual, power-operated, or automatic,) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

4. Verifying that each ECCS corner room watertight door is closed, except during entry to and exit from the room.

b. Verifying that, when tested pursuant to Specification 4.0.5, each:

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2. LPCI pump develops a flow of at least 7200 gpm against a test line pressure greater than or equal to 130 psig.

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c. For the LPCS, LPCI and HPCS systems, at least once per 18 months:

1. Performing a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence and verifying that each automatic valve in the flow path actuates to its correct position. Actual injection of coolant into the reactor vessel may be excluded from this test.

2. Performing a CHANNEL CALIBRATION of the:

   a) Discharge line "keep filled" pressure alarm instrumentation and verifying the:

      1) High pressure setpoint and the low pressure setpoint of the:

      o
      o
      o

b) LPCI subsystems to be ≤400 psig and 55 psig respectively.

c) Header delta P instrumentation and verifying the setpoint of the:

1) LPCS system and LPCI subsystems to be ± 1 psid.

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4. Visually inspecting the ECCS corner room watertight door seals and room penetration seals and verifying no abnormal degradation, damage, or obstructions.

In addition the suppression chamber must be operable in order for the LPCI system to operate successfully. The following excerpts from the technical specificacions apply to the suppression chamber as it relates to the LPCI system.

Limiting Condition for Operation

3.5.3 The suppression chamber shall be OPERABLE:

a. In OPERATIONAL CONDITION 1, 2, or 3 with a contained water volume of at least 128,800 ft3, equivalent to the level of 26 ft 2 1/2 in.

Action

a. In OPERATIONAL CONDITION 1, 2, or 3 with the suppression chamber water level less than the above limit, restore the water level to within the limit within 1 hour or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

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c. With one suppression chamber water level instrumentation channel inoperable, restore the inoperable channel to OPERABLE status within 7 days or verify the suppression chamber water level to be greater than or equal to 26 ft 2 1/2 or 14 ft 0 in., as applicable, at least once per 12 hours by local indication.

d. With both suppression chamber water level instrumentation channels inoperable, restore at least one inoperable channel to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours and verify the suppression chamber water level to be greater than or equal to 26 ft 2 1/2 in. or 14 ft 0 in., as applicable, at least once per 12 hours by local indication.

Surveillance Requirements

4.5.3.1 The suppression chamber shall be determined OPERABLE by verifying:

a. The water level to be greater than or equal to, as applicable:

1. 26 ft 2 1/2 in. at least once per 24 hours.

2. 14 ft 0 in. at least once per 12 hours.

b. Two suppression chamber water level instrumentation channels OPERABLE by performance of a:

1. CHANNEL CHECK at least once per 24 hours,

2. CHANNEL FUNCTIONAL TEST at least once per 31 days, and

3. CHANNEL CALIBRATION at least once per 18 months, with the low water level alarm setpoint at greater than or equal to 26 ft 4 in.

3.3.2.6 Tests

The major tests of the LPCI system are summarized in Table 3.3-2. Operability of MOVs is verified quarterly via stroke testing and a full flow test is also performed quarterly.

Although it is not a test, shiftly surveillance verifies the condition of the RHR pumps, the position of the drywell manual valves in the LPCI injection lines, and the alignment of all MOV's essential to correct LPCI system operation.

3.3.2.7 Maintenance

No scheduled maintenance which disables LPCI components while the plant is at power is planned. Unscheduled maintenance is permitted on system components provided applicable safety and radiological administrative controls can be satisfied. Unscheduled maintenance activities possible during plant operation include:

- Replacement or repair of actuation and control circuitry

- Electrical maintenance on motor driven components

- MOV and pump mechanical maintenance that does not result in a breech of the LPCI system boundary.

- MOV and pump mechanical maintenance that breeches the system boundary when double isolation from reactor pressure/temperature can be achieved. Isolation here is taken to mean an accessible manual valve or a motor- operated valve that can be racked out. It is assumed that check valves do not provide a secure means of isolation. (Note that in the case of the RHR A and B trains double isolation must not only be achieved at the injection line end, but also at the Shutdown Cooling suction line end.)

Section 3.3.2.5 indicates the period of time that one or more LPCI subsystems may be inoperable due to unscheduled maintenance. In summary, with just one of the low pressure reflood subsystems (LPCS and three LPCI trains) inoperable, the subsystem must be restored within seven days. With two of the low pressure reflood subsystems inoperable, one of the subsystems must be restored to operability within 72 hours. Otherwise the plant must be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

A summary of unscheduled maintenance acts allowed on the LPCI system while the plant is in full power operation is given in Table 3.3-3. The following items pertain to this table:

- Although permitted, unscheduled maintenance on check valves and manual valves is not listed on the table because of the significantly lower frequencies of occurrence when compared to MOVs.

- It is assumed that safety procedures and the requirement for double isolation will result in the LPCI injection MOV (F042) and the associated RHR pump being racked out when maintenance on a component involves opening up the RHR line. However, this is not a significant contributor to system unavailability since RHR pump and F042 A/B/C valve indication is provided in the control room and checked shiftly. For those components that can be double isolated, the most significant possibility of a "failure to restore" fault lies with the manual maintenance isolation valves (F098 A/B/C). No control room indication is provided for these valves/and the only time misalignment is certain to be detected is during quarterly system full-flow tests. For this reason, only the first two components entered in Table 3.3-3 reflect the fact that the pump and injection valve circuit breakers are racked out for maintenance that breeches the LPCI boundary. Thereafter only the F098 maintenance valve alignment away from normal is shown.

- The need for double isolation at the Shutdown Cooling suction line when mechanical maintenance is performed on certain components (e.g. the RHR pumps) dictates that the F006A/B and the F008 MOV's be racked out. (The F009 valve is in containment and is assumed inaccessible). However, the LaSalle Unit 2 procedures indicate that the F008 "Shutdown Cooling Outboard Isolation Valve" is to be normally racked out when the valve is to remain in the closed position. Thus, the 2E12-F008 valve circuit breaker is not indicated in the "Components Out of Normal Alignment" column of Table 3.3-3.

- The manual maintenance isolation valves is the drywell (F092A/B/C) are assumed to be inaccessible during full power operation, and hence cannot be used to achieve LPCI line double isolation.

- Each of the system MOV's and pumps has a feed circuit breaker in the power supply lines off its associated MCC. In addition to the maintenance activity shown in Table 3.3-3, unscheduled electrical maintenance on these circuit breakers is anticipated. This activity is only of interest for components that must change state and it is assumed that no other system components are impacted. Failure to restore the breaker after maintenance is not considered likely because the component indicator lights in the control room receive their power through the breaker.

3.3.3 System Operation

3.3.3.1 Normal Operation

During the normal plant operation, the LPCI system is in standby. One water leg pump operates continuously to keep the LPCS and LPCI A pump discharge line filled and a separate pump keeps the LPCI B and C lines water filled. The suppression chamber must also be operable with its level between 26' 10" and 26' 2 1/2" and its temperature at or below 100F.

3.3.3.2 Abnormal Operation

LPCI operation is automatic when either the low reactor water level (-129") or the high drywell pressure (1.69 psig) signal is received or when the manual pushbutton is depressed. When LPCI initiation occurs, the following events take place and should be verified by the operator.

a. If normal auxiliary power is available, the RHR pumps will start without delay. When on Standby Diesel generator power, the RHR pumps start after a five second delay.

b. The emergency pump cubicle cooling systems actuate and continue to operate until their associated pumps are shut down and room temperature falls below 104F.

c. The RHR injection valves (F042 A/B/C) will open when reactor pressure and pressure downstream of the injection valve decreases to less than 500 psig and power is available to the respective RHR pump. Coolant will be injected when pressure drops below RHR pump discharge pressure and the check valve opens.

d. RHR heat exchanger A and B bypass MOVs are interlocked to stay open for ten minutes. This ensures the maximum amount of water flow will be available for injection into the vessel.

e. A number of MOVs used in other RHR modes are automatically repositioned if they are not correctly aligned for LPCI operation when an initiation signal is received. The following valves isolate:

- o RHR Heat Exchanger flow to RCIC (F026 A/B)
- o RHR Heat Exchanger flow to the Suppression Pool (F011 A/B)
- o RHR Test Return (F024 A/B and F021)
- o Suppression Pool Spray (F027 A/B)
- o RHR Steam Pressure Reducing Valves (F051 A/B)
- o RHR Discharge to RCIC and Suppression Pool (F065 A/B)
- o Heat Exchanger Steam Reducer Bypass (F087 A/B)
- o RHR Steam Line Isolation Valve (F052 A/B)

f. If the RHR system is in a test status when the initiation signals are received the following actions also occur:

- o DG "O"/DG "A" start
- o Breakers 1413, 2413/1423 trip
- o Primary Containment Vent Supply Fans 2VP02CB trip
- o All DG trips are disabled except: High differential Overcurrent, Manual and Overspeed

g. When reactor water level is at least two-thirds of the normal level, two of the RHR pumps can be shut off manually, or used for other purposes. The remaining LPCI train and LPCS combine to maintain reactor water level.

3.3.4 System Fault Tree

3.3.4.1 Description

Simplified diagrams of the three LPCI subsystems showing the mechanical components included in the fault tree models are shown in Figures 3.3-16 through 3.3-18.

There are a number of components (e.g. the steam condensing isolation MOVs 2E12-F087 A/B) that appear in the fault trees only as contributors to LPCI system unavailability due to component unscheduled maintenance that breeches the LPCI system boundary. These components form part of the LPCI pressure boundary but do not perform a function essential to successful LPCI operation. They are indicated on the detailed drawings (3.3-1 through 3.3-4) but have been omitted from the simplified diagrams.

There are twelve developed events in the LPCI fault trees. Seven are transfers from the electric power fault trees: the 4160 VAC buses 241Y and

242Y; the 480 VAC MCC's 235Y-2, 236Y-1, and 236Y-2; and the 125 VDC buses 211Y and 212Y. One developed event transfers from the LOCA initiation logic B models developed elsewhere (LOCA logic A is developed in LPCI). Another of the logic developed events is for the reactor pressure/valve interlock logic developed in the LPCS tree. Two of the developed events represent the RHR pump cubicle cooling systems (HVAC) and are transfers from the ECCS Equipment Area Cooling System fault trees. Finally one developed event is a manual valve failure in the LPCI train C line that is modeled in the Shutdown Cooling System fault tree.

3.3.4.2 Success/Failure Criteria

The LPCI system is successful if one of the three independent trains operates at rated capacity conveying water from the suppression pool and injecting it into the reactor vessel for time interval in which it is required. LPCI failure occurs upon one of the following:

1. Both normal and emergency electrical power is lost (Division 1 & 2).

2. Both 211Y and 212Y 125Vdc buses are lost.

3. ECCS Equipment Area Cooling is lost for both the SE and NW cubicles.

4. All three LPCI trains fail due to various combinations of pump failures, injection MOV failures, flow diversions, pipe ruptures, or maintenance outages.

5. Debris in the suppression pool (most likely insulation from the drywell) clogs all three RHR suction strainers to an extent greater than 50 percent.

The top event of the LPCI system tree is:

FAILURE OF LCI SYST TO INJECT COOLANT WITH 1-OF-3 INJ
PATH AND 1-OF-3 PUMPS.

3.3.4.3 Assumptions

In addition to the general assumptions regarding fault tree development (listed at the beginning of this volume), the following assumptions specific to the LPCI system were made:

1) There are several large branch lines used for auxiliary functions (e.g. Suppression Pool Clean-up) that are normally locked closed by a manual valve and sealed by a blind flange during normal operation. It is highly unlikely that such a line could be inadvertently left open and not detected during the various start-up procedures; therefore,these lines are not modeled as diversion paths.

2) Inadvertent opening of the suppression pool spray MOV 2E12-F027A/B creates an insignificant diversion path back to the suppression pool (4-inch line compared to the 18-inch LPCI lines).

3) Inadvertent opening of both drywell spray MOVs (F016A/B and F017A/B) creates a large diversion path for LPCI train A or B flow. However, the valves are interlocked so that only one can be open at a time unless: 1) a high drywell signal is present, 2) the LPCI injection MOV is closed and 3) a LOCA logic signal (high drywell pressure or low reactor vessel water level) is present. These valves have no automatic actuation so creation of this diversion path requires double faults: Operator error in opening the valves and an interlock failure. For these reasons and the fact that the mistake can be readily recognized and corrected, the only failure mode modeled is a common control system fault (due to cable fire) that drives open both F016 and F017 regardless of interlocks.

4) Inadvertent opening of the RPV Head Spray MOV (F023) creates a partial diversion of LPCI train A flow. However, this is not considered a failure mode of LPCI because the diverted water is still delivered to the reactor core. Although it is possible that the head spray line could be used to inject about 1/4 of normal LPCI train A flow in the event the LPCI injection path is unavailable, credit is not taken for this alternate alignment.

5) Inadvertent opening of one of the Shutdown Cooling return MOVs (F053A or B) partially diverts LPCI flow in that line to the associated reactor recirculation line. This is considered a LPCI failure mode if a LOCA has occurred in the particular recirculation line. However, if the recirculation line is intact, the Shutdown Cooling return line is treated as an alternate LPCI injection path.

6) There are several safety relief valve lines associated with each of the three LPCI trains. None are larger than 4-inches diameter, hence, it is assumed that they cannot act as significant diversion paths for LPCI flow. (The RHR/LPCI line ranges from 24-inch pipe at the pump suction to the 12-inch LPCI injection line.) An inadvertently opened safety/ relief valve in the one-inch line off the RHR pump suction does not create a large enough path to significantly affect pump NPSH. (The NPSH of the RHR pumps is set largely by the depth of water in the suppression pool.)

7) The minimum flow bypass line protects the RHR pumps from overheating when an RHR mode discharge path has not been established yet. The usual sequence for LPCI operation has the RHR pump start upon receiving a LOCA initiation signal and the LPCI injection valve opens when reactor pressure drops below 500 psig. In certain accident sequences some time may elapse before the injection MOV opens. During this time the pump would be 'dead-headed' if the minimum flow MOV failed closed. The RHR pump

manufacturer indicates, however, that the pumps will operate 30 to 60 minutes under no-flow conditions before they overheat. (The exact time-to-failure is dependent on the pump cubicle environment.) Even taking the minimum time-to-failure of 1/2 hour, it is highly likely that either RPV pressure will have dropped such that the LPCI injection valve opens, or various control room indicators will have warned the operator of a problem with the RHR pump flow. Control room indicators include a position indicator for the minimum flow bypass MOV, pump discharge pressure and alarm (400 psig), RHR line flow indicator, and a pump bearing temperature recorder. For these reasons failure of the pump discharge bypass line to provide minimum flow after pump initiation is not considered a significant contributor to pump failure.

8) The 8-inch minimum flow bypass line at the discharge of each RHR pump contains a 4-inch diameter flow restrictor. It is therefore too small to act as a significant diversion path should the minimum flow bypass MOV remain open when LPCI flow is required.

9) The RHR pump motors are air-cooled and analysis indicates that the ECCS Equipment Area Cooling System must operate to keep pump cubicle temperatures within operational limits. The pump seals are cooled by a dedicated water cooling system which is part of the CSCS cooling system. (The CSCS also cools the heat exchangers in the ECCS Equipment Areas HVAC.) Analysis indicates that the pump seals begin to fail in 15 - 20 seconds after loss of seal cooling if the pumped water temperature significantly exceeds 160F. However, because the suppression pool water temperature is likely to be much lower (<100F initially) and because failure of the seals is not likely to impact successful short term operation of the RHR pump, seal cooling is not considered an essential support system to LPCI.

10) Failure of a heat exchanger bypass valve (F048 A/B) to remain open prior to or during LPCI operation does not significantly affect system success. With the bypass MOV closed, water is routed through the heat exchanger and still injected into the reactor vessel via the LPCI injection line. Time to full LPCI injection flow may be increased slightly, but it is assumed to have negligible impact on system success.

11) The possibility of water hammer failure of the pump discharge line due to failure of the water leg fill subsystem is neglected. The water leg pump operates continuously to maintain the LPCI lines in a filled condition and it is indicated in the control and checked shiftly. In addition the RHR pump discharge line pressure is indicated and alarmed in the control room, so failures of the water leg fill subsystem are readily detected. When the water leg fill system is out of service the RHR lines can be manually filled via the Flushing Water Supply line. Even in the event that the RHR

line is not water filled when the RHR pump starts, the design of the pump discharge line is such that pipe rupture due to water hammer is unlikely (i.e., the low pressure piping is actually the same as the high pressure piping at LaSalle).

12) If a Shutdown Cooling MOV (F006 A/B) in the RHR pump suction line should inadvertently open while the other RHR train is operating in the Shutdown Cooling mode, a direct path between the RPV and the suppression pool is created. The FSAR indicates that this may cause 'flashing' in the RHR lines that could severely damage the suppression pool strainer and/or the RHR pump. It is conservatively assumed that inadvertent opening of train A and B's F006 MOV while the other RHR train is in Shutdown Cooling mode fails that train's RHR pump.

    In addition, LPCI train C is linked to the common Shutdown Cooling suction 'T' by piping that is normally closed by a "L.C." manual valve (F067). Since the valve state is not indicated in the control room and is not checked during shiftly or daily surveillance, misalignment would not be detected until one of the trains initiated Shutdown Cooling. It is conservatively assumed that mechanical valve failure or human error in leaving it open fails the train C pump due to flashing, if either train A or B is in Shutdown Cooling mode.

Table 3.3-1 LPCI Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
4160V BUS 241Y	2E12-C002A	Motor-driven pump	FTS/FTR	Loss of all Train A MOV indication lights in control room	Loss of LPCI Train A	Loss of LPCI Train A
480 VAC BUS 241Y	2E12-F042A	MOV	FTO	Loss of position lights in control room	Loss of LPCI Train A and remote injection	Loss of LPCI Train A remote injection
480 VAC MCC 235Y-1	2E12-F042A	MOV	FTO/FTC	Loss of position lights in control room (If FTO, various pump/flow indications in control room)	If FTO: RHR A pump may be dead-headed, overheat in 30-60 min. if no flow is established.	
					If FTC: About l/20 of LPCI Train A flow diverts to suppression pool	Action must be taken to prevent pump A from overheating OR small portion of Train A flow is diverted
4160 VAC BUS 242Y	2E12-C002B	Motor-driven pump	FTS/FTR	Loss of all Train B & C MOV indication lights in control room	Loss of LPCI Train B	
	2E12-C002C	"	"	"	Loss of LPCI Train C	Loss of LPCI Trains B and C
480 VAC MCC 236Y-1	2E12-F042B	MOV	FTO	Loss of position lights in control room	Loss of LPCI Train B automatic and remote injection	

Table 3.3-1 LPCI Support Systems Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
	2E12-F064B	MOV	FTO/FTC	Loss of position lights in control room (IF FTO, various pump/flow indications in control room)	If FTO: RHR B pump may be dead-head, overheat in 30-60 min. if no flow is established If FTC: About 1/20 of LPCI Train B flow diverts to suppression pool	Loss of LPCI Train B automatic and remote injection Action must be taken to prevent RHR pump B from overheating <u>OR</u> small portion of Train B flow is diverted
480VAC MCC 236Y-2	2E12-F042C	MOV	FTO	Loss of position lights in control room	Loss of LPCI Train C automatic and remote injection	
	2E12-F064C	MOV	FTO/FTC	Loss of position lights in control room If FTO, various pump/flow indications in control room)	If FTO: RHR C pump may be dead-headed, overheat in 30-60 min. if no flow is established If FTC: About 1/20 of LPCI Train C flow diverts to suppression pool	Loss of LPCI Train C automatic and remote injection Action must be taken to prevent RHR pump C from overheating <u>OR</u> small portion of train C flow is diverted
<u>125 VDC POWER</u> DIST PNL 211Y	2E12-C002A Control/ Actuation	Motor-driven pump	FTS/FTR	Loss of pump indication lights in control room	RHR pump A inoperable - Fail LPCI Train A	
	Initiation and interlock logic for LPCI A/LPCS		Inoperable	Alarmed in control room	No LPCI Train A initiation on LOCA	Fails LPCI train A

Table 3.3-1 LPCI Support Systems Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
DIST PNL 212Y	2E12-C002B Control/ Actuation	Motor-driven pump	FTS/FTR	Loss of pump indication lights in control room	RHR pump B inoperable - Fail LPCI Train B	
	2E12-C002C Control/ Actuation	Motor-driven pump	FTS/FTR	Loss of pump indication lights in control room	RHR pump C inoperable - Fail LPCI Train C	
	Initiation and interlock logic for LPCI B & C		Inoperable	Alarmed in control room	No LPCI trains B or C initiation on LOCA	Fail LPCI trains B and C
CSCS Equipment Cooling Water System						
RHR Service Water System (Div. 1)	2E12-C002A	Motor-driven pump	Fail seal cooling, leakage	Service water lights in control control room Leak detected in pump cubicle	Leakage does not fail pump in short term. If gross seal failure occurs pumped water could flash damaging pump.	Coolant leakage into RHR pump A cubicle. Possible long-term failure of pump.
RHR Service Water System (Div. 2)	2E12-C002B 2E12-C002C	Motor	Fail seal	"	"	Coolant leakage into RHR pumps B and C cubicle. Possible long-term failure of pumps.
CSCS Equipment Cooling System						
NW Cubicle Cooling	2E12-C002A and related I & C	Motor-driven pump	FTR (overheat or control)	Cubicle temperature indicated and alarmed in control room. HVAC fan indicated in control room.	After about one hour, overheat of pump motor trips the RHR pump A and fails LPCI train A. Pump instrumentation and control circuitry in cubicle may be affected earlier.	LPCI Train A succeeds initially but continued operation is threatened one hour after loss of cubicle cooling.

Table 3.3-1 LPCI Support Systems Interface FMEA (Concluded)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
SE Cubicle Cooling	2E12-C002B 2E12-C002C and related I & C	Motor-driven pumps	FTR (overheat or control)	"	After about six to ten min. over-heat of pump motors trips RHR pumps	LPCI Trains B and c succeed initially but continued operation is threatened

Table 3.3-2 LPCI System Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
LOS-RH-M1	System Operability (Alignment)	All motor-operated valves required for LPCI operation and the drywell manual isolation valves		No	---	Monthly	---	Alignment: Shiftly Operability: Quarterly
		LPCI/LPCS Water Leg Pumps		No	---	Monthly	---	Monthly
LOS-RH-Q1	Pump Inservice	2E12-C002A/B/C	Pumps	No	---	Quarterly	---	Alignment: Shiftly Operability: Quarterly
		2E-F064A/B/C	MOVs	No	---	Quarterly	---	" "
		2E-F064A/B/C and 2E12-F021	"	Yes	Yes	"	---	" "
		2E12-F027A/B	"	Yes	No	"	---	" "
		2E12-F048A/B	"	Yes	Yes	"	---	" "
LOS-RH-Q2	Value Exercise	2E12-F004A/B/C	MOVs	Yes	No	Quarterly	---	Alignment: Shiftly Operability: Quarterly
		2E12-C002A/B/C	Pumps	Yes[1]	"	"	---	" "
		2E12-F006A/B	MOVs	Yes	"	"	---	" "
		2E12-F047A/B	"	Yes[2]	"	"	---	" "
		2E12-F003A/B	"	"	"	"	---	" "
		2E12-F016A/B	"	"	"	"	---	" "

1) RHR pumps are placed in "Pull-to-Lock" while F004 valves are tested.
2) Valve is out of alignment only briefly.
3) Valve is only briefly out of alignment. Interlocks prevent both F016 & F017 from being open at once.

Table 3.3-2 LPCI System Test Summary (Concluded)

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
		2E12-F017A/B	"	"	"	"	---	" "
		2E12-F048A/B	"	Yes	Yes	"	---	" "
		2E12-F024A/B	"	"	"	"	---	" "
		2E12-F064A/B/C	"	"	"	"	---	" "
LIS-PC-203	RHR Activation	PS-2B21-N048 A/B/C/D	Switch/ Initiation Logic	Yes	No	Quarterly	---	Indication: Shiftly Operability: Quarterly
LIS-NB-204	RHR Activation	DPIS-2B21-N037B/D	Switch/ Initiation Logic	Yes	No	18 Months	---	Indication: Shiftly Operability: 18 Months

Table 3.3-3 Low Pressure Coolant Injection Unscheduled Maintenance Summary

Component Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E12-C002A/B/C	Pumps	Mechanical[1]/ electrical	Pump circuit breaker	Yes			Alignment: Shiftly Operability: Quarterly
		Mechanical[2]	Pump circuit breaker	Yes			"
			MOV 2E12-F004A/B/C				"
			MOV 2E12-F006A/B(3)				"
			Man. 2E12-F098A/B/C				Alignment: Quarterly
			MOV 2E12-F042A/B/C circuit breaker				Alignment: Shiftly Operability: Quarterly
2E12-F006A/B	MOV	Mechanical[2]	MOV 2E12-F004A/B	Yes			Alignment: Shiftly Operability: Quarterly
			MOV 2E12-F006B/A(3) (in other train) circuit breaker				"
			MOV 2E12-F042A/B circuit breaker				"
			Man. 2E12-F098A/B				Alignment: Quarterly
			Pump 2E12-C002A/B circuit breaker				Alignment: Shiftly Operability: Quarterly
2E12-F064A/B/C	MOV	Mechanical[2]	MOV 2E12-F004A/B/C	Yes			"
			MOV 2E12-F006A/B				"
			circuit breaker				"
			Man. 2E12-F098A/B/C				Alignment: Quarterly
2E12-F088A/B/C	Safety relief valve	Mechanical[2]	MOV 2E12-F004A/B/C	Yes			Alignment: Shiftly Operability: Quarterly
			MOV 2E12-F006A/B[3]				"
			circuit breaker				"
			Man. 2E12-F098A/B/C				Alignment: Quarterly

1) Maintenance not involving a breach of LPCI system boundary.
2) Maintenance involving breaching the LPCI system boundary and requiring double isolation from reactor pressure.
3) Inoperability of this component only impacts other modes of RHR.

Table 3.3-3 Low Pressure Coolant Injection Unscheduled Maintenance Summary (Concluded)

Component Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E12-C003	Pump	Mechanical[2]	Man. 2E12-F098B/C	Yes			Alignment: Quarterly
2E21-C002	Pump	Mechanical[2]	Man. 2E12-F098A	Yes			
2E12-F047A/B	MOV	Mechanical[1]	2E12-F006A/B circuit breaker 2E12-F009A/B	Yes			Alignment: Shiftly Operability: Quarterly Alignment: Quarterly
2E12-B001A/B	Heat exchanger	Mechanical[2]	2E12-F098A/B	Yes			Alignment: Quarterly
2E12-F051A/B	Pneumatic valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F087A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F055A/B	Safety/ relief valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F060A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F065A/B	Pneumatic valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F074A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F087A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F042A/B/C	MOV	Mechanical[1]/ electrical	Valve circuit breaker	Yes			Alignment: Shiftly Operability: Quarterly

1) Maintenance not involving a breach of LPCI system boundary.
2) Maintenance involving breaching the LPCI system boundary and requiring double isolation from reactor pressure.

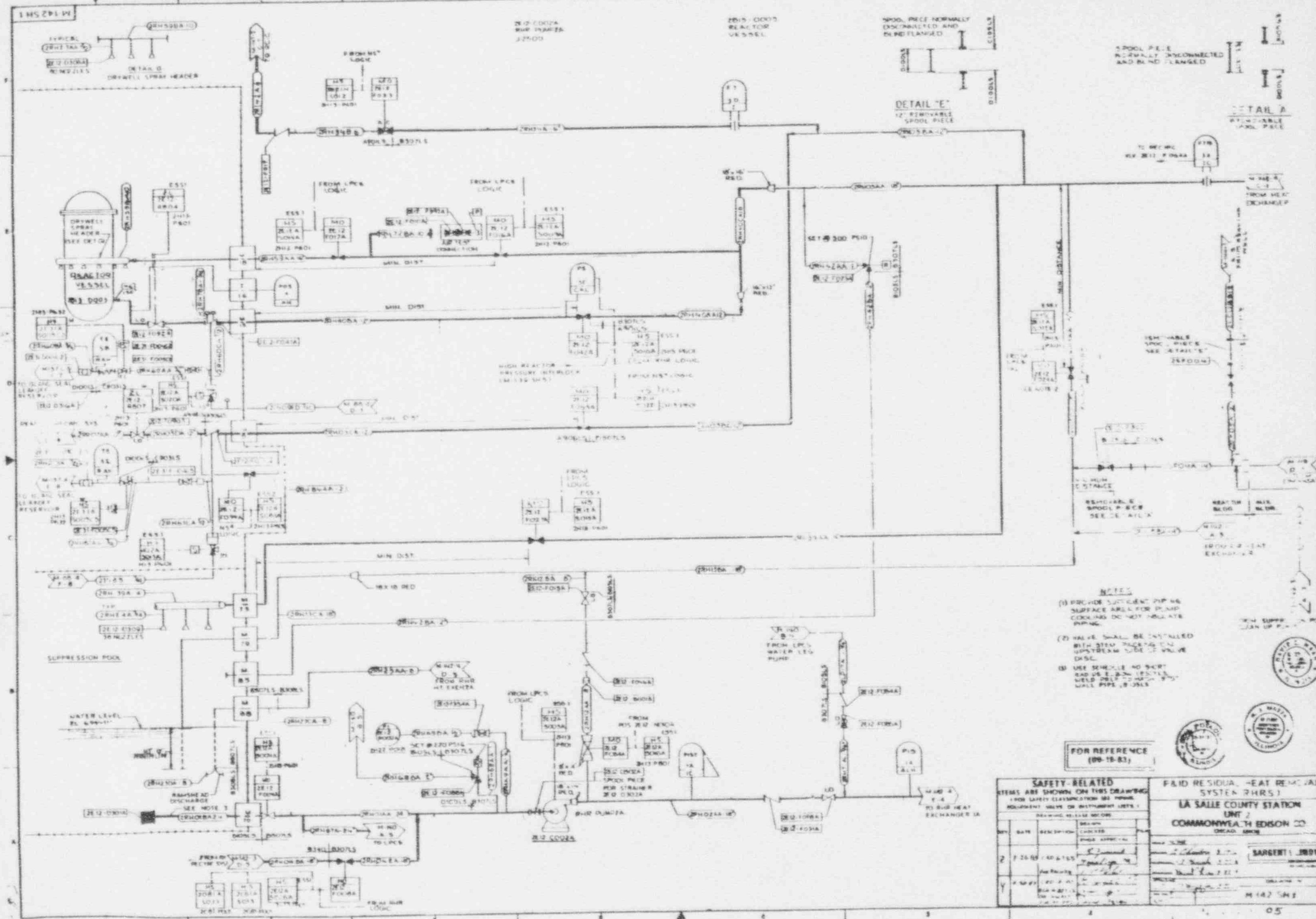


Figure RX-1 LPCI System P&ID

Figure 3.3-1 LPCI System P&ID - Train A

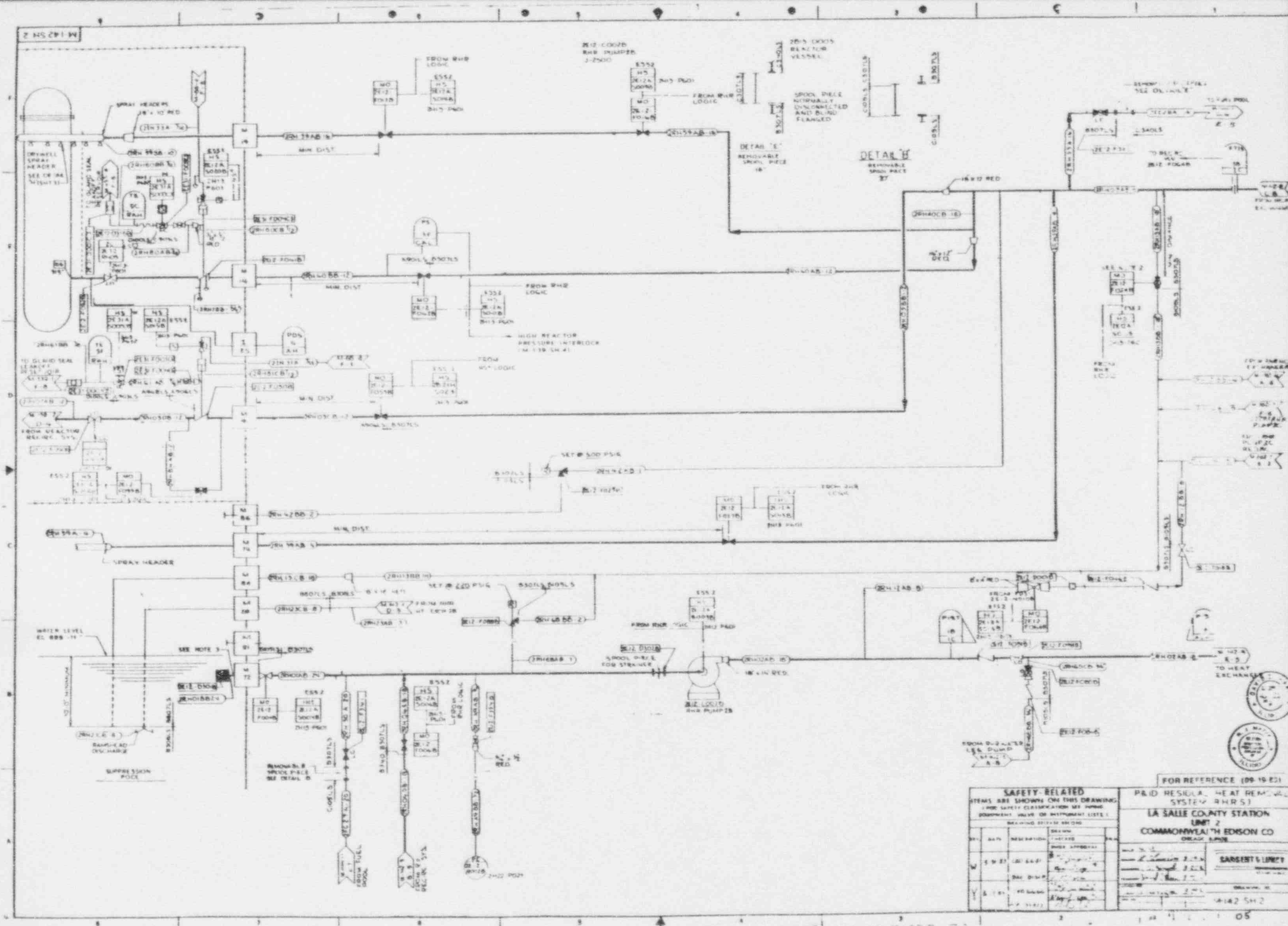


Figure B.X-2 LPCI System P&ID - Train B

Figure 3.3-2 LPCI System P&ID - Train B

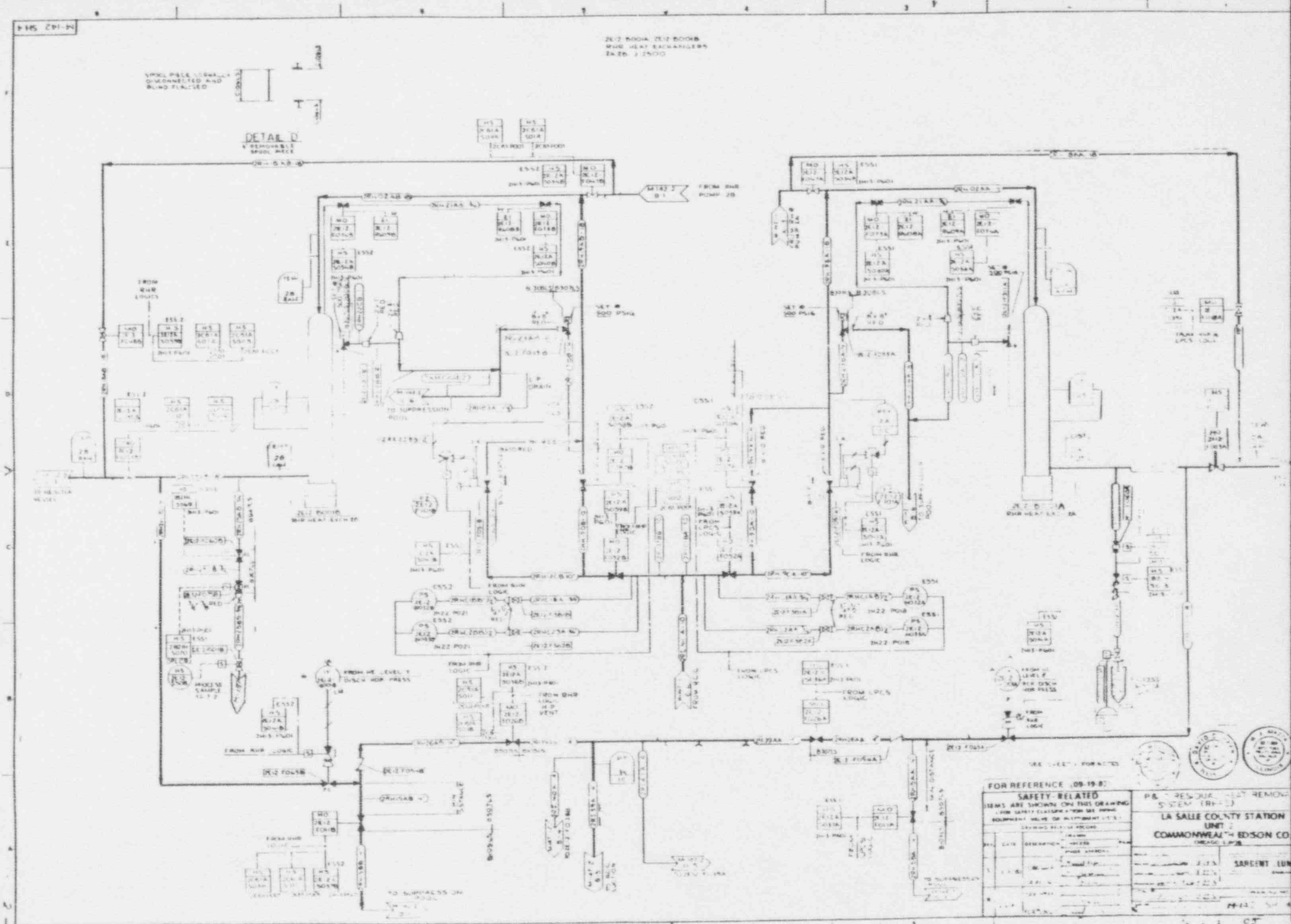


Figure B.X-3 LPCI System P&ID – A & B Heat Exchangers

Figure 3.3-3 LPCI System P&ID - A & B Heat Exchangers

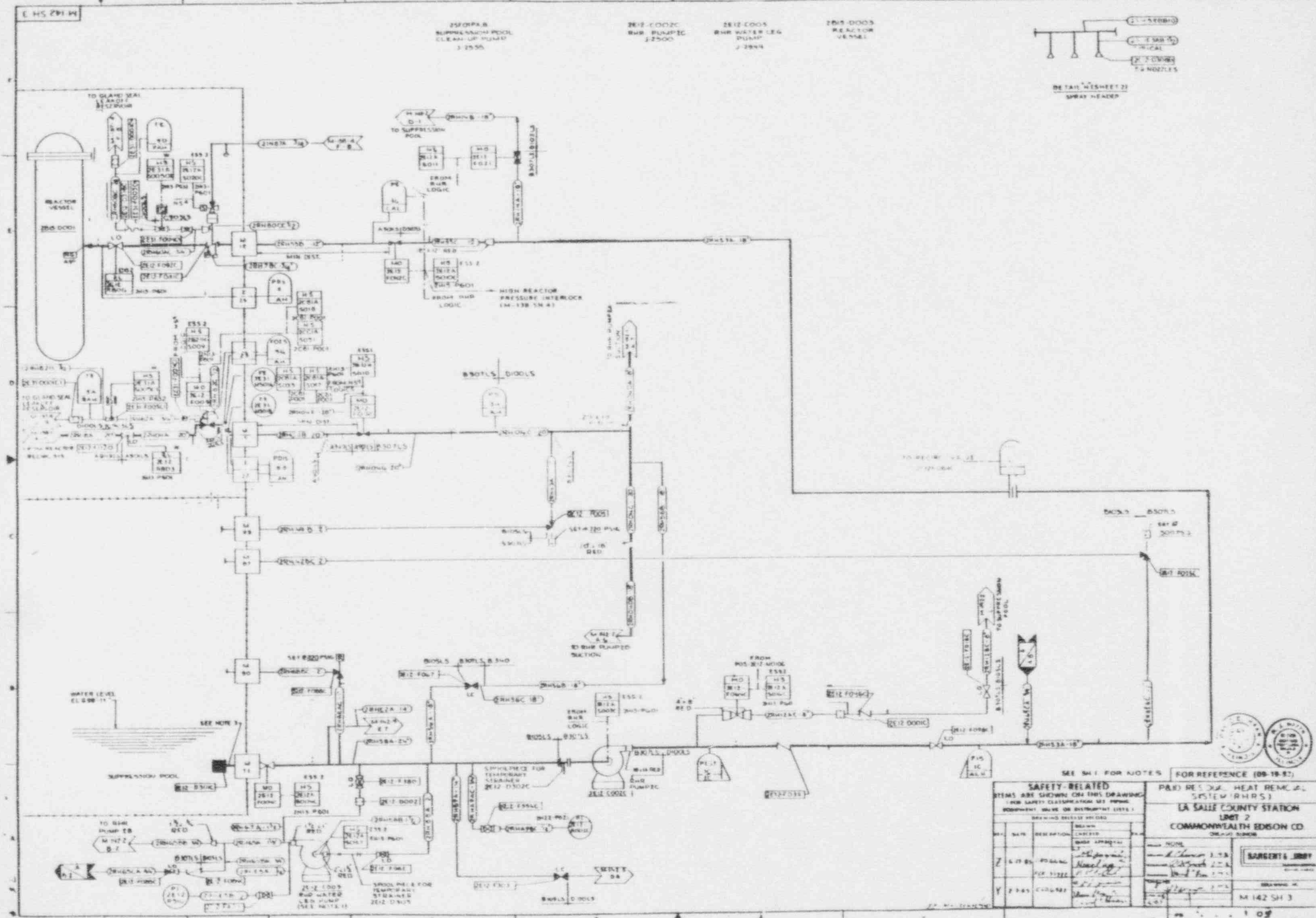
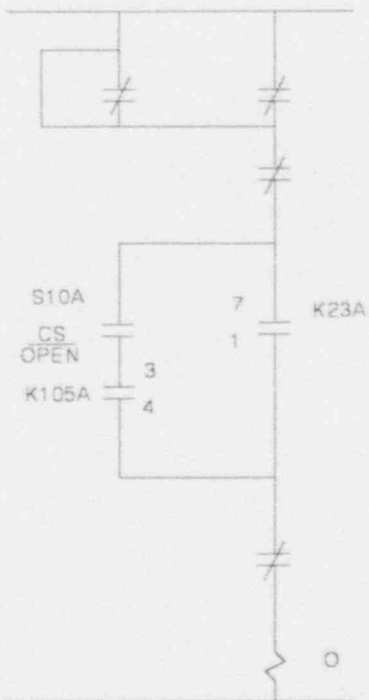


FIGURE B.x.4 LPCI System P&ID - Train C

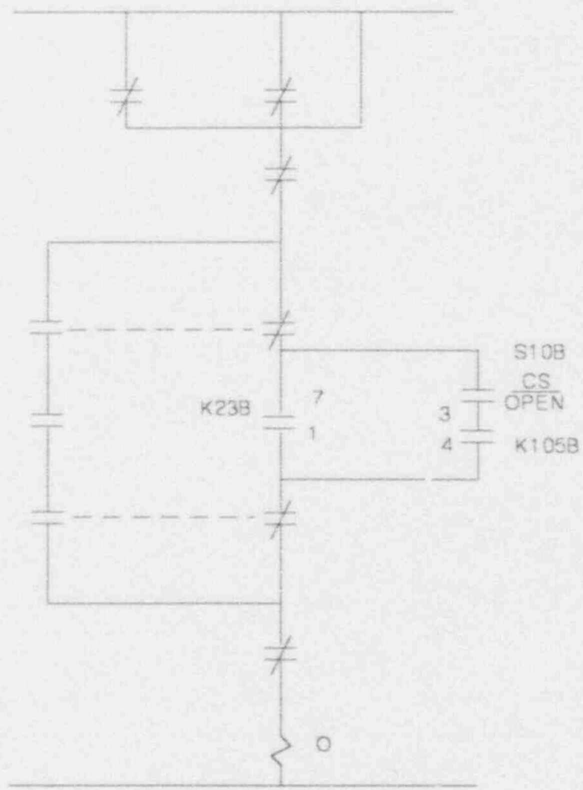
Figure 3.3-4 LPCI System P&ID - Train C

F042A NC FC



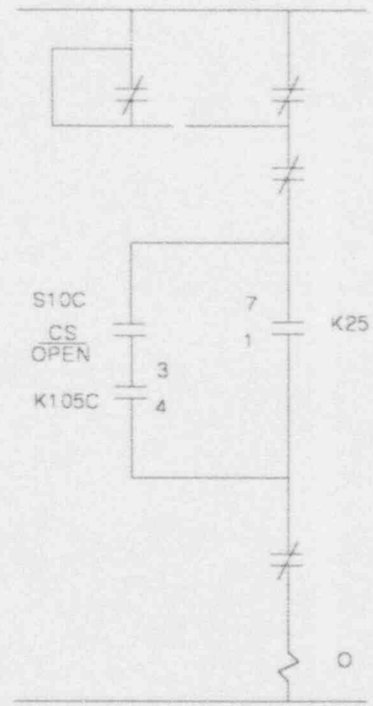
CONTROL CIRCUIT
1E-2-4220BQ

F042B NC FC



CONTROL CIRCUIT
1E-2-4220BR

F042C NC FC

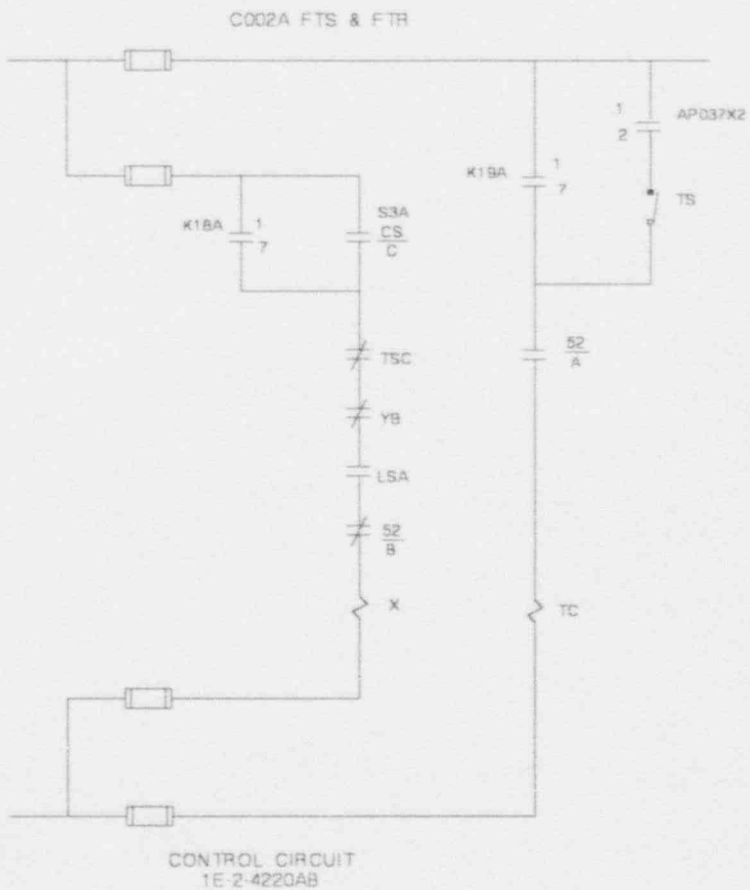


CONTROL CIRCUIT
1E-2-4220BS

LPCI BX1.DRW

Figure 3.3-5 LPCI Valve Control Circuits

LPC12A.DRW


C002A FTS & FTR
K18A
S3A
CS/C
K19A
AP037X2
TS
52/A
TSC
YB
LSA
52/B
X
TC
CONTROL CIRCUIT
1E-2-4220AB

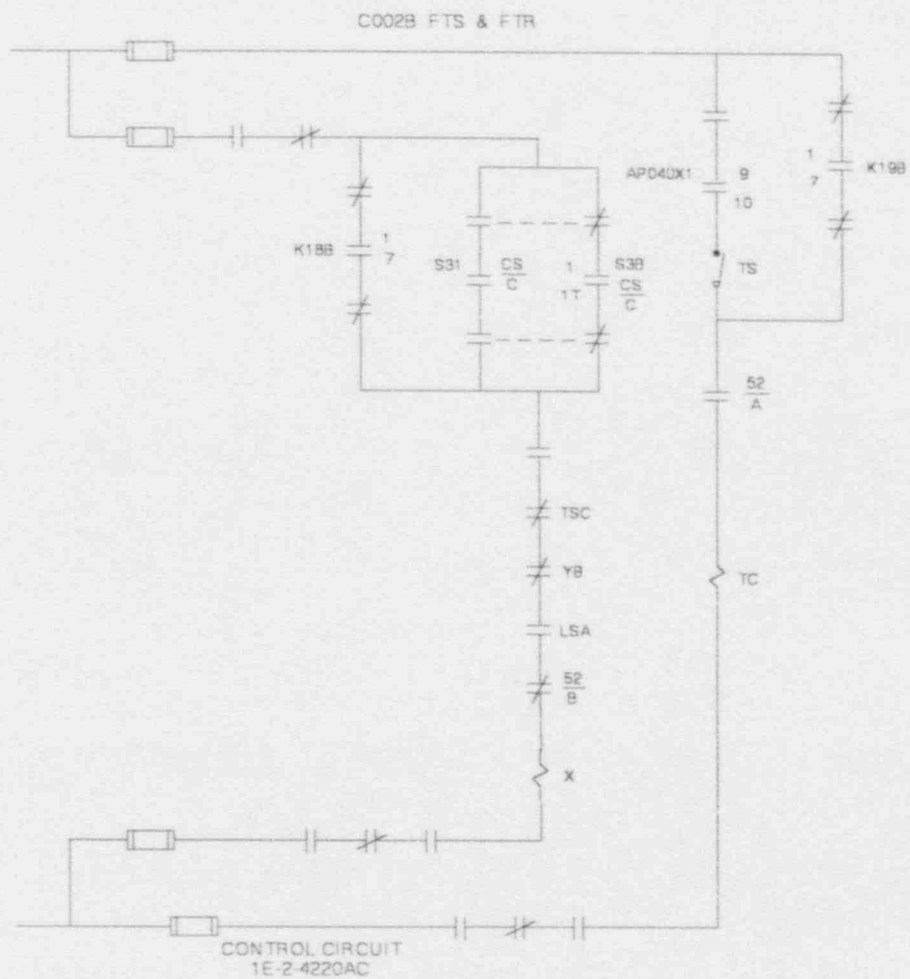
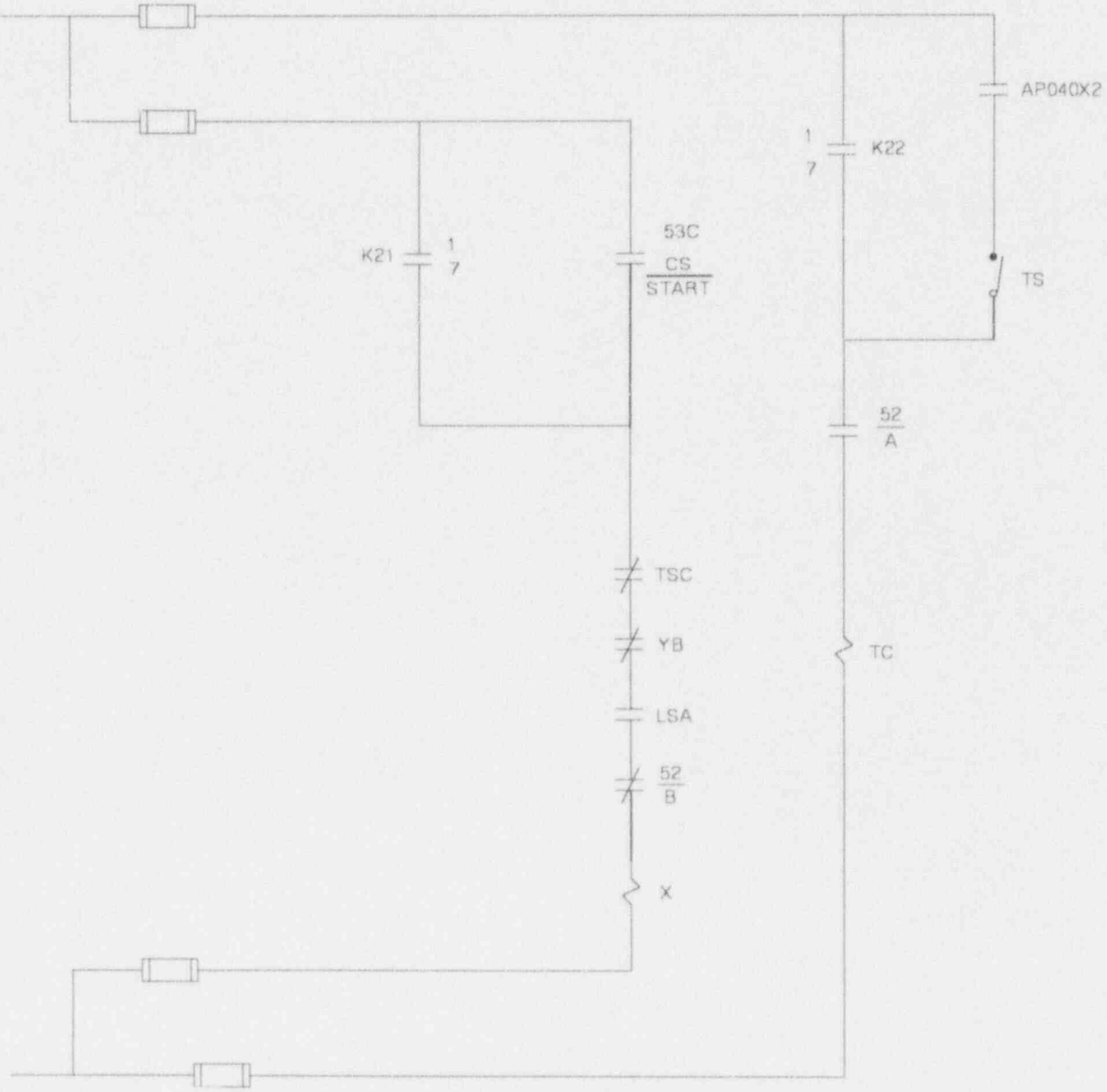

C002B FTS & FTR
K18B
S31
CS/C
S3B
CS/C
AP040X1
K19B
TS
52/A
TSC
YB
LSA
52/B
X
TC
CONTROL CIRCUIT
1E-2-4220AC

Figure 3.3-6a LPCI Pump Control Circuits

C002C FTS & FTR



CONTROL CIRCUIT

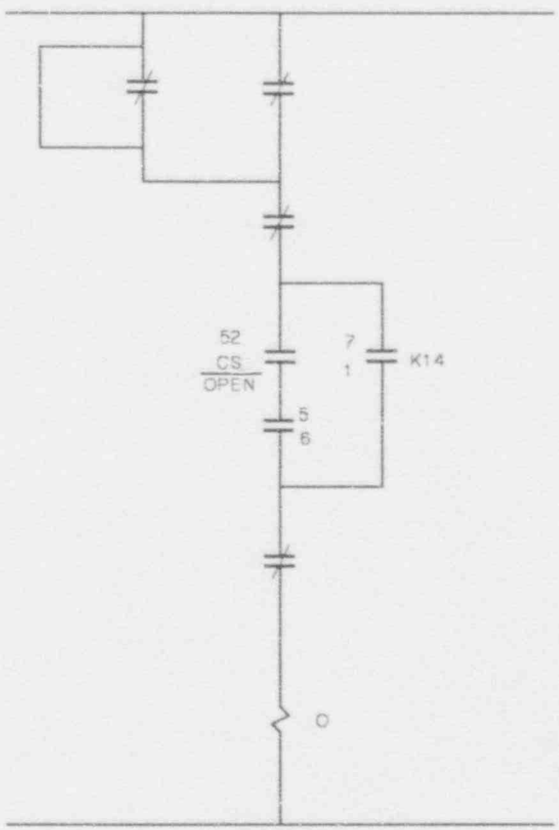
1E-2-4220AD

LPC123.DRW

Figure 3.3-6b LPCI Pump Control Circuits (Concluded)

LPCI 3A.DRW

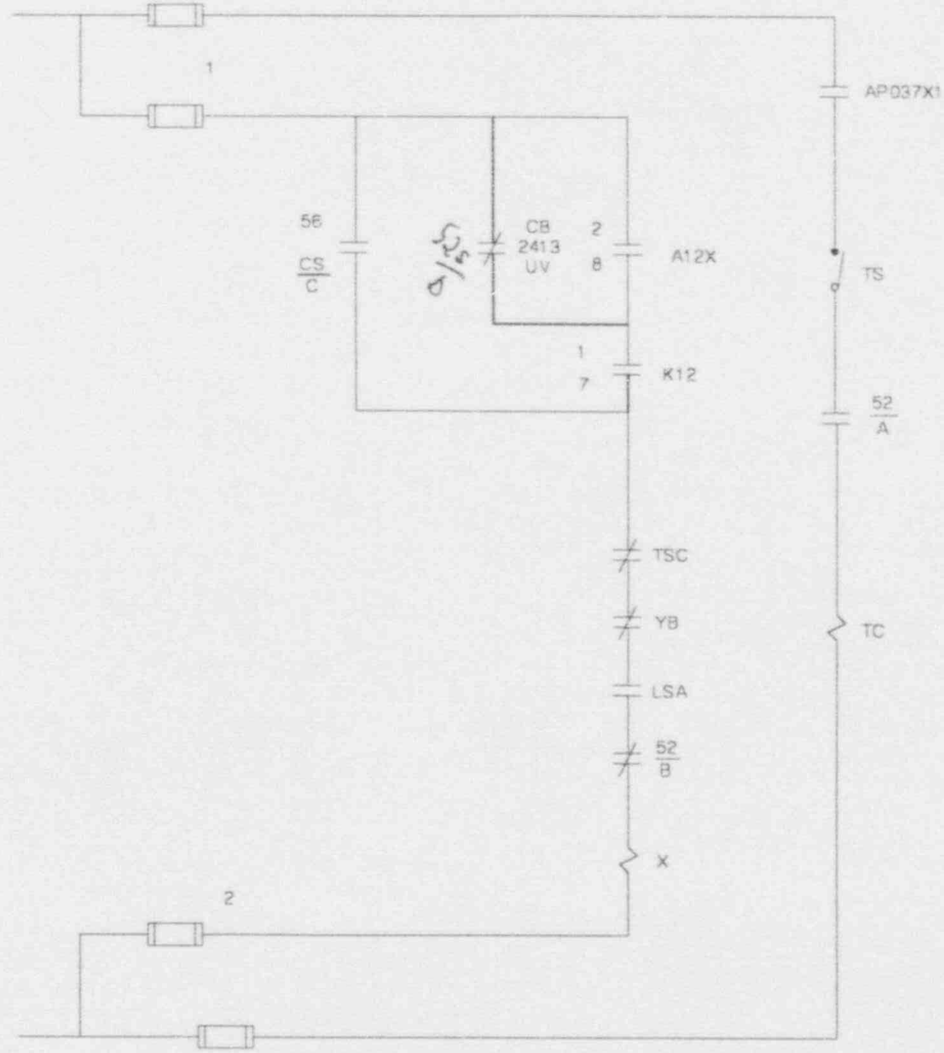
F005 NC FC



CONTROL CIRCUIT

1E-2-4221 AB

C001 FTS & FTR

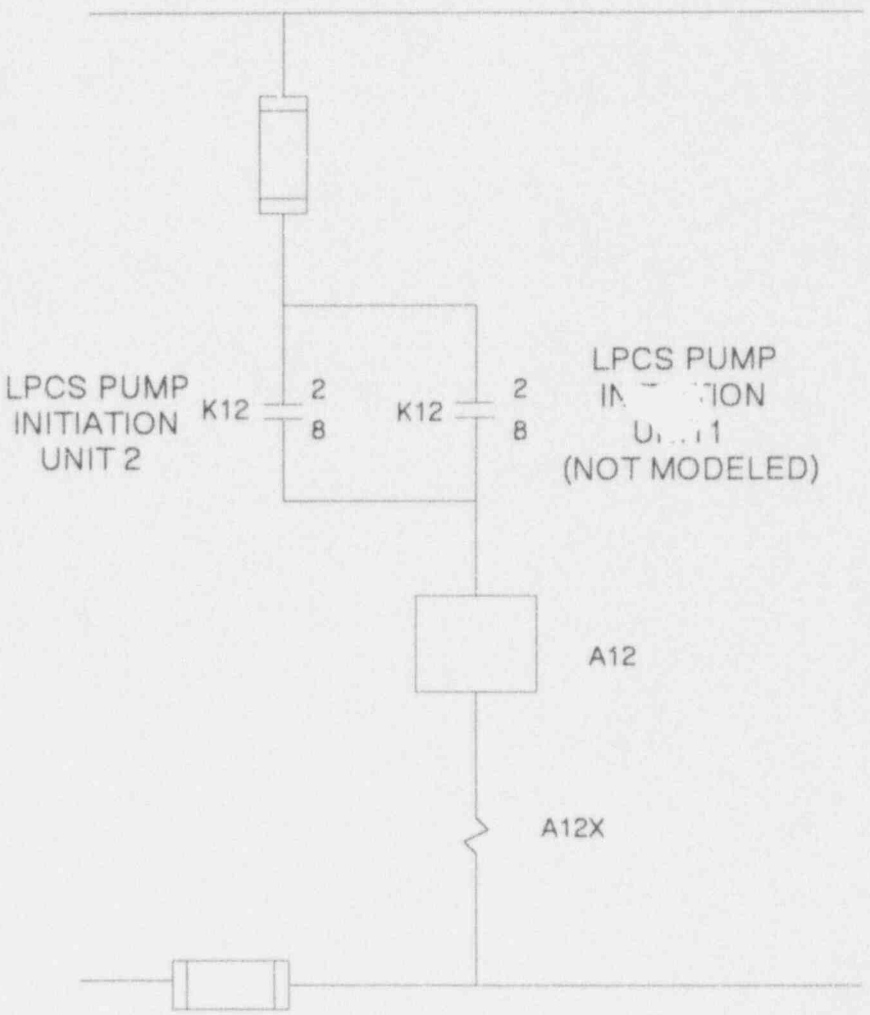


CONTROL CIRCUIT

1E-2-4221 AA

Figure 3.3-7a LPCS Valve and Pump Control Circuits

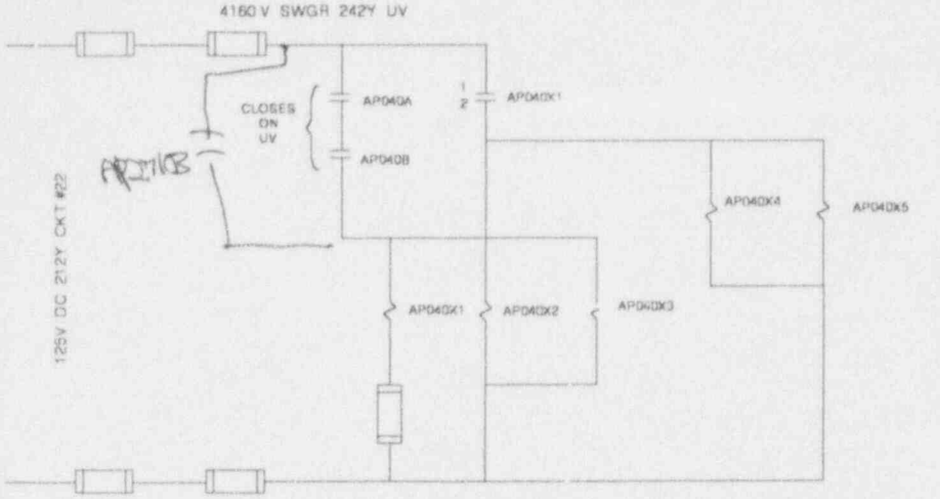
125V DC 211Y CKT #13



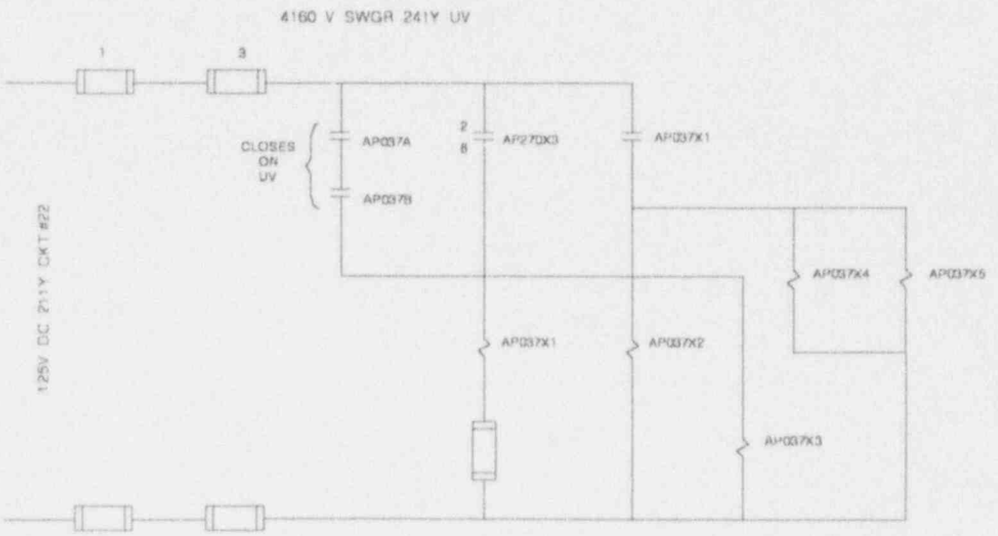
1E-4412AJ

LPC13B.DRW

Figure 3.3-7b LPCS Pump Actuation Circuit



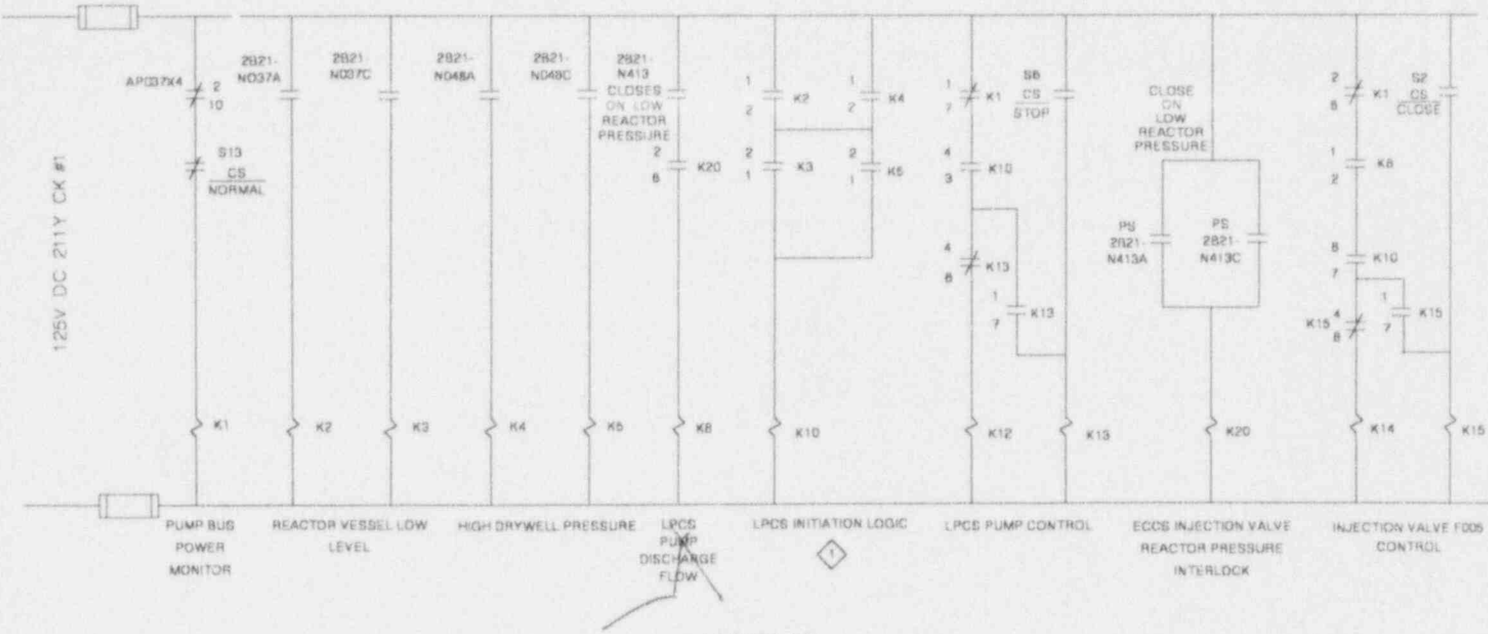
1E-2-4005AT



1E-2-4005AM

LPC14.DRW

Figure 3.3-8 Under-Voltage Trips for LPCS and LPCI Pumps



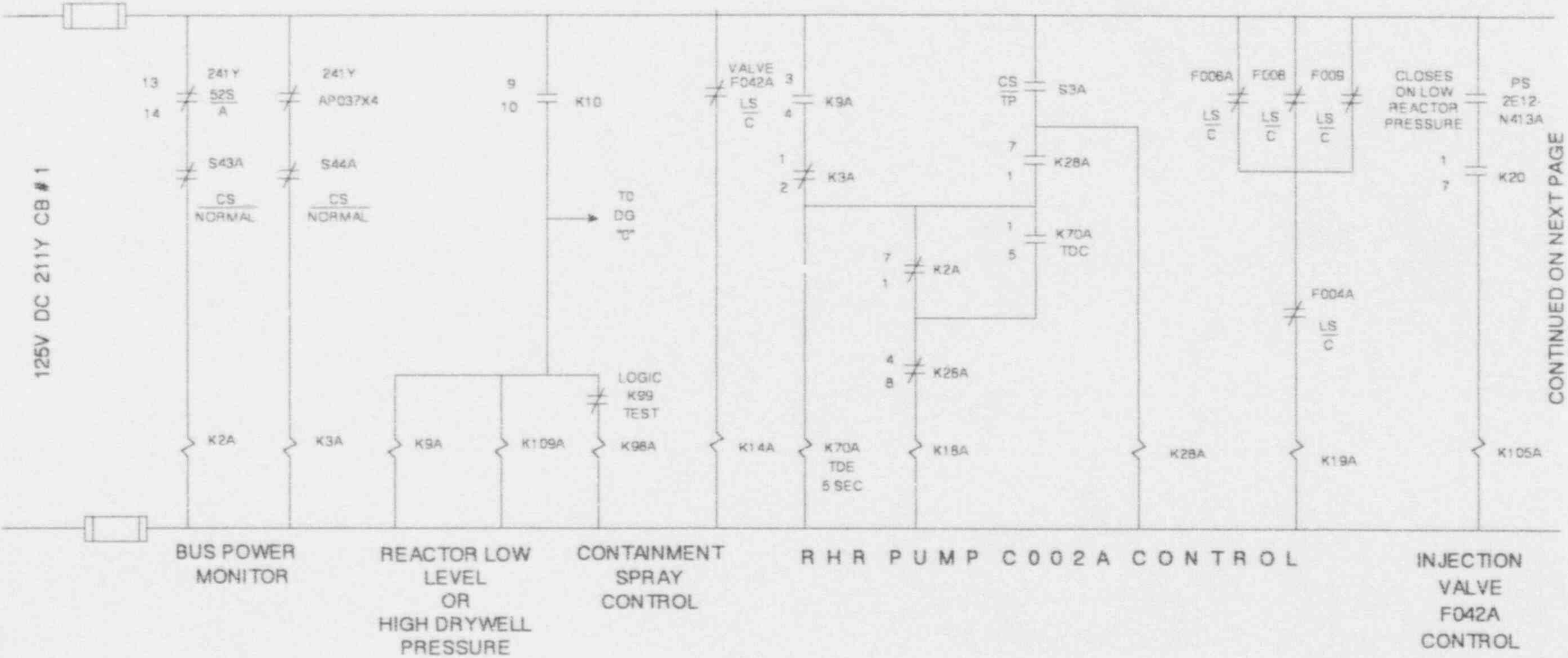
1E-2-4221AD

Low Rx Pressure

LPCI5A.DRW

Figure 3.3-9a LPCS and LPCI Train A Pump and Valve Actuation Logic

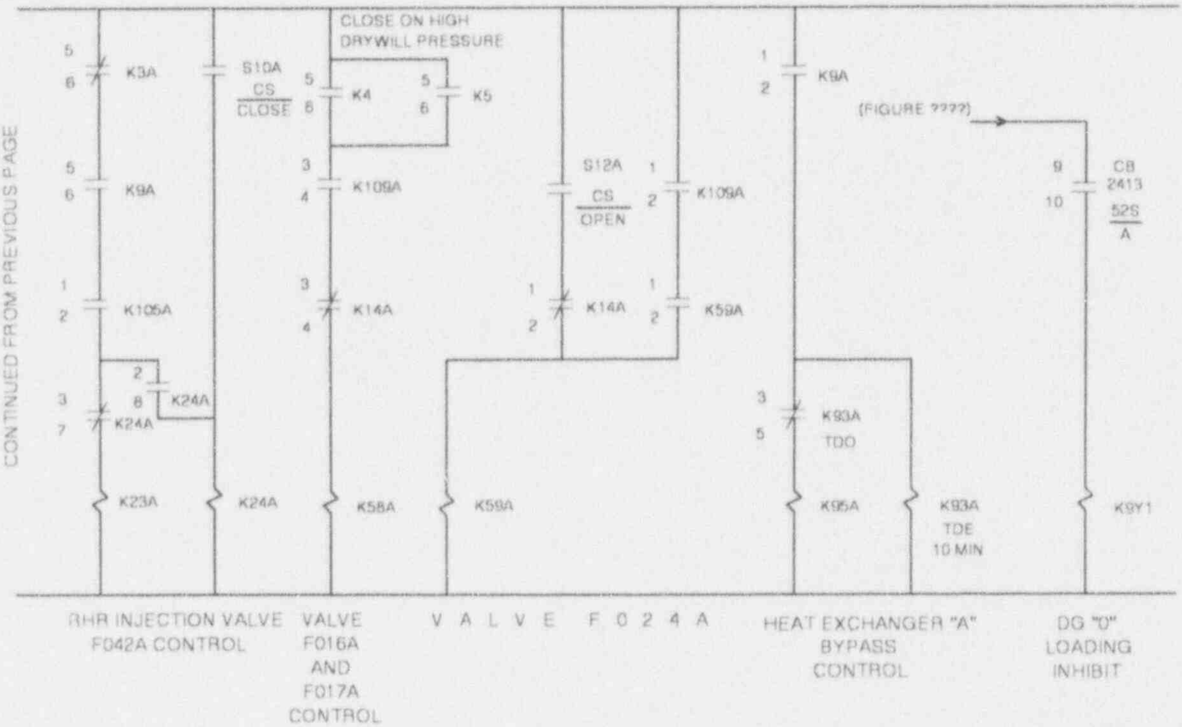
_PC15B.DRW



1E-2-4220AH

Figure 3.3-9b LPCS and LPCI Train A Pump and Valve Actuation Logic (Continued)

$\mathcal{N}$

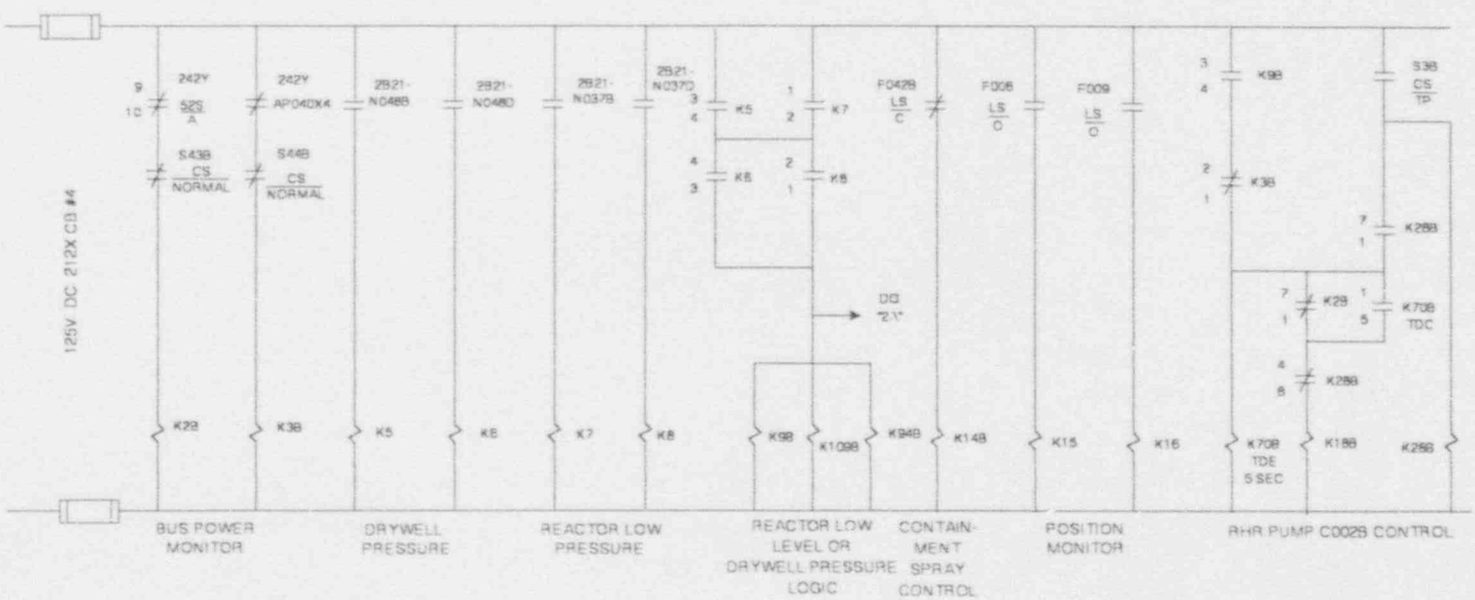


1E-2-4220AJ

LPC15C.DRW

Figure 3.3-9c LPCS and LPCI Train A Pump and Valve Actuation Logic (Concluded)

LPCI6A.DRW

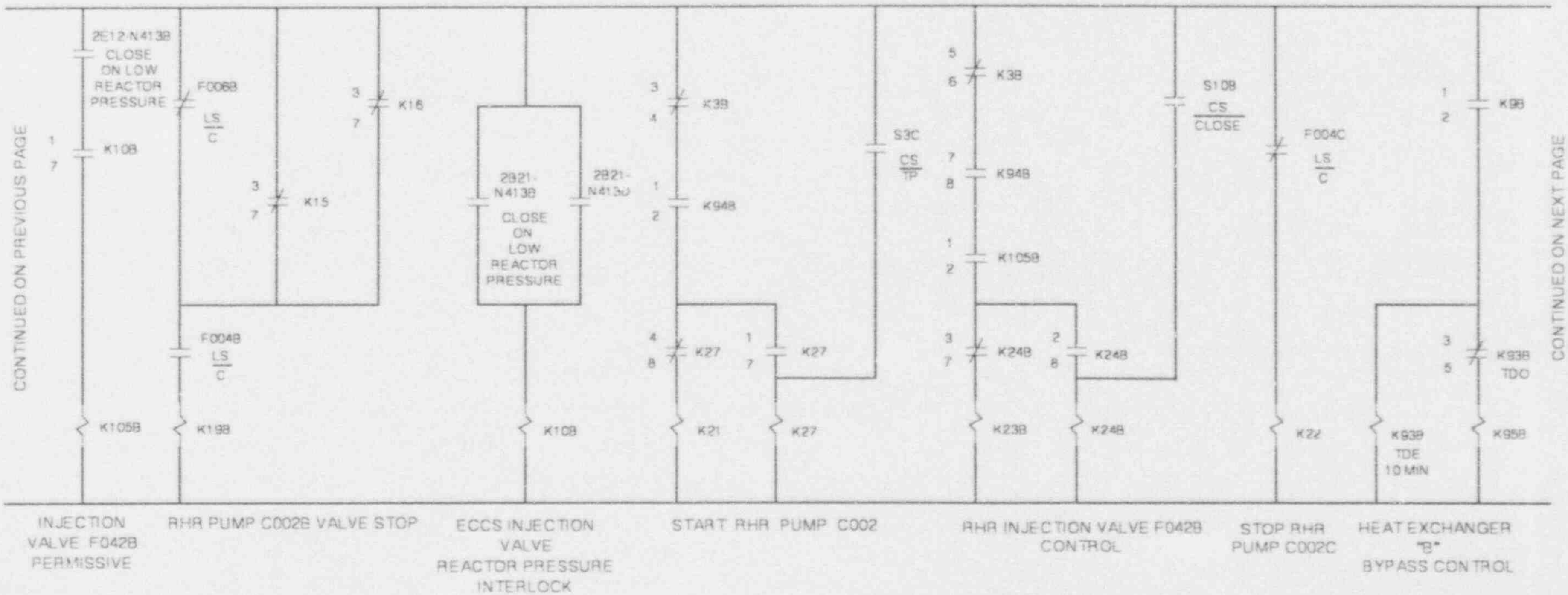


CONTINUED ON NEXT PAGE

1E-2-4220AK

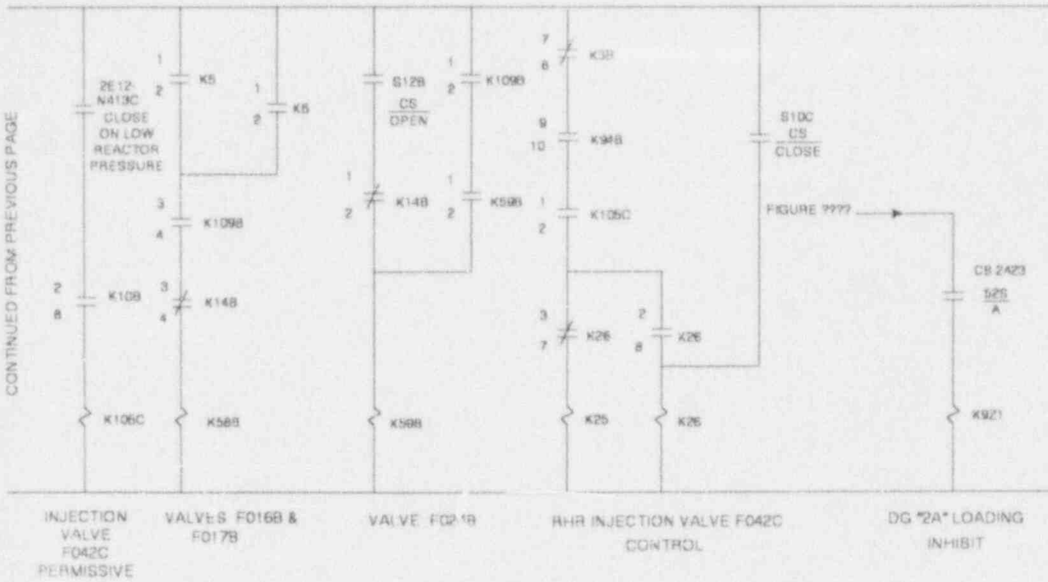
Figure 3.3-10a LPCI Train B and C Pump and Valve Actuation Logic

LPCI 6B.DRW



1E-2-4220AL

Figure 3.3-10b LPCI Train B and C Pump and Valve Actuation Logic (Continued)

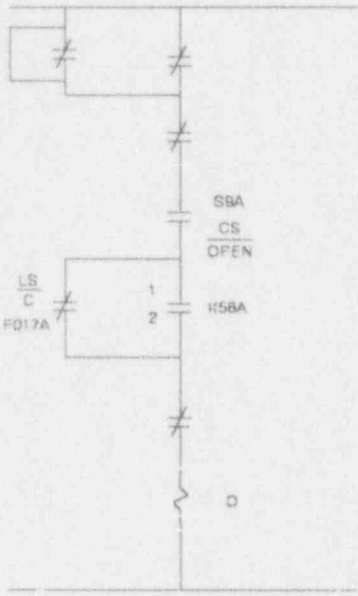


1E-2-4220AM

LPCI6C.DRW

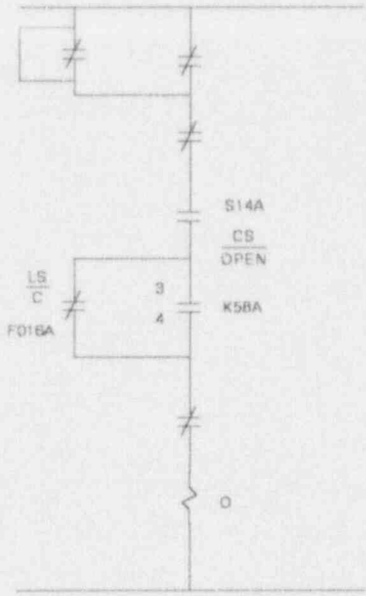
Figure 3.3-10c LPCI Train B amd C Pump and Valve Actuation Logic (Concluded)

F016A NC FC



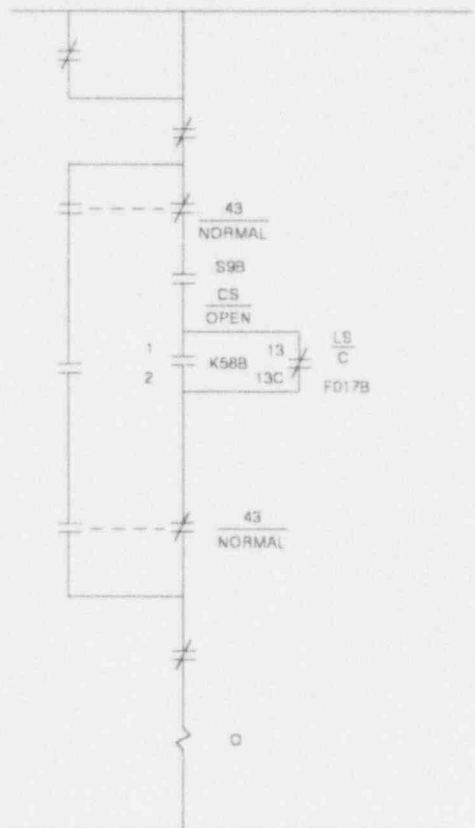
CONTROL CIRCUIT
1E-2-4220BE

F017A NC FC



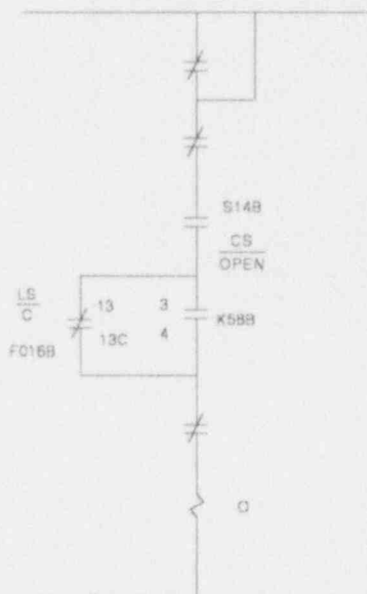
CONTROL CIRCUIT
1E-2-4220BE

F016B NC FC



CONTROL CIRCUIT
1E-2-4220BG

F017B NC FC



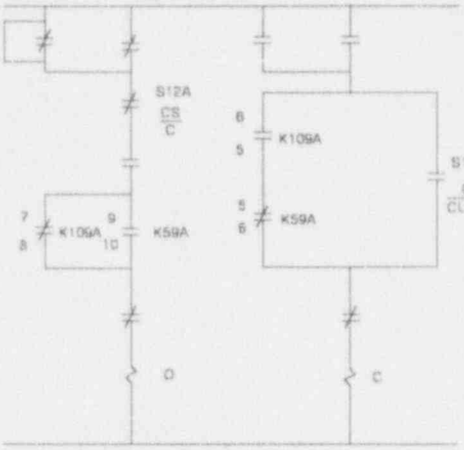
CONTROL CIRCUIT
1E-2-4220BM

K58A AND K58B RECIEVE NO SIGNAL

LPCI7.DRW

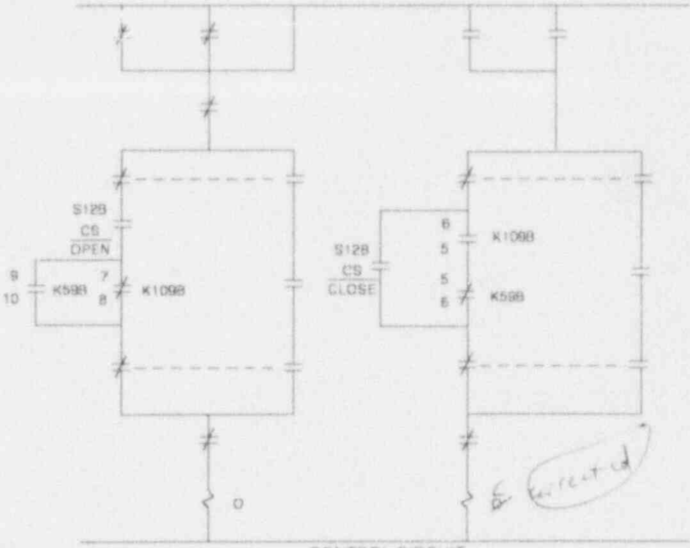
Figure 3.3-11 Containment Spray Mode Valve Control Circuits

F024A NC FC



CONTROL CIRCUIT
1E-2-4220BK

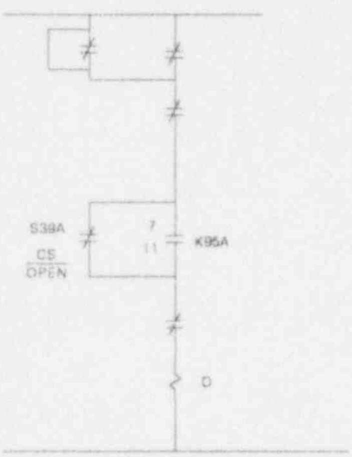
F024B NC FC



CONTROL CIRCUIT
1E-2-4220BL

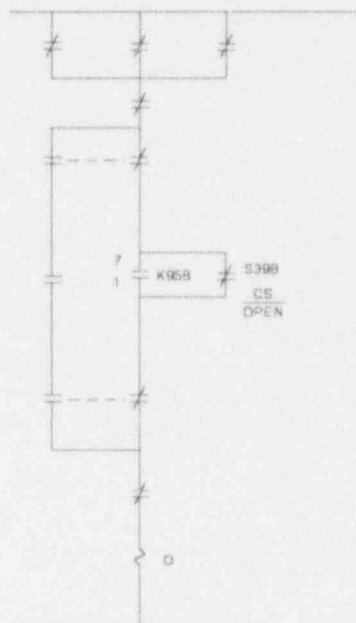
MODELED LOCA OR SPURIOUS LOCA AND FAILURE OF F024A,B TO CLOSE (K59A,B). NO LOCA OR NO SIGNAL IMPLIES INTERNAL CONTROL CIRCUIT FAULT OF K109A,B CP7,8 ONLY AND IS INCLUDED IN THE CONTROL CIRCUIT (i.e., K59A,B NO FO).

F048A NO FO



CONTROL CIRCUIT
1E-2-4220BS

F048B NO FO



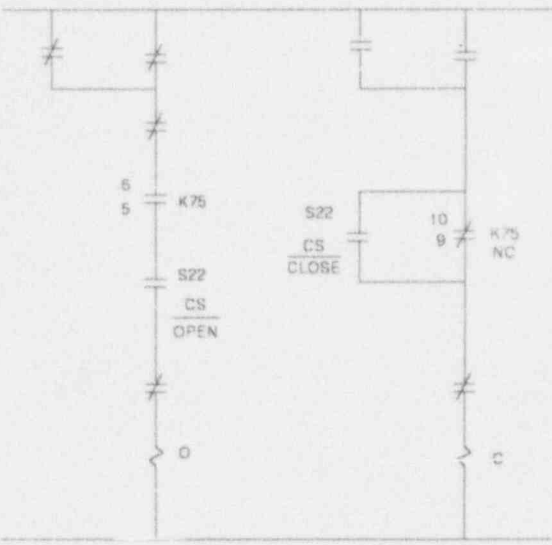
CONTROL CIRCUIT
1E-2-4220BU

MODELED LOCA OR SPURIOUS LOCA RESULTING IN VALVE REMAINING OPEN (i.e., K95A,B NO FC).

LPCI8 DRW

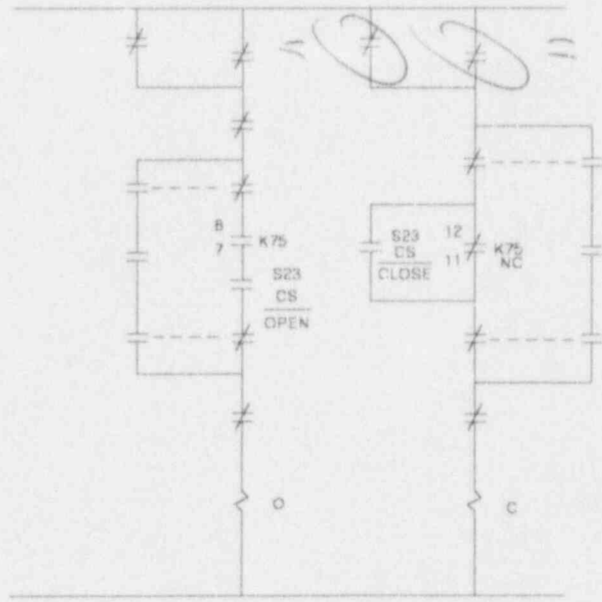
Figure 3.3-12 Suppression Pool cooling Mode Valve Control Circuits

F053A NC FC



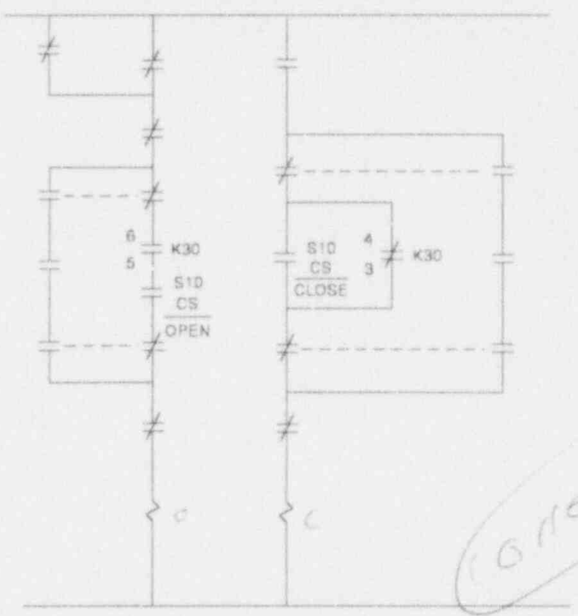
CONTROL CIRCUIT
1E-2-4220BX

F053B NC FC



CONTROL CIRCUIT
1E-2-4220BZ

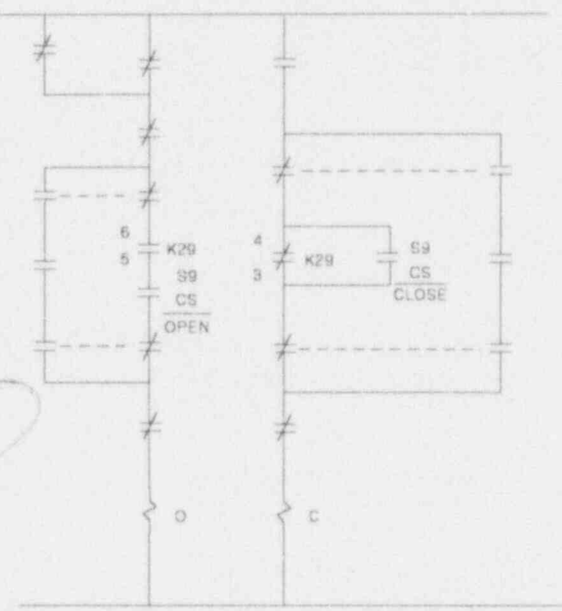
F008 NC FC



corrected

CONTROL CIRCUIT
1E-2-4220BC

F009 NC FC

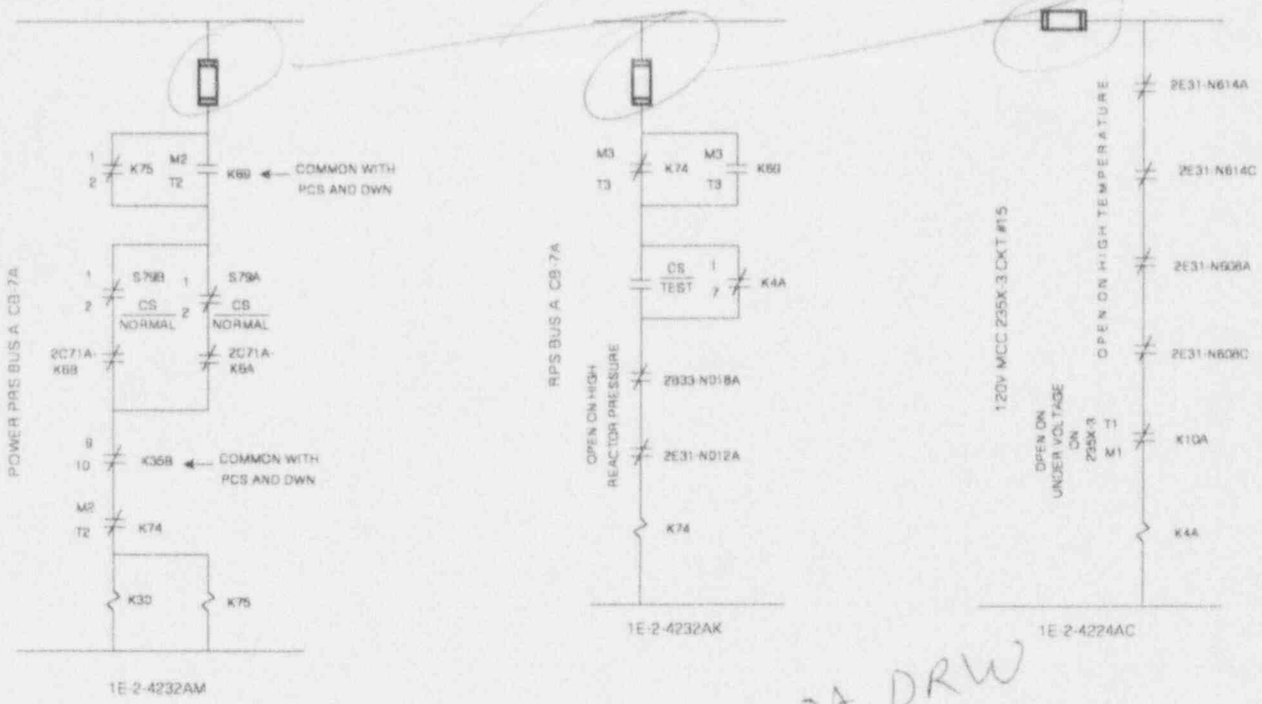


CONTROL CIRCUIT
1E-2-4220BD

LPCI9. DRW

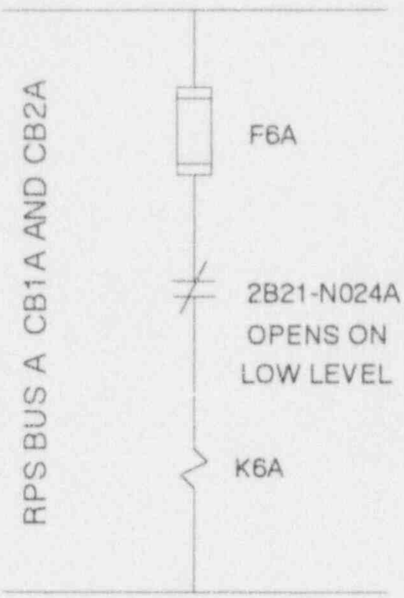
Figure 3.3-13 Shutdown Cooling Mode Valve Control Circuits

Corrected

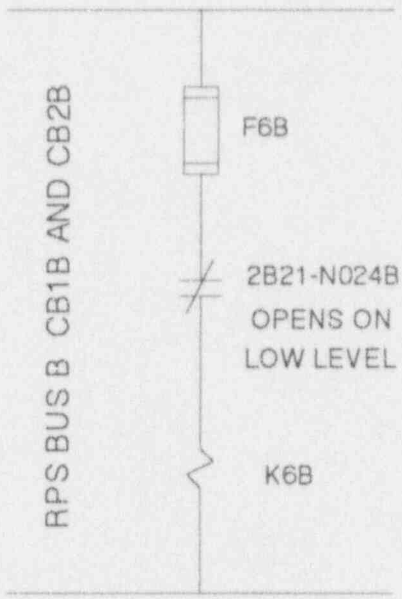


LPCI10A.DRW

Figure 3.3-14a LPCI and LPCS Outboard Isclation Logic



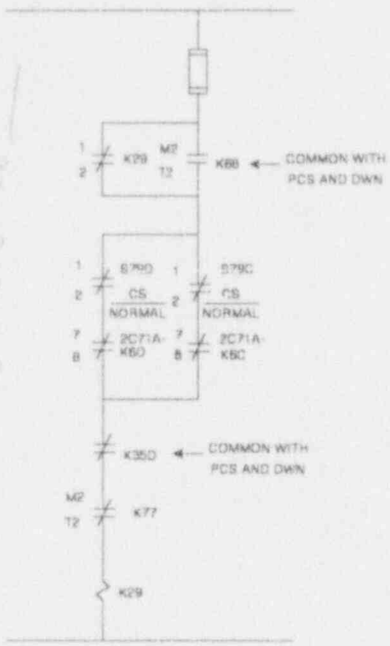
1E-2-4215AC



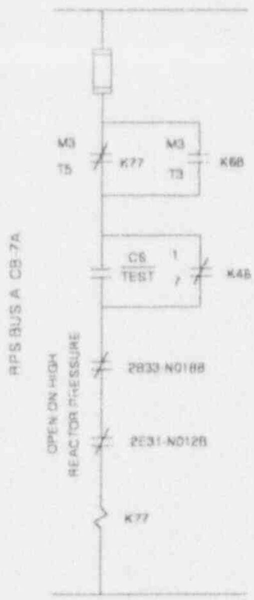
1E-2-4215AE

LPCI10B.DRW

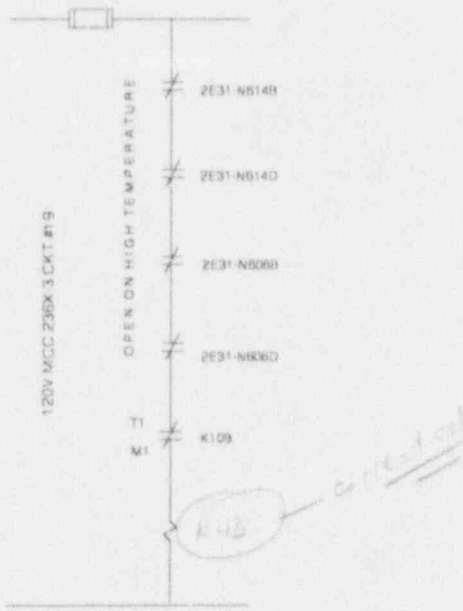
Figure 3.3-14b LPCI and LPCS Outboard Isolation Logic (Concluded)



1E-2-4232AM



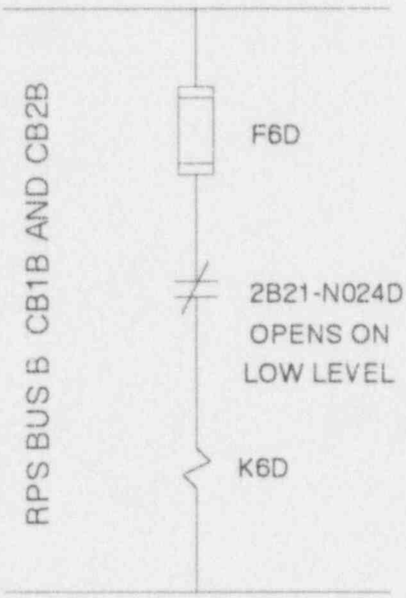
1E-2-4232AK



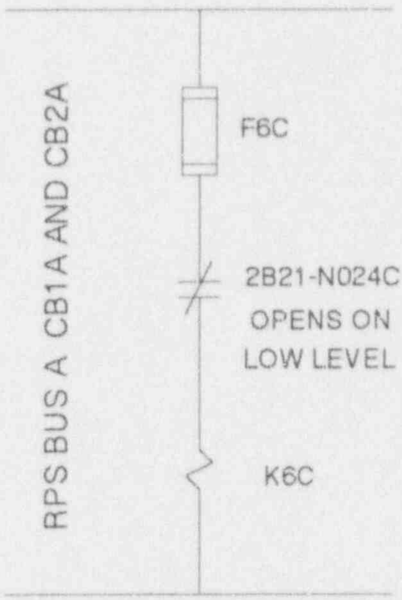
1E-2-4224AC

LPCI11A.DRW

Figure 3.3-15a LPCI and LPCS Inboard Isolation Logic



1E-2-4215AF



1E-2-4215AD

LPCI11B.DRW

Figure 3.3-15b LPCI and LPCS Inboard Isolation Logic (Concluded)

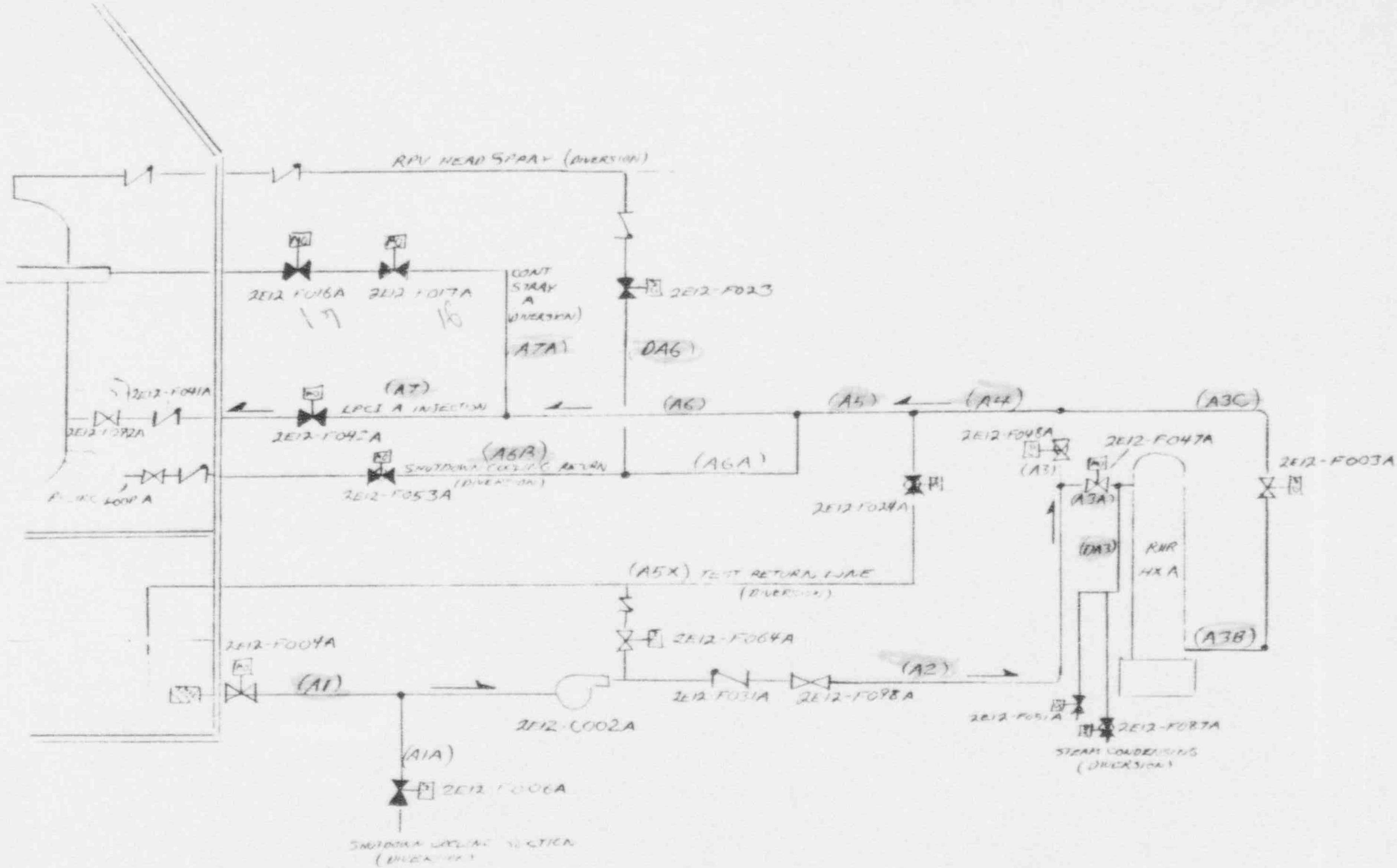


Figure B.X-11 Low Pr... ...A Simplified Diagram

Figure 3.3-16 Simplified Diagram for Fault Tree Construction - LPCI Train A

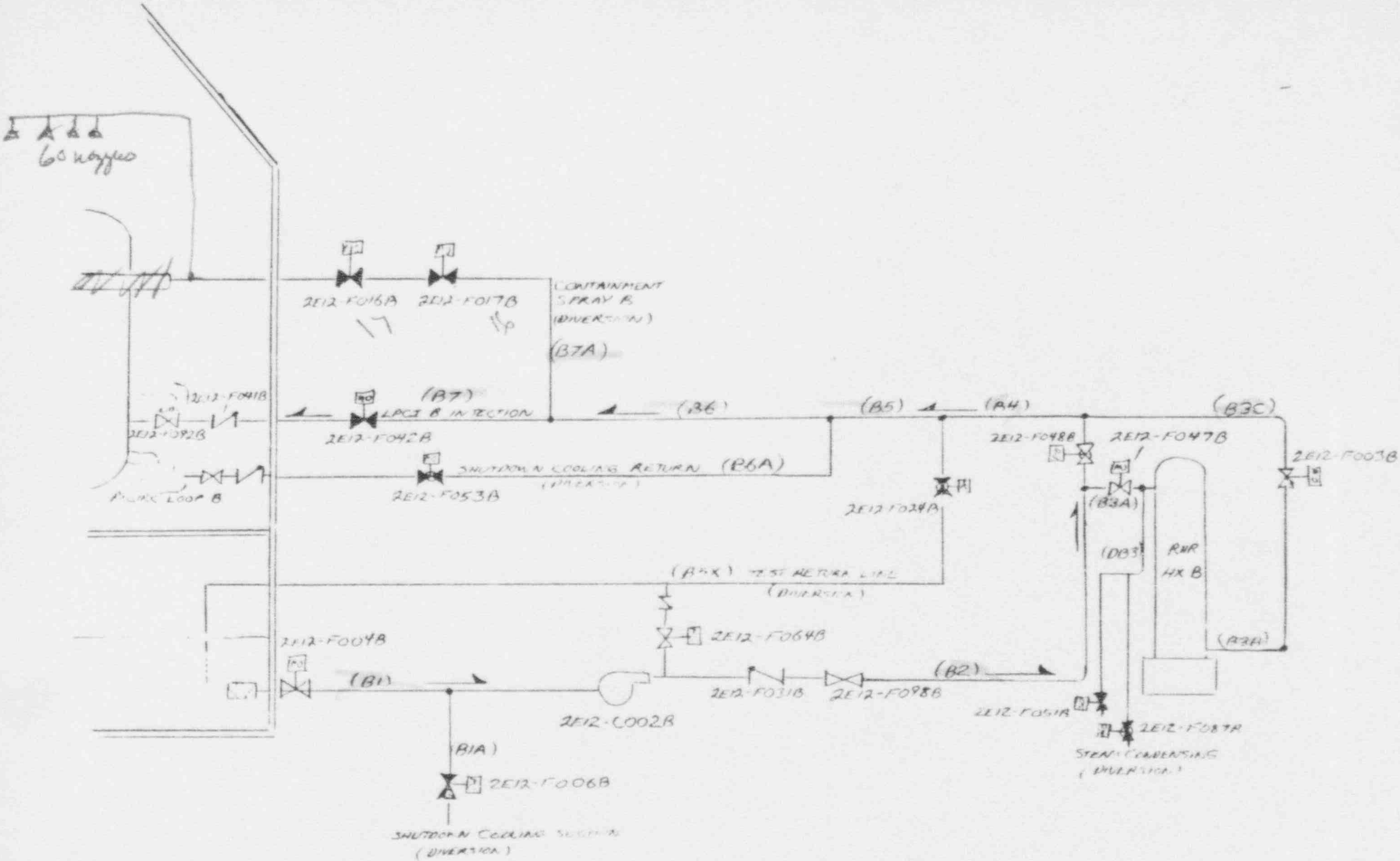


Figure B.X-12 Low Pressure Coolant Injection Train B Simplified Diagram

Figure 3.3-17 Simplified Diagram for Fault Tree Construction - LPCI Train B

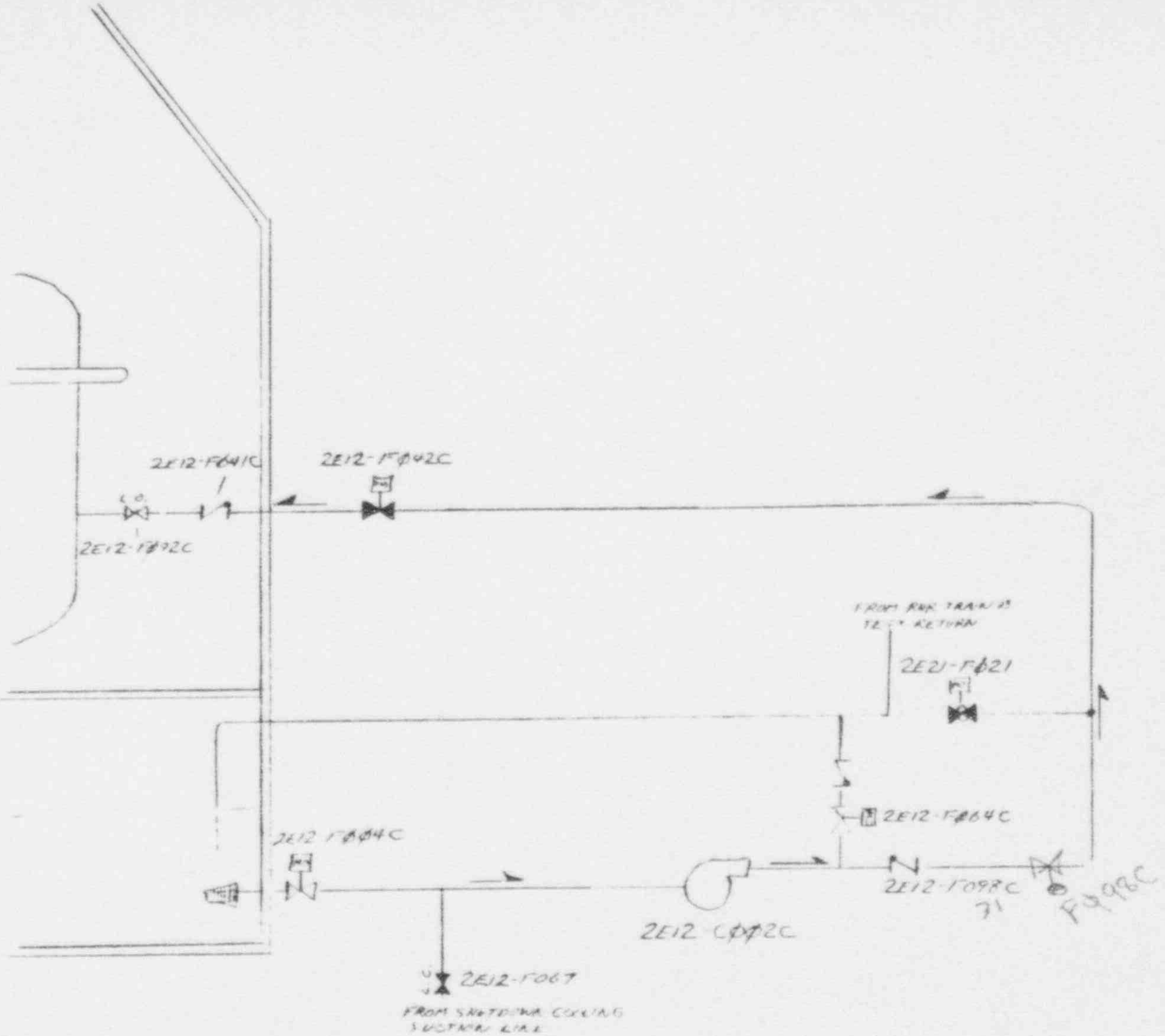


FIGURE B.X-13 Low Pressure Coolant Injection Train C Simplified Diagram

Figure 3.3-18 Simplified Diagram for Fault Tree Construction - LPCI Train C

4.0 PRESSURE CONTROL SYSTEMS

4.1 Automatic Depressurization System (ADS)

4.1.1 System Function

The ADS provides a method of automatically depressurizing the reactor vessel following small breaks in the system pressure boundary or transients in which high pressure injection has failed. This rapid reduction in pressure allows the Low Pressure Coolant Injection (LPCI) mode of RHR and the Low Pressure Core Spray (LPCS) to inject coolant into the reactor vessel to keep the core cooled. ADS in conjunction with the low pressure injection systems acts as a backup to the High Pressure Core Spray System (HPCS).

4.1.2 System Description

4.1.2.1 General Description

Eighteen safety/relief valves, connected to the four main steam lines between the vessel and the inboard main steam isolation valves, protect the reactor vessel from overpressure. The arrangement of these valves is shown in Figure 4.1-1. Each of these valves serves a dual function as both a safety and a relief valve. The safety function is mechanically actuated by an internal bellows and spring. The relief function is actuated by an external pneumatic cylinder that opens the valve independently of the mechanical actuator. Seven of these valves (C, D, E, R, U, S and V) also serve as ADS valves. The ADS function is actuated by the same pneumatic cylinder that opens the valve for the relief function. Air to the pneumatic cylinder for each valve is applied by any one of three solenoid valves which when open admit air to a header connected to the pneumatic cylinder. This arrangement is shown in Figure 4.1-2. For the seven valves designated for ADS, two of the solenoid valves are controlled by ADS signals with the third solenoid valve controlled by relief signals. Actuating air is supplied by Drywell Pneumatics. An accumulator in the air supply line for each valve provides reserve air for operation of the valve if the air supply is lost. The ADS valve opening is initiated by the simultaneous occurrence of a low reactor vessel water level (Level 1) and High Drywell pressure or only low reactor vessel water level after an eight minute delay.

Flow Path

High pressure steam from the reactor vessel flows from the vessel through the main steam lines, out the ADS valves. The discharge of each valve is separately piped to the suppression pool.

Locations

The ADS valves and piping are located in the primary containment drywell. Support systems (drywell pneumatics) are located in the reactor building and control equipment is located in the reactor building and the control room.

Component Descriptions

Safety Relief Valves

Each safety/relief valve is an 8-inch Crosby spring loaded safety with an external pneumatic piston operator that operates the valve independently of the internal mechanical actuator. The valve is constructed so that malfunctions of the pneumatic operator cannot interfere with the safety function. The valve is capable of operating against a backpressure of 40% of the maximum inlet pressure.

Discharge Line

Each discharge line is sized to limit the outlet pressure from the valve to less than 40% of the maximum inlet pressure. Vacuum reliefs on each line prevent steam condensation from drawing water into the line which could inhibit the valve discharge or cause water hammer damage. Each line is terminated in a "T-quencher", a cross extension with a blank endcap on one end of the horizontal leg and a drilled endcap on the other. ADS valve discharge exits the T-quencher through the drilled endcap and creates a swirling effect in the suppression pool to minimize thermal and mechanical stresses.

Accumulators

An accumulator and check valve in the air supply line to each ADS valve provides 42 gallons of reserve air for valve operation should the drywell pneumatics air supply fail. Each accumulator contains a sufficient air volume to open the valve and hold it open against the drywell design pressure of 45 psig. The accumulators are also sized to operate their respective ADS valves two times at 70% of drywell design pressure following a failure of pneumatic supply to the accumulator.

4.1.2.2 System Interfaces

A failure modes and effects analysis (FMEA) of LPCI support system interfaces is shown in Table 4.1-1. The support system interfaces are discussed below.

Electrical

The 125 VDC Power System (211Y for Train A/212Y for Train B) provides electrical control power to the solenoid operated air pilot valves for the ADS trip system.

The ADS accumulators are supplied with nitrogen (N^2) from the drywell pneumatic system. Normally the drywell pneumatic compressor is on the line providing 175 psig N^2 to the ADS accumulators. In the event that both compressors are lost, two banks of N^2 bottles provide N^2 to the accumulators when the accumulator pressure drops to 160 psig. Each bank consists of a manifold with 4 attached N^2 bottles. The bottles are checked periodically both banks together are capable of operating the ADS valves for two hours following the loss of the drywell pneumatic compressors. The manifolds are located in the reactor building.

In addition, there is an Emergency Pressurization Station in the Auxiliary Building in an aisle located between the Auxiliary Electric Equipment Room and the reactor building wall. This station is provided to allow indefinite operation of the ADS valves using N^2 bottles brought to that point.

A detailed description of the drywell pneumatic system is given in Section 9.2. of this report.

4.1.2.3 Instrumentation and Control

1) System Actuation

Two three way solenoid valves (A & B), connected in parallel between the ADS accumulator and the ADS valve pneumatic cylinder control the actuating air to the ADS valve. This arrangement and the control circuitry is shown in Figure 4.1-3. Opening either solenoid valve will admit air to the pneumatic cylinder opening the ADS valve. There are two separate ADS initiating logic trains, Train A controls the A solenoid, Train B the B solenoid. Both trains operate identically with the simultaneous occurrence of the following initiating signals.

a. Reactor vessel low low low water level - Level 1 (-129")
b. High drywell pressure 1.69 psig (Bypassed if Level 1 exists 8 min)
c. Confirmatory reactor vessel low water level - Level 3 (12.5")
d. Sufficient low pressure core cooling pump discharge pressure on one pump - RHR B, C - 119 psig, and LPCS, RHR "A" - 146 psig

Each initiating logic train consists of two independent logic networks. For Train A each network controls two output relays. Relays K4A and K6A are controlled by one network, relays K7A and K8H are controlled by the other network. The A solenoids for ADS valves C, D, E and R are energized by the simultaneous closing of the K4A contacts from one network and the K7A contacts from the other network. The A solenoids for valves S, U and V are energized by the simultaneous closing of the K6A contacts from the first network and the K8A contacts from the second network. The B solenoids are controlled by the B train in a similar manner.

The networks in Train A and B controlling the K4 and K6 relays are completed when both a reactor vessel Level 1 and Level 3 signals exist in conjunction with a high drywell pressure signal. The Level 1 signal also starts an eight minute timer that will bypass the high drywell pressure signal if the Level 1 signal persists for eight minutes. Completion of this part of the network circuit energizes a 105 second timer which will close a contact in series with a RHR or LPCS pump running permissive contact. If ar RHR or LPCS pump is running and the 105 second timer is timed out, the network circuit will be completed energizing the K4 and K6 relays. This will complete one-half of the logic necessary to generate an initiate signal from the train containing the network.

The other half of the logic necessary to generate an initiate signal comes from the second network in each train which controls the K7 and K8 relays. This network is completed when a reactor vessel Level 1 water level signal exists in conjunction with a high drywell pressure and an RHR or LPCS pump run signal. This network also incorporates an eight minute bypass of the high drywell pressure signal just as the first network does. When all of these signals exist simultaneously the network circuit will be completed energizing the K7 and K8 relays. This network does not require a confirmatory low water level signal (Level 3) nor does it incorporate a 105 second time delay.

2) Instrumentation

PARAMETER	CONDITION	SETPOINT
Drywell pressure signal sealed-in	High Drywell Pressure	1.69 psig
Reactor Vessel Low Water Level Confirmed	Low Reactor Water Level	Level 3 (+12.5")
ADS A Logic Initiated	Initiated	----
ADS B Logic Initiated	Initiated	----
ADS C Logic Initiated	Initiated	----
ADS D Logic Initiated	Initiated	----
ADS Control Power Failure or Test	Test Keylock Switch in TEST or Loss of Control Power	----
ADS Valve Accumulator Pressure	Low Accumulator Pressure	152.5 psi

ADS in TEST status	One ADS Trip Logic in TEST	----
Fault ADS Test Procedure	Test jacks connected to more than one ADS logic division	----
Manual ADS Initiation	Pushbutton Armed	----
ADS Valve Fully Open		Valve Full Open

Pressure Signals used in Control Logic

Drywell pressure is sensed by four switches and is used for the ADS function only. High drywell pressure indicates that a LOCA has actually occurred or that drywell cooling has failed. It will not open the ADS valves without the other initiating signals; it seals in and must be reset in order to clear the ADS initiation logic.

RHR and LPCS pump discharge pressure is used in the ADS initiation logic It assures that a method of inventory make up is available before the ADS actuates.

Reactor Vessel Water Level

Indicator switches sensing a level of -129" indicates a Loss of Coolant Accident has occurred. A confirmatory signal of +12.5" insures that an actual low level exists.

4.1.2.4 Operator Actions

The ADS system is designed to function automatically when required without operator actions. The primary responsibility of the operator is to verify system operability on a regular basis and proper operation following an initiation. Should portions of the initiation or control circuitry malfunction the operator can manually actuate the system or open individual valves.

4.1.2.5 Technical Specification Limitations

Limiting Conditions for Operation

The LaSalle Technical specifications require that both division 1 and division 2 contain 6 operable ADS valves with the ADS actuation instrumentation channels, trip setpoints, and response times as given in section 3.3.3 of the technical specifications.

These requirements apply during plant conditions 1, 2, and 3 when pressure is greater than 122 psig.

When these conditions are not satisfied, the inoperable valve must be restored within 14 days or the plant placed in hot shutdown within the next 12 hours and steam dome pressure reduced to less than 122 psig in the next 24 hours. If more than 1 of the required valves becomes inoperable, the plant must be placed in hot shutdown within 12 hours and the steam dome pressure reduced to less than 122 psig within the next 24 hours. If the steam actions are given in section 3.3.3 of the technical specifications.

Surveillance Requirements

1. At least once per 31 days, perform a channel functional test of the accumulator backup compressed gas system low pressure alarm system.

2. At least once per 18 months:

   a) Perform a system functional test which includes simulated automatic actuation of the system throughout its emergency operating sequence, but excluding actual valve actuation.

   b) Manually opening each ADS valve and observing the expected change in the indicated valve position.

   c) Perform a channel calibration of the accumulator backup compressed gas system low pressure alarm system and verifying an alarm setpoint of 50 + 40, - 0 psig on decreasing pressure.

   d) Perform a logic system functional test and simulated automatic operation of all channels.

   e) Demonstrate the response time of each ADS trip function to be within the limits shown in Table 3.3.3-3.

3. Each ECCS actuation instrumentation channel shall be demonstrated OPERABLE by the performance of the channel check, channel functional test and channel calibration at the frequencies shown in Table 4.3.3.1-1.

4.1.2.6 Tests

The ADS system tests which affect the system availability are summarized in Table 4.1-2.

4.1.2.7 Maintenance

Scheduled routine maintenance is not performed on the ADS system during plant operation. A summary of the expected unscheduled maintenance activities during plant operations is given in Table 4.1-3.

4.1.3 System Operations

4.1.3.1 Normal Operations

The ADS system is not used in normal operations.

4.1.3.2 Abnormal Operation

The Automatic Depressurization System is required to automatically reduce system pressure during a small break loss of coolant accident so the low pressure cooling systems can operate to cool the core. ADS is required to be operable whenever reactor pressure is greater than 122 psig event though the low pressure cooling system can provide adequate core cooling up to 350 psig. Only 6 ADS valves may be inoperable indefinitely.

When the ADS initiate parameters are satisfied the ADS valves open relieving reactor pressure to the suppression pool.

4.1.4 System Fault Tree

4.1.4.1 Fault Tree Description

A simplified diagram of the ADS system used for fault tree modeling is shown in Figure 4.1-2. The system has been divided into labeled segments for modeling. Component control and actuation system diagrams developed for system modeling are shown in Figure 4.1-3 and 4.1-4.

The fault tree contains one top event labeled "Failure of the ADS System to Relieve Pressure with Three of Seven Relief Valves". There are 24 developed events in the fault tree where the ADS system interfaces with both the electrical power distribution system and the drywell pneumatics system.

4.1.4.2 Success/Failure Criteria

Successful operation of the ADS system occurs when the system pressure is relieved to allow the low pressure injection systems to inject coolant into the reactor vessel. The success criteria for the system is defined as 3 of 7 ADS valves open. Failure of the system can result from the simultaneous failure of:

1) 5 of the 7 ADS valves

2) Both actuation instrumentation trains of ADS

3) Both solenoid valves supplying air to 5 of the 7 ADS valves

4.1.4.3 Major Assumptions

In addition to the general assumptions regarding fault tree development (listed at the beginning of this volume), the following assumptions specific to the ADS system were made:

1) Failures of the vacuum breakers that connect each ADS discharge pipe to the drywell atmosphere were not modeled for the following reasons:

   The failure would have to occur within a short time after the ADS valves had been operating, i.e., slow leakage into the discharge pipe would equalize pressure and

   It is felt that any water leg established in the discharge pipe from a failure of the vacuum breakers would not prevent the system from performing its required function.

   Stuck open vacuum breakers are treated in the level II/III PRA analysis. The resulting bypass of the suppression pool affects the radionuclide release.

2) The error of commission, operator incorrectly resets the timer following automatic initiation is not modeled in the fault tree. Since for ATWS accident scenarios, thermal-hydraulic calculations reported in volume 3 of this report showed that inhibiting ADS and then manually depressurizing would not make a significant difference in the accident progression. This is true whether high pressure injection (HPCS) or low pressure injection (LPCS or LPCI) is working.

3) No tests or maintenance on ADS mechanical components can be accomplished during reactor operations.

4.1.5 References

1) FSAR

   System description

   Section 1.2.2.5.2
   Section 6.3.2.2.2
   Section 5.2.2.4.1

   Instrumentation

   Section 7.3.1.1.1.2

2) Technical Specifications

   Limiting Condition for Operation

   Section 3.5.1
   Section 3.3.3

Surveillance Requirements

Section 4.5.1
Section 4.3.3

Basis

Section 3/4.5.1

3) Operator Training Manual

Chapter 37
Chapter 21

4) Drawings

P&ID: M-66
I&C: IE-2-4201AA - AP
Master Diagrams: NB
Cable Tabulation: NB

5) Procedures

LTS-600-6 Rev.2
LOS-MS-R2 Rev.1
LOS-MS-R4 Rev.0
LOP-MS-03 Rev.1
LES-NB-102 Rev.1
LES-NB-103 Rev.1
LIS-NB-102 Rev.1
LIS-NV-17 Rev.1
LIS-PC-04 Rev.5
LIS-PC-203 Rev.1

6) Other Sources

Kuosheng Unit 1 PRA
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Table 4.1-1 ADS Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
125 VDC Bus 211Y	Initiation Logic A		Fail to Initiate	CR alarm	Loss of the 'A' ADS trip system	Loss of a single trip system will not interfere with system operation
125 VDC Bus 212Y	Initiation Logic B		Fail to Initiate	CR alarm	Loss of 'B' ADS trip system	Loss of a single trip system will not interfere with system operation
Drywell Pneumatic Syst-m	All ADS Valves		Loss of Driving Fluid for ADS valves	CR alarm	Loss of the 'A' ADS trip system cause a loss of ability to recharge the N^2 accumulators for the SRVs These accumulators are sized to allow 2 valve operations following a loss of the drywell pneumatic system. In addition, 2 banks of N^2 bottles capable of operating the ADS valves for 2 hours backup the compressor supply to the accumulators	A complete long-term loss of the drywell pneumatic system will disable ADS

Table 4.1-2 ADS COMPONENT/SUBSYSTEM TEST SUMMARY

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency (Mo)	Test Outage (Hr)	Component/Subsystem Alignment/Operability Verification Frequency
NB102	Timer Calibration	Initiation Logic	Relays	One train of Initiation Logic	No	3	4	
NB103	Timer FT	Initiation Logic	Relays	One train of Initiation Logic	No	1	4	
NB204	Level Signal Cal FT	Initiation Logic	Level Sensing	Level sensors Initiation Logic	No	Cal 3	4	
PC203	Drywell Press Cal	Initiation Logic	Pressure Sensor	Drywell Pressure Instruments (Place) logic in 1* (2 & 3)	No	3	4	
PC204	Drywell Press FT	Initiation Logic	Pressure Sensor		No	3	4	

Table 4.1-3 ADS Unscheduled Maintenance Summary

Component/ Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance with no Auto-Return	Allowed During Plant Operation?	Frequency	Outage	Frequency of Alignment/ Operability Verification
ADS	Relief Valves	Mechanical	None	No	**	**	
		Electrical	Relay Logic	Yes			
		I & C	Relay Logic	Yes			

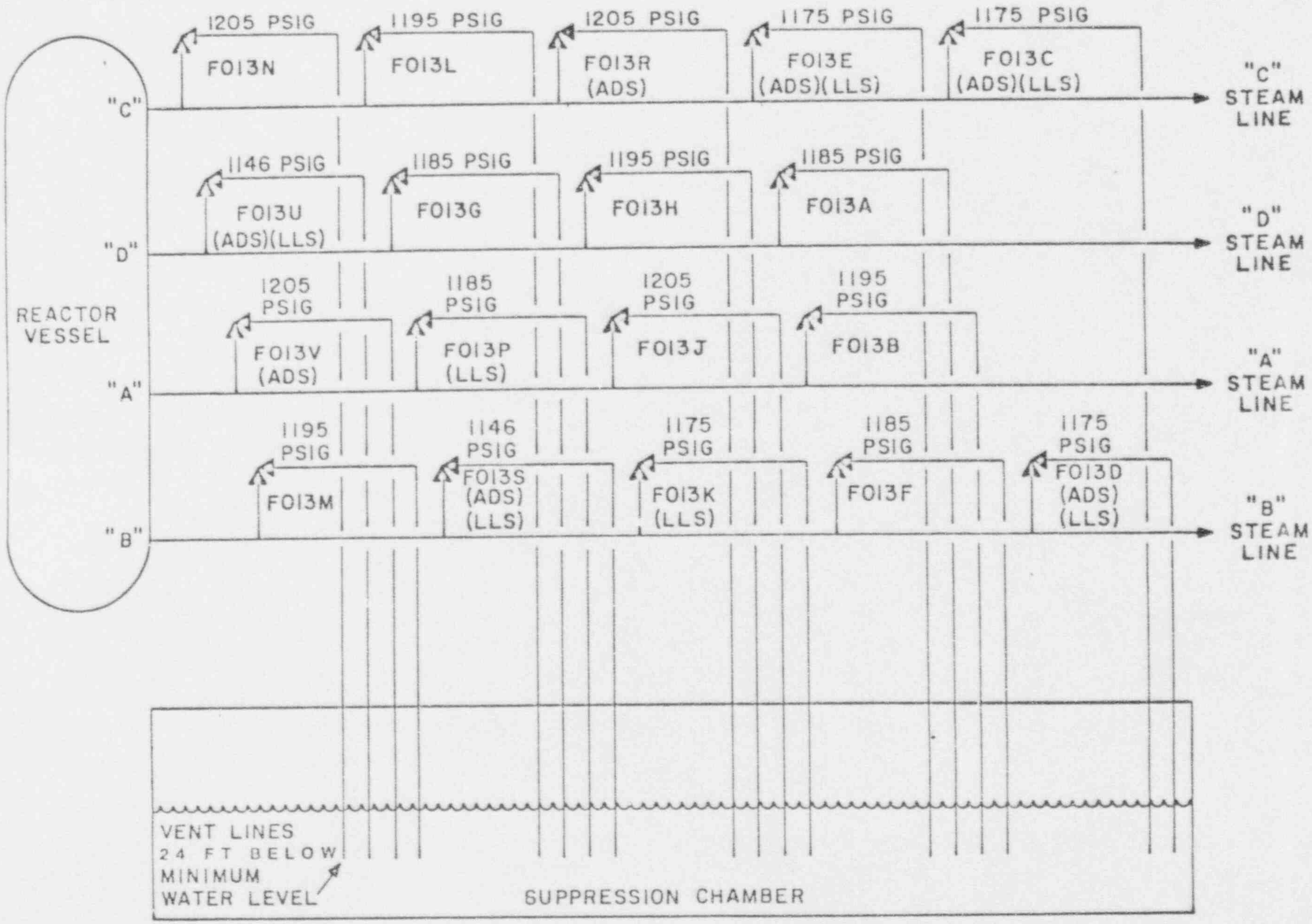
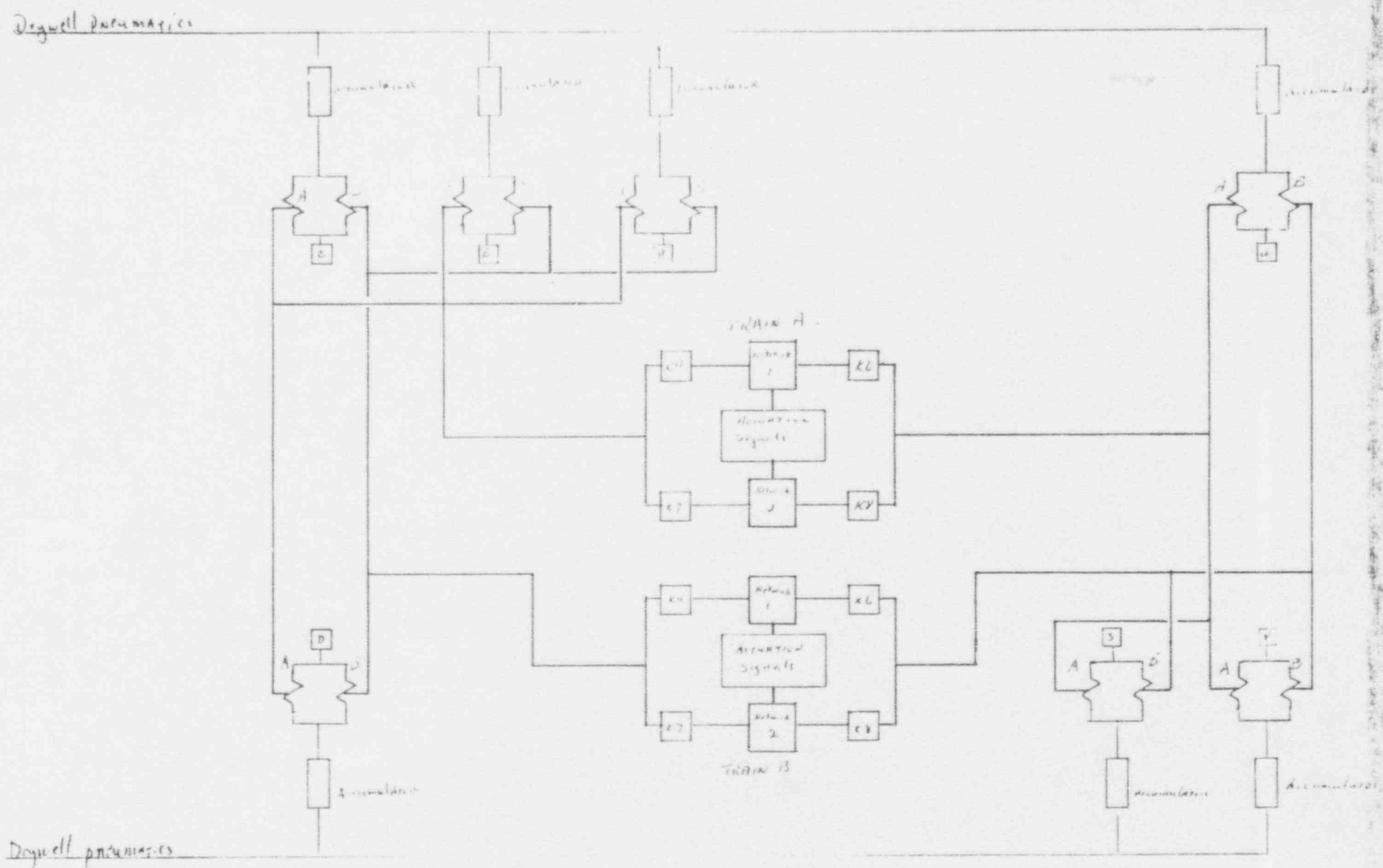


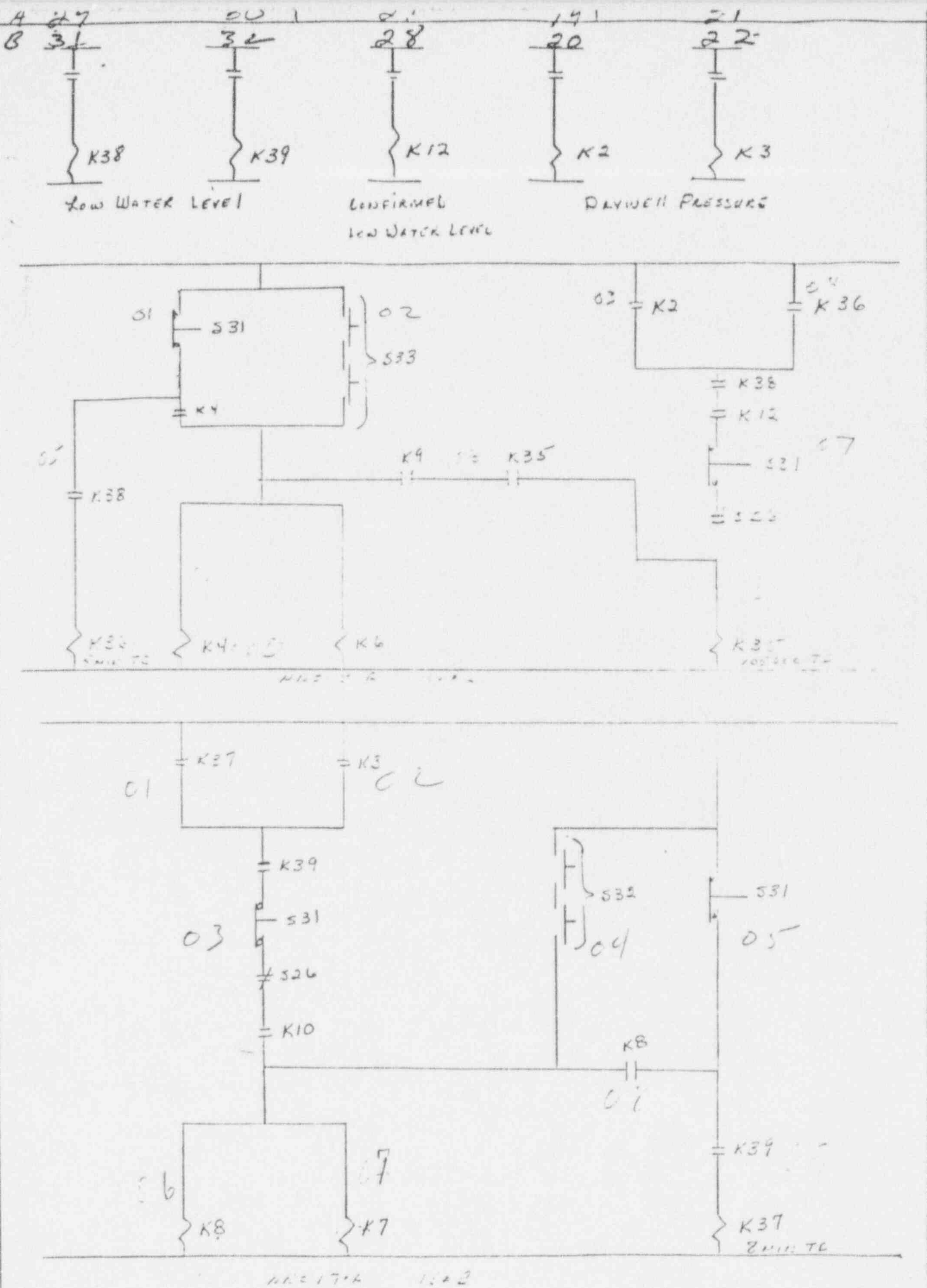
FIGURE B.X.1 ADS/PRESSURE RELIEF SYSTEM SIMPLIFIED DRAWING

Figure 4.1-1 Simplified Diagram of ADS/Relief System



B.X.2 ADS Control Simplified Diagram

Figure 4.1-2 Simplified Diagram of ADS Acutation System

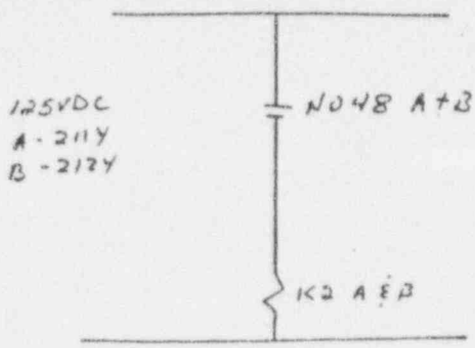


A
B
31
32
28
20
22
K38
K39
K12
K2
K3
Low Water Level
Confirmed Low Water Level
Drywell Pressure
01
S31
02
S33
K4
K38
K9
K35
K2
K36
K12
S21
K4
K6
01
K37
K3
K39
S31
03
S26
K10
S32
04
05
K8
K7
K37
2 min TC

B.X.3

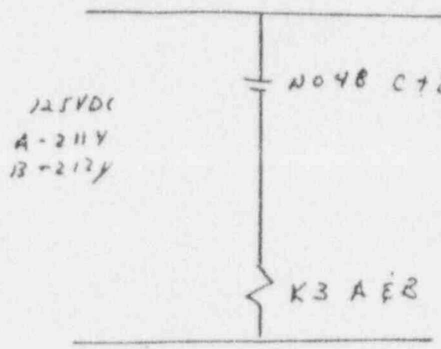
Figure 4.1-3 Schematics of ADS Actuation Logic Circuitry - I

Hi Dry Well Press (A & B)



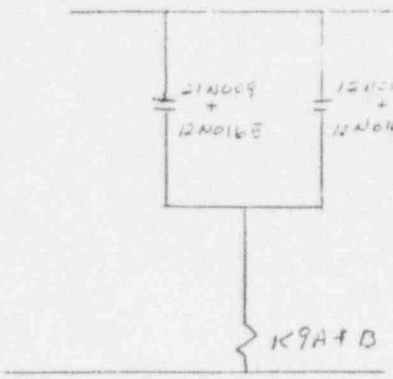
A = 19
B = 20

H. Dry Well Press (A & B)



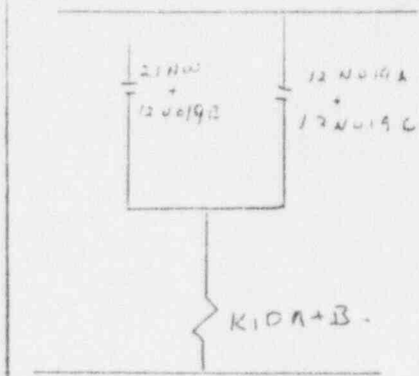
A = 21
B = 22

RHR Pump Running (A & B)



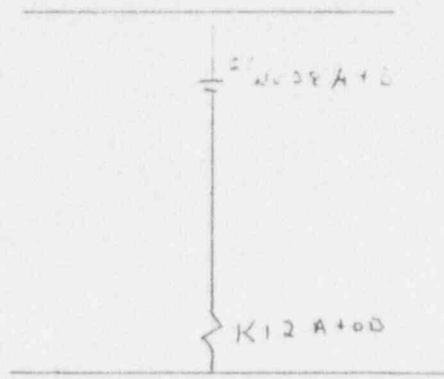
A = 23
B = 24

RHR Pump Running (C & D)



A = 25
B = 26

RX lo lo Water level (A & B)



A = 27
B = 28

B.X.4

Figure 4.1-4 Schematics of ADS Actuation Logic Circuitry - II

5.0 HEAT REMOVAL SYSTEMS

5.1. Power Conversion System

5.1.1 System Function

The Power Conversion System (PCS) is designed to produce electrical power from the steam coming from the reactor, condense the steam, demineralize the resulting condensate, and return it to the reactor as feedwater. In terms of this PRA, the only required function of the PCS is the condensation of the steam produced by decay heat coming from the reactor vessel. This function is accomplished by the Main Steam System, the condenser, and their required support systems.

5.1.2 System Description

5.1.2.1 General Design

A simplified schematic of the PCS modeled in this study is shown in Figure 5.1-1.

Flow Path

The steam is conducted from the reactor vessel through four main steam lines (MSL). The MSLs are designed to conduct steam from the reactor vessel to the turbine over the full range of power operation. There is a steam flow restrictor and an air-operated primary inboard main steam isolation valve (MSIV) on each MSL that the steam must flow through before reaching the containment wall. Safety/relief valves are incorporated into the system as tapoffs on the MSLs upstream of the flow restrictors. These valves relieve pressure to the suppression pool, where the steam can be condensed.

On the other side of the containment wall is the steam tunnel, acting as an interface between the containment and the turbine building. Before passing through the steam tunnel the steam must flow through air-operated outboard main steam isolation valves, one on each MSL, on its way to the turbine. The four main steam lines all pass through the steam tunnel to an equalizing header in the turbine building. From the equalizing header the main steam is conducted to equipment requiring steam for operation and ultimately is transported to the main condenser.

During normal power operation, the steam is used to drive the main turbine and the turbine-driven feedwater pumps and as a heat source for the second stage feedwater heaters and other auxiliary equipment. In addition to these steam loads, there is a block of five turbine bypass valves capable of passing 25% of the rated flow to the condenser. For this study, the flow path through the turbine bypass valves is the major interest since, for most of the accidents, the main turbine will be tripped and this will be the only flow path available. The flow path from the main steam supply headers to the turbine-driven feedwater pumps is also required for the Feedwater System (Section 2.1).

During normal plant operation, steam expanding through the low-pressure segment of the main turbine is directed downward into the single-shell condenser through exhaust openings in the bottom of the turbine casings and is condensed. The condenser also serves as a heat sink for several other flows, such as exhaust steam from the feed pump turbines, cascading heater drains, feedwater heater shell operating vents, and condensate pump suction vents.

Other flows, occurring periodically or continuously, originate from the minimum recirculation flows of the reactor feed pumps, condensate booster pumps, and condensate pumps, feedwater line startup flushing, turbine equipment clean drains, low-point drains deaerating steam, condensate makeup, etc. During transient conditions the condenser receives turbine bypass steam and feedwater heater and drain tank high-level dumps. These drain tanks include the moisture separator, reheater, and feedwater heater drain tanks. The condenser also is designed to receive relief valve discharges from the PCS equipment.

The condenser is cooled by the Circulating Water System (CWS) that removes the heat rejected from the condenser. The Circulating Water System consists of three, high volume, low pressure pumps and associated piping that provide cooling water continuously to the main condenser. Each CWS pump takes a suction from the cooling water lake and discharges into a common pipe, which directs the circulating water to the main condenser. As the cooling water passes through the condenser tubes, it absorbs the latent heat of vaporization from the condensing steam. The warmed circulating water passes out of the turbine building and is returned to the lake via a discharge canal.

Condenser vacuum is maintained by condensing steam and the Main Condenser Evacuation System. This system removes noncondensible gases from air inleakage and disassociation products originating in the reactor and discharges them to the Off-Gas System.

The Turbine Gland Sealing System helps prevent air inleakage into or radioactive steam leakage out of the turbine and condenser.

Component Descriptions

The main steam piping consists of four 26-inch diameter lines from the outermost main steamline isolation valves to the 36-inch diameter main steam equalizing header and four 28-inch diameter lines from this header to the main turbine stop valves. The use of four main steamlines and the equalizing header permits testing of the turbine stop valves and MSIVs during station operation.

A main steamline flow restrictor is provided on each of the four main steamlines. It is designed to minimize the differential pressure across the reactor core and to limit the loss of coolant from the reactor vessel following a steamline rupture outside the primary containment. The action prevents reactor vessel water level from decreasing below the level of the core within the time required to close the main steamline isolation valves. The main steamline flow restrictor is also designed to withstand the maximum pressure difference (1375 psid) expected across the restrictor, following the complete severance of a main steamline. It limits the coolant blowdown rate to the choke flow rate of 7.12 x 106 lbm/hr. Each restrictor is a complete assembly welded in the main steamline between the reactor vessel and the inboard main steamline isolation valve, downstream of the main steamline safety/relief valves. The restrictor assembly consists of a venturi type nozzle insert welded into the main steamline.

The purpose of the MSIVs is to limit the release of radioactive material by isolating the nuclear system process barrier and the primary containment barrier, and to limit the loss of reactor water inventory in the event of a major steamline break outside the primary containment. The MSIVs are designed to isolate the steam flow in sufficient time under these conditions to limit the release of reactor coolant and radioactive materials to within established limits, yet the valves close slowly enough so that the design limits of the nuclear steam supply system are not exceeded.

Two MSIVs are welded in a horizontal run of piping in each of the four main steamlines, with one valve inside, as close as possible to the primary containment barrier and the other valve just outside the barrier. The inboard/outboard MSIVs use separate energy sources for operation in order to allow independent closing capability. The valves are designed to close despite a single control or valve failure. The isolation valves use local stored energy (i.e., springs and/or compressed air) to provide closing capability without reliance on electrical power, and are designed to isolate during and after seismic (earthquake) loading.

Two 18-inch diameter lines from the main steam equalizing header provide steam for the second stage reheaters, feedwater pump turbines, and other auxiliary equipment. Each main steam auxiliary supply header is supplied with a motor-operated shutoff valve.

The two 18-inch diameter lines from the main steam equalizing header also supply steam to the turbine bypass valve manifold. The turbine bypass valve manifold is connected to the condenser by five 12-inch-diameter lines.

The turbine bypass system consists of multiple hydraulically operated control valves mounted on a valve manifold. These valves are operated automatically by the turbine electrohydraulic control system following a turbine trip. The manifold is connected to the main steamlines upstream of the turbine main stop valves. The bypass valve outlet manifold is piped to the main condenser through five separate pressure breakdown assemblies. Each assembly reduces pressure by successive throttlings through a series of multiple orifice plates. Each of the five condenser nozzles is designed for a flow of 710,000 lbm/hr at an inlet pressure of 250 psig.

The main condenser is a single pass, twin bank, divided water box, surface condenser. Each bank of tubes has upper and lower tube bundles. It is divided into three latitudinal compartments by two divider plates or tube sheets. The condenser hotwell has horizontal and vertical baffles to ensure a normal retention of a two-minute duration of all condensate from the time it enters the hotwell until it is removed by the condensate pumps. Condensate is retained in the main condenser for a minimum of two minutes to permit radioactive decay before the condensate enters the condensate system.

The condenser is designed to handle 7.6 x 106 lbm/hr total turbine exhaust steam and to remove 7.34 x 109 btu/hr heat load. The surface area of the main condenser is 950,000 ft^2 with a shell design pressure capable of pressures between 30 inches of mercury absolute vacuum and 15 psig. Circulating water, flowing through the condenser tubes at a rate of 617,000 gpm (full capacity), will experience a 24.1F rise across the condenser.

Three circulating water pumps are located in the Lake Screen House, and are used during main condenser operation. The pumps are vertically mounted, mixed flow volute pumps, each capable of providing 205,500 gpm flow to the main condenser. Each pump is fitted with an eight-inch recirculation line that discharges a minimum flow to the suction forebay to limit damaging hydraulic forces to the pump and associated piping during the pump start sequence.

The CWS pumps take suction from a forebay that includes bar racks and traveling screens. The bar racks are essentially slanted bars used to screen rough debris from the incoming lake water. The traveling screens consist of a continuous belt of screen baskets that remove smaller debris from the lake water after it has passed through the bar racks. The screen sectioned belt is installed vertically in each forebay. Each screen belt consists of 46 basket sections with 3/8 inch stainless steel wire mesh. The belt is ten feet wide and each basket is approximately 18 inches high.

The Main Condenser Evacuation System consists of two 100% capacity, twin-element, two-stage, steam jet air ejector (SJAE) units, complete with condensers. The SJAEs are driven by main steam reduced in pressure to 200 psig by an automatic steam-pressure-reducing valve station. The first stage draws gases from the main condenser, mixes it with steam, and exhausts the gas-steam mixture to the SJAE condenser. The condenser (cooled by Condensate System flow) condenses the steam leaving the noncondensible gases. The second stage of the SJAE then draws the noncondensibles from the SJAE condenser. The second stage is non-condensing and discharges the gas-steam mixture directly to the Off-Gas System.

The Turbine Gland Sealing System consists of a sealing steam evaporator, two 100% capacity gland steam condensers, and associated equipment. The sealing steam evaporator are used to produce clean nonradioactive steam from condensate supplied by the Condensate System. Main steam is used to evaporate the condensate. This steam flows through the gland seals to the gland steam condenser where it is condensed. Non-condensable gases that have leaked into the sealing steam are drawn off by two exhaust blowers and discharged to the station stack.

5.1.2.2 System Interfaces

A failure modes and effects analysis of the PCS indicating the support system interfaces is shown in Table 5.1-1. The PCS requires operation of the main turbine Electrohydraulic Control (EHC) System and the Circulating Water System. The system interfaces for both systems are listed below since they were included in the PCS fault tree. The support system interfaces are discussed below.

Shared Components

The PCS requires that the main condenser be available for steam condensation.

The main condenser is required to supply condensate to the condensate pumps.

The feedwater turbine-driven pumps require that at least one MSIV be open for transportation of steam to the pump turbines.

Electrical

The MSIV solenoids require power from both divisions of the Class 1E electrical power system. One of two solenoids on each inboard and outboard MSIV is powered by 120 VAC RPS Bus A. The other solenoids are powered by RPS Bus B. MSIV closure can occur if control power to actuation circuits is lost.

The circulating water pumps are powered by the normal electrical power system 4160 VAC buses 242X (Pump 2CW01PB) and 241X (Pumps 2CW01PA and 2CW01PC). The CWS pumps are equipped with synchronous motors that require excitation. The excitation power is provided by normal power system 480 VAC MCCs 232Y-1 (2CW01PB) and 231Y-1 (Pumps 2CW01PA and 2CW01PC).

The turbine EHC system requires power for both valves and pumps. The two pumps require power from normal electrical 480 VAC load centers 231A and 232A. The control valves for the turbine bypass valves all are powered from 1E 480 VAC MCC 236Y-3 and require control power from 125 VDC bus 212X.

Actuation

The MSIV isolation logic is powered by RPS Buses A and B. Associated logic is powered by 125 VDC buses 211Y and 212Y and 1E 480 VAC MCCs 236X-2 and 235X-3.

Control

Opening and closing of the MSIVs is accomplished by pneumatic actuators. The drywell pneumatic system provides nitrogen to the inboard MSIVs while the instrument air system provides air to the outboard MSIVs. Opening of the turbine bypass valves requires operation of the turbine EHC system.

Component Cooling

The main condenser requires operation of the Circulating Water System for condensation of steam from the reactor vessel. Operation of the SJAEs and the Turbine Gland Sealing System are also required to maintain condenser vacuum.

Room Cooling

No components in the PCS require room cooling.

5.1.2.3 Instrumentation and Control

System Actuation

The PCS is normally in operation during power operation. Following closure of the main turbine stop valves, the turbine EHC system will open the turbine bypass valves to provide a flow path to the condenser. For some transients, MSIV closure will occur directly or indirectly. The MSIVs close on any one of the following Primary Containment Isolation System (PCIS) signals:

a. Reactor water level (Level 1)
b. Main steam line high flow
c. Main steam line low pressure
d. Main condenser low vacuum
e. Main steam line high radiation
f. Main steam line tunnel high temperature or high area vent differential temperature

During normal plant operation, the isolation control system sensors and trip controls that are essential to safety are energized. When abnormal conditions are sensed, trip channel sensor contacts open causing contacts in the trip logic to open and thereby initiating isolation. Loss of both RPS bus power supplies also initiates isolation.

For the main steamline isolation valve control, four channels are provided for each measured variable. One channel of each variable is connected to a particular logic in order to maintain channel independence and separation. Logic A is shown in Figure 5.1-2. One output of the inboard logic actuator is used to control one solenoid of the inboard and outboard valves of all four main steamlines, and one output of the outboard logic actuator is used to control the other solenoid of both inboard and outboard valves for all four main steamlines.

Each main steamline isolation valve is fitted with two control solenoids. For each valve to close automatically, both of its solenoids must be deenergized. Each solenoid receives inputs from two logics, and a signal from either can cause deenergization of the solenoid. The inboard MSIV logic is shown in Figure 5.1-3.

The MSIVs can be reopened once the trip signal clears by turning the MSIV control switches to the "CLOSE" position and pushing the inboard and outboard reset buttons.

The turbine bypass valves are automatically opened by the EHC if the main turbine control or stop valves cannot pass the generated steam. The main turbine stop valves close following a turbine trip. The bypass valves automatically trip closed whenever the vacuum in the main condenser falls below approximately 23 inches Hg abs. or upon loss of the turbine EHC system.

The bypass valves can be opened manually from the control room.

Component Control

Turbine bypass valve control is provided by the turbine EHC system. As indicated in Figure 5.1-4, a pressure control unit develops a control signal representing nuclear boiler steam flow demand. It provides a fast and controlled response to pressure and flow changes and to pressure setpoint changes over the entire operating range.

The process input is turbine throttle pressure measured by redundant pressure transducers. In order to maintain adequate pressure control during turbine stop valve testing, the transducers sense pressure at a pressure averaging manifold. The two pressure inputs are compared with a desired throttle pressure setpoint producing pressure error signals. The desired throttle pressure setpoint can be varied by operating a motor driven potentiometer using an increase/decrease pushbutton. The motor speed limits the rate of setpoint change to 1 psi/second.

The two identical pressure regulators units are redundant and both are capable of providing adequate pressure control response. To insure positive control by one regulator, a +10 psi bias is normally placed on the "B" regulator.

Regulator outputs are sent to a high value gate (HVG) where the error signal calling for the more open control valve position is passed on. Normally the control valve that has been biased will have the smallest error signal and it will be stopped at the HVG.

The pressure error signal leaving the HVG is converted into a percent steam flow demand, which will be related to the pressure error by a gain unit as shown in Figure 5.1-3.

The output of the gain unit is sent to both a summing junction and a low value gate (LVG) called the pressure load gate. At the summing junction, the steam flow demand signal is then compared to the turbine control valve signal equivalent to the turbine steam flow. If steam flow produced exceeds turbine steam flow, the summing junction output represents a bypass valve demand. A small close bias is added to insure bypass valves are positively closed during normal operation.

A high value gate compares the summing junction output with an input from a bypass jack. The bypass jack can be used during reactor shutdown or cooldown when it may be desirable to open a bypass valve a small amount for cooling purposes.

From the high value gate the bypass valve steam demand passes to the low value gate which serves two functions:

1) Prevents opening bypass valves when condenser vacuum is low (7" hg vacuum) to keep from overpressurizing the condenser.

2) Prevents concurrent opening of the bypass and control valves to a value greater than that permitted by the maximum combined flow limiter.

The output of the LVG is a bypass valve demand signal and is sent to the bypass valve flow control unit.

The maximum combined flow limiter is an adjustable potentiometer which places an upper bound on the total turbine and bypass steam flow demand. This prevents an excessively fast blowdown in the event of a large upscale demand signal failure. During power operation the limiter is set 5% above the load limit to keep it from limiting during normal pressure transients at maximum power conditions.

<u>Instrumentation</u>

The PCS contains instrumentation to monitor and shut down the system if required. Temperature, pressure, flow, and radiation sensing elements are used throughout the PCS for indication in the control room and also to initiate alarms and protective functions. In addition to the protective signals that isolate the MSIVs, the PCS generates reactor scram signals on main steamline high radiation, MSIV closure, and main turbine stop valve closure.

Indication is provided in the control room for the MSIV position. In addition annunciation is provided for the individual isolation signals.

5.1.2.4 Operator Actions

Operation of the PCS for decay heat removal may require operator actions. Specifically, if the MSIVs close as a consequence of an initiating event, the operator is directed to reopen them if possible.

5.1.2.5 Technical Specifications

There are several technical specifications applicable to the PCS which address Limiting Conditions for Operation and Surveillance Requirements.

Limiting Condition for Operation

Technical Specification 3.4.7 describes the limiting condition for operation applicable to the MSIVs. During power operation, two MSIVs per main steam line must be operable. With one or more MSIVs inoperable: maintain at least one MSIV operable in each affected main steam line that is open and within eight hours either restore the inoperable valve(s) to operable status or isolate the affected main steam line by use of a deactivated MSIV in the closed position. Otherwise, be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

Technical Specification 3.7.10 describes the limiting condition for operation applicable to the main turbine bypass valves. During power operation, the main turbine bypass system must be operable or be restored to operable within two hours. Otherwise the thermal power of the reactor must be reduced to less than 25% of the rated thermal power within the next four hours.

Surveillance Requirements

Technical Specification 4.7.10 describes the surveillance requirements for the turbine bypass system. According to this specification, each turbine bypass valve must be completely cycled once every seven days. Every 18 months, a system functional test that includes simulated automatic actuation must be performed to demonstrate that each valve actuates to its correct position within 200 milliseconds.

5.1.2.6 Test

The tests that can affect the operability of the PCs to remove decay heat are summarized in Table 5.1-2. These tests are all related to the MSIV isolation actuation circuits. Calibration or functional testing of each circuit results in deenergizing one or two solenoids on each MSIV. Spurious failure of another channel during this test will result in MSIV closure.

5.1.2.7 Maintenance

No scheduled maintenance which disables components while the plant is at power is allowed. Unscheduled maintenance is allowed within the technical specification limitations. However, no unscheduled maintenance which would affect the availability of the PCS as a decay heat removal system was identified.

5.1.3 System Operation

5.1.3.1 Normal Operation

During power operation, the Power Conversion System uses all the steam produced in the reactor to generate electricity. The MSIVs are open, the main condenser is functioning, the EHC system is controlling the steam flow to the condenser, and the Circulating Water System is removing heat from the condenser. The Turbine Gland Sealing System is operating to prevent inleakage of air into the condenser and the Main Steam Evacuation System is functioning to remove noncondensible gases.

5.1.3.2 Abnormal Operation

Following a turbine trip, the main turbine stop valves close and the EHC system responds by opening the turbine bypass valves. Depending on the transient initiator, the MSIVs may close. Manual reopening of the MSIVs thus may be required. The Circulating Water System, Turbine Gland Sealing System, and Main Condenser Evacuation System must continue to operate.

5.1.4 System Fault Tree

5.1.4.1 Description

A simplified diagram of the PCS indicating only the mechanical components included in the PCS fault tree is shown in Figure 5.1-5. The fault tree includes the EHC system and the circulating water system.

5.1.4.2 Success/Failure Criteria

Successful operation of the PCS following a turbine trip requires opening of one of five turbine bypass valves to conduct steam to the condenser. Only one of four main steam lines is required to remain open. In addition, one of three Circulating Water System loops is required to operated to remove heat from the condenser and the Main Condenser Evacuation System and the Turbine Gland Sealing System are required to maintain condenser vacuum. The failure of the PCS will occur if one of the following occurs:

1) All four main steam lines close. Closure of each main steam line will occur if one of two MSIVs close.

2) MSIV closure will occur if a one-out-of-two twice isolation logic is met.

3) All five turbine bypass valves fail to open or remain open.

4) The EHC system fails.

5) Loss of condenser vacuum occurs due to failure of the Main Condenser Evacuation System or the Turbine Gland Sealing System.

6) All three circulating Water System loops fail resulting in loss of condenser vacuum.

The top event of the PCS fault tree is the following:

FAILURE OF THE PCS TO CONDENSE STEAM WITH 1-OF-5 BYPASS VALVES AND 1-OF-4 MAIN STEAM LINES"

5.1.4.3 Assumptions

In addition to the general assumptions regarding fault tree development (listed at the beginning of this volume), the following assumptions specific to the PCS system were made:

1) A rupture of any of the main steam lines or the equalization header was assumed to result in failure of the PCS. However, ruptures in some locations can be isolated (a recovery action).

2) The steam paths to the turbine driven feedwater pumps, off-gas reheaters, steam-jet air ejectors, and second stage reheaters were not modeled. These paths would provide redundant pathways to the condenser.

3) The main steam stop valves were assumed close for all initiators. The turbine bypass system was thus assumed to be the only pathway to the condenser.

4) The Main Condenser Evacuation System and the Turbine Gland Sealing System were treated as undeveloped events. Failure of either system would result in loss of condenser vacuum and subsequent MSIV closure.

5) Operation of one-of-three Circulating Water System pumps was assumed sufficient to condense steam generated by decay heat and thus maintain condenser vacuum.

6) The gravity-feed gland water system for the CWS pumps was not developed in the fault tree.

7) Failure to automatically start the redundant EHC hydraulic pump was not developed.

5.1.5 References

1) FSAR

System Descriptions	Sections 10.1 - 10.4.4
Instrumentation	Section 7.3.1.1.2
Technical Specification	Limiting Conditions for Operation, Sections 3.3.2, 3.4.7, and 3.7.10 Surveillance Requirements, Sections 4.3.2.1 - 4.3.2.3, 4.4.7, and 4.7.10

2) Operator Training Manual	Chapters 21, 25, 26, and 33
3) Drawings	P&IDs: M116, M63, and M2116, M-81 I&Cs: IE-2-4203AA-4203ZH, IE-2-4216AA, IE-2-4224AA-4224AF, IE-2-4232AA-4232AQ General Arrangement: M-204, M-206, M-316, M-318, M-368 M-376, M-388, M-398, M-406, M-408, M-541, M-542, M-545, M-561, M-562, M-580, & M-581
4) Procedures	LIS-MS-01 LIS-MS-02 LIS-MS-03 LIS-MS-06 LIS-MS-204 LIS-MS-205 LIS-MS-404 LIS-MS-405

Table 5.1-1 Power Conversion System Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
Turbine EHC System	2B21-MSBPV1	Hydraulic Operated Valve	Closed		Loss of one of five turbine bypass lines	Loss of main turbine bypass (all five lines)
	2B21-MSBPV2	Hydraulic Operated Valve	Closed		Loss of one of five turbine bypass lines	
	2B21-MSBPV3	Hydraulic Operated Valve	Closed		Loss of one of five turbine bypass lines	
	2B21-MSBPV4	Hydraulic Operated Valve	Closed		Loss of one of five turbine bypass lines	
	2B21-MSBPV5	Hydraulic Operated Valve	Closed		Loss of one of five turbine bypass lines	
480 VAC MCC 236X-2	2B21-F418A	Motor Operated Valve	Fail as is (open)	Loss of valve indication lights	No effect	No effect
	2B21-F418B	Motor Operated Valve	Fail as is (open)	Loss of valve indication lights	No effect	
480 VAC MCC 232B-1	2B21-F422A	Motor Operated Valve	Fail as is (open)	Loss of valve indication lights	No effect	No effect
480 VAC MCC 232Y-2	2B21-F422B	Motor Operated Valve	Fail as is (open)	Loss of valve indication lights	No effect	No effect

Table 5.1-1 Power Conversion System Support Systems Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
Instrument Air	2B21-F028A	Air Operated Valve	Closed	Position indication	Loss of redundant air supply required to keep MSIV open. Local accumulator air supply assumed to leak off. MSIV closes.	Loss of redundant air supply required to keep all outboard MSIVs open. All outboard MSIVs assumed to close. All four main steam lines shut.
	2B21-F028B	Air Operated Valve	Closed	Position indication	Loss of redundant air supply required to keep MSIV open. Local accumulator air supply assumed to leak off. MSIV closes.	
	2B21-F028C	Air Operated Valve	Closed	Position indication	Loss of redundant air supply required to keep MSIV open. Local accumulator air supply assumed to leak off. MSIV closes.	
	2B21-F028D	Air Operated Valve	Closed	Position indication	Loss of redundant air supply required to keep MSIV open. Local accumulator air supply assumed to leak off. MSIV closes.	
120 VAC RPS Bus B	2B21-F028A	Air Operated Valve Solenoid	Closed	Loss of solenoid indication light	Closure of one of two solenoids on the MSIV	Closure of one of two solenoids on each MSIV - No effect
	2B21-F028B	Air Operated Valve Solenoid	Closed	Loss of solenoid indication light	Closure of one of two solenoids on the MSIV	
	2B21-F028C	Air Operated Valve Solenoid	Closed	Loss of solenoid indication light	Closure of one of two solenoids on the MSIV	
	2B21-F028D	Air Operated Valve Solenoid	Closed	Loss of solenoid indication light	Closure of one of two solenoids on the MSIV	

Table 5.1-1 Power Conversion System Support Systems Interface FMEA (Continued)

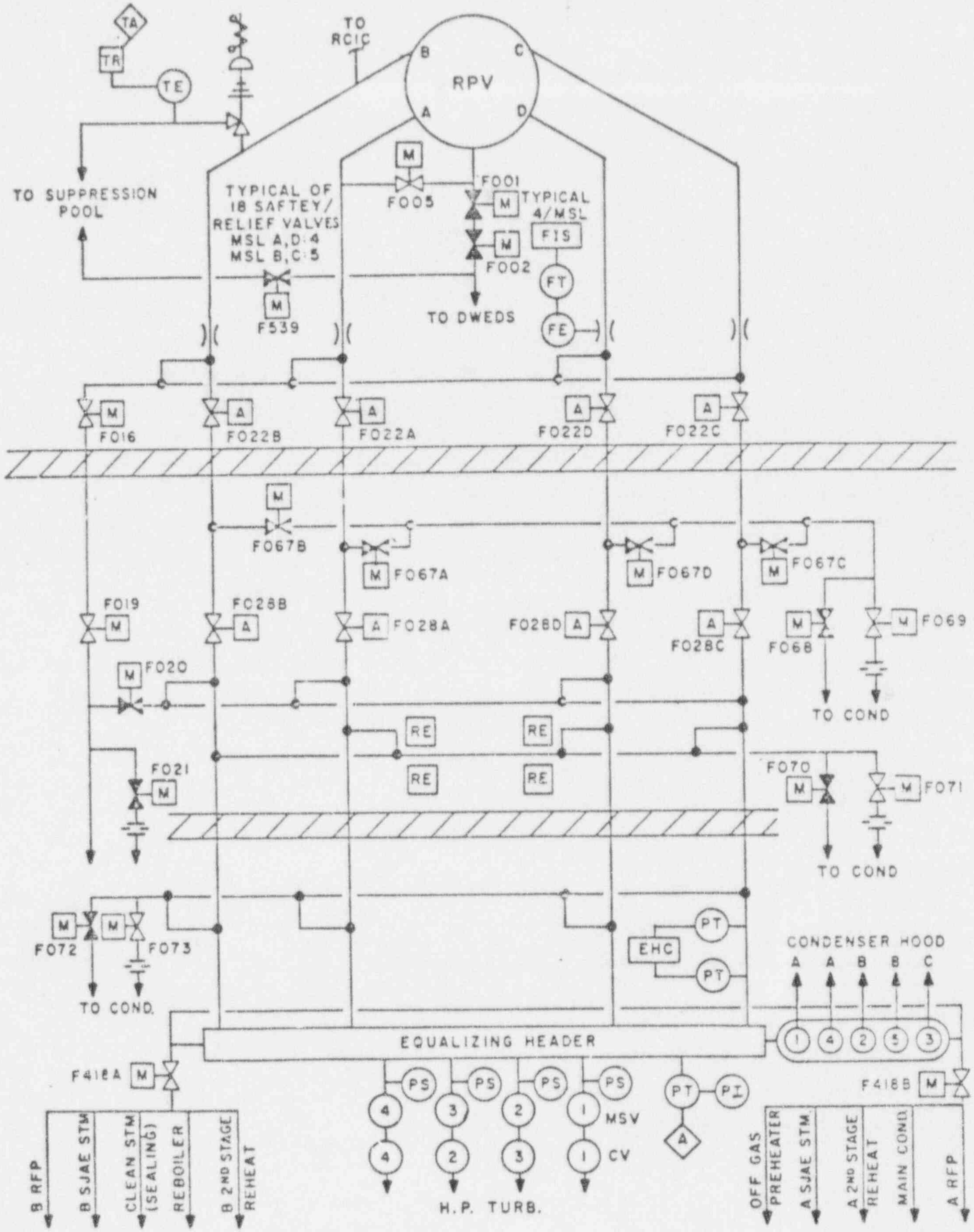
Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
Drywell Air	2B21-F022A	Air Operated Valve	Closed	Position indication	Loss of redundant air supply required to keep MSIV open. Local supply in accumulator assumed to leak off. MSIV closes.	Loss of redundant air supply required to keep all inboard MSIVs open. All inboard MSIVS assumed to close. All four main steam lines shut.
	2B21-F022B	Air Operated Valve	Closed	Position indication	Loss of redundant air supply required to keep MSIV open. Local supply in accumulator assumed to leak off. MSIV closes.	
	2B21-F022C	Air Operated Valve	Closed	Position indication	Loss of redundant air supply required to keep MSIV open. Local supply in accumulator assumed to leak off. MSIV closes.	
	2B21-F022D	Air Operated Valve	Closed	Position indication	Loss of redundant air supply required to keep MSIV open. Local supply in accumulator assumed to leak off. MSIV closes.	
120 VAC RPS Bus A	2B21-F022A	Air Operated Valve Solenoid	Closed	Loss of solenoid indicating light	Close one of two solenoids on the MSIV	Closure of one of two solenoids on each MSIV - No Effect
	2B21-F022B	Air Operated Valve Solenoid	Closed	Loss of solenoid indicating lights	Close one of two solenoids on the MSIV	
	2B21-F022C	Air Operated Valve Solenoid	Closed	Loss of solenoid indicating lights	Close one of two solenoids on the MSIV	
	2B21-F022D	Air Operated Valve Solenoid	Closed	Loss of solenoid indicating lights	Close one of two solenoids on the MSIV	

Table 5.1-1 Power Conversion System Support Systems Interface FMEA (Concluded)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
Circulating Water System	Main Condenser	Condenser	Loss of cooling	Annunciated	Loss of condenser vacuum	Closure of MSIVs and turbine bypass valves - fails system.
Main Condenser Evacuation System	Main Condenser	Condenser	Loss of vacuum	Annunciated	Loss of condenser vacuum	Closure of MSIVs and turbine bypass valves - fails system.
Turbine Gland Sealing System	Main Condenser	Condenser	Loss of vacuum	Instrumentation	Loss of condenser vacuum	Closure of MSIVs and turbine bypass valves - fails system.

Table 5.1-2 Power Conversion System Test Summary

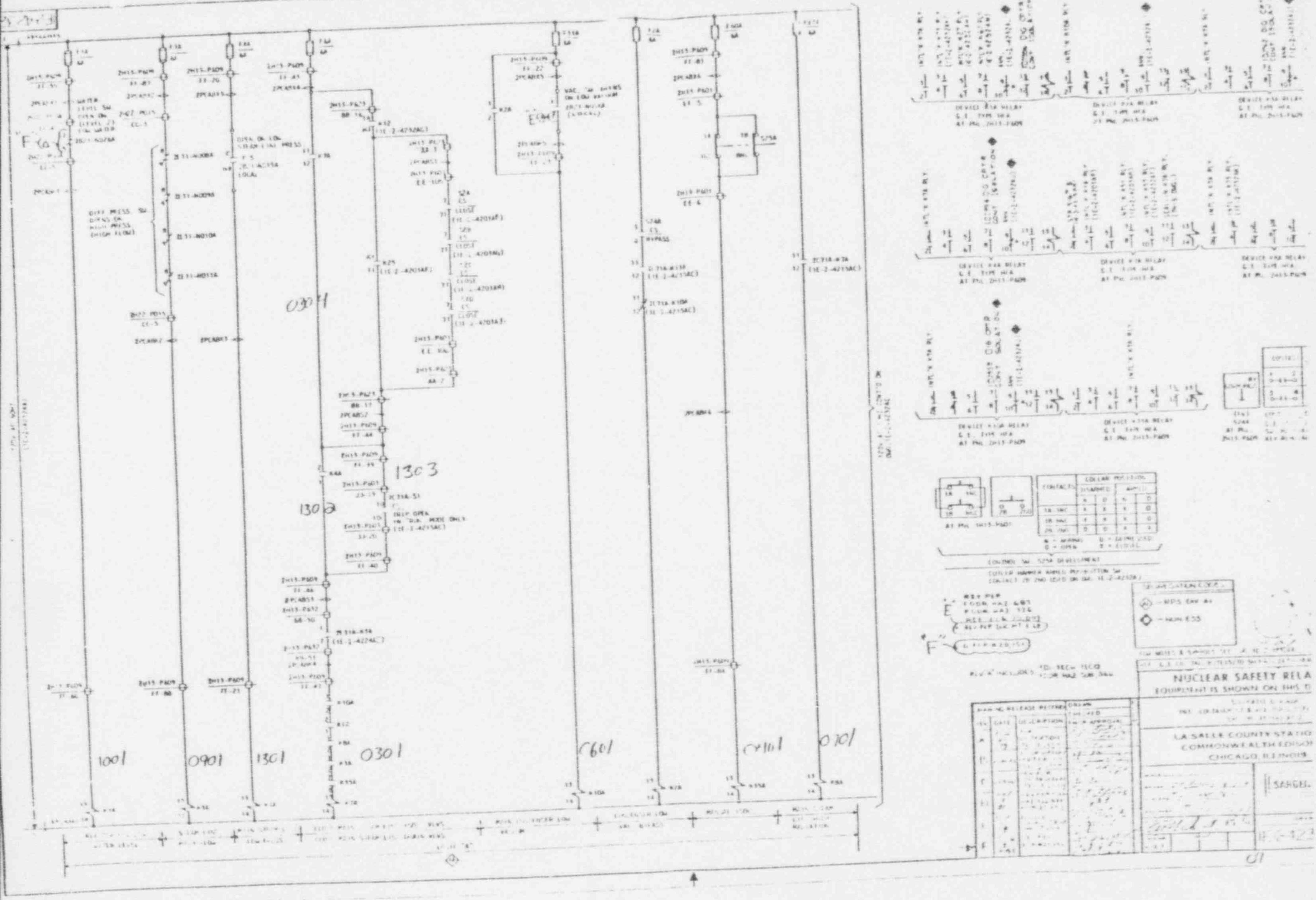
Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency (Mo)	Test Outage (Hr)	Component/Subsystem Alignment/Operability Verification Frequency
LIS-MS-01	Calibration	MSIVs	Solenoids	Yes	No	3	4	Checked during procedure only
	Functional	MSIVs	Solenoids	Yes	No	1	2	Checked during procedure only
LIS-MS-02	Calibration	MSIVs	Solenoids	Yes	No	18	4	Checked during procedure only
	Functional	MSIVs	Solenoids	Yes	No	1	2	Checked during procedure only
LIS-MS-03	Calibration	MSIVs	Solenoids	Yes	No	18	4	Checked during procedure only
	Functional	MSIVs	Solenoids	Yes	No	1	2	Checked during procedure only
LIS-MS-05	Calibration	MSIVs	Solenoids	Yes	No	3	4	Checked during procedure only
	Functional	MSIVs	Solenoids	Yes	No	1	2	Checked during procedure only
LIS-MS-204	Calibration	MSIVs	Solenoids	Yes	No	18	4	Checked during procedure only
LIS-MS-205	Calibration	MSIVs	Solenoids	Yes	No	18	4	Checked during procedure only
LIS-MS-404	Functional	MSIVs	Solenoids	Yes	No	1	2	Checked during procedure only
LIS-MS-405	Functional	MSIVs	Solenoids	Yes	No	1	2	Checked during procedure only



TA
TR
TE
TO RCIC
RPV
B
C
A
D
TO SUPPRESSION POOL
TYPICAL OF 18 SAFTEY/ RELIEF VALVES MSL A,D:4 MSL B,C:5
M
F005
F001
TYPICAL 4/MSL
FIS
F002
FT
FE
F539
TO DWEDS
F016
F022B
F022A
F022D
F022C
F067B
F067A
F067D
F067C
F019
F028B
F028A
F028D
F028C
F068
F069
F020
RE
TO COND
F021
F070
F071
F072
F073
TO COND.
PT
EHC
CONDENSER HOOD
EQUALIZING HEADER
F418A
F418B
PS
MSV
CV
PI
H.P. TURB.
B RFP
B SJAE STM
CLEAN STM (SEALING)
REBOILER
B 2ND STAGE REHEAT
OFF GAS PREHEATER
A SJAE STM.
A 2ND STAGE REHEAT
MAIN COND.
A RFP

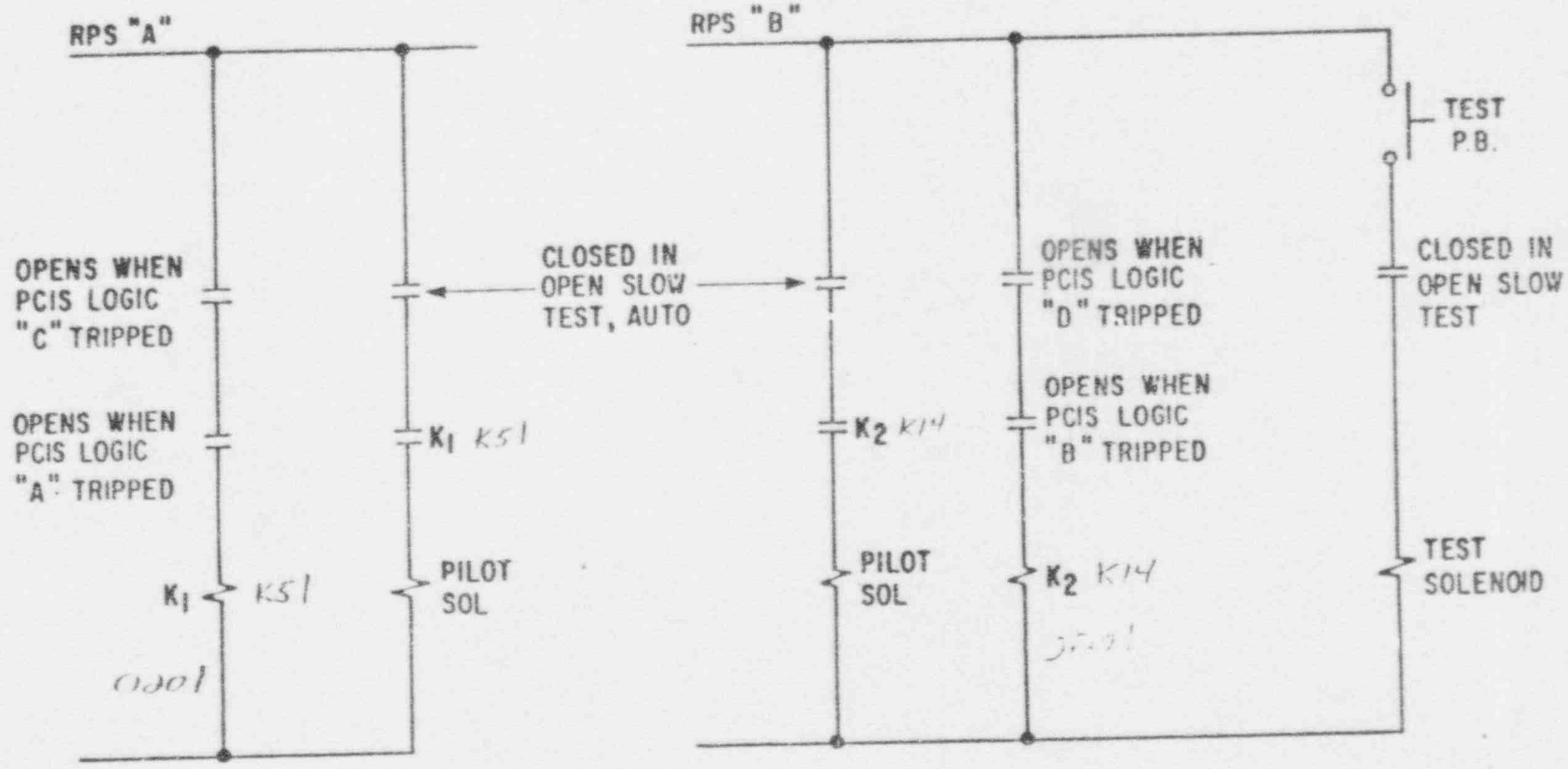
Figure 6.X-1

Figure 5.1-1 Simplified Schematic of the Power Conversion System (PCS)



NUCLEAR SAFETY RELA
EQUIPMENT IS SHOWN ON THIS D
LA SALLE COUNTY STATIO
COMMONWEALTH EDISO
CHICAGO, ILLINOIS
SARGEN
DEVICE K5A RELAY
G.E. TYPE HFA
CONTROL SW. S25A DEVELOPMENT
SEGREGATION CODE
RPS DIV A1
NON ESS
DIFF. PRESS. SW.
1001
0901
1301
0301
0304
1303
1302
C601
0101

Figure 5.1-2 Example MSIV Isolation Logic - Train A



IN BOARD MSIV

B.X-3

Figure 5.1-3 Inboard MSIV Isolation Logic

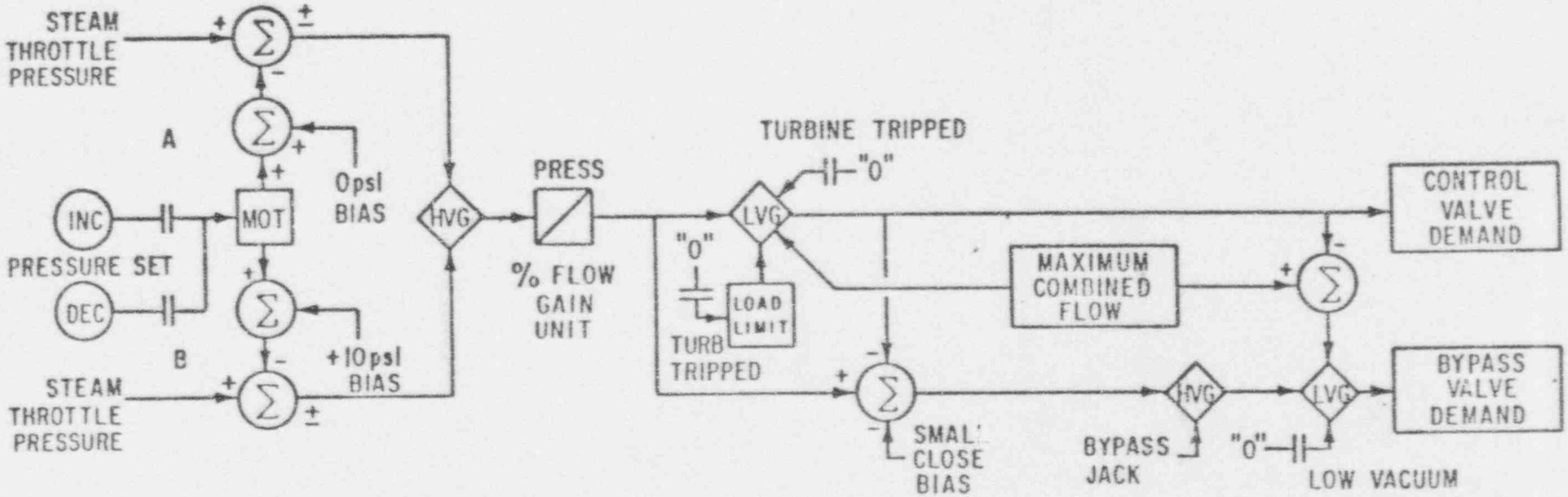


FIGURE 15-4 BYPASS CONTROL UNIT

Figure 5.1-4 Turbine Bypass Control Unit Logic

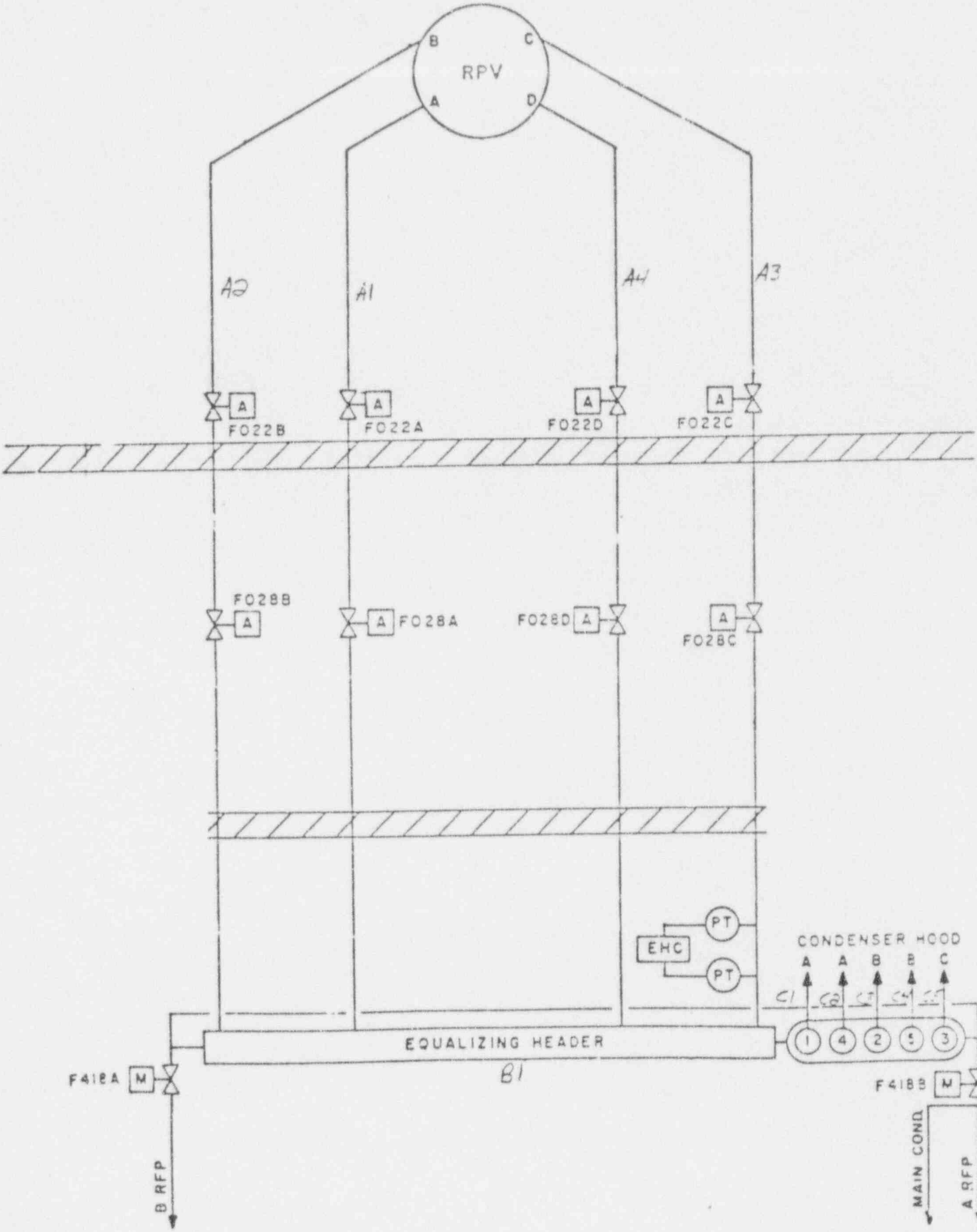

RPV
A
B
C
D
A2
A1
A4
A3
F022B
F022A
F022D
F022C
F028B
F028A
F028D
F028C
EHC
PT
PT
CONDENSER HOOD
A
A
B
B
C
C1
1
4
2
5
3
EQUALIZING HEADER
B1
F418A
F418B
M
B RFP
MAIN COND
A RFP

Figure 6.1-5

Figure 5.1-5 Simplified Schematic of Power Conversion System used for Fault Tree Construction

5.2 Shutdown Cooling Mode of RHR System (SDC)

5.2.1 System Function

The shutdown cooling mode is an integral part of the RHR system. It is operated following a normal reactor shutdown whenever the reactor is taken to a cold shutdown condition. The initial phase of nuclear system cooldown is accomplished by dumping steam from the reactor vessel to the main condenser. When nuclear system temperature has decreased to where the steam supply pressure is not sufficient to maintain the turbine shaft gland seals, vacuum in the main condenser cannot be maintained and the RHR system is placed in the shutdown cooling mode of operation. The shutdown cooling subsystem is able to complete cooldown to 125F within 20 hours after the control rods have been inserted and can maintain the nuclear system at or below 125F for reactor refueling and servicing.

During the initial phase of reactor cooldown, only a portion of RHR system heat exchanger capacity is required for shutdown cooling operation. This leaves the remaining portion of the RHR system with its heat exchanger, associated pumps, and valving available for the LPCI mode. The LPCI mode is shifted to shutdown cooling mode after the reactor is depressurized so the proper cooling rate may be achieved with the lower reactor water inlet temperature.

5.2.2 System Description

5.2.2.1 General Design

The Shutdown Cooling mode of the RHR system consists of two independent fluid trains that take suction from one of the reactor recirculation loops through a common suction line. The water is pumped through the RHR heat exchangers and returned to the recirculation loops via train A or B of the RHR system. The SDC trains are configured from RHR trains A and B, and use the RHR pumps, heat exchangers, and test return lines. Detailed one-line diagrams of the two SDC/RHR trains are shown in Figures 5.2-1 through 5.2-4.

Flow Path

The RHR System is normally aligned for operation in the LPCI mode and retained in standby during normal plant operation. In a normal cooldown or once the core reflood requirements of LPCI are assured in an accident situation, the operator will manually realign either RHR Train A or B to the Shutdown Cooling mode. To do so any other RHR mode of operation must first be terminated by manually closing the appropriate injection/return valve (s) and shutting down the RHR pump in that train. The suppression pool suction MOV (F004A/B) is closed and procedures are initiated to flush the RHR lines and heat exchanger, pre-heat the lines, and startup the CSCS system that provides the RHR heat exchanger, pump seal, and pump room cooling water. For the SDC mode of operation, the common suction line for

RHR loops A and B is in the shape of a 'T' with inboard and outboard SDC isolation MOVs (F009 and F008) in the line from recirculation loop 'A' and an MOV (F006A/B) in the branch to each of the RHR suction lines. The appropriate suction valves are opened and the heat exchanger bypass valve (F048A/B) is opened. Once the RHR pump is started, the Shutdown Cooling discharge isolation valve (F053A/B) is throttled open within 8 seconds. Delaying this throttling action will result in the pump minimum flow bypass valve opening and reactor water level will decrease as coolant is pumped to the suppression pool.

The RHR pumps now take suction from reactor recirculation loop A via a suction line that is common to the RHR A and B train (see Figure 5.2-4). The reactor water is passed through the RHR heat exchangers and subsequently returned to a reactor recirculation loop (A loop for RHR Train A, B loop for Train B). The operator controls the relative flow through and around the heat exchanger by adjusting the heat exchanger bypass valves (F048A/B) and outlet valves (F003A/B).

In RHR loop A, part of the shutdown cooling flow can be diverted through MOV F023 to a spray nozzle in the reactor head. This spray maintains saturated conditions in the reactor vessel head volume by condensing steam being generated by the hot reactor vessel walls and internals. The spray also decreases thermal stratification in the reactor vessel coolant, ensuring that the water level in the reactor vessel can rise. The higher water level provides conduction cooling to more of the mass of metal of the reactor during the reactor cooldown process.

Locations

Most of the RHR Train A components are located in the northwest corner of the reactor building basement. The RHR A Heat Exchanger is enclosed in a cubicle which extends from 694' to the 710' elevation. The shutdown cooling line return MOV (F053A) is located at the 740' elevation just before the line penetrates the primary containment.

The RHR Train B components are predominantly located in the southeast corner of the reactor building basement. The RHR B heat Exchanger is also enclosed in its own cubicle and extends from 694' to the 710' elevation. The train B shutdown cooling line MOV (F053B) is also located at the 740' elevation prior to the point at which the line penetrates the primary containment.

Component Descriptions

The RHR shutdown cooling components common to LPCI trains A and B are described in the LPCI system description in Section 3.3. This includes the RHR pumps and their associated minimum flow lines, the pump discharge lines and their associated check valves, maintenance valves, and water-leg fill systems, and RHR heat exchanger inlet, outlet, and bypass MOV's.

The 18-inch common suction lines off the RHR pump A and pump B suction lines each contain an 18-inch, motor-operated gate valve (2E12-F006A/B). These valves are normally closed when the plant is at full power and interlocked with the suppression pool suction MOVs (F004A/B) in the same train so that both valves cannot be open at the same time. The operator manually opens the F006(A or B) valve from the control room in order to establish SDC suction flow. However, due to the possibility of piping damage if reactor water drains to the suppression pool, the F006A/B valves are interlocked such that they cannot be opened if the isolation MOV in any line to the suppression pool is open. The valves interlocked to the F006A/B valves are the pump suction MOVs (F004A/B), the suppression pool spray MOVs (F027A/B), and the test return line MOVs (F024A/B). The only exception is the minimum flow bypass valve (F064A/B). The common 20-inch 'T' pipe joining the SDC Trains A and B suction lines contains two Shutdown Cooling suction isolation valves (F009 and F008), and a manual maintenance valve.

The outboard suction isolation valve (2E12-F008) is a 20-inch, motor-operated gate valve located outside containment. The valve is normally closed and the LaSalle operating procedures indicate that the MOV feed breaker is normally racked out during plant operations when the valve is to remain closed. This means that the breaker must be locally restored, manually, when the operator wishes to open the F008 valve. The valve is designed to operated with a maximum 150 psid pressure differential.

The inboard suction isolation valve (2E12-F009) is a 20-inch, motor-operated gate valve located inside the drywell. This normally closed valve is designed to operate against a maximum 150 psid pressure differential and is manually activated from the control room. This MOV is normally fed by the 480 VAC MCC 236Y-1, but can also be manually switched to the 480 VAC MCC 235X-1 if the normal power supply is lost.

Also within the containment is a locked-open, 20-inch manual maintenance isolation valve (2E12-F020). It is equipped with a position switch which indicates in the control room.

The RHR Train B side of the suction 'T' is connected by an 18-inch line to the RHR Train C suction (See Figure 5.2-4). This line is normally closed by a locked-closed manual valve (2E12-F067).

The SDC trains each return the cooled reactor water to a different recirculation loop via 12-inch return lines. The return lines each contain an SDC return MOV (F053A/B), a testable check valve, and a manual maintenance valve. The shutdown cooling return valves (2E12-F053A/B) are 12-inch, motor-operated globe valves that are normally closed. The MOVs can be throttled to adjust the shutdown cooling flowrate. The 12-inch testable check valves (2E12-F050A/B) in each SDC return line are located inside the drywell. These valves are provided with air operators to permit exercising and testing during plant operation. Valve position is monitored by indicator lights in the control room. The air actuators cannot prohibit the valve from opening with flow, nor can the actuator open or hold the valve open against any significant differential pressure across it. The 12-inch manually operated, locked-open gate valves (2E12- F090A/B) are located between the recirculation loop and the testable check valve in each SDC line. It is used to isolate the SDC train from the reactor vessel during shutdown maintenance periods. Remote position indicator lights are provided in the control room.

The shutdown cooling return line off the RHR A loop also contains a 6-inch RPV head spray line (See Figure 5.2-1). The line is normally closed by a motor-operated globe valve (2E12-F023). Between this head spray MOV and the reactor vessel are three check valves - one in the RHR system, and two indicated as part of the RCIC injection line.

Train A and B of RHR each contains a heat exchanger. These heat exchangers are of the inverted U-tube type and are located in the northwest and southeast corner cubicles in the reactor building with the pumps. Each heat exchangers' capacity is designed to maintain the suppression pool temperature below 200F after a LOCA with 100F service water. For purposes of this PRA, one heat exchanger is sufficient to perform the function of containment heat removal.

5.2.2.2 System Interfaces

A failure modes and effect analysis (FMEA) of shutdown cooling mode equipment support system interfaces is shown in Table 5.2-1. The support system interfaces are discussed below.

Shared Components

Many of the components in shutdown cooling loops A and B are also used in other RHR configurations - Containment Spray, Low Pressure Coolant Injection, Suppression Pool Cooling, and Steam Condensing. The same RHR pumps, heat exchangers and flow paths are used except that the pump suction, heat exchanger flow control, and injection MOVs for the various modes may be positioned differently. During standby operation the same water-leg pump is used to keep the RHR A and LPCS lines filled, while another pump is dedicated to keeping RHR B and C lines water filled.

Electrical

Both divisions of the Class 1E electrical system provide power to the shutdown cooling loops for operation of the RHR pumps, system MOVs, and system instrumentation and controls. The RHR A pump motor is supplied by the 4160 VAC distribution system from bus 241Y. The Train A MOVs are powered by the 480 VAC MCC 235Y-2 off bus 241Y. The only exceptions are the pump minimum flow bypass valve and the SDC return MOV (F053A) which are powered by 480 VAC MCC 235Y-1.

The RHR B pump motor is supplied by the 4160 VAC distribution system from bus 242Y. Off the 242Y bus, the train B MOVs are powered by the 480 VAC

MCC 236Y-1. The only exception is the SDC return MOV (F053B) which is powered by 480 VAC MCC 235Y-1.

The SDC suction outboard isolation MOV (F008) in the common suction line is powered by the 480 VAC MCC 235X-1. The suction inboard isolation MOV (F009) in the same line is normally powered by the 236Y-1 MCC, but can be manually aligned to the alternate 235X-1 MCC.

The 125 VDC distribution system (Div. 1) supplies power to the RHR A interlock logic circuits and control power for the RHR A pump motor. The Division 2 125 VDC distribution system supplies power to the RHR B interlock logic circuits and also provides control power for the RHR B pump motor.

Actuation

As noted above, the Division 1 and 2 125 VDC distribution system supplies power to the respective RHR interlock logic circuits. Electrical power for actuation of MOVs is provided by a 480/120 VAC transformer for each valve.

Control

As noted above, the Division 1 and 2 125 VDC distribution system supplies the control power for the respective RHR pumps. Control power for the various system MOVs is obtained from 480/120 VAC transformers in the MCCs powering the valve motors.

Component Cooling

The CSCS system provides cooling for both RHR heat exchangers. For long term cooling, this is an essential support system for removing decay heat from the containment.

The CSCS system also cools the RHR pump seals. It must be in operation whenever pumped water temperature exceeds 160F or the seals may fail in as little as 20 seconds. However, failure of the pump seals is not judged to be a fault that prevents the RHR pumps from functioning adequately for the purposes of shutdown cooling.

The RHR pump motors are air-cooled and depend on the ECCS Equipment Area Cooling System to keep the pump cubicle temperature within their design temperature limits (212F).

Room Cooling

The RHR pump motors are air-cooled and depend on the ECCS Equipment Area Cooling System to maintain pump cubicle temperatures within qualification limits. There is an ECCS Equipment Area Cooling System dedicated to cooling the NW cubicle (which contains the RHR A pump) and a separate system dedicated to SE cubicle cooling (containing the RHR B and C pumps).

5.2.2.3 Instrument and Control

System Actuation

The Shutdown Cooling mode of RHR is manually initiated. During a normal shutdown, nuclear system cooldown is accomplished by dumping steam from the reactor vessel to the main condenser. After the steam supply pressure has decreased to where it is no longer sufficient to maintain the turbine shaft gland seals, the main condenser vacuum cannot be maintained and the operator initiates the Shutdown Cooling mode of RHR. When undergoing a normal shutdown, the initiation of SDC is a long process involving considerable operator manipulations. All valve positioning is manually initiated, the RHR lines are flushed and the lines are pre-heated, the CSCS system to the heat exchangers is manually started, and the cooldown rate is manually adjusted by controlling the SDC return MOVs and the heat exchanger outlet and bypass MOVs.

Shutdown Cooling may also be initiated as a means of core heat removal following LPCI core reflood. In this case, the SDC startup procedure may be shortened (line flushing and warm-up may not be needed); however, the operator still realigns the pump suction and discharge paths manually. It should be noted that for the first ten minutes following a LPCI initiation signal most of the pumped water bypasses the heat exchanger because the bypass MOV is interlocked such that it cannot be closed.

The circuit logic diagrams used in the fault tree modeling are shown under the description of the LPCI system in Section 3.3. Since the pumps are the same and much of the circuitry is shared between the different modes of RHR and the LPCS system, all the circuits are shown in one place.

Component Cooling

The operator manually controls the position of the SDC return valves (F053A/B), head spray valve (F023), heat exchangers bypass valves (F048A/B), and heat exchanger outlet valves (F003A/B) in order to establish the desired degree of core cooling.

The operator manually opens (closes) the SDC suction MOVs (F006A/B, F008, & F009) and they do not change positions unless they receive an isolation signal.

The SDC suction isolation (F008 and F009), return (F053A/B), and head spray (F023) valves isolate on the following conditions:

a) High Reactor Pressure 135 psig - sensed at the recirculation pump suction line.

b) High RHR Shutdown Cooling Suction line flow - 3 times normal at 135 psig.

c) High RHR cubicle differential area temperatures.

d) Manual pushbutton (for PCIS) B and/or D depressed at benchboard section of panel 2H13-P601.

e) Reactor Level low at 12.5".

These valves can be manually opened when all of the above conditions are cleared.

Component control descriptions for the RHR pumps, minimum flow bypass MOV's, and water leg pumps are provided in the LPCI system description in Section 3.3.

Instrumentation

Valves

All motor-operated valves have lighted position indicators in the control room. The SDC outboard suction MOV (F008) is normally racked out during normal plant operations when the valve is to remain closed. For any other MOV in the RHR system this would result in loss of the control room indicator lights. However, the F008 indicator lights are powered by a separate 120 VAC supply off the same MCC that powers the valve. Thus, F008 position indication in the control room does not depend on having a closed valve feed breaker.

RHR Pumps

Indicators for each RHR pump in the control room show whether the pump is on, off, or in pull-to-lock. Pump current is also indicated. Two pressure switches are installed in each pump discharge pipeline and linked to control room indicators to indicate that the pumps are operating following an initiation signal. (The same pressure signal is also used in the automatic depressurization system to verify availability of low-pressure core cooling.) Pump and motor bearing temperatures can be monitored using the plant process computer during pump operation.

SDC System Flow

Flow in each RHR pump discharge line is sensed by an orifice-type flow element in the pump discharge lines. Indication of system flow for each train is provided on the RHR panel in the control room. The pump minimum flow bypass valve is positioned according to the indication received from this flow sensor. Flow in the shutdown cooling suction line is sensed by a pressure differential type flow element. Flow indication for this line is provided in the control room and is alarmed at three times normal flow. This flow sensor also provides the system isolation trip for the SDC valves.

Control Room Monitors

1. RHR Hx Water Level	0-100 %
2. RHR Hx Outlet Conductivity	0-10 mho's/cm
3. RHR Hx Temperatures	0-600F
a. Shell side inlet	
b. Shell side outlet	Multipoint recorder
c. Tube side outlet	
4. RHR Hx Inlet Steam Pressure	0-600 psig
5. RHR Hx Service Water side flow element	0-8000 gpm
6. RHR Pump	
a. RHR Discharge piping pressure	0-400 psi
b. RHR Pump flow (Loop)	0-10,000 gpm
c. RHR Pump Amps	0-150 amps
7. RHR Pump Room temperature	
a. Duct	0-300F
b. Area	0-300F
8. Drain Header Conductivity	0-25 mho/cm
9. Reactor Level Fuel Zone	-111" to -311"
10. Leak Detection	
a. Valve Stem Leakage	150-600F
b. Area Leak Detection	0-150F
11. Service Water Effluent Radiation	10-1 to 106 cps

Major Alarms

a. RHR Pump Cubicle Temp Hi - 149F

b. RHR Pump Breaker Closed - Breaker CLosed

c. RHR Pump A, B Flow Above Minimum (>550 gpm) - Alarm at 1500 gpm increasing, resets at 1010 gpm decreasing.

d. RHR Pump A/B Disch Press Hi/Low - 400/55 psig

e. RHR Pump Auto Trip - multiple

f. RHR Pump Cubicle Cooler Fan Auto Trip - Overload

g. LPCI System Actuated - Drywell pressure 1.69 psig, Rx Level -129".

h. LPCI Manual Initiation Pushbutton Armed - PB Armed

i. RHR B/D (A/C) Drywell Press Hi - 1.69 psig

j. RHR B/D (A/C) Reactor Level 1 Low - -129"

k. RHR Equip Area Diff Temp or Ambient Temp Hi (Area - 130 ± 2 F. Diff temp - 30 ± 2 F)

l. RHR Service Water Pump Auto Trip - Overload

m. RHR Service Water Rad Hi - 6 cps

n. RHR Service Water Strainer 1(2) Diff Press Hi - 8 psid, 4 psid after backwash

o. RHR Hx Outlet Conductivity Hi - 10 umho

p. RHR Service Water Sump Level Hi Hi - Alarm 2' 11" below top of sump, reset 5' 10" below top of sump.

q. RHR Hx A/B Discharge Cooling Water Temp Hi - 125F

r. RHR Hx A/B Inlet Water Temp Hi - 400F

5.2.2.4 Operator Actions

The Shutdown Cooling mode of RHR is manually initiated. It is operated following a normal reactor shutdown to cooldown the reactor. It may also be used following LPCI core reflood. In a normal shutdown, the nuclear system is cooled by dumping steam from the reactor vessel to the main condenser. When nuclear system temperature has decreased to where the steam supply pressure is not sufficient to maintain the turbine shaft gland seals, vacuum in the main condenser cannot be maintained and the RHR system is manually placed in the shutdown mode of operation.

The operator first closes the suppression pool suction MOV (F004A/B) and then opens the SDC suction valve for the train being used (F006A/B) and various flush/fill valves to flush the RHR line with condensate water. The operator then realigns several RHR valves, closes the heat exchanger outlet valve, closes the breaker on the SDC outboard suction isolation valve (F008), and opens both SDC suction header isolation valves (F008 and F009) to warm-up the RHR loop. When the entire loop has has reached a temperature of approximately 200F, the operator opens the heat exchanger bypass MOV (F048A/B), starts the CSCS system to the heat exchanger, and starts the associated RHR pump. Within 8 seconds (to prevent reactor water from draining to the suppression pool through an open minimum flow line) the operator throttles open the SDC return line MOV (F053A/B). If plant conditions permit, the reactor recirculation pump in the loop receiving the SDC flow is shutdown.

The operator may then gradually adjust the cooldown rate by throttling open the heat exchanger outlet stop (F003A/B) and throttling closed the heat exchanger bypass stop (F048A/B). At this time, reactor vessel head cooling may be initiated if desired (Train A only) to collapse the reactor steam dome bubble. To do so, the operator throttles open the head spray MOV F053.

The SDC system is manually shutdown when no longer required Technical Specifications.

5.2.2.5 Technical Specification Limitations

There are no Technical Specification Limitations pertaining specifically to the Shutdown Cooling mode of the RHR system because the reactor is shutdown when it is normally in use. However the ECCS Limiting Conditions for Operation (see LPCI Section 3.3.2.5) impact the availability of the major portion of the SDC Trains A and B.

5.2.2.6 Tests

The major tests that impact the SDC mode of RHR are the same as those listed for the LPCi system in Table 3.3-2. The table has been edited to cover only those components affecting SDC (see Table 5.2-2).

Although it is not a test, shiftly surveillance verifies the condition of the RHR pumps and the correct alignment of all MOVs during standby operation. This alignment is such that the RHR trains can rapidly and automatically initiate LPCI when called upon.

5.2.2.7 Maintenance

No scheduled maintenance which disables SDC components while the plant is at power is planned. Unscheduled maintenance is permitted on system components provided applicable safety and radiological administrative controls can be satisfied. Unscheduled maintenance activities possible during plant operation are much the same as those listed for the LPCI system and include:

- o Replacement or repair of actuation and control circuitry

- o Electrical maintenance on motor driven components

- o MOV and pump mechanical maintenance that does not result in a breech of the SDC system boundary.

- o MOV and pump mechanical maintenance that breeches the system boundary when double isolation from reactor pressure/temperature can be achieved. Isolation here is taken to mean an accessible manual valve or a motor- operated valve that can be racked out. It is assumed that check valves do not provide a secure means of isolation. (Note that in the case of the RHR A and B trains double isolation must not only be achieved at the injection line end, but also at the Shutdown Cooling suction line end.)

A summary of unscheduled maintenance acts allowed on the A and B trains of the RHR system while the plant is in full power operation is given the Table 5.2-3. (Only the activities that impact the successful operation of the SDC mode have been included.) The following comments pertain to this table:

- o Although permitted, unscheduled maintenance on check valves and manual valves is not listed on the table because of the significantly lower frequencies of occurrence when compared to MOVs.

- o It is assumed that safety procedures and the requirement for double isolation will result in the RHR pump and the SDC return MOV (F053A/B) being racked out when maintenance on the component involves opening up the RHR line However this is not a significant contributor to system unavailability because RHR pump indication is provided in the control room and checked shiftly. For those components that can be doubly isolated, the most significant possibility of "failure to restore" fault lies with the manual maintenance isolation valves (F098A/B). No control room indication is provided for these valves and the only time misalignment is certain to be detected is during quarterly system full-flow tests. For this reason only the first two components entered in Table 5.2-3 reflect the fact that the pump circuit breaker is racked out for maintenance that breeches the RHR boundary. Thereafter, only the F098 maintenance valve alignment away from normal is shown.

- o The manual maintenance isolation valves in the drywell (F092A/B - LPCI injection, F090A/B - SDC return, and F020A/B - SDC suction) are assumed to be inaccessible during full power operation, and hence cannot be used to achieve RHR line double isolation.

o Each of the system MOV's and pumps has a feed circuit breaker in the power supply lines in its associated MCC. In addition to the maintenance activity shown in Table 5.2-3, unscheduled electrical maintenance on these circuit breakers is anticipated. This activity is only of interest for components that must change state and it is assumed that no other system components are impacted. Failure to restore the breaker after maintenance is not considered likely because the component indicator lights in the control room receive power through this breaker.

5.2.3 System Operation

5.2.3.1 Normal Operatic

During the normal plant operation, Trains A and B of the RHR system are in standby and ready to initiate the LPCI function. One water leg pump operates continuously to keep the LPCS and RHR A pump discharge line filled and a separate pump keeps the RHR B and C lines water filled. The SDC suction MOVs - F006A/B, F008, and F009 are closed as are the SDC return line valves (F053A/B). In addition, the F008 MOV feed breaker is racked out.

The SDC mode of RHR is operated during a normal reactor shutdown and cooldown. The initial phase of nuclear system cooldown is accomplished by dumping steam from the reactor vessel to the main condenser. When the steam supply pressure is no longer sufficient to maintain the turbine shaft gland seals, vacuum in the main condenser cannot be maintained and the RHR system is manually placed in the shutdown cooling mode of operation.

The steps the operator must take to initiate SDC during normal shutdown are described in Section 5.2.2.4.

5.2.3.2 Abnormal Operation

The Shutdown Cooling mode of RHR may also be used to remove decay heat following LPCI core reflood. The steps the operator must take to initiate SDC during abnormal conditions are described in Section 5.2.2.4.

5.2.4 System Fault Tree

5.2.4.1 Description

Simplified diagrams of the two SDC trains of RHR showing the mechanical components included in the fault tree models are shown in Figures 5.2-5 and 5.2-6.

There are a number of components (e.g. the steam condensing isolation MOVs 2E12-F087A/B) that appear in the fault trees only as contributors to SDC system unavailability due to component unscheduled maintenance that breeches the RHR system boundary. These components form part of the SDC pressure boundary but do not perform a function essential to successful operation. They are indicated on the detailed drawings (5.2-1 through 5.2-4) but have been omitted from the simplified diagrams.

There are thirty-eight developed events in the SDC fault tree. Twenty three of these events are transfers from the LPCI fault trees. Since much of the SDC flow path and components are common to the LPCI mode RHR configuration, they have not been modeled again in the SDC fault tree. Four of the developed events are transfers from the electric power fault trees: the 480 VAC MCC's 235Y-1, 235Y-2, 235X-1, and 236Y-1. Five of the events are transfers from containment isolation development in the PCS fault tree (including the RPS buses A and B). Two of the developed events represent spurious LOCA signals in the A and B LOCA networks. They have been developed in the SPC fault trees. Two more of the events are transfers from the CSCS system fault tree and represent the supply of cooling water to the RHR heat exchangers. Finally, the last two developed events are transfers from the ECCS Equipment Area Cooling System fault trees and represent the development of the RHR pumps cubicle cooling.

5.2.4.2 Success/Failure Criteria

The SDC system is successful if one of the two independent trains operates at full capacity for the duration of the accident scenario it is required for. It conveys water from a reactor recirculation loop, passes it through the heat exchanger to cool, and returns it to a recirculation loop. SDC failure occurs upon one of the following:

1. Both normal and emergency power is lost for both trains.

2. Both 211Y and 212Y 125 VDC buses are lost.

3. Divisions 1 & 2 of the CSCS system to the heat exchangers is lost.

4. ECCS Equipment Area Cooling is lost for both the SE and NW cubicles.

5. The SDC inboard (F009) or outboard (F008) suction isolation valve fails to open.

6. Both SDC trains fail due to various combinations of pump failures, injection or suction MOV failures, flow diversions, pipe ruptures, or maintenance outages.

The top event of the SDC system tree is:

FAILURE OF SDC SYST TO REMOVE HEAT WITH 1-OF-2 LOOPS AND 1-OF-2 HT EXCHS.

5.2.4.3 Assumptions

In addition to the general assumptions regarding fault tree developments (listed at the beginning of this volume), the following assumptions specific to the SDC system were made:

1. There are several large branch lines used for auxiliary functions (e.g. Suppression Pool Clean-up) that are normally locked closed by a manual valve and sealed by a blind flange during normal operation. It is highly unlikely that such a line could be inadvertently left open and not detected during the various start-up procedures. Therefore these lines are not modeled as diversion paths.

2. Inadvertent opening of the LPCI injection valve creates a diversion path for SDC flow, but the water is still conveyed to the reactor core. It is assumed that the heat removal function is still met. No credit is taken for the LPCI line as an alternate SDC injection path.

3. Inadvertent opening of both drywell spray MOVs (F016A/B and F017A/B) creates a large diversion path for SDC train A or B flow. However, the valves are interlocked so that only one can be open at a time unless 1) a high drywell (LOCA logic) signal is present and 2) the LPCI injection MOV is closed. The valves do not have automatic actuation so the possibility of an error on opening the valves and a simultaneous interlock failure is low. For these reasons and the fact that the mistake can be readily recognized and corrected, the only failure mode modeled is a common control system fault (due to cable fire) that drives open both F016 and F017 regardless of interlocks.

4. There are several safety relief valve lines associated with the two SPC trains. None are larger than 4 inches in diameter, hence, it is assumed that they cannot act as significant diversion paths for SDC flow. (The RHR/SDC line ranges from 24-inch pipe at the pump suction to the 12-inch SDC return line.) An inadvertently opened safety/relief valve in the one-inch line off the RHR pump suction does not create a large enough path to significantly affect pump NPSH. (The NPSH of the RHR pumps is set largely by the depth of water in the suppression pool.)

5. The minimum flow bypass lines protect the RHR pumps from overheating before an RHR mode discharge path has been established. The usual sequence for SDC operation has the operator either initiating the RHR A or B train in SDC mode during a normal shutdown or switching the RHR A or B train from LPCI (or another RHR mode) over to SDC operation. In so doing, the injection MOV or any other RHR mode is closed and the pump continues to run with only the minimum flow line open to the

suppression pool until SDC flow is established. During this time the pump would be 'dead-headed,' if the minimum flow MOV failed closed. The RHR pump manufacturer indicates, however, that the pumps will operate 30 to 60 minutes under no-flow conditions before they overheat. (The exact time-to-failure is dependent on the pump cubicle environment.) Even taking the minimum time-to-failure of 1/2 hour, it is highly likely that either the operator will have established SDC flow, or various control room indicators will have warned the operator of a problem with the RHR pump flow. Control room indicators include a position indicator for the minimum flow bypass MOV, pump discharge pressure and alarm (400 psig), RHR line flow indicator, and a pump bearing temperature recorder. For these reasons failure of the pump discharge bypass line to provide minimum flow after pump initiation is not considered a significant contributor to pump failure.

6. The 8-inch minimum flow bypass line at the discharge of each RHR pump contains a 4-inch diameter flow restrictor. It is therefore too small to act as a significant diversion path should the minimum flow bypass MOV remain open when SDC flow is required.

7. The RHR pump motors are air-cooled and analysis indicates that the ECCS Equipment Area Cooling System must operate to keep pump cubicle temperature within operational limits. The pump seals are cooled by a dedicated water cooling system which is a part of the CSCS cooling system. (The CSCS also cools the heat exchangers in the ECCS Equipment Areas HVAC.) Analysis indicates that the pump seals begin to fail in 15 - 20 seconds after loss of seal cooling if the pumped water temperature significantly exceeds 160F. It is likely that the RHR pumps will be pumping water at 160F or greater when SDC is in operation. However, loss of pump seals and the leakage that ensues is not considered to have a severe enough impact on pump performance that SDC would not succeed over its mission time. For this reason, seal cooling is not considered an essential support system to SDC.

8. The possibility of waterhammer failure of the pump discharge line due to failure of the water-leg pump is neglected The pump is operated continuously to maintain the RHR lines in a filled condition. The RHR pump discharge line pressure is indicated and alarmed in the control room, so failures of the water-leg fill system are readily detected. When the water-leg fill system is out of service the RHR lines can be manually filled via the Flushing Water Supply line. Even in the event that the RHR line is not water filled when the RHR pump starts, the design of the pump discharge line is such that pipe rupture due to water hammer is unlikely.

9. Successful operation of the RPV Head Spray is not assumed to be essential to success of the Shutdown Cooling System. The LaSalle

SDC Startup and Operational Procedures only mention using the head spray as a final step "if desired" to collapse a steam dome bubble. Only Train A of the SDC has a head spray line.

10. No credit is taken for use of the 6-inch head spray line as an alternate injection path for partial SDC flow.

Table 5.2-1 SDC Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
4160 VAC <u>BUS 241Y</u>	2E12-C002A	Motor-driven pump	FTS/FTR	Loss of all Train A MOV indication lights in control room	Loss of SDC Train A pump and SDC remote actuation of Trains A & B suction and return MOVs	Fails SDC Trains A & B
480 VAC MCC 235Y-2	2E12-F006A F004A	MOVs	FTO	Loss of position lights in control room	Loss of remote actuation of Train A valves. SDC and suppression pool suction	
	2E12-F053A, F053B	MOVs	FTO	Loss of position lights in control room	Loss of both Train A and Train B remote actuation of SDC return valves	
	2E12-F048A	MOV	FTC	Loss of position lights in control room	Most suppression pool water is routed around the heat exchanger. Inadequate heat removal	Loss of remote actuation of Train A suction MOVs and Trains A & B SDC return valves and loss of remote control of water flow through heat exchanger. Fails SDC Trains A & B.
480 VAC MCC 235X-1	2E12-F008	MOV	FTO	Loss of position lights in control room	Loss of remote actuation of SDC outboard suction isolation valve	
	2E12-F009	MOV	FTO if 236Y-1 also unavailable	Loss of F009 position lights in control room	Loss of the backup power supply to the SDC inboard suction isolation valve. if MCC 236Y-1 is unavailable also, valve cannot be remotely actuated	Unable to remotely actuate SDC outboard suction valve. Fails SDC Trains A & B for the short term
4160 VAC <u>BUS 242Y</u>	2E12-C002B	Motor-driven pump	FTS/FTS	Loss of all Train B MOV indication lights in control room	Loss of SDC Train B	Fails SDC Train B
480 VAC MCC 236Y-1	2E12-F006B, F00 8B	MOVs	FTO	Loss of position lights in control room	Loss of remote actuation of Train B SDC and suppression pool suction valves	

Table 5.2-1 SDC Support Systems Interface FMEA (continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
	2F12-F048B	MOV	FTC	Loss of position lights in control room	Most suppression pool water is routed around the heat exchanger. Inadequate heat removal	Loss of remote actuation of Train B suction MOVs and loss of remote control of water flow through heat exchanger. Fails SDC Train B.
125V DC POWER						
DIST PNL 211Y	2E12-C002A Control/Actuation	Motor-driven pump	FTS/FTR	Loss of pump indication lights in control room	RHR pump A inoperable - Fail SDC Train A	Fails SDC Train A
DIST PNL 212Y	2E12-C002B Control/Actuation	Motor-driven pump	FTS/FTR	Loss of pump indication lights in control room	RHR pump B inoperable - Fail SDC Train B	Fails SDC Train B
CSCS Equipment Cooling Water System						
RHR Service Water System (Div. 1)	2E12-C002A	Motor-driven pump	Fail seal cooling, leakage	Service water pumps indicated/alarmed in control room. Leak detected in pump cubicle.	Leakage does not fail pump in short term. If gross seal failure occurs, pumped water could flash damaging pump.	Coolant leakage into RHR pump A cubicle. Possible damage to pump over long-term.
	2E12-B001A	RHR Heat Exchanger	No heat removal	Service water pump condition and Htx inlet/outlet temps indicated in control room	Loss of SDC Train A heat removal	Fails SDC Train A
RHR Service Water System (Div. 2)	2E12-C002B	Motor-driven pump	Fail seal cooling, Leakage	Service water pumps indicated/alarmed in control room. Leak detected in pump cubicle	Leakage does not fail pump in short term. If gross seal failure occurs, pumped water could flash, damaging pump.	Coolant leakage into RHR pumps B and C cubicle. Possible damage to pump over long-term

Table 5.2-1 SDC Support Systems Interface FMEA (Concluded)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
	2E12-B001B	RHR Heat Exchanger	No heat removal	Service water pump condition and Htx inlet/outlet temps indicated in control room	Loss of SDC Train B heat removal	Fails SDC Train B
<u>ECCS Equipment Cooling System</u>						
NW Cubicle Cooling	2E12-C002A and related I & C	Motor-driven pump	FTR (overheat or control)	Cubicle temper-indication lights and alarmed in control room. HVAC fan indicated in control room.	After about one hour, overheat of pump motor trips the RHR pump A and fails SDC train A. Pump instrumentation and control circuitry in cubicle may be affected earlier.	SDC Train A succeeds initially but continued operation is threatened one hour after loss of cubicle cooling.
SE Cubicle Cooling	2E12-C002B and related I & C	Motor-driven pump	Fail seal (overheat or control)	"	After about six to ten min. overheat of pump motor trips RHR pump failing SDC Train B. Pump instrumentation and control circuitry in cubicle	SDC Train B succeeds initially but continued operation is threatened about six to ten minutes after loss of cubicle cooling.

Table 5.2-2 Shutdown Cooling System Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
LOS-RH-M1	System Operability (Alignment)	All motor-operated valves required for SDC operation and the drywell manual isolation valves		No	---	Monthly	---	Alignment: Shiftly Operability: Quarterly
		RHR/LPCS Water Leg	Pumps	No	---	Monthly	---	Monthly
LOS-RH-Q1	Pump Inservice	2E12-C002A/B	Pumps	No	---	Quarterly	---	Alignment: Shiftly Operability: Quarterly
		2E12-F064A/B	MOVs	No	---	Quarterly	---	" "
		2E12-F024A/B and 2E12-F021	"	Yes	Yes	"	---	" "
		2E12-F027A/B	"	Yes	No	"	---	" "
		2E12-F048A/B	"	Yes	No	"	---	" "
LOS RH-Q2	Value Exercise	2E12-F004A/B	MOVs	Yes	No	Quarterly	---	Alignment: Shiftly Operability: Quarterly
		2E12-C002A/B	Pumps	Yes[1]	"	"	---	" "
		2E12-F004A/B	MOVs	Yes	"	"	---	" "
		2E12-F047A/B	"	Yes[2]	"	"	---	" "
		2E12-F003A/B	"	"	"	"	---	" "
		2E12-F016A/B	"	Yes[3]	"	"	---	" "
		2E12-F017A/B	"	"	Yes	"	---	" "

1) RHR pumps are placed in "Full-to-Lock" while F004 valves are tested.
2) Valve is out of alignment only briefly.
3) Valve is only briefly out of alignment. Interlocks prevent both F016 & F017 from being open at once.

Table 5.2-2 Shutdown Cooling System Test Summary (Concluded)

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
		2E12-F048A/B	"	Yes[2]	Yes	"	---	" "
		2E12-F024A/B	"	"	"	"	---	" "
		2E12-F064A/B	"	"	"	"	---	" "

2) Valve is out of alignment only briefly.

Table 5.2-3 Shutdown Cooling System Unscheduled Maintenance Summary

Component/ Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance with no Auto-Return	Allowed During Plant Operation?	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E12-C002A/B	Pumps	Mechanical[1]/ electrical	Pump circuit breaker	Yes			Alignment: Shiftly Operability: Quarterly
		Mechanical[2]	Pump circuit breaker MOV 2E12-F006A/B circuit breaker Man. 2E12-F098A/B	Yes			" " " Alignment: Quarterly
2E12-F009	MOV	Mechanical[1]/ electrical	Valve circuit breaker	No			Alignment: Shiftly Operability: Only during shutdown or refueling
2E12-F008	MOV	"	"	Yes			"
2E12-F006A/B	MOVs	"	"	Yes			Alignment: Shiftly Operability: Quarterly
2E12-F006A/B	MOV	Mechanical[2]	MOV 2E12-F006B/A (circuit breaker in other train) Man. 2E12-F098A/B Pump 2E12-C002A/B circuit breaker	Yes			" Alignment: Quarterly Alignment: Shiftly Operability: Quarterly
2E12-F064A/B	MOV	Mechanical[2]	MOV 2E12-F006A/B circuit breaker Man. 2E12-F098A/B	Yes			" Alignment: Quarterly
2E12-F088A/B	Safety relief valve	Mechanical[2]	MOV 2E12-F006A/B circuit breaker Man. 2E12-F096A/B	Yes			Alignment: Shiftly Operability: Quarterly Alignment: Quarterly

1) Maintenance not involving a breach of SDC system boundary.
2) Maintenance involving breaching the SDC system boundary and requiring double isolation from reactor pressure.

Table 5.2-3 Shutdown Cooling System Unscheduled Maintenance Summary (Concluded)

Component/ Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance with no Auto-Return	Allowed During Plant Operation?	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E12-C003 2E21-C002	Pump Pump	Mechanical[1]/ electrical	Man. 2E12-F098B Man. 2E12-F098A	Yes			Alignment: Shiftly Operability: Quarterly
2E12-F047A/B	MOV	Mechanical[2]	2E12-F006A/B circuit breaker Man. 2E12-F098A/B	Yes			Alignment: Shiftly Operability: Quarterly Alignment: Quarterly
2E12-B001A/B	Heat exchanger	Mechanical[2]	2E12-F098A/B	Yes			Alignment: Quarterly
2E12-F051A/B	Pneumatic valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F087A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F055A/B	Safety/ relief valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F060A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F065A/B	Pneumatic valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F074A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F087A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"

2) Maintenance involving breaching the SDC system boundary and requiring double isolation from reactor pressure.

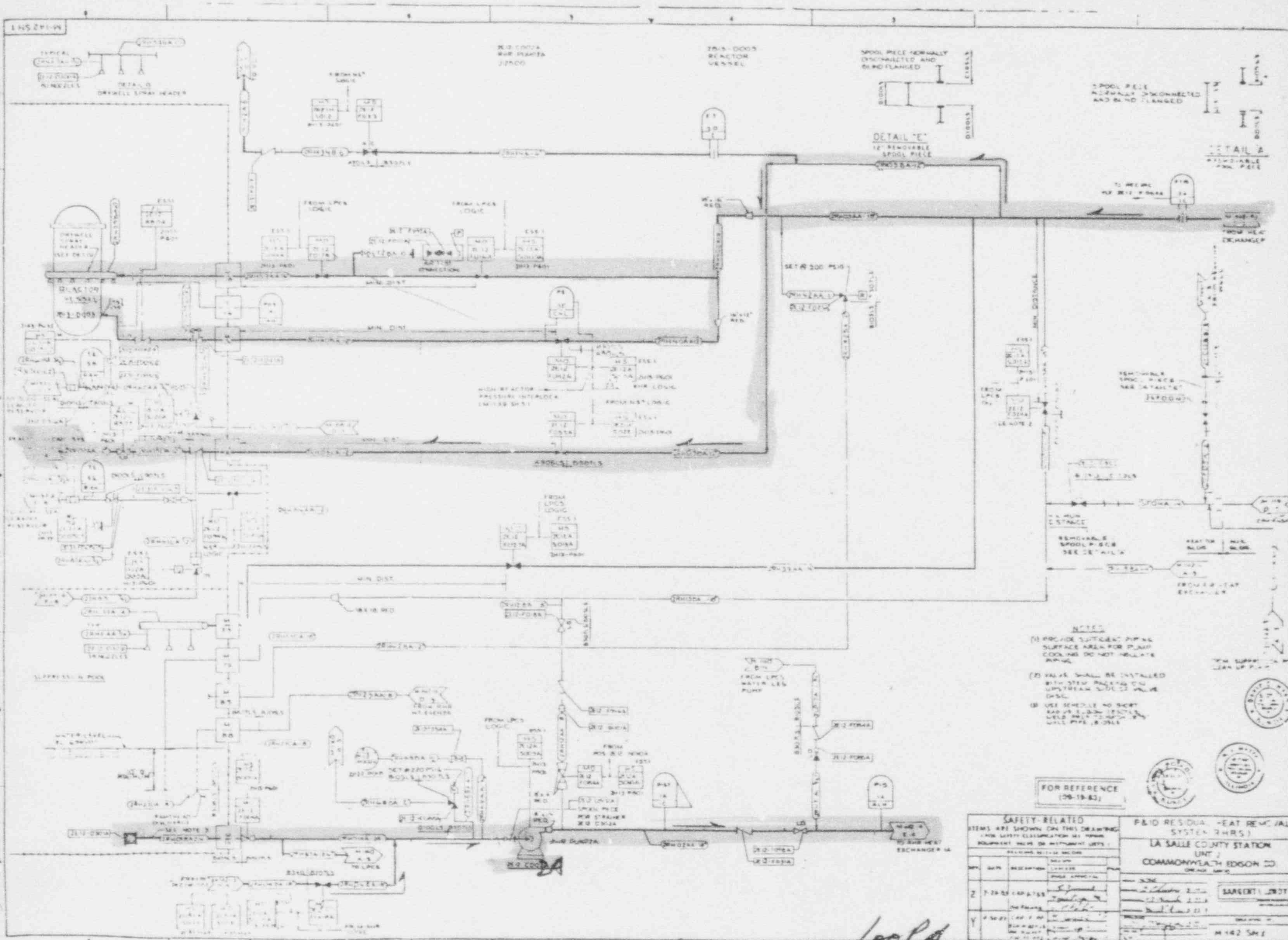


FIGURE B.X-1 SHUTDOWN COOLING SYSTEM P&ID

Loop A

Figure 5.2-1 Shutdown Cooling System P&ID - Train A

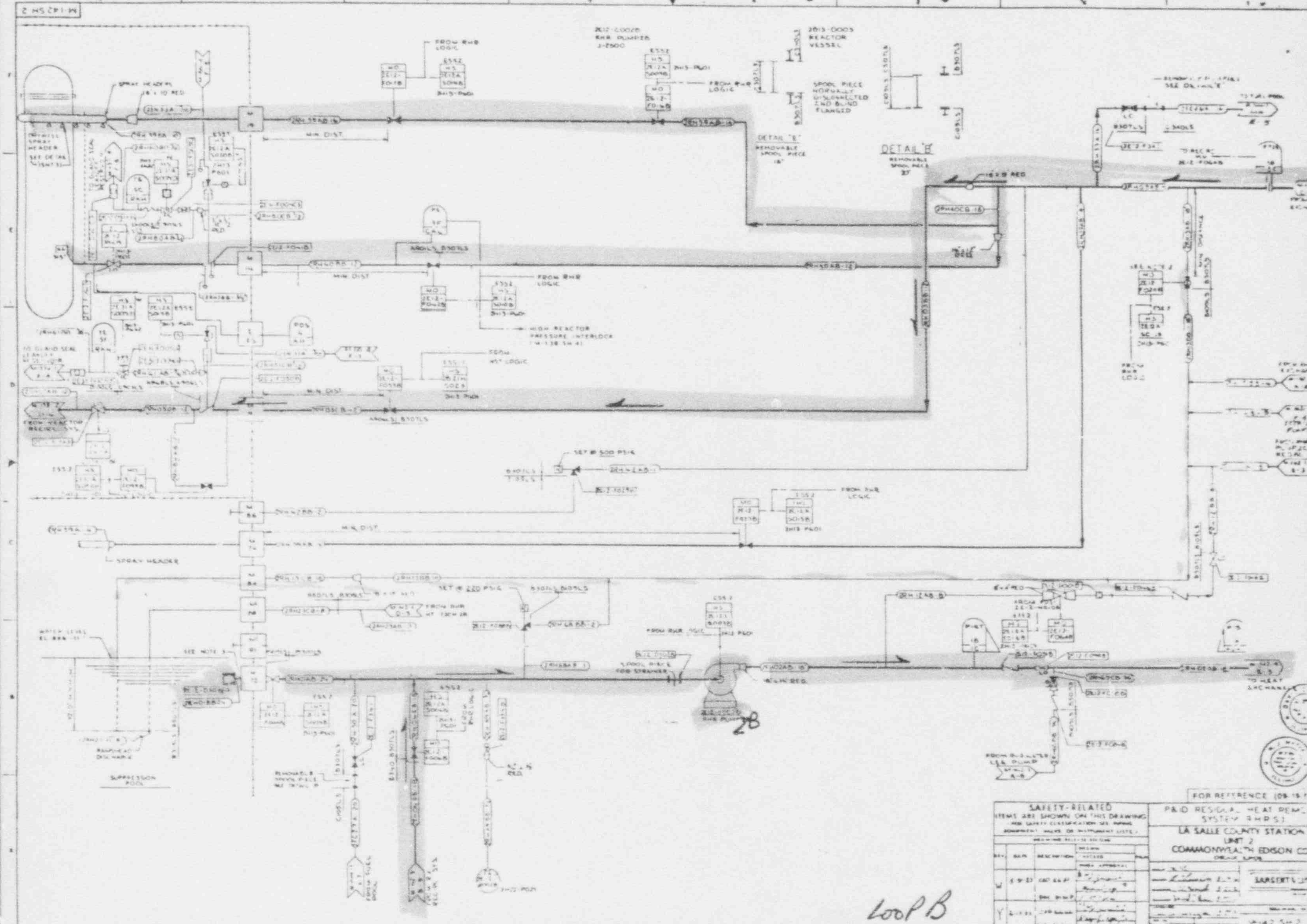


FIGURE B.X-2 SHUTDOWN COOLING SYSTEM P&ID - ~~Loop B~~

Figure 5.2-2 Shutdown Cooling System P&ID - Train B

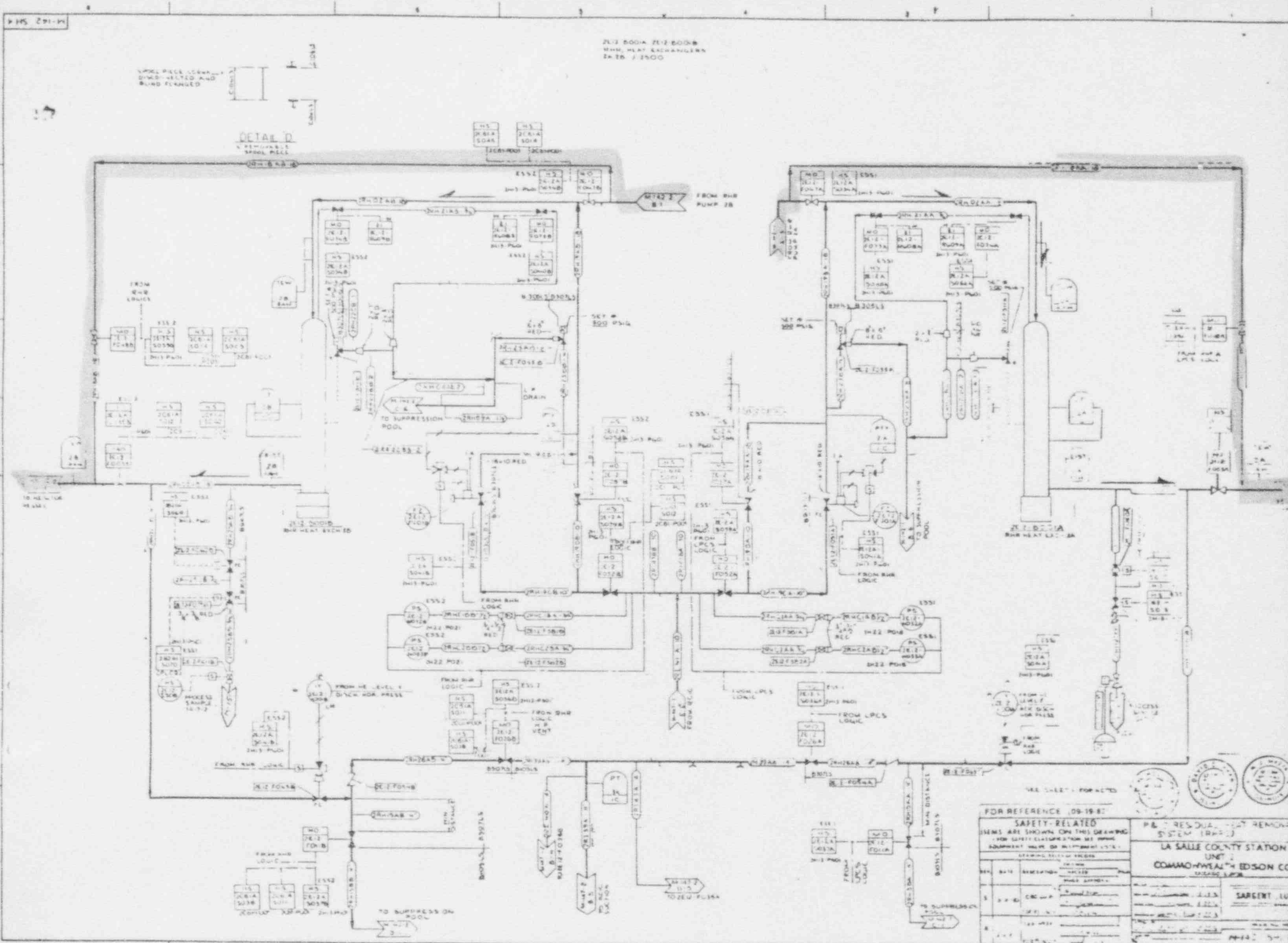


FIGURE B.X-3 SHUTDOWN COOLING SYSTEM P&ID - HEAT EXCHANGERS

Figure 5.2-3 Shutdown Cooling System P&ID - Heat Exchangers

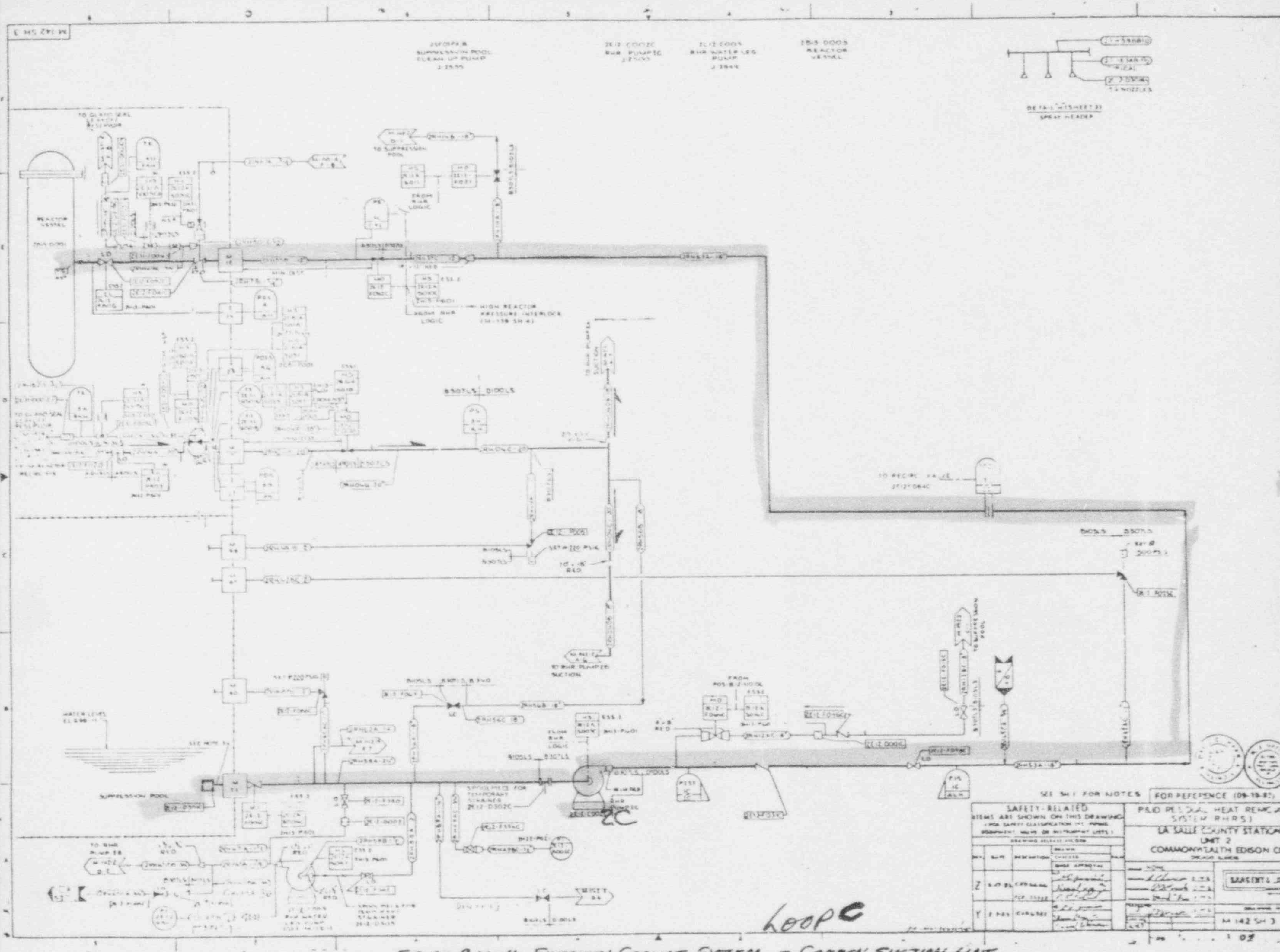


FIGURE B.X-4 SHUTDOWN COOLING SYSTEM - COMMON SUCTION LINE

Figure 5.2-4 Shutdown Cooling System P&ID - Common Suction Line

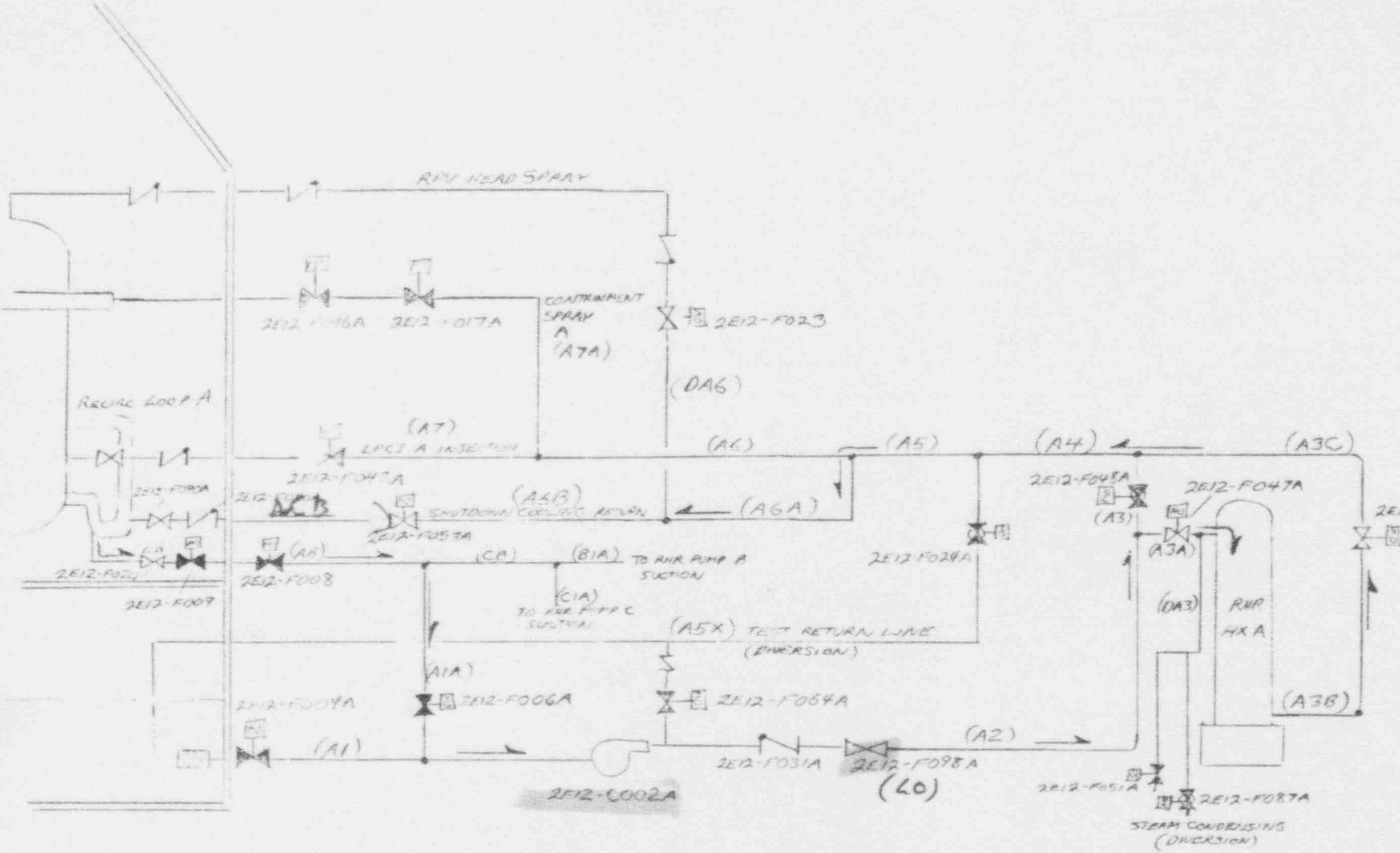


FIGURE B.X-5 Shutdown Cooling System — ~~[illegible]~~ Loop A A Simplified Diagram

Figure 5.2-5 Simplified Schematic of Shutdown Cooling System for Fault Tree Construction - Train A

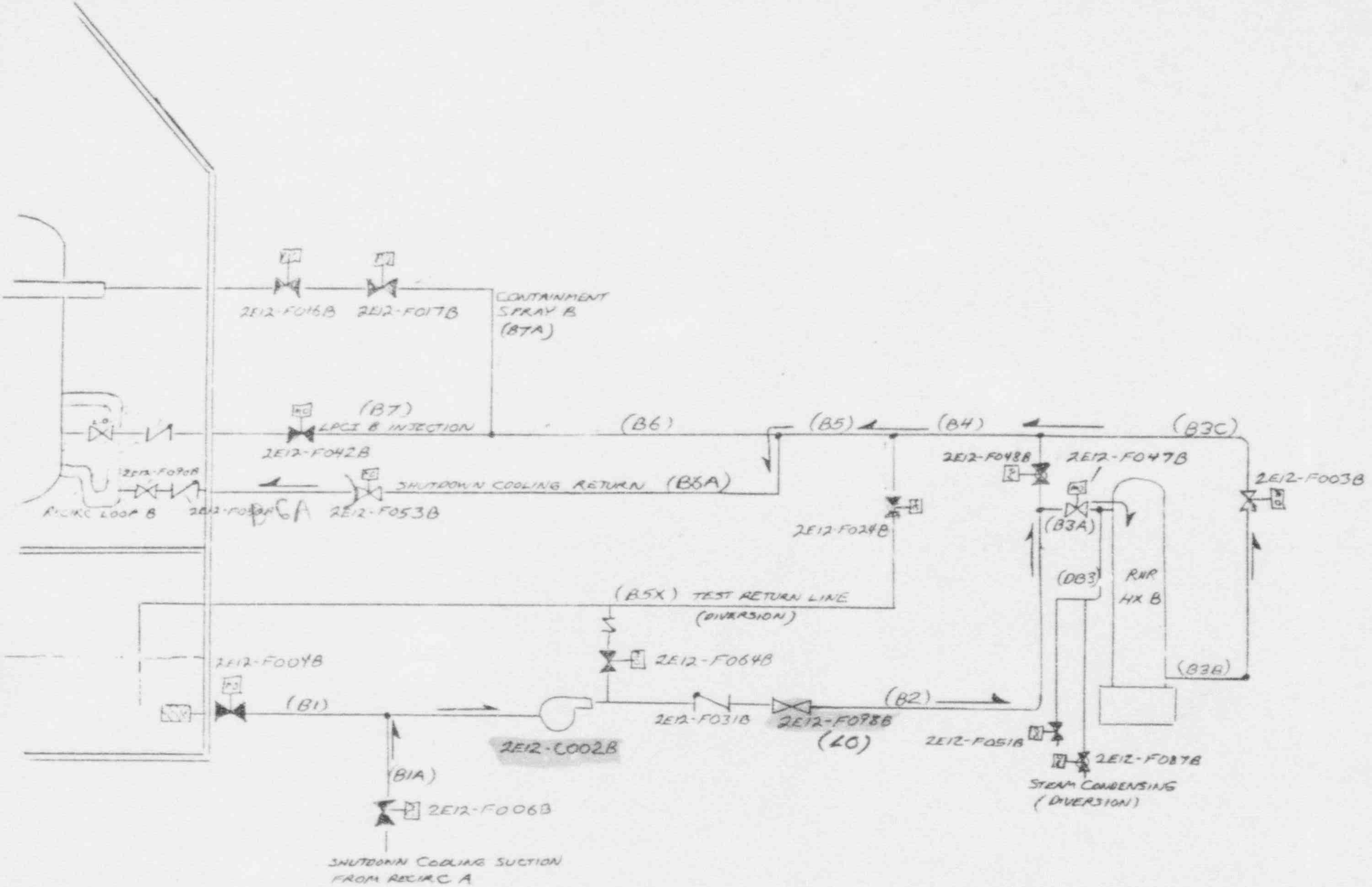


FIGURE B.X-6 Shutdown Cooling System — ~~Train~~ Loop B Simplified Diagram

Figure 5.2-6 Simplified Schematic of Shutdown Cooling System for Fault Tree Construction - Train B

5.3. Suppression Pool Cooling Mode of RHR (SPC)

5.3.1 System Function

Suppression Pool Cooling (SPC) is a subsystem of the RHR system and a subpart of the containment cooling mode. The containment cooling mode consists of suppression pool cooling and containment spray.

In the event of a LOCA, the short-term energy release from the reactor primary system will be dumped to the suppression pool. Subsequent to the accident, fission product decay heat will result in a continuing energy dump to the pool. If this energy is not removed from primary containment, it will eventually result in unacceptable suppression pool temperatures and containment pressures. The containment cooling mode of the RHR system is used to limit the temperature of the water in the suppression pool such that, immediately after the design-basis LOCA, pool temperature does not exceed 170F. Tests show that at 170F, complete condensation of blowdown steam from this LOCA can be expected. Complete condensation is also likely at higher pool temperatures, but no test data is available.

5.3.2 System Description

5.3.2.1 General Design

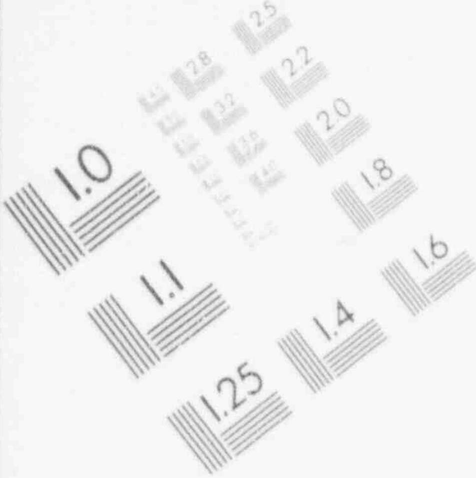
The Suppression Pool Cooling subsystem consists of two independent fluid trains that draw water from the suppression pool, pass it through the RHR heat exchangers, and return it to the suppression pool. The SPC trains are configured from RHR trains A and B and use the RHR pumps, heat exchangers, and test return lines. Detailed one-line diagrams of the two SPC/RHR trains are shown in Figures 5.3-1 through 5.3-3.

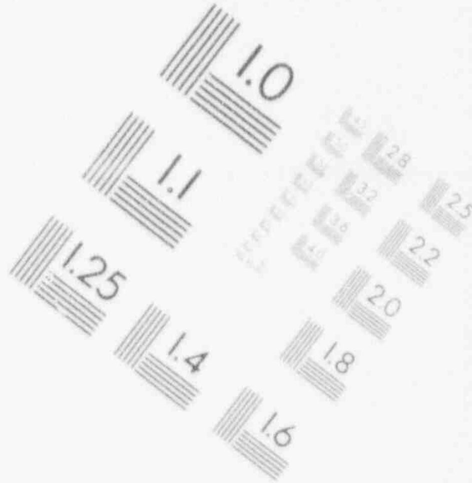
Flow Path

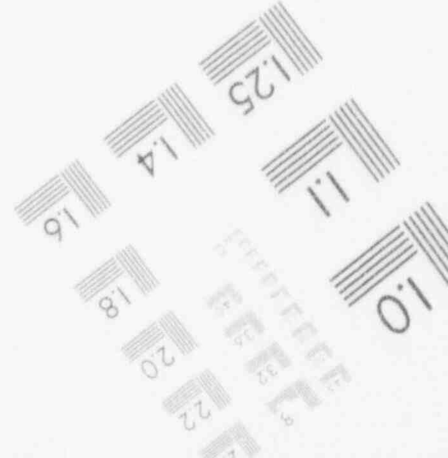
The RHR System is aligned for LPCI mode and held in standby during normal plant operation. Normally, once the core reflood requirements are satisfied, the operator will manually realign either RHR train A or B in the Suppression Pool Cooling mode. To do so, the LPCI injection MOV (or the injection MOV of any other RHR mode) is manually closed, the CSCS system which supplies cooling water to the desired heat exchanger is started, the full flow test stop valve (F024A/B) in the loop's test return line is throttled open and the degree of heat removal is adjusted by throttling closed the heat exchanger bypass MOV (F048A/B). The RHR pump then takes suction from the suppression pool, the water is at least partially routed through the heat exchanger, and it is returned to the suppression pool via the full flow test line. Approximately five percent of total pump flow can be directed to the suppression chamber spray ring by opening MOV F027A/B in the 4-inch wetwell spray line. (This option can be used to cool any noncondensible gases collected in the free volume above the suppression pool.)

2

IMAGE EVALUATION TEST TARGET (MT-3)







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Locations

Most of the RHR Train A components are located in the northwest corner of the reactor building basement. The RHR A Heat Exchanger is enclosed in a cubicle and extends from 694' to the 710' elevation. The full flow test return line MOV (F024A) is located at the 710' elevation.

The RHR Train B components are predominantly located in the southeast corner of the reactor building basement. The RHR B Heat Exchanger is also enclosed in its own cubicle and extends from 694' to the 710' elevation. The train B full flow test return line MOV (F024B) is located at the 710' elevation.

Component Description

The SPC components common to RHR trains A and B are described in the LPCI system description in Section 3.3. This includes the RHR pumps and their associated minimum flow lines, the pump suction line MOV's and the suppression pool strainers, the pumps' discharge lines and their associated check valves, maintenance valves, and water leg fill systems, and RHR heat exchanger inlet, outlet, and bypass MOV's.

The RHR Heat Exchangers are described more completely in the Shutdown Cooling System Description (Section 5.2).

The 18-inch test return line to the suppression pool for each train contains an 18-inch, motor-operated globe valve (2E12-F024A/B) that is normally closed. The test return MOVs receive close signals upon LOCA initiation. Thereafter the valves may be manually opened from the control room should the operator wish to initiate suppression pool cooling. However these test return MOVs are interlocked such that with a LOCA signal present, they cannot be opened unless their respective LPCI injection valves are closed.

5.3.2.2 System Interfaces

A failure modes and effect analysis (FMEA) of SPC support system interfaces is shown in Table 5.3-1. The support system interfaces are discussed below.

Shared Components

Most of the components in the SPC mode are also used in other RHR configurations - Shutdown Cooling, Low Pressure Coolant Injection, Containment Spray, and Steam Condensing. The same RHR pumps, heat exchangers and flowpaths are used except that the pump suction, heat exchanger flow control, and injection MOVs for the various modes may be positioned differently. During standby operation the same water-leg pump is used to keep the RHR A and LPCS lines filled, while another pump is dedicated to keeping RHR B and C lines water filled.

Electrical

A separate division of the Class 1E electrical system provides power to each SPC train for operation of the RHR pumps, system MOVs, and system instrumentation and controls. The RHR A pump motor is supplied by the 4160 VAC distribution system from bus 241Y. The Train A MOVs are powered by the 480 VAC MCC 235Y-2 off bus 241Y. The only exception is the pump minimum flow bypass valve which is powered by MCC 235Y-1.

The RHR B pump motor is supplied by the 4160 VAC distribution system from bus 242Y. Off the 242Y bus, the train B MOVs are powered by the 480 VAC MCC 236Y-1.

The 125 VDC distribution system (Div. 1) supplied power to the RHR A interlock logic circuits and control power for the RHR A pump motor. The Division 2 125 VDC distribution system supplied power to the RHR B interlock logic circuits and also provides control power for the RHR B pump motor.

Actuation

As noted above, the Division 1 and 2 125 VDC distribution system supplies power to the RHR interlock logic circuits.

Control

As noted above, the Division 1 and 2 125 VDC distribution system supplies the control power for the RHR pumps. Control power for the various system MOVs is obtained through 480/120 VAC transformers off the MCCs powering the valve motors.

Component Cooling

The CSCS system provides cooling for the Train A and B RHR heat exchangers. Over the long term this support system is essential to remove decay heat from the containment suppression pool.

The CSCS system also cools the RHR pump seals. It must be in operation whenever pumped water exceeds 160F or the seals may fail in as little as 20 seconds. However, failure of the pump seals is not judged to be a fault that prevents the RHR pumps from functioning adequately for the purposes of SPC.

The RHR pump motors are air-cooled and depend on the ECCS Equipment Area Cooling System to keep the pump cubicle temperature within their qualification temperature limit (212F).

Room Cooling

The RHR pump motors are air-cooled and depend on the ECCS Equipment Area Cooling System to maintain pump cubicle temperatures within qualification limits. There is an ECCS Equipment Area Cooling System dedicated to cooling the NW cubicle (which contains the RHR A pump) and a separate train dedicated to SE cubicle cooling (RHR B and C pumps). Cooling water is supplied by the CSCS system.

5.3.2.3 Instrumentation and Control

System Actuation

Suppression Pool Cooling is manually initiated. Normally the operator would change either RHR Train A or B over to the SPC mode from the LPCI mode once the core reflood requirements are satisfied. To do so, the CSCS system is manually started, the LPCI injection MOV (or the injection MOVs of any other RHR mode) is manually closed from the control room, the full flow test return MOV (F024A/B) is throttled open, and the operator establishes the desired level of cooling by adjusting the heat exchanger bypass and outlet stop MOVs. It should be noted that the normally open heat exchanger bypass MOV's are interlocked such that they cannot be closed for the first ten minutes following a LPCI initiation signal.

If the LOCA logic has been reset and a new LPCI initiation signal is received during suppression pool cooling, the RHR train will automatically revert to the LPCI mode.

The logic diagrams for actuation of RHR pumps A and B (if they are not already operating) and for the various MOVs used in the SPC mode of operation are shown in Section 3.3, the LPCI system description, along with all the components used in the other modes of operation. Much of the actuation logic is common to the various modes and, if not, at least is in the same electrical circuit or is connected to a common circuit.

Component Control

The operator manually controls the test return (F024A/B), heat exchanger bypass (F048A/B), and heat exchanger outlet (F003A/B) MOVs in order to establish the desired degree of suppression pool cooling. If the LOCA logic system is reset and a new LPCI initiation signal is received the RHR trains will automatically realign to LPCI mode (F024A/B close and F048A/B open).

The control circuits for the SPC components are also shown in Section 3.3, the LPCI system description.

Instrumentation

Valves

All motor-operated valves in the RHR trains have lighted position indicators in the control room. If a LOCA initiation signal is present and 2E12-F024A/B is opened, the white manual override light located between the valve Open and Close position indicators will illuminate.

RHR Pumps

Indicators for each RHR pump in the control room show whether the pump is on, off, or in pull-to-lock. The current being drawn by the pump is also indicated. Two pressure switches are installed in each pump discharge pipeline and linked to control room indicators to verify that pumps are operating following an initiation signal. (This pressure signal is also used in the automatic depressurization system to verify availability of low-pressure core cooling.) A pressure indicator is also provided in the suction line of each RHR pump. The RHR pump and motor bearing temperatures can be monitored using the plant process computer during pump operation.

SPC System Flow

Flow in each RHR train is sensed by an orifice-type flow element in the pump discharge lines. Indication of system flow for each train is provided by meters on the RHR panel in the control room. The pump minimum flow bypass valve is controlled according to the indication received from this flow sensor.

Control Room Monitors	Parameter Range
1. RHR Hx Water Level	0-100 %
2. RHR Hx Outlet Conductivity	0-10 mho's/cm
3. RHR Hx Temperatures	0-600F
a. Shell side inlet	
b. Shell side outlet	Multipoint recorder
c. Tube side outlet	
4. RHR Hx Inlet Steam Pressure	0-600 psig
5. RHR Hx Service Water side flow element	0-8000 gpm
6. RHR Pump	
a. RHR Discharge piping pressure	0-400 psi
b. RHR Pump flow (Loop)	0-10,000 gpm
c. RHR Pump Amps	0-150 amps
7. RHR Pump Room temperature	
a. Duct	0-300F
b. Area	0-300F
8. Drain Header Conductivity	0-25 mho/cm
9. Reactor Level Fuel Zone	-111" to -311"
10. Leak Detection	
a. Valve Stem Leakage	150-600F

b. Area Leak Detection 0-150F

11. Service Water Effluent Radiation 10-1 to 106 cps

Major Alarms

a. RHR Pump Cubicle Temp Hi - 149F

b. RHR Pump Breaker Closed - Breaker Closed

c. RHR Pump A, B Flow Above Minimum (≥550 gpm) - Alarm at 1500 gpm increasing, resets at 1010 gpm decreasing.

d. RHR Pump A/B Disch Press Hi/Low - 400/55 psig

e. RHR Pump Auto Trip - multiple

f. RHR Pump Cubicle Cooler Fan Auto Trip - Overload

g. LPCI System Actuated - Drywell pressure 1.69 psig, Rx Level -129".

h. LPCI Manual Initiation Pushbutton Armed - PB Armed

i. RHR B/D (A/C) Drywell Press Hi - 1.69 psig

j. RHR B/D (A/C) Reactor Level 1 Low - -129"

k. RHR Equip Area Diff Temp or Ambient Temp Hi (Area - 130 2F. Diff temp - 30 2F)

l. RHR Service Water Pump Auto Trip - Overload

m. RHR Service Water Rad Hi - 6 cps

n. RHR Service Water Strainer 1(2) Diff Press Hi - 8 psid, 4 psid after backwash

o. RHR Hx Outlet Conductivity Hi - 10 umho

p. RHR Service Water Sump Level Hi Hi - Alarm 2' 11" below top of sump, reset 5' 10" below top of sump.

q. RHR HX A/B Discharge Cooling Water Temp Hi - 125F

r. RHR HX A/B Inlet Water Temp Hi - 400F

5.3.2.4 Operator Actions

The Suppression Pool Cooling mode of RHR is manually initiated. The operator will normally decide to initiate either RHR Train A or B in SPC mode only after the core reflood requirements have been satisfied. To do so, the operator first closes the return/injection valve of the RHR mode to be terminated. Startup of CSCS cooling water to the heat exchangers is then manually initiated if it is not already in operation. The normally open RHR heat exchanger outlet MOV (F003A/B) is then closed and the heat exchanger bypass MOV (F048A/B) is verified open. If the train has been previously operating in another RHR mode, the RHR pump will be running with the minimum flow bypass line open, otherwise the RHR pump is manually started. The operator then establishes the desired level of cooling by throttling open the test return MOV to the suppression pool and adjusting the heat exchanger bypass and outlet MOVs.

The SPC mode must be manually shutdown. One exception is if the LOCA logic has been reset and a new LOCA signal is received. In this case the RHR trains will automatically revert to the LPCI mode.

5.3.2.5 Technical Specification Limitations

The following excerpts from the LaSalle Unit 2 technical specifications apply to the SPC system during operational conditions 1, 2 and 3.

<u>Limiting Condition for Operation</u>

3.6.2.3 The suppression pool cooling mode of the residual heat removal (RHR) system shall be OPERABLE with two independent loops, each loop consisting of:

a. One OPERABLE RHR pump and

b. An OPERABLE flow path capable of recirculating water from the suppression chamber through an RHRSW heat exchanger.

<u>Action</u>

a. With one suppression pool cooling loop inoperable, restore the inoperable loop to OPERABLE status within 72 hours or be in a least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With both suppression pool cooling loops inoperable, be in at least HOT SHUTDOWN within 12 hours and in COLD SHUTDOWN* within the next 24 hours.

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*Whenever both RHR subsystems are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

Surveillance Requirements

4.6.2.3 The suppression pool cooling mode of the RHR system shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic), in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. By verifying that each of the required RHR pumps develops a flow of at least 7200 gpm on recirculation flow through the RHR heat exchanger and the suppression pool when tested pursuant to Specification 4.0.5.

5.3.2.6 Tests

The major tests that impact the SPC mode of RHR are the same as those listed for the LPCI mode of operation in Table 3.3-2. The table has been edited to cover only those components affecting SPC (see Table 5.3-2).

Although it is not a test, shiftly surveillance verifies the condition of the RHR pumps and the correct alignment of all MOVs during standby operation. This alignment is such that the RHR trains can rapidly and automatically initiate LPCI when called upon.

5.3.2.7 Maintenance

No scheduled maintenance which disables SPC components while the plant is at power is planned. Unscheduled maintenance is permitted on system components provided applicable safety and radiological administrative controls can be satisfied. Unscheduled maintenance activities possible during plant operation are much the same as those listed for the LPCI system and include:

- Replacement or repair of actuation and control circuitry

- Electrical maintenance on motor driven components

- MOV and pump mechanical maintenance that does not result in a breech of the SPC system boundary.

- MOV and pump mechanical maintenance that breeches the system boundary when double isolation from reactor pressure/temperature can be achieved. Isolation here is taken to mean an accessible manual valve or a motor- operated valve that can be racked out. It is assumed that check valves do no provide a secure means of isolation. (Note that in the case of the RHR A and B trains double isolation must not only be achieved at the injection line end, but also at the Shutdown Cooling suction line end.)

Section 5.3.2.5 indicates the period of time that one or more SPC trains may be inoperable due to unscheduled maintenance. In summary, with one of the suppression pool cooling loops inoperable, the loop must be restored within 72 hours or the plant must be in at least hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours. With two of the SPC loops inoperable the plant must be in at least hot shutdown within 12 hours and in cold shutdown within the next 24 hours.

A summary of unscheduled maintenance acts allowed on the A and B trains of the RHR system while the plant is in full power operation is given the Table 5.3-3. (Only the activities that impact the successful operation of the SPC mode have been included.) The following comments pertain to this table:

- o Although permitted, unscheduled maintenance on check valves and manual valves is not listed on the table because of the significantly lower frequencies of occurrence when compared to MOVs.

- o It is assumed that safety procedures and the requirement for double isolation will result in the RHR pump being racked out when maintenance on a component involves opening up the RHR line. However, this is not a significant contributor to system unavailability because RHR pump indication is provided in the control room and checked shi ly. For those components that can be double isolated, the most significant possibility of a "failure to restore" fault lies with the manual maintenance isolation valves (F098 A/B). No control room indication is provided for these valves and the only time misalignment is certain to be detected is during quarterly system full-flow tests. For this reason, only the first two components entered in Table 5.3-3 reflect the fact that the pump circuit breaker is racked out for maintenance that breeches the RHR boundary. Thereafter only the F098 maintenance valve alignment away from normal is shown.

- o The manual maintenance isolation valves is the drywell (F092A/B/C) are assumed to be inaccessible during full power operation, and hence cannot be used to achieve RHR line double isolation.

- o Each of the system MOV's and pumps has a feed circuit breaker in the power supply lines off its associated MCC. In addition to the maintenance activity shown in Table 5.3-3, unscheduled electrical maintenance on these circuit breakers is anticipated. This activity is only of interest for components that must change state and it is assumed that no other system components are impacted Failure to restore the breaker after maintenance is not considered likely because the component indicator lights in the control room receive their power through the breaker.

5.3.3 System Operation

5.3.3.1 Normal Operation

During the normal plant operation, Trains A and B of the RHR system are in standby and ready to initiate the LPCI function. One water leg pump operates continuously to keep the LPCS and RHR A pump discharge line filled and a separate pump keeps the RHR B and C lines water filled. The suppression chamber must also be operable with its level between 26' 10" and 26' 2 1/2" and its temperature at or below 100F.

5.3.3.2 Abnormal Operation

The SPC mode of RHR is manually actuated. The SPC mode will normally be initiated when suppression pool temperature has reached 120F following reactor vessel blowdown. SPC may also be initiated anytime that the suppression pool water temperature exceeds 100F during normal plant operation.

The steps the operator must take to initiate SPC during abnormal conditions are described in Section 5.3 2.4.

5.3.4 System Fault Tree

5.3.4.1 Description

Simplified diagrams of the two SPC trains of RHR showing the mechanical components included in the fault tree models are shown in Figures 5.3-4 and 5.3-5.

There are a number of components (e.g., the steam condensing isolation MOVs 2E12-F087 A/B) that appear in the fault trees only as contributors to SPC system unavailability due to component unscheduled maintenance that breeches the RHR system boundary. These components form part of the SPC pressure boundary but do not perform a function essential to successful SPC operation. They are indicated on the detailed drawings (5.3-1 through 5.3-3) but have been omitted from the simplified diagrams.

There are twenty-five developed events in the SPC fault tree. Twenty-one of these events are transfers from the Shutdown Cooling and LPCI fault trees. Since much of the SPC flowpath and components are common to these other RHR modes, they have not been modeled again in the SPC fault tree. The remaining four developed events are transfers from the electric power fault trees: the 480 VAC MCC's 235Y-2, and 236Y-1, and the 125 VDC buses 211Y and 212Y.

5.3.4.2 Success/Failure Criteria

The SPC system is successful if one of the two independent trains operates at rated capacity for the duration of the accident scenario it is required for. It conveys water from the suppression pool, passes it through the heat exchanger to cool, and returns it to the suppression pool. SPC failure occurs upon one of the following:

1. Both normal and emergency power is lost (Division 1 & 2).

2. Both 211Y and 212Y 125 VDC buses are lost.

3. Divisions 1 & 2 of the CSCS system to the heat exchangers are lost

4. ECCS Equipment Area Cooling is lost for both the SE and NW cubicles.

5. Both SPC trains fail due to various combinations of pump failures, injection MOV failures, flow diversions, pipe ruptures, or maintenance outages.

6. Debris in the suppression pool (most likely insulation from the drywell) clogs the Train A and B RHR suction strainers to an extent greater than 50 percent.

The top event of the SPC system tree is:

FAILURE OF SPC SYST TO REMOVE POOL HEAT WITH 1-OF-2 LOOPS AND 1-OF-2 HT EXCHS.

5.3.4.3 Assumptions

In addition to the general assumptions regarding fault tree development (listed at the beginning of this volume), the following assumptions specific to the SPC system were made:

1. There are several large branch lines used for auxiliary functions (e.g. Suppression Pool Clean-up) that are normally locked closed by a manual valve and sealed by a blind flange during normal operation. It is highly unlikely that such a line could be inadvertently left open and not detected during the various start-up procedures. Therefore these lines are not modeled as diversion paths.

2. Inadvertent opening of either the LPCI injection MOV (F042A/B), the SHUTDOWN COOLING injection MOV (F053A/A) or the RPV Head Spray injection MOV (F023) opens a SPC flow diversion path to the RPV (and thus away from the suppression pool). However, in many of the transient scenarios, the RPV pressure will be significantly higher than wetwell pressure. Since all three of these injection lines contain check valves, the higher RPV pressure will prevent these lines from acting as a major diversion to SPC flow. In cases where the RPV is at low pressure, the water will be diverted but will flow out of the break or through the ADS valves back to the

suppression pool. Since the energy is being removed from the water by the heat exchangers, as long as it is returned to the suppression pool and the cycle is completed, the function can be classified as a success. Thus inadvertent opening of any of these injection MOVs is not modeled as a contributor to SPC failure.

In addition,the SPC (test return) line lies at a considerably lower elevation than the injection/return lines for any of the other RHR modes. Compare the elevation of the 2E12-F024 MOV (test return valve) which is - 710' with the elevation for the Shutdown Cooling, LPCI, and Drywell Spray injection MOV's - 740', 761' and 772' respectively. Thus, even if these diversion paths to SPC flow were open, the elevation difference alone insures that most of the flow would go to the suppression pool via the current SPC path. For this reason and the fact that drywell spray water returns to the suppression pool via the downcomers anyway, inadvertent opening of the CSS valves (F016, F017) is not modeled as a failure mode of Suppression Pool Cooling.

In the case of a rupture in one of the higher elevation lines outside of the primary containment, the situation be different. If the accident (LOCA) is such that the containment is pressurized, the opening up of a path to the lower pressure reactor building may provide a DP sufficient to drive the SPC flow out the higher elevation breach. (e.g., a containment pressure of 2 atm. represents approximately 35 feet of water head if the building is at atmospneric pressure.) It is conservatively assumed that the wetwell is sufficiently pressurized such that ruptures in the SCS, LPCI, or CSS injection lines divert enough flow to fail SPC.

3. There are several safety relief valve lines associated with the two SPC trains. None are larger than 4 inches diameter, hence, it is assumed that they cannot act as significant diversion paths for SPC flow. (The RHR/SPC line ranges from 24 inch pipe at the pump suction to the 18 inch SPC return line.) An inadvertently opened safety/relief valve in the one-inch line off the RHR pump suction does not create a large enough path to significantly affect pump NPSH. (The NPSH of the RHR pumps is provided largely by the depth of water in the suppression pool.)

4. The minimum flow bypass lines protect the RHR pumps from overheating when an RHR mode discharge path has not been established yet. The usual sequence for SPC operation has the operator switching either the RHR A or B train from LPCI (or another RHR mode) over to SPC operation. In so doing, the injection MOV of the other RHR mode is closed and the pump continues to run with only the minimum flow line open to the suppression pool until SPC flow is established. During this time, the pump would be 'dead-headed' if the minimum flow MOV failed closed. The RHR pump manufacturer indicates, however, that the

pumps will operate 30 to 60 minutes under no-flow conditions before they overheat. (The exact time-to-failure is dependent on the pump cubicle environment.) Even taking the minimum time-to-failure of 1/2 hour, it is highly likely that either the operator will have established SPC flow, or various control room indicators will have warned the operator of a problem with the RHR pump flow. Control room indicators include a position indicator for the minimum flow bypass MOV, pump discharge pressure and alarm (400 psig), RHR line flow indicator, and a pump bearing temperature recorder. For these reasons, failure of the pump discharge bypass line to provide minimum flow after pump initiation is not considered a significant contributor to pump failure.

5. The 8-inch minimum flow bypass line at the discharge of each RHR pump contains a 4-inch diameter flow restrictor It is therefore too small to act as a significant diversion path should the minimum flow bypass MOV remain open when SPC flow is required.

6. The RHR pump motors are air- cooled and analysis indicates that the ECCS Equipment Area Cooling System must operate to keep pump cubicle temperatures within operational limits. The pump seals are cooled by a dedicated water cooling system which is part of the CSCS cooling system. (The CSCS also cools the heat exchangers in the ECCS Equipment Area HVAC.) Analysis indicates that the pump seals begin to fail in 15 - 20 seconds after loss of seal cooling if the pumped water temperature significantly exceeds 160F. It is possible that the RHR pumps will be pumping water at 160F or greater when SPC is in operation in some scenarios. However, loss of the pump seals and the leakage that ensues is not considered to have a severe enough impact on pump performance that SPC would not succeed over its mission time. For this reason, seal cooling is not considered an essential support system to SPC.

7. The possibility of waterhammer failure of the pump discharge line due to failure of the water-leg fill subsystem is neglected. The water leg pump operates continuously to maintain the RHR lines in a filled condition. It is indicated in the control room and checked shiftly. In addition, the RHR pump discharge line pressure is indicated and alarmed in the control room, so failures of the water leg fill subsystem are readily detected. When the water leg fill system is out of service, the RHR lines can be manually filled via the Flushing Water Supply line. Even in the event that the RHR line is not water filled when the RHR pump starts, the design of the pump discharge line is such that pipe rupture due to water hammer is unlikely.

8. If a Shutdown Cooling MOV (F006 A/B) in the RHR pump suction line should inadvertently open while the other RHR train is operating in the Shutdown Cooling mode, a direct path between the RPV and the suppression pool is created. The FSAR indicates that this may

cause 'flashing' in the RHR lines that could severely damage the suppression pool strainer and/or the RHR pump. It is conservatively assumed that inadvertent opening of Train A or B's F006 MOV while the other RHR train is in Shutdown Cooling mode fails that train's RHR pump.

9. Failure of the heat exchanger bypass valve (F048A/B) to close or remain closed results in approximately 60 percent of SPC flow being routed around the RHR heat exchanger. It is assumed that this fault prevents adequate heat removal from the pumped suppression pool water and hence fails Suppression Pool Cooling for that train.

10. Success in establishing suppression pool spray has not been modeled. Only five percent of total RHR pump flow can be directed to the suppression chamber spray ring through the 4-inch wetwell spray line. Thus the line cannot act as an alternate SPC return line to the suppression pool. In addition, the successful operation of suppression pool spray is not essential to the successful cooling of suppression pool water.

Table 5.3-1 SPC Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
4160 VAC BUS 241Y	2E12-C002A	Motor-drive pump	FTS/FTR	Loss of all Train A MOV indication lights in control room	Loss of SPC Train A	Fails SPC Train A
480 VAC MCC 235Y-2	2E12-F024A	MOV	FTO	Loss of position lights in control room	Loss of Train A remote actuation of return valve	
	2E12-Y F048A	MOV	FTC	Loss of position lights in control room	Most suppression pool water is routed around the heat exchanger. Inadequate heat removal	Loss of remote actuation of SPC return valve and loss of remote control of water flow through heat exchanger. Fails SPC Train A
4160 VAC BUS 242Y	2E12-C002B	Motor-driven pump	FTS/FTR	Loss of SPC Train B MOV indication lights in control room		Fails SPC Train B
480 VAC MCC 236Y-1	2E12-F024B	MOV	FTO	Loss of position lights in control room	Loss of Train B remote actuation of SPC return valve	
	2E12-F048B	MOV	FTC	Loss of position lights in control room	Most suppression pool water is routed around the heat exchanger. Inadequate heat removal	Loss of remote actuation of SPC return valve and loss of remote control of water flow through heat exchanger. Fails SPC Train B
125 VDC POWER DIST PNL 211Y	2E12-C002A Control/ Actuation	Motor-driven pump	FTS/FTR	Loss of pump indication in control room	RHR pump A inoperable - Fail SPC Train A	Fails SPC Train A
DIST PNL 212Y	2E12-C002B Control/ Actuation	Motor-driven pump	FTS/FTR	Loss of pump indication lights in control room	RHR pump B inoperable - Fail SPC Train B	Fails SPC Train B

Table 5.3-1 SPC Support Systems Interface FMEA (Concluded)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
<u>CSCS Equipment Cooling Water System</u>						
RHR Service Water System (Div. 1)	2E12-C002A	Motor-drive pump	Fail seal cooling, leakage	Service water pumps indicated/ alarmed in control room. Leak detected in pump cubicle	Leakage does not fail pump in short term. If gross seal failure occurs, pumped water could flash damaging pump.	Coolant leakage into RHR pump A cubicle. Possible damage to pump over long-term.
	2E12-B001A	RHR heat exchanger	No heat removal	Service water pump condition and Htx inlet/outlet temps indicated in control room	Loss of SPC Train A heat removal	Fails SPC Train A
RHR Service Water System (Div. 2)	2E12-C002B	Motor-driven pump	Fail seal cooling, Leakage	Service water pumps indicated/ alarmed in control room. Leak detected in pump cubicle	Leakage does not fail pump in short term. If gross seal failure occurs, pumped water could flash, damaging pump.	Coolant leakage into RHR pumps B and C cubicle. Possible damage to pump over long-term
	2E12-B001B	RHR Heat Exchanger	No heat removal	Service water pump condition and Htx inlet/outlet temps indicated in control room	Loss of SPC Train B heat removal	Fails SPC Train B
<u>ECCS Equipment Cooling System</u>						
NW Cubicle Cooling	2E12-C002A and related I & C	Motor driven pump	FTR (overheat or control)	Cubicle temperature indicated and alarmed in control room. HVAC fan indicated in control room.	After about one hour, overheat of pump motor trips the RHR pump A and fails SPC train A. Pump instrumentation and control circuitry in cubicle may be affected earlier.	SPC Train A succeeds initially but continued operation is threatened one hour after loss of cubicle cooling.
SE Cubicle Cooling	2E12-C002B and I & C	Motor-driven pump	FTR (overheat or control)	"	After about six to ten min. overheat of pump motor trips RHR pump failing SPC Train B. Pump instrumentation and control circuitry in cubicle may be affected earlier.	SPC Train B succeeds initially but continued operation is threatened about six to ten minutes after loss of cubicle cooling.

Table 5.3-2 SPC System Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
LOS-RH-M1	System Operability (Alignment)	All motor-operated valves required for SPC operation and the drywell manual isolation valves		No	---	Monthly	---	Monthly Operability: Quarterly
		RHR/LPCS Water Leg	Pumps	No	---	Monthly	---	Monthly
LOS-RH-Q1	Pump Inservice	2E12-C002A/B	Pumps	No	---	Quarterly	---	Alignment: Shiftly Operability: Quarterly
		2E12-F064A/B	MOVs	No	---	Quarterly	---	" "
		2E12-F024A/B and 2E12-F021	"	Yes	Yes	"	---	" "
		2E12-F027A/B	"	Yes	No	"	---	" "
		2E12-F048A/B	"	Yes	Yes	"	---	" "
LOS-RH-Q2	Value Exercise	2E12-F004A/B	MOVs	Yes	No	Quarterly	---	Alignment: Shiftly Operability: Quarterly
		2E12-C002A/B	Pumps	Yes[1]	"	"	---	" "
		2E12-F006A/B	MOVs	Yes	"	"	---	" "
		2E12-F047A/B	Pumps	Yes[2]	"	"	---	" "
		2E12-F003A/B	"	"	"	"	---	" "
		2E12-F016A/B	"	Yes[3]	"	"	---	" "
		2E12-F017A/B	"	"	Yes	"	---	" "
		2E12-F048A/B	"	Yes[2]	Yes	"	---	" "
		2E12-F024A/B	"	"	"	"	---	" "
		2E12-F064A/B	"	"	"	"	---	" "

1) RHR pumps are placed in "Pull-to-Lock" while F004 valves are tested.
2) Valve is out of alignment only briefly.
3) Valve is only briefly out of alignment. Interlocks prevent both F016 & F017 from being open at once.

Table 5.3-3 Suppression Pool Cooling Unscheduled Maintenance Summary

Component/ Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E12-C002A/B	Pumps	Mechanical[1]/ electrical	Pump circuit breaker	Yes			Alignment: Shiftly Operability: Quarterly
		Mechanical[2]	Pump circuit breaker	Yes			"
			MOV 2E12-F004A/B				"
			MOV 2E12-F006A/B[3] circuit breaker				"
			Man. 2E12-F098A/B				Alignment: Quarterly
2E12-F024A/B	MOV	Mechanical[1]/ electrical	valve circuit breaker	Yes			Alignment: Shiftly Operability: Quarterly
2E12-F006A/B	MOV	Mechanical[2]	MOV 2E12-F004A/B	Yes			
			MOV 2E12-F0068B/A[3] (circuit breaker in other train)				"
			Man. 2E12-F098A/B				Alignment: Quarterly
			Pump 2E12-C002A/B circuit breaker				Alignment: Shiftly Operability: Quarterly
2E12-F064A/B	MOV	Mechanical[2]	MOV 2E12-F004A/B	Yes			"
			MOV 2E12-F0064A/B[3] circuit breaker				"
			Man. 2E12-F098A/B				Alignment: Quarterly
2E12-F088A/B	Safety relief valve	Mechanical[2]	MOV 2E12-F004A/B	Yes			Alignment: Shiftly Operability: Quarterly
		MOV 2E12-F006A/B[3] circuit breaker					"
		Man. 2E12-F098A/B					Alignment: Quarterly
2E12-C003	Pump	Mechanical[2]	Man. 2E12-F098B	Yes			Alignment: Quarterly
2E21-C002	Pump	Mechanical[2]	Man. 2E12-F098A	Yes			
2E12-F047A/B	MOV	Mechanical[2]	2E12-F006A/B[3] circuit breaker	Yes			Alignment: Shiftly Operability: Quarterly
			Man. 2E12-F098A/B				Alignment: Quarterly

1) Maintenance not involving a breach of SPC system boundary.
2) Maintenance involving breaching the SPC system boundary and requiring double isolation from reactor pressure.
3) Inoperability of this component only impacts other modes of RHR.

Table 5.3-3 Suppression Pool Cooling Unscheduled Maintenance Summary (Continued)

Component/ Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E12-B001A/B	Heat exchanger	Mechanical[2]/	Pump circuit breaker	Yes			Alignment: Quarterly
2E12-F051A/B	Pneumatic valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F024A/B	MOV globe	Mechanical[2]/	2E12-F098A/B	Yes			"
2E12-F055A/B	Safety/ relief valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F060A/B	MOV	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F065A/B	Pneumatic valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F074A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F087A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"

2) Maintenance involving breaching the SPC system boundary and requiring double isolation from reactor pressure.

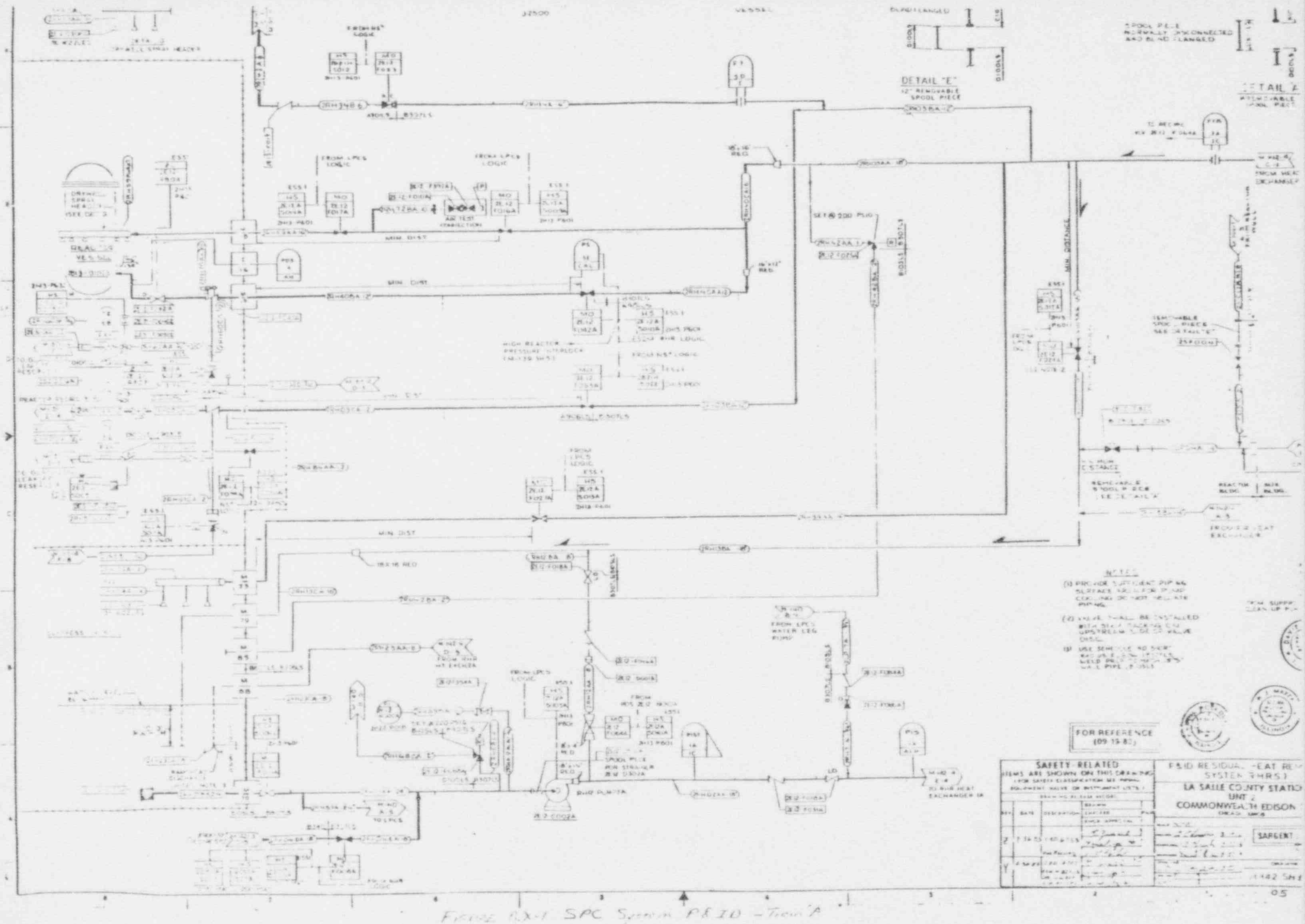

Figure RX-1 SPC System P&ID - Train A

Figure 5.3-1 Suppression Pool Cooling Mode P&ID - Train A

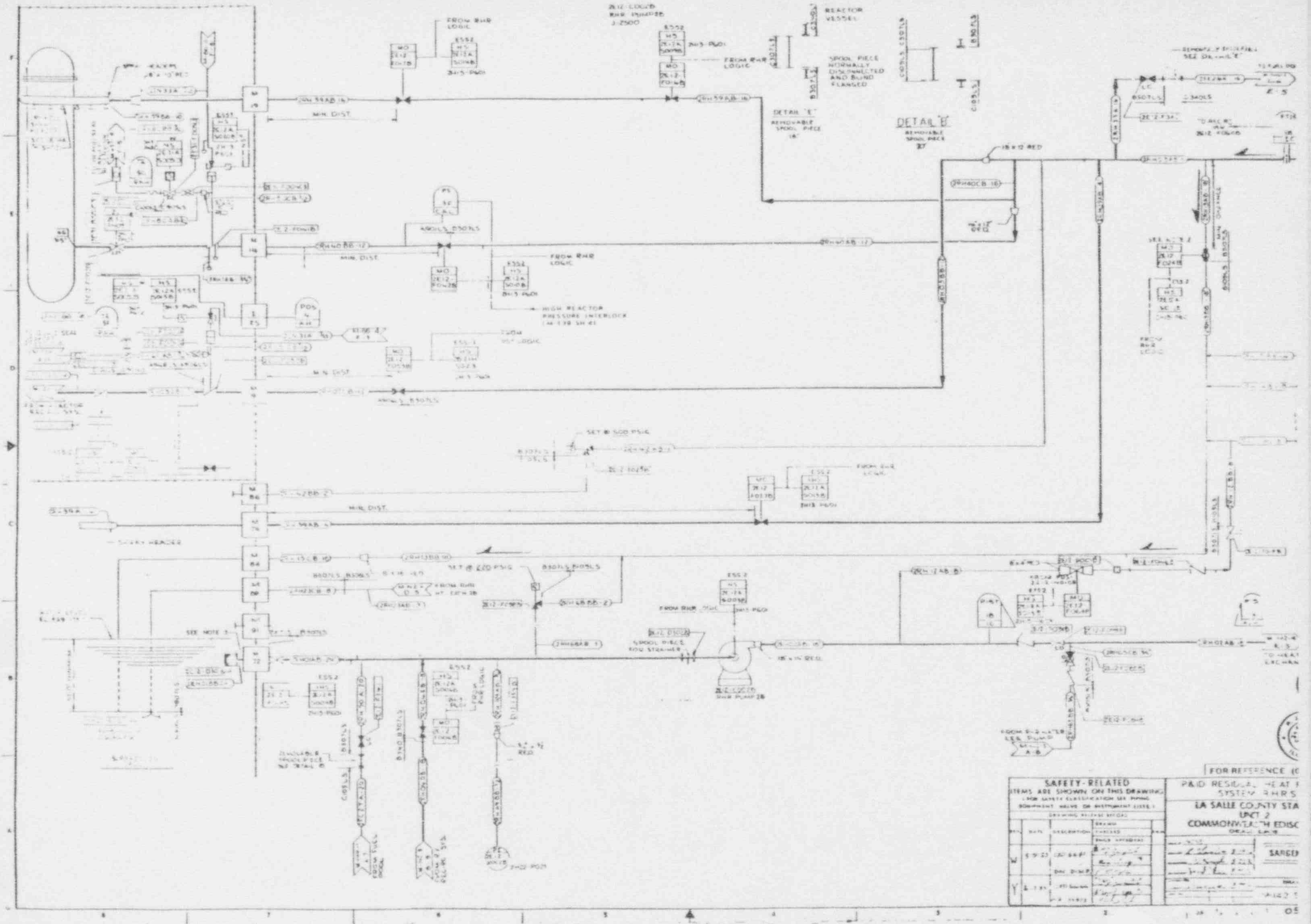

Figure EX-2 SPC System P&ID - Train B

Figure 5.3-2 Suppression Pool Cooling Mode P&ID - Train B

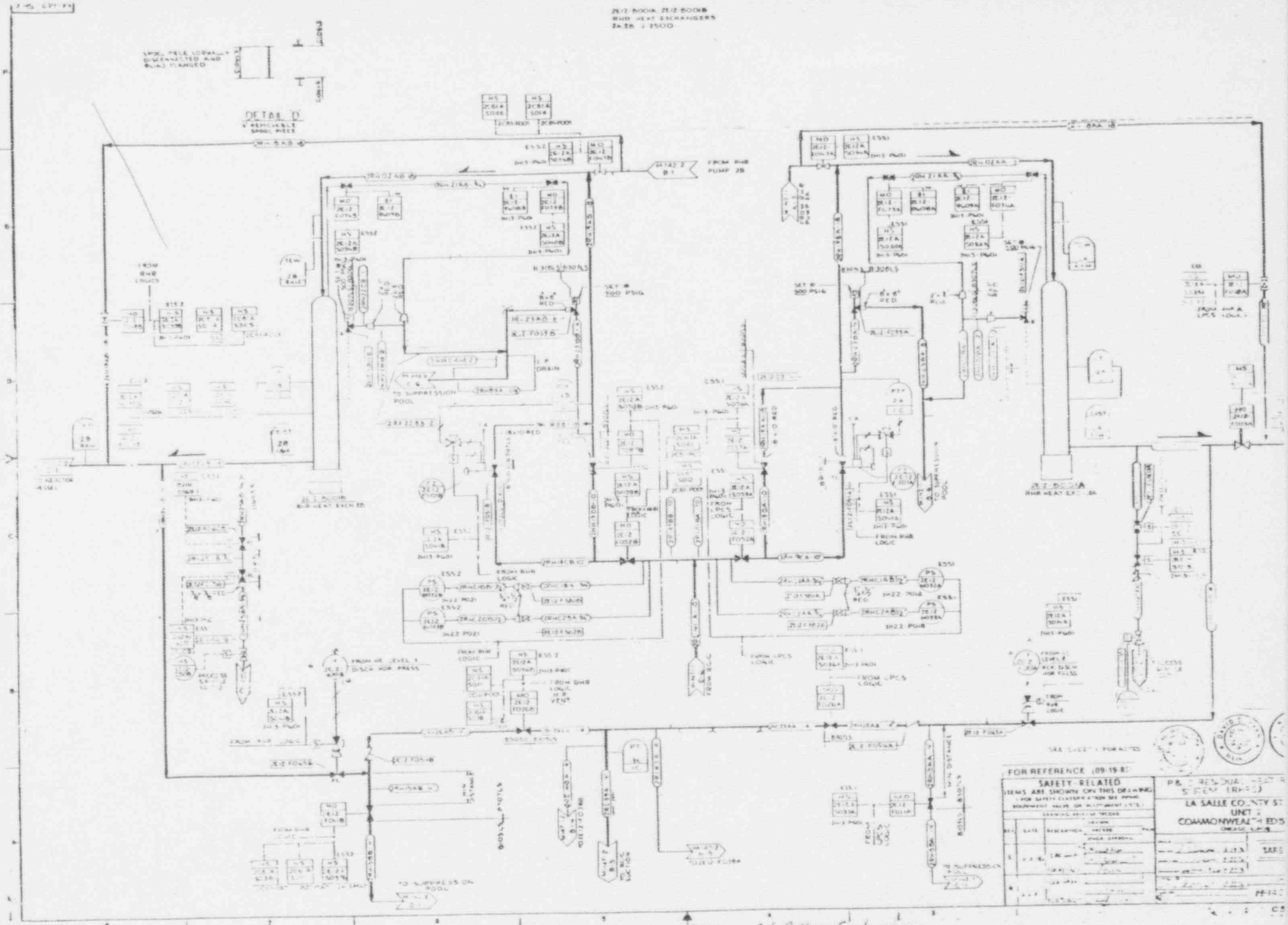

Figure B.x-3 SPC System P&ID - A&B Heat Exchangers

Figure 5.3-3 Suppression Pool Cooling Mode P&ID - Heat Exchangers

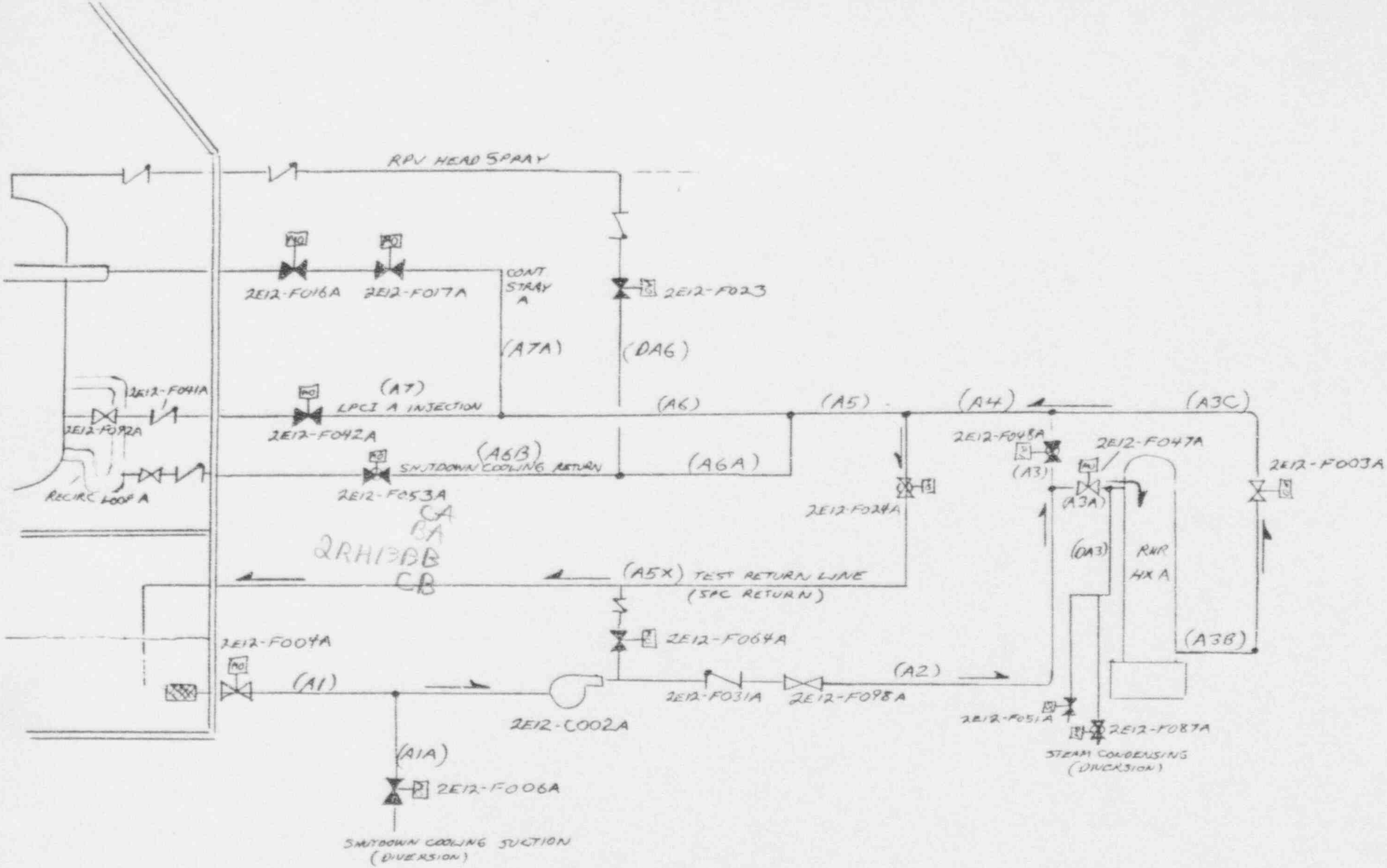

FIGURE B.X-5 Suppression Pool Cooling — Train A Simplified Diagram

Figure 5.3-4 Simplified Schematic of SPC Mode for Fault Tree Contstruction - Train A

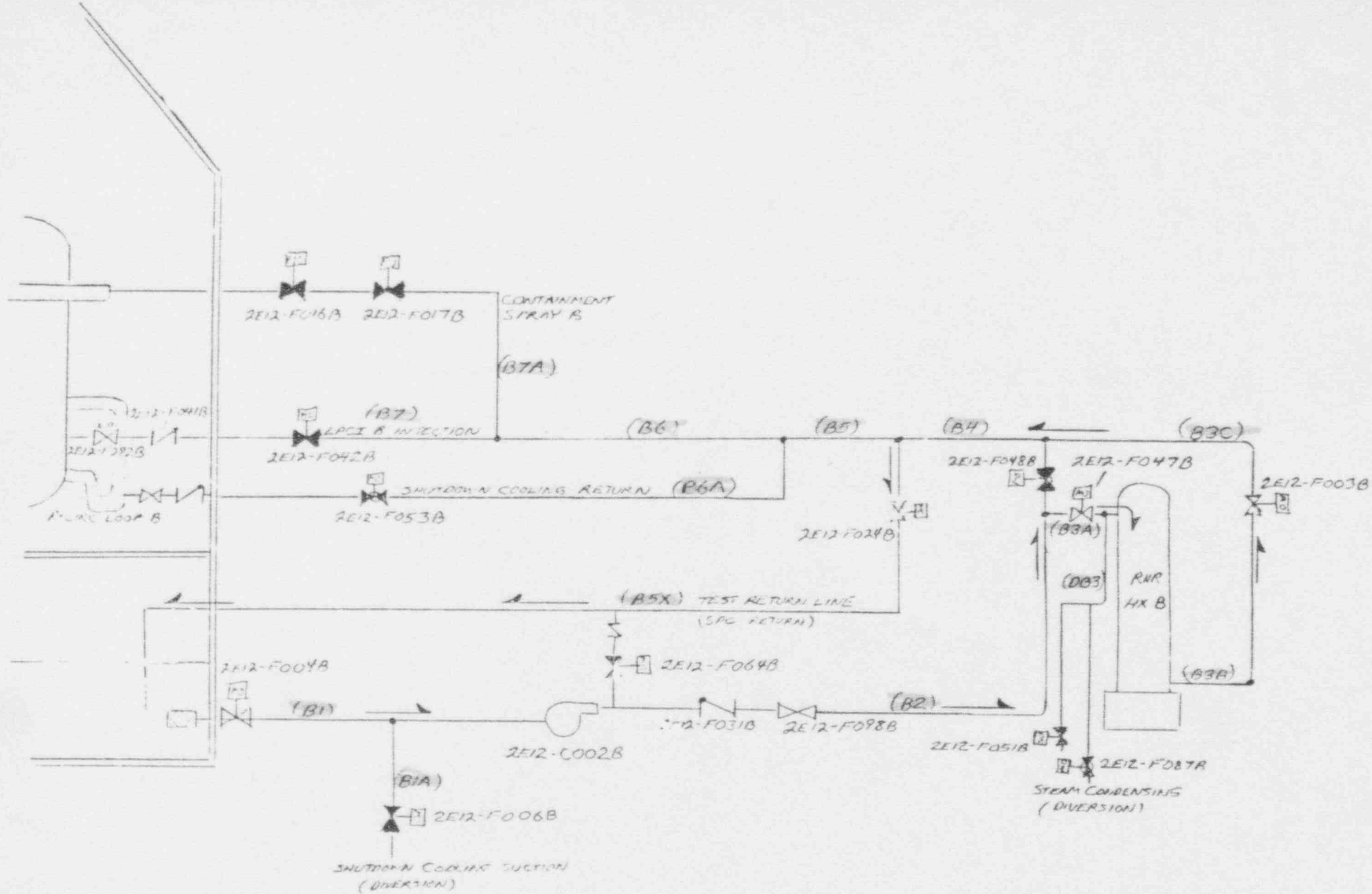

FIGURE B.X-6 Suppression Pool Cooling — Train B Simplified Diagram

Figure 5.3-5 Simplified Schematic of SPC Mode for Fault Tree Construction - Train B

5.4. Containment Spray Mode of RHR (CSS)

5.4.1 System Function

The Containment Spray System (CSS) is a subsystem of the RHR system and a subpart of the containment cooling mode. The containment cooling mode consists of suppression pool cooling and containment spray.

Containment spray is used to depressurize and cool the drywell atmosphere. The drywell spray removes energy from the drywell atmosphere by condensing the water vapor.

5.4.2 System Description

5.4.2.1 General Design

The Containment Spray subsystem consists of two independent fluid trains that draw water from the suppression pool, pass it through the RHR heat exchangers, and deliver it to the drywell spray headers. The CSS trains are configured from RHR trains A and B and use the RHR pumps, heat exchangers, and the drywell spray lines. Detailed one-line diagrams of the two CSS/RHR trains are shown in Figures 5.4-1 through 5.4-3.

Flow Path

The RHR System is aligned for LPCI mode and held in standby during normal plant operation. Normally, once the core reflood requirements are satisfied the operator may manually realign either RHR Train A or B in the Containment Spray mode. To do so, the LPCI injection MOV (or the injection MOV and any other mode) is manually closed, the CSCS system which supplies cooling water to the desired heat exchanger is started, the containment spray inboard (F017A/B) and outboard (F016A/B) valves are throttled open and the degree of heat removal is adjusted by throttling closed the heat exchanger bypass MOV (F048A/B). The RHR pump then takes suction from the suppression pool, the water is at least partially routed through the heat exchanger, and it is delivered to the drywell spray headers via the containment spray line. Subsequently the spray collects in the bottom of the drywell until the water level rises to the level of the downcomers. The water then overflows to the suppression pool.

Locations

Most of the RHR Train A components are located in the northwest corner of the reactor building basement. The RHR A Heat Exchanger is enclosed in a cubicle and extends from 694' to the 710' elevation. The drywell containment spray line MOVs (F016A & F017A) are located at the 761' and 772' elevations respectively.

The RHR Train B components are predominantly located in the southeast corner of the reactor building basement. The RHR B Heat Exchanger is also enclosed in its own cubicle and extends from 694' to the 710' elevation. The train B drywell spray line MOVs (F016B & F017B) are located at the 761' and 772' elevations.

Component Descriptions

The CSS components common to RHR trains A and B are described in Section 3.3, the LPCI system description. This includes the RHR pumps and their associated minimum flow lines, the pump suction line MOV's and the suppression pool strainers, the pumps discharge lines and their associated check valves, maintenance valves, and water leg fill systems, and RHR heat exchanger inlet, outlet, and bypass MOV's.

The RHR Heat Exchangers are described more completely in the the Shutdown Cooling system description in Section 5.2.

The 16-inch containment spray line for each train contains two 16-inch, motor-operated gate valves (F016A/B and F017A/B) that are normally closed. These valves can normally be opened manually one at a time. However, both can be opened if LPCI has initiated, high drywell pressure exists, and the F042A/B MOV (LPCI injection) is closed. The CSS valves are designed to operate with a maximum of 350 psid across the gate. These MOVs are not automatically actuated either in the open or close mode.

Drywell pressure, (the permissive for manual initiation) is monitored by four absolute pressure switches - two for Train A, two for Train B - mounted in instrument racks outside the primary containment in the reactor building. The switches are electrically connected so that no single sensor failure can prevent initiation of a CSS train.

5.4.2.2 System Interfaces

A failure modes and effect analysis (FMEA) of CSS support system interfaces is shown in Table 5.4-1. The support system interfaces are discussed below.

Shared Components

Most of the components in the CSS Trains A and B are also used in other RHR configurations - Shutdown Cooling, Low Pressure Coolant Injection, Suppression Pool Cooling, and Steam Condensing. The same RHR pumps, heat exchangers and flow paths are used except that the pump suction, heat exchanger flow control, and injection MOVs for the various modes may be positioned differently. During standby operation the same water-leg pump is used to keep the RHR and LPCS lines filled, while another pump is dedicated to keeping RHR [illegible] and C lines water filled.

Electrical

A separate division of the Class 1E electrical system provides power to each CSS train for operation of the RHR pumps, system MOVs, and system instrumentation and controls. The RHR A pump motor is supplied by the 4160 VAC distribution system from bus 241Y. The Train A MOVs are powered by the 480 VAC MCC 235Y-2 off bus 241Y. The only exception is the pump minimum flow bypass valve which is powered by MCC 235Y-1.

The RHR B pump motor is supplied by the 4160 VAC distribution system from bus 242Y. Off the 242Y bus, the train B MOVs are powered by the 480 VAC MCC 236Y-1.

The 125 VDC distribution system (Div. 1) supplies power to the RHR A interlock logic circuits and control power for the RHR A pump motor. The Division 2 125 VDC distribution system supplies power to the RHR B interlock logic circuits and also provides control power for the RHR B pump motor.

Actuation

As noted above, the Division 1 and 2 125 VDC distribution system supplies power to the RHR interlock logic circuits.

Control

As noted above, the Division 1 and 2 125 VDC distribution system supplies the control power for the RHR pumps. Control power for the various system MOVs is obtained through 480/120 VAC transformers off the MCCs powering the valve motors.

Component Cooling

The CSCS system provides cooling for the Train A and B RHR heat exchangers. Over the long term this is an essential support system for removing decay heat from the containment.

The CSCS system also cools the RHR pump seals. It must be in operation whenever pumped water exceeds 160F or the seals may fail in as little as 20 seconds. However, failure of the pump seals is not judged to be a fault that prevents the RHR pumps from functioning adequately for the purposes of CSS.

The RHR pump motors are air-cooled and depend on the ECCS Equipment Area Cooling System to keep the pump cubicle temperature within their qualification temperature limit (212F).

Room Cooling

The RHR pump motors are air-cooled and depend on the ECCS Equipment Area Cooling System to maintain pump cubicle temperatures within qualification limits. There is an ECCS Equipment Area Cooling System dedicated to cooling the NW cubicle (which contains the RHR A pump) and a separate system dedicated to SE cubicle cooling (RHR B and C pumps). Cooling water is supplied by the CSCS system.

5.4.2.3 Instrumentation and Control

System Actuation

Containment Spray is manually initiated. Normally the operator would convert either RHR Train A or B over to the CSS mode from the LPCI mode if high drywell pressure exists and the core reflood requirements have been satisfied. To do so, the CSCS system is manually started, the LPCI injection MOV (or the injection MOVs of any other RHR mode) are manually closed from the control room, the drywell containment spray MOVs (F016A/B and F017A/B) are throttled open, and the operator establishes the desired level of cooling by adjusting the heat exchanger bypass and outlet stop MOVs. It should be noted that the normally open heat exchanger bypass MOV's are interlocked such that they cannot be closed for the first ten minutes following a LPCI initiation signal.

If the LOCA logic has been reset and a new LPCI initiation signal is received during the drywell containment spray mode, the RHR train will automatically revert to the LPCI mode. However, the containment spray MOVs (F016 and F017) do not close automatically.

The logic diagrams for actuation of RHR pumps A and B (if they are not already operating) and for the various MOVs used in the CSS mode of operation are shown in Section 3.3, the LPCI system description, along with all the components used in the other modes of operation. Much of the actuation logic is common to the various modes and, if not, at least is in the same electrical circuit or is connected to a common circuit.

Component Control

The operator manually controls the containment spray (F016A/B and F017A/B), heat exchanger bypass (F048A/B), and heat exchanger outlet (F003A/B) MOVs in order to establish the desired degree of drywell containment heat removal. When drywell depressurization has been achieved the operator manually closes the containment spray MOVs.

The control circuits for the CSS components are also shown in Section 3.3, the LPCI system description.

Instrumentation

Valves

All motor-operated valves in the RHR trains have lighted position indicators in the control room. If a LOCA initiation signal is present and the F016A/B and F017A/B MOVs are opened, the white manual override lights located between the valve Open and Close position indicators will illuminate.

RHR Pumps

Indicators for each RHR pump in the control room show whether the pump is on, off, or in pull-to-lock. The current being drawn by the pump is also indicated. Two pressure switches are installed in each pump discharge pipeline and linked to control room indicators to verify that pumps are operating following an initiation signal. (The pressure signal is also used in the automatic depressurization system to verify availability of low-pressure core cooling.) A pressure indicator is also provided in the suction line of each RHR pump. The RHR pump and motor bearing temperatures can and should be monitored using the plant process computer during pump operation.

CSS System Flow

Flow in each RHR train is sensed by an orifice-type flow element in the pump discharge lines. Indication of system flow for each train is provided by meters on the RHR panel in the control room. The pump minimum flow bypass valve is positioned according to the indication received from this flow sensor.

Drywell Pressure

High pressure in the drywell is a necessary permissive for initiation of CSS. It is monitored by two absolute pressure switches for each CSS train. The switches are electrically configured such that no single sensor failure can prevent initiation of CSS train.

Control Room Monitors	Parameter Range
1. RHR Hx Water Level	0-100 %
2. RHR Hx Outlet Conductivity	0-10 mho's/cm
3. RHR Hx Temperatures	0-600F
a. Shell side inlet	
b. Shell side outlet	Multipoint recorder
c. Tube side outlet	
4. RHR Hx Inlet Steam Pressure	0-600 psig
5. RHR Hx Service Water side flow element	0-8000 gpm
6. RHR Pump	
a. RHR Discharge piping pressure	0-400 psi
b. RHR Pump flow (Loop)	0-10,000 gpm
c. RHR Pump Amps	0-150 amps
7. RHR Pump Room temperature	
a. Duct	0-300F
b. Area	0-300F

8. Drain Header Conductivity 0-25 mho/cm

9. Reactor Level Fuel Zone -111" to -311"

10. Leak Detection
    a. Valve Stem Leakage :)-600F
    b. Area Leak Detection 0-150F

11. Service Water Effluent Radiation 10-1 to 106 cps

Major Alarms

a. RHR Pump Cubicle Temp Hi - 149F

b. RHR Pump Breaker Closed - Breaker Closed

c. RHR Pump A, B Flow Above Minimum (>550 gpm) - Alarm at 1500 gpm increasing, resets at 1010 gpm decreasing.

d. RHR Pump A/B Disch Press Hi/Low - 400/55 psig

e. RHR Pump Auto Trip - multiple

f. RHR Pump Cubicle Cooler Fan Auto Trip - Overload

g. LPCI System Actuated - Drywell pressure 1.69 psig, Rx Level -129".

h. LPCI Manual Initiation Pushbutton Armed - PB Armed

i. RHR B/D (A/C) Drywell Press Hi - 1.69 psig

j. RHR B/D (A/C) Reactor Level 1 Low - -129"

k. RHR Equip Area Diff Temp or Ambient Temp Hi (Area - 130 2F. Diff temp - 30 2F)

l. RHR Service Water Pump Auto Trip - Overload

m. RHR Service Water Rad Hi - 6 cps

n. RHR Service Water Strainer 1(2) Diff Press Hi - 8 psid, 4 psid after backwash

o. RHR Hx Outlet Conductivity Hi - 10 umho

p. RHR Service Water Sump Level Hi Hi - Alarm 2' 11" below top of sump, reset 5' 10" below top of sump.

q. RHR HX A/B Discharge Cooling Water Temp Hi - 125F

r. RHR HX A/B Inlet Water Temp Hi - 400F

5.4.2.4 Operator Actions

The Containment Spray mode of RHR is manually initiated. The operator will normally decide to initiate either RHR Train A or B in CSS mode only if high drywell pressure/temperature exists and the core reflood requirements have been satisfied. To do so, the operator first closes the return/injection valve of the RHR mode to be terminated. Startup of CSCS system to supply cooling water to the heat exchangers is then manually initiated if it is not already in operation. The normally open RHR heat exchanger outlet MOV (F003A/B) is then closed and the heat exchanger bypass MOV (F048A/B) is verified open. If the train has been previously operating in another RHR mode, the RHR pump will be running with the minimum flow bypass line open, otherwise the RHR pump is manually started. The operator then establishes the desired level of cooling by throttling open the drywell spray MOVs and adjusting the heat exchanger bypass and outlet MOVs.

The CSS mode must be manually shutdown. If the LOCA logic has been reset and a new LOCA signal is received, the RHR trains will automatically revert to LPCI, but the CSS injection MOVs do not automatically close.

5.4.2.5 Technical Specification Limitations

There are no Technical Specification Limitations that pertain specifically to the drywell containment spray mode of the RHR system. No credit is taken in the FSAR design basis analysis for post-LOCA heat removal or fission product control due to containment spray system operation.

5.4.2.6 Tests

The major tests that impact the CSS mode of RHR are the same as those listed for the LPCI system in Table 3.3-2. The table has been edited to cover only those components affecting CSS (see Table 5.4-2).

Although it is not a test, shiftly surveillance verifies the condition of the RHR pumps and the correct alignment of all MOVs during standby operation. This alignment is such that the RHR trains can rapidly and automatically initiate LPCI when called upon.

5.4.2.7 Maintenance

No scheduled maintenance which disables CSS components while the plant is at power is planned. Unscheduled maintenance is permitted on system components provided applicable safety and radiological administrative controls can be satisfied. Unscheduled maintenance activities possible during plant operation are much the same as those listed for the LPCI system and include:

- Replacement or repair of actuation and control circuitry

- Electrical maintenance on motor driven components

- MOV and pump mechanical maintenance that does not result in breech of the CSS system boundary.

- MOV and pump mechanical maintenance that breeches the system boundary when double isolation from reactor pressure/ temperature can be achieved. Isolation here is taken to mean an accessible manual valve or a motor-operated valve that can be racked out. It is assumed that check valves do no provide a secure means of isolation. (Note that in the case of the RHR A and B trains double isolation must not only be achieved at the injection line end, but also at the Shutdown Cooling suction line end.)

A summary of unscheduled maintenance acts allowed on the A and B trains of the RHR system while the plant is in full power operation is given the Table 5.4-3. (Only the activities that impact the successful operation of the CSS mode have been included.) The following comments pertain to this table:

- Although permitted, unscheduled maintenance on check valves and manual valves is not listed on the table because of the significantly lower frequencies of occurrence when compared to MOVs.

- It is assumed that safety procedures and the requirement for double isolation will result in the RHR pump being racked out when maintenance on a component involves opening up the RHR line. However, this is not a significant contributor to system unavailability since RHR pump indication is provided in the control room and checked shiftly. For those components that can be double isolated, the most significant possibility of a "failure to restore" fault lies with the manual maintenance isolation valves (F098 A/B). No control room indication is provided for these valves and the only time misalignment is certain to be detected is during quarterly system full-flow tests. For this reason, only the first two components entered in Table 5.4-3 reflect the fact that the pump circuit breaker is racked out for maintenance that breeches the RHR boundary. Thereafter, only the F098 maintenance valve alignment away from normal is shown.

- The manual maintenance isolation valves in the drywell (F092A/B) are assumed to be inaccessible during full power operation, and hence cannot be used to achieve RHR line double isolation.

- Each of the system MOVs and pumps has a feed circuit breaker in the power supply lines off its associated MCC. In addition to the maintenance activity shown in Table 5.4-3, unscheduled electrical maintenance on these circuit breakers is anticipated. This activity is only of interest for components that must change state and it is assumed that no other system components are impacted. Failure to restore the breaker after maintenance is not considered likely because the component indicator lights in the control room receive their power through the breaker.

5.4.3 System Operation

5.4.3.1 Normal Operation

During the normal plant operation, Trains A and B of the RHR system are in standby and ready to initiate the LPCI function. One water-leg pump operates continuously to keep the LPCS and RHR A pump discharge line filled and a separate pump keeps the RHR B and C lines water filled. The suppression chamber must also be operable with its level between 26' 10" and 26' 2 1/2" and its temperature at or below 100F.

5.4.3.2 Abnormal Operation

The CSS mode of RHR is manually actuated. The CSS mode will normally be initiated when drywell pressure has reached 1.69 psig following a LOCA, and the core reflood requirements have been satisfied.

The steps the operator must take to initiate CSS during abnormal conditions are described in Section 5.4.2.4.

5.4.4 System Fault Tree

5.4.4.1 Description

Simplified diagrams of the two CSS trains of RHR indicating the mechanical components included in the fault tree models are shown in Figures 5.4-4 and 5.4-5.

There are a number of components (e.g. the steam condensing isolation MOVs 2E12-F087 A/B) that appear in the fault trees only as contributors to CSS system unavailability due to component unscheduled maintenance that breeches the RHR system boundary. These components form part of the CSS pressure boundary but do not perform a function essential to successful CSS operation. They are indicated on the detailed drawings (5.4-1 through 5.4-3) but have been omitted from the simplified diagrams.

There are seventeen developed events in the CSS fault tree. Twelve of these events are transfers from the LPCI, Shutdown Cooling, and Suppression Pool Cooling fault trees. Since much of the CSS flowpath and components are common to these other RHR modes, they have not been modeled again in the CSS fault tree. Four of the developed events are transfers from the electric power fault trees: the 480 VAC MCC's 235Y-2, and 236Y-1, and the 125 VDC buses 211Y and 212Y. The remaining developed event is a transfer from the LOCA logic a model developed in the LPCI fault tree (the LOCA B logic is developed in CSS).

5.4.4.2 Success/Failure Criteria

The CSS system is successful if one of the two independent trains operates at full capacity for the duration of the accident scenario it is required for It conveys water from the suppression pool, passes it through the heat exchanger to cool, and delivers it to the drywell spray spargers. CSS failure occurs upon one of the following:

1. Both normal and emergency power is lost (Division 1 & 2).

2. Both 211Y and 212Y 125 VDC buses are lost.

3. Divisions 1 & 2 of the CSCS system to the heat exchangers is lost

4. ECCS Equipment Area Cooling is lost for both the SE and NW cubicles.

5. Both CSS trains fail due to various combinations of pump failures, injection MOV failures, flow diversions, pipe ruptures, or maintenance outages.

6. Debris in the suppression pool (most likely insulation from the drywell) clogs the Train A and B RHR suction strainers to an extent greater than 50 percent.

The top event of the CSS system tree is:

FAILURE OF CSS SYST TO REMOVE CMT HEAT WITH 1-OF-2 LOOPS AND 1-OF-2 HT EXCHS.

5.4.4.3 Assumptions

In addition to the general assumptions regarding fault tree development (listed at the beginning of this volume), the following assumptions specific to the CSS system were made:

1. There are several large branch lines used for auxiliary functions (e.g. Suppression Pool Clean-up) that are normally locked closed by a manual valve and sealed by a blind flange during normal operation. It is highly unlikely that such a line could be inadvertently left open and not detected during the various start-up procedures. Therefore these lines are not modeled as diversion paths.

2. Inadvertent opening of either the LPCI injection MOV (F042A/B), the SHUTDOWN COOLING injection MOV (F053) or the RPV Head Spray injection MOV (F023) opens a CSS flow diversion path to the RPV

(and thus away from the drywell sprays). However, in essentially all important LOCA or transient scenarios RPV pressure will be significantly higher than wetwell pressure. Since all three of these injection lines contain check valves, the higher RPV pressure will prevent these lines from acting as a major diversion to CSS flow. Thus inadvertent opening of any of these injection MOVs is not modeled as a contributor to CSS failure.

3. There are several safety relief valve lines associated with the two CSS trains. None are larger than 4-inches diameter, hence, it is assumed that they cannot act as significant diversion paths for CSS flow. (The RHR/CSS line ranges from 24-inch pipe at the pump suction to the 16-inch CSS return line.) An inadvertently opened safety/relief valve in the one-inch line off the RHR pump suction does not create a large enough path to significantly affect pump NPSH. (The NPSH of the RHR pumps is set largely by the depth of water in the suppression pool.)

4. The minimum flow bypass lines protect the RHR pumps from overheating when an RHR mode discharge path has not been established yet. The usual sequence for CSS operation has the operator switching either the RHR A or B train from LPCI (or another RHR mode) over to CSS operation. In so doing, the injection MOV of the other RHR mode is closed and the pump continues to run with only the minimum flow line open to the suppression pool until CSS flow is established. During this time the pump would be 'dead-headed' if the minimum flow MOV failed closed. The RHR pump manufacturer indicates, however, that the pumps will operate 30 to 60 minutes under no-flow conditions before they overheat. (The exact time-to-failure is dependent on the pump cubicle environment.) Even taking the minimum time-to-failure of 1/2 hour, it is highly likely that either the operator will have established CSS flow, or various control room indicators will have warned the operator of a problem with the RHR pump flow. Control room indicators include a position indicator for the minimum flow bypass MOV, pump discharge pressure and alarm (400 psig), RHR line flow indicator, and a pump bearing temperature recorder. For these reasons failure of the pump discharge bypass line to provide minimum flow after pump initiation is not considered a significant contributor to pump failure.

5. The 8-inch minimum flow bypass line at the discharge of each RHR pump contains a 4-inch diameter flow restrictor. It is therefore too small to act as a significant diversion path should the minimum flow bypass MOV remain open when CSS flow is required.

6. The RHR pump motors are air-cooled and analysis indicates that the ECCS Equipment Areas Cooling System must operate to keep pump cubicle temperatures within operational limits. The pump seals are cooled by a dedicated water cooling system which is part of the

CSCS cooling system. (The CSCS also cools the heat exchangers in the ECCS Equipment Areas HVAC.) Analysis indicates that the pump seals begin to fail in 15 - 20 seconds after loss of seal cooling if the pumped water temperature significantly exceeds 160F. It is possible that the RHR pumps will be pumping water at 160F or greater when CSS is in operation in some scenarios. However, loss of the pump seals and the leakage that ensues is not considered to have a severe enough impact on pump performance that CSS would not succeed over its mission time. For this reason, seal cooling is not considered an essential support system to CSS.

7. The possibility of waterhammer failure of the pump discharge line due to failure of the water-leg fill subsystem is neglected. The water leg pump operates continuously to maintain the RHR lines in a filled condition. It is indicated in the control room and checked shiftly. In addition, the RHR pump discharge line pressure is indicated and alarmed in the control room, so failures of the water leg fill subsystem are readily detected. When the water leg fill system is out of service, the RHR lines can be manually filled via the Flushing Water Supply line. Even in the event that the RHR line is not water filled when the RHR pump starts, the design of the pump discharge line is such that pipe rupture due to water hammer is unlikely.

8. If a Shutdown Cooling MOV (F006 A/B) in the RHR pump suction line should inadvertently open while the other RHR train is operating in the Shutdown Cooling mode a direct path between the RPV and the suppression pool is created. The FSAR indicates that this may cause 'flashing' in the RHR lines that could severely damage the suppression pool strainer and/or the RHR pump. It is conservatively assumed that inadvertent opening of Train A or B's F006 MOV while the other RHR train is in Shutdown Cooling mode fails that train's RHR pump.

9. Failure of the heat exchanger bypass valve (F048A/B) to close or remain closed results in approximately 60 percent of CSS flow being routed around the RHR heat exchanger. It is assumed that this fault prevents adequate heat removal from the pumped suppression pool water and hence fails that containment spray train.

Table 5.4-1 CSS Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
4160 VAC BUS 241Y	2E12-C002A	Motor-driven pump	FTS/FTR	Loss of all Train A MOV indication lights in control room	Loss of CSS Train A	Fails CSS Train A
480 VAC MCC 235Y-2	2E12-F016A, F017A	MOVs	FTO	Loss of position lights in control room	Loss of Train A remote actuation of drywell spray MOVs	
	2E12-F048A	MOV	FTC	Loss of position lights in control room	Most suppression pool water is routed around the heat exchanger. Inadequate heat removal	Loss of remote actuation of CSS spray MOVs and loss of remote control of water flow through heat exchanger. Fails CSS Train A
4160 VAC BUS 242Y	2E12-C002B	Motor-driven pump	FTS/FTR	Loss of all Train B MOV indication lights in control room	Loss of CSS Train B	Fails CSS Train B
480 VAC MCC 236Y-1	2E12-F016B, F017B	MOVs	FTO	Loss of position lights in control room	Loss of Train B remote actuation of drywell spray MOVs	
	2E12-F048B	MOV	FTC	Loss of position lights in control room	Most suppression pool water is routed around the heat exchanger. Inadequate removal	Loss of remote actuation of SPC spray MOVs and loss of remote control of water flow through heat exchanger. Fails CSS Train B
125V DC POWER DIST PNL 211Y	2E12-C002A Control/ Actuation	Motor-driven pump	FTS/FTR	Loss of pump indication lights in control room	RHR pump A inoperable - Fail CSS Train A	Fails CSS Train A

Table 5.4-1 CSS Support System Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
DIST PNL 212Y	2E12-C002B Control/ Actuation	Motor-driven pump	FTS/FTR	Loss of pump indication lights in control room	RHR pump B inoperable - Fail CSS Train B	Fails CSS Train B
<u>CSCS Equipment Cooling Water System</u>						
RHR Service Water System (Div. 1)	2E12-C C002A	Motor-driven pump	Fail seal cooling, leakage	Service water pumps indicated/ alarmed in control room. Leak detected in pump cubicle	Leakage does not fail pump in short term. If gross seal failure occurs, pump water could flash damaging pump.	Coolant leakage into RHR pump A cubicle. Possible damage to pump over long-term.
	2E12-B001A	RHR Heat Exchanger	No heat removal	Service water condition and Htx pump condition inlet/outlet temps indicated in control room	Loss of CSS Train A heat removal	Fails CSS Train A
RHR Service Water System (Div. 2)	2E12-C002B	Motor-driven pump	Fail seal cooling, Leakage	Service water pumps indicated/ alarmed in control room. Leak detected in pump cubicle.	Leakage does not fail pump in short term. If gross seal failure occurs, pumped water could flash, damaging pump.	Coolant leakage into RHR pumps B and C cubicle. Possible damage to pump over long-term
	2E12-B001B	RHR Heat Exchanger	No heat removal	Service Water pump condition and Htx inlet/ outlet temps indicated in control room	Loss of CSS Train B heat removal	Fails CSS Train B

Table 5.4-1 CSS Support System Interface FMEA (Concluded)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
<u>ECCS Equipment Cooling System</u> NW Cubicle Cooling	2E12-C002A and related I&C	Motor-driven pump	FTR (overheat or control)	Cubicle temperature indicated and alarmed in control room. HVAC fan indicated in control room.	After about one hour, overheat of pump motor trips the RHR pump A and fails CSS train A. Pump instrumentation and control circuitry in cubicle may be affected earlier	CSS Train A succeeds initially but continued operation is threatened one hour after loss of cubicle cooling.
<u>ECCS Equipment Cooling System</u> SE Cubicle Cooling	2E12-C002B and related I&C	Motor-driven pump	FTR (overheat or control)	"	After about six to ten min. overheat of pump motor trips RHR pump failing CSS Train B. Pump instrumentation and control circuitry in cubicle may be affected earlier.	CSS Train B succeeds initially but continued operation is threatened about six to ten minutes after loss of cubicle cooling.

Table 5.4-2 CSS System Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
LOS-RH-M1	System Operability (Alignment)	All motor-operated valves required for CSS operation and the drywell manual isolation valves		No	---	Monthly	---	Alignment: Shiftly Operability: Quarterly
		RHR/LPCS Water Leg	Pumps	No	---	Monthly	---	Monthly
LOS-RH-Q1	Pump Inservice	2E12-C002A/B	Pumps	No	---	Monthly	---	Alignment: Shiftly Operability: Quarterly
		2E12-F064A/B	MOVs	No	---	Quarterly	---	" "
		2E12-F024A/B and 2E12-F021	"	Yes	Yes	"	---	" "
		2E12-F027A/B	"	Yes	No	"	---	" "
		2E12-F048A/B	"	Yes	Yes	"	---	" "
LOS-RH-Q2	Value Exercise	2E12-F004A/B	MOVs	Yes	No	Quarterly	---	Alignment: Shiftly Operability: Quarterly
		2E12-C002A/B	Pumps	Yes[1]	"	"	---	" "
		2E12-F006A/B	MOVs	Yes	No	"	---	" "
		2E12-F047A/B	"	Yes[2]	Yes	"	---	" "
		2E12-F003A/B	"	"	"	"	---	" "
		2E12-F016A/B	"	Yes[3]	Yes	"	---	" "

1) RHR pumps are placed in "Pull-to-Lock" while F004 valves are tested.
2) Valve is out of alignment only briefly.
3) Valve is only briefly out of alignment. Interlocks prevent both F016 & F017 from being open at once.

Table 5.4-2 CSS System Test Summary (Concluded)

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
		2E12-F017A/B	"	"		"	---	" "
		2E12-F048A/B	"	Yes[2]	Yes	"	---	" "
		2E12-F024A/B	"	"	"	"	---	" "
		2E12-F064A/B	"	"	"	"	---	" "

2) Valve is out of alignment only briefly.

Table 5.4-3 Containment Spray System Unscheduled Maintenance Summary

Component/ Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance with no Auto-Return	Allowed During Plant Operation?	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E12-C002A/B	Pumps	Mechanical[1]/ electrical	Pump circuit breaker	Yes			Alignment: Shiftly Operability: Quarterly
		Mechanical[2]	Pump circuit breaker	Yes			"
			MOV 2E12-F004A/B				"
			MOV 2E12-F006A/B[3] circuit breaker				"
			Man. 2E12-F098A/B	Yes			Actuation: Quarterly
2E12-F016A/B	MOV	Mechanical[1]/ electrical	Valve circuit breaker	Yes			Alignment: Shiftly Operability: Quarterly
2E12-F017A/B	"	"	"	"			"
2E12-F006A/B	MOV	Mechanical[2]/	MOV 2E12-F004A/B	Yes			
			MOV 2E12-F006B/A[3] (circuit breaker in other train)				"
			Man. 2E12-F098A/B				Alignment: Quarterly
			Pump 2E12-C002A/B circuit breaker				Alignment: Shiftly Operability: Quarterly
2E12-F064A/B	MOV	Mechanical[2]	MOV 2E12-F004A/B	Yes			"
			MOV 2E12-F006A/B[3] circuit breaker				" "
			Man. 2E12-F098A/B				Alignment: Quarterly
2E12-F088A/B	Safety relief valve	Mechanical[2]	MOV 2E12-F004A/B	Yes			Alignment: Shiftly Operability: Quarterly
			MOV 2E12-F006A/B[3] circuit breaker				" "
			Man. 2E12-F098A/B				Alignment: Quarterly

1) Maintenance not involving a breach of CSS system boundary.
2) Maintenance involving breaching the CSS system boundary and requiring double isolation from reactor pressure.
3) Inoperability of this component only impacts other modes of RHR.

Table 5.4-3 Containment Spray System Unscheduled Maintenance Summary (Concluded)

Component/ Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance with no Auto-Return	Allowed During Plant Operation?	Frequency	Outage	Frequency of Alignment/ Operability Verification
2E12-C003	Pump	Mechanical[2]	Man 2E12-F098B	Yes			Alignment: Quarterly
2E21-C002	Pump	Mechanical[2]	Man 2E12-F098A	Yes			Alignment: Quarterly
2E12-C002A/B	MOV	Mechanical[2]/	2E12-F006A/B[3] circuit breaker Man. 2E12-F098A/B	Yes			Alignment: Shiftly Operability: Quarterly Alignment: Quarterly
2E12-B001A/B	Heat exchanger	Mechanical[2]	2E12-F098A/B	Yes			Alignment: Quarterly
2E12-F051A/B	Pneumatic valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F078A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F055A/B	Safety/ relief valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F060A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F065A/B	Pneumatic valve	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F065A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"
2E12-F087A/B	MOV globe	Mechanical[2]	2E12-F098A/B	Yes			"

2) Maintenance involving breaching the CSS system boundary and requiring double isolation from reactor pressure.
3) Inoperability of this component only impacts other modes of RHR.

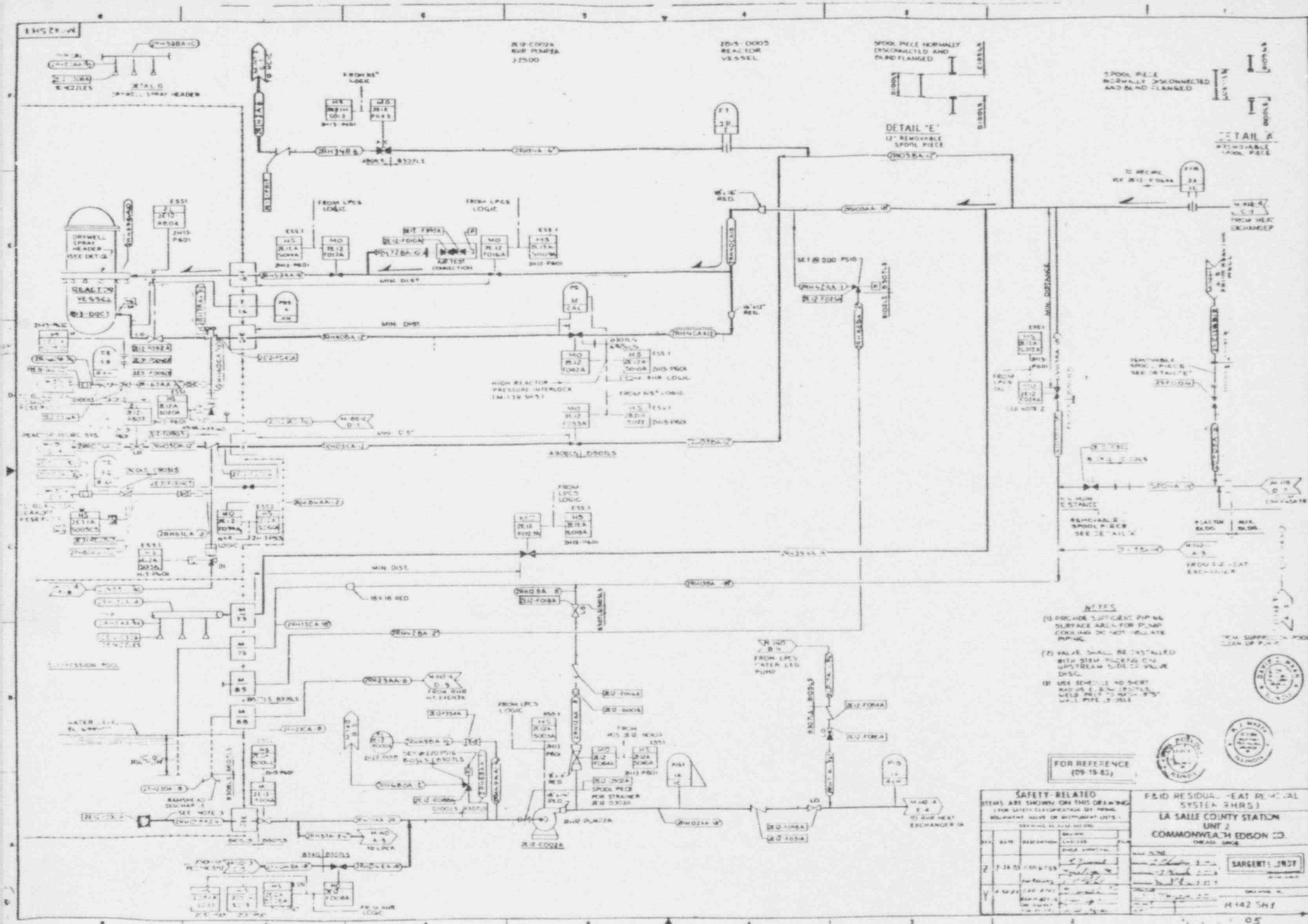

Figure 6.X-1 CSS System P&ID - Train A

Figure 5.4-1 Containment Spray Mode P&ID - Train A

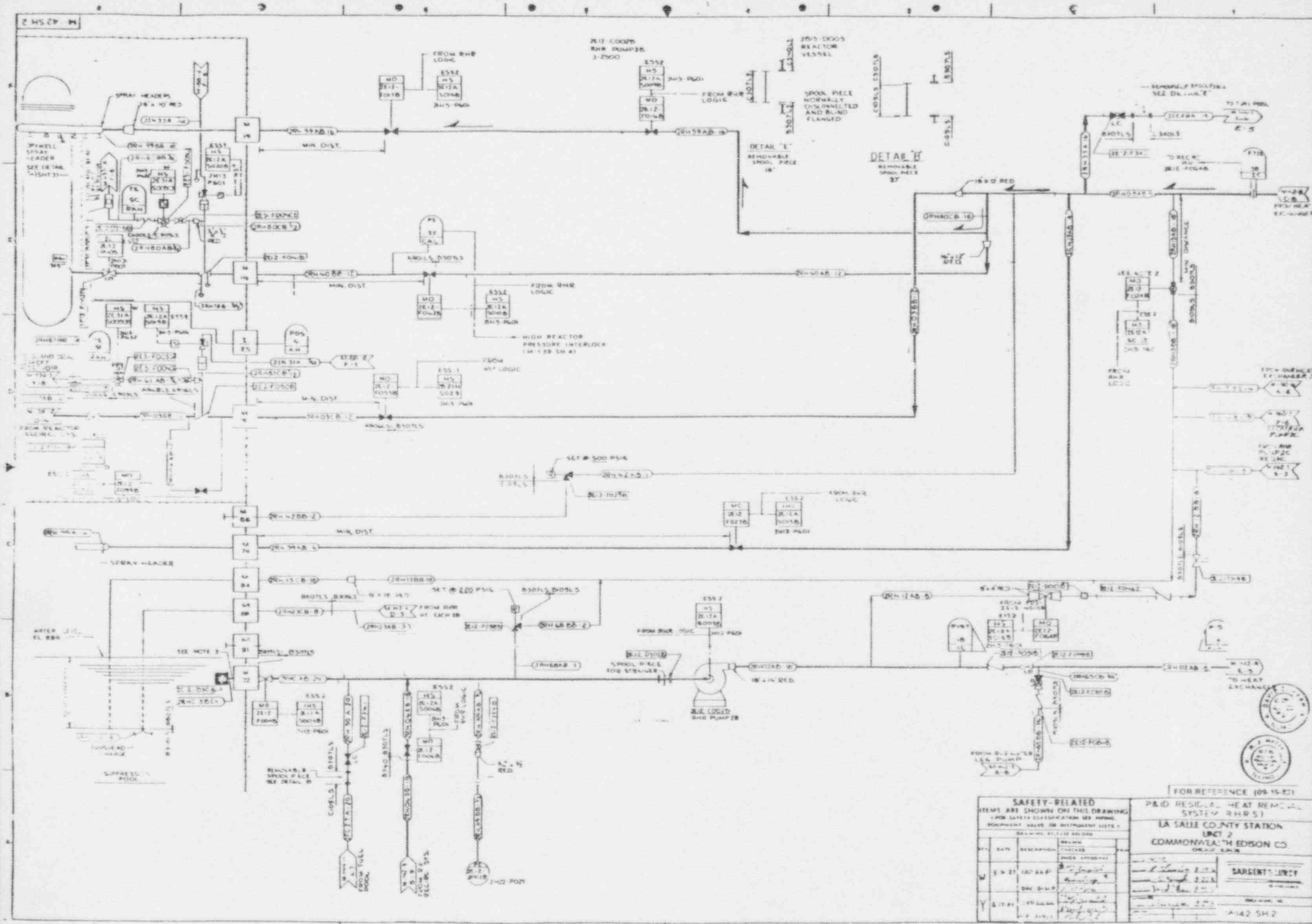

Figure B.X-2 CSS System P&ID – Train B

Figure 5.4-2 Containment Spray Mode P&ID - Train B

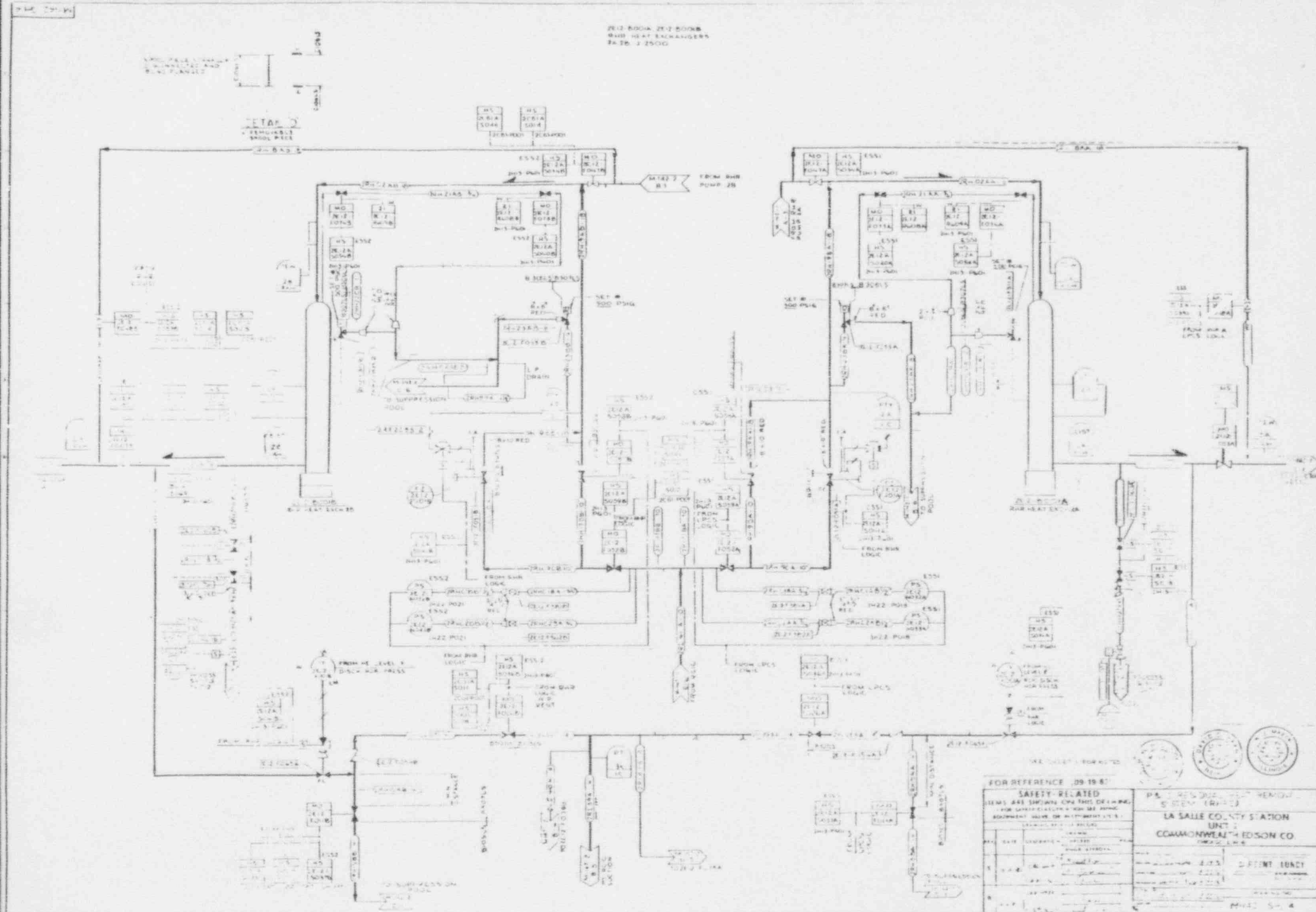

Figure Bx-3 CSS System P&ID - A&B Heat Exchangers

Figure 5.4-3 Containment Spray Mode P&ID - Heat Exchangers

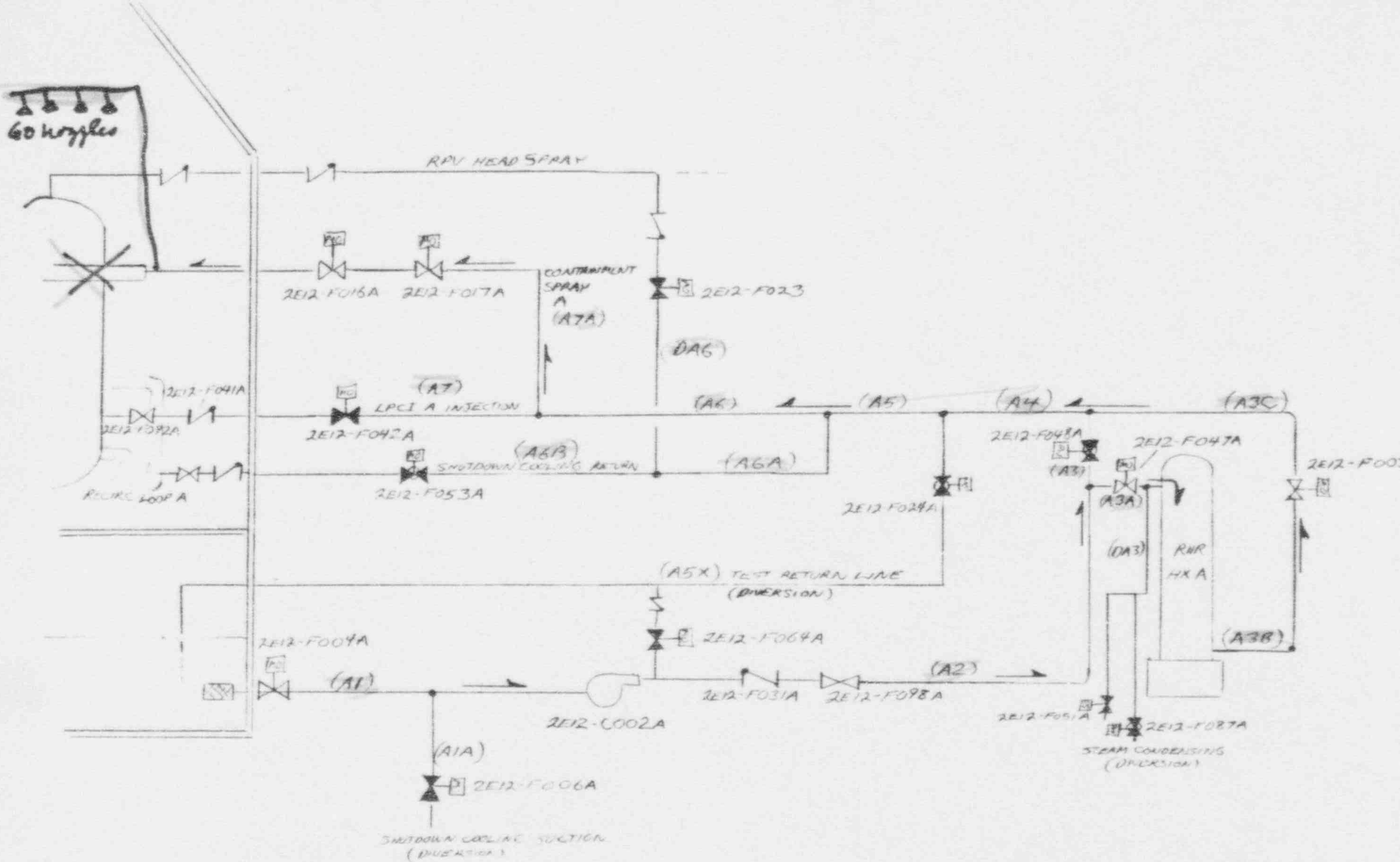

Figure B.X-6 Containment Spray — Train A Simplified Diagram

Figure 5.4-4 Simplified Schematic of Containment Spray Mode for Fault Tree Construction - Train A

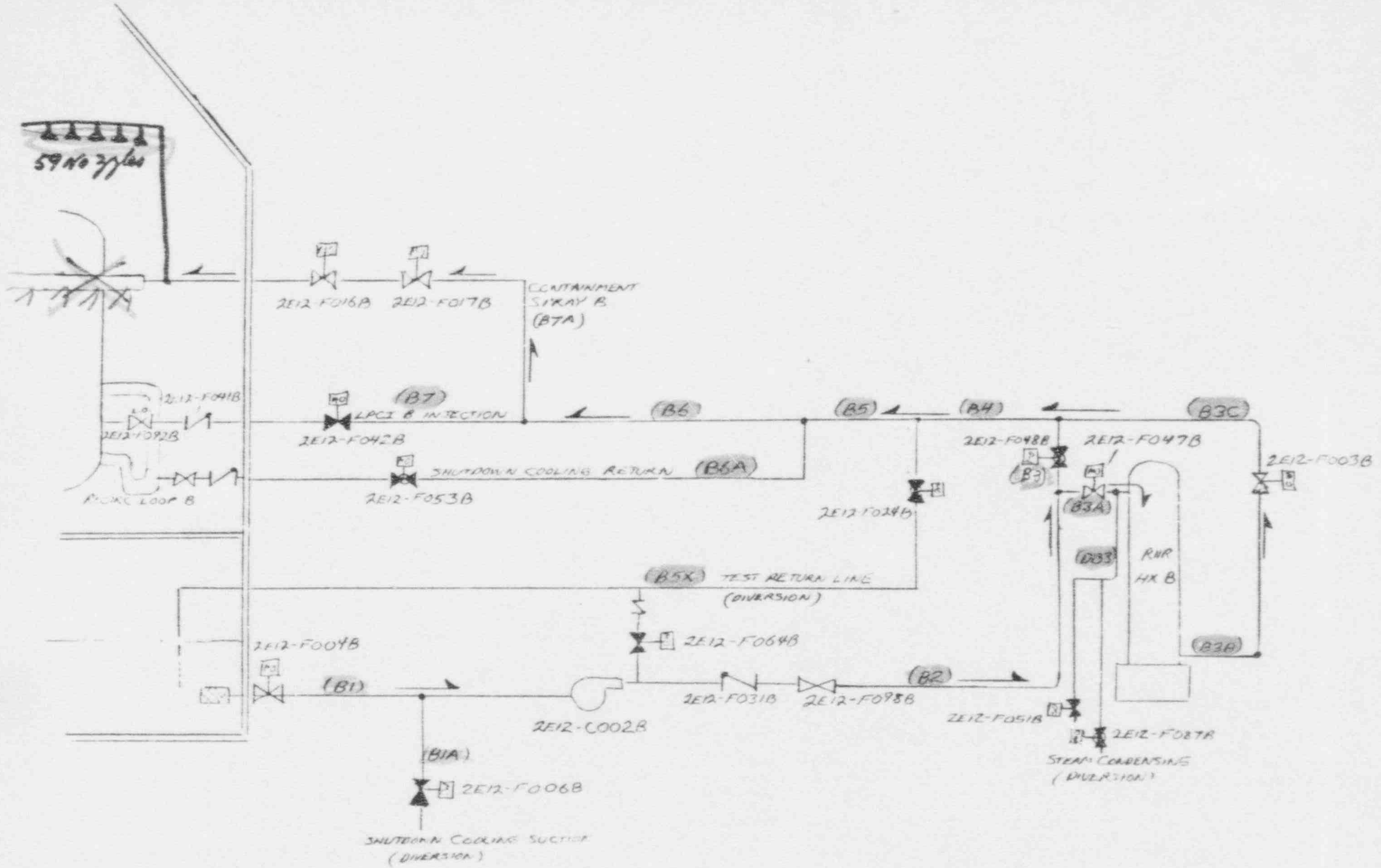

FIGURE B.X-7 Containment Spray — Train B Simplified Diagram

Figure 5.4-5 Simplified Schematic of Containment Spray Mode for Fault Tree Construction - Train B

6.0 REACTIVITY CONTROL SYSTEMS

6.1 Reactor Protection System/Alternate Rod Insertion (RPS/ARI)

6.1.1 System Function

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Component Descriptions

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Component Cooling

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System Actuation

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Instrumentation

6.1.2.4 Operator Actions

6.1.2.5 Technical Specification Limitations

6.1.2.6 Tests

6.1.2.7 Maintenance

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6.1.4 System Fault Tree

6.1.4.1 Fault Tree Description

6.1.4.2 Success/Failure Criteria

6.1.4.3 Major Assumptions

Table 6.1-1 Reactor Protection System Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)

Table 6.1-2 Reactor Protection System Component/Subsystem Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency (Mo)	Test Outage (Hr)	Component/Subsystem Alignment/Operability Verification Frequency

Table 6.1-3 Reactor Protection System Component/Subsystem Maintenance Summary

Component Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification

Figure 6.1-1 Simplified Schematic of Reactor Protection System

Figure 6.1-2 Component Control Circuits

Figure 6.1-3 Component Actuation Circuits

6.2 Standby Liquid Control System (SBLC)

6.2.1 System Function

The Standby Liquid Control System (SBLC) provides an alternate means of shutting down the reactor, independent of the control rod drive system. A neutron absorber solution, sodium pentaborate, is injected into the reactor vessel to shut down the reactor and keep it subcritical as cooldown and xenon decay occur. This system does not provide a prompt reactor shutdown rather, shutdown occurs in the time frame of one to two hours as the sodium pentaborate solution is injected.

6.2.2 System Description

6.2.2.1 General Design

The Standby Liquid Control System injects borated water into the reactor vessel through a single injection line. The system consists of a storage tank, redundant pumps, inlet and explosive outlet valves, and associated piping. A detailed one-line diagram of the SBLC is shown in Figure 6.2-1.

Flow Path

Upon manual initiation, sodium pentaborate solution flows through a single outlet pipe from the storage tank. The flow then splits into one of two parallel, cross-tied paths. Within each parallel path is a motor-operated valve, a positive- displacement pump (protected by a relief valve) and an explosive-operated (squib) valve. Because of the cross-ties, a successful flowpath can include either inlet MOV, either pump, and either squib valve. The two parallel paths then join to form a single injection line feeding the poison sparger in the lower plenum of the reactor vessel.

Locations

The SBLC is located in the secondary containment of the reactor building. However, the injection line penetrates the primary containment and also the bottom head of the reactor vessel.

Component Descriptions

Sodium pentaborate solution is contained in a stainless steel covered storage tank (2C41-A001) with a capacity of 5150 gallons. The solution is maintained at a temperature range of 75 to 85F. A heater (A) maintains this temperature range. (Another heater (B) is used only for initial solution preparation.) Initial mixing is aided by an air sparger penetrating the tank. The tank outlet line is located on the side of the tank to prevent possible plugging of the line due to sodium pentaborate precipitation. The short pipe leading from the storage tank to the two pump suction MOVs also has electrical heat tracing in order to prevent sodium pentaborate precipitation.

There are two pump suction MOV valves (2C41-F001A and B) in the SBLC, one for each pump line. These normally-closed 3-inch globe valves separate the sodium pentaborate solution upstream from the water filling the rest of the system during standby. Upon SBLC initiation, both MOVs open to provide a flowpath from the storage tank to either pump.

The two pumps in the SBLC (2C41-C001A and B) are 100 percent capacity positive displacement types. Only one pump is used. Each pump delivers 43 gallons per minute and is powered by a 40 hp motor. Each pump is protected by a relief valve set at 1400 psig. Also, check valves downstream of the pump and relief valve protect against backflow to the idle pump.

Two explosive-operated (squib) injection valves (2C41-F004A and B) isolate the SBLC from the reactor vessel injection line. These 1-inch valves provide a zero leakage seal during standby and yet are highly reliable when called upon to open. When either of two primers in each valve is fired electrically, a plunger shears off the end cap of the inlet to the valve, thereby allowing flow to pass through the valve. After each firing of the squib valve the explosive mechanism and the inlet end cap must be replaced.

Primary containment isolation on the injection line is provided by two 1-inch check valves, one inside containment (2C41-F007) and one outside (2C41-F006). A manual valve inside containment (2C41-F008) is also provided for maintenance purposes.

For pump testing purposes, a 210 gallon test tank with associated piping is provided. The manual valves in the test lines are normally-closed.

A 24-inch pipe termed a head tank is connected by 3-inch piping to the pump suction lines. This head tank provides a positive pressure differential across the inlet MOVs (during standby) such that there is no leakage of sodium pentaborate solution past the MOVs. (Heat tracing is not provided for piping downstream of the MOVs.) An orifice in the piping to the head tank restricts flow between the head tank and the pump inlet piping.

Finally, although not part of the SBLC, a Reactor Water Cleanup System (RWCU) containment isolation valve (2G33-F004) must close in order for the SBLC to be successful. This normally-open 6-inch MOV automatically receives a close signal when the SBLC is initiated.

6.2.2.2 System Interfaces

A failure modes and effects analysis (FMEA) of SBLC support system interfaces is shown in Table 6.2-1. The support system interfaces are discussed below.

Shared Components

The SBLC has no components which are shared by other safety systems. MOV 2G33-F004, which must close for SBLC to be successful, is part of the RWCU.

RWCU is not a safety system, but the containment isolation function of MOV 2G33-F004 is a safety function.

Electrical

Both divisions of the Class 1E electrical system power the SBLC. One MOV (2C41-F001A), pump (2C41-C001), and squib valve (2C41-F004A) are powered by the Division 1 480 VAC motor control center (MCC) 235Y-1. Similar components in Loop B are powered by the Division 2 MCC 236Y-1. Electric power to the storage tank heater (B) is provided by MCC 235Y-1, while the pipe trace heating is supported by the normal power MCC 234X- 1. Finally, MOV 2G33-F004 is powered by the normal power MCC 235X-1.

Actuation

Electrical power for manual initiation of the SBLC is provided by the Division 1 and 2 MCCs powering the components. For each electrical component a transformer converts the 480 VAC from the MCCs to 120 VAC.

Control

No control is required when the SBLC is operating. However, in standby the storage tank heater (B) and the pipe heat tracing are locally-controlled. Power for these simple control systems is obtained through transformers from the MCCs powering these components.

Component Cooling

The SBLC does not depend upon component cooling.

Room Cooling

The SBLC does not require room cooling during its approximately two-hour mission time.

6.2.2.3 Instrumentation and Control

System Actuation

The SBLC is manually initiated. A keylock switch is provided in the control room for actuation. Turning the switch from the "OFF" position to "SYS A" or "SYS B" initiates the SBLC. Initiation results in both inlet MOVs (2C41-F001A and B) and both squib valves (2C41-F004A and B) opening, and one of the two pumps starting. Also, the RWCU MOV (2G33-F004) closes.

The success-oriented logic diagram for actuation of one pump (2C41-C001A) is shown in Figure 6.2-2. Pump 2C41-C001A starts if the keylocked switch is turned to "SYS A" and if at least one of the two inlet MOVs is fully open. Similarly, the other pump (2C41-C001B) starts if the switch is turned to "SYS B".

Actuation logic for the inlet MOVs (2C41-F001A and B) is shown in Figure 6.2-3. Both valves open upon SBLC initiation if the test tank outlet valve (2C41-F031) is fully closed. As mentioned previously, both MOVs open if the switch is turned to either "SYS A" or "SYS B".

The squib valve (2C41-F004A and B) actuation logic is shown in Figure 6.2-4. Both valves open if the SBLC initiation switch is turned to either "SYS A" or "SYS B". No interlocks exist for these valves.

Finally, closure logic for the RWCU isolation valve (2G33-F004) is shown in Figure 6.2-5

Component Control

During standby the only control systems working in the SBLC are the temperature controllers for the storage tank heater and the pipe heat tracing.

During SBLC operation essentially no control is necessary. All valves are fully opened and one of the two pumps runs at maximum capacity.

Instrumentation

The following instrumentation in the control room indicate the status of the SBLC:

1) Storage tank (2C41-A001) level - indicator
2) Inlet MOV (2C41-F001A and B) position - lights
3) Pump (2C41-C001A and B) status - lights
4) Pump discharge pressure - indicator
5) System initiation keylock switch
6) Squib valve (2C41-F004A and B) continuity monitor - lights
7) Squib valve continuity current - indicators
8) Maintenance valve (2C41-F008) position - lights
9) Test tank outlet valve (2C41-F031) position - lights

In addition, the following control room alarms exist:

1) Storage tank high level - 4827 gal (88%)
2) Storage tank low level - 4587 gal (84%)
3) Storage tank high temperature - 110F
4) Storage tank low temperature - 70F
5) Squib valve circuit failure - loss of electrical continuity

6.2.2.4 Operator Actions

The SBLC is manually actuated. Initiation is accomplished by inserting a key into the keylocked switch located in the control room and turning the switch from "OFF" to "SYS A".

If the SBLC does not function properly, as indicated by valve indication lights and pump (2C41-C001A) discharge pressure, then the operator is to turn the keylocked switch to "SYS B". This then reinitiates the SBLC with the other pump (2C41-C001B). No control of the SBLC is required during the approximately two-hour mission time.

6.2.2.5 Technical Specifications

Technical specifications 3.1.5 (Limiting Condition for Operation) and 4.1.5 (Surveillance Requirements) apply to the SBLC. Both are summarized below.

Limiting Condition for Operation

During power operation and startup, one inlet MOV (2C41-F001A or B), one pump (2C41-C004A or B) and/or one squib valve (2C41-F004A or B) may be inoperable for a maximum of seven days. If these components cannot be repaired within this period, then the plant must be placed in at least hot shutdown within 12 hours. Also, the entire SBLC may be inoperable for a maximum of eight hours. If not repaired within this period the plant must be placed in at least hot shutdown within 12 hours.

Surveillance Requirements

Every 24 hours the following must be performed:

1) Check of sodium pentaborate solution in storage tank for proper volume and temperature

2) Check of heat tracing circuit by observing temperature indication

At least once every 31 days the following must be performed:

1) Test of both pumps using test tank flow path

2) Verification of squib valve electrical continuity

3) Verification of sodium pentaborate solution concentration

4) Verification of positions of valves not locked, sealed, or otherwise secured

At least once every 18 months during shutdown the following must be performed:

1) Initiation of one of the loops, including a squib valve, and verification of flow path from the pump to the reactor vessel. Both squib valves must be tested within 36 months.

2) Verification of pump flow of at least 41.2 gpm at a pressure greater than 1220 psig

3) Verification that each pump relief valve setpoint is less than or equal to 1400 psig and that premature relief does not occur

4) Demonstration that all heat traced piping between the storage tank and the reactor vessel is not plugged

5) Demonstration that the storage tank heaters are operable

6.2.2.6 Test

The major tests of the SBLC are summarized in Table 6.2-2. A monthly pump test is the major test performed while the plant is at power. The other major testing occurs every 18 months and involves the inlet MOVs, explosive valves, and relief valves. Also, flow through the entire system is verified at that time.

6.2.2.7 Maintenance

No scheduled maintenance which disables components while the plant is at power is planned. However, unscheduled maintenance is allowed within the technical specification limitations. As stated in Section 6.2.2.5, a component in the SBLC may be out for unscheduled maintenance for one week while the plant is at power if only one loop is disabled. However, if the entire SBLC is disabled, repairs must be completed within eight hours.

A summary of unscheduled maintenance acts allowed on the SBLC is presented in Table 6.2-3. Although allowed, unscheduled maintenance on check valves and manual valves is not listed on the table because of the significantly lower frequencies of occurrence when compared with MOVs.

6.2.3 System Operation

6.2.3.1 Normal Operation

During plant normal operation the SBLC is in standby. The electric heaters for the storage tank and heat traced pipe operate as needed to keep the sodium pentaborate solution within required temperature limits.

6.2.3.2 Abnormal Operation

The SBLC is manually actuated. Consideration for initiation of the SBLC is made when the control rod drive system is incapable of shutting down the reactor and any of the following conditions exist:

1) Reactor power starts to increase

2) Calculations indicate that criticality will be reached in the next hour

3) In the judgement of the ranking licensed supervisor, a hazard exists to the environment, the plant, or personnel. Once the decision to initiate SBLC has been made, LOA-SC-02, Revision 2 applies. The shift engineer is responsible for the actual initiation. A key is inserted into the keylocked switch and the switch is turned from "OFF" to "SYS A". This actuates the opening of the two inlet MOVs (2C41-F001A and B) and the opening of the two explosive valves (2C41-F004A and B). Also, the RWCU isolation valve 2G33-F004 is closed. When either inlet MOV is fully open, pump 2C41- C001A automatically starts. The system then operates at maximum capacity until the storage tank is empty or the operator turns off the SBLC. If pump 2C41-C001A fails to start, then the initiation switch is turned to "SYS B", which reactuates the valves listed previously and starts pump 2C41-C001B.

6.2.4 System Fault Tree

6.2.4.1 Description

A simplified diagram of the SBLC indicating only the mechanical components included in the fault tree model is shown in Figure 6.2-6. Four developed events are in the SBLC fault tree. These events are transfers from the electric power fault trees for the 480 VAC MCCs 235Y-1, 236Y-2, 234X-1, and 235X-1. The data for the basic events in the SBLC fault tree are presented in Table 6.2-4.

6.2.4.2 Success/Failure Criteria

SBLC operation is successful if sufficient sodium pentaborate solution from the storage tank is injected into the reactor vessel through one of two pump loops. Failure of the SBLC occurs if one of the following occurs:

1) The injection line between the explosive valves and the reactor vessel fails

2) Both pump loops fail

3) The storage tank or piping to the inlet MOVs fails

4) The RWCU isolation MOV fails to close

The top event of the SBLC is the following:

"FAILURE OF STDBY LIQUID CTRL TO INJECT BORON SOL WITH 1-OF- 2 PUMPS AND 1-OF-1 INJ PATH"

6.2.4.3 Assumptions

In addition to the general assumptions listed at the beginning of this volume with regard to fault tree development, the following assumptions specific to the SBLC were made:

1) The return line to the test tank has two normally-closed manual valves (2C41-F016 and 17). Both of these valves are opened monthly for the pump test. If these valves are left open following the test, no indications would be present. Therefore, this line is included as a diversion path.

2) The test tank elevation is lower than the storage tank. If the test tank outlet valve (2C41-F031) is open during SBLC operation, diversion of sodium pentaborate solution back to the test tank (resulting in overflowing of the tank) could significantly reduce the total amount of sodium pentaborate injected into the reactor vessel. Therefore, this line is included as a diversion path.

3) The head tank elevation is higher than that of the storage tank. The line has a restricting orifice and a locked-closed manual valve in parallel. If this valve is opened during SBLC operation, the head tank water would drain into the pump inlet lines. However, the contents of the head tank is less than ten percent of the storage tank, so the opening of this dilution line is not considered to be a failure mode.

4) If the single locked-closed manual valve (2C41-F304) between the clean condensate system and the SBLC storage tank is open during SBLC operation, the contents of the storage tank could be diluted sufficiently to fail the SBLC. This valve failure is included as a dilution source.

5) If the single manual valve (2C41-F306) between service air and the SBLC storage tank is open during operation, pump cavitation could occur as a result of air bubbles being introduced into the storage tank solution. This valve failure is included as a failure mode for the system.

6.2.5 References

1) FSAR

System description	Section 9.3.5
Instrumentation	Section 7.1.2.19
	Section 7.4.1.2
Technical specifications	Limiting Condition for Operation, Section 3.1.5
	Surveillance Requirements, Section 4.1.5
	Bases, Section 3/4.1.5

2) Operator Training Manual — Chapter 10

3) Drawings	P&ID M-145 I&C IE-2-4209AA through AD I&C IE-2-4228AK I&C IE-2-4232AH General Arrangement M-6 through 8 Master Diagrams (S&L Electrical Dept.) SC01 through 08 and SC76 Cable Tabulation (S&L) 2SC01 through 06
4) Procedures	LOS-SC-M1 Rev. 8 LOS-SC-R1 Rev. 6 LOS-SC-R2 Rev. 4 LOS-SC-R3 Rev. 4 LOS-SC-R4 Rev. 1 LOP-SC-02 Rev. 2 LOP-SC-02E Rev. 5 LOP-SC-02M Rev. 3 LMP-SC-1 Rev. 0 LIS-SC-02 Rev. 2 LIP-SC-02 Rev. 0 LIP-SC-01 Rev. 1 LES-SC-01 Rev. 2 LOP-SC-01 Rev. 4 LOP-SC-03 Rev. 2 LOP-SC-04 Rev. 3 LOP-SC-05 Rev. 3 LOP-SC-06 Rev. 1 LOP-SC-07 Rev. 1 LTS-100-26 Rev. 3 LIS-SC-03 Rev. 3 LIS-SC-01 Rev. 3 LOA-SC-01 Rev. 1 LOA-SC-02 Rev. 2 LOA-SC-03 Rev. 2
4) Other Sources	Kuosheng Unit 1 PRA (draft) Shoreham PRA <u>Nuclear Power Experience</u>

Table 6.2-1 Standby Liquid Control System Support System Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
480 Vac MCC 235Y-1	2C41-F004A	Explosive valve	Closed	Loss of electrical continuity in control room	Loss of one redundant injection valve	
	2C41-C001A	Motor-driven pump	FTS/FTR	Loss of power available indication in control room	Loss of one redundant pump	
	2C41-F001A	MOV	Closed	Loss of position lights in control room	Loss of one redundant inlet valve	Loss of one redundant injection loop and pump
	2C41-D002	Tank electric heater	Fails to heat	Loss of status lights in control room	In standby precipitation of sodium pentaborate could result. Mission time is too short for this to occur during operation.	Possible plugging of tank outlet line, or reduced sodium pentaborate solution strength which chould result in system failure
480 Vac MCC 236Y-2	2C41-F004B	Explosive valve	Closed	Same as 2C41-F004A	Loss of one redundant injection valve	
	2C41-C001B	Motor-driven pump	FTS/FTR	Same as 2C41-C001B	Loss of one redundant pump	
	2C41-F001B	MOV	Closed	Same as 2C41-F001A	Loss of one redundant inlet valve	Loss of one redundant injection loop and pump
480 Vac MCC 234X-1	Pipe heater 1606	Heat tracing	Fails to heat	Temperature checked daily	In standby, precipitation of sodium pentaborate could result. Could plug inlet MOVs. Not a failure mode during mission time.	Possible plugging of both inlet MOVs, resulting in system failure
480 Vac MCC 235X-1	2G33-F004	MOV	Open	Loss of position lights in control room	Dilution of sodium pentaborate solution in reactor coolant, resulting in possible system failure	Dilution of sodium pentaborate solution in reactor coolant resulting in possible system failure

Table 6.2-2 Standby Liquid Control System Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
LOS-SC-M1 Rev. 8	Pump start and run	2C41-C001A	Pump	No	---	1		Monthly
		2C41-C001B	Pump	No	---	1		Monthly
	Premature opening	2C41-F029A	Relief valve	No	---	1		Monthly
		2C41-F029B	Relief valve	No	---	1		Monthly
	Electrical continuity	2C41-F004A	Explosive valve	No	---	1		Monthly
		2C41-F004B	Explosive valve	No	---	1		Monthly
	Flow	2C41-F002A	Manual valve	No	---	1		Monthly
		2C41-F002B	Manual valve	No	---	1		Monthly
		2C41-F003A	Manual valve	No	---	1		Monthly
		2C41-F003B	Manual valve	No	---	1		Monthly
		2C41-F033A	Check valve	No	---	1		Monthly
		2C41-F033B	Check valve	No	---	1		Monthly
	Not applicable	2C41-F031	Manual valve	Yes	---	1		Monthly

Table 6.2-2 Standby Liquid Control System Test Summary (Continued)

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
		2C41-F016	Manual valve	Yes	---	1		Monthly
		2C41-F017	Manual valve	Yes	---	1		Monthly
LOS-SC-R1 Rev. 6	Valve operation	2C41-F004A	Explosive valve	Yes	No	36	Shut-down	Monthly
		2C41-F004B	Explosive valve	Yes	No	36	Shut-down	Monthly
	Opening at setpoint	2C41-F029A	Relief valve	No	---	36	Shut-down	Monthly
		2C41-F029B	Relief valve	No	---	36	Shut-down	Monthly
	Flow	2C41-F008	Manual valve	No	---	18	Shut-down	Monthly
		2C41-F007	Check valve	No	---	18	Shut-down	18 Months
		2C41-F006	Check valve	No	---	18	Shut-down	18 Months
	Not applicable	2C41-F001A	MOV	Yes	No	18	Shut-down	Monthly
		2C41-F001B	MOV	Yes	No	18	Shut-down	15 Months
		2C41-F031	Manual valve	Yes	No	18	Shut-down	18 Months
		2C41-F016	Manual valve	Yes	No	18	Shut-down	18 Months
		2C41-F017	Manual valve	Yes	No	18	Shut-down	18 Months

Table 6.2-2 Standby Liquid Control System Test Summary (Concluded)

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
LOS-SC-R2 Rev. 4	Valve cycling	2C41-F001A	MOV	Yes	Yes	18	Shut-down	Monthly
		2C41-F001B	MOV	Yes	No	18	Shut-down	Monthly
LOS-SC-R3 Rev. 4	Flow	2SC01A	Heat traced piping	No	---	18	Shut-down	Monthly
		2C41-F017	Manual valve	Yes	No	18	Shut-down	18 Months
LOS-SC-R2 Rev. 4	Valve cycling	2C41-F001A	MOV	Yes	Yes	18	Shut-down	Monthly
		2C41-F001B	MOV	Yes	No	18	Shut-down	Monthly
LOS-SC-R3 Rev. 4	Flow	2SC01A	Heat traced piping	No	---	18	Shut-down	Monthly

Table 6.2-3 Standby Liquid Control System Unscheduled Maintenance Summary

Component Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2C41-F004A	Explo-sive valve	Electrical	Valve actuation circuit	Yes			Monthly
		Mechanical	-	No			36 Months
2C41-F004B	Explo-sive valve	Electrical	Valve actuation circuit	Yes			Monthly
		Mechanical	-	No			36 Months
2C41-C001A	Pump	Mechanical/ electrical	-	Yes			Monthly
			2C41-F003A				Monthly
			2C41-F002A				Monthly
			Pump circuit breaker				
2C41-C001B	Pump	Mechanical/ electrical	-	Yes			Monthly
			2C41-F003B				Monthly
			2C41-F002B				Monthly
			Pump circuit breaker				
2C41-F029A	Relief valve	Mechanical	-	Yes			Monthly
			2C41-F003A				Monthly
			2C41-F002A				Monthly
2C41-F029B	Relief valve	Mechanical	-	Yes			Monthly
			2C41-F003B				Monthly
			2C41-F002B				Monthly
2C41-F029A	MOV	Electrical/ mechanical	MOV circuit breaker	Yes			Monthly
				No			18 Months
2C41-F029B	MOV	Electrical/ mechanical	MOV circuit breaker	Yes			Monthly
				No			18 Months
2SC01A	Heat traced pipe	Electrical/ breaker	Heat tracing circuit	Yes			Daily

Table 6.2-3 Standby Liquid Control System Unscheduled Maintenance Summary (Concluded)

Component Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage	Frequency of Alignment/ Operability Verification
2C41-A001	Storage tank heater	Electrical	Heater circuit breaker	Yes			Daily
2C33-F004	MOV	Electrical/ mechanical	MOV circuit breaker	Yes			18 Months 18 Months

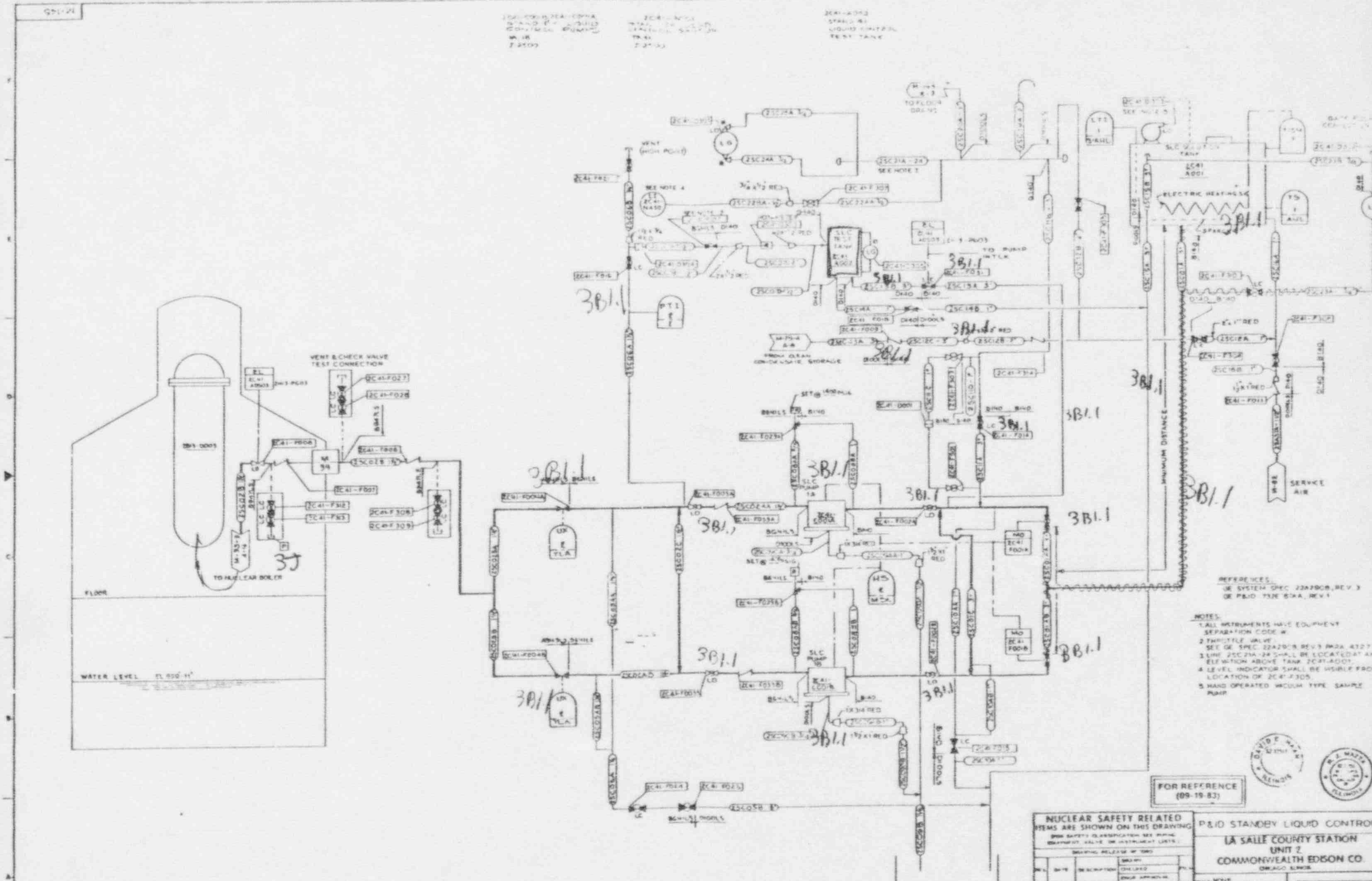


Figure B.X-1 Standby Liquid Control System P&ID

Figure 6.2-1 Standby Liquid Control System P&ID

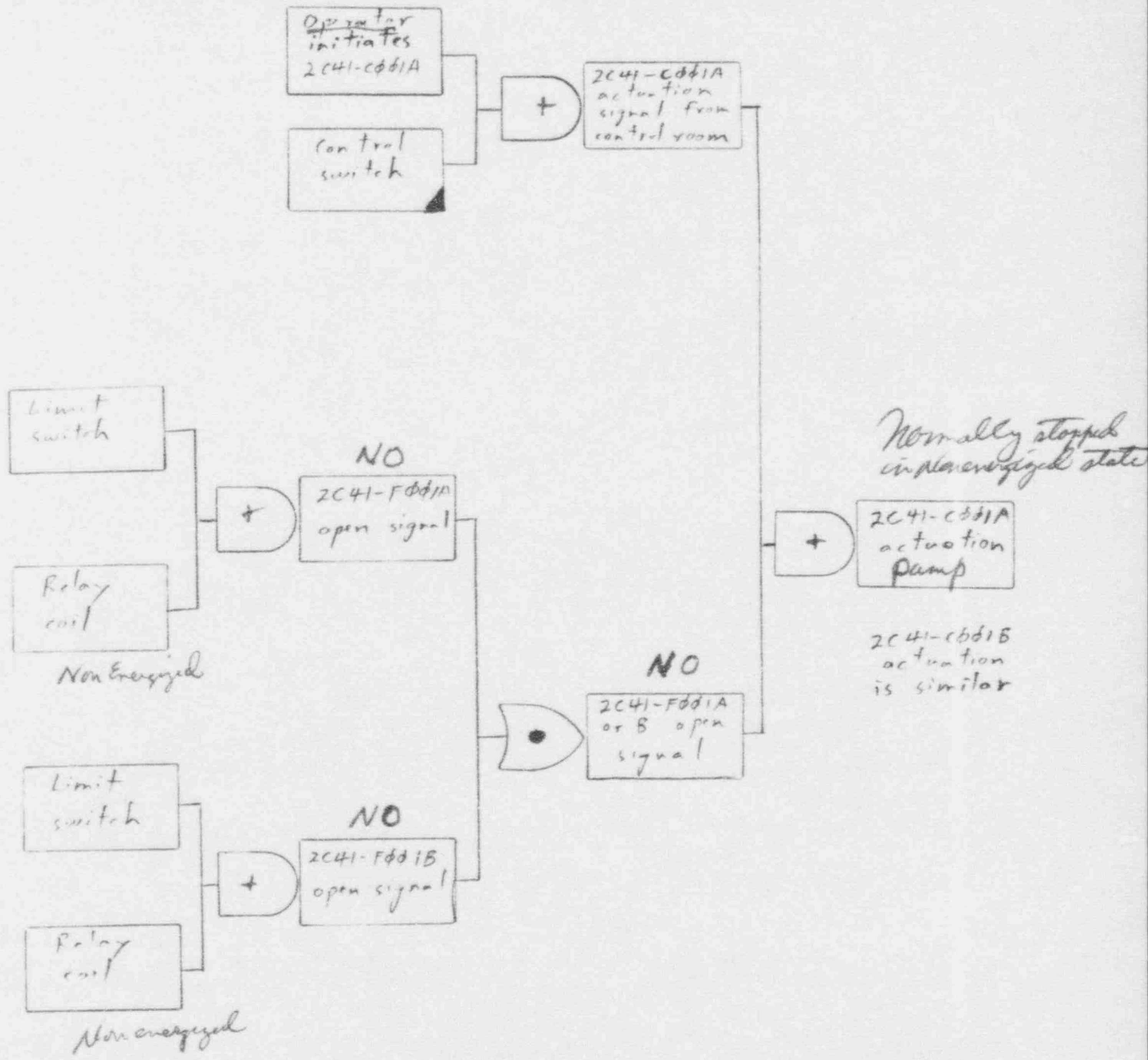


Figure B.X-2 Standby Liquid Control System Pump Actuation Logic

Figure 6.2-2 Standby Liquid Control System Pump Actuation Logic

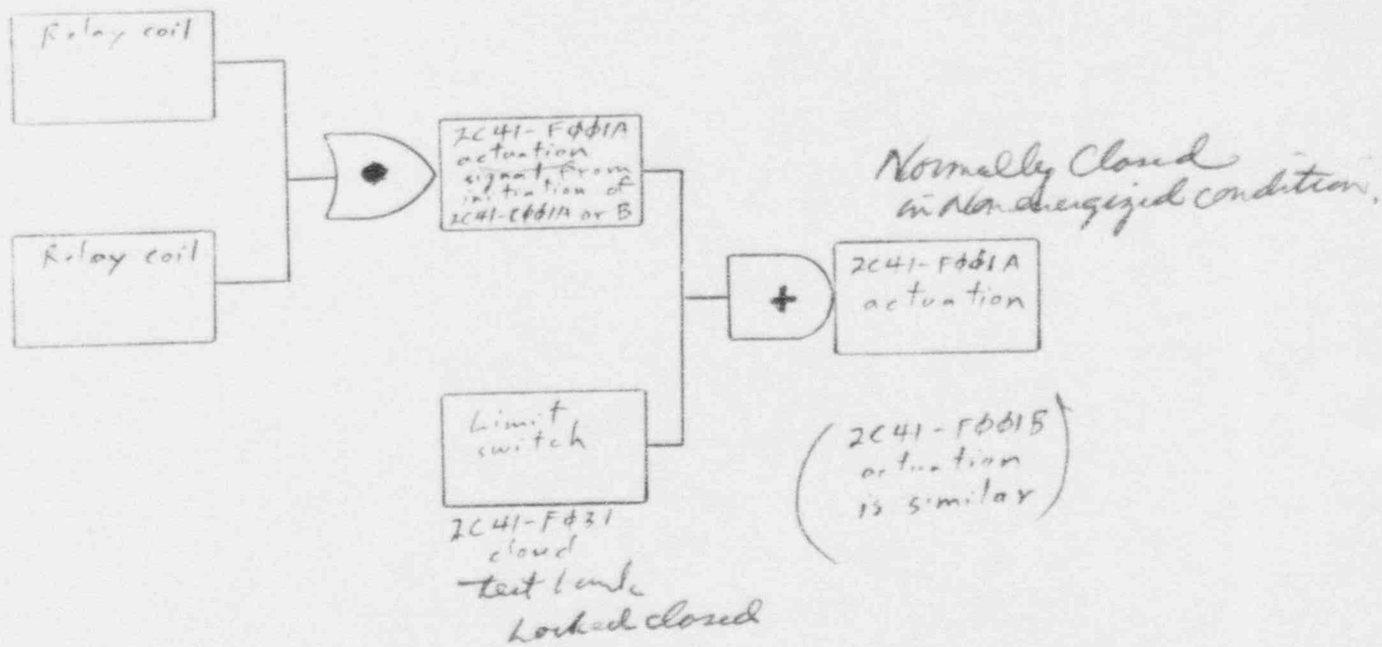
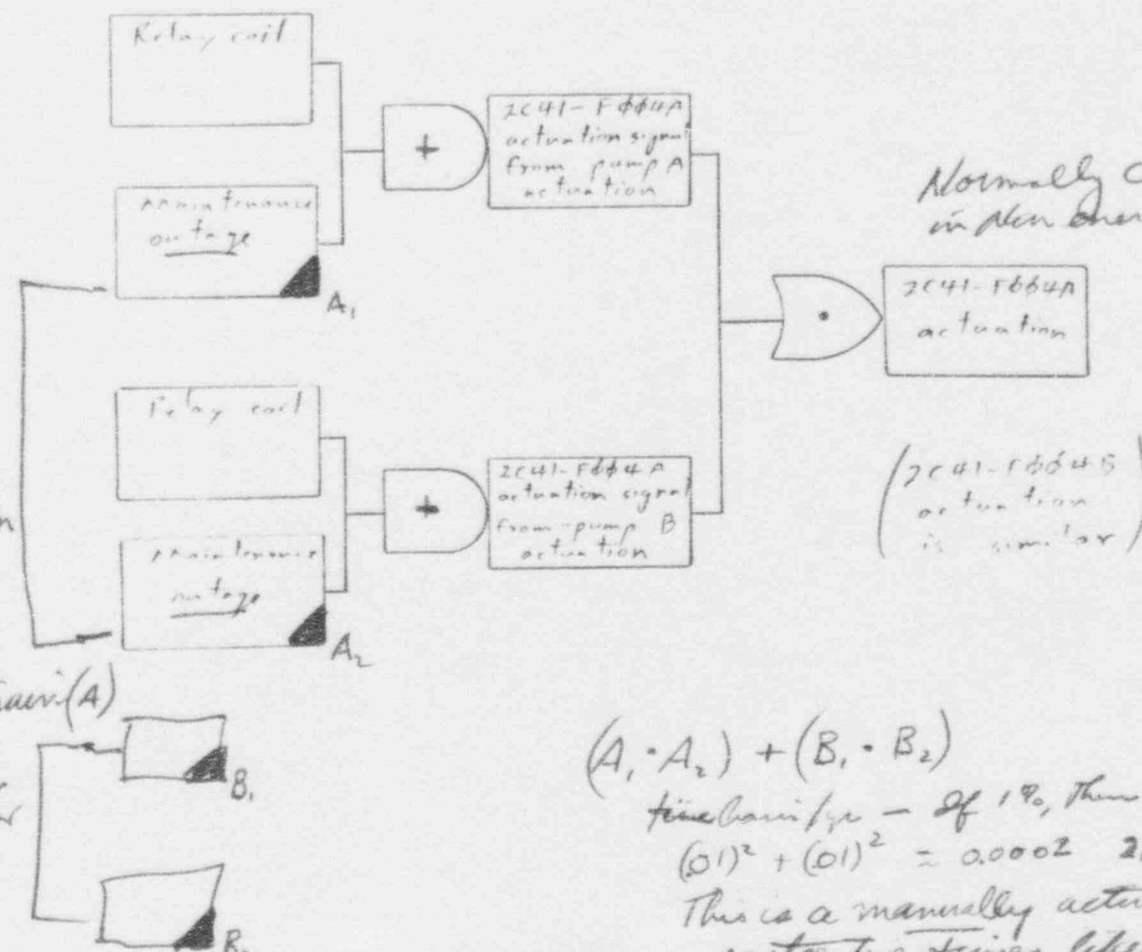


Figure B.X-3 Standby Liquid Control System Inlet MOV Actuation Logic

Figure 6.2-3 Standby Liquid Control System Inlet MOV Actuation Logic requires double tag out of commission to prevent availability on one train (A)



Normally closed in non energized condition.

(2C41-F004B actuation is similar)

ditto for train B

$(A_1 \cdot A_2) + (B_1 \cdot B_2)$

~~time~~ basis/yr – If 1%, then

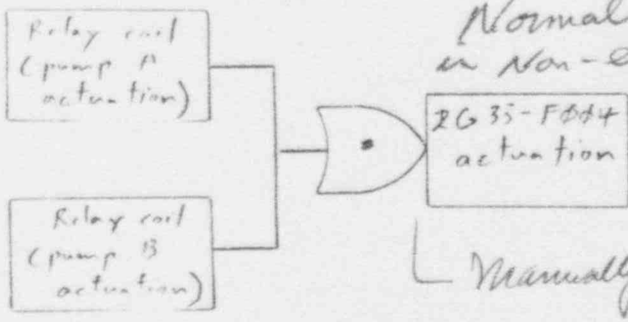
$(.01)^2 + (.01)^2 = 0.0002$ 2×10^{-4} nonavailability, but

This is a manually activated system with restorative times like 20-min available

so prob of non-restoration (10^{-4}) gives point estimates like 2×10^{-8} for not having at least one train available to enable ~~to~~ actuation signal.

Figure 5.X-4 Standby Liquid Control System Explosive Valve Actuation Logic

Figure 6.2-4 Standby Liquid Control System Explosive Valve Actuation Logic



Normally Open in Non-energized condition.

Manually initiated

but backed up by any ~~#~~ prior primary Containment Isolation signal which would have closed G33-F004 and G33-F001.

This is a back-up assurance action for closure of RWCU suction into SBLC - it is a system isolation in contrast to primary cont isolation.

Figure 8X-5 Reactor Water Cleanup System Isolation MOV Actuation Logic

Figure 6.2-5 Reactor Water Cleanup System Isolation MOV Actuation Logic

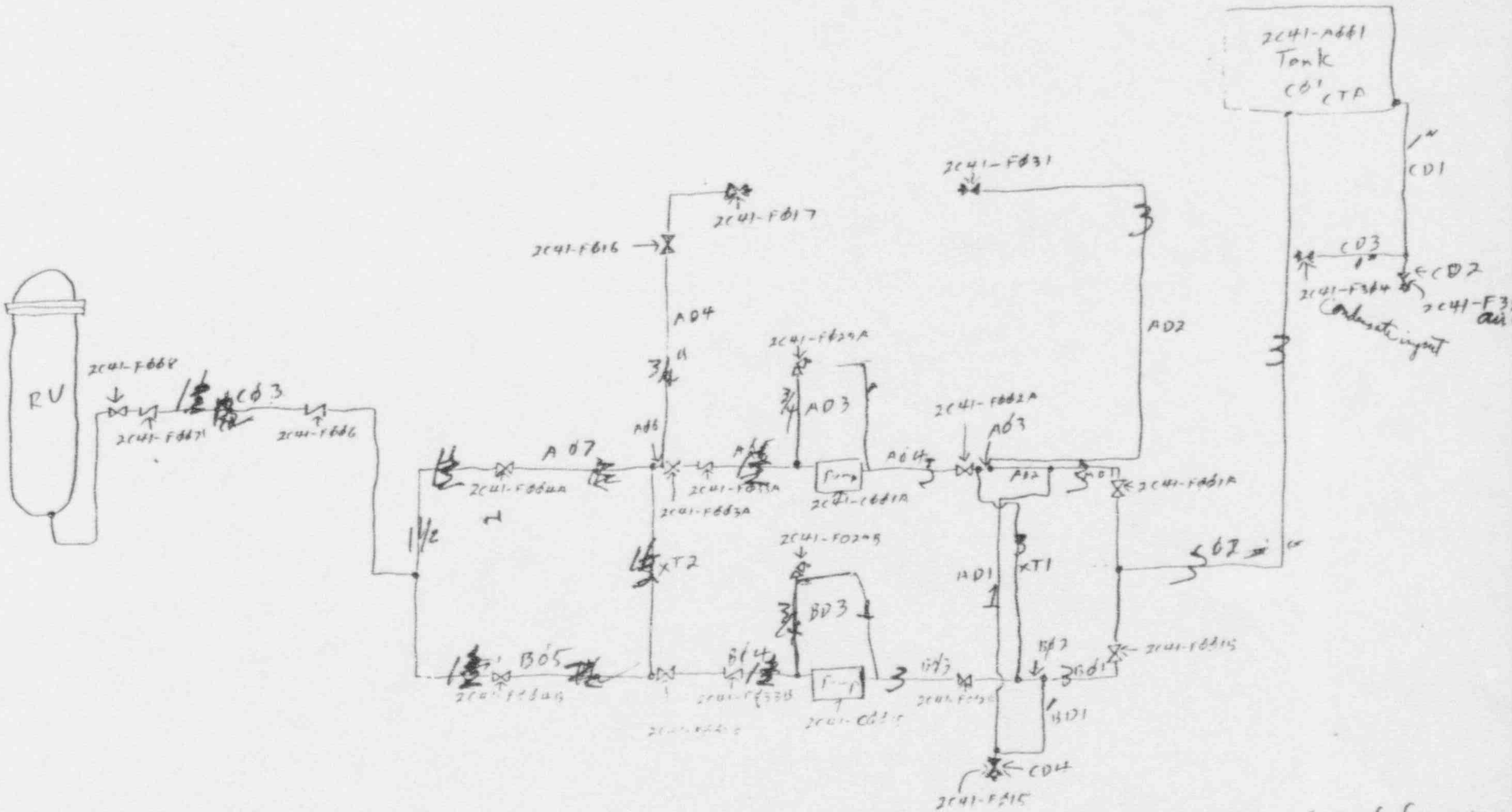


Figure 2 simplified piping diagram. (Note - for seismic purposes the detailed piping diagram should be used.)

Figure B.X-5

Figure 6.2-6 Simplified Schematic of Standby Liquid Control System for Fault Tree Construction

6.3 Recirculation Pump Trip (RPT) System (Anticipated Transient Without Scram

6.3.1 System Function

The recirculation pump trip (RPT-ATWS) is implemented to reduce the power level of the core with the control rods out by increasing the effective void content of the core, which in turn introduces negative reactivity into the core. This results in a reduction of the calculated primary system pressure rise following postulated ATWS events.

6.3.2 System Description

6.3.2.1 General Design

The RPT-ATWS logic is derived from relays activated by low-low water level (L2) or high reactor pressure, with a one-out-of-two-twice logic. Contacts from these relays are arranged in a logic scheme so that energizing various combinations of the relays, will energize the RPT trip coil (TC2), for each of the power sources circuit breakers (3A and 3B). Each main circuit breaker has two trip coils. One trip coil is activated by an RPT-ATWS signal, relay trip coil TC2, the other is derived and activated from relays in the reactor protection system (RPS), relay trip coil TC1. The simplified circuit diagram used for fault tree modeling is shown in Figure 6.3-1.

The RPT-ATWS system is diverse and redundant from the reactor protection system.

6.3.2.2 System Interfaces

Electrical

The plant electrical distribution system provides power to the RPT. Thus with a combination of relay coils and contact pairs the trip relay coil will be energized. The breaker 3A control and related circuits are supplied by 125 VDC, Bus 211X. The control breaker 3B and related circuits are supplied by 125 VDC, Bus 212X.

6.3.2.3 Instrumentation and Control

System Actuation

The RPT is automatically actuated by a low low level or high reactor pressure. Manual actuation of the RPT-ATWS system is not possible.

6.3.2.4 Technical Specifications

The RPT-ATWS has some limiting conditions for operation and surveillance requirements, which are briefly described below.

The RPT-ATWS shall be OPERABLE in operational condition 1 (Power Operations). With a RPT-ATWS instrumentation channel trip setpoint less conservative than the allowable values, the channel shall be declared inoperable until it is restored.

With the number of operable channels one less than required by the minimum operable channels requirement for one trip function in one trip system, the inoperable channel shall be restored to OPERABLE status within 14 days or be in at least STARTUP condition within the next eight hours.

Each RPT-ATWS system instrumentation channel shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL FUNCTIONAL TEST, and CHANNEL CALIBRATION.

LOGIC SYSTEM FUNCTIONAL TESTS and simulated automatic operation of all channels shall be performed at least once per 18 months.

RPT-ATW Instrumentation and Setpoints

	Minimum Operable	Trip	Allowable
1. Reactor Vessel Water Low Low, L2	1	-50 inches	-57 inches
2. Reactor Vessel Pressure - High	1	1135 psig	1150 psig

RPT-ATW Surveillance Requirements

	Channel	Channel Functional	Channel
1. Reactor Vessel Water Level Low Low, L2	one/8 hours	one/31 days	one/18 months
2. Reactor Vessel Pressure - High	N/A	one/31 days	one/92 days

6.3.2.5 Test and Maintenance

According to the RPT-ATWS surveillance requirements, the model takes into account channel functional test and channel calibration for reactor vessel pressure - high trip function, as are described in LaSalle Instrument Maintenance surveillances LIS-NB-209 and LIS-NB-409 respectively. Because of the scheduled maintenance included in these procedures, no unscheduled maintenance is modeled.

6.3.3 <u>System Operations</u>

During normal operation the sensors and related contacts are open, and the output relays are deenergized. There are two level sensors and two pressure sensors per each trip coil TC2. Thus any pair of sensors from different trip coils will activate the whole system.

6.3.4 System Fault tree

6.3.4.1 Success Logic Diagram

The success oriented logic diagram is shown in Figure 6.3-2.

6.3.4.2 Success/Failure Criteria

The success criteria for RPT-ATWS system is defined as successful trip of both recirculation pumps after a low low level (L2) or high reactor pressure. Thus failure to trip either of the two Breakers 3A or 3B will fail the RPT-ATWS trip function

The top event is defined as "Recirculation Pump Trip Fails After ATWS Initiator".

6.3.4.3 Assumptions

In constructing the fault tree for the HPCS system, the following assumptions were made in addition to the general assumptions given at the beginning of this volume:

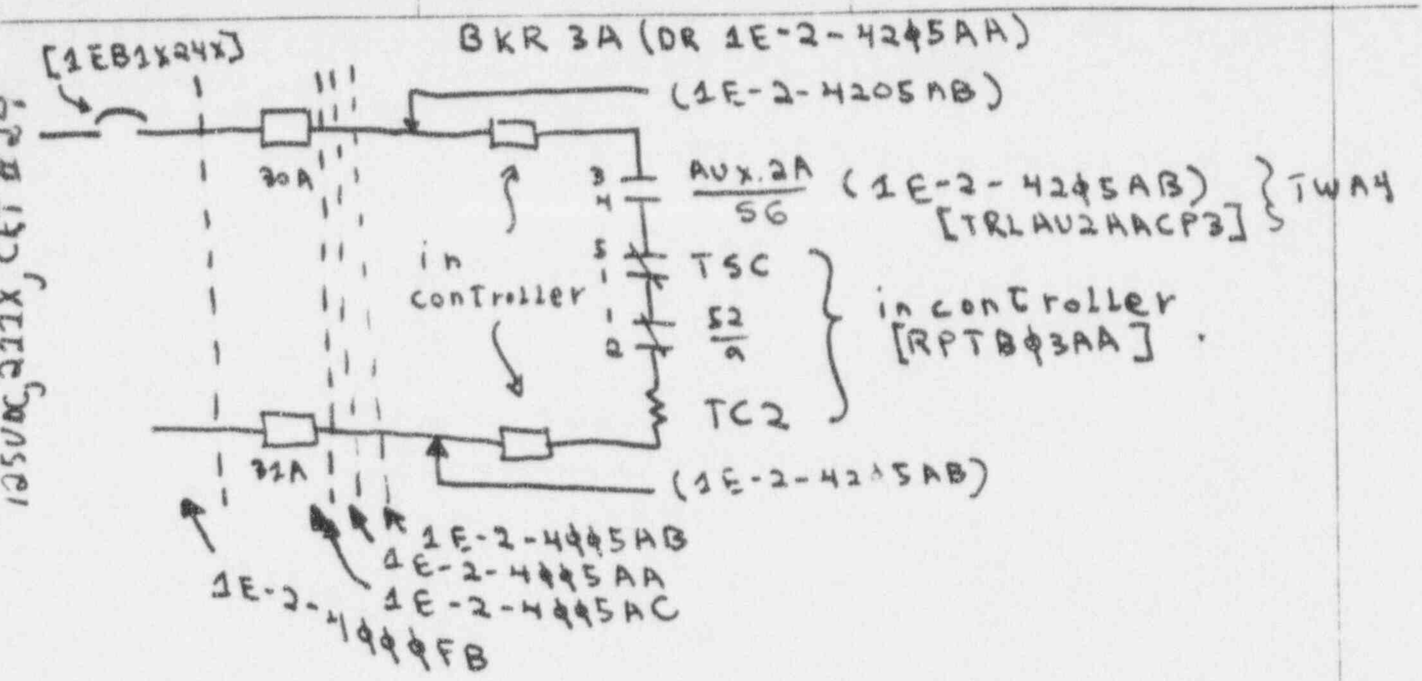
1) Failure of one RPT trip breaker will fail the system.

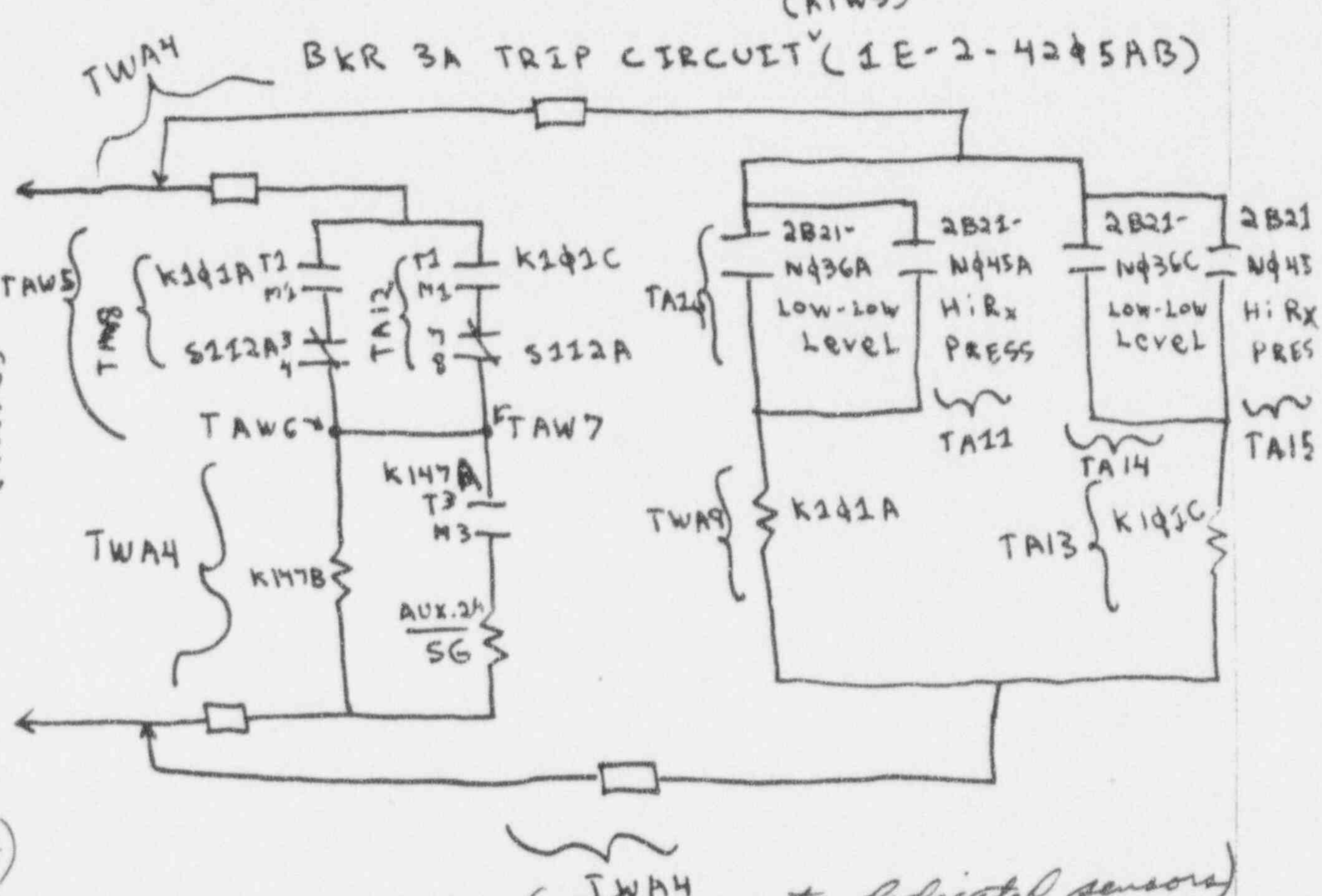
Table 6.3-1 Recirculation Pump Trip - ATWS Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
125 VDC from 211X CKT#24	BRK 3A Pump 2B33 -C001A	Control BRK	Failure to trip	CR Alarm	It will prevent one control circuit breaker (3A) from tripping	Failure of one recirculation pump to trip
125 VDC from 212X CKT#24	BRK 3B pump 2B33 -C001B	Control BRK	Failure to trip	CR Alarm	It will prevent one control circuit breaker (3B) from tripping	"

Table 6.3-2 Recirculation Pump Trip - ATWS Component/Subsystem Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Test Outage	Component/Subsystem Alignment/Operability Verification Frequency
LIS-NB-209 LIS-NB-03	Channel functional test	Channel A,B,C,D level and pressure	Trip Channel	One channel (A,B,C,D) out at a time	No	31 days	4 hours per channel per month	4 hours (1/2 shift) (alarmed in CR for test switch)
LIS-NB-409	Channel calibration for reactor vessel pressure	Channel A,B,C,D	Pressure Sensor	One channel (A,B,C,D) out at a time	No	92 days	2 hours per channel	8 hours (alarmed in CR for test switch)





Note

Duplicate functional circuitry (with separate dedicated sensors) exists entirely independent from ATWS (RPS) circuits shown here. It is the ARI circuitry (package separately provided to Sandia).

Figure B.X-1A BREAKER 3A Control and Actuation Circuit

Figure 6.3-1a RPT Breaker 3A Control and Actuation Circuit

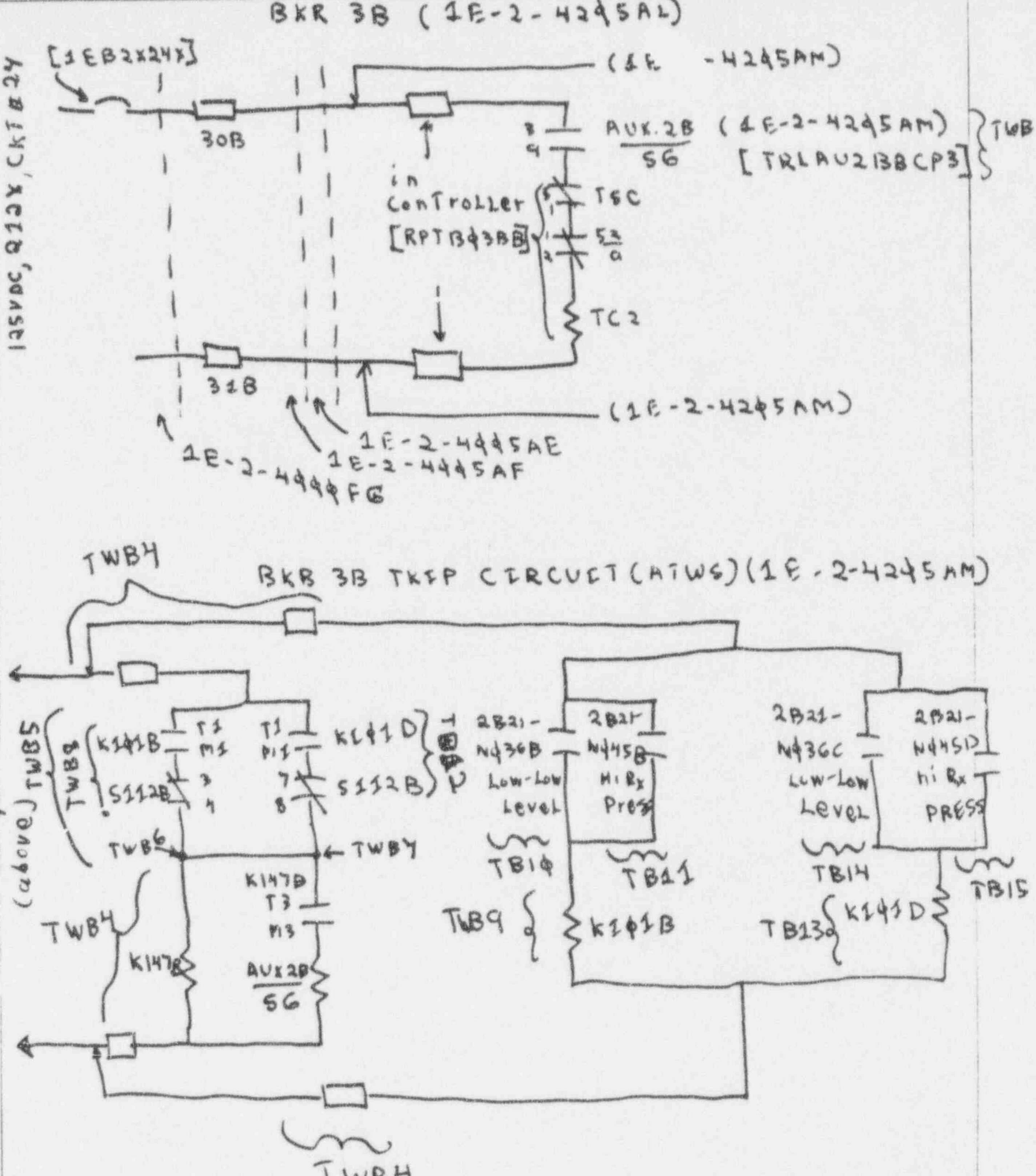
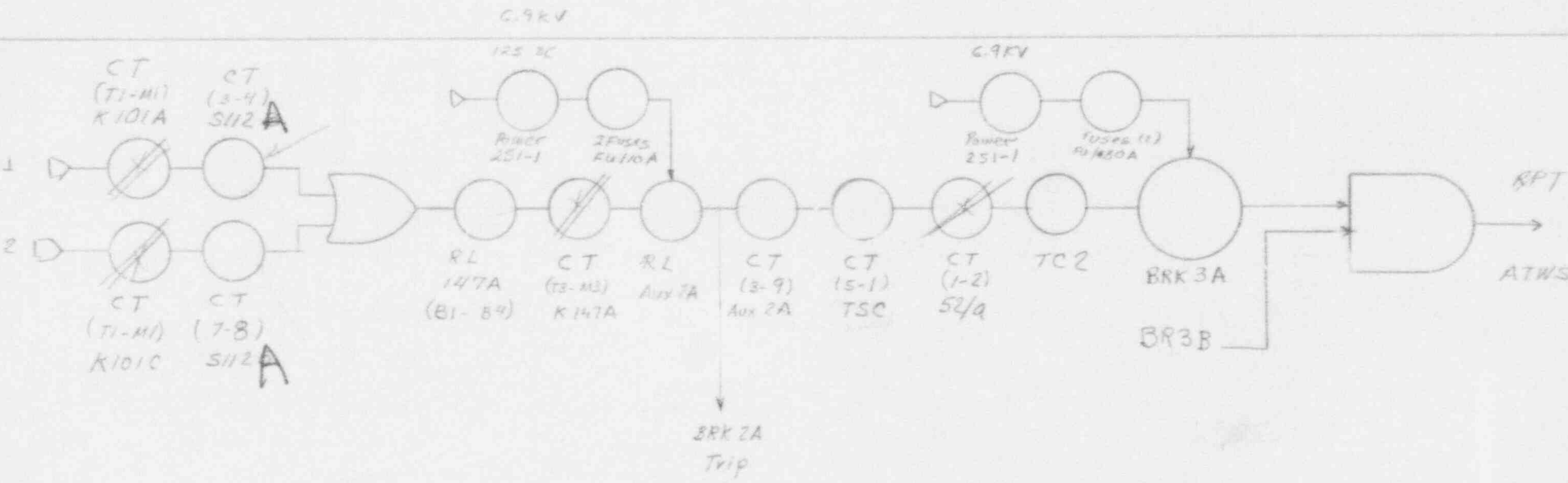


Figure B.X-1B BREAKER 3B Control and Actuation Circuit

Figure 6.3-1b RPT Breaker 3B Control and Actuation Circuit



Success Mode: BKR 3A

BKR 3B Similar

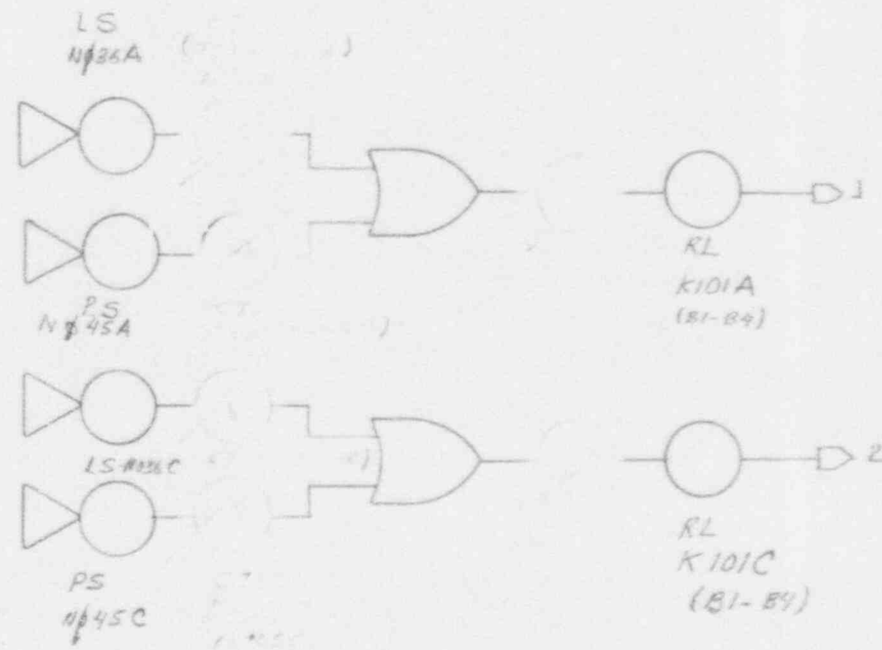


Figure 6.3-2 Success Oriented Logic Diagram for Breaker 3A (3B Similar)

7.0 ELECTRICAL SUPPORT SYSTEMS

7.1 System Description of the AC Auxiliary Electric Power System

7.1.1 System Function

The purpose of the AC auxiliary electric power system is to distribute electric power to the plant equipment and to provide control and protection for this equipment. The system provides AC power during startup, power operation and shutdown. It is designed to provide:

A reliable source of power to plant loads that are necessary for power generation or nuclear safety, electrical isolation and physical separation of redundant Engineered Safety Feature (ESF) power supplies, and

a system of automatic detection and isolation of electrical faults.

The auxiliary AC system is required for the operation of pumps, fans and motor-operated valves for the important plant systems. Exceptions are the turbine-driven feedwater and RCIC pumps, two DC-powered emergency pumps, and various air and DC operated valves. In addition AC power is used for control of components powered from the motor control centers of the standby (emergency) AC power system, but DC power is used for control of all components tied to the AC switchgear and load centers.

7.1.2 System Description

7.1.2.1 General Design

The overall electrical system comprises the main system, which supports both the offsite and auxiliary AC power systems, and the auxiliary AC power system. The auxiliary power system is divided into Class 1E and Non-Class 1E Electrical Systems.

Main Power System

The main power system at LaSalle distributes the generated electric power to the offsite power system and, in addition, provides a source of power for the station auxiliary electric power system. A simplified single-line diagram of the overall power system is given in Figure 7.1.1. The figure shows the output of the Unit 1 and Unit 2 main generators connected to the grid system through a ring bus arrangement. Also shown are the unit auxiliary transformers (UAT's 241 and 141) and station auxiliary transformers (SAT's 242 and 142). These transformers provide power for the 6900-volt and 4160 volt major switch groups which supply power for all plant auxiliaries. Note that, in

Figure 7.1.-1, components associated with LaSalle Unit 1 have components identified by numbers starting with "1" and Unit 2 components are identified by numbers starting with "2".

Auxiliary AC Electric System

The Auxiliary AC Electric System at LaSalle Unit 2 includes Class 1E and Non-Class 1E systems. Both systems can be supplied by the unit auxiliary transformer (UAT 241) and the station auxiliary transformer (SAT 242).

The UAT is connected directly to the Main Generator output and is capable of supplying all auxiliary power during normal operation. The full capacity System Auxiliary Transformer is normally available to supply unit auxiliary power. When the main generator trips, switch groups fed from the UAT automatically transfer to the SAT. When the SAT trips, its switch groups transfer to the UAT except for bus 243 which is picked up by Diesel Generator 2B.

Seven major switch groups supply power for all Unit 2 auxiliaries. The major groups are as follows:

1) Buses 251 and 252 which supply 6.9 KV to non-ESF equipment.

2) Buses 241X and 242X which supply 4.16 KV to non-ESF related equipment.

3) Buses 241Y, 242Y and 243 which are ESF buses, distributing 4.16 KV to safety-related equipment.

Class 1E and Non-Class 1E Systems

The Class 1E power system is arranged so that any design basis event (DBE) will neither cause a loss of electrical power to enough engineered safety features (ESF), surveillance devices or protection system devices to jeopardize the station, nor cause a loss of equipment that could result in a reactor power transient capable of causing significant damage to the fuel or reactor coolant system. (ESF systems are those required to mitigate the consequences of postulated accidents).

In addition, Class 1E systems are designed to meet the following "physical" criteria:

a) continue to perform their function after being subjected to the effects of any DBE

b) maintain stable voltage and frequency such that load performance is not degraded to the extent that damage to the fuel or reactor coolant system can occur

c) be labeled in a distinctive manner

d) be physically separated from their redundant counterparts or protected as required to prevent common mode failure

e) provide at least the minimum loads required for safe shutdown, post-shutdown, and post-accident conditions despite any single failure.

All ESF equipment important to plant safety is divided among the three divisions of the unit's Class 1E AC power system switchgear. In the event of the total loss of offsite and main auxiliary power, the auxiliary power required for safe shutdown is supplied from the diesel generators. Two ESF groups (Divisions 2 and 3) are supplied by the Unit 2 diesel generators (D/Gs) while the third group (Division 1) for each unit is supplied by the shared (0) D/G. With this arrangement of physically and electrically independent loads and power supplies, the total loss of any one ESF division cannot prevent the safe shutdown of the reactor, unless concurrent, nonelectrical, failures occur.

Non-Class 1E equipment may also be supplied from Class 1E buses provided the Class 1E systems are maintained at an acceptable level. Although the Non-Class 1E AC electric system is not required to support engineered safety features, it is addressed in the analysis, because it does provide power for essential support systems and for systems whose failure could result in initiating events.

The power distribution from the major switch groups to the 480-volt switchgear is shown in Figure 7.1.2.

The major electrical loads on the Non-Class 1E AC system are listed in Table BX-1. Major loads on the Class 1E system are given in Table BX-2.

Three emergency diesel generators are provided as alternate power sources for the Class 1E system, one for each of the Class 1E major switch groups (241Y, 242Y and 243). Bus 243 is served by DG2B Bus 242Y by DG2A and Bus 241Y by DGO, the swing diesel, which also serves an equivalent function for Unit 1. Each diesel generator is rated for 4160 volts, 2700 KVA, continuous, with a minimum starting time of 23 seconds from admission of air to rated voltage and frequency. The capacity of each diesel generator is sufficient to carry the engineered safeguard system loads and still drive additional motor- operated valves as discussed in other system descriptions.

The auxiliaries of each diesel generator are powered and controlled by the AC train served by the generator or by the corresponding DC power train. Each diesel generator is served by its own fuel system and supply, and its own air starting system. Field flashing is required for generator start.

Each diesel generator will be automatically started by either undervoltage on the associated 4KV bus, the ECCS manual initiation pushbutton for the associated D/G, low water level (Level 3) in the reactor vessel, or high pressure in the primary containment. If power from both the UAT and SAT to the 4160V division buses is lost, all 4160 KV loads in Div. 1 and Div. 2 are shed. Div. 3 loads are not shed. After each diesel generator has attained a normal frequency and voltage, its breaker closes. If normal AC power is still present and the diesel generator was started by low level or high drywell pressure, the diesel generator breaker will not close, and the set must be manually shutdown. If normal AC power is lost and high drywell and low level signals are not present, only the loads needed for safe shutdown are automatically or manually connected as the situation requires. If a safety feature signal then appears, any nonemergency load automatically secures, and the required safety loads are started automatically as required. Electrical inte locks, consisting of auxiliary breaker position switches, prevent the paralleling of 2 diesel generators through the unit ties without an offsite source connected to one of the buses. Additional interlocks prevent the closure of a diesel generator breaker unless all other AC sources to that bus are open.

Locations

Most of the Unit 2 major switchgear for the auxiliary electric power system is located in two switchgear rooms in the auxiliary building. The unit auxiliary transformer and system auxiliary transformers for Unit 2, are outside north of the Unit 2 reactor building. Motor control centers and distribution panels are located around the plant area to be convenient to the plant equipment they serve.

7.1.2.2 System Interfaces

The Auxiliary AC Electric Power System requires support from other plant systems in order to function properly. These include DC control power, room cooling, and cooling for the heat exchangers in the diesel generator cooling systems. These support system interfaces are detailed in Table 7.1.3.

7.1.2.3 Instrumentation and Control

The emergency AC electric power system operates continuously, with the exception of the diesel generators, so that the status of the system is always displayed. In addition, there is much instrumentation connected to the diesel generators and their required support subsystems so that the availability of the diesel generators is also always displayed. In the event of a plant emergency, the control of the system is automatic, although if a failure of automatic actuation occurs, manual control is required.

Presented in Table 7.1.4 are the control room annunciators associated with various faults of the emergency system. Included are the operator actions required to correct the fault. A system failure usually results in several alarms. By analyzing these the operator can determine the specific cause. In addition to the alarms listed in the table, many other indications concern the availability and reliability of the diesel generator subsystems, which are the only portions of the system in standby (not continuous) operation. Automatic system responses to AC power faults are also summarized in Table 7.1.3.

Indirect instrumentation for, and display of, the emergency AC system operation is provided by the performance of the systems and components powered by it. For example, the operation (or lack of) the battery chargers and inverters in the DC system, indicates the status of emergency AC motor control centers, load centers, and switchgear.

7.1.2.4 Operator Actions

Except for recovery no operator actions are necessary for AC electrical system operation because the system operates continuously except for the diesel generators, and they are started automatically upon loss of offsite power or an ECCS signal. Recovery actions are discussed in Section 7.1.2.3, specifically in Table 7.1.3. The actions summarized in that table are detailed in procedures LOA-AP-01 through LOA-AP-06.

7.1.2.5 Technical Specification Limitations

The following technical specifications apply to operational conditions 1, 2 and 3. (Note that section identifications given are those in the technical specifications.)

A.C. Sources - Operating

Limiting Condition for Operation

3.8.1.1 As a minimum, the following AC electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Separate and independent diesel generators 0, 1A, 2A and 2B with:

   1. For diesel generator 0, 1A and 2A:

      a. A separate day fuel tank containing a minimum of 250 gallons of fuel.

      b. A separate fuel storage system containing a minimum of 31,000 gallons of fuel.

   2. For diesel generator 2B, a separate fuel storage tank/day tank containing a minimum of 29,750 gallons of fuel.

   3. A separate fuel transfer pump.

Applicability: Operational Conditions 1, 2, and 3.

Action

a. With either one offsite circuit or diesel generator 0 or 2A of the above required AC electrical power sources inoperable, demonstrate the OPERABILITY of the remaining AC sources by performing Sur- veillance Requirements 4.8.1.1.1a. within 1 hour, and 4.8.1.1.2a.4. for one diesel generator at a time, within 8 hours, and at least once per 8 hours thereafter restore at least two offsite circuits and diesel generators 0 and 2A to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With one offsite circuit and diesel generator 0 or 2A of the above required AC electrical power sources inoperable, demonstrate the OPERABILITY of the remaining AC sources by performing Surveillance Requirements 4.8.1.1.1a. within 1 hour, and 4.8.1.1.2a.4., for one diesel generator at a time, within 8 hours, and at least once per 8 hours thereafter restore at least one of the inoperable AC sources to OPERABLE status within 12 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following

24 hours. Restore at least two offsite circuits and diesel generators 0 and 2A to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT SHUTDOWN within the next 12 hour and in COLD SHUTDOWN within the following 24 hours.

c. With both of the above required offsite circuits inoperable, demonstrate the OPERABILITY of the remaining AC sources by performing Surveillance Requirement 4.8.1.1.2a.4., for one diesel generator at a time, within 8 hours, and at least once per 8 hours thereafter, unless the diesel generators are already operating restore at least one of the inoperable offsite circuits to OPERABLE status within 24 hours or be in at least HOT SHUTDOWN within the next 12 hours. With only one offsite circuit restored to OPERABLE status, restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With diesel generators 0 and 2A of the above required AC electrical power sources inoperable, demonstrate the OPERABILITY of the remaining AC sources by performing

Surveillance Requirements 4.8.1.1.1a. within 1 hour and 4.8.1.1.2a.4., for one diesel generator at a time, within 4 hours and at least once per 8 hours thereafter restore at least one of the inoperable diesel generators 0 and 2A to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours. Restore both diesel generators 0 and 2A to OPERABLE status within 72 hours from time of initial loss or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

e. With diesel generator 2B of the above required AC electrical power sources inoperable, demonstrate the OPERABILITY of the remaining AC sources by performing Surveillance Requirements 4.8.1.1.1a. within 1 hour, and 4.8.1.1.2a.4., for one diesel generator at a time, within 6 hours, and at least once per 8 hours thereafter restore the inoperable diesel generator 2B to OPERABLE status within 72 hours or declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

f. With diesel generator 1A of the above required AC electrical power sources inoperable, demonstrate the OPERABILITY of the remaining AC sources by performing Surveillance Requirements 4.8.1.1.1a. within 1 hour, and 4.8.1.1.2a.4. for diesel generator 2A, within 2 hours, and at least once per 8 hours thereafter restore the inoperable diesel generator 1A to OPERABLE status within 72 hours or declare standby gas treatment system subsystem A, Unit 1 drywell and suppression chamber hydrogen recombiner system, and control room and auxiliary electric equipment room emergency filtration system train A inoperable and take the ACTION required by Specifications 3.6.5.3, 3.6.6.1, and 3.7.2 continued performance of Surveillance Requirements 4.8.1.1.1a. and 4.8.1.1.2a.4 for diesel generator 2A is not required provided the above systems are declared inoperable and the ACTION of their respective specifications is taken.

4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E distribution system shall be:

a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments and indicated power availability, and

b. Demonstrated OPERABLE at least once per 18 months during shutdown by manually transferring unit power supply from the normal circuit to the alternate circuit.

4.8.1.1.2 Each of the above required diesel generators shall be demonstrated OPERABLE:

a. In accordance with the frequency specified in Table 4.8.1.1.2-1 on a STAGGERED TEST BASIS by:

   1. Verifying the fuel level in the day fuel tank.

   2. Verifying the fuel level in the fuel storage tank.

   3. Verifying the fuel transfer pump starts and transfers fuel from the storage system to the day fuel tank.

   4. Verifying the diesel starts from ambient condition and accelerates to 900 rpm + 5%, -2% in less than or equal to 13 seconds.* The generator voltage and frequency shall be 4160 150 volts and 60 + 3.0, - 1.2 Hz within 23 seconds* after the start signal.

   5. Verifying the diesel generator is synchronized, loaded to greater than or equal to 2600 kW within 60 seconds,* and operates with this load for at least 60 minutes.

   6. Verifying the diesel generator is aligned to provide standby power to the associated emergency buses.

7. Verifying the pressure in all diesel generator air start receivers to be greater than or equal to 200 psig.

b. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by checking for and removing accumulated water from the day fuel tanks.

c. At least once per 92 days and from new fuel oil prior to addition to the storage tanks by verifying that a sample obtained in accordance with ASTM-D270-1975 has a water and sediment content of less than or equal to 0.05 volume percent and a kinematic viscosity @ 40C of greater than or equal to 1.9 but less than or equal to 4.1 when tested in accordance with ASTM-D975-77, and an impurity level of less than 2 mg of insolubles per 100 mL when tested in accordance with ASTM-D2274-70.

These diesel generator starts from ambient conditions shall be performed only once per 184 days in these surveillance tests and all other engine starts for the purpose of this surveillance testing shall be preceded by an engine prelube period and/or other warmup procedures recommended by the manufacturer so that mechanical stress and wear on the diesel engine is minimized.

d. At least once per 18 months during shutdown by:

1. Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service.

2. Verifying the diesel generator capability to reject a load of greater than or equal to 1190 kW for diesel generator 0, greater than or equal to 638 kW for diesel generators 1A and 2A, and greater than or equal to 2381 kW for diesel generator 2B while maintaining engine speed less than or equal to 75% of the difference between nominal speed and the overspeed trip setpoint or 15% above nominal, whichever is less.

3. Verifying the diesel generator capability to reject a load of 2600 kW without tripping. The generator voltage shall not exceed 5000 volts during and following the load rejection.

4. Simulating a loss-of-offsite power by itself, and:

a) For Divisions 1 and 2 and for Unit 1 Division 2:

1) Verifying deenergization of the emergency buses and load shedding from the emergency buses.

2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency buses with permanently connected loads within 13 seconds, energizes the auto- connected loads and operates for greater than or equal to 5 minutes while its generator is so loaded. After energization, the steady-state voltage and frequency of the emergency buses shall be maintained at 4160 150 volts and 60 1.2 Hz during this test.

b) For Division 3:

1) Verifying deenergization of the emergency bus.

2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency bus with its loads within 13 seconds and operates for greater than or equal to 5 minutes while its generator is so loaded. After energization, the steady-state voltage and frequency of the emergency bus shall be maintained at 4160 150 volts and 60 1.2 Hz during this test.

5. Verifying that on an ECCS actuation test signal, without loss-of-offsite power, diesel generators 0, 2A, and 2B start on the auto-start signal and operate on standby for greater than or equal to 5 minutes. The generator voltage and frequency shall be 4160 + 416, -150 volts and 60+ 3.0, -1.2 Hz within 13 seconds after the auto-start signal the steady-state generator voltage and frequency shall be maintained within these limits during this test.

6. Simulating a loss-of-offsite power in conjunction with an ECCS actuation test signal, and:

a) For Divisions 1 and 2:

1) Verifying deenergization of the emergency buses and load shedding from the emergency buses.

2) Verifying the diesel generator starts on the auto-start signal, energizes the emergency

buses with permanently connected loads within 13 seconds, energizes the auto- connected emergency loads through the load sequencer and operates for greater than or equal to 5 minutes while its generator is loaded with the emergency loads. After energization, the steady state voltage and frequency of the emergency buses shall be maintained at 4160 416 volts and 60 1.2 Hz during this test.

b) For Division 3:

1) Verifying deenergization of the emergency bus.

2)Verifying the diesel generator starts on the auto-start signal, nd 60 1.2 Hz during this test

7. Verifying that all diesel generator 0, 2A, and 2B automatic trips except the following are automatically bypassed on an ECCS actuation signal:

a) For Divisions 1 and 2 - engine overspeed, generator differential current, and emergency manual stop.

b) For Division 3 - engine overspeed, generator differential or overcurrent, and emergency manual stop.

8. Verifying the diesel generator operates for at least 24 hours. During the first 2 hours of this test, the diesel generator shall be loaded to greater than or equal to 2860 kW and during the remaining 22 hours of this test, the diesel generator shall be loaded to 2600 kW. The generator voltage and frequency shall be 4160 + 420, -150 volts and 60 + 3.0, -1.2 Hz within 13 seconds after the start signal the steady-state generator voltage and frequency shall be maintained within these limits during this test. Within 5 minutes after completing this 24 hour test perform Surveillance Requirement 4.8.1.1.2.d.4.a).2) and b).2).*

9. Verifying that the auto-connected loads to each diesel generator do not exceed the 2000-hour rating of 2860 kW.

10. Verifying the diesel generator's capability to:

    a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

    b) Transfer its loads to the offsite power source, and

    c) Be restored to its standby status.

11. Verifying that with diesel generator 0, 2A, and 2B operating in a test mode and connected to its bus:

*If Surveillance Requirements 4.8.1.1.2.d.4.a)2) and/or b)2) are not satisfactorily completed, it is not necessary to repeat the preceding 24 hour test. Instead, the diesel generator may be operated at 2600 kW for 1 hour or until operating temperature has stabilized.

    a) For Divisions 1 and 2, that a simulated ECCS actuation signal overrides the test mode by returning the diesel generator to standby operation.

    b) For Division 3, that a simulated trip of the diesel generator overcurrent relay trips the SAT feed breaker to bus 243 and that the diesel generator continues to supply normal bus loads.

12. Verifying that the automatic load sequence timer is OPERABLE with the interval between each load block within 10% of its design interval for diesel generators 0 and 2A.

13. Verifying that the following diesel generator lockout features prevent diesel generator operation only when required:

    a) Generator underfrequency.

    b) Low lube oil pressure.

    c) High jacket cooling temperature.

    d) Generator reverse power.

    e) Generator overcurrent.

    f) Generator loss of field.

g) Engine cranking loc' out.

At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting diesel generators 0, 2A, and 2B simultaneously, during shutdown, and verifying that all three diesel generators accelerate to 900 rpm + 5, -2% in less than or equal to 13 seconds.

a. At least once per 10 years by:

1) Draining each fuel oil storage tank, removing the accumulated sediment and cleaning and tank using a sodium hypochlorite or equivalent solution, and

2) Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND, of the ASME Code in accordance with ASME Code Section 11, Article IWD-5000.

4.8.1.1.3 Reports - All diesel generator failures, valid or non-valid, shall be reported to the Commission pursuant to Specification 6.6.B. Reports of diesel generator failures shall include the information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977. If the number of failures in the last 100 valid tests, on a per nuclear unit basis, is greater than or equal to 7, the report shall be supplemented to include the additional information recommended in Regulatory Position c.3.b of Regulatory Guide 1.108, Revision 1, August 1977.

TABLE 4.8.1.1.2-1 DIESEL GENERATOR TEST SCHEDULE

Number of Failures in Last 100 Valid Tests*	Test Frequency
1	At least once per 31 days
2	At least once per 14 days
3	At least once per 7 days
4	At least once per 3 days

A.C. Distribution - Operating

Limiting Condition for Operation

3.8.2.1 The following AC distribution system electrical divisions shall be OPERABLE and energized:

a. Division 1, consisting of

1. 4160-volt bus 241Y.
2. 480-volt buses 235X and 235Y.
3. 480-volt MCCs 235X-1, 235X-2, 235X-3, 235Y-1 and 235Y-2.
4. 120-volt AC distribution panels in 480-volt MCCs 235X-1, 235X-2, 235X-3 and 235Y-a.

b. Division 2, consisting of

1. 4160-volt bus 242Y.
2. 480-volt buses 236X and 236Y.
3. 480-volt MCCs 236X-1, 236X-2, 236X-3, 236Y-1 and 236Y-2.
4. 120-volt AC distribution panels in 480-volt MCCs 236X-1, 236X-2, 236X-3 and 236Y-2.

*Criteria for determining number of failures and number of valid tests shall be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, Revision 1, August 1977, where the last 100 tests are determined on a per nuclear unit basis. With the exception of the semiannual fast start, no starting time requirements are required to meet the valid test requirements of Regulatory Guide 1.108.

c. Division 3, consisting of:

1. 4160-volt bus 243.
2. 480-volt MCC 243-1.
3. 120-volt AC distribution panels in 480-volt MCC 243- 1.

d. Unit 1 Division 1, consisting of

1. 4160-volt bus 141Y.
2. Breaker 1414 OPERABLE or closed.

e. Unit 1 Division 2, consisting of

1. 4160-volt bus 142Y.
2. 480-volt buses 136X and 136Y.
3. 480-volt MCCs 136X-1, 136X-2, 136X-3, 136Y-1, and 136Y-2.
4. 120-volt AC distribution panels in 480 volt MCCs 136X-1, 136X-2, 136X-3, and 136Y-2.

Action

a. With either Division 1 or Division 2 of the above required AC distribution system inoperable or not energized, restore the inoperable division to OPERABLE and energized status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

b. With Division 3 of the above required AC distribution system inoperable or not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

c. With Unit 1 Division 1 or Unit 1 Division 2 of the above required AC distribution systems inoperable or not energized, restore the inoperable division to OPERABLE and energized status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

d. With both Unit 1 Division 1 and Unit 1 Division 2 of the above required AC distribution systems inoperable or not energized, restore at least one of the inoperable AC distribution systems to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

Surveillance Requirements

4.8.2.1 The above required AC distribution system electrical divisions shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment and voltage on the buses/panels.

7.1.2.6 Tests

Tests of the AC auxiliary electric system are either:

Performed without affecting system availability, or
Performed during reactor shutdown

7.1.2.7 Maintenance

Scheduled routine maintenance is not performed on the AC auxiliary electric system during plant operation. Unscheduled maintenance (replacement, repair, or adjustment) is permitted on components, providing applicable safety and radiological administrative controls can be satisfied, and the limiting conditions for operation are not violated (See Section 7.1.2.5). Unscheduled maintenance activities expected during plant operation include:

Replacement or repair of actuation and control circuitry
Mechanical maintenance on buses and circuit breakers

A summary of expected maintenance during plant operations is given in Table 7.1.5.

7.1.2.8 System Performance During Accident Conditions

The major internal accident conditions which impact the AC electrical system are loss of offsite power and loss of coolant accidents (LOCA). These initiating events call for starting of the emergency diesel generators and rearrangement of major circuit connections by actuation of automatic circuit breakers.

7.1.3 System Operation

7.1.3.1 Normal Operation

During normal plant operation the auxiliary AC electrical system is functioning, with electric power on all AC buses. All circuit breakers are closed, except those in the alternate feed paths to the major switch groups and the circuit breakers which connect the emergency diesel generators to the 4160-volt ESF buses. The emergency diesel generators are not running.

7.1.3.2 Abnormal Operation

7.1.3.2.1 General

In the event of loss of offsite power, all three emergency diesel generators will start, and the circuit breakers connecting them to the 4160-volt buses will close. If high drywell pressure and low reactor level signals are not present, only the loads needed for safe shutdown are automatically or manually connected as the situation requires.

In the case of a loss of coolant event, (evidenced by drywell pressure and reactor level signals), the diesel generators will start, but the circuit breakers connecting them to the ESF buses will not close. Unless subsequent events require the application of emergency power, the diesels will be shut down manually.

7.1.3.2.2 Automatic Circuit Breaker Actuation

Although all of the circuit breakers in the power distribution system can be considered automatic, in the sense that they will open on overcurrent without manual intervention, they can be divided into four general categories:

Type A - No External control circuit
Type B - Controller actuated by auxiliary contacts
Type C - Controller actuated by bus overcurrent relay(s) Type D -
Controller actuated by combination of inputs, as described below. (These are referred to as automatic circuit breakers.)

In the auxiliary AC electric power system analysis, failures of Type A breakers are considered to be local faults, and Type B and C failures include controller faults which are modeled as undeveloped events. Type D breakers include those which are used to apply power to (and remove power from) the major switch groups. The actuation circuits for these breakers are modeled explicitly in the auxiliary AC electric power fault tree.

Automatic circuit breakers, and their associated actuation circuits are intended to place the auxiliary AC power system in the appropriate configuration for normal or abnormal operations. Their functions include:

Switching buses to the UAT if the SAT fails
Switching buses to the SAT if the UAT fails
Connecting emergency diesel generators to ESF buses
Shedding non-essential loads during abnormal operating conditions.

The automatic circuit breakers are usually positioned by actuation circuits which are driven by various pressure, temperature and level sensors, and by protective relays in the power distribution system. The protective relays detect electrical anomalies such as overcurrent and undervoltage at buses in both the main and auxiliary power systems and in the ring bus connecting the plant output to the power grid. Inputs from the sensors to each circuit breaker actuation circuit are converted into appropriate logic ("actuate" or "no actuate") decisions by combinations of circuit connections and logic relays. These outputs control contacts which actuate, or permit actuation of, the circuit breakers. To protect against improper combinations of circuit breaker closures, the actuation circuits are interlocked using auxiliary contacts which are open or closed, depending on circuit breaker position.

The automatic circuit breakers important to operation of the auxiliary AC power system, their function, and their status under various electric power conditions, is shown in Table 7.1.6.

7.1.4 System Fault Tree

7.1.4.1 Fault Tree Description

A simplified diagram of the auxiliary AC electric power system (used for fault tree modeling) is shown in Figure 7.1.3. The automatic circuit breaker actuation systems included in the fault tree are not shown due to the difficulty in rendering a simplified version which would be readily understandable. However, logic block diagrams based on those actuation circuits, and used in preparing the model, are included as Figures 7.1.4 through 7.1.23.

The fault tree is presented in Section of this report. Table 7.1.X provides the data used to quantify the fault trees.

7.1.4.2 Success/Failure Criteria

The auxiliary AC electric power system, supports other systems by providing power to those buses needed to distribute it to plant equipment. There are, therefore, many success criteria and top events distributed throughout the overall plant model. The success criteria for these top events is the presence of electric power and the top event definitions are of the form "Loss of Power at (Voltage) Bus XXX".

7.1.4.3 Major Assumptions

The following assumptions were made in constructing the fault tree for auxiliary AC electric system.

1. The ring bus connecting the main generators to the power grid, and associated components were not considered. Failures of this equipment were assumed to be part of the loss of offsite power rate.

2. Equipment auxiliary to the emergency diesel generators was not included. Failures of this equipment are subsumed in the diesel generator failure rate.

3. Immediate operator actions were not modeled.

4. Failure-to-restore events were not included, due to the extensive alarm system which covers all of the AC buses, and the potential for shift checks to reveal loss of power at a bus.

5. Circuit breaker controllers were modeled as undeveloped events because they are all similar (exclusive of their automatic actuation features) and can be treated as "black boxes" for the purpose of quantifying the fault trees.

6. It was assumed that switchgear and switchgear actuation systems did not require room cooling.

Table 7.1.1
Major Loads on Non-Class 1E Electrical System

251	252
1. SWGR 251-1	1. SWGR 252-1
2. Condensate & Booster Pumps A&C	2. Condensate & Booster Pump B&D
3. Electrode Boiler QA	3. Electrod Boiler OB
4. Inerting Steam Electrode Boiler	4. MD Rx Feed Pump
5. 480V Swgr 231 A & B 233 A & B	5. 480V Swgr 232 A & B 234 A & B

141X	142X
1. Circ. Water Pumps A & C	1. Circ. Water Pump B
2. Service Water Pump A	2. Service Water Pump B
3. Heater Drain Pumps A & C	3. Heater Drain Pumps B & D
4. Unit 1 Service Air Compressor	4. Service Water Jockey Pump OA
5. 480V Swgr 131X & Y 137X & Y	5. 480V Swgr 132X & Y 138X & Y

Table 7.1.2
Major Loads on Class 1E AC Electrical System

241Y

1. LPCS Pump
2. RHR Pump 1A
3. SWGR 235X & 235Y
4. D/G "O"
5. Bus tie to 241X
6. Bus tie to 141Y
7. CRD Pump 1A
8. SWGR 233
9. Recirc MG set A
10. Primary Containment Water Chiller A
11. Suppression Pool C/U Pump B

242Y

1. D/G 2A
2. RHR Pump 1B & 1C
3. SWGR 236X & 236Y
4. Bus tie to 242X
5. Bus tie to 142Y
6. Sup Pool C/U Pump A
7. CRD Pump 1B
8. SWGR 234X and 234Y
9. Recirc MG Set B
10. Primary Containment Water Chiller B

243

1. D/G B (HPCS)
2. HPCS Pump
3. MCC 243-1

The diesel generators supply the following buses:

a) D/G "O" supplies buses 141Y (Unit 1) and 241Y.
b) D/G "2A" supplies bus 242Y.
c) D/G "2B: supplies bus 243.

Table 7.1.3
Control Room Alarms and Operation Actions for AC System Faults

LOSS OF SYSTEM AUXILIARY TRANSFORMER,
SAT 242, DURING POWER OPERATION

I.

A. <u>Symptoms</u>

1. Alarms.

On Panel 2PM01J::

a. SAT 242 Undervoltage.

b. SAT 242 Sudden Pressure.

c. SAT 242 Protective Relay Trip.

d. Bus 252 Feeder Breaker 2522 Auto Trip.

e. Bus 241-Y Feeder Breaker 2412 Auto Trip.

f. Bus 242-Y Main Breaker 2422 Trip.

On Panel 2H13-P601:

g. Bus 243 Main Breaker 2432 Auto Trip.

On Panel OPM12J:

h. 345 KV OCB 1-6 Trip.

i. 345 KV OCB 4-6 Trip.

2. Momentary Alarms.

On Panel H13-P601:

a. 4 KV Bus 243/MCC 243-1 Undervoltage.

b. 4 KV Bus 243 Breaker Auto Trip.

B. Automatic Actions

1. AUTO TRANSFER of buses that are normally supplied from SAT 242 to their alternate supply as indicated below:

Bus	Alternate Supply	ACB
252	UAT 241	2521
241-Y	UAT 241	2415
242-Y	UAT 241	2425
243	DG 23	2433

2. AUTO START of DG 2B.

3. AUTO START DG 0, DG 2A, if auto transfer does not occur.

C. Immediate Operator Actions

1. CHECK that a loss of SAT 242 has occurred.

2. VERIFY that automatic transfer of buses has occurred.

3. VERIFY Diesel 2B Auto Starts.

4. VERIFY Diesel) & 2A Auto Starts if auto transfer to Bus 241-Y and 242-Y does not occur.

5. NOTIFY the Shift Supervisor.

D. Subsequent Operator Actions

1. DISPATCH an operator to the System Auxiliary Transformer, SAT 242, control cabinet to determine the cause of the loss.

2. INFORM the Load Dispatcher of the cause of the loss and of the corrective action being taken.

3. INFORM the Operating Engineer of the transformer failure.

4. REFER to Technical Specification Section 3.8.

5. REFER to LOP-AP-02, Restoring System Auxiliary Transformer to Service During Unit Operation.

6. SHUTDOWN DG 0, DG 2A, and DG 2B if not needed in accordance with LOP-DG-09, LOP-DG-03, or LOP-DG-06 respectively.

Failure of Bus 241-Y or Bus 242-Y to
Transfer to Unit Auxiliary Transformer, UAT 241
Upon Loss of Power from System Auxiliary
Transformer SAT 242

A. Symptoms

1. Failure of Bus 241-Y to transfer to UAT 241.

a. Alarms - on panel 2PM01J:

1) Bus 241-Y Feeder Breaker Auto Trip.

2) Bus 231-233-237 Undervoltage.

3) 480V Bus 235X-Y Undervoltage.

b. Momentary Alarm - on panel 2PM01J:

1) 480V Bus 235X-Y MN FD BKR Auto Trip.

2) 4KF Bus 241X-Y Undervoltage.

Note

This alarm should be cleared when DG 0, energizes Bus 241-Y.

2. Failure of Bus 242-Y to transfer to UAT 241.

a. Alarm - on panel 2PM01J:

1) Bus 232-234-238 Undervoltage.

2) Bus Feeder Breaker Auto Trip.

b. Momentary alarms - on panel 2PM01J:

1) 4KV Bus 242X-Y Undervoltage.

2) 480V Bus 236X-Y Undervoltage.

Note

These alarms may be cleared when DG 2A, Energizes Bus 242.

B. Automatic Actions

1. AUTO START of DG 0 or DG 2A.

2. AUTO TRANSFER of the affected Bus 241-Y or 242-Y to its respective Diesel Generator.

3. Bus 242-x is DEENERGIZED if bus 242-Y is the affected bus.

4. Load shedding of Bus 241-Y plus AUTO TRIP of Feed Bkr. to Bus 233 on Bus 241-Y undervoltage.

5. Load shedding of Bus 242-Y plus AUTO TRIO of Feed Bkr. to Bus 234X-Y on Bus 242-Y undervoltage.

C. Immediate Operator Actions

1. CHECK that a bus has failed to transfer to UAT 241.

2. VERIFY that the affected bus has transferred to its respective Diesel Generator as indicated below:

BUS	DIESEL GENERATOR
241Y	DG 0
242Y	DG 2A

3. VERIFY a Primary Containment Chill Water Water System and a Primary Containment Ventilation fan are RUNNING.

4. NOTIFY the Shift Supervisor.

5. If bus 242-X is DEENERGIZED:

   a. ATTEMPT to CLOSE feed breaker ACB 2421 from UAT 241 to Bus 242-X.

   b. If ACB 2421 fails to CLOSE, REDUCE Reactor Power as necessary to maintain condenser vacuum to continue Power Operations due to loss of the following main components:

      1) Circulating Water Pump 2B.

      2) Service Water Pump 2B.

      3) Service Water Jockey pump "OA".

4) Heater Drain Pump 2B & 2D.

5) Station Air Compressor "0".

c. If Circulating Water Pump 2B was one of two running pumps, START the idle Circulating Water Pump Fed from Bus 241-x.

6. REFER to Attachment A of LOA-AP-07, Loss of Auxiliary Electric Power, if any buses are picked up on a diesel generator. Do not exceed 2860 KW for 2 hours.

D. <u>Subsequent Operator Actions</u>

1. NOTIFY Shift Supervisor to Classify the Event and INITIATE GSEP if Appropriate.

2. DISPATCH an operator to the affected bus's circuit breaker control cabinet to DETERMINE the cause of the failure to automatically close.

3. DISPATCH an operator to System Auxiliary Transformer (SAT) 242 to DETERMINE the cause of the Trip.

4. Start the idle Air Compressor if required due to the loss of '0' station Air Compressor.

5. INFORM the Load Dispatcher of the cause of the failure and of the corrective action being taken.

6. SHUTDOWN any Diesel Generators that are running unloaded.

7. INFORM the Operating Engineer of the failure of a bus to transfer to UAT 241.

8. REFER to Technical Specification Section 3.8.

II. LOSS OF A 4KV ESS BUS

A. <u>Symptoms</u>

1. Loss of Bus 241Y.

Alarms - on panel 2PM01J:

a. 4KV Bus 241X-Y UNDERVOLTAGE.

b. BUS 231-233-237 UNDERVOLTAGE.

c. 480V BUS 235X-Y UNDERVOLTAGE.

d. Bus 241X-Y Tie Breaker 2415 TRIP.

e. BUS 241Y FEEDER BKR AUTO TRIP.

Alarms - on panel 2H13-P603:

a. Chan A-1 Rx Auto SCRAM

b. Chan A-2 Rx Auto SCRAM

2. Loss of Bus 242Y.

Alarms - on panel 2PM01J:

a. 4KV Bus 242X-Y Undervoltage

b. Bus 232-234-238 Undervoltage

c. 480V Bus 236X-Y Undervoltage

d. Bus 242X-Y Tie Breaker 2425 Trip

e. Bus 242Y Feeder Bkr Auto Trip

Alarms - on panel 2H13-P603:

a. Chan B-1 Rx Auto Scram

b. Chan B-2 Auto Scram

3. Loss of Bus 243

Alarms - on panel 2H13-P601:

a. 4KV Bus 243 MCC Undervoltage

b. 4KV Bus 243 Breaker Auto Trip

B. <u>Automatic Actions</u>

1. Normal feed to the affected bus opens

2. Alternate feed to the affected bus is interlocked open, if an overcurrent has occurred

3. Unit Tie to the affected bus is interlocked open if an overcurrent has occurred

4. Auto Start of the Diesel Generator serving the affected bus:

BUS	ESS DIVISION	DIESEL GENERATOR
241Y	I	DG 0
242Y	II	DG 2A
243	III	DG 2B

5. If an overcurrent has occurred, the associated Diesel Generator will close to faulted bus, then trip on its own overcurrent. Diesel Generator overcurrent is bypassed by an ECCS signal.

6. The affected bus and its associated load buses will be DEENERGIZED.

Note

With loss of the following Division ESS Buses, the Containment Isolation valves associated with that bus, will not operate until power is restored to the appropriate bus.

7. Loss of Division I Bus will cause the Primary Containment Isolation Outboard valves to receive an isolation signal. However, the outboard MSIVs will not close.

8. Loss of Division II Bus will cause the Primary Containment Isolation Inboard valves to receive an isolation signal. However, the inboard MISVs will not close.

C. IMMEDIATE OPERATOR ACTIONS

1. Check that an ESS bus has failed to reenergize.

2. Check status of all potential feeders to the affected bus.

3. Check associated bus and targets to determine the cause of the trip and for visual signs of damage.

4. Transfer the deenergized R.P.S. bus to its backup power supply in accordance with LOP-RP-01, Reactor Protection System MG Set Start-up and Operation.

5. Reset the Reactor Scram Logic and Refer to LOA-PC-02, Primary Containment Isolation, to Reset the Primary Containment Isolation Logic.

6. Verify a Primary Containment Chiller and Vent Fan are running.

7. Notify the Shift Supervisor.

8. If the cause of the loss is known, correct or isolate the problem from the affected bus if possible.

9. If the cause of the loss is not know, or if the problem cannot be quickly corrected or isolated from the affected bus and Bus 241X is deenergized reduce reactor power to maintain condenser vacuum and commence subsequenc action. If only one (1) Circ. Water Pump is available, the discharge gates must be throttled to prevent runout.

CAUTION

Care musc be taken to insure that the faulted bus is not tied to an unfaulted bus.

10. If the problem has been corrected or isolated, reenergize the affected bus as per Attachment A as follows:

    a. If the normal power source is available, attempt to energize the bus from the normal power source as follows:

AFFECTED BUS	NORMAL SOURCE	ACB
241Y	SAT 242	2412
242Y	SAT 242	2422
243	SAT 242	2432

    b. If the alternate power sources available, and the designated normal feed breakers fail to close, energize the bus from the alternate power source as follows:

AFFECTED BUS	ALTERNATE SOURCE	ACB
241Y	UAT 241	2415
242Y	UAT 241	2425

c. If the Diesel Generators are available, and the alternate power source fails to close, ENERGIZE the bus from the Diesel Generators as follows:

AFFECTED BUS	DIESEL GENERATOR	ACB
241Y	D.G. "0"	2413
242-Y	D.G. 2A	2423
243	D.G. 2B	2433

D. Subsequent Operator Actions

Note

REFER to Attachment A of LOA-AP-05 for key instrumentation/components that will be lost from loss of an ESF AC bus; COMPARE all redundant indications at the same parameter and INSURE that all unaffected records are tracking properly by comparing indications with other indications of the same parameters.

1. DETERMINE the cause of the loss of CORRECT or ISOLATE the problem from the affected bus if possible.

2. If the problem has been corrected or isolated and no other source of power is available, the affected bus may be energized through its associated bus tie as follows:

   a. To ensure that the affected bus's loads are tripped, place the appropriate Control Switches in the PULL-TO-LOCK position.

   b. Close the crosstie circuit breakers from the Unit 1 bus to the affected bus as indicated below.

AFFECTED BUS	UNIT 2(1) BUS	ACB
241Y	141Y	1414 and 2414
242Y	142Y	1424 and 2424

   c. Sequentially restart loads as required. Do not exceed 3000A on any bus feed breaker or 1200A on any crosstie breaker.

   d. If bus is being supplied by a Diesel Generator, do not exceed the following limits, (refer to Attachment A of LOA-AP-07, Loss of Auxiliary Electrical Power, for approximate load KW):

1) Maximum Generator Operating Amps 494.

2) Emergency Generator Load 2860 KW for two hours.

3. If power has been restored (other than by Unit tie) to the affected bus, and the load capacity is available, restart equipment that has tripped as required.

4. If a 250/125 VDC battery charger will remain lost for over one hour, cross tie the associated buses to the opposite unit per 1OP-DC-02, changing Modes of Operation in the D.C. Electrical System. If no 250 VDC battery charger is subsequently available, secure the 250 VDC loads listed in Step D.2.c. of LOA-AP-07, Loss of Auxiliary Electrical Power.

Note

The securing of these loads could cause a total loss of Main Turbine lubrication, Main Generator seals, Process Computer components, and Control Rod Position indication if more switchgear or buses are subsequently lost.

5. Shutdown any Diesel Generators that are running unloaded.

6. Dispatch an operator to the affected bus's circuit breaker control cabinet to determine the cause of the failure to automatically close.

7. Inform the Load Dispatcher of the cause of the loss and of the corrective action being taken.

8. Inform the Operating Engineer of the failure of an ESS bus to reenergize.

9. Refer to Technical Specification Section 3.8.

III. LOSS OF A NON ESS BUS

A. Symptoms

Alarms - on Panel 2PMC1J

1. Loss of Bus 251

a. 6.9KV Bus feeder breaker 2511 auto trip

b. 6.9KV Bus 241 Feeder Breaker 2511 auto trip

c. 480V Bus 231-233 undervoltage

d. 6.9V Bus Main Breaker Trip

2. Loss of Bus 252

a. 6.9KV Bus 252 Feeder Breaker 2522 auto trip

b. 6.9KV Bus 251 252 undervoltage

c. 480V 232-234 undervoltage

d. 6.9KV Bus Main Breaker Trip

3. Loss of Bus 241-X

a. 4KV Bus 241-X Feeder Breaker Auto Trip

b. 4KV Bus 241X-Y undervoltage

c. Bus 231-233-237 undervoltage

4. Loss of Bus 242-X

a. 4KV Bus 242-X Feeder Breaker Auto Trip

b. 4KV 242X-Y undervoltage

c. Bus 232-233-238 undervoltage

B. <u>Automatic Actions</u>

1. The affected bus's alternate feed breaker has failed to close, or has tripped while the normal supply is not available.

2. The affected bus and associated load buses will be deenergized.

C. <u>Immediate Operator Actions</u>

1. Check that a Non ESS bus has failed to reenergize.

2. Verify that any required alternate equipment is operating. Start alternate equipment as necessary.

3. Dispatch an operator to the affected bus to check targets and inspect for obvious damage

4. Notify the Shift Supervisor.

5. If necessary, reduce power to maintain condenser vacuum. If only one Circ. Water Pump is running, the Discharge Gates must be throttled to prevent runout.

D. Subsequent Operator Actions

Note

Refer to Attachment A of LOA-AP-05 for key instruments/components which may be required to obtain cold shutdown, but which may be lost. Use alternate systems/components/indication if power cannot be restored.

1. Determine the cause of the loss.

2. If the cause of the loss is known, correct or isolate the problem from the affected bus if possible.

Caution

Care must be taken to insure that a faulted bus is not tied to an unfaulted source.

3. After the problem has been corrected or isolated, reenergize as follows:

    a. If the normal power source is available, attempt to energize the bus from the normal power source as per Attachment A by closing the appropriate breaker below:

Affected Bus	Normal Source	ACB
251	UTA 241	2511
252	SAT 242	2522
241-X	UAT 241	2411
242-X	SAT 242	2425

    b. If the alternate power source is available, and the designated normal feed breaker fails to close, attempt to energize the bus from the alternate power source by turning on the synchroscope and closing the appropriate breaker below:

Affected Bus	Alternate Source	ACB
251	SAT 242	2512
252	UAT 241	2521
241-X	SAT 242	2412
241-X	UAT 241	2422

4. If power has been restored to the bus, restart as necessary any loads that have tripped.

5. If power has not been restored to Bus 251 or Bus 252, reduce power in accordance with LOA-RR-06, Loss of Recirculation Flow - Single Pump.

6. Inform the Load Dispatcher of the cause of the loss and of the corrective action being taken.

7. Return the system to a normal lineup as soon as possible.

IV. LOSS OF A 480 VAC ESS BUS

A. Symptoms

1. Loss of Bus 235X-Y

Alarms - on Panel 2PM01J

A. 480 Bus 235X-Y Main Feed Breaker Auto Trip

B. 480 Bus 235X-Y undervoltage

C. 480 Transformer 235X-Y overload

Alarms - on panel 2H13-P603

a. Chan A-1 Rx Auto Scram

b. Chan A-2 Rx Auto Scram

2. Loss of Bus 236X-Y

Alarms - on panel 2PM01J

a. 480 Bus 236X-Y Main Feed Breaker Auto Trip

b. 480 Bus 236X-Y undervoltage

c. 480 Transformer 236X-Y overload

Alarms - on Panel 2H13-P603

a. Chan B-1 Rx Auto Scram

b. Chan B-2 Auto Scram

B. Automatic Actions

1. The affected bus and its associated load buses will be deenergized.

Note

With the loss of the following Division ESS MCCs, Containment Isolation valves associated with that MCC, will not operate until power is restored to the appropriate MCC.

2. Loss of MCC 235X will cause the Primary Division 1 Containment Isolation signal Outboard valves to receive an isolation signal. However, the Outboard M.S.I.V's will not close.

3. Loss of MCC 236X will cause the Primary Division II Containment Isolation Inboard valves to receive an isolation signal. However, the Inboard M.S.I.V.'s will not close.

C. Immediate Operator Actions

1. Determine which ESS bus has lost power by checking control room panel indications.

2. Transfer the deenergized RPS bus to its backup power supply if available, in accordance with LOP-RP- 01, Reactor Protection System MG-Set Start-up and Operation.

3. Reset the Reactor Scram Logic and refer to LOA-PC-02, Primary Containment Isolation, to reset the Primary Containment Isolation Logic.

4. Notify the shift supervisor.

5. If the cause of the loss is know, correct or isolate the problem from the affected bus and reenergize the bus.

6. If the loss of the bus was due to loss of the 4.16 KV bus that feeds the 480 V bus, refer to LOA-AP- 03, Loss of a 4KV ESS bus.

D. Subsequent Operator Actions

1. Determine the cause of the loss and correct or isolate the problem from the affected bus if possible.

2. Refer to Attachment A for key instrumentation/ components that will be lost from loss of an ESF AC bus compare all redundant indications of the same parameter and insure that all unaffected recorders are tracking properly by comparing indications with other indications of the same parameter.

3. If the bus can be reenergized, restore power to the bus per LOP-AP-06, returning a 480 V transformer to service.

4. If the loss of a bus was due to an overcurrent condition:

   a. Do not attempt to reenergize the affected bus until a general inspection has been performed and no damage to the bus and its associated equipment has been observed.

   b. Reenergize the affected bus if no damage has occurred.

   c. When power has been restored to the affected bus, restart equipment that has tripped as required.

5. If a 250/125 VDC battery charger will remain lost for over one hour, cross tie the associated buses to the opposite unit per LOP-DC-02, changing modes of operation in the D.C. electrical system. If no 250 VDC battery charger is subsequently available, secure the 250 VDC loads listed in Step D.2.c of LOA- AP-07, Loss of Auxiliary Electrical Power.

   Note

   The securing of these loads could cause a total loss of Main Turbine lubrication, main generator seals, various Process Computer-components, and Control Rod Position Indication if more switchgear/buses are subsequently lost.

6. Refer to Technical Specification Section 3.8.

Table 7.1.6
AUTOMATIC CIRCUIT BREAKER STATUS

UAT and Breaker Lost*	Connects	Normal Status	UAT 241 Lost	SAT 242 Lost	Both SAT
2511	UAT 241/BUS 251	Closed	Open	Closed	Open
2512	SAT 242/BUS 251	Open	Closed	Open	Open
2521	UAT 241/BUS 252	Open	Open	Closed	Open
2522	SAT 242/Bus 252	Closed	Closed	Open	Open
2412	SAT 242/BUS 241Y	Closed	Closed	Open	Open
2411	UAT 241/BUS 241X	Closed	Open	Closed	Open
2421	UAT 241/BUS 242X	Open	Open	Closed	Open
2422	SAT 242/BUS 242Y	Closed	Closed	Open	Open
2415	BUS 241Y/BUS 241X	Open	Closed	Closed	Open
2425	BUS 242Y/BUS 242X	Closed	Closed	Closed	Open
2413	BUS 241Y/DG 0	Open	Open	Open	Closed
2423	BUS 242Y/DG 2A	Open	Open	Open	Closed
2433	BUS 243/DG 2B	Open	Open	Closed	Closed
2432	SAT 242/BUS 243	Closed	Closed	Open	Open

*Loss of offsite power

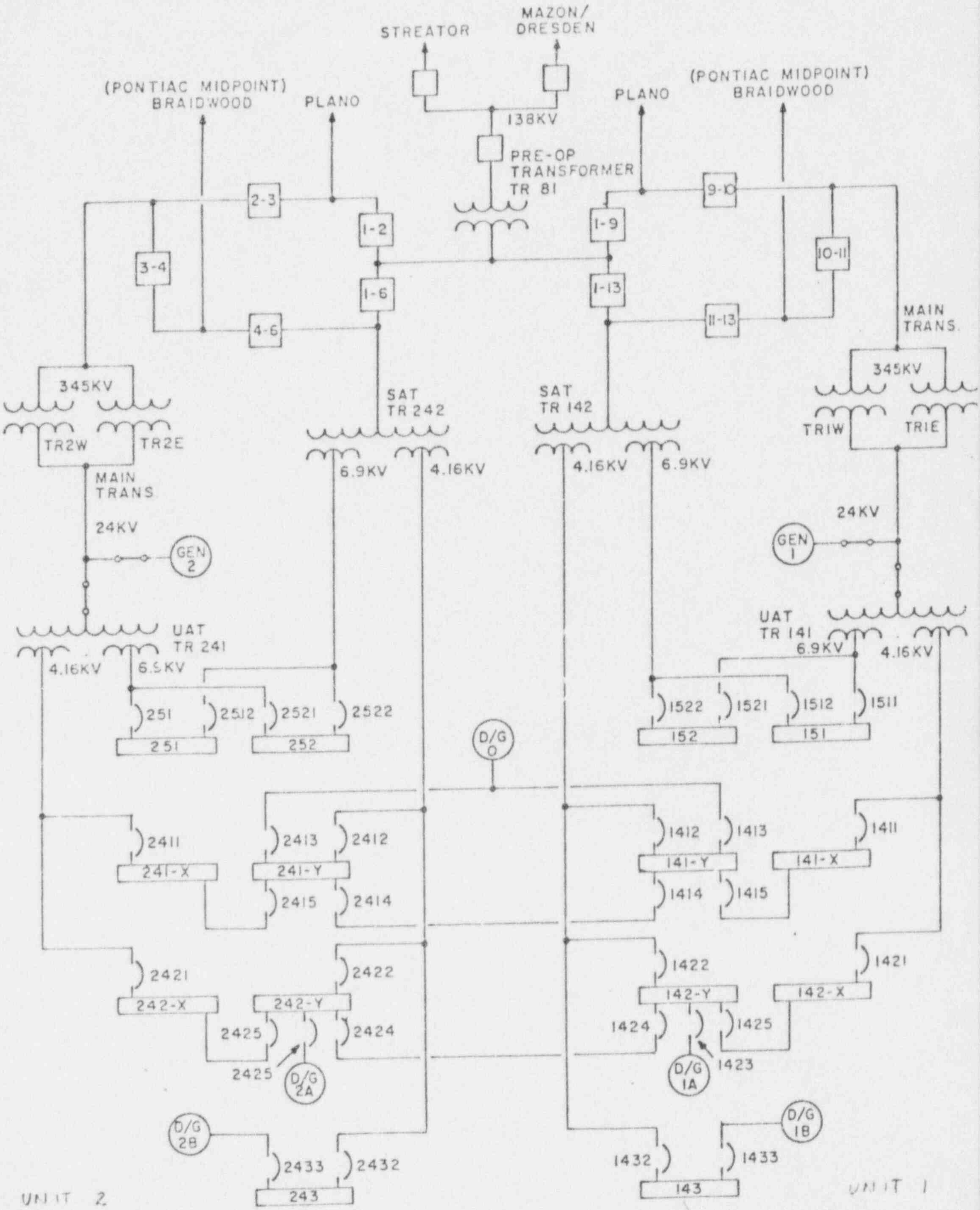
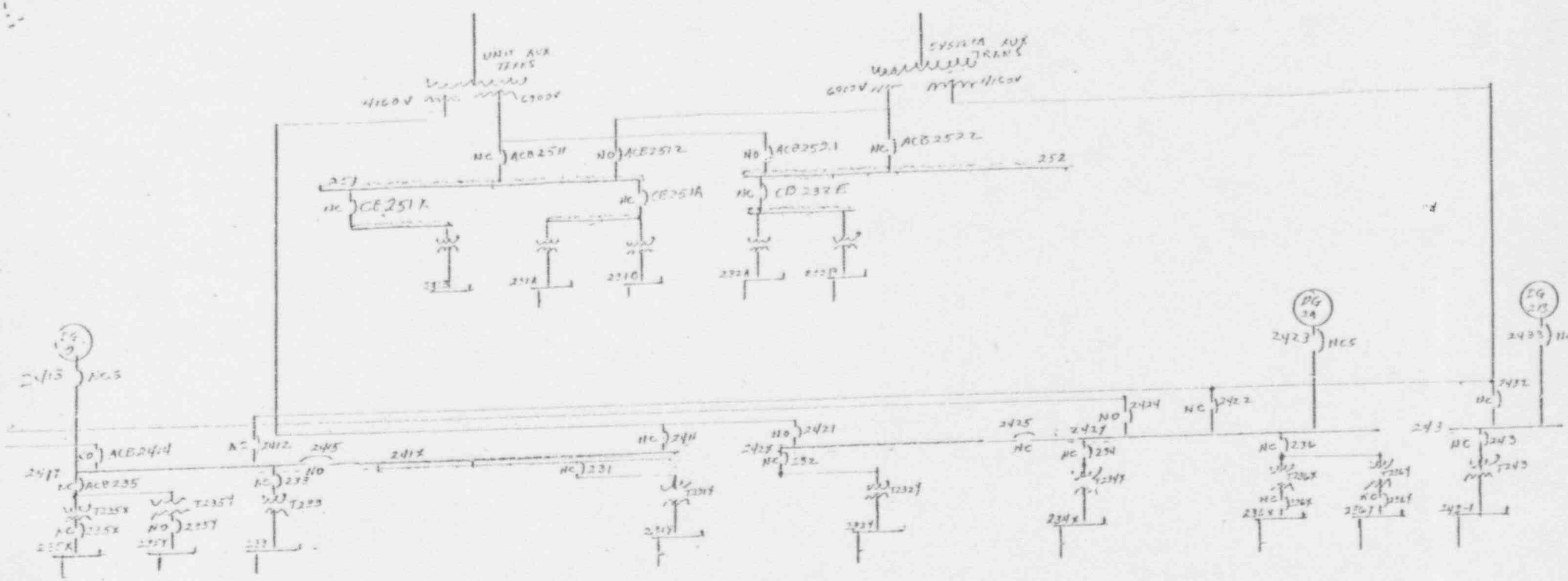


FIGURE ~~42-1~~ B.X.1 AC DISTRIBUTION SYSTEM



B.X.3 AUXILIARY AC ELECTRIC POWER SYSTEM

FIGURE B.X.4 SUCCESS LOGIC DIAGRAM - ACB 2412 REMAIN CLOSED

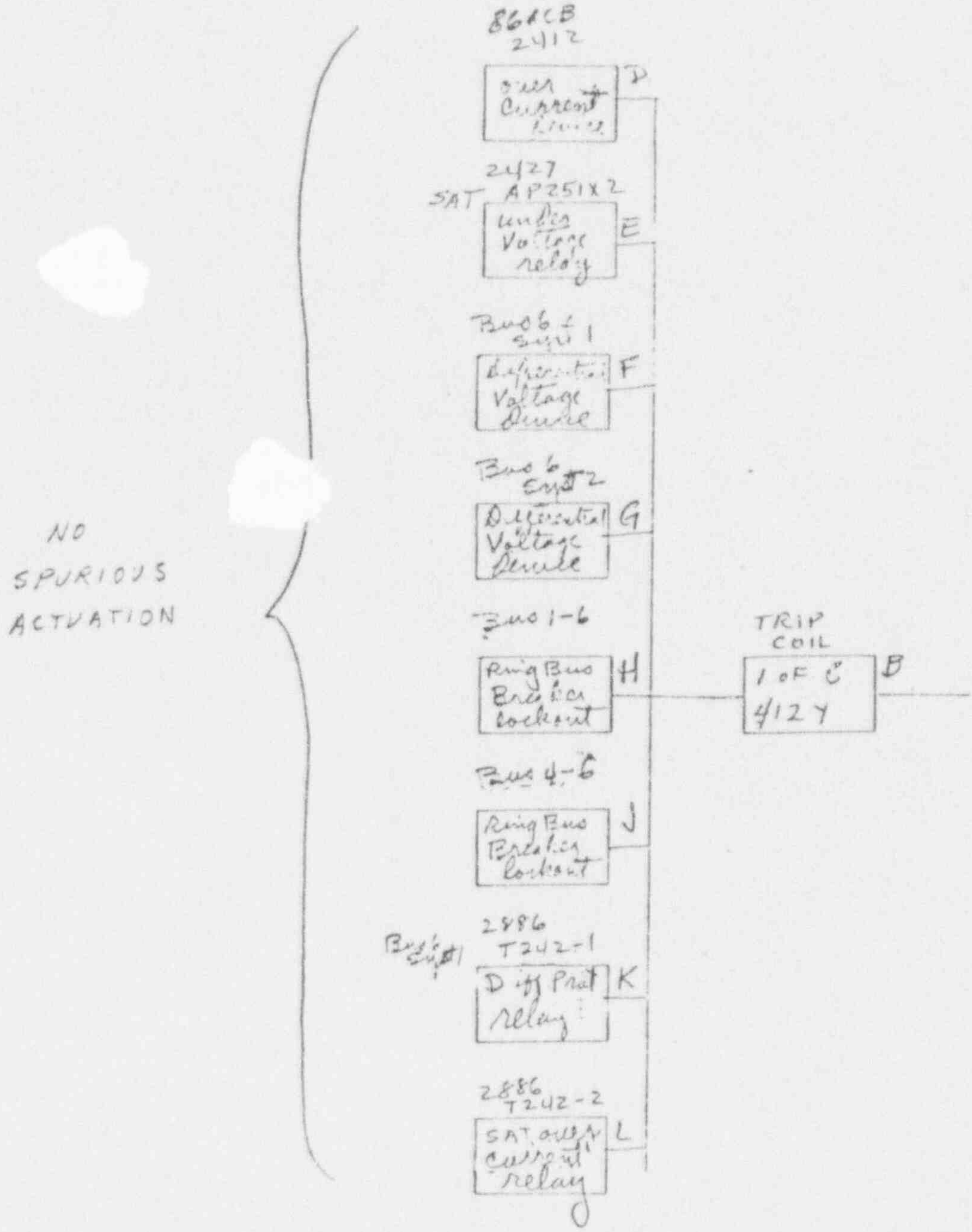
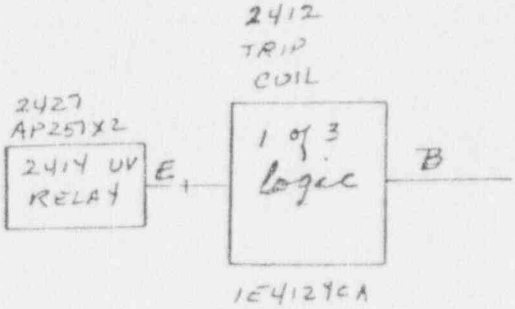


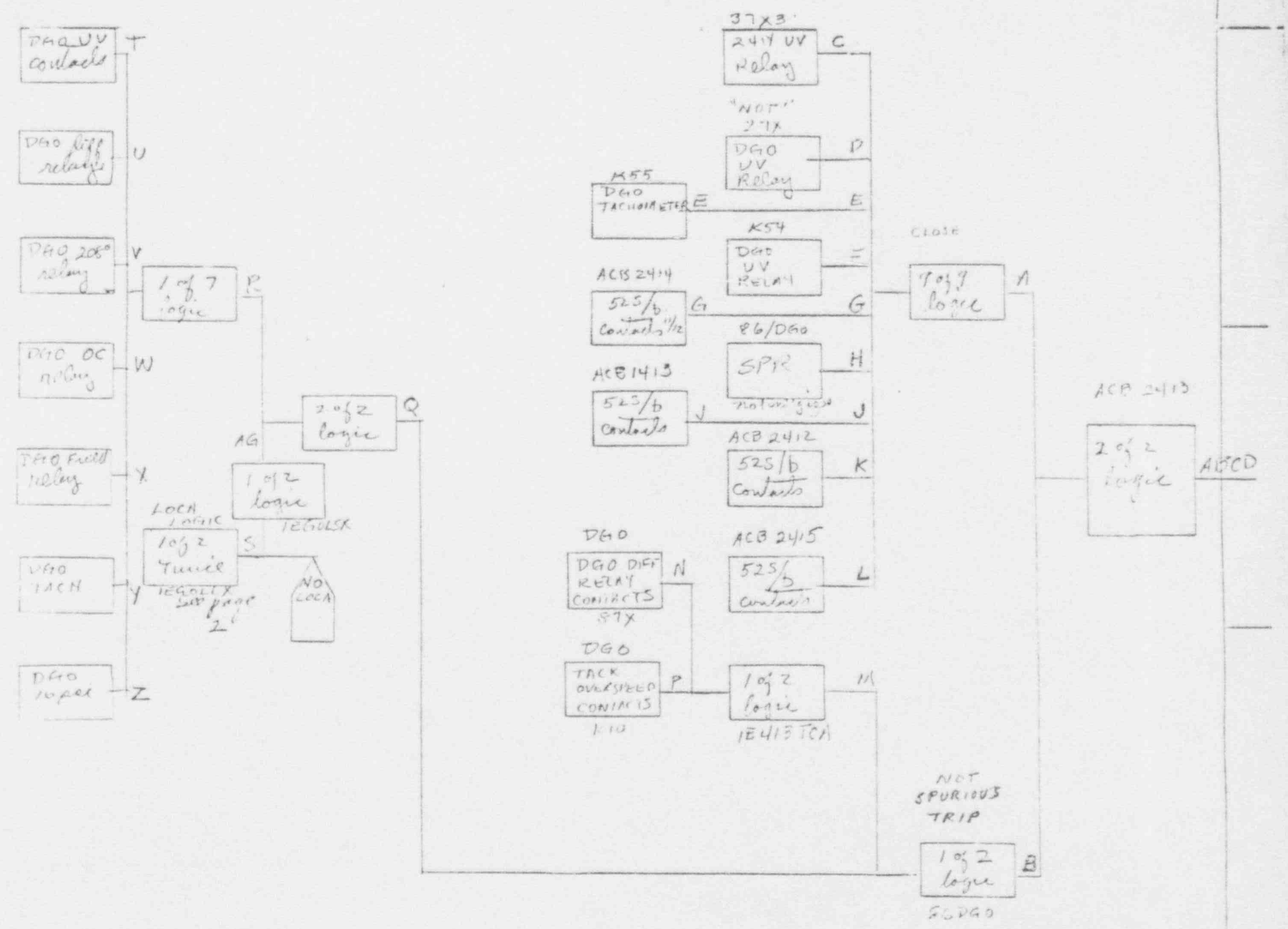
FIGURE B.X.5 SUCCESS LOGIC DIAGRAM - ACB2412 TRIP



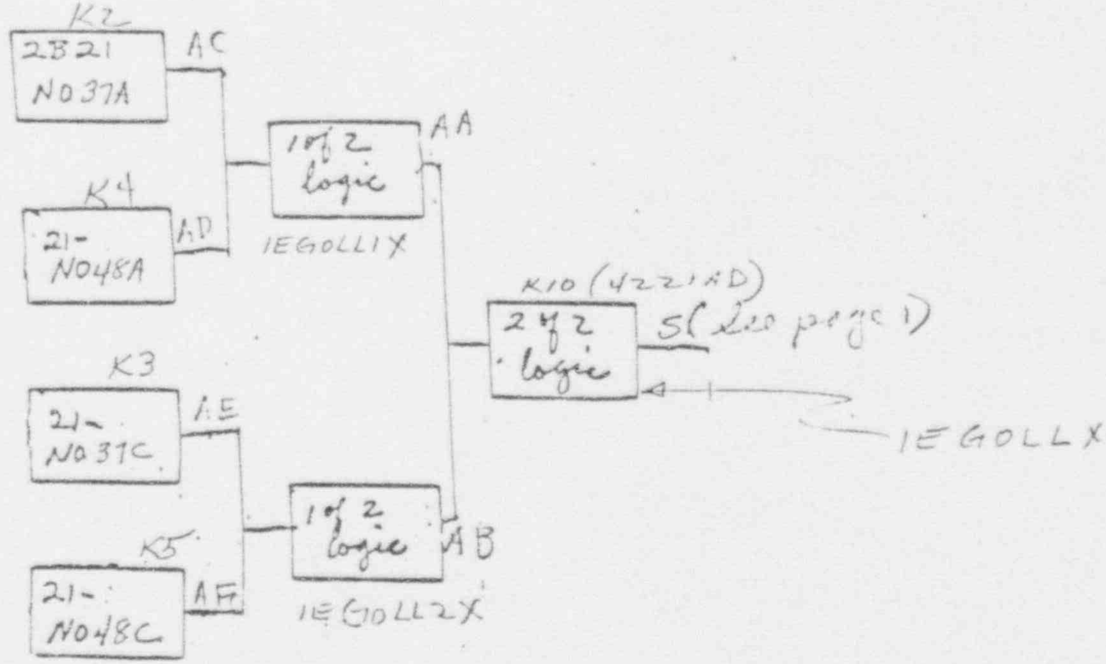
E.X.6 SUCCESS LOGIC DIAGRAM

ACB 2413

CLOSE (PAGE 1)



F.V. 7 LOGIC DIAGRAM - ACB 2413 CLOSE (PAGE 2)



B. X. 8 SUCCESS LOGIC DIAGRAM - ACB 2422 TRIP

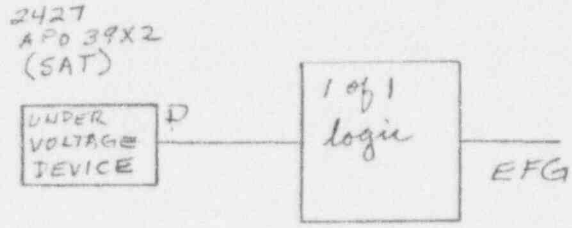
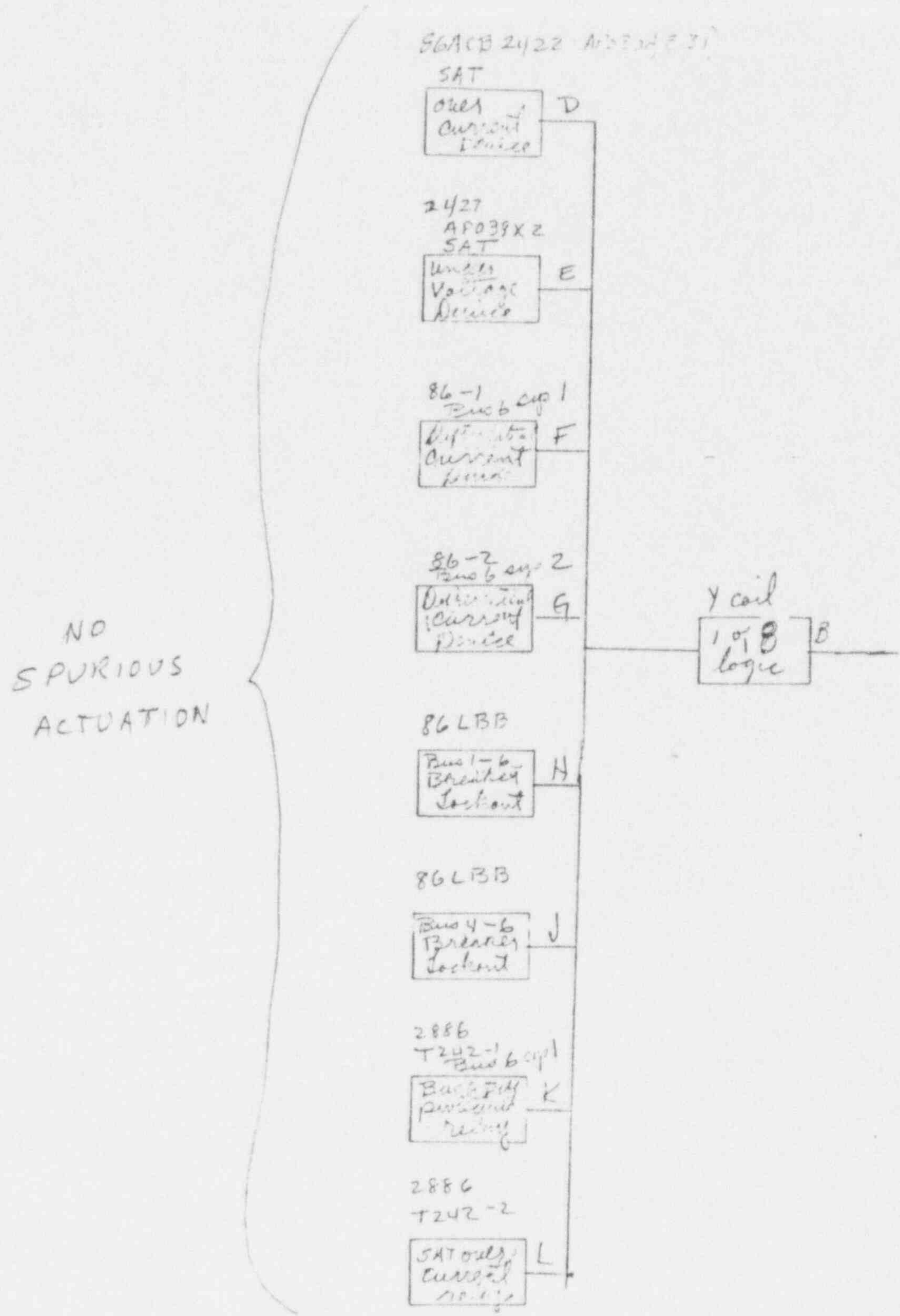


FIGURE B.X.9 SUCCESS LOGIC DIAGRAM - ACB 2422 REMAIN CLOSED



B.X.10 SUCCESS LOGIC DIAGRAM — ACB2423 CLOSE (PAGE 1)

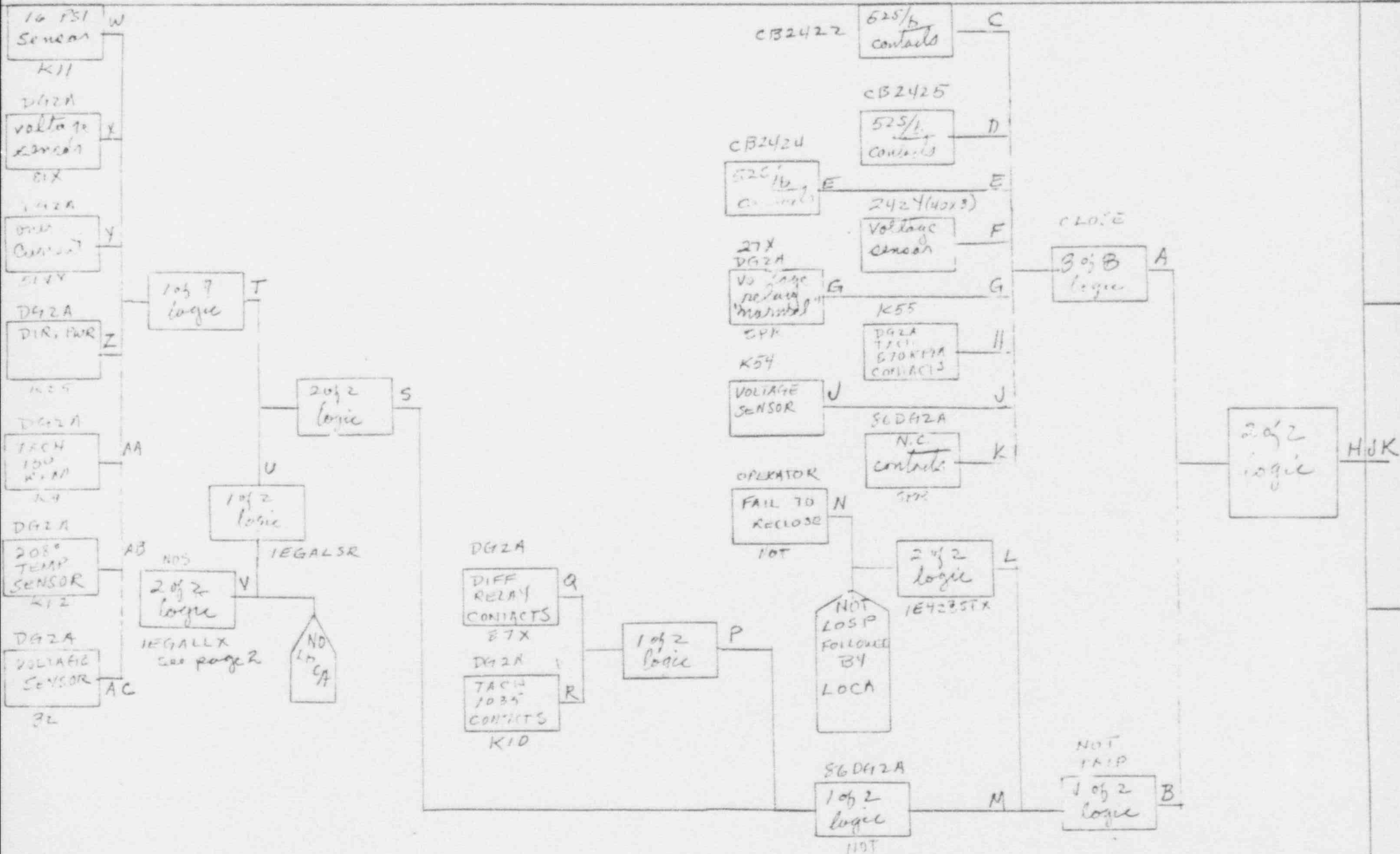
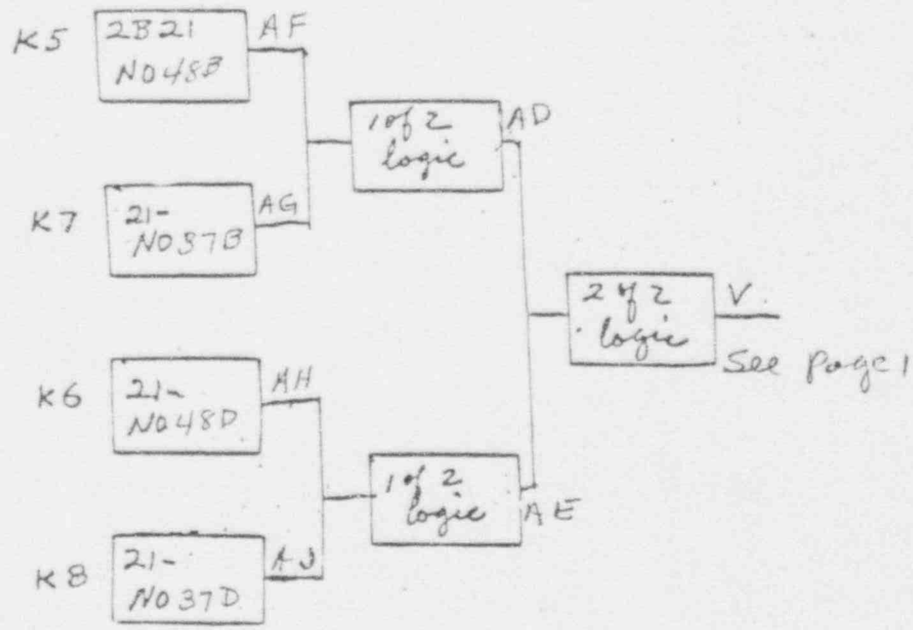
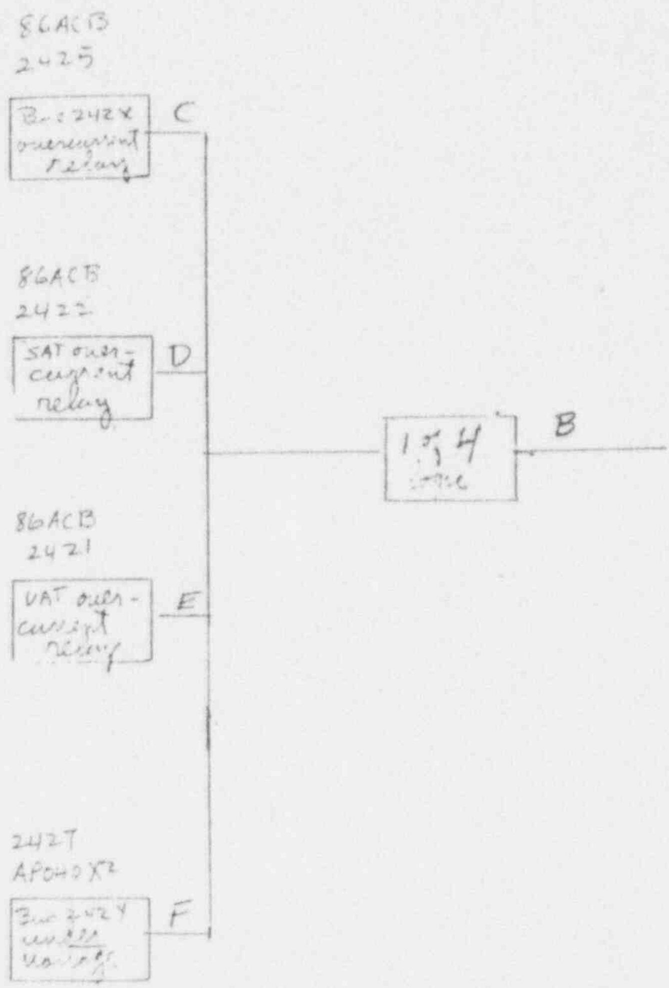


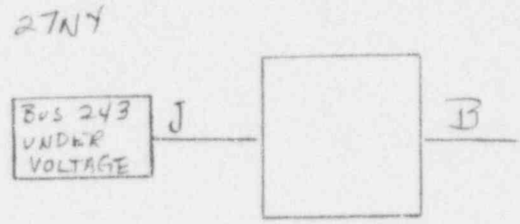
FIGURE B.X.10 SUCCESS LOGIC DIAGRAM-ACB2423 CLOSE (PAGE 2)



B.X.11 SUCCESS LOGIC DIAGRAM - ACB2425 TRIP

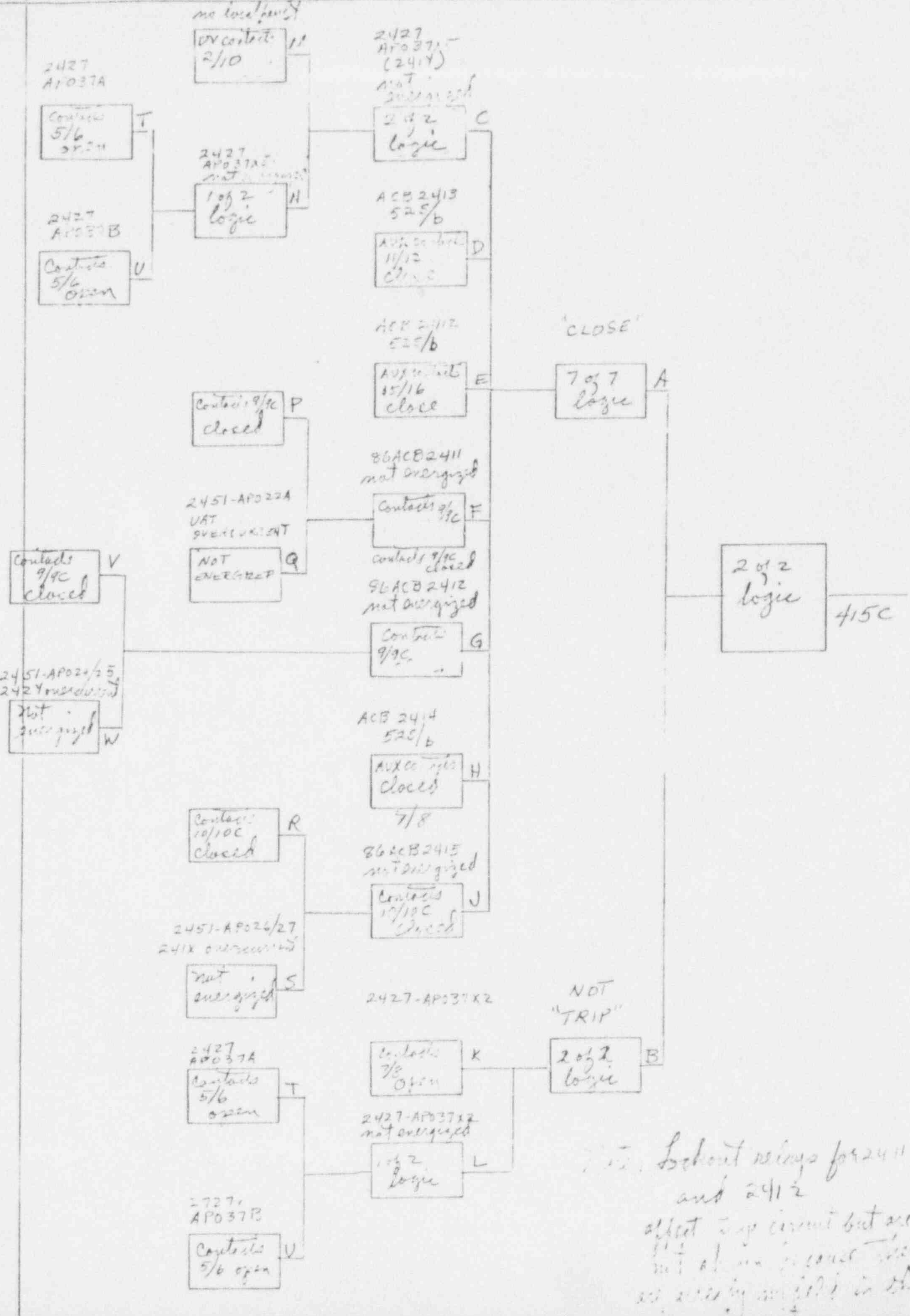


B.X.12 SUCCESS LOGIC DIAGRAM – ACB 2432 TRIP



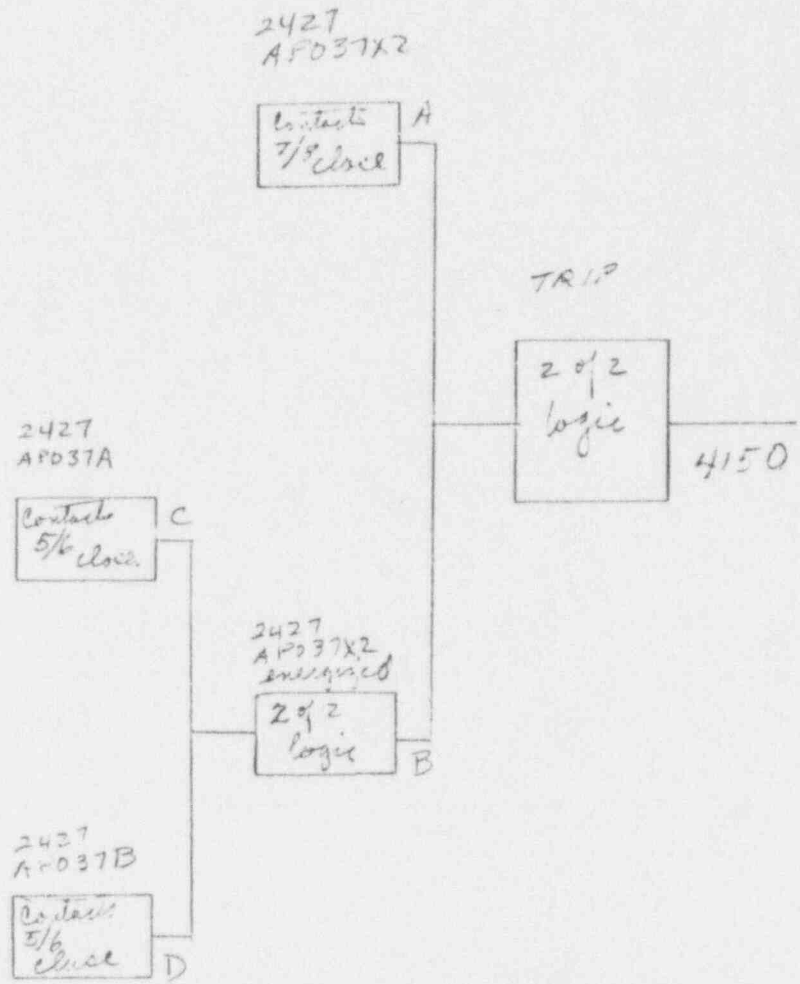
Note: Of the signals which could cause a trip of the circuit breaker only undervoltage on Bus 243 would be expected [illegible]
[illegible]

B.X.13 Success Logic Diagram - ACB 2415 CLOSE



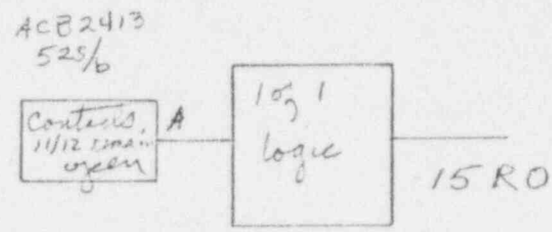
Lockout relays for 2411 and 2412 affect trip circuit but are not shown because they are already [illegible] in the

B.X.14 SUCCESS LOGIC DIAGRAM - ACB 2415 TRIP



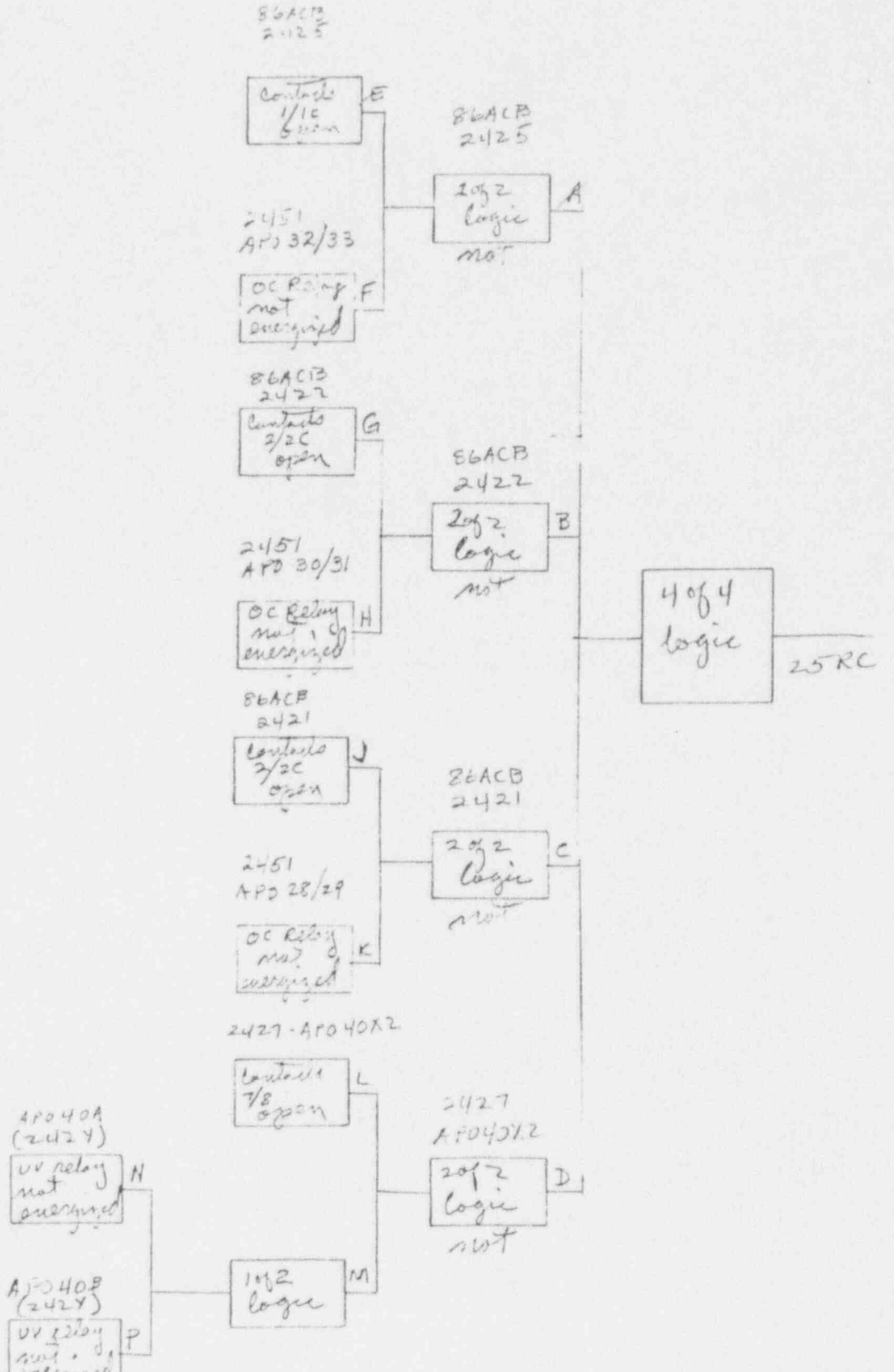
Note: Breakers ACB 2411, 2412 and 2415 are not expected to actuate in these cases (no loss of offsite power). Also, spurious actuation of the "close" circuit will not prevent circuit breaker trip.

B.X.15 — SUCCESS LOGIC DIAGRAM - ACB 2415 REMAIN OPEN

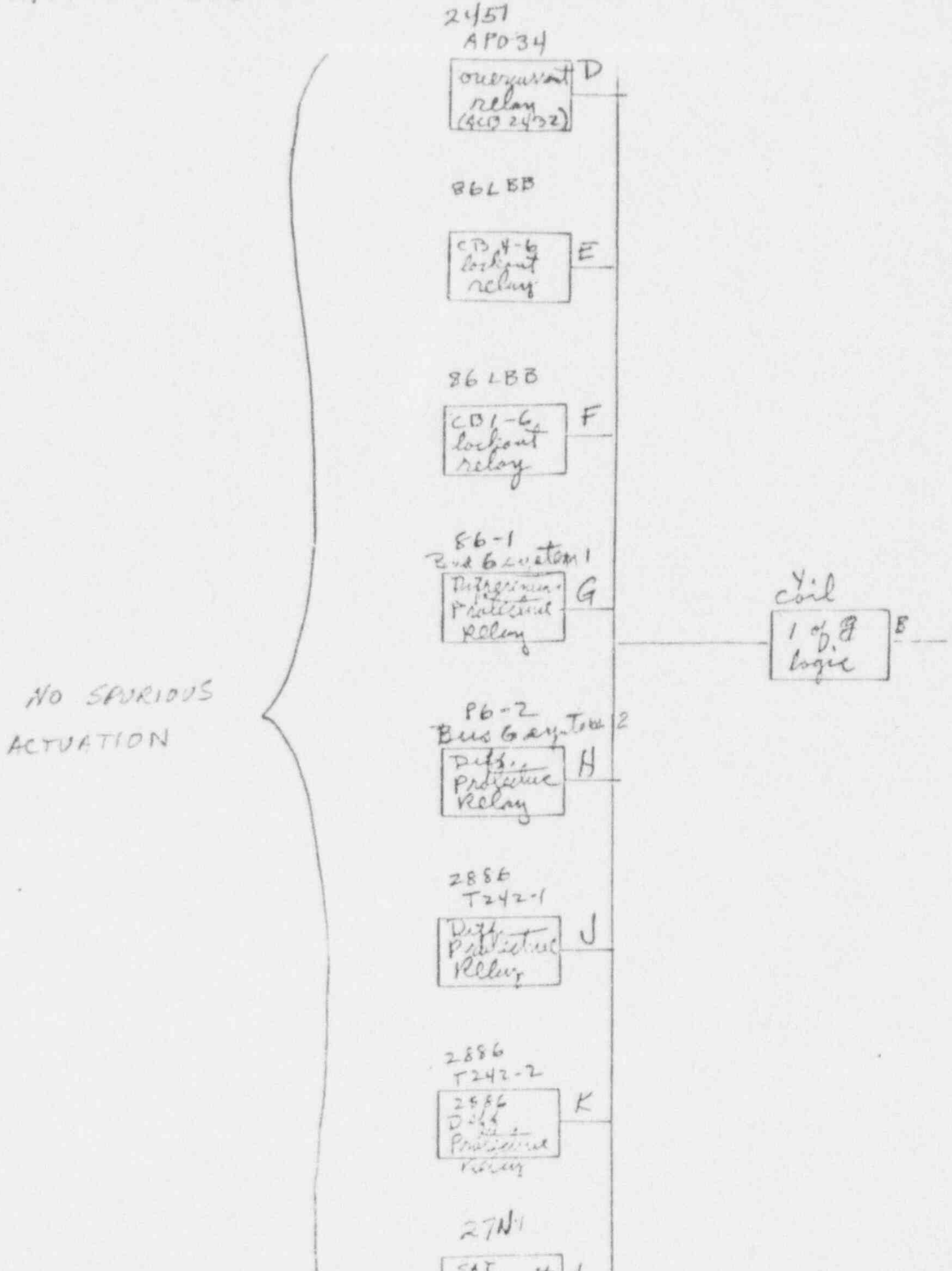


Note: Assuming LOSP, DG 3 running, ACB 2413 closed and ACB 2412 tripped; only spurious closure of ACB 2413 52S/b contacts 11/12 would be required to close ACB 2415

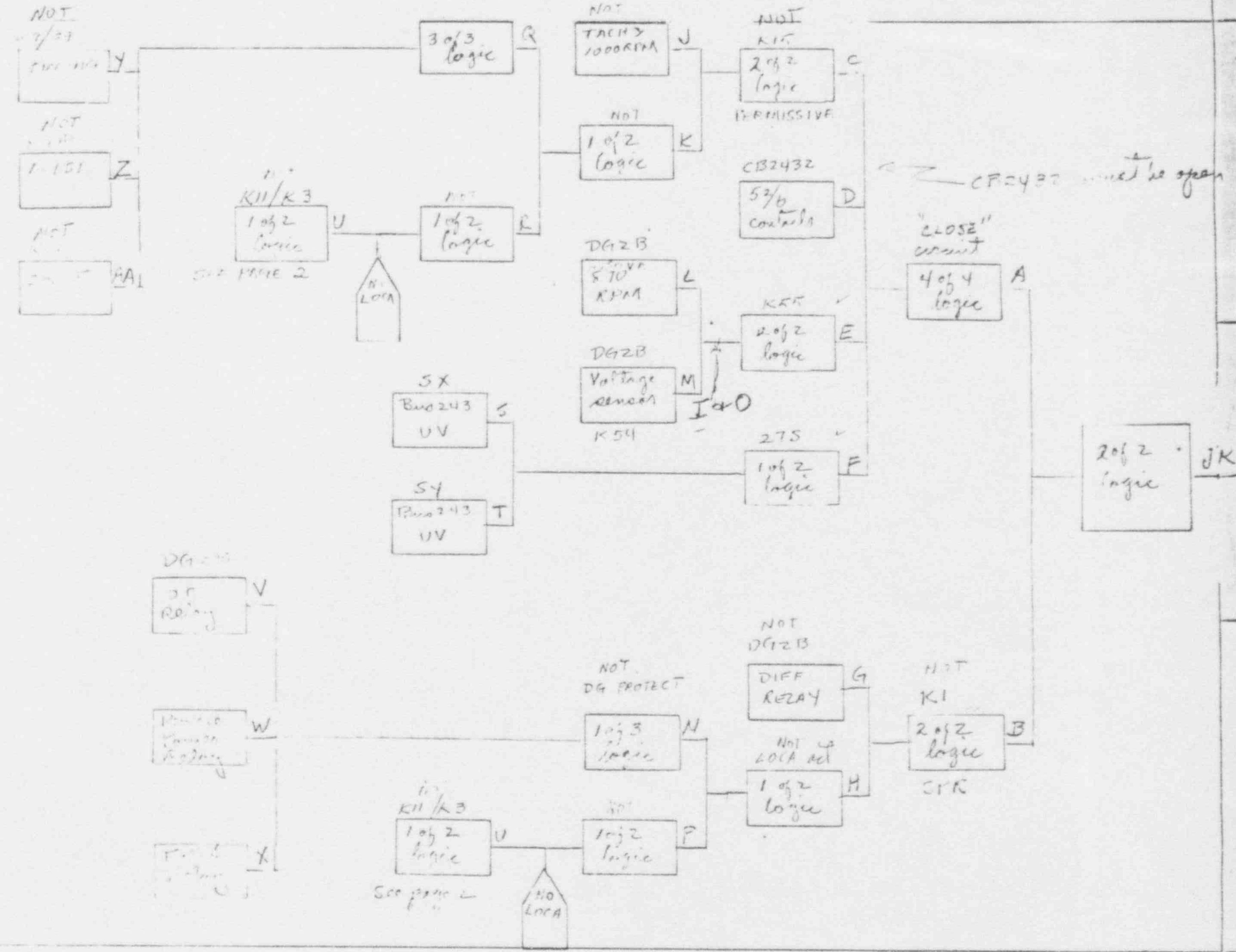
B.X.16 SUCCESS LOGIC DIAGRAM - ACB 2425 REMAIN CLOSED



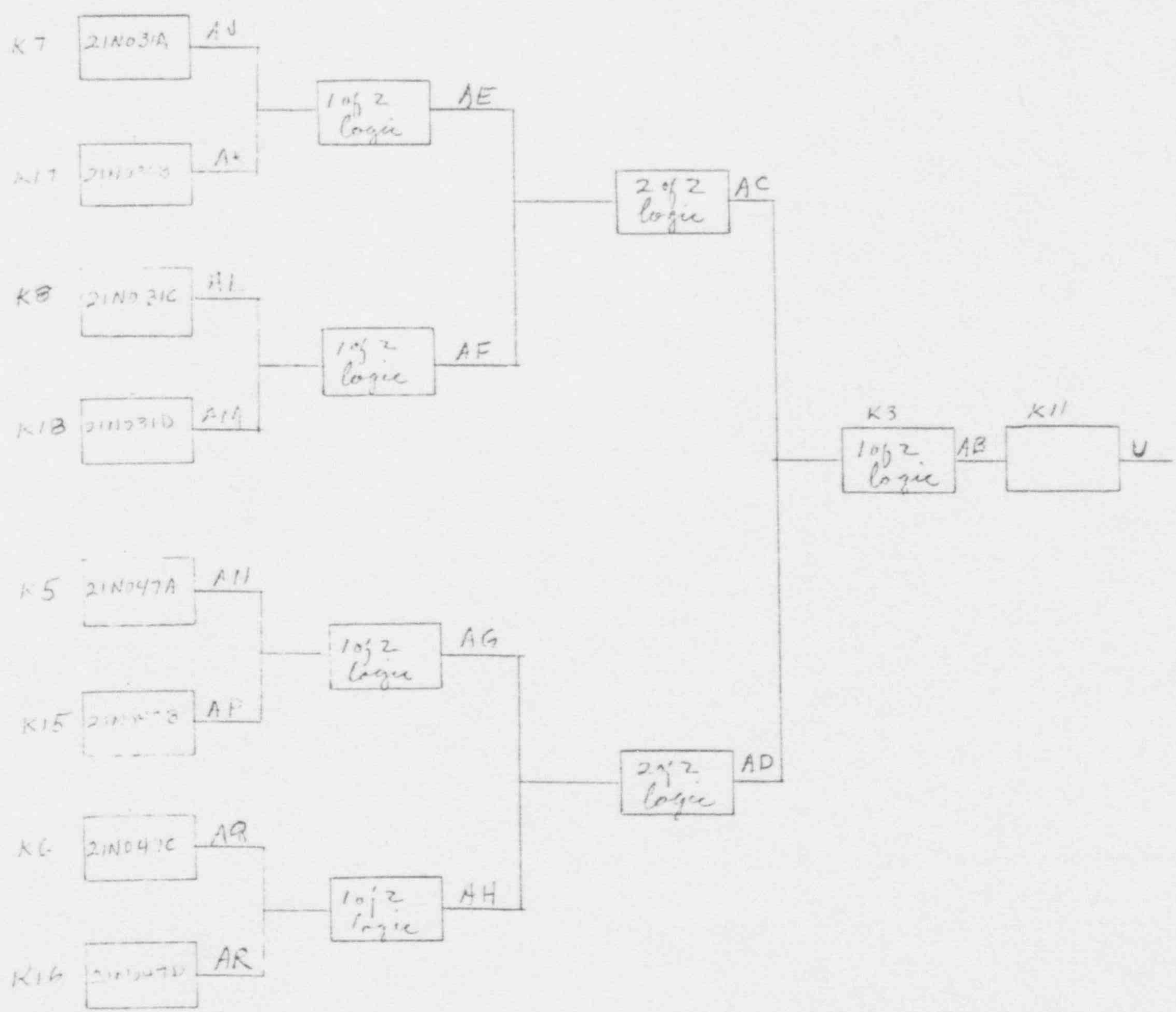
B.X.17 SUCCESS LOGIC DIAGRAM - ACB 2432 REMAIN CLOSED



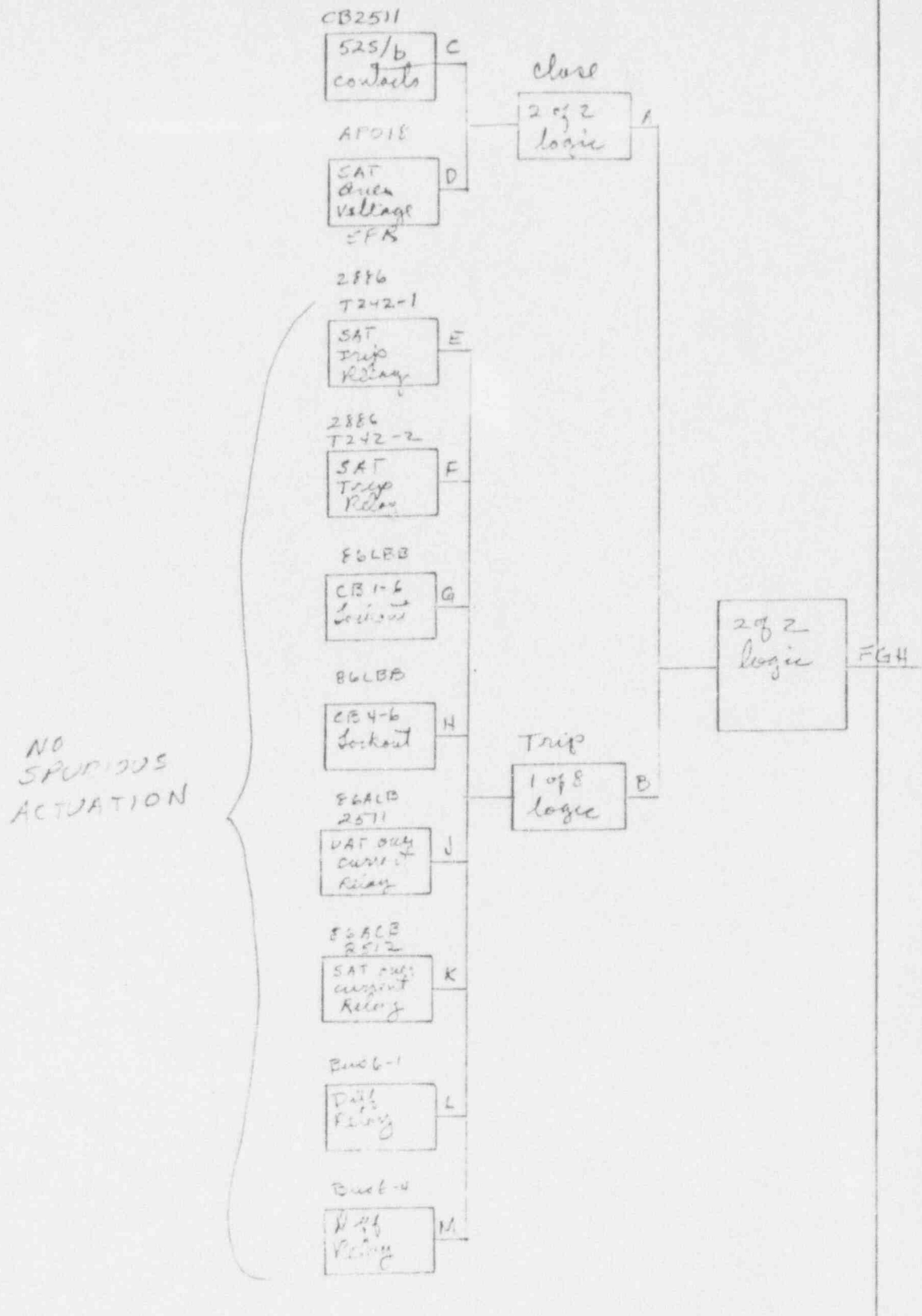
B.X.18 SUCCESS LOGIC DIAGRAM – ACB 2433 CLOSE (PAGE 1)



B.X.18 SUCCESS LOGIC DIAGRAM - ACB2433 CLOSE (PAGE 2)

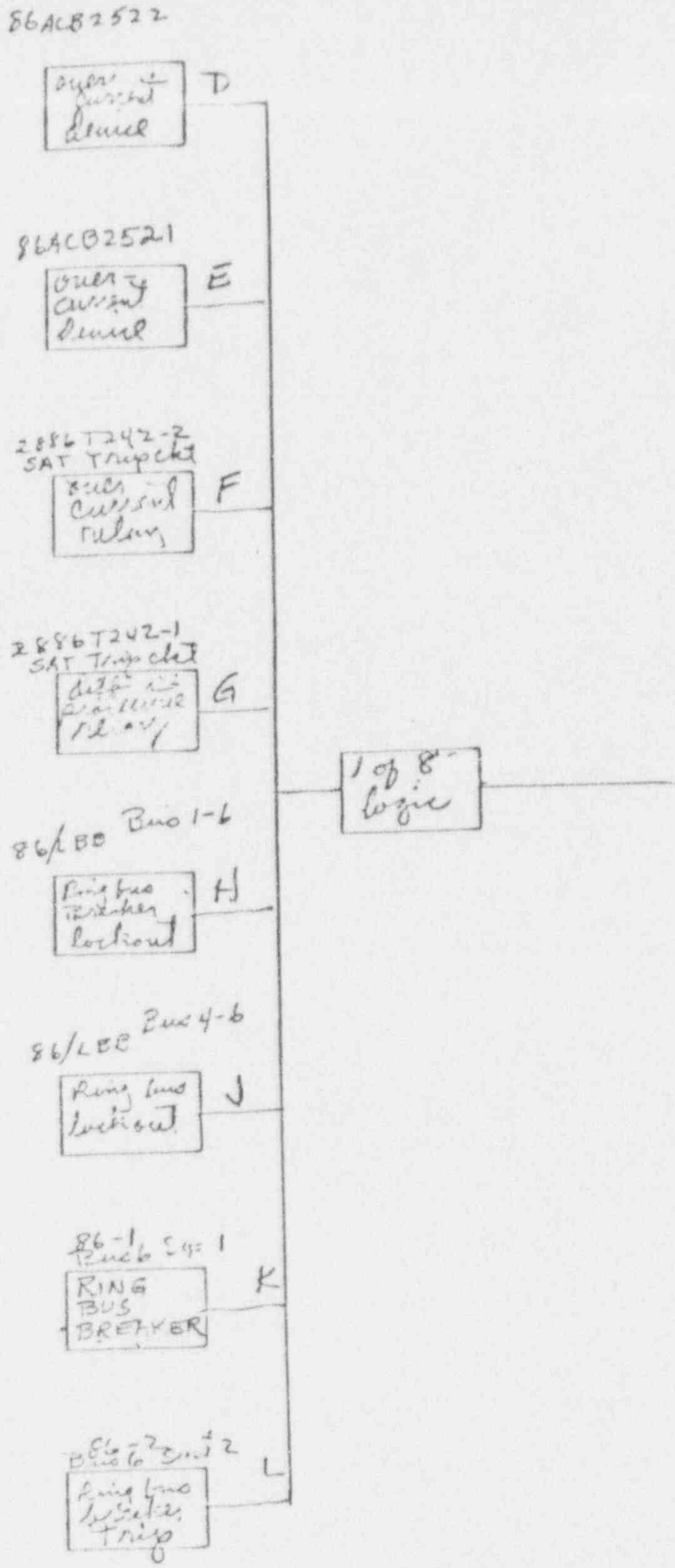


B.X.2.19 SUCCESS LOGIC DIAGRAM - ACB 2512 CLOSE



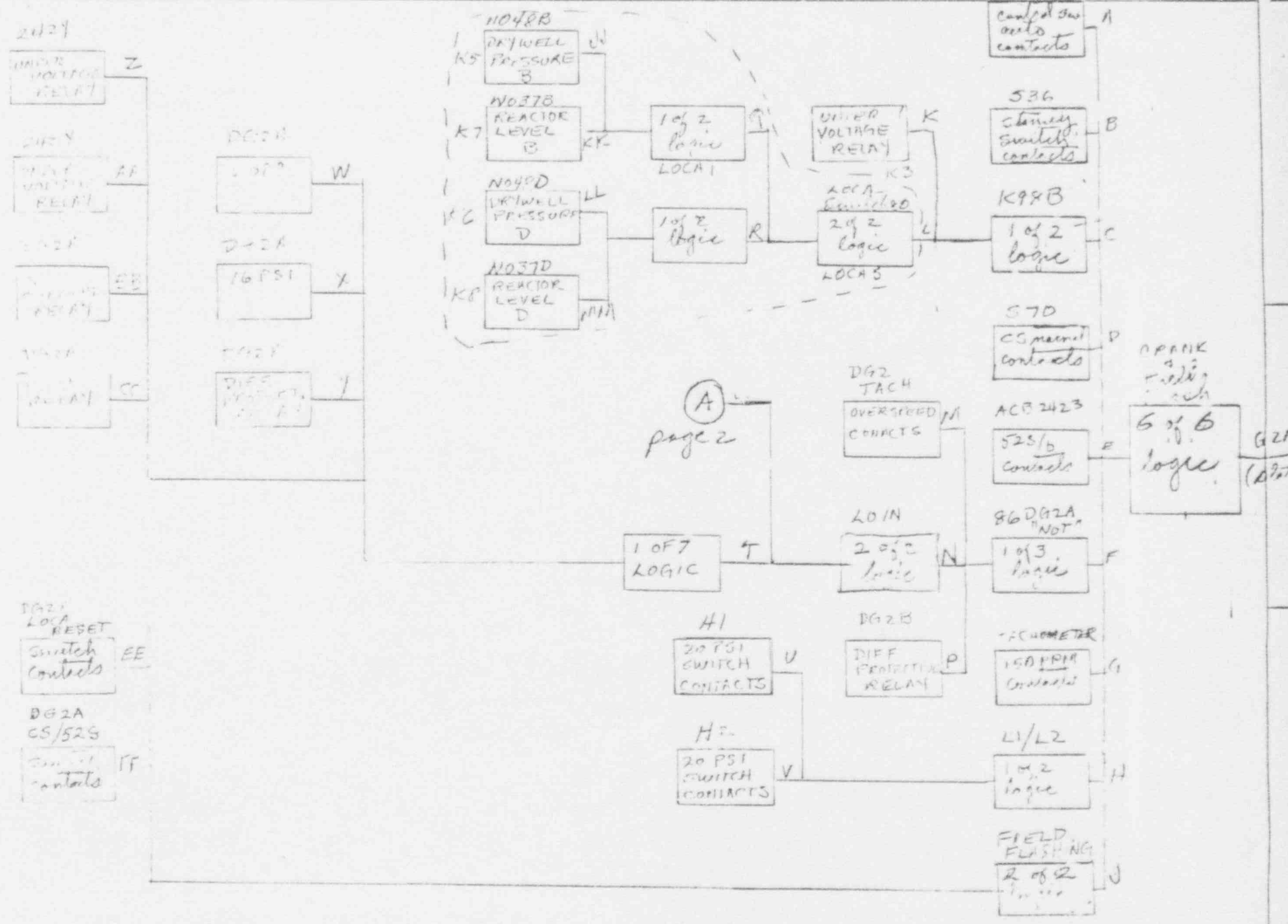
Note: Spurious actuations of 86ACB 2511 and 86ACB 2512 affect both the "close" and "trip" circuits of ACB 2512. For simplicity they are [illegible] as part of the "trip" logic.

B.X.20 SUCCESS LOGIC DIAGRAM - ACB 2522 REMAIN CLOSED

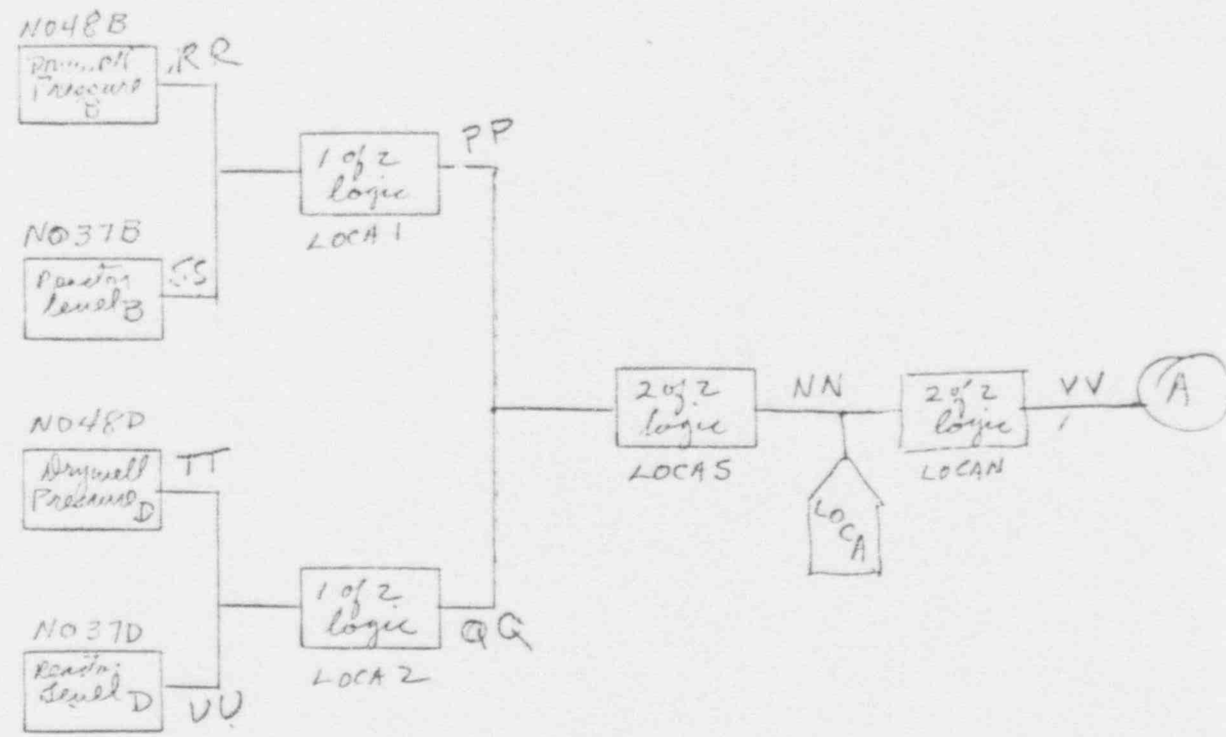


22-141 50 SHEETS
22-142 100 SHEETS
22-144 200 SHEETS

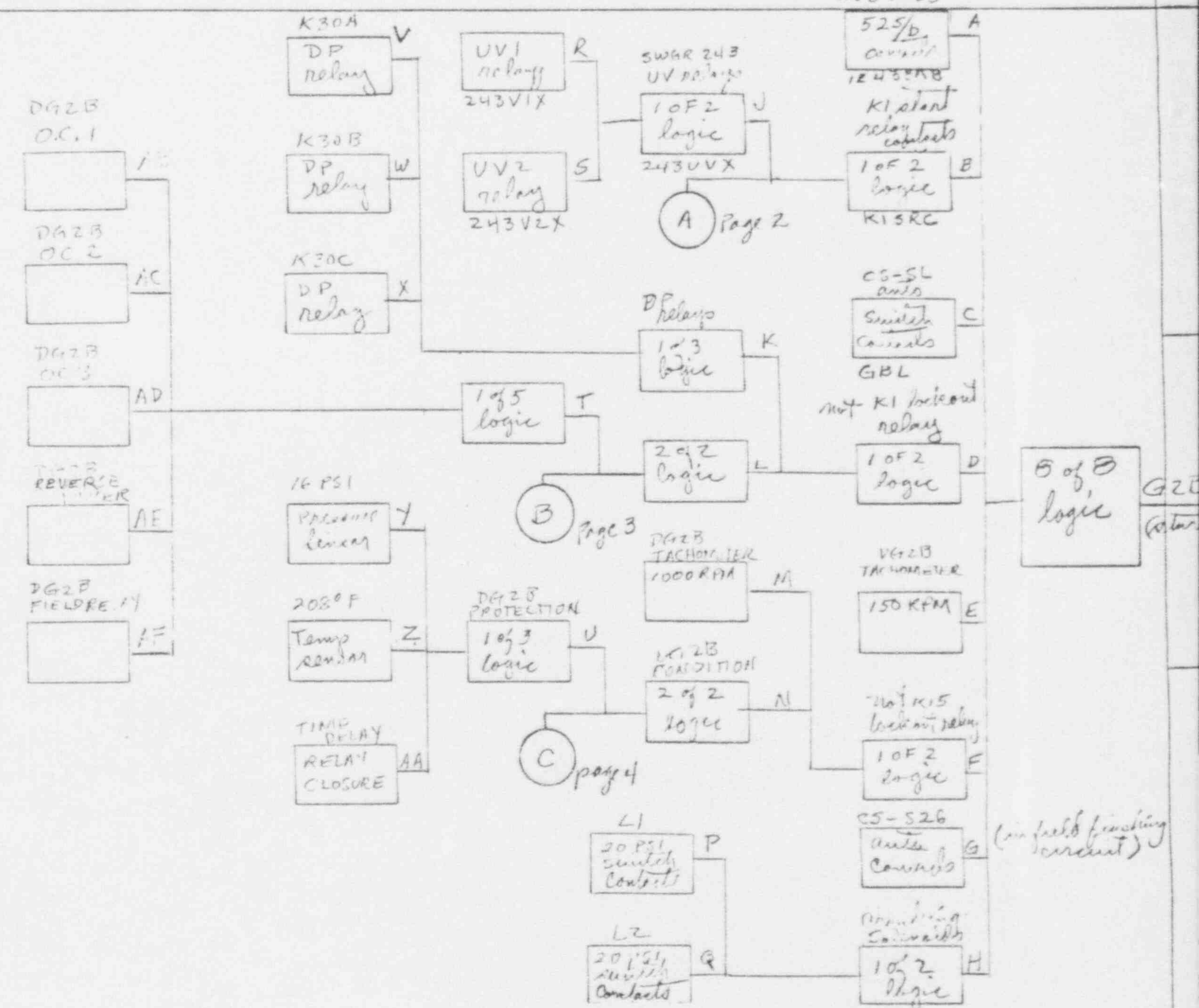
B.X.22 SUCCESS LOGIC DIAGRAM – DG2A START (PAGE 1)



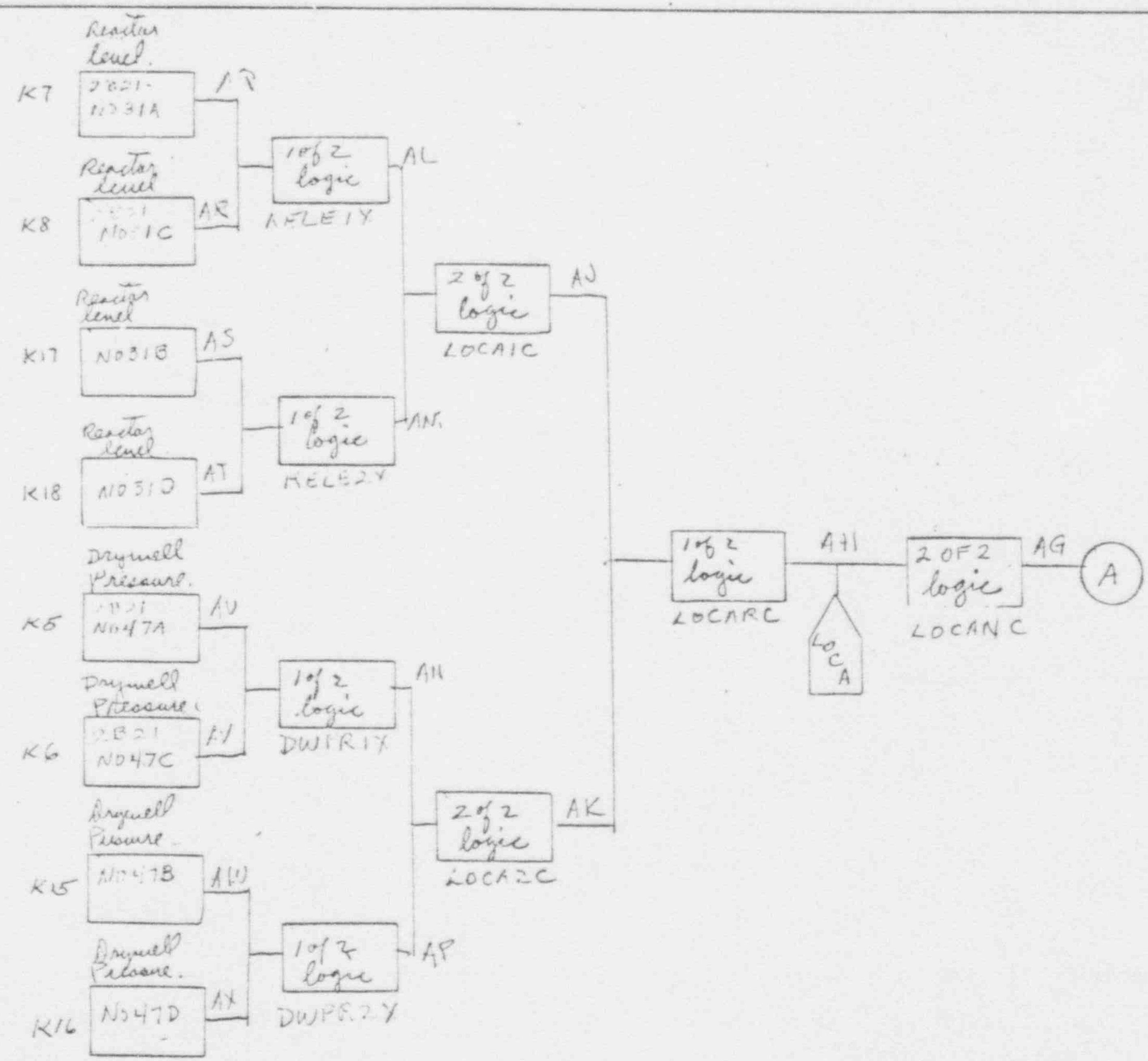
B.X.22 SUCCESS LOGIC DIAGRAM - DG2A START (PAGE 2)



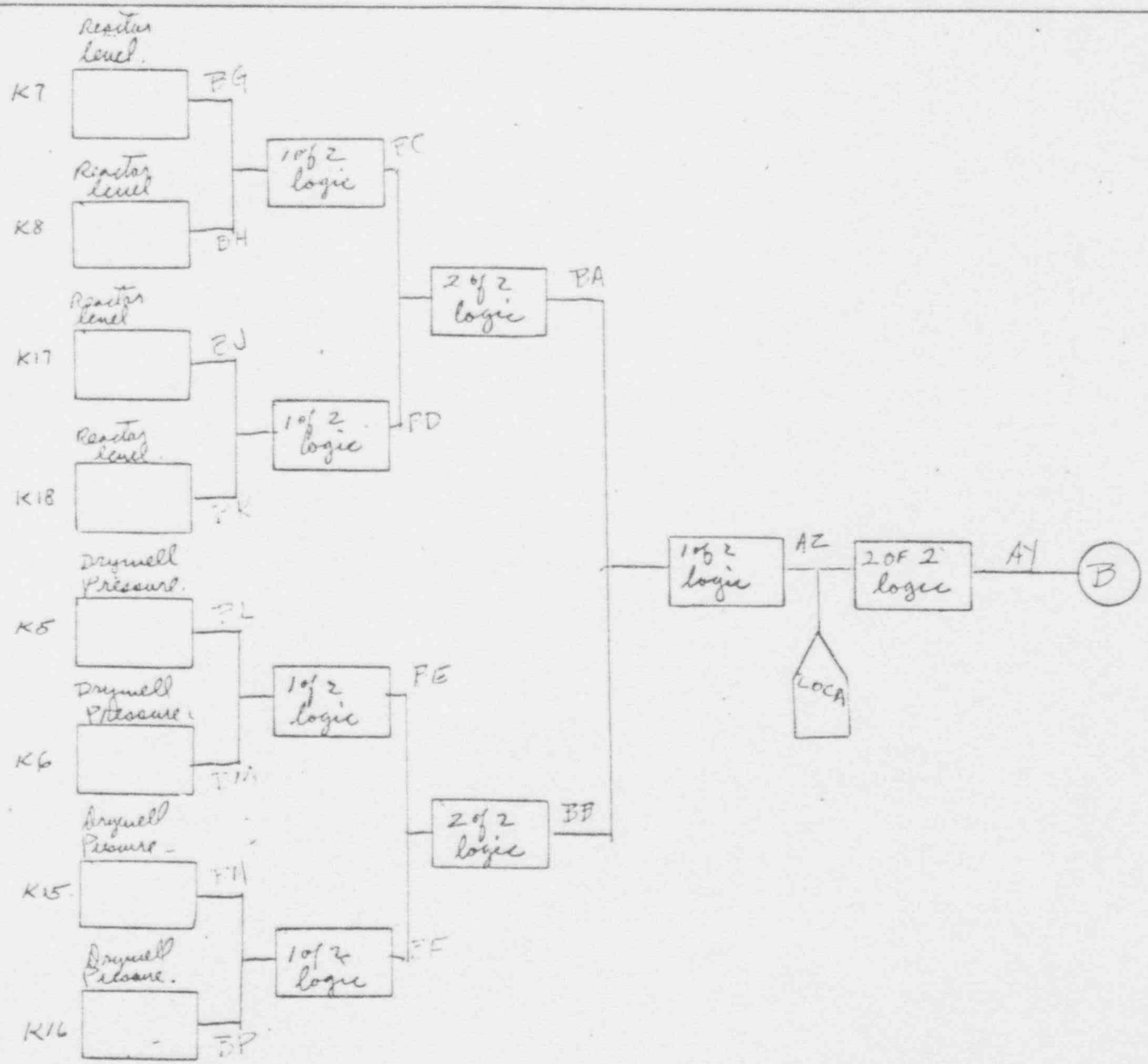
B.X.23 SUCCESS LOGIC DIAGRAM - DG2B START (PAGE 1)



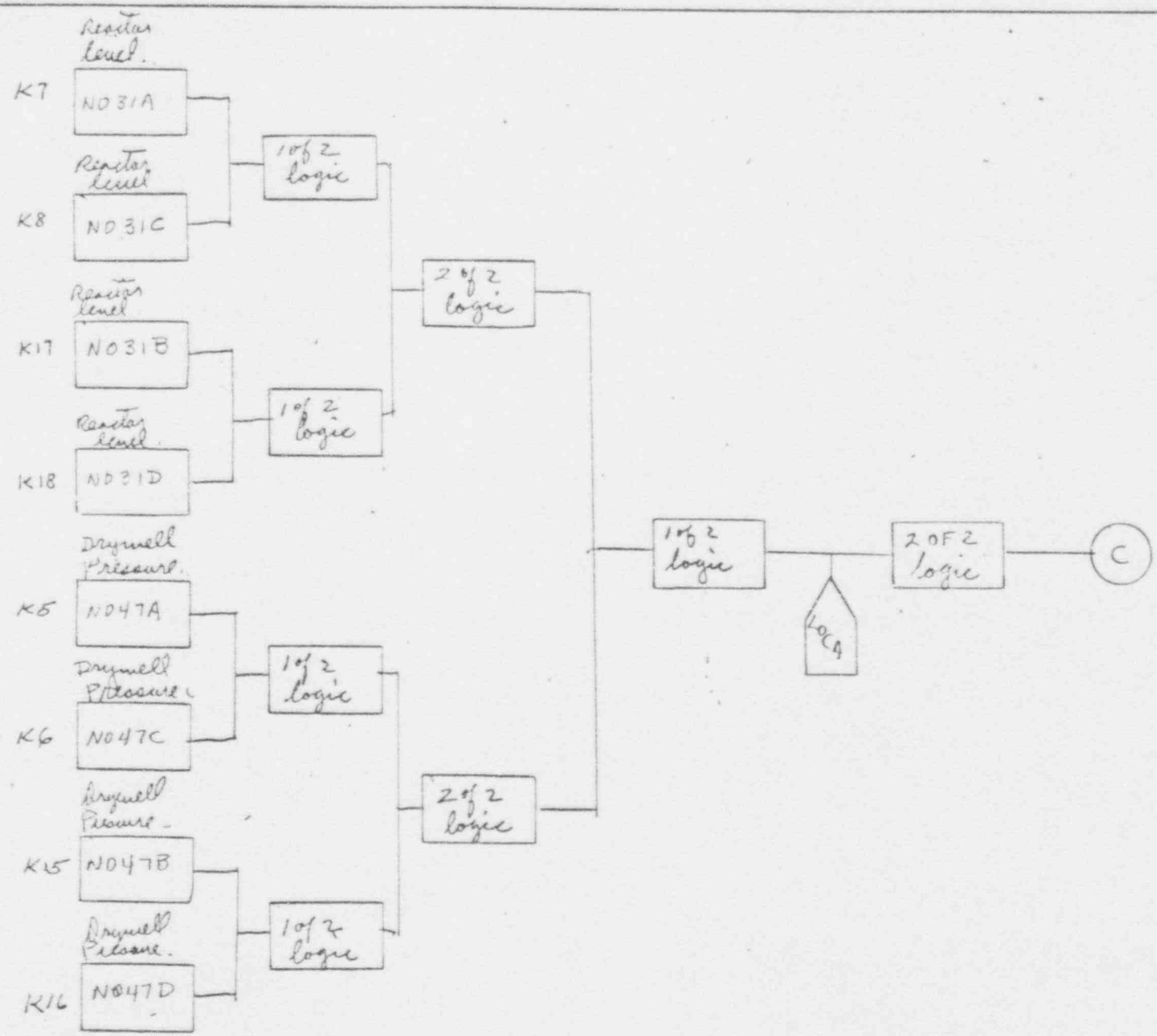
B.X. 22 SUCCESS LOGIC DIAGRAM – DG2B START (PAGE 2)



B.X.2B SUCCESS LOGIC DIAGRAM - DG 2B START (PAGE 3)



B.X.2F SUCCESS LOGIC DIAGRAM - DG2B START (PAGE 4)



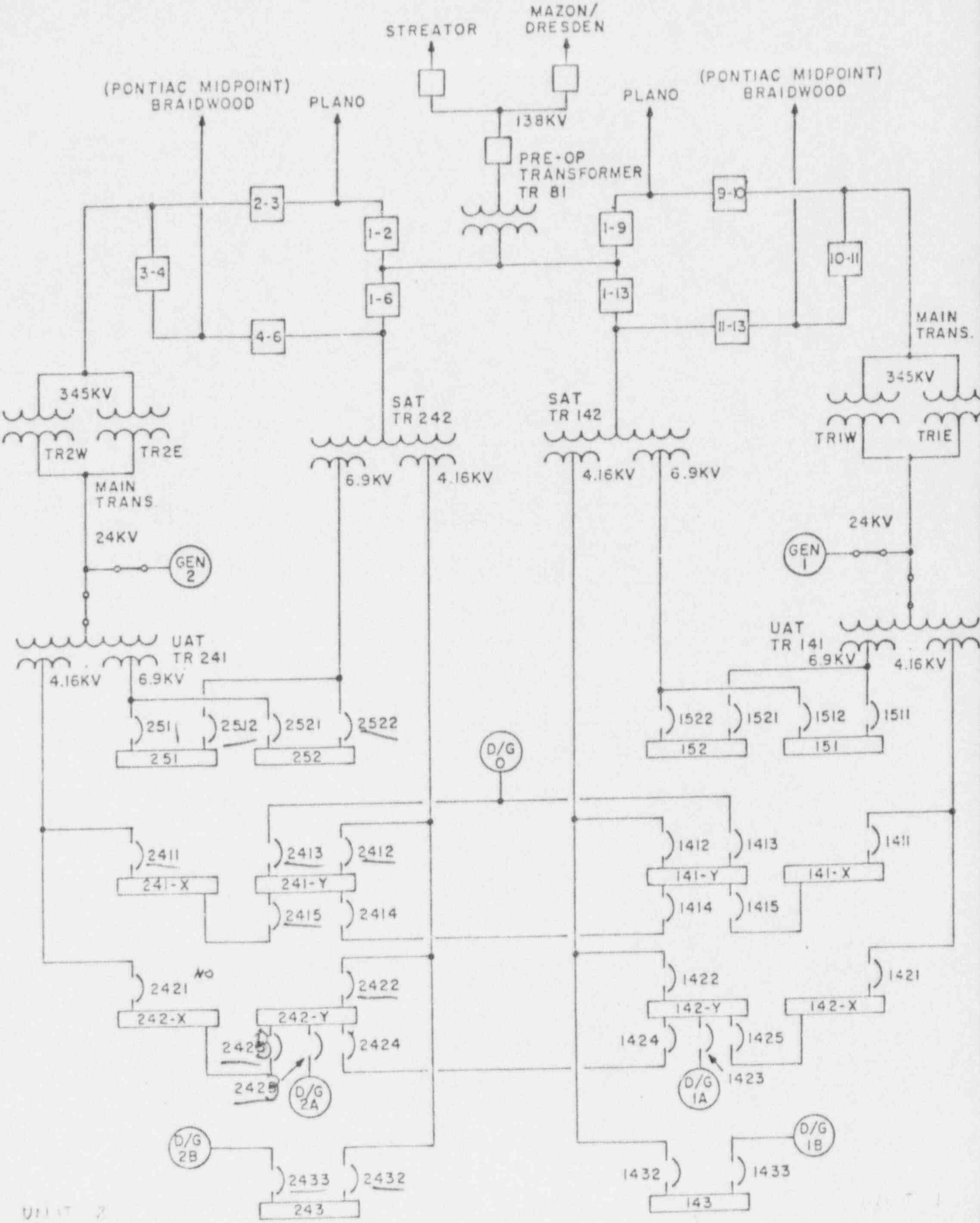


FIGURE 42-1 AC DISTRIBUTION SYSTEM

7.2 System Description of the Class 1E DC Power Systems

7.2.1 System Function

The purpose of the Class 1E 125 VDC power systems is to provide control power for both normal and emergency operation of plant equipment and to provide power for automatic operation of ESF protection systems during abnormal and accident conditions. The 250 VDC system provides power to turbine emergency bearing oil pumps, generator emergency seal oil pumps, the RCIC system and backup feed to the computers.

7.2.2 System Description

7.2.2.1 General Design

The DC distribution system is divided into Class 1E and non Class 1E systems. Class 1E is the safety classification of the electric equipment and systems that are essential to the emergency shutdown of the reactor, containment isolation, reactor core cooling and containment and reactor heat removal or are otherwise essential in preventing significant release of radioactive material to the environment. The class 1E DC systems analyzed are the 250 VDC system and the 125 VDC systems (ESF divisions 1,2, and 3). Simplified one-line diagrams of these systems are given in Figures 7.2.1 and 7.2.2. Non-class 1E systems consist of the river screen house 125 VDC system, relay house 125 VDC, 24/48 VDC and miscellaneous DC systems. Since the non class 1E systems are not required for support of the front-line systems addressed in the study, they are not included in this analysis.

Class 1E D-C Power Systems

The class 1E systems include one 250-volt system and three 125-volt systems. The major components of each system are:

- a battery charger (driven by AC power)
- a battery
- a distribution complex, including ESF and non-ESF buses
- instrumentation and alarms

Each Class 1E system is physically and electrically independent, so that a failure involving one system cannot jeopardize the others.

The battery charger for each system is powered from a motor control center (MCC) in the Class 1E Auxiliary AC Electrical System. If offsite power is lost, these AC MCC's are supplied by the emergency diesel generators. Each charger is designed to supply the normal and emergency DC loads of its system, and also charge (or maintain the charge of) its associated battery.

The battery for each system has sufficient capacity to supply all essential loads of the system for four hours, given loss of the battery charger or the AC electrical system.

The 250 VDC system distributes power to two DC Motor Control Centers (221X,221Y). There is no circuit breaker between the battery and the bus so the battery is always connected to it. The bus receives power from the charger through the charger feeder breaker. If this breaker trips open it will alarm in the control room. It the circuit breaker for bus 221X or 221Y trips it also will alarm in the control room. Bus voltage is monitored in the control room.

Division 1 and 2 125 VDC systems are similar to the 250 VDC system. Each system receives power from either the charger or the battery and distributes power to an ESF bus and a non-ESF bus. Division 1 buses are 211Y (ESF) and 211X, division 2, 212Y (ESF) and 212X. Crossties are provided from Unit 1 buses for maintenance functions only. Division 3 has only one bus, 213 (HPCS only). The battery and charger can be isolated from the bus. There is a crosstie to bus 113 of Unit 1. The electrical loads on the Class 1E DC systems are listed in Table 7.2.1.

Locations

The 250 VDC system battery is located on the ground floor of the auxiliary building in its own ventilated room. The Division 1 125 VDC Battery (2A) is in a battery room within the Division 1 switchgear room. The Division 2 125 VDC Battery (2B) is similarly located in the Division 2 Switchgear Room. The Division 3 125 VDC Battery (2C) is located in a battery room within the HPCS Switchgear Room. The battery chargers and switchgear for each of the systems are located in the switchgear room appropriate to the power division they serve, i.e.

125 VDC 2A - Division 1 Switchgear Room
125 VDC 2B - Division 2 Switchgear Room
125 VDC 2C - HPCS SwitchgearRoom

7.2.2.2 System Interfaces

The Class 1E DC power systems require AC power to supply the battery chargers. The support requirements are shown in Table 7.2.2

7.2.2.3 Instrumentation and Control

The Class 1E DC Power Systems operate continuously, so the status of the systems is always displayed. There is no automatic actuation of system components, other than the tripping of circuit breakers under over current conditions. The major manual control feature is the provision for crosstying the Unit 2 systems with the Unit 1 DC systems at the bus (MCC) level. This enables Unit 2 DC loads to be supplied by Unit 1 in the event of system faults or if equipment is isolated for test or maintenance.

The control room alarms and indications for the DC power systems are presented in Table 7.2.3.

7.2.2.4 Operator Actions

Except for recovery, no operator actions are required for the Class 1E DC systems, because the system operates continuously. The primary recovery action would be to cross tie a DC bus to Unit 1 in the event of Unit 2 bus failure. This would be accomplished by manually closing the appropriate (normally-open) circuit breaker.

7.2.2.5 Technical Specifications

The following technical specifications apply to operational conditions 1, 2 and 3. (Note that section identifications given are those in the technical specifications.)

D.C. Distribution - Operating

Limiting Condition for Operation

3.8.2.3 The following D.C. distribution system electrical divisions shall be OPERABLE and energized:

a. Division 1, consisting of

1. 125-volt battery 2A
2. 125-volt full capacity charger.
3. 125-volt distribution panel 211Y.

b. Division 2, consisting of

   1. 125-volt battery 2B.
   2. 125-volt full capacity charger.
   3. 125-volt distribution panel 212Y.

c. Division 3, consisting of

   1. 125-volt battery 2C.
   2. 125-volt full capacity charger.
   3. 125-volt distribution panel 213.

d. Unit 1 Division 2, consisting of

   1. 125-volt battery 1B.
   2. 125-volt full capacity charger.
   3. 125-volt distribution panel 112Y.

<u>Action</u>:

a. With either Division 1 or Division 2 inoperable or not energized, restore the inoperable division to OPERABLE and energized status within 2 hours or be in at least HOT SHUTDOWN within the next 12hours and in COLD SHUTDOWN within the following 24 hours.

b. With Division 3 inoperable or not energized, declare the HPCS system inoperable and take the ACTION required by Specification 3.5.1.

c. With Unit 1 Division 2 inoperable or not energized, restore the inoperable division to OPERABLE and energized status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

<u>Surveillance Requirements</u>

4.8.2.3.1 Each of the above required D.C. distribution system electrical divisions shall be determined OPERABLE and energized at least once per 7 days by verifying correct breaker alignment, indicated power availability from the charger and battery, and voltage on the panel with an overall voltage of greater than or equal to 125 volts.

4.8.2.3.2 Each 125-volt battery and charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

1. The parameters in Table 4.8.2.3.2-1 meet the Category A limits, and

2. Total battery terminal voltage is greater than or equal to 128 volts on float charge.

b. At least once per 92 days and within 7 days after a battery discharge with battery voltage below 110 volts, or battery overcharge with battery terminal voltage above 150 volts, by verifying that:

1. The parametters in Table 4.8.2.3.2-1 meet the Category B limits,

2. There is no visible corrosion at either terminals or connectors, or the connection resistance of these items is less than 150 x 10-6 ohm, and

3. The average electrolyte temperature of at least 10 connected cells is above 60F.

c. At least once per 18 months by verifying that:

1. The cells, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration,

2. The cell-to-cell and terminal connections are clean, tight, free of corrosion, and coated with anticorrosion material,

3. The resistance of each cell and terminal connection is less than or equal to 150 x 10-6 ohm, and

4. The battery charger will supply at least 200 amperes for Division 1, 75 amperes for Division 2, and 50 amperes for Division 3 at a minimum of 130 volts for at least 8 hours.

d. At least once per 18 months, during shutdown, by verifying that either:

1. The battery capacity is adequate to supply and maintain in OPERABLE status all of the actual emergency loads for the design cycle when the battery is subjected to a battery service test, or

2. The battery capacity is adequate to supply a dummy load, which is verified to be greater than the actual emergency load, of the following profile while maintaining the battery terminal voltage greater than or equal to 105 volts.

   a) Division 1, greater than or equal to:

      1) 456.2 amperes for the first 60 seconds,
      2) 224.0 amperes for the next 14 minutes,
      3) 208.0 amperes for the next 15 minutes,
      4) 132.0 amperes for the next 30 minutes, and
      5) 64.0 amperes for the last 180 minutes.

   b) Division 2, greater than or equal to:

      1) 488.5 amperes for the first 60 seconds,
      2) 237.6 amperes for the next 14 minutes,
      3) 177.6 amperes for the next 15 minutes,
      4) 141.6 amperes for the next 30 minutes, and
      5) 54.4 amperes for the last 180 minutes.

   c) Division 3, greater than or equal to:

      1) 58.4 amperes for the first 60 seconds,
      2) 11.1 amperes for the next 239 minutes.

   d) Unit 1 Division 2, greater than or equal to:

      1) 488.5 amperes for the first 60 seconds,
      2) 237.6 amperes for the next 14 minutes,
      3) 177.6 amperes for the next 15 minutes,
      4) 141.6 amperes for the next 30 minutes, and
      5) 54.4 amperes for the last 180 minutes.

   e. At least once per 60 months, during shutdown, by verifying that the battery capacity is at least 80% of the manufacturers rating when subjected to a performance discharge test. Once per 60-month interval, this performance discharge test may be performed in lieu of the battery service test.

Surveillance Requirements (Continued)

f. Annual performance discharge tests of battery capacity shall be given to any battery that shows signs of degradation or has reached 85% of the service life expected for the application. Degradation is indicated when the battery capacity drops more than 10% of rated capacity from its average on previous performance tests, or is below 90% of the manufacturer's rating.

Table 4.8.2.3.2-1
Battery Surveillance Requirements

Parameter	Category A(1): Limits for each designated pilot cell	Category B(2): Limits for each connected cell	Category B(2): Allowable$ST(3)$SP value for each
Electrolyte Level	>Minimum level indication mark and ≤ 1/4"above maximum level indication mark	>Minimum level indication mark, and ≤ 1/4"above maximum level indication mark	Above top of plates, and not overflowing
Float Voltage	≥ 2.13 volts	≥ 2.13 volts$ST(c)$SP	> 2.07 volts
Specific Gravity(a)	≥ 1.200(b) ≥ 1.195*(b)	≥ 1.195, ≥ 1.190* Average of all connected cells > 1.205 > 1.200*	Not more than .020 below the average of all connected cells Average of all connected cells ≥ 1.195(b) ≥ 1.190*

(a) Corrected for electrolyte temperature and level.
(b) Or battery charging current is less than 2 amperes when on float charge.
(c) May be corrected for average electrolyte temperature.
(1) For any Category A parameter(s) outside the limit(s) shown, the battery may be considered OPERABLE provided that within 24 hours all the Category B measurements are taken and found to be within their allowable values, and provided all Category A and B parameter(s) are restored to within limits within the next 7 days.
(2) For any Category B parameter(s) outside the limit(s) shown, the battery may be considered OPERABLE provided that the Category B parameters are within their allowable values and provided the Category B parameter(s) are restored to within limits within 7 days.
(3) Any Category B parameter not within its allowable value indicates an inoperable battery.

*For division 3 batteries only.

7.2.2.6 Tests

Tests of the Class 1E DC Power Systems are either:

Performed without affecting system availability, or
Performed during reactor shutdown

7.2.2.7 Maintenance

Because of the provision for cross-tie of DC buses with the Unit 1 DC power systems, there is no significant maintenance, either scheduled or unscheduled, which would result in the unavailability of buses in the Class 1E DC power systems.

7.2.2.8 System Performance During Accident Conditions

The major internal accident conditions which would impact the Class 1E DC power systems are loss of offsite power and coincident (or subsequent) failure of the emergency AC diesel generators (station blackout). While these events would not call for any reconfiguration of the DC systems, they would require that DC power be supplied from the system batteries rather than the AC power-driven battery chargers. Failure to restore either offsite power or the emergency diesel generators would eventually result in battery depletion. The result would be loss of supply to the loads listed in Table 7.2.1.

7.2.3 System Operation

7.2.3.1 Normal Operations

During normal operation, the Class 1E DC power systems are functioning, with electric power on all DC buses. All circuit breakers are closed, except those which cross tie the DC buses to their corresponding buses in Unit 1. The DC loads are supplied by the battery chargers, driven by buses of the Auxiliary AC Electrical System. The chargers are also trickle-charging the batteries.

7.2.3.1 Abnormal Operations

In the event of loss of offsite power, coupled with failure of the emergency AC diesel generators, the Class 1E DC power distribution system will be powered by the batteries, with battery charger input unavailable. The batteries are sized to start and carry normal DC loads for 4 hours following a loss of all AC sources, plus all DC loads required for safe shutdown, and loads required for switching operations needed to limit the consequences of an accident.

Since the Unit 2 Class 1E DC systems are not interconnected, loss of the AC motor control center which powers a battery charger will result in reliance on the battery for that system to supply its DC power loads. (See Figures 7.2.1 and 7.2.2.) Of particular interest in this regard is AC motor control center 235X-3. Loss of this AC motor control center would deactivate the charger for both the 250 VDC system and the Division 1 125 VDC system.

7.2.4 System Fault Tree

7.2.4.1 Fault Tree Description

Simplified diagrams of the Class 1E DC Power Systems (used for fault tree modeling) are shown in figures 7.2.3 and 7.2.4. The fault tree is presented in Section of this report. Table provides the data used in the fault trees.

7.2.4.2 Success/Failure Criteria

The Class 1E DC Power Systems support other systems by providing power to those DC buses needed for plant equipment. There are, therefore, many success criteria and top events distributed through the overall plant model. The success criteria for each of these top events is the presence of electric power at a bus and the top event definitions are the form "Loss of Power at Bus XXX".

7.2.4.3 Major Assumptions

1. Immediate operator actions were not included.

2. Unavailability due to maintenance was not considered because the D.C. buses are normally fed from Unit 1 while maintenance is performed which would disrupt the unit 1 systems.

3. Failure-to-restore events were not included, due to the extensive alarm system which covers all of the DC buses, and the potential for shift checks to reveal loss of power at a bus.

4. It was assumed that room cooling was not required for battery and switchgear rooms.

References

Table 7.2.2 Class 1 DC Power Systems Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Ef (Sub) System System Funct
AC Power 4160V Bus 241Y	250 VDC Bus 2	DC Bus	Loss of AC supply to battery charger	Alarms in control room	Loss of primary DC supply to DC bus	Potential lo depletion
	125 VDC Bus 2A	DC Bus	Loss of AC supply to battery charger	Alarms in control room	Loss of primary DC supply to DC bus	
AC Power 4160 V Bus 242Y	125 VDC Bus 2B	DC Bus	Loss of AC supply to battery charger	Alarms in control room	Loss of primary DC supply to DC bus	
AC Power 416 V Bus 243	125 VDC Bus 213	DC Bus	Loss of AC supply to battery charger	Alarms in control room	Loss of primary DC supply to DC bus	Potential lo depletion

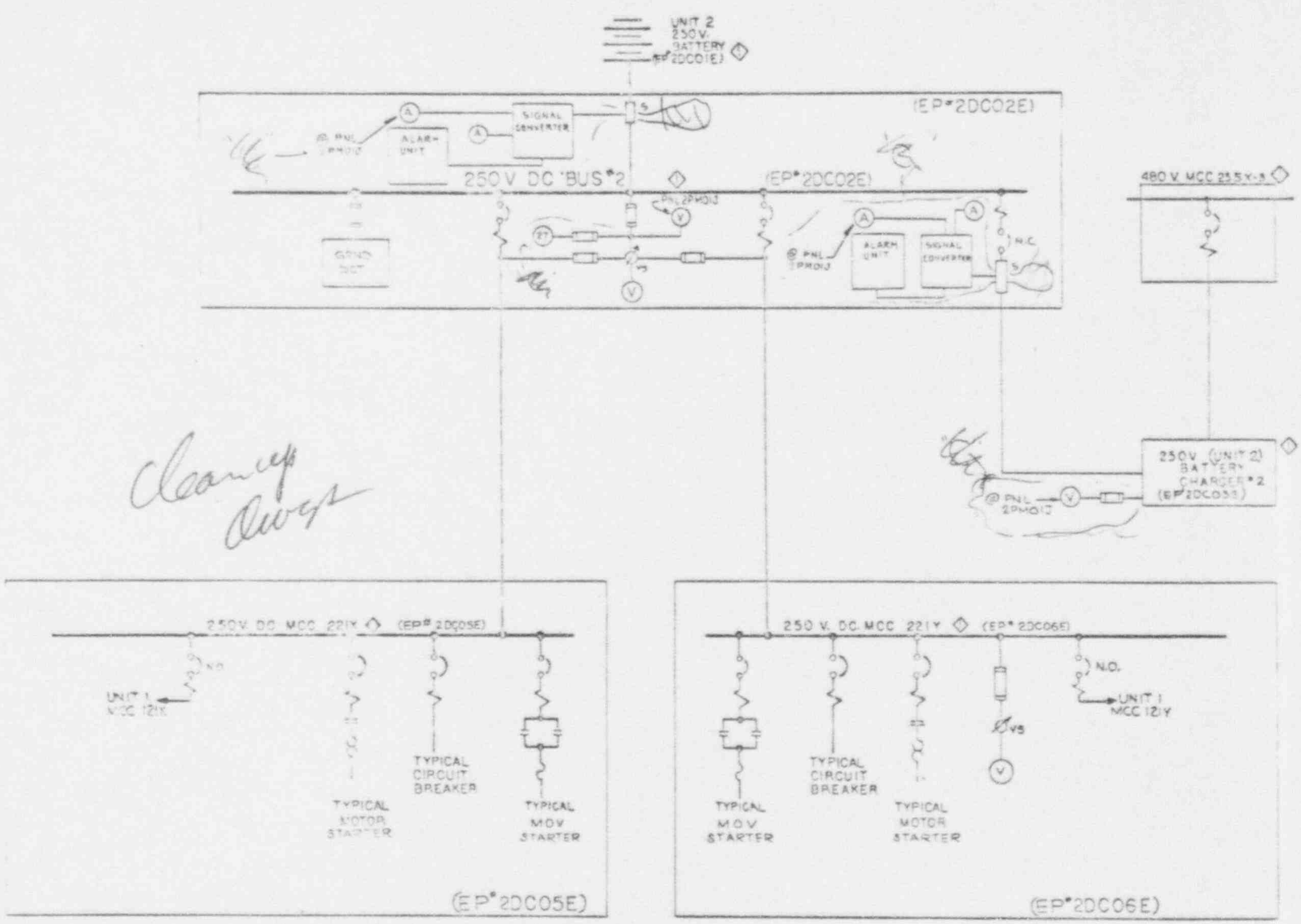


FIGURE B.X.1 ~~Class 1E~~ Safety Related 250 VDC Power System

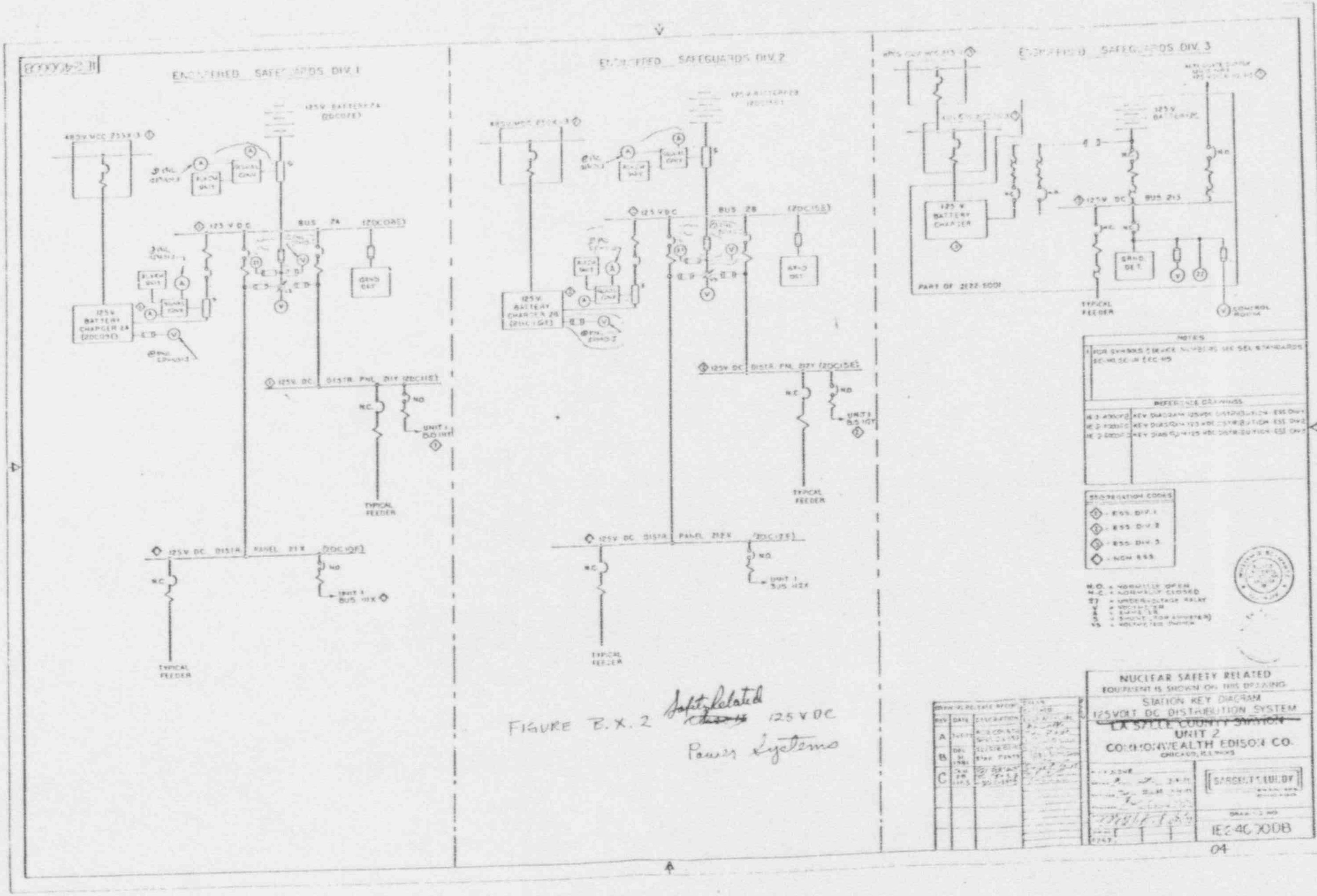


FIGURE B.X.2 Safety Related ~~Class 1E~~ 125 V DC Power Systems

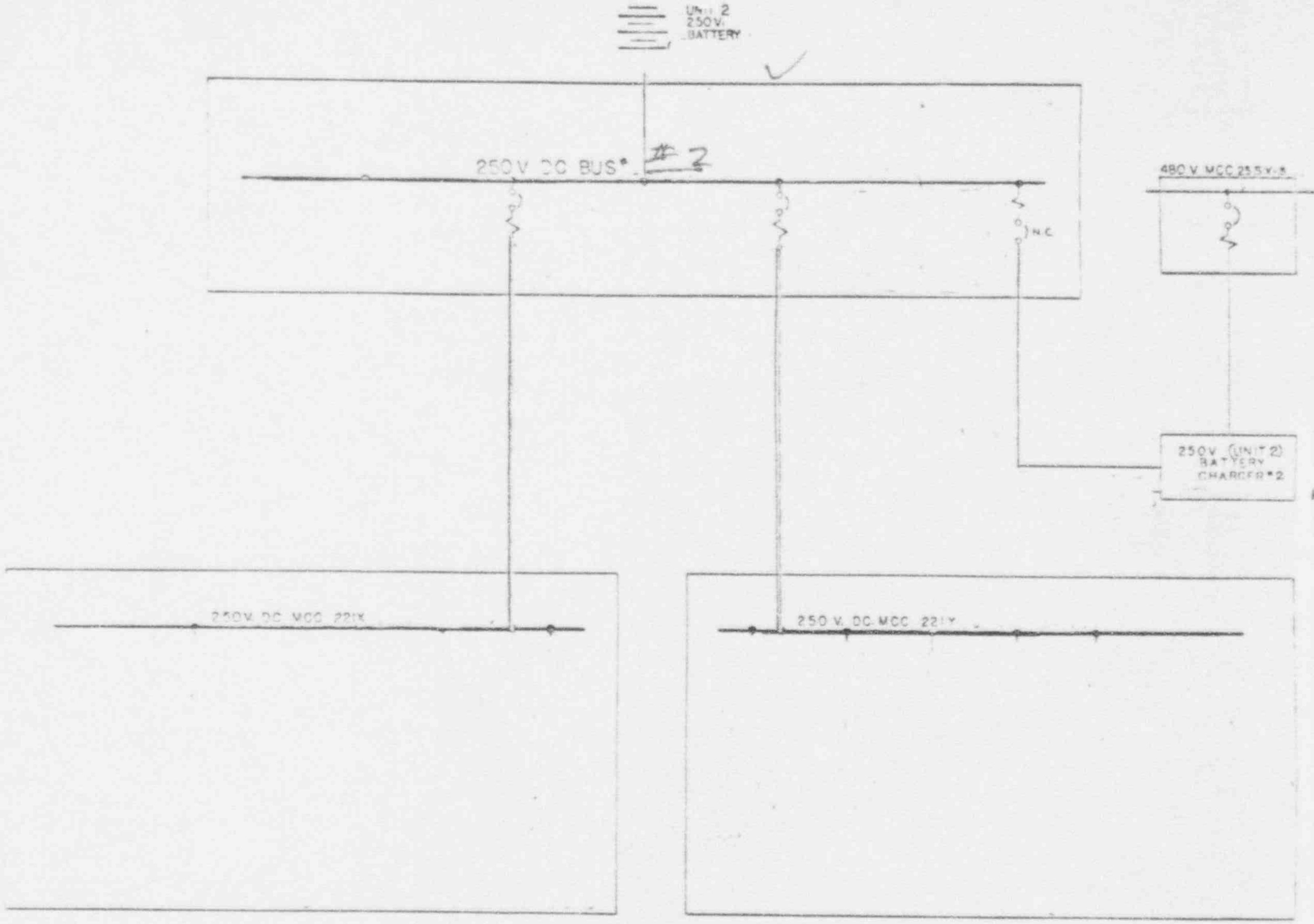


FIGURE B.X.3 SIMPLIFIED DIAGRAM OF ~~CLASS IE~~ Safety Related 250 VDC SYSTEM

FIGURE B.X.4 SIMPLIFIED DIAGRAMS OF Safety Related
125VDC POWER SYSTEMS

8.0 FLUID SUPPORT SYSTEMS

8.1 Reactor Building Closed Cooling Water System (RBCCW)

8.2 Turbine Building Closed Cooling Water (TBCCW) (WT)

8.2.1 System Function

The purpose of the Turbine Building Closed Cooling Water (TBCCW) system is to provide cooling water to the turbine generator auxiliary systems, service air compressors, motor-driven feedwater and condensate pumps, and other equipment located in the turbine building, during normal plant operation or during abnormal operating conditions.

8.2.2 System Description

8.2.2.1 General Design

The Turbine Building Closed Cooling Water (TBCCW) system is a closed cooling water loop. The system contains two motor-driven, horizontal pumps, two horizontal straight tube type heat exchangers and one expansion tank. The essential equipment cooled by TBCCW, during accident conditions while offsite power is available, are condensate and condensate booster pump coolers, station air compressor air coolers and oil coolers, and the motor-driven reactor feed pump oil coolers. A simplified diagram of the TBCCW system is shown in Figure 8.2-1.

1) Flow Path

The TBCCW is a closed cooling water circuit. The TBCCW pumps take a suction from the operating heat exchanger and discharge to the cooling water supply header. The cooling water flows through various system load coolers and heat exchangers, which are arranged in parallel, and then discharges to the return header. The return water is then passed through one of the two TBCCW system heat exchangers where the heat absorbed in the load coolers is transferred to the service water system. The water flows to the pump suction and is circulated. In order to provide cooling to the service air compressor cooling water system (Intercoolers, aftercoolers and lube oil coolers), the TBCCW is provided with an additional small centrifugal pump and heat exchanger cooled also by the service water system. The expansion tank taps into the system between the system heat exchanger and the pumps.

2) Component Description

Circulating Pumps

The two 100% capacity TBCCW pumps are horizontal centrifugal pumps, and are arranged in parallel in the loop. Normally one pump is in service, the other in standby. Pump capacity is 2500 gpm at a discharge head of 100 ft. (43.4 psig) and a net positive suction heat (NPSH) of 20 ft. The pumps are located on the mezzanine level of the turbine building near the centerline dividing Units 1 and 2. The pumps are 100 HP and 4 V powered from swgr 231A and swgr 232A. The pumps are manual operated from the control room with a pistol grip handle (spring return to normal position). The actuation system is provided with overcurrent and undervoltage protection circuits.

System Heat Exchangers

The two TBCCW heat exchangers are horizontal, straight tube, single pass, counterflow heat exchangers rated at 20 x 106 BTU/hr. each. The TBCCW passes through the shell side and service water passes through the tube side. Service water is regulated automatically to maintain less than 110F TBCCW outlet temperature. Maximum design flow is 2500 gpm on both the tube side and the shell side. Each heat exchanger is 100% capacity and, therefore, only one is normally in service. The other serves as a standby. The heat exchangers are located immediately west of the circulating pumps.

Expansion Tank

The 2000 gallon capacity expansion tank is a horizontally mounted cylindrical tank vented to atmosphere. It provides the net positive suction head for the TBCCW pumps and accommodates volume changes in the system. It is filled from the clean condensate system and its level is controlled automatically. Accidental overflow is directed to a floor drain sump by an overflow pipe. It is located on Radwaste roof.

The system is not provided with Motor-Operated valves, and for the flows path considered in this analysis, there are no solenoid or air operated valves except for two in the service air compressor line (2WT034 AND 2WT156). All valvel are normally open except for the one outlet valve on the idle heat exchanger (manual valve). The solenoid valves fail open on loss of power.

8.2.2.2 System Interfaces

A support system FMEA is presented in Table 8.2.1.

Electrical

The plant electrical distribution system provides power to the TBCCW system for operation of the two main pumps, the auxiliary pump, and system instrumentation and controls. The main TBCCW pump motors, 2WT01PA and 2WT01PB are supplied by MCC's 231A and 232A, respectively. The auxiliary pump, 2WT02P, is supplied by MCC 231A.

Component Cooling

The service water system (SWS) provides cooling to the main TBCCW heat exchangers 2WT01AA and 2WT01AB and to the station air heat exchanger 2WT02A.

8.2.2.3 Instrumentation and Control

1) System Actuation

The TBCCW system is normally operating and the pumps can be initiated manually at control room panel 2PM09J. The TBCCW is not provided with automatic start, but it is provided with overcurrent and undervoltage protection. All other components must be operated locally.

2) Component Controls

There is a temperature detector TEWIC-2 located in the heat exchanger common discharge line. A rise in temperature causes the service water control valve 2WS029 to open and a decrease causes it to close.

The level control of the expansion tank is accomplished by a liquid level switch and the make-up control valve 2WT053. At a level of 1000 gallons, the level switch causes the make-up valve to open by energizing the solenoid which admits instrument air. At a level of 1700 gallons, the level switch causes the make-up valve to close. The valve is normally closed fails closed on loss of air or power. If the valve should fail open, the water will overflow into the floor drain sump. There are manual isolation valves.

3) Instrumentaion

The following instrumentation is in the control room at panel 2PM01J:

a) Pump Discharge Header Pressure Indicator

b) Discharge Header Temperature Incicator

The following alarms are also available at control room panel 2PM01J:

a) TBCCW Pump Auto Trip (2A and 2B)

b) TBCCW Pump Discharge Header Pressure (low, 57psig)

c) TBCCW Pump discharge Header Temperature (HI, 110 ^{o}F)

8.2.2.4 Operator Actions

Normally TBCCW is operating with one running pump and one heat exchanger. No operator actions are required except for shifting operating pumps or heat exchangers in case of malfunction of the normally operating components.

8.2.2.5 Technical Specification/Test and Maintenance

The TBCCW is not safety related and does not require safety inspection. Because this system is normally in operation, the only required functional tests are during initial start-up or after maintenance.

8.2.3 System Operation

8.2.3.1 Normal Operation/Abnormal

During normal and abnormal operation, the TBCCW system continuously provides recycled cooling water to remove the maximum expected heat loads of equipment in the turbine building.

8.2.4 System Fault Tree

8.2.4.1 Fault Tree Description

A simplified diagram of the TBCCW system showing all components modeled in the fault tree is shown in Figure 8.2-1. For the purpose of fault tree development, the system has been broken into pipe segments which are labled. Table 8.2.2 shows the relationship of the fault tree notation to the P&ID notation.

8.2.4.2 Success/Failure Criteria

The success criteria for the TBCCW system is defined as successful cooling of each essential component, and requires that at least one TBCCW pump, one heat exchanger and a cooling water flow path to the component is available. Thus a partial failure of the TBCCW system can occur if a flow path to a particular component is not available yet other components are being adequately cooled.

There are three top events in the TBCCW system:

1) SY-LUBE-IAS01CBA which is the failure to remove heat from the station air compressor IAS01CBA lube oil cooler (which is modeled in the IA fault tree).

2) SY-CCWE-IAS01CBA which is the failure to provide cooling to the station air intercooler and aftercooler for

station air compressor IAS01CBA (which is modeled in the IA fault tree).

3) TCWF-1OF1H-1OF2P which is the failure of TBCCW to remove heat using one pump and one HTX. This interfaces with both the motor-driven feedwater pump oil and seal coolers which are modeled in the main feedwater system fault tree and the condensate and condensate booster pump lube oil coolers which are modeled in the condensate system fault tree.

8.2.4.3 Major Assumption

In the fault tree analysis of the TBCCW system, the following assumptions were made.

1) Since the TBCCW is a closed loop system with a limited make-up capability, diversion paths greater than two inches in diameter, will fail the system even with the makeup system operating.

2) Failure of the expansion tank is only considered for seismic analysis.

3) The failing closed of the make-up control valve was not considered. For seismic failures, all ruptures will be too large for the make-up system to handle; otherwise, a very long time (several hours) would be required to lower the tank level to the point where it would disable the system.

4) Failure of the pump 2WT02P or the heat exchanger 2WT02A for cooling the station air compressor fails the station air compressor due to lack of sufficient forced cooling.

5) Each pump is considered running 50% of the time thus, maintenance is not explicitly modeled. It will be considered in recovery where the maintenance unavailability will be added to the operator failure to recover probability.

6) The second heat exchanger, 2WT005B, is not modeled. Credit will be taken in the recovery analysis if appropriate.

7) Pipe segments TIA and TOA include all other segments greater than or equal to 2" in diameter for purposes of the rupture failure event. In the location analysis, these events would be assigned locations representing the location of all 2" or greater pip in the system. Pipe segment TB2 is less than 2" in diameter and appears

separately on the fault tree affecting omly the appropriate sub-portion of the system.

8) Circuit breaker DC power is not modeled as a failure since the pumps are initially operation. This will not cause a pump trip. For sequences where AC power is lost, manual restart is possible if DC power has not failed in the cut set. This is treated in the recovery analysis.

8.2.5 References

1) P&ID: M-124

2) Electrical Drawings: 1E2-4098

3) Master Diagrams: WT Electrical

4) LSCS-FSAR: Section 9.2.8

5) LaSalle Systems Training Manual: Chapter 53

Table 8.2.1
Support Systems Interface FMEA Turbine Building Closed Cooling Water (TBCCW)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
SWS	2WT01AA	HTX	Fails to provide cooling	CR Hi Temp alarm 118F	Loss of HTX "A" will disable the TBCCW system if it is the operating HTX.	A long term failure of the functioning HTX will disable the TBCCW system.
	2WT01AB	HTX	Fails to provide cooling	CR Hi Temp alarm 118F	Loss of HTX "B" will disable the TBCCW system if it is the operating HTX.	"
	2WT02A	HTX	Fails to provide cooling	CR station air compressor auto trip alarm	Loss of HTX for the SA compressor will disable only the part of the system cooling the SA compressor.	A long term failure of the HTX for the SA compressor will result in failure of the SA compressor.
480 V SWGR 231A	2WT01PA	MDP	Fails to run	CR auto trip alarm & light	Loss of a running pump will partialy disable the system	Loss of ac power in a running train, will partially disable the TBCCW system
	2WT02P	MDP	Fails to run	CR station air compressor auto trip alarm	Loss of the pump for cooling the SA compressor will disable only part of the system cooling the SA compressor.	Failure of the pump for forced cooling of the SA compressor will result in failure of the SA compressor.
480 SWGR 232A	2WT01PB	MDP	Fails to run	CR auto trip alarm & light	Loss of a running pump will partialy disable the system	Loss of ac power in a running train will partially disable the TBCCW system

Table 8.2.2
Relation of P&ID to Fault Tree Nomenclature

Pipe Segment	P&ID	Fault Tree
TB1	2WT088	TCW088XX
	2WT171	TCW171XX
	2WT087	TCW087XX
	2WT034	TCW034XD
	2SA01C	IAS01CBA
		(Inter and after coolers)
TIB	2WT165	TCW165XX
	2WT106	TCW106XX
	2WT02A	TCW02AXX
	2SA0IC	IAS0ICBA
		(Lube oil cooler)
TOB	2WT163	TCW163XX
	2WT162	TCW162XX
	2WT107	TCW107XX
	2WT164	TCW164XX
	2WT02P	TCW02PXD
TB2	2WT035	TCW035XX
	2WT170	TCW170XX
	2WT156	TCW156XD
	Pipe Seg TB2	TCWPSTB2
T11	2WT001A	TCW001AX
	2WT002A	TCW002AX
	2WT007A	TCW007AX
	2WT01PA	TCW01PAD
T12	2WT001B	TCW001BX
	2WT002B	TCW002BX
	2WT007B	TCW007BX
	2WT01PB	TCW01PBE
T13	2WT01T	TCW01TXX
	2WT057	TCW057XX
	2WT058	TCW058XX
TO1	2WT006A	TCW006AX
	2WT005A	TCW005AX
	2WT01AA	TCW01AAX

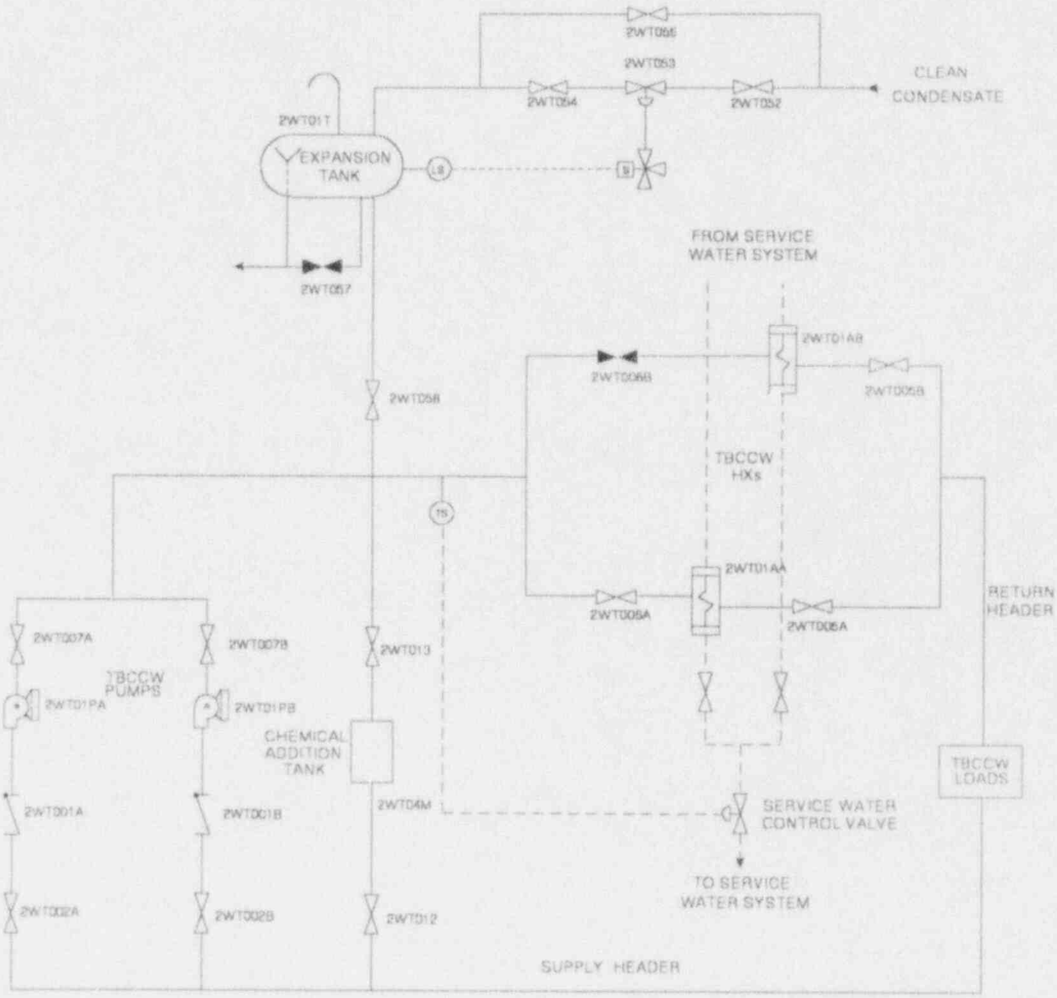


Figure 8.2-1 Turbine Building Closed Cooling Water System (Sheet 1)

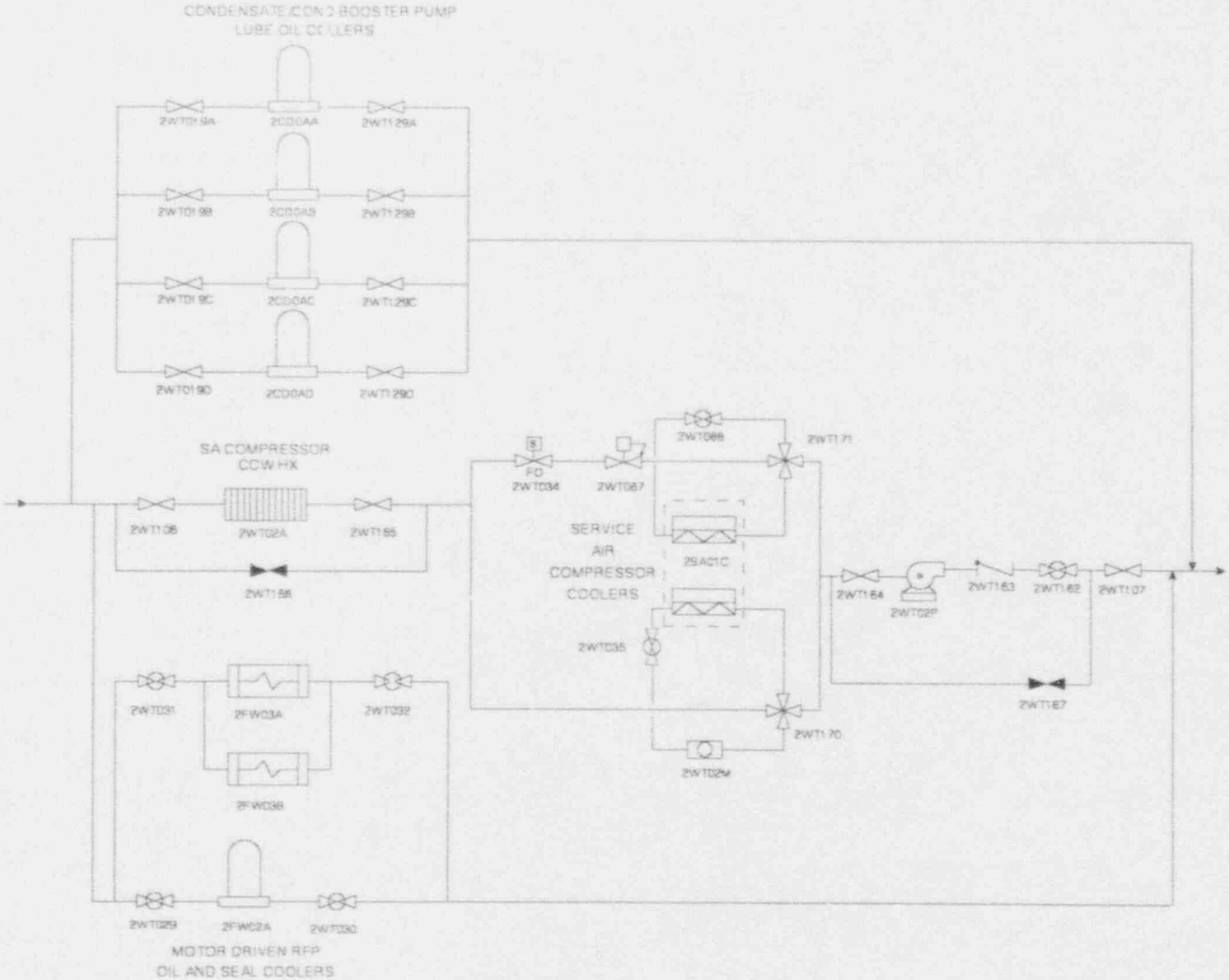


Figure 8.2-1 Turbine Building Closed Cooling Water System (Sheet 2 - Loads)

8.3 Service Water System (SWS) (WS)

8.3.1 System Function

The purpose of the Service Water System (SWS) is to provide cooling water to various equipment in the turbine building, reactor building, auxiliary building, service building, and radwaste facility during normal plant conditions, shutdown, and abnormal plant conditions when offsite power is available.

8.3.2 System Description

8.3.2.1 General Design

The service water system for both units, consists of five service water pumps (four are normally running, one is an installed spare), two service water jockey pumps (normally used only for low flow or low pressure conditions), three service water strainers (one is an installed spare), and the valves and piping necessary to provide cooling water throughout the plant. The essential equipment cooled by service water are the TBCCW system, RBCCW system, Station/Instrument Air, and the main turbine oil cooling system.

1) Flow Path

The service water pumps take their suction from the water tunnel in the lake screen house, and discharge to a common header which supplies the service water strainers. From the strainers, service water is distributed to the many components to be cooled in the plant and then discharged back to the lake. A simplified diagram of the SWS system is shown in Figure 8.3-1.

2) Component Descriptions

Water Tunnel

The water tunnel is located under the lake screen house basement floor and is a seismic Category I structure. Water is drawn from the lake thru six, 36" pipes and normally open valves.

Service Water Pumps

There are five service water pumps, two pumps per unit, with the fifth pump as a spare. Each pump can provide 100% of needed flow to one unit after a trip; therefore, two pumps (one for each unit) are needed, assuming both units are shutdown. The pumps are located in the basement of the screen house, each has a capacity of 16,000 gpm and delivers a discharge pressure of 90 to 100 psig. They can be classified as five single stage, twin suction, horizontal centrifugal pumps which are driven by AC motors rated at 1250 hp and 4160 volts.

Jockey Pumps

Both service water jockey pumps are single stage, twin suction, horizontal centrifugal pumps. They have a capacity of 5,000 gpm at their normal discharge pressure of 90 to 100 psig. They are located in the basement of the lake screen house. The pumps are used during plant shutdown when low service water flow conditions are required. They may also be used to provide minimum flow requirements during a loss of offsite power. This is possible because the jockey pumps can be manually connected to the emergency diesel generator. The jockey pumps have the capability of being operated from the remote shutdown panel.

Service Water Strainers

There are three strainers - one per unit and an installed spare. Each has a rated capacity of 32,000 gpm. The strainers are a basket type, which have been divided into two separate sections by a vertical separator wall.

Service Water Discharge Standpipes

There are two 48" standpipes in each unit. The service water effluent is discharged to these standpipes and is then directed to the circulating water discharge.

8.3.2.2 System Interfaces

A support system FMEA is presented in Table 8.3.1

Electrical

The plant electrical distribution system provides power to the Service Water System for operation of the five main pumps, the two jockey pumps, and two motor operated valves. For the pumps and valves which supply unit 2, the power supplies are described below:

Component	Identifier	Power	Source
MOV	2WS025	480V	MCC 231A-2
MP	2WS01PB	4160V	SW. GR. 242X
MP	2WS01PA	4160V	SW. GR. 242X
MP	0WS01P	4160V	SW. GR. 241X
MOV	2WS191	480V	MCC 231A-2
MP	0WS02PA	4160V	SW. GR. 142X
MP	0WS02PB	4160V	SW. GR. 242X
STR	2WS01F	480V	MCC 232Y-1

Component Cooling

The lake is used by the service water system as ultimate heat sink, thus the SWS takes water from the lake and provides cooling to the different heat loads and finally discharges to the lake.

8.3.2.3 Instrumentation and Control

1) System Actuation

The normally running SWS can be manually initiated if needed at the control room panel 2PM09J, the jockey pumps and the main pumps being located at the same panel.

2) Component Control

The main pumps are provided with auto-trip to protect them from overcurrent, neutral overcurrent and undervoltage; the main pumps and jockey pumps are not provided with automatic restart.

Pneumatic valves 2WS029 and 2WS035, are supplied by the Instrument Air system (IA), both fail open on loss of IA. The temperature sensor ITEW/WT056, located in the common exit header of the TBCCW heat exchangers, is used to control the pneumatic valve 2WS029. The temperature sensor 2TE/T0050, located on the turbine oil tank 2T001S, is used to control the pneumatic valve 2WS035.

3) Instrumentation

The following instrumentation is available at control room panels 1PM10J and 2PM10J:

a) Service Water Pump Discharge Header Pressure

b) Service Water Header Pressure (each unit)

c) Service Water Jockey Pump Amps

d) RBCCW HTX Service Water Valve 2WS175 Position Indication.

The following alarms are also available at control room panels 1PM10J and 2PM10J:

a) Service Water Pump Auto Trip

b) Service Water Drainer Diff Press Hi (10 psid)

c) Service Water Jockey Pump Auto Trip

d) Service Water Header Pressure LO (80 psig)

e) Service Water Transfer Switch In Emergency (Remote Shutdown System Operation)

8.3.2.4 Operator Actions

Normally SWS is operating with two running pumps. No operator actions are required except for shifting operating pumps or strainers in case of malfunction of the normally operating components.

8.3.2.5 Test and Maintenance

The SWS is normally in operation, the only tests required are functional tests during initial system startup or after maintenance. Maintenance is performed on an as-needed basis.

8.3.2.6 Technical Specification

The SWS is a continually operating non-safety system necessary for reactor operation; consequently, there are no applicable Technical Specifications; since, if it fails, the plant will trip.

8.3.3 System Operation

8.3.3.1 Normal Operation

The SWS is designed to supply water during normal plant operation and normal shutdown. In normal operation, two of the main pumps are running for each unit with the fifth main pump and jockeys in standby.

8.3.3.2 Abnormal Operation

During abnormal plant conditions, the SWS is able to meet the minimum requirements with one of two main pumps per unit or two jockey pumps. The jockey pumps can also be operated from the remote shutdown panel. Their actuation is considered as a recovery action.

8.3.4 System Fault Tree

8.3.4.1 Fault Tree Description

A simplified diagram of the SWS system showing all components modeled in the fault tree is shown in Figure 8.3-1. For the purpose of fault tree development, the system has been broken into pipe segments which are labled. Table 8.3.2 shows the relationship of the fault tree notation to the P&ID notation.

8.3.4.2 Success/Failure Criteria

The success criteria for the SWS system is defined as successful cooling of each essential sub-system like TBCCW, station air, and main turbine oil cooling system, and requires that at least one main SWS pump, one strainer, and a cooling path to the component is available. Thus a partial failure of the SWS system can occur if a flow path to a particular component is not available, yet other components are being adequately cooled. For purposes of this analysis it was assumed that the other unit was operating and that it needed its two main pumps. Failure of the whole system requires failure of the two operation pumps for this unit only.

The service water system has five top events:

1) SY-HRSH-TCW01AAX which is the failure to remove heat from the operating TBCCW heat exchanger (assumed to be TCW01AAX).

2) SY-HRSH-TCW02AXX which is the failure to remove heat from the station air compressor heat exchanger TCW02AXX.

3) SY-HRSH-TOC01AAX which is the failure to remove heat from the normally operating main turbine lube oil cooler 1A.

4) SY-HRSH-2WR01AA which is the failure to remove heat from RBCCW heat exchanger 2WR01AA.

5) SY-HRSH-2WR01AB which is the failure to remove heat from RBCCW heat exchanger 2WR01AB.

8.3.4.3 Major Assumptions

In the fault tree analysis of the SWS system the following assumptions were made

1) The system is assumed to be in normal operating status at the start of the accident: two main pumps are supplying each unit and one is spare.

2) Flow lines less than one third the diameter of the main pipe are not considered as diversion paths since they will not divert sufficient flow to prevent satisfaction of the success criteria.

3) Failures in the SWS are assumed to have a prompt detection interval, since the SWS is a continuously running system and failure will result in plant trip if not corrected.

4) Since the SWS is normally in operation with two pumps, an additional conditional event EE-MDP-PSW-XX-R is added, with a probability of one third, to represent the probability of a specific configuration of pumps being in operation at any one time (the pumps are rotated to allow equal wear). Maintenance is assumed to be on the non-operating loop and therefore, is not explicitly modeled.

5) Operation of the jockey pumps and starting the third main pump is treated as a recovery action and not explicitly modeled. Also, shutdown of the other unit and use of one of its two pumps is treated as a recovery action.

6) Circuit Breaker DC power is not modeled as a failure since the pumps are initially operating. This will not cause a pump trip. For sequences where AC power is lost, manual restart is possible if DC power has not failed in the cut set. This is treated in the recovery analysis.

8.3.5 References

1) P&ID: M-68 and M-125

2) Electrical Drawings: 1E-0-4449 and 1E-2-4097

Electrical

3) Master Diagrams: WS

4) LSCS-FSAR: Section 9.2.2

5) LaSalle Systems Training Manual: Chapter 55

Table 8.3.1
Support Systems Interface FMEA Service Water System (SWS)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Asssuming No Recovery)
4160 V SWGR 241X	2WS01PA 0WS01P	MDP "	Fails to run "	CR Auto-trip Alarm	Loss of one running pump will partially disable the SWS.	Loss of ac power to a running pump will disable the train but not the system since only one pump is necessary for successful system operation following a reactor trip.
4160 V SWGR 242X	2WS01PB	MDP	Fails to run	CR Auto-trip Alarm	Loss of one running pump will partially disable the SWS.	"
IA	2WS029 2WS035	AOV "	Fails open "	-	No effect on system operation.	No effect on system operation.
480 V SWGR 231A-2	2WS025 2WS191	MOV	Fails as is	-	Valves normally open, no effect on system operation.	No effect on system operation.
480V MCC 232Y-1	2WS025	MOV	Fails open	Hi Diff Press Alarm	Failure of auto backwash over a long time would result in loss of system flow.	No effect on system operation during accident conditions.

Table 8.3.2
Relation of P&ID to Fault Tree Nomenclature

Pipe Segment	P&ID	Fault Tree
WIA	2WS026A	PSW026AX
WI1	2WS025	PSW025DX
WO2	2WS028	PSW030X
	2WS029	PSW029X
	2WS030	PSW028X
WI6	2WS216	PSW216XX
WO5	2WS114	PSW114
	2WS175	PSW175
WO3	2WS217	PSW217X
WIC	2WS032A	PSW032AX
	2WS033A	PSW033AX
WI7	2WS191	PSW191DX
WO4	2WS034	PSW036X
	2WS035	PSW035X
	2WS036	PSW034X
WI2	2WS005	PSW005X
	2WS01F	PSW01FX
	2WS004	PSW004X
	Pip Seg WI2	PSWPSWI2
WO1	2WS027A	PSW027AX
	Pip Seg WI6	PSWPSWI6
WI3	2WS002B	PSW002BX
	2WS003B	PSW003BX
	2WS001B	PSW001BX
	Pip Seg WI3	PSWPSWI3
	2WS01PB	PSW01PBB
WI4	2WS002A	PSW002AX
	2WS003A	PSW003AX
	2WS001A	PSW001AX
	2WS01PA	PSW01PAA
	Pip Seg WI4	PSWPSWI4

Table 8.3.2 (Concluded)
Relation of P&ID to Fault Tree Nomenclature

Pipe Segment	P&ID	Fault Tree
WI5	0WS002	PSW002SX
	0WS003	PSW003SX
	0WS01P	PSW01PSA
	0WS001	PSW001SX
WIE	2WS085B	PSW085BX
	2WS086B	PSW086BX
	2WS088B	PSW087BX
	2WS087B	PSW088BX
WID	2WS088A	PSW088AX
	2WS085A	PSW085AX
	2WS086A	PSW086AX
	2WS087A	PSW087AX

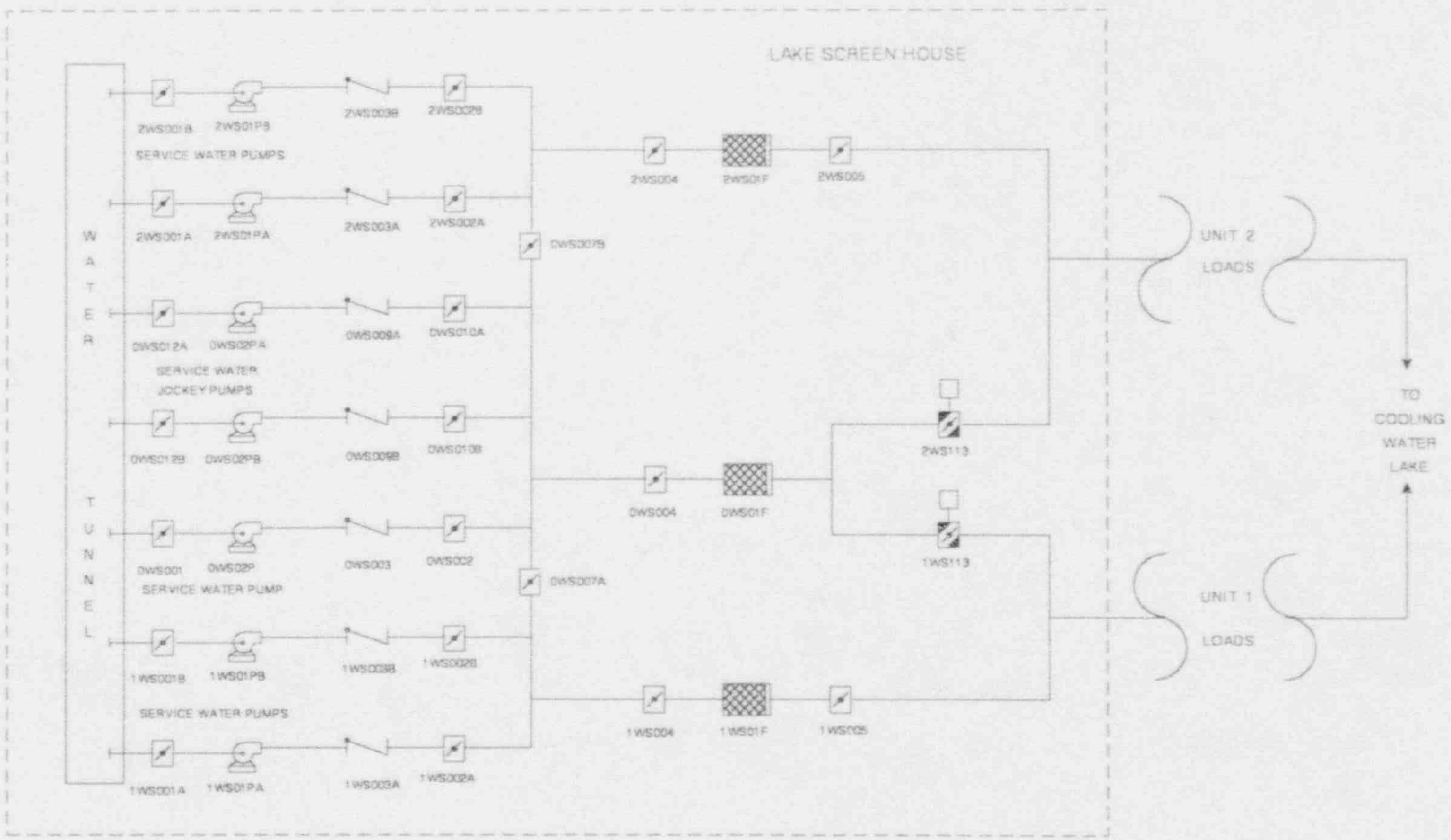


Figure 8.4-1 SWS Unit 2 Loads (Sheet 1)

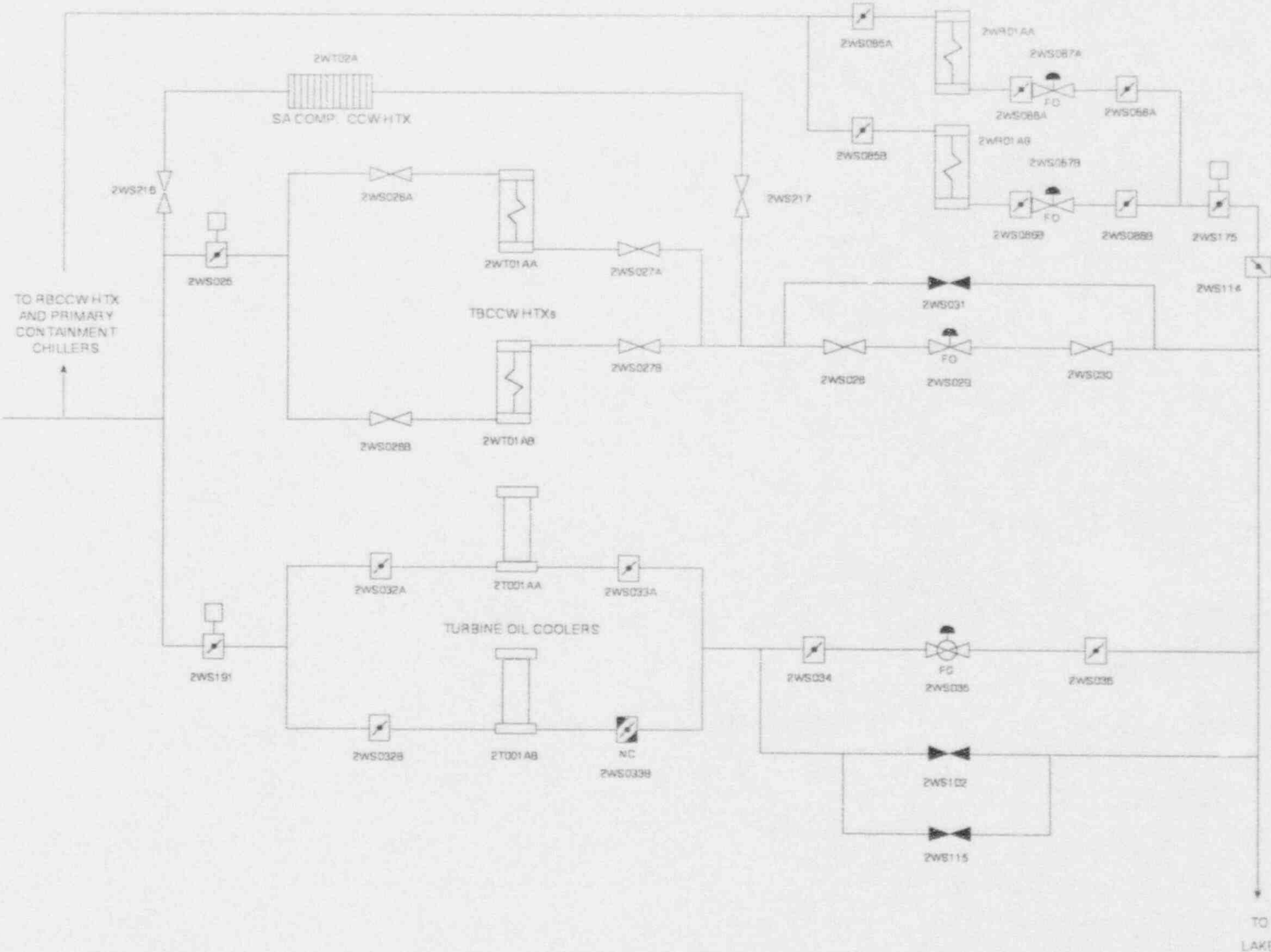


Figure 8.4-1 SWS Unit 2 Loads (Sheet 2)

8.4 <u>Core Standby Cooling System (CSCS)</u>

8.4.1 System Function

The Core Standby Cooling Systems (CSCS) Equipment Cooling Water System provides component cooling during operation of the individual Core Standby Cooling Systems, (RHR heat exchangers, CSCS area cooling coils, diesel generators, RHR pump seal coolers, and the LPCS pump motor cooling coils). The system also provides a source of emergency make-up water for fuel pool cooling and can provide containment flooding for post accident recovery.

8.4.2 System Description

8.4.2.1 General Design

The CSCS system consists of three divisions which independently supply filtered cooling water to their respective loads. There are eight cooling water pumps for Unit 2. One Unit 1 pump, the DG pump, is designated as a swing pump supplying either unit.

The three divisions of CSCS consist of the following. Figure 8.4-1 shows the Unit 2 layout.

Division 1: three pumps supplying:

a. RHR heat exchanger "A".
b. RHR pump "A" seal cooler.
c. Diesel generator "0" cooler.
d. Unit 1 and Unit 2 LPCS pump motor coolers.
e. Unit 1 and Unit 2 N.E. area coolers (RCIC and LPCS corner room).
f. Unit 1 and Unit 2 N.W. area coolers (RHR pump "A" corner room).
g. Fuel pool emergency make-up supply "A".

NOTE: Loads c-f above are supplied by the swing pump (D/G cooling water pump "OA") located on Unit 1 side.

Division 2: Four pumps supplying:

a. RHR heat exchanger "B".
b. RHR pump "B" seal cooler.
c. RHR pump "C" seal cooler.
d. Diesel generator "A" cooler.
e. South East area cooler (RHR pump "B" and "C" corner room).
f. Fuel pool emergency make-up supply "B".
g. Containment flooding supply.

Division 3: One pump supplying:

a. Diesel generator "B" cooler (HPCS D/G).
b. South West area cooler (HPCS corner room).

Flow Path

Lake cooling water from the CSCS pond is supplied to the Unit 2 CSCS components through three supply lines. These lines take a suction off the water tunnel in the lake screen house. The water is discharged back to the CSCS pond through three discharge lines. The CSCS system also provides water for fuel pool emergency make-up and containment flooding under abnormal operating conditions.

Locations

The CSCS equipment is located in the reactor building basement, lake house, and diesel generator building.

The CSCS pumps are located in the basement of the diesel generator building. The basement is divided into three water-tight rooms (for flooding protection). Each room contains the pumps and strainers for one of the three divisions of the CSCS.

Component Descriptions

CSCS Pond

The CSCS pond is an excavation within the cooling lake with a capacity of 150 x 106 gal. The top water elevation of the pond is approximately 10 ft. below the normal surface elevation of the cooling lake. The approximate depth of the CSCS pond is 5 ft. (assuming the lake has been drained via dike break).

The CSCS pond has sufficient capacity to shut down the plant during the following conditions:

a. Only the CSCS pond is available
b. Extreme postulated evaporative conditions
c. LOCA in one unit
d. Normal shutdown in the other unit
e. Largest demand of fire protection water.

Lake Screen House Water Tunnel

The lake screen house water tunnel distributes the lake cooling water to the CSCS system. Cooling lake water is routed to the tunnel from the circ water suction bay via six supply headers. Three of these headers supply nine pumps on Unit 1 and the other three supply eight pumps on Unit 2.

System Pumps

RHR Service Water Pumps

There are four RHR service water pumps per unit - two for division one, and two for division two. They are single stage, single volute, horizontal centrifugal pumps. Two 50% capacity pumps are assigned to each RHR heat exchanger. Pump design flow and pressure is 4000 GPM and 150 psig respectively.

The pumps size are based on the following minimum equipment cooling water flow requirements:

1. RHR Heat Exchangers - 7400 gpm
2. RHR Pump Seal Coolers - 20 gpm

Diesel Cooling Water Pumps

The diesel generator cooling water pumps are single stage, single volute, horizontal centrifugal pumps. There is 1-100% capacity pump per unit and one that supplies the swing diesel. Pump design pressure is 150 psig. Pump design flow for the swing DG pump is 2000 gpm and for the DG pumps 1300 gpm (both units).

Pump capacity is based on the following minimum flow requirements:

1. Swing (ODG) pump
   D/G cooler - 840 gpm
   LPCS motor coolers - 8 gpm (4 gpm per unit)
   N.E. area coolers - 440 gpm (220 gpm per unit)
   N.W. area coolers - 300 gpm (750 gpm per unit)

2. DG pumps
   D/G cooler - 840
   S.E. area coolers - 240 gpm

HPCS Diesel Cooling Water Pumps

The HPCS diesel generator cooling water pumps are single stage, single volute, horizontal centrifugal pumps. There is 1-100% capacity pump for each unit. The design pressure and flow of the pump is 184 psig and 1000 gpm respectively.

The capacity of the pump is based on the following:

1. HPCS cooler - 800 gpm

2. S.W. area cooler - 150 gpm

System Cooling Water Strainers

The CSCS strainer consist of a series of parallel tubes in a shell with a water box at one end and a rotating plate at the other end. Water flows into the tubes from the water box and through small holes in the tube wall to the strainer outlet. Debris collects along the inner wall of the tubes. The rotating plate at the other end of the tube seals the tubes except for the pair of tubes aligned to a backwash arm penetrating the plate. When this end of the tube is aligned to the backwash arm, the water flows to the lower pressure of the backwash line carrying debris collected in the tube out of the strainer.

RHR Heat Exchangers

The RHR heat exchangers are vertical U-tube type heat exchangers that have a capacity of 41.6 x 106 BTU-HR. They require 7400 gpm of service water each.

Discharge Pipes

Identical divisions of both Unit 1 and Unit 2 CSCS are combined on the discharge side to form three return pipes that route the water back to the CSCS pond.

The discharge pipe outlets at the CSCS pond are located above the normal level of the cooling lake and they are protected from missiles by a reiforced concrete structure. A weir is located in the discharge chute to prevent debris from being washed into the discharge pipes by wave action when system is not in use.

8.4.2.2 System Interfaces

Electrical

The plant electrical distribution system provides power to the CSCS system for operation of the pumps, system MOVs, and system instrumentation and controls. System Power supplies are as follows:

RHR Service Water Pumps

Pump A: 480 V Swgr 235X
Pump B: 480 V Swgr 235Y
Pump C: 480 V Swgr 236X
Pump D: 480 V Swgr 236Y

Diesel Cooling Pumps

D/G OA: Both 480 Swgr 135X and 480V Swgr 235X
D/G 2A: 480 V Swgr 236X
HPCS D/G: 480 Swgr 243-1

D.C. Control power is supplied by each respective division 125 Vdc battery.

8.4.2.3 Instrumentation and Control

1) System Actuation

Diesel Generator Cooling Water Pump

The pump has a three position switch (Start-Auto-Stop). The pump will start automatically on a start signal to the associated diesel generator when the diesel reaches 150 RPM (assuming the switch is in the "auto" position).

HPCS Diesel Generator Cooling Water Pump

The pump has a switch with positions identical to those mentioned above. It also starts when in the "auto" position and a start signal is supplied to the HPCS diesel (150 RPM).

RHR Service Water Pumps and the Fuel Pool Make-up Pumps

These pumps also have the same three position switch (Start-Normal-Stop). They are manually operated. In addition the RHR "C" and "D" pumps can be operated from the Remote Shutdown Panel. In order to accomplish this, the remote shutdown transfer switch must be in the "EMERG" position. This, of course, takes control of the C and D pumps from the main control room.

Cubicle Cooling Systems

Each of the reactor building basement corner rooms are normally cooled by the reactor building HVAC. The cubicle cooling systems will automatically initiate to assist in cooling the rooms when the pumps in the rooms start up. Starting the pump (or pumps) in one corner room with auto start both the cubicle cooling room fan and its associated cooling water pump. Each system also has a high temperature seal-in which seals if the room temperature reaches 108F. The fan and pump will keep running until 104F is reached (when the plant HVAC should handle it).

The cubicle cooling systems for the D/G basement rooms are auto started when the RHR Service Water Pumps in the room start. The fans will also stop when the pumps stop. These systems are also supplementary to the normal plant HVAC in these four rooms.

<u>System Strainers</u>

The strainers automatically backwash every eight hours when in operation or when a high differential pressure across the strainers (4 psid) exists. The tubes of the strainer are cleaned one pair at a time in consecutive order by a backwash arm. The arm rotates over the end of the tubes and the debris is backwashed from the strainer and flushed into the discharge piping downstream of the coolers. A high differential pressure alarms in the control room

3) Instrumentation

Control Room Instrumentation

a. RHR Service Water Outlet Temperature

1. Multipoint recorder: 40F - 600F
2. High temperature alarm in control room (125F)

Local Instrumentation

Temperature:

1. At each divisional intake pipe
2. At outlet of each cooled component

Pressure:

1. At each pump discharge

Strainer Differential Pressure:

1. At each strainer

2. High DP alarm in control room (8 psid normal or 4 psid after the backwash cycle - initiates backwash if in auto mode for backwash).

Flow:

1. Flow elements are provided but not used for each cooled component except the RHR heat exchangers.

2. A flow element is installed in fuel pool emergency M/U test line.

Radiation Monitoring

a. RHR service water heat exchanger effluent is monitored by a gamma sensitive scintillation detector, as part of the process rad monitoring system. After the sample is drawn and counted it is returned to the effluent pipe.

b. An alarm will be given in the control room for high radiation (6 cps). Probable cause would be tube leaks from RHR.

Alarms (H13-P601 Panel)

	SETPOINT
a. RHR H.X. Cooling Water Hi Temp A(B)	125F
b. RHR Service Water Strainer Hi P A(B)	8 psid before or 4 psid after
	automatic backwash
c. RHR Service Water Pump	Overload when switch in
Tripped A(B, C, or D)	Normal After Start and BKR Open
d. RHR Service Water High Rad A(B)	6 cps
e. D/G Service Water Pump/Strainer Failure (pump will trip when it overloads due to strainer backwash).	Pump Overload/ Excessive backwash

8.4.2.4 Operator Actions

The diesel generator and cubicle cooling portions of the CSCS system are designed to auto start upon demand. The operator is only required to verify system operability on a regular basis and proper operation following a system start. The RHR portion of the CSCS system is manually controlled. The operator will be required to properly operate this portion of the system during operation of the RHR system.

8.4.2.5 Technical Specification Limitations

The following technical specifications apply to the HPCS system during operational conditions 1, 2 & 3.

RHR Service Water

Two independent RHR service water (RHRSW) subsystems each consisting of two operable pumps capable of transferring water through the associated RHR heat exchanger must be operable.

If one RHRSW subsystem becomes inoperable, it must be restored within 72 hours or the plant must be placed in hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

If both RHRSW subsystems become inoperable, the plant must be placed in hot shutdown within 12 hours and be in cold shutdown within the next 24 hours.

Surveillance Requirements

Each residual heat removal service water system subsystem shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve in the flow path that is not locked, sealed or otherwise secured in position, is in its correct position.

Diesel Generator Cooling Water

The independent Unit 2 Division 1, 2 and 3 and the Unit 1 Division 2 diesel generator cooling water subsystems each consisting of one operable diesel generator cooling water pump, capable of transferring cooling water to the associated diesel generator, must be operable. If one or more diesel generator cooling water subsystems becomes inoperable, the associated diesel generator must be declared inoperable. The actions required in this case are defined by Specifications 3.k.1.1 or 3.1.1.2, which apply to the diesel generators.

Surveillance Requirements

Each of the above required diesel generator cooling water subsystem shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve, manual, power operated or automatic, in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months by verifying that:

1. Each pump starts automatically upon receipt of a start signal for the associated diesel generator, and

2. The Division 1 pump starts automatically upon receipt of a start signal for the LPCS pump in Unit 2.

CSCS POND

The CSCS pond shall be operable as defined in the surveillance requirements. If the CSCS pond becomes inoperable, it must be restored within 90 days or the plant placed in hot shutdown within the next 12 hours and in cold shutdown within the following 24 hours.

Surveillance Requirements

The CSCS pond shall be determined OPERABLE at least once per 18 months by determining that:

a. No sediment deposition in excess of 1.5 foot has occurred in the intake flume or in the CSCS pond as determined by a series of sounding cross-sections compared to as-built soundings.

b. The pond bottom elevation is less than or equal to 686.5 feet.

c. Sediment deposition anywhere within the lake screenhouse behind the bargrill is not greater than one foot in thickness.

8.4.2.6 Tests

Tests which affect the CSCS system are summarized in Table 8.4.1. These are not tests of the CSCS system but tests of the components cooled by the individual CSCS sub-system. These tests only verify sub-system operability and do nt contribute to system unavailability.

8.4.2.7 Maintenance

Maintenance activities affecting the CSCS system availability are summarized in Table 8.4.2.

8.4.3 System Operations

8.4.3.1 Normal Operation

During normal reactor operation the CSCS system is maintained in a standby condition. The CSCS subsystem flow paths are aligned to supply cooling flow to their respective components when they are placed in operation. Portions of the system may be operated as required to augment HVAC cooling.

8.4.3.2 Abnormal Operation

During off normal conditions those portions of the CSCS system required for frontline system support will be operated. The HPCS and diesel generator cooling water systems pumps will auto start when their respective diesel reaches 150 RPM during startup. Flow paths are already aligned and no valve positions need to be changed. The RHR cooling water pumps of the CSCS system must be manually started when required. The flow paths for these portions of CSCS are already aligned for operation and no valve position changes are required

8.4.4 System Fault Tree

8.4.4.1 Fault Tree Description

Simplified diagrams of the mechanical portions of the CSCS system used for fault tree modeling are shown in Figures 8.4-2 thru 8.4.4. For the purpose of fault tree developement, the system has been broken up into pipe segments which are labeled. The complete fault tree is presented at the end of this appendix.

There are 10 top events in the fault tree. Each top event represents a CSCS subsystem interface with a frontline system component. Electric power interfaces with various CSCS system components account for the 21 developed events in the fault tree.

Table 8.4.3 contains the data used to quantify the fault tree.

8.4.4.2 Success/Failure Criteria

Successful operation of the CSCS system occurs when the individual subsystems provide adequate cooling to the components supplied by that subsystem. Failures occur when cooling flow to any cooled component is disrupted. This can result from component or subsystem failures. Events resulting in a subsystem failure include:

1) Loss of one pump in either of the RHR cooling subsystems.
2) Plugging of the strainer in any of the subsystem flow paths.
3) Pump failure in any of the Diesel Generator cooling subsystems.
4) Piping failures in the subsystem flow path.

8.4.4.3 Assumptions

Model Related

In addition to the general fault tree development assumptions listed at the beginning of this appendix, the following specific assumptions were made for the CSCS fault tree.

Cooling flow loss to the RHR pump seal coolers would not fail the RHR system and was not modeled.

Both pumps in each RHR SW subsystem must be operating for adequate heat removal capability of the RHR system.

Quantification Related

To be added.

8.4.5 References

1) FSAR

System description	Section 9.2.1 Section 9.4.5.3
Technical Specifications	Limiting Condition for Operation Section 3.7.1 Surveillance Requirements Section 4.7.1 Basis Section 3/4.7.1

2) Operator Training Manual — Chapter 40

3) Drawings

P&ID M-134
M-87

I&C IE-2-4089AA
IE-2-4220AF - AG
IE-2-4220AU
IE-2-4220CB - CC
IE-2-4009AB - AC
IE-2-4009AF
IE-2-4223AR - AT
IE-0-4412AC - AD

General Arrangement
M-222
M-223
M-220
M-221
M-230
M-228
M-229
M-213
M-399
M-398
M-405
M-409
M-419
M-415

Cable Tabulation
2DG01 - 2DG21

4)	Procedures	LOS-RH-Q1 Rev.8 LOS-RH-Q2 Rev.5A LOS-OP-Q1 Rev.7A LOS-DG-M1 Rev.12 LOS-DG-M2 Rev.XX LOS-DG-M3 Rev.XX LOS-DG-Q1 Rev.7 LOS-DG-Q2 Rev.X LOS-DG-Q3 Rev.X LOS-DG-SA1 Rev.0 LOS-DG-SA2 Rev.X LOS-DG-SA3 Rev.X
5)	Other Sources	Kuosheng Unit 1 PRA Nuclear Power Experience

SUPPORT SYSTEM/FRONTLINE SYSTEM INTERFACE FMEA

Frontline System CSCS

Support (Sub) System Failure	Frontline System Component Affected Identifier Type	Frontline System Component Failure Mode	Detection or Recovery Potential	Frontline System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - E (Sub) Syste System Func
480 VAC MCC 235X	RHR Service Water Pump A	Deenergized	CR Alarm	Loss of cooling flow to RHR HX 2A	Failure of HX with att system
480 VAC MCC 235Y	RHR Service Water Pump B	Deenergized	CR Alarm	Loss of cooling flow to RHR HX 2A	Failure of HX with att system
480 VAC MCC 236X	RHR Service Water Pump C	Deenergized	CR Alarm	Loss of cooling flow to RHR HX 2B	Failure of HX with att system
480 VAC MCC 236Y	RHR Service Water Pump D	Deenergized	CR Alarm	Loss of cooling flow to RHR HX 2B	Failure of HX with att system
480 VAC MCC 235X MCC 135X	ODG Cooling Water Pump (Pump Power can be supplied from either unit	Deenergized	CR Alarm	Loss of cooling flow to RHR HX 2B and LPCS pump cooler	Failure of ODG with at power suppl pump
480 VAC MCC 236X	DG2A Cooling Water Pump	Deenergized	CR Alarm	Loss of cooling flow to DG2A	Failure of attendant l supply to B
480 VAC MCC 243-1	HPCS Diesel Cooling Water Pump	Deenergized	CR Alarm	Loss of cooling flow to the HPCS Diesel	Failure of supply with emergency p
Division 1	RHRSW pumps	Fail to start	CR indicating	Loss of cooling flow to RHR HX 2A	Failure of

SUPPORT SYSTEM/FRONTLINE SYSTEM INTERFACE FMEA

Frontline System CSCS

Support (Sub) System Failure	Frontline System Component Affected Identifier Type	Frontline System Component Failure Mode	Detection or Recovery Potential	Frontline System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - E (Sub) Syste System Func
Division 2 of the 125 Vdc Battery	RHR SW pumps 2C & 2D	Fail to start	CR indicating light	Loss of cooling flow to RHR HX 2B	Failure of HX with att system
	DG cooling water pump 2A	Fail to start	CR indicating light	Loss of cooling flow to DG 2A	Failure of attendant 1 supply to B

Table A.X.Y. COMPONENT/SUBSYSTEM TEST SUMMARY

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Te Ou
LOS-RH-Q1	Inservice test	2E12-F068A 2E12-F068B	MOV MOV	Valves are stroked through full range	Valves are returned to normal standby lineup by test	3	--
		2E12-F332A 2E12-F332B 2E12-F332C 2E12-F332D	Manual Valves	Yes	Valves are returned to normal standby lineup by test		
		2E12-C002A 2E12-C002B 2E12-C002C 2E12-C002D	Pumps	Running	In normal operating lineup		
LOS-RH-Q2	Valve	2E12-F068A 2E12-F068B	MOV	Valve stroke test	Valves are returned to normal standby lineup by test	3	--
		2E12-F336A	MOV	Valve stroke test	Valves are returned to normal standby lineup by test		
LOS-LP-Q1	LPCI inservice test	ODG01P	Pump	Running	In normal operating lineup	3	--
LOS-DG-M1	ODG operability test	ODG01P System flow path	Pump valves	Running in normal lineup	In normal operating lineup	1	--

Table A.X.Y. COMPONENT/SUBSYSTEM TEST SUMMARY

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency	Te Ou
LOS-DG-SA1	ODG semiannual operability test	"	"	"		6	"
LOS-DG-M1	DG2A operability test	2DG01P system flow path	Pump valves	Running in normal lineup	In normal operating lineup	1	--
LOS-DG-M3	DG2A operability test	"	"	"	"	"	"
LOS-DG-Q2	DG2A auxiliaries inservice test	"	"	"	"	3	"
LOS-DG-Q3	DG2A auxiliaries inservice test	"	"	"	"	"	"
LOS-DG-SA2	DG2A auxiliaries inservice test	"	"	"	"	6	"
LOS-DG-SA3	DG2A semiannual operability	"	"	"	"	"	"

Table 8.4.2 Core Standby Cooling System Unscheduled Maintenance Summary

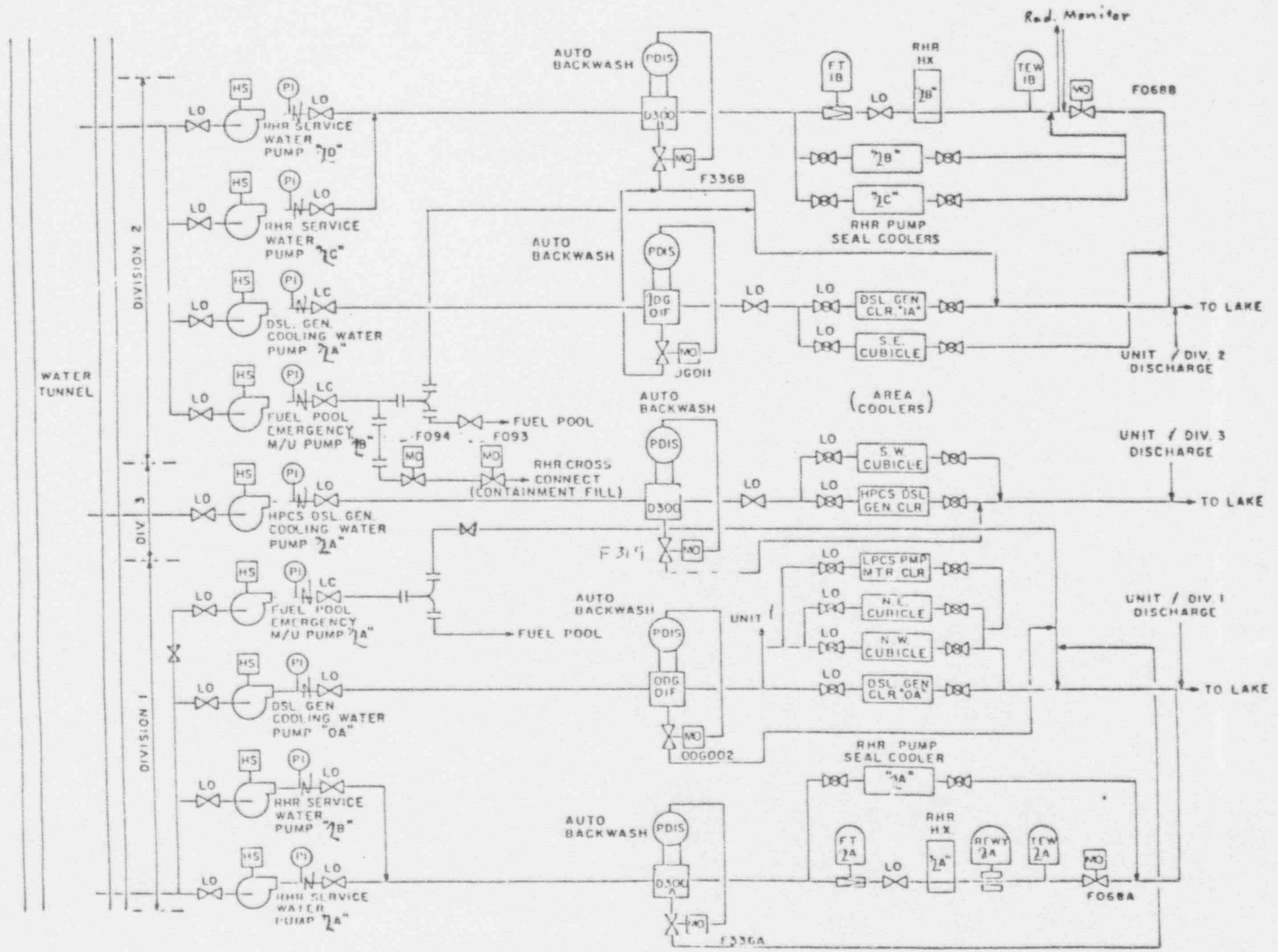
Component Subsystem	Type	Type of Maintenance$ST(1)$SP	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Cutage
2E21-C300A	RHR SW pump	Mechanical	F330A,F332A	Yes		
	2A	Electrical	Pump power supply breaker	Yes		
			Control power	Yes		
2E12-C300B	RHR SW pump	Mechanical	F330B,F332B	Yes		
	2B	Electrical	Pump power supply breaker	Yes		
			Control power	Yes		
2E12-C300C	RHR SW pump	Mechanical	F330C,F332C	Yes		
	2C	Electrical	Pump power supply breaker	Yes		
			Control power	Yes		
2E12-C300D	RHR SW pump	Mechanical	F330D,F332D	Yes		
	2D	Electrical	Pump power supply breaker	Yes		
			Control power	Yes		
2E12-D300A	Train A RHR SW	Mechanical	F014A,F336A F332A,F332B	Yes		
	Strainer	Electrical	Strainer power supply breaker	Yes		
			Strainer control power	Yes		
2E12-D300B	Train B SW RHR SW	Mechanical	F014B,F336B F332C,F332D	Yes		

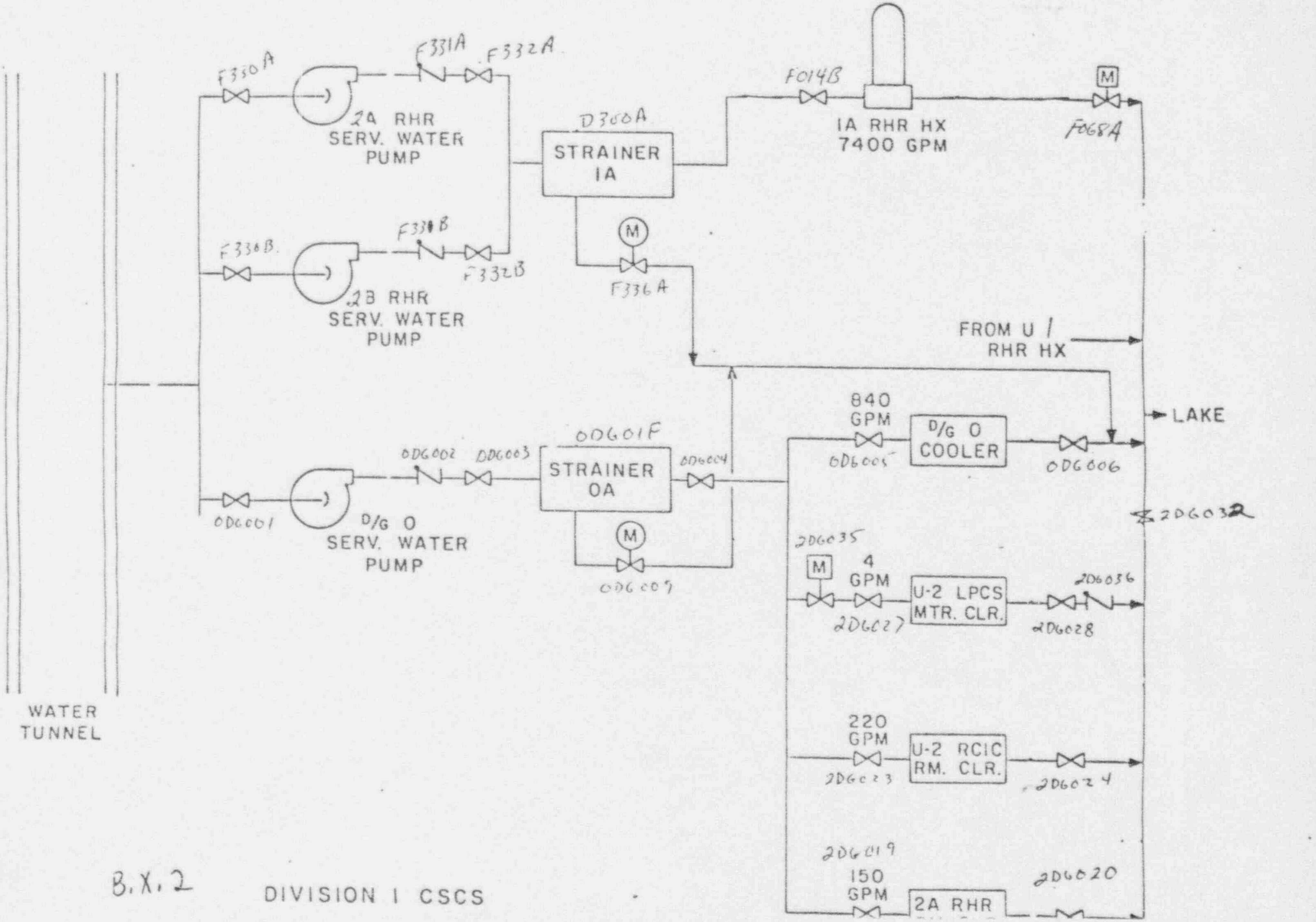
Table 8.4.2 Core Standby Cooling System Unscheduled Maintenance Summary

Component Subsystem	Type	Type of Maintenance$ST(1)$SP	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage
ODG01P	ODG Cooling Water Pump	Mechanical	ODG001,ODG003	Yes		
		Electrical	Pump power supply breaker	Yes		
			Control power	Yes		
ODG01F	ODG cooling water strainer	Mechanical	ODG003,ODG004 ODG009	Yes		
		Electrical	Strainer power supply breaker	Yes		
			Strainer control power	Yes		
2DG01P	DG2A cooling water pump	Mechanical	2DG001,2DG003	Yes		
		Electrical	Pump power supply breaker	Yes		
			Control power	Yes		
2DG01P	DG2A cooling water pump	Mechanical	2DG001,2DG003	Yes		
		Electrical	Pump power supply breaker	Yes		
			Control power	Yes		
2DG01F	DG2A cooling water strainer	Mechanical	2DG003,2DG004 2DG011	Yes		
		Electrical	Strainer power supply breaker	Yes		
			Strainer control power	Yes		
2E22-C002	HPCS	Mechanical	F310,F311	Yes		

Table 8.4.2 Core Standby Cc›ling Sysrem Unscheduled Maintenance Summary

Component Subsystem	Type	Type of Maintenance$ST(1)$SP	Components out of Normal Alignment for Maintenance	Allowed During Plant Operation	Frequency	Outage
2E12-D300A	HPCS cooling water strainer	Mechanical	F311,F312 F319	Yes		
		Electrical	Strainer power supply breaker	Yes		
			Strainer control power	Yes		


Rad. Monitor
WATER TUNNEL
DIVISION 2
DIV 3
DIVISION 1
RHR SERVICE WATER PUMP "2D"
RHR SERVICE WATER PUMP "2C"
DSL. GEN. COOLING WATER PUMP "2A"
FUEL POOL EMERGENCY M/U PUMP "2B"
HPCS DSL. GEN. COOLING WATER PUMP "2A"
FUEL POOL EMERGENCY M/U PUMP "2A"
DSL GEN COOLING WATER PUMP "OA"
RHR SERVICE WATER PUMP "2B"
RHR SERVICE WATER PUMP "2A"
HS
PI
LO
LC
MO
AUTO BACKWASH
PDIS
D300
F336B
2DG DIF
JG011
ODG DIF
ODG002
F336A
F319
F094
F093
FUEL POOL
RHR CROSS CONNECT (CONTAINMENT FILL)
FT 1B
RHR HX
"2B"
TEW 1B
F068B
"2C"
RHR PUMP SEAL COOLERS
DSL GEN CLR "1A"
S.E. CUBICLE
(AREA COOLERS)
S.W. CUBICLE
HPCS DSL GEN CLR
LPCS PMP MTR CLR
N.E. CUBICLE
N.W. CUBICLE
DSL GEN CLR "OA"
UNIT 1
RHR PUMP SEAL COOLER
"2A"
FT 2A
REWT 2A
TEW 2A
F068A
TO LAKE
UNIT / DIV. 2 DISCHARGE
UNIT / DIV. 3 DISCHARGE
UNIT / DIV. 1 DISCHARGE
Av 1



B.X.2

DIVISION I CSCS

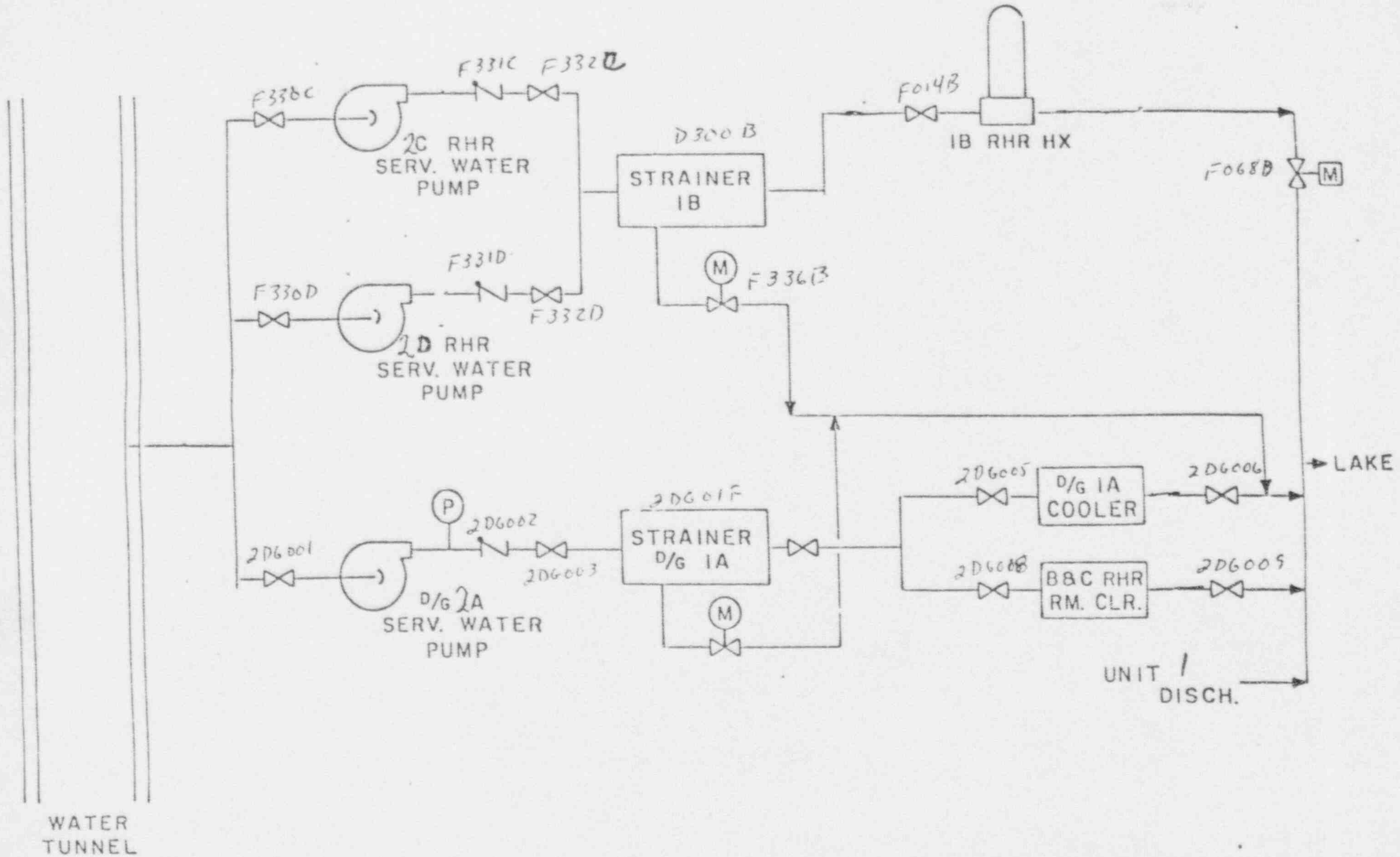
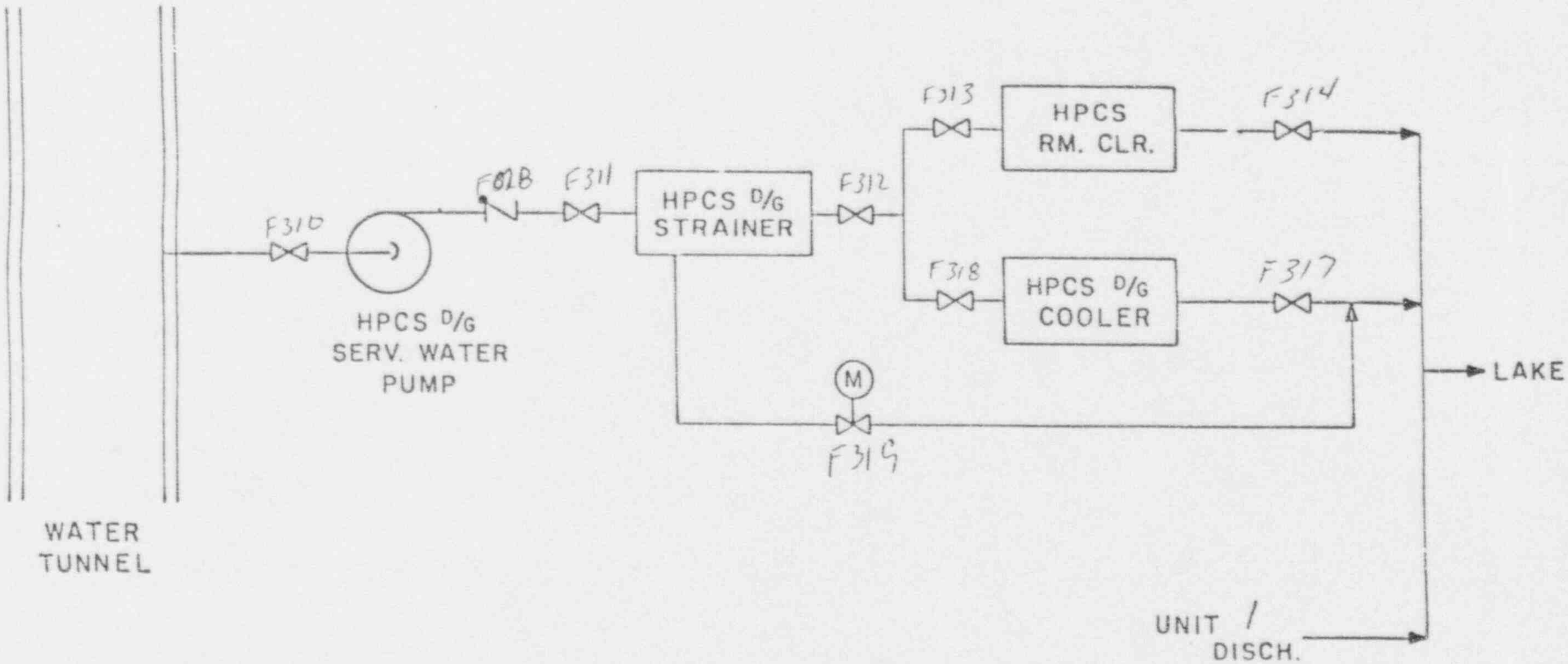


Figure B.X.3 Division 2 CSCS



DIVISION 3 CSCS

9.0 AIR SUPPORT SYSTEMS

9.1 Instrument Air

9.1.1 System Function

The purpose of the Instrument Air System (IAS) is to provide a compressed supply of instrument quality air for air operated control devices and instruments outside the drywell.

9.1.2 System Description

9.1.2.1 General Design

The instrument and service air headers are supplied by three station air compressors connected in parallel, each with its own intake filter/silencer and aftercooler. There are three trains of receivers and filter-dryer units, one train for each compressor. They filter and dry the compressed air that will be supplied to the IA and SA loop headers. Two of the station compressors normally supply all compressed air requirements throughout the plant, with the third compressor as a backup. The running compressors are alternated on a regular basis to ensure equal service. Figure 9.1-1 shows the system mechanical arrangement.

<u>Component Description</u>

Station Air Compressor

Each station air compressor is a four stage centrifugal compressor with independently driven impellers. All air flow is internal and each stage discharges to separate coolers, providing both intercooling and aftercooling. The air flow leaving each cooler is directed through a moisture separator which removes water and oil droplets prior to being routed to the next stage. Each compressor may be operated in either the Modulate, Modulate + 2 Step, or Unload mode of control which is selected by the operator in the control room. Two compressors normally supply all compressed air requirements for pneumatic valves, instruments, and controls throughout the plant, with the third compressor as standby. Each compressor develops a discharge pressure of 115 psig and has a capacity of 1750 scfm. The compressors are located near the center of the turbine building at elevation 710'-6".

<u>Air Receivers</u>

The air receivers in the Instrument Air and Service Air System serve two functions: (1) to absorb compressor output surges, and (2) to provide a storage volume of compressed air should a loss of ac power occur. There are three plant air receivers of 200 cubic foot capacity each, two instrument air receivers of 200 cubic foot capacity each, and two service air receivers of 150 cubic foot capacity each.

Air Filter-Dryer Units

Prefilters

The prefilter is a disposable cartridge type filter. Its function is to separate oil, water and dust particles from the compressed air before the air is sent to the air dryers.

Air Dryers

The air dryer is a heatless unit utilizing desiccant to remove moisture from the compressed air leaving the pre-filter. There are two drying towers per dryer unit one in service while the other is being reactivated. The reactivation of the desiccant is accomplished by purging the tower with dry air. The drying tower and the tower being reactivated automatically shifts modes of operation every five minutes therefore, on a ten minute cycle, each tower has dried air for five minutes. On a loss of ac control power to the air dryer, reactivation stops and both towers automatically line-up to dry the compressed air entering the dryer. The desiccant has the capacity of drying the compressed air for a period of four hours without requiring reactivation.

After Filters

The after filter is similar in construction to the pre-filter. The disposable cartridges are rated to remove 98% of all particles 0.07 microns and larger and are enclosed in a vessel assembly mounted vertically above the pre-filters on the air dryer bedplate.

9.1.2.2 System Interfaces

The results of an FMEA analysis are presented in Table 9.1.1.

Electrical

Each of the IA compressors are supplied by different 4.16 kV switch gear. Compressors 0SA01C and 1SA01C receive power from unit one buses, SWGR 142X and 141X respectively compressor 2SA01C receives power from unit two bus, SWGR 241X.

Component Cooling

The turbine building closed cooling water system provides cooling water for the service air compressors. Compressor 2SA01C and its intercoolers, aftercoolers and lube oil coolers are supplied by unit 2 TBCCW. Compressors 0SA01C and 1SA01C and their coolers are supplied by unit 1 TBCCW.

9.1.2.3 Instrumentation and Control

System Actuation

The IAS compressor 2SA01C is manually actuated from main control room panel 2PM03J. The other compressors are actuated from the unit one control room or locally.

The station air compressors are provided with auto trip for low lube oil pressure, high discharge air temperature, hi/low lube oil temperature and overcurrent/neutral overcurrent.

9.1.2.4 Test and Maintenance

The IAS is normally in operation, inspection of equipment is made and system performance verified periodically and after maintenance.

9.1.2.5 Technical Specification

The IAS is normally in operation , thus no technical specifications are addressed for this system.

9.1.3 System Operation

Two compressors normally supply all compressed air requirements, while the third one is in standby and are rotated on a regular base. Each compressor develops a discharge pressure of 115 psig. Should a loss of ac power occur, the receivers would supply air to the supply header from both directions for two or three minutes for either unit, but not for both.

9.1.4 System Fault Tree

9.1.4.1 Fault Tree Description

A simplified diagram used in fault tree modeling in shown in Figure 9.1-2. This is one top event in the fault tree which represents failure to supply air to the supply ring. All interface segments to specific components are developed in their respective fault trees. The components supplied by instrument air which are modeled in other fault trees are:

1) MSIV's (outboard) 2B21-F028A,B,C,D.

2) Feedwater control valve 2FW005.

3) Emergency makeup 2CD023 and overflow 2CD015 to condensate tank

9.1.4.2 Success/Failure Criteria

The success criteria of IAS is the adequate supply of instrument air pressure to the component in question, by two IA compressors and two dryers. The top event is: "Failure of IAS system to provide air with 2-OF-3 MDC and 2-OF-3 IAD.

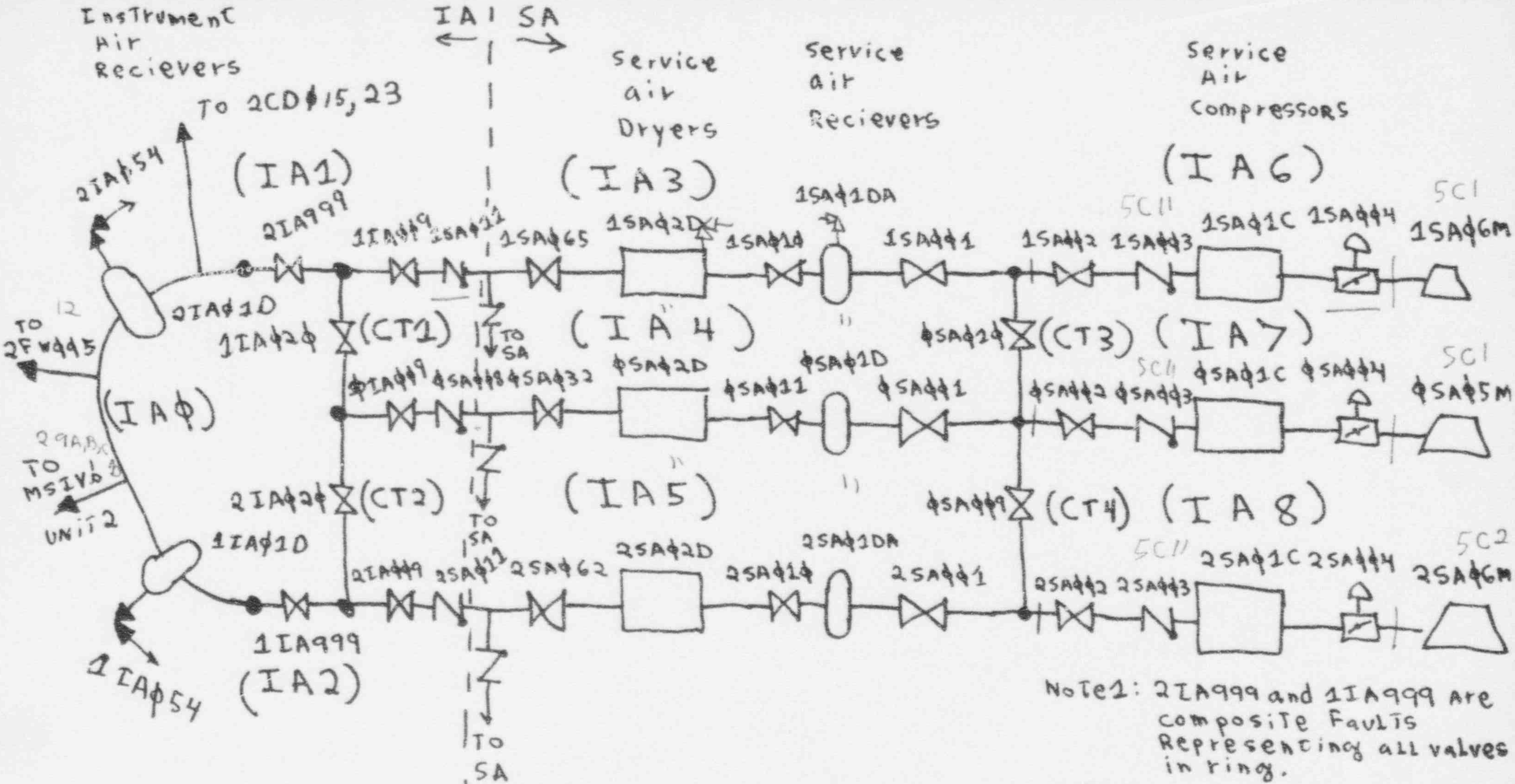
9.1.4.3 Assumptions

1) Failure of IA compressors by auto-trip for over-current/neutral current was not explicitly modeled.

2) While the IAS is formed as a double loop for the whole plant the model considered only one loop with one common header to supply all the components. It was felt that the increased complexity that would be introduced would not lead to any significant events since there are only normally open manual valves in the system and at least two flow paths to each component supplied. Only failures of the relief valves, air receivers and a general event representing sufficient leakage anywhere in the ring or in side lines are modeled

3) Since IAS is normally in operation with two of three compressors running, an additional conditional event EE-MDC-IAS-XX-R is added in each combination pair of compressors with a probability of one third.

4) No explicit maintenance is modeled for the operating IAS compressors, all maintenance is lumped onto the standby compressor and will be treated as part of the recovery analysis. It increases the probability of non-recovery.



Note1: 2IA999 and 1IA999 are composite Faults Representing all valves in ring.

Note2: on Fault Tree
IA → IAS
SA → IAS
in identifiers-
IA3 and IA6 = TRAIN A
IA4 and IA7 = TRAIN C
IA5 and IA8 = TRAIN B

FIGURE B.X-2 Simplified Diagram Used in Fault Tree Model of Instrument Air

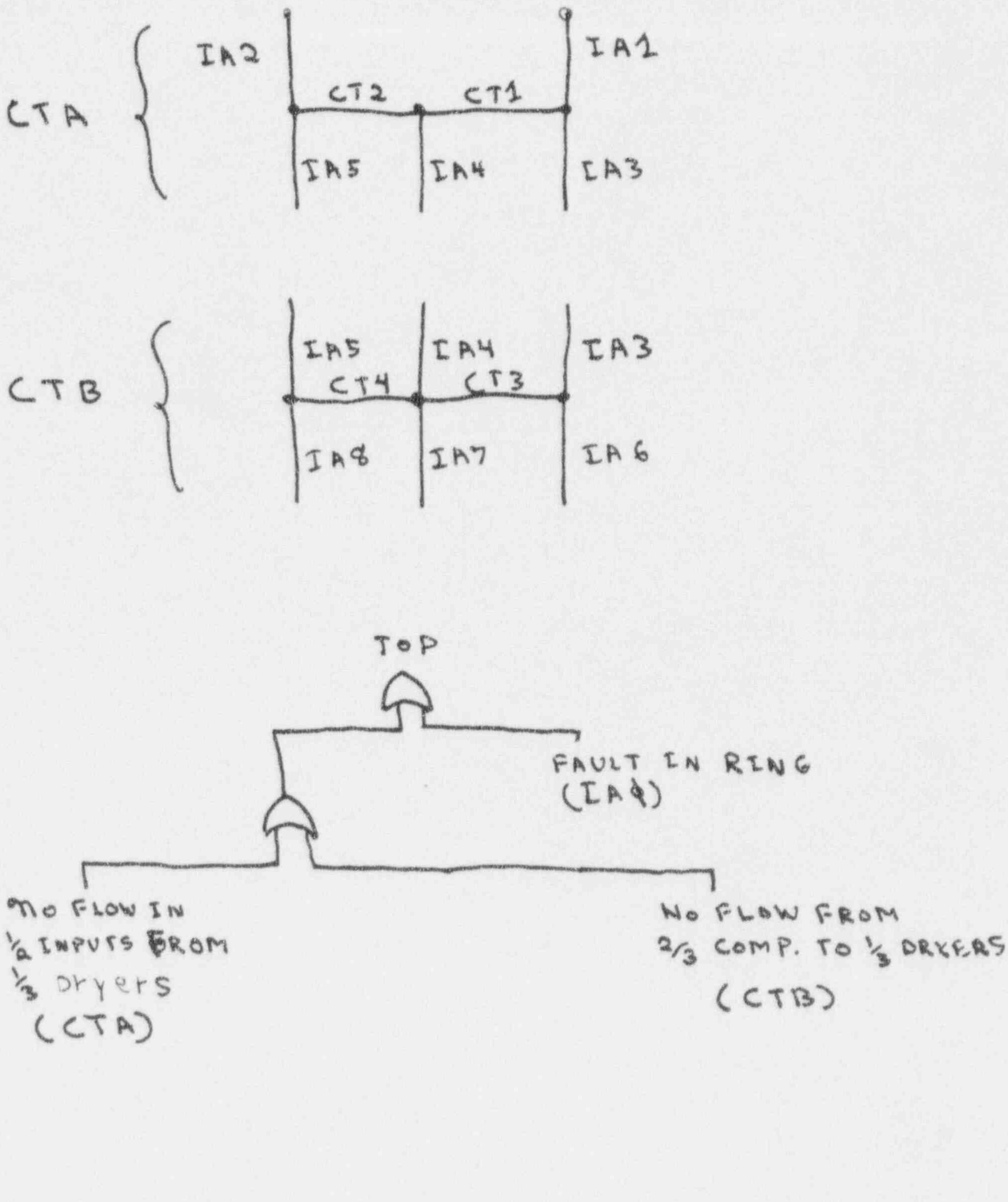


Figure B.X.-3 TOP LOGIC OF IA TREE

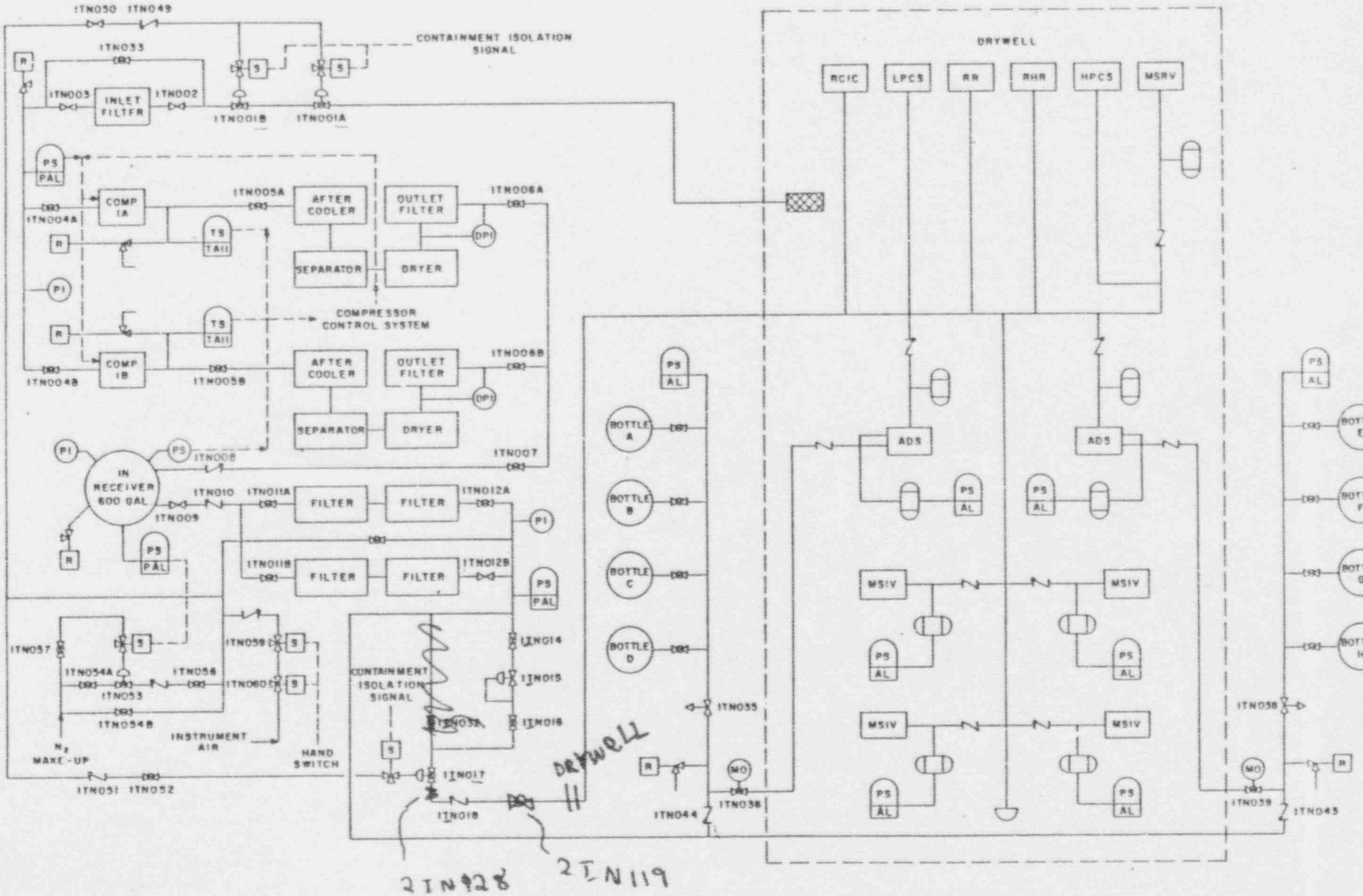


FIGURE 6B-8 DRYWELL PNEUMATIC SYSTEM

9.2 Drywell Pneumatic

9.2.1 System Function

The purpose of the Drywell Pneumatic System (DPS) is to provide a compressed supply of instrument quality gas to the pneumatic operated valves within the primary containment during normal and abnormal operating conditions.

9.2.2 System Description

9.2.2.1 General Design

The Drywell Pneumatic System consists of two compressors, each of them designed for full capacity with the second compressor utilized as a backup. The DPS also has two trains of dryers and filters, and one receiver. The Drywell Pneumatic System takes its supply from the atmosphere of the containment and returns it to the containment to the valve operators. The essential equipment supplied by the Drywell Pneumatic System are the ADS safety-relief valves, and the inboard MSIVs valves. Figure 9.2.-1 shows the mechanical arrangement of the Drywell Pneumatic System.

Flow Path

The DPS compressor takes suction from inside the drywell. The gas passes through one of two parallel pre-filters (one filter acts as a standby) and enters the compressor suction. The compressor increases the gas pressure and discharges to the dryer arrangement, and enters the DPS receiver. The gas leaving the receiver enters the DPS filters prior to discharging to the DPS supply headers. The supply line tapping off the headers before the reducer is directed to the ADS valves and accumulators. In order to supplement the compressed gas supply to the ADS accumulators, two sets of four DPS bottles tap into the DPS headers just before they penetrate the containment. The compressed gas passing through the reducer (regulated to 100 psig) passes through containment isolation valves and enters the drywell. The regulated header supplies the inboard MSIVs, as well as, RCIC, RR, RHR, LPCS and HPCS.

Component Description

Compressors

The DPS compressor is a two stage reciprocating compressor with non-lubricated carbon rings. Each compressor (two per unit) has a rated capacity of 80 scfm at a discharge pressure of 175 psig.

The compressor is controlled by system pressure as monitored at the IN receiver. Each compressor is designed for full capacity with the second compressor utilized as a backup. The compressors cycle as required to keep pace with system demand.

DPS Distribution

The distribution of the DPS gas is via one of two paths, a regulated header and an unregulated header. The regulated header is maintained between 90-100 psig and supplies all the system requirements with the exception of ADS. ADS is supplied an unregulated gas pressure from the receiver between 165 to 175 psi. The gas supplied to ADS is backed up by the DPS bottles.

DPS Bottles

Eight bottles are used to supplement the DPS system when ADS accumulator pressure drops below 160 psig. These have a capacity of 275 SCF per bottle. The bottles are used only when normal operation of the DPS system is incapable of meeting the ADS valve accumulator pressure requirements.

DPS Emergency Pressurization Station

Pipe connections are located in the Auxiliary Bldg-731' elevation - east of the Aux. Elect. Equipment Room. These connections allow pneumatic pressure to be supplied to the ADS accumulators via the IN bottle banks.

DPS Aftercooler

There are two coolers, located downstream of their respective compressor. The coolers are used to cool the air exiting the compressors prior to drying. Their normal capacity is 80 scfm.

DPS Dryers

There are two desiccant type dryers for each compressor. Normally one dryer will be in service for each operating compressor and the other will be regenerating. Dryer operation is automatic and each has a capacity of 90 scfm.

DPS Outlet Filters

There are two after filters, one for each compressor. The after filters are rated for 1-micron particles.

DPS Gas Receiver

The receiver has a capacity of 600 gallons and its design pressure is 200 psig. The IN gas receiver acts as a storage volume and also serves to suppress compressor surges on the system. There are two filter units, consisting of two filters in series per unit, that filter the gas leaving the receiver to the loads.

9.2.2.2 System Interfaces

Electrical

The plant electrical distribution system provides power to the Drywell Pneumatic System for operation of the two compressors, 2IN01CA supplied by 480 V MCC 233-2, and compressor 2IN01CB supplied by 480 V MCC 234X-2.

System Actuation

The reactor building closed cooling water system, supplies cooling water for the DPS system aftercoolers, 2IN04AA and 2IN04AB.

The results of an FMEA analysis are presented in Table 9.2.1.

9.2.2.3 Instrumentation and Control

System Actuation

The DPS compressors are manually actuated from panel 2IN01CA. The running compressor is controlled by system pressure as monitored at DPS receiver, pressure sensor 2PS-IN0001. The standby compressor is auto-started on low pressure (162.5 psig), if the running compressor fails or is insufficient to maintain pressure. The DPS compressors are also provided with auto-trips in low lube oil pressure, high discharge gas temperature, and hi/low suction pressure.

The PCIS (Group II) closes valves, IN001A, IN001B, and IN017, on low-low-low water level (L1) or high drywell pressure.

9.2.2.4 Test and Maintenance

The DPS is normally in operation, inspection of equipment is made and system performance verified periodically and after maintenance.

9.2.2.5 Technical Specification

Since only portions of the DPS are safety related, surveillance requirements are addressed only for the isolation valves, as part of PCIS, and for the nitrogen bottles.

9.2.3 System Operation

The DPS is designed to supply compressed gas to operate valves in the drywell during normal and abnormal conditions.

9.2.4 System Fault Tree

9.2.4.1 Fault Tree Description

The fault tree has three top events which represent the pneumatic supply to the two ADS trains and the inboard MSIV's. The model for the ADS valves includes the compressors, air receiver, and nitrogen bottle reserve air supply and stops just before valves 2IN100 and 2INI01 which are modeled in the ADS fault tree. The MSIV supply also includes the compressors and air receiver and the branch line with the reducing valve (2IN015). The MSIVs and their accumulators are modeled in the PCS fault tree.

9.2.4.2 Success/Failure Criteria

The essential components supplied by Drywell Pneumatic System are the inboard MSIVs and ADS safety/relief valves. Thus a partial failure of the DPS can occur if a flow path to a particular component is not available, yet other components are being adequately supplied. The success criteria for the inboard MSIVs header requires, successful operation of the DPS compressor, at least one filter train, and the supply path to the header is available. The success criteria for the ADS safety-relief valves requires successful supply of instrument gas either by DPS compressor or by the nitrogen bottle bank.

The three top events are:

1) "Failure of DPS syst to provide air with 1-of-2E MDC and 1-of-2D DAD". This is event DPS1-1OF2E-1OF2D and supplies the inboard MSIVs.

2) "Failure of DPS syst to provide air with 1-of-2E MDC and 1-of-2D DAD". This is event DPS6-1OF2E-1OF2D and supplies ADS valves R,E,U,C.

3) "Failure of DPS syst to provide air with 1-of-2E MDC and 1-of-2D DAD". This is event DPSA-1OF2E-1OF2D and supplies ADS valves D,S,F.

9.2.4.3 Assumptions

In the fault tree analysis of the Drywell Pneumatic System the following assumptions were made.

1) Failure of the DPS compressor by auto-trip, (low lube oil pressure, high discharge gas temperature and Hi/Low suction pressure) was not explicitly modeled.

2) Failure of the aftercooler by failure of the cooling system (RBCCS) was not considered given t [illegible] here is no trip system at this point.

3) Isolation valves are assumed to fail by actual PCIS isolation signals or by spurious actuation.

4) Since DPS is normally in operation with one of two compressors, an additional conditional event EE-MDC-DPS- X-RV is added with a probability of one half to turn on each compressor 50 percent of the time.

5) No explicit maintenances are modeled for the running DPS compressors. Maintenance will be treated in the recovery analysis where it will be added to the non recovery probability for starting the standby pump.

Table 9.2.1 Drywell Pneumatic (DPS) Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Ef (Sub) System System Funct
480V SWGR 236X-2	2IN001A 2IN017 2IN031 2IN074	NV " " "	Fails closed " " "	CR indicating light c/o CR Power Supply alarm 1/2 scram	Loss of the ability to recharge air receiver and/or accumulators for MSIVs and SRVs	Complete iso Pneumatic su and result i in less than
	2IN100 2IN101	" "	Fails open "		No effect	No effect
480V SWGR 235X-2	2IN001B 2IN075	NV "	Fails closed "	CR indicating light c/o CR power supply alarm 1/2 scram	Loss of the ability to recharge air receiver and accumulators for MSIVs and SRVs	Complete iso Pneumatic su DPS system, MSIVs closin
	2IN100 2IN101	" "	Fails closed "		No effect	No effect
480V SWGR 235X-2	2IN001B 2IN075	NV "	" "	CR indicating light c/o CR power supply alarm 1/2 scram	Loss of the ability to recharge air receiver and accumulators for MSIVs and SRVS	Complete iso Pneumatic su DPS system, MSIVs closin minutes
480V SWGR	2IN059	NV	Fails closed	CR power supply	No direct effect, isolates IA	No direct eff

Table 9.2.1 Drywell Pneumatic (DPS) Support Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Ef (Sub) System System Funct
480V SWGR 233-2	2IN0ICA 2IN03DA	MDC DAD	Fails to run Fails to operate	CR indicator light out CR power supply alarm	Loss of the ability to recharge air receiver and accumulators for MSIVs SRVs	Complete loss pneumatic sup operating gra and low press of standby tr
480V SWGR 234X-2	2IN0ICB 2IN03DB	MDC DAD	Fails to run Fails to operate	"	"	"

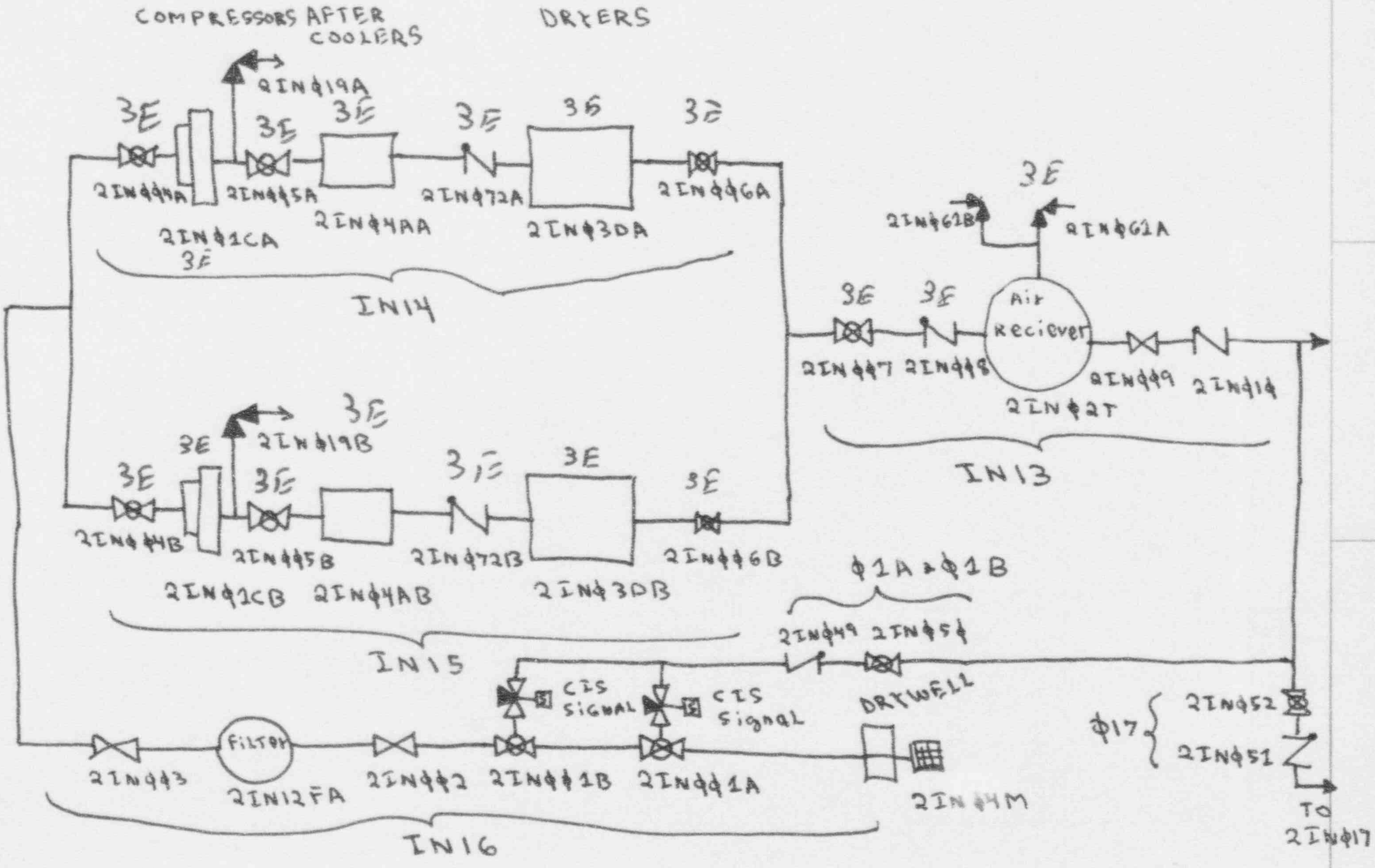


Figure B.X-2a DRYWELL Pneumatic System Simplified Diagram For Fault Tree Modeling

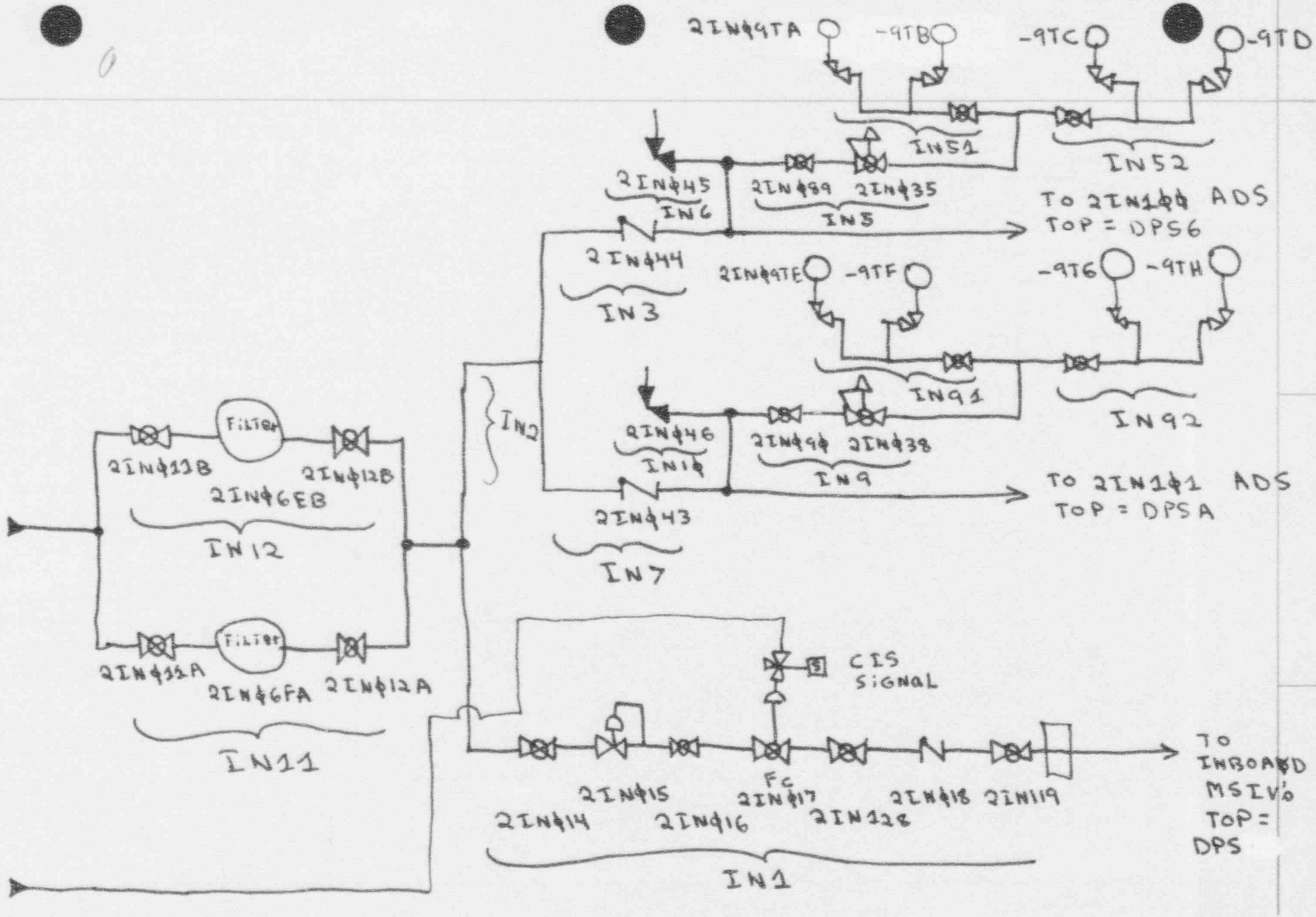


Figure B.X-2b DRYWELL Pneumatic System Simplified Diagram For Fault Tree Modeling

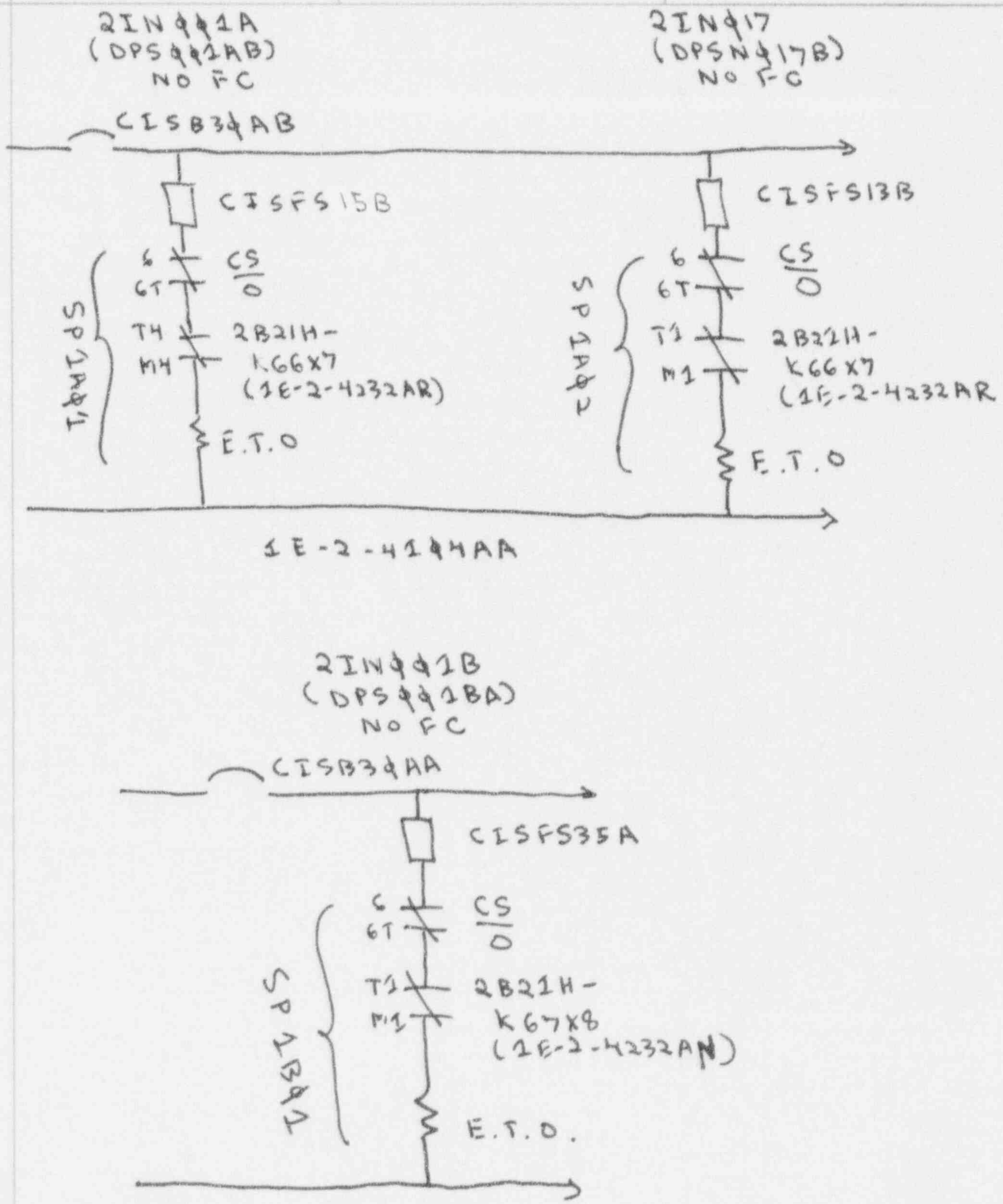


Figure B.X - 3 Valve Control Circuits

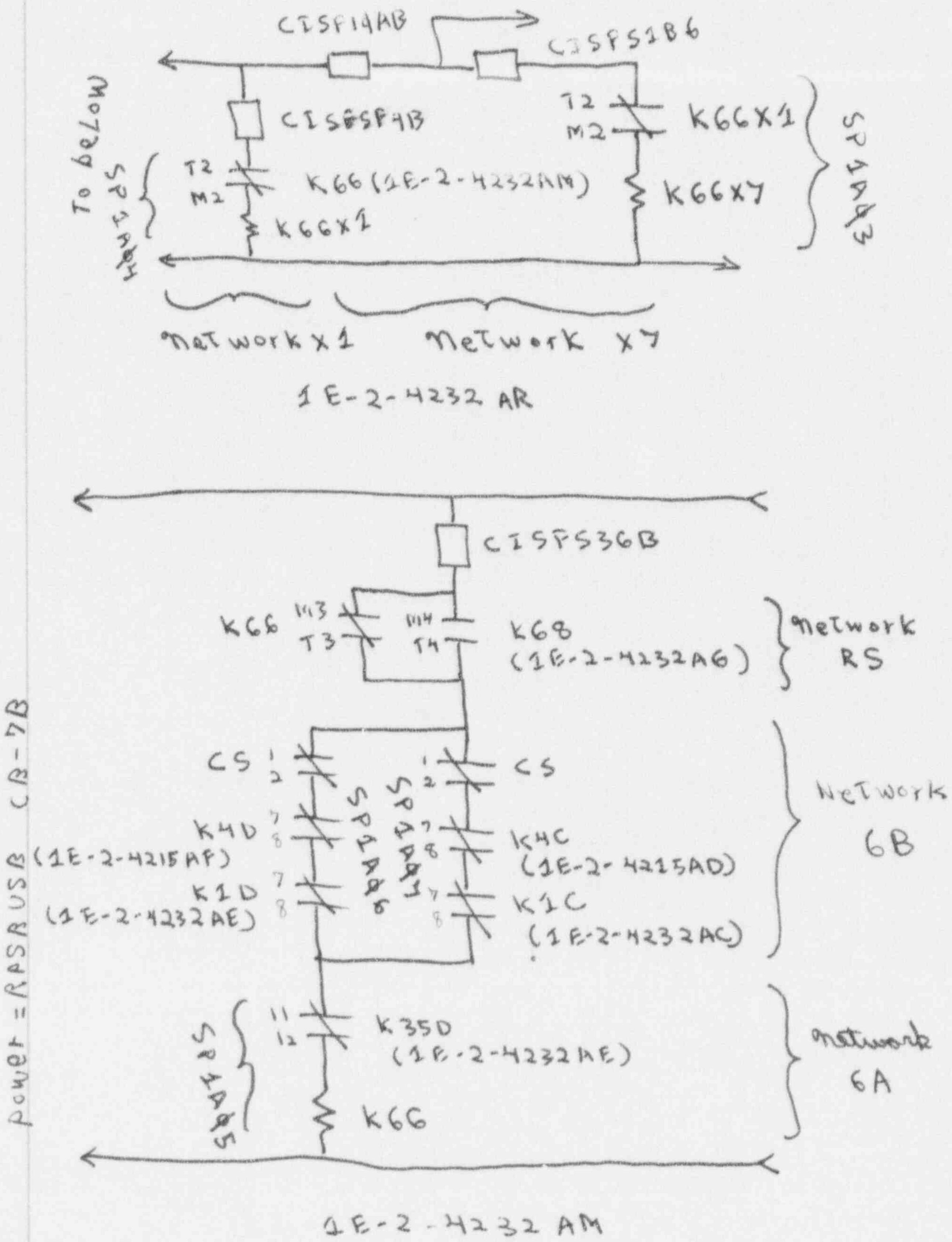
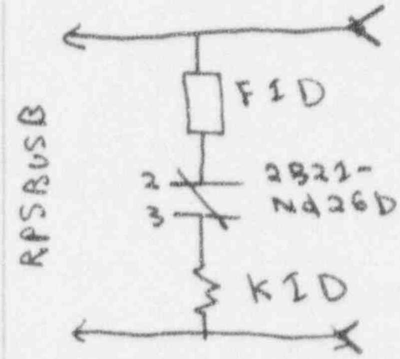
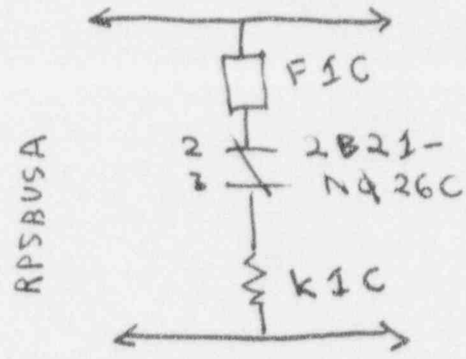


Figure B.X-4a Isolation Logic Inboard

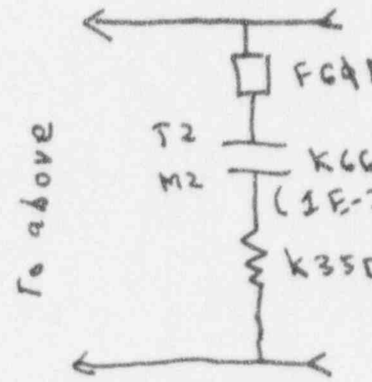


1E-2-4232AE
(Modeled in PCS)

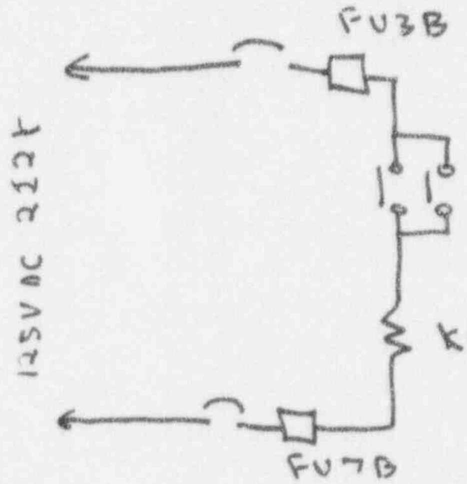


1E-2-4232AC
(Modeled in PCS)

water Level SW - opens on Low-Low Level (LVL2) (will be changed To LVL1)

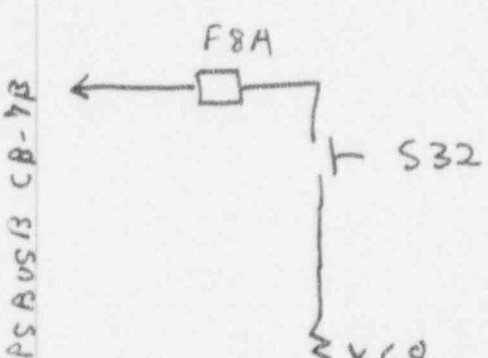


1E-2-4232AE
(Modeled in PCS)

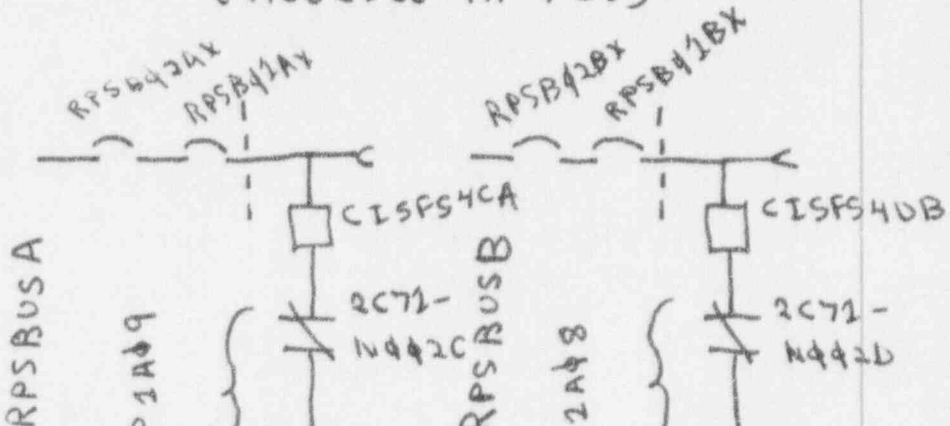


Manual Isolation

1E-2-4232AT
(Modeled in PCS)



1E-2-4232AG
Manual Reset
(NOT Modeled)



1E-2-4215AD
Network 4C

1E-2-4215AF
Network 4D

OPENS ON High Drywell Pressure

Figure B.X-4 b Isolation Logic Inboard

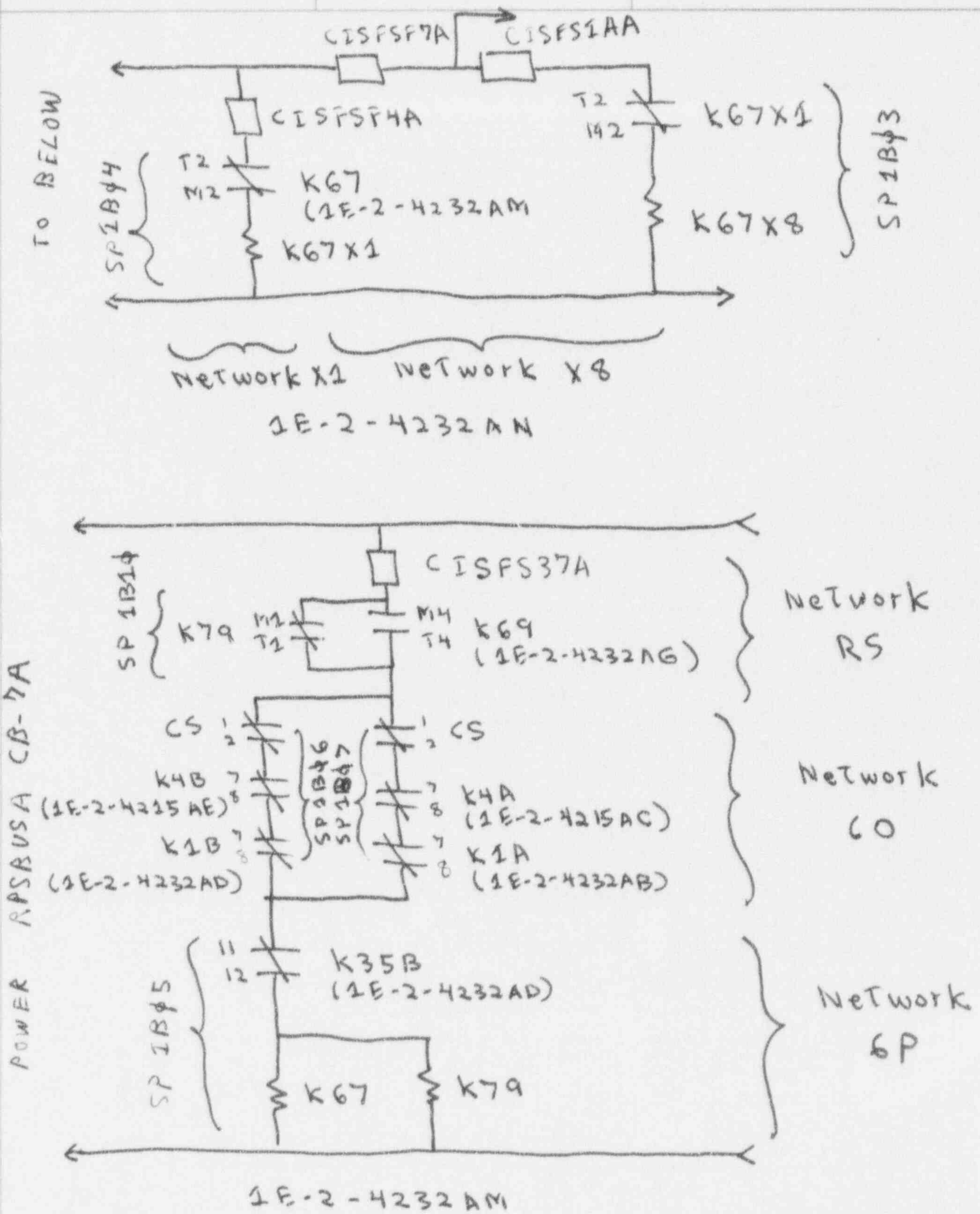


Figure B.X-5a Isolation Logic Outboard

10.0 EQUIPMENT AREA COOLING SYSTEMS

10.1. ECCS Equipment Areas Cooling System

10.1.1 System Function

The system removes equipment heat from emergency core cooling system (ECCS) cubicles whenever the ECCS equipment is required for service. Each of the cubicle cooling subsystems is capable of dissipating the heat produced by the operation of corresponding ECCS equipment and limiting the inside temperature to a maximum of approximately 148F after a design - basis accident.

This system does not operate during normal plant operation. During normal operation, the reactor building ventilation system provided the ventilation required to keep cubicle temperatures below 104F.

10.1.2 System Description

10.1.2.1 General Design

The ECCS Equipment Areas Cooling System (ECCS-EACS) consists of six independent fan/air coil cooling units built up in a housing. Air supply ducts are provided for air distribution in each cubicle. The air circulated through each cubicle is cooled by its respective fan-coil unit. Four ECCS pump cubicles are each cooled by a fan-coil unit as are the two RHR Service Water pump cubicles. However, cubicle cooling is not considered an essential support system for the RHR Service Water pumps so the fan-coil units for those cubicles have not been modeled. The four pump cubicles requiring ECCS Equipment Areas Cooling are: the Northwest Cubicle (RHR pump A), the Southwest Cubicle (HPCS pump), the Southeast Cubicle (RHR pumps B and C), and the Northeast Cubicle (LPCS pump and RCIC pump).

Loss of an ECCS-EACS subsystem does not necessarily preclude operation of the ECCS equipment in the cubicle it serves.

Detailed one-line diagrams of the four ECCS-EACS are shown in Figure 10.1-1.

Flow Path

Each ECCS-EACS subsystem circulates reactor building air in a closed loop through its associated pump cubicle during abnormal station conditions. The fan in each fan-coil unit is electrically interlocked with respective ECCS equipment operations. However, the flow of cooling water in each air-cooling coil is maintained at all times.

There are no air dampers in the ECCS-EACS subsystems modeled.

During normal station operation, the reactor building ventilation system purges a small quantity of ventilation air through each ECCS equipment cubicles.

Locations

The ECCS-EACS fan-coil units are located in the upper reactor building basement level of their respective pump cubicle corners (NE, NW, SE and SW corners).

Component Description

The RHR pump A (NW cubicle) and the HPCS pump (SW cubicle) cooling fans (2VY01C and 2VY02C) are each direct drive, vane axial fans. Each operates at a capacity of 18,000 cfm and total pressure of 4.0 inches of water. The fans are air-cooled and served by the same divisional power supply serving the equipment being cooled. The fans are normally in standby and are started automatically when the respective ECCS pumps start. The fans can also be manually started at local panels.

The RHR pumps B and C (SE cubicle) cooling fans (2VY03C) is a van axial, direct drive fan with a capacity of 26,400 cfm and a total pressure of 4.0 inches water. The fan motor is air cooled and is powered by MCC 236Y-1, which also supplied the RHR B and C pumps. The fans starts automatically with its associated ECCS equipment or may be manually started at a local panel.

The LPCI/RCIC pumps (NE cubicle) cooling fan is also a vane axial, direct drive fan. It has 28,500 cfm capacity at a total pressure of 4 inches water. The fan motor is air cooled and is powered by MCC 235Y-2, which also supplied the LPCS pumps. The fans starts automatically with the LPCS pump or may be manually started locally.

The NW and SW cubicles cooling coils (2VY01A and 2VY02C) are water cooled with water continually supplied by the ECCS equipment cooling water system. The coils each handle 150 gpm flow and have a cooling capacity of 748, 700 Btu/hr.

The SE cubicle cooling coil (2VY03C) handles 220 gpm from the same source and has a cooling capacity of 1.0 x 10$ST6$SP Btu/hr.

The NE cubicle cooling coil (2VY04A) is similarly water cooled with a water flow rate of 240 gpm and a cooling capacity of 1.19 x 10$ST6$SP Btu/hr.

10.1.2.2 System Interfaces

A failure modes and effect analysis (FMEA) of ECCS-EACS support system interfaces is shown in Table 10.1.1. The support system interfaces are discussed below.

Shared Components

The ECCS-EACS contains no components which are shared by other safety systems.

Electrical

Each fan-coil unit in the four ECCS-EACS subsystems modeled is powered by the same divisional power supply that powers the ECCS equipment it cools.

The RHR pump A and the LPCS/RCIC cubicle cooling fans are powered by the 480Vac MCC 235Y-2 off 4160V bus 241Y. The [illegible] pumps B and C cubicle cooling fan is powered by the 480Vac MCC 236Y-1 off bus 242Y. The HPCS pump cubicle cooling fan is powered by the 480Vac MCC 243-1 off the 243 bus.

Actuation

Electrical power for actuation of the fans is provided by a 480 V/120Vac transformer off the MCC power lines to each fan. The air-cooling coils require no electrical actuation.

Control

Control power for the fans is obtained through the 480V/120Vac transformers off the MCCS powering them.

Component Cooling

The CSCS Equipment Cooling Water System, Divisions 1, 2, and 3 supply the cooling water to the air-cooling coils of the ECCS-EACS. Division 1 supplies water to the RHR pump A and LPCS/RCIC cubicle coils. Division 2 supplies the cooling water to the RHR pump B cubicle coil while Division 3 supplies the HPCS pump cubicle coil.

Room Cooling

The ECCS-EACS fans motors are air cooled, and the fan-coil units themselves provide the room cooling.

10.1.2.3 Instrumentation and Control

System Actuation

CSCS cooling water flows through the air-cooling coils at all times and is not modulated.

Each ECCS-EACS fan is controlled by a three-position (STOP-AUTO-START) switch with a spring return to AUTO.

The RHR pump A (NW Cubicle) vent fan is controlled at panel 2PL34J by handswitch 2HS-VY001. In Auto, this fan is started when DG-0 starts its loading sequence or the DG-0 breaker 2413 opens and RHR pump A starts.

The HPCS pump (SW cubicle) vent fan is controlled at panel 2PL32J by handswitch 2HS-VY002. In AUTO this fan starts once the HPCS pump starts.

The RHR pumps B and C (SE cubicle) fan is controlled by handswitch 2HS-VY003 at the 2PL33J panel. In AUTO if cubicle temperature is less than 108F, this fan starts if DG-2A begins its loading sequences or B of C RHR pumps start and ACB 2423 opens.

The LPCS/RCIC pumps (NE cubicle) vent fan is controlled at 2PL35J panel by handswitch 2HS-VY004. In AUTO, provided cubicle temperature is less than 108F, the vent fan will start if DG-0 starts its loading sequence of the LPCI or RCIC pumps starts and ACB 2413 opens.

The fan-coil units can be operated manually, but the auto start signal from the operation of ECCS equipment overrides the manual switch.

A success-oriented logic diagram for actuation of one of the ECCS-EACS fan is shown in Figure 10.1-2.

Component Control

The actuation of the ECCS-EACS fans is described above. Once started the fans operate at full capacity until they are automatically shutdown.

The RHR pump A cubicle fan is automatically stopped when the following actions occur simultaneously: DG-0 stops its loading sequence, RHR pump A cubicle temperature drops below 104F, and RHR pump A stops.

The HPCS pumps cubicle fan stops automatically once the HPCS pump stops AND the cubicle room temperature drops less than 104F.

The RHR pumps B and C vent fan auto stops if DG-2A stops its loading sequence AND B and C RHR pumps stop, AND RHR B/C pump cubicle temperature drops less than 104F.

The LPCS/RCIC pump cubicle vent fan stops automatically if DG-0 stops its loading sequence AND both the LPCI and RCIC pumps are stopped AND cubicle drops below 104F.

Instrumentation

Fans

All four fans have indicator lights at local indicator panels only. The ESF display and a control room alarm indicate fan trip due overload.

Cooling Coils

There is no instrumentation directly indicating the condition of water flow in the air-cooling coils. Cooling Coil discharge air temperature is indicated in the control room (0-250F).

System Flow

Differential pressure across the cooling coils (0-3 inches water) and the supply fans (0-6 inches water) associated with each ECCS-EACS subsystem is indicated locally.

Room Temperature

Pump cubicle temperature indication (0-300F) is provided in the control room.

Major Alarms

High cubicle temperature alarms (149F) are sounded locally and in the control room.

10.1.2.4 Operator Actions

The initiation of the ECCS-EACS is completely automatic. No operator action is assumed. The primary responsibility of the operator is to verify system operability following an initiation.

10.1.2.5 <u>Technical Specification Limitations</u>

There are no LaSalle Technical Specifications limitations pertaining directly to the ECCS-EACS.

10.1.2.6 Tests

The tests that check the operability of ECCS-EACS components are summarized in Table 10.1.2. The checks actually only verify the fact that the ECCS-EACS fans start automatically when the associated ECCS equipment is started. However, due to the extended period of time that the ECCS pumps operate during the tests, inoperability of, for example, a coiling coil is likely to be indicated by a high cubicle temperature alarm.

No LaSalle Unit 2 tests were found that render an ECCS-EACS subsystem inoperable.

Although it is not a test, daily surveillance verifies that pump cubicle temperatures are within specified limits (50F to 150F).

10.1.2.7 Maintenance

No scheduled maintenance which disables ECCS-EACS components while the plant is at power is planned. Unscheduled maintenance is permitted on system components provided applicable safety controls can be satisfied. Unscheduled maintenance activities expected during plant operation include:

Replacement or repair of actuation and control circuitry.

Electrical maintenance on motor driven components

Mechanical maintenance on the fans and air-cooling coils

A summary of unscheduled maintenance acts allowed on the ECCS Equipment Areas Cooling System while the plant is in full power operation is given in Table 10.1.3. Not included in this table is expected unscheduled maintenance on the feed circuit breaker in the power supply lines for each motor-operated fans.

10.1.3 System Operation

10.1.3.1 Normal Operation

During normal plant operation the ECCS-EACS subsystems are in standby with CSCS cooling water flowing through the air-cooling coils. Ventilation air for the ECCS equipment cubicles is provided by the reactor building ventilations system with exhaust air induced to each cubicle to ensure air circulation and proper pressure differentials between areas of lesser and greater potential contamination.

10.1.3.2 Abnormal Operation

When the ECCS equipment in the four cubicles is actuated the reactor building ventilation system trips off and the associated ECCS-EACS subsystems automatically initiate. The automatic initiation signals override any manual control signal.

The conditions under which each ECCS-EACS subsystem shuts down are given in Section 10.1.2.3.

10.1.4 System Fault Tree

10.1.4.1 Description

Simplified diagrams of the four ECCS-EACS subsystems showing the mechanical components included in the fault tree models are shown in Figure 10.1-3.

The complete ECCS Equipment Areas Cooling System fault trees are included at the end of this appendix.

There are seven developed events in the ECCS-EACS fault trees. Three are transfers from the electric power fault trees - the 480 Vac MCCs 235Y-2, 236Y-1, and 243-1. The remaining four developed events represent cooling water supplied to each of the four coiling coils. These events are developed in the CSCS Equipment Cooling Water System fault tree.

The data for the basic events in the ECCS-EACS fault trees are presented in Table 10.1.4.

10.1.4.2 Success/Failure Criteria

Each of the independent ECCS-EACS subsystems is successful if the associated fan starts and runs at full capacity drawing air through the coiling coil, and the CSCS cooling water to the coil continues to flow as long as the ECCS pump(s) in the cubicle is in operation. An ECCS-EACS subsystem fails if one of the following occurs:

1. One of the CSCS divisions fails to deliver sufficient cooling water (Division 1 fails both the RHR A pump and LPCS/RCIC pump cubicle cooling).

2. The associated normal and emergency power is lost (Division 1 power loss fails both the RHR A pump and LPCS/RCIC pump cubicle cooling).

3. The fan, cooling coil, or actuation fails, ducting ruptures, or the subsystem is out of service due to maintenance outages.

The top events of the ECCS-EACS fault trees look like:

ROOM ROOMRRR COOLING OR VENTILATION SYSTEM FAULTS

where ROOMRRR is one of the four pumps cubicle names.

10.1.4.3 Assumptions

Model Related

In addition to the general assumptions regarding fault tree development (listed at the beginning of the appendix), the following assumptions specific to ECCS-EACS were made:

1. The contribution to cubicle cooling from operation of the Standby Gas Treatment System is negligible and is not modeled.

2. The fan-coil units are connected to the pump cubicles by short segments or ducting. Major ruptures in this ducting are assumed to result in inadequate cooling air flow to the cubicle.

3. The fan associated with an air-cooling coil will be racked out when maintenance is performed on the coil. Failure to restore the circuit breaker after such maintenance may go unnoticed since there are no fan indication lights in the control room.

Quantification Related

To be added.

Table 10.1.1 ECCS Equipment Areas Cooling Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Ef (Sub) System System Funct
4160V <u>BUS 241Y</u> 480Vac MCC235Y-2	2VY01C	Motor-driven fan	FTS/FTR	Fan indicated locally. Room temp. indicated/ alarmed in control room.	Loss of RHR pump A (NW cubicle) cooling	
	2VD04Y	"	"	"	Loss of LPCS/RCIC pump (NE cubicle) coolingg	Fails RHR A cubicle cool
4160V <u>BUS 242Y</u> 480 Vac MCC236Y-1	2VY03C	Motor-driven fan	FTS/FTR	Fan indicated locally. Room temp. indicated/ alarmed in control room.	Lcss of RHR pumps B & C (SE curicle) cooling	Fails RHR B (SE cubicle)
4160V <u>BUS 243</u> 480Vac	2VD02C	Motor-driven fan	FTS/FTR	Fan indicated locally. Room temp indicated/ alarmed in control room	Loss of HPC pump (SW cubicle) cooling	Fails HPCS p (SW cubicle)

Table 10.1.1 ECCS Equipment Areas Cooling System Component/System Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency (Mo)	Te Ou
LOS-RH-Q1	Pump Inservice	2VY01C	Motor-driven fan	No	No	---	
		2VD03C	"	"	"	"	
LOS-LP-Q1	Pump Inservice	2VY04C	"	"	"	"	
LOS-WP-Q1	Pump Inservice	2VY02C	"	"	"	"	

Table 10.1.3 ECCS Equipment Areas Cooling System Unscheduled Maintenance Summary

Component/ Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance with no Auto-Return	Allowed During Plant Operation?	Frequency	Outage
2VY01C, 2VY02C, 2VY03C, 2VY04C	Motor-driven fans	Mechanical/ electrical	Pump circuit breaker	Yes		
2VY01, 2VY02, 2VY03, 2VY04	Air cooling coils	Mechanical	Fan circuit breaker	Yes		

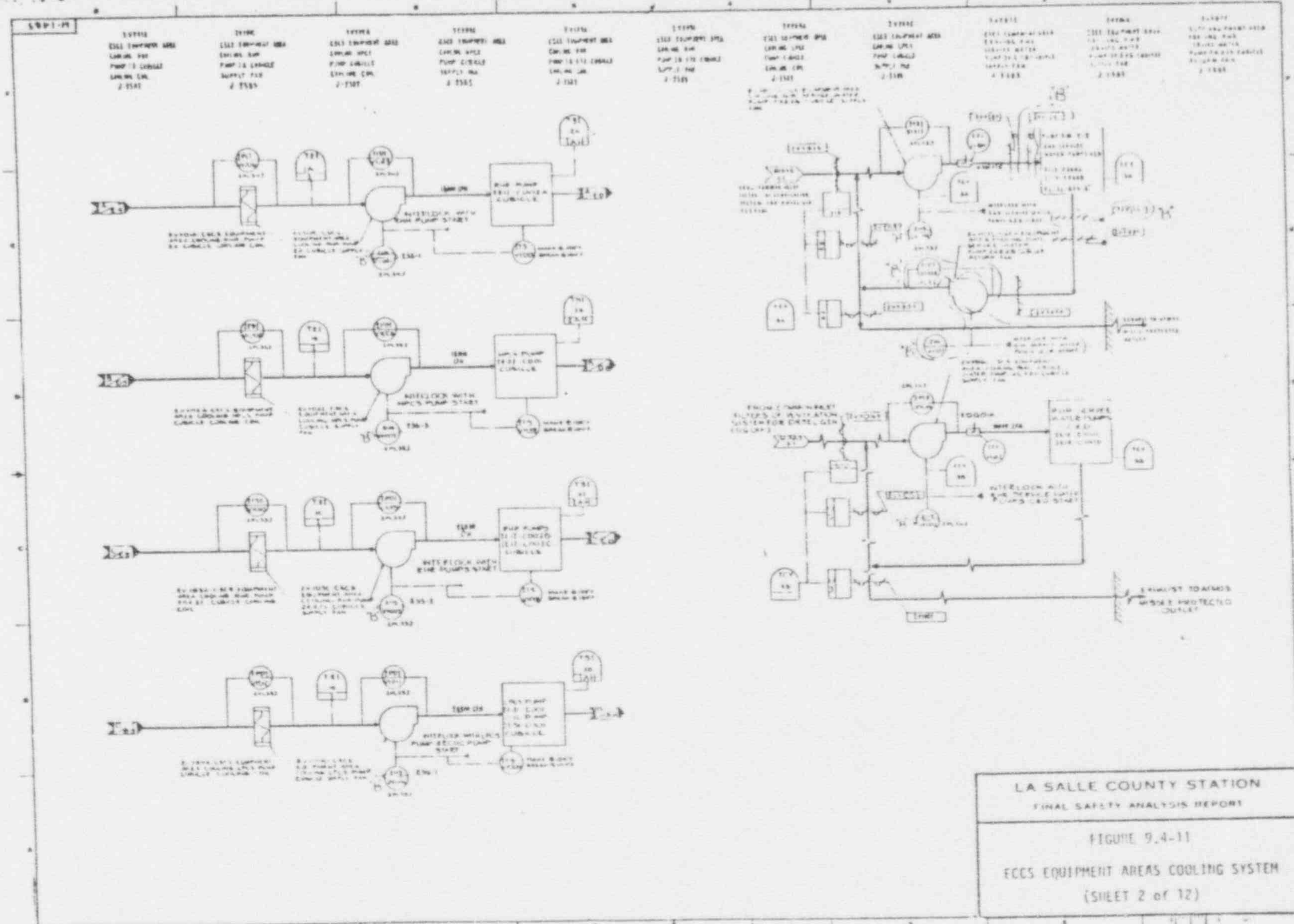


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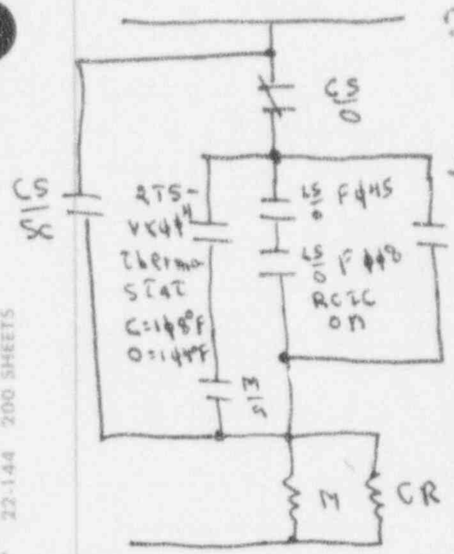
FIGURE 9.4-11

ECCS EQUIPMENT AREAS COOLING SYSTEM
(SHEET 2 of 12)

Figure ~~8.4-1~~ 10.1 ECCS Equipment Areas Cooling System

2VY04C

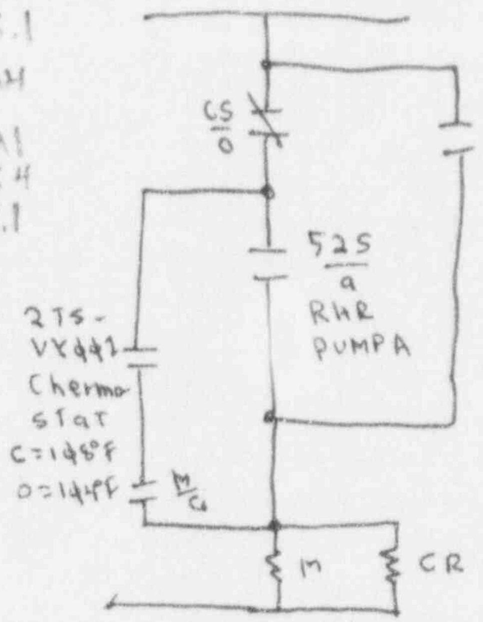


235X-2 - 3G.1
2PL35J - 3H4
FAN - 3H1
2E51-F048 - 3I4
F045 - 3F.1
241X - 4F2

SW
NE

1E-2-4089AB
(LPCS & RCIC)

2VY01C



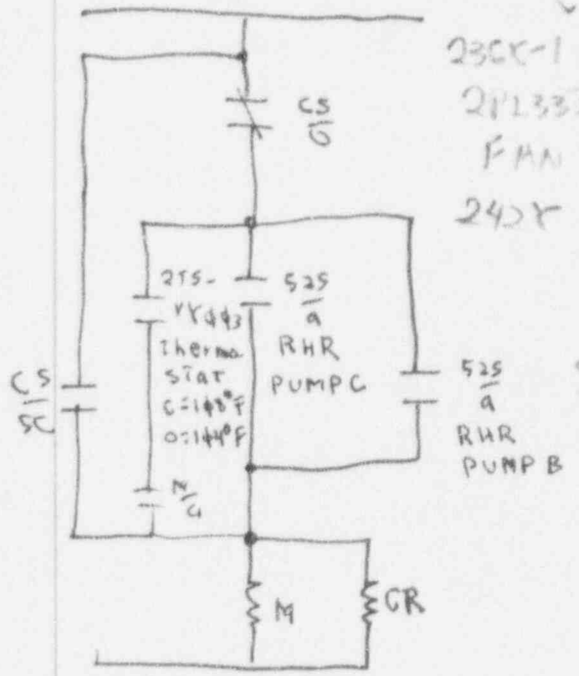
235X-2 - 3G.1
2PL34J - 3H1
FAN - 3H1
241X - 4F2

3H5

NW

1E-2-4089AA
(RHR PUMP A)

2VY03C



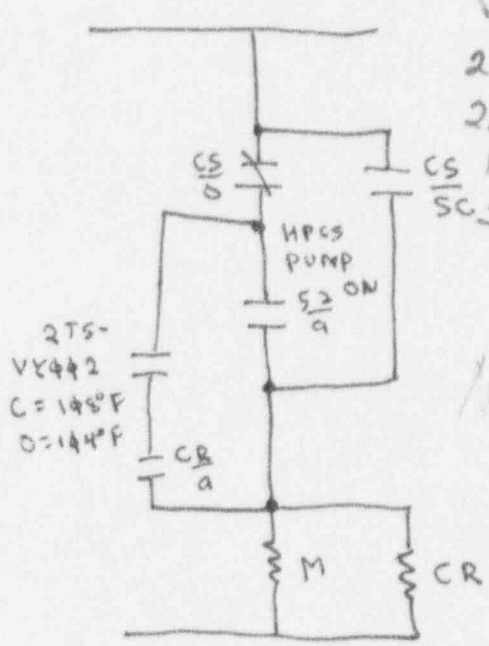
235X-1 - 3G.1
2PL33J - 3H1
FAN - 3H1
242X - 4E4

3H3

SE

1E-2-4089AA
(RHR PUMP B/C)

2VY02C



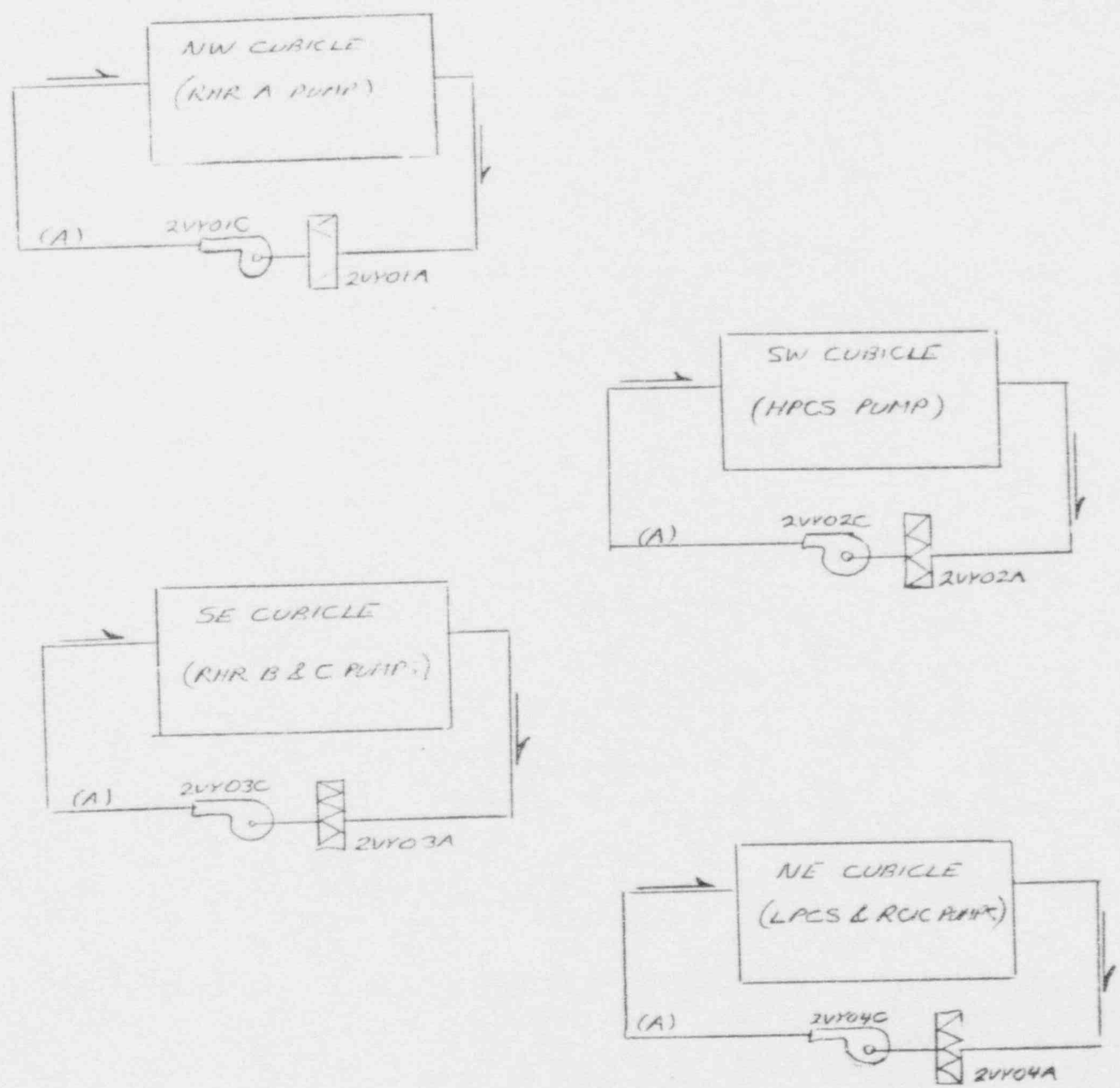
243-1 - 5D2
2PL32J - 3H1
FAN - 3H1
243 - 5D2

3H2

SW

1E-2-4089AA
(HPCS PUMP)

Figure ~~B.X-2~~ 10.1 PUMP ROOM Cooling Fans



10.1
FIGURE B.X-3 ECCS EQUIPMENT AREAS COOLING SYSTEM

Table B.X.1 ECCS Equipment Areas Cooling Systems Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Effect of Support (Sub) System Failure on Overall System Function (Assuming No Recovery)
4160V BUS 241Y 480Vac MCC235Y-2	2VY01C	Motor-driven fan	FTS/FTR	Fan indicated locally. Room temp indicated/ alarmed in control room.	Loss of RHR pump A (NW cubicle) cooling	~~Fails RHR A pump cubicle cooling (NW cubicle)~~
	2VY04C	-	-	-	Loss of LPCS/RCIC pump (NE cubicle) cooling	Fails RHR A pump and LPCS/RCIC pump cubicle cooling (NE, NW cubicles)
4160V BUS 242Y 480 Vac MCC236Y-1	2VY03C	Motor-driven fan	FTS/FTR	Fan indicated locally. Room temp indicated/ alarmed in control room	Loss of RHR pumps B & C (SE cubicle cooling	Fails RHR B & C pump cubicle cooling (SE cubicle)
4160V BUS 243 480Vac MCC243-1	2VY02C	Motor-driven fan	FTS/FTR	Fan indicated locally. Room temp indicated/ alarmed in control room	Loss of HPCS pump (SW cubicle) cooling	Fails HPCS pump cubicle cooling (SW cubicle)

Table B.X.2. ECCS Equipment Areas Cooling System Component/System Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test?	Automatic Return upon Initiation?	Test Frequency (Mo)	Test Outage (Hr)	Component/Subsystem Alignment/Operability Verification Frequency
LOS-RH-Q1	Pump Inservice	2VY01C	Motor-driven fan	No	NO	Quarterly	--	Quarterly
		2VY03C	"	"	"	"	"	"
LOS-LP-Q1	Pump Inservice	2VY04C	"	"	"	"	"	"
LOS-HP-Q1	Pump Inservice	2VY02C	"	"	"	"	"	"

Table B.X.3 ECCS Equipment Areas Cooling System Unscheduled Maintenance Summary

Component/ Subsystem *	Type	Type of Maintenance (1)	Components out of Normal Alignment for Maintenance with no Auto-Return	Allowed During Plant Operation?	Frequency	Outage	Frequency of Alignment/ Operability Verification
2VY01C, 2VY02C, 2VY03C, 2VY04C	Motor-driven fans	Mechanical/ electrical	Fan circuit breaker	Yes	—	—	Quarterly
2VY01A, 2VY02A, 2VY03A, 2VY04A	Air cooling coils	Mechanical	Fan circuit breaker	Yes	—	—	Quarterly

10.2. D-G Facilities Ventilation System

10.2.1 System Function

The diesel-generator ventilation system provides year-round ventilation of the D-G rooms, day tank rooms, and diesel oil storage tank rooms. The system removes equipment heat and provides combustion air for the diesel generators while they are in operation.

The D-G Facilities Ventilation System (D-GVS) is normally inoperative during normal station operating conditions, except for the diesel fuel storage tank room ventilation fans. These fans draw a nominal quantity of ventilation air through their associated D-G rooms, diesel oil day tank rooms, and diesel fuel storage tank rooms. This is done independent of D-G operation to maintain a environment.

Each D-GVS subsystem is designed to limit its associated D-G room temperature to 122F in conformance with diesel-generator equipment ratings. In winter unit heaters maintain room temperatures above 65F.

10.2.2 System Description

10.2.2.1 General Design

The D-G Facilities Ventilation System consists of three independent subsystems that each circulate outside air through one of the three diesel-generator rooms (DG-0 -swing diesel, DG-2A, and DG-2B -HPCS diesel). Each D-GVS subsystem is interlocked to start when its respective diesel generator starts. All are inlets and outlets to the D-G rooms contain normally open electro-thermal link fire dampers that automatically isolate the D-G and fuel tank rooms upon activation of the fire protection system.

A continually running auxiliary fan in each subsystem draws a small amount of D-G room through the associated day tank and fuel storage tank rooms. This portion of the D-GVS is not modeled as essential successful D-G operation. The tank room fans and the isolation dampers associated with the rooms will not be addressed further in this system description. Refer to Section 10.2.4.3, model related assumptions, for a discussion of the reasons that this section of the D-GVS is neglected.

The HPCS diesel-generator ventilation system also includes a subsystem to provide ventilation of the HPCS D-G cooling water pump room, the HPCS switchgear room, and the battery room. This subsystem is not considered an essential element of HPCS D-GVS for the following reasons:

- o Room cooling is not modeled as an essential support system to the HPCS D-G cooling water pump
- o Auto trip of the cooling water pump room and switchgear/battery room fans is alarmed in the control room.
- o Only a small quantity of air is drawn through the switchgear rooms (200 cfm). It is likely that based on the low heat generation rate of the equipment in this room the passive open room damper will provide for adequate natural circulation over the HPCS mission time.
- o Analysis indicates that concentrations of H_2 in closed battery rooms build up very slowly (and only when the batteries are being charged). With the passive battery room dampers open, it is unlikely that the H_2 concentration in the battery room would ever reach the 4% level considered hazardous.

Flow Path

Each D-GVS subsystem draws outside air in through a supply filter. Downstream of the filter 10-15 percent of the air passes to the diesel generator combustion air intake, while 50-70 percent travels to the D-G room vent fan intake. The remainder is used by the ECCS Equipment Areas Cooling System to cool the RHR Service Water pump cubicles. In the case of the HPCS D-GVS, about 20 percent is used in HPCS D-G cooling water pump room ventilation.

The air traveling to the D-G room vent fan intake is drawn through a motor-operated damper, mixes with a portion of D-G room air being recirculated, and is conveyed to the D-G room by the fan. A small portion of the room air (<10 percent) is drawn through the tank rooms by the tank room vent fan. The major portion of the room air passes out to an exhaust shaft. From there, the air is either exhausted to the outside by positive pressure, or a portion may be recirculated to the D-G room vent fan intake.

Locations

The major D-GVS components for DG-0 (swing diesel) are in the La Salle Unit 1 Diesel-Generator Building in the vicinity of the diesel generator room (730' elev). Similarly, the major D-GVS components for DG-2A and DG-2B (HPCS DG) are located in the Unit 2 Diesel-Generator Building around the diesel- generator room they serve (approx. 740' elev).

Component Description

All three D-G room vent supply fans (OVD01C,2VD03C,2VD01C) are vane acial, 480 Vac direct drive fans having a capacity of 50,000 cfm and a total operating pressure of 3.0 inches water. The fans are air-cooled and served by the divisional power supply corresponding to the D-G they serve. The fans are normally in standby and are started automatically when the respective diesel-generators start. The fans can also be manually started at local panels.

The ventilation supply filters for the three D-GVS subsystems (OVD01F,2VD02F,2VD01F) are of the low efficiency type using a glass fiber filter media. The pressure drop across these filters when clean is .17 inch water and .35 inch water when dirty.

The outside air motor-operated dampers (MODs) at the supply fan intakes (OVD01Y,2VD09Y,2VD01Y) are normally closed, opposed blade dampers which are driven by 120 Vac servo motors according to room temperature control logic. The dampers open upon D-G start-up and spring return to close when unpowered.

The exhaust air MODs (OVD03Y,2VD11Y,2VD03Y) off the D-G room exhaust shafts are identical to the outside air (intake) dampers. They are normally closed, open on D-G start-up, and spring return to close when de-energized. They are also positioned by the D-G room temperature controller and are powered from the same 120 Vac distribution panels.

The return air MODs (OVD02Y,2VD10Y,2VD02Y) in the recirculation lines are also identical to the outside air dampers, except that they are normally open and spring return to open when de-energized. These MODs are also positioned by the D-G room temperature control system. They are powered from the same 120 Vac distribution panels off the same MCCs as the other dampers.

The fire dampers at all inlets and outlets to and from the D-G rooms (OVD40Y,OVD41Y,2VD43Y, etc.) are normally held open by thermal links. The link material melts at about 165F or upon receiving an electrical impulse from fire protection system actuation. The dampers will then fall shut isolating the D-G room from air flow. The electro-thermal link damper remains as is upon loss of power, and once tripped they must be manually reopened on location.

10.2.2.2 System Interfaces

A failure modes and effect analysis (FMEA) of D-GFS support system interfaces is shown in Table 10.2.1. The support system interfaces are discussed below.

Shared Components

The RHR Service Water pump cubicle cooling systems (subsystems of ECCS-Equipment Areas Cooling System) draw their ventilation air through the D-GVS vent supply filters. The ventilation system for service water pumps "A" and "B" draws from the HPCS D-GVS filter (2VD01F) while the service water pumps "C" and "D" cubicle ventilation draws from the DG-2A D-GVS filter (2VD02F).

Electrical

Each D-GVS subsystem is powered by the divisional power supply corresponding to the diesel generator it is serving.

The swing diesel D-GVS fan (0VD01C) is normally powered from the Unit 1 480 Vac MCC 135X-2. The motor-operated dampers in this subsystem receive their power via a 480 V/120 Vac transformer off MCC 135X-2. If the Unit 1 MCC is lost the motor- operated components of the swing diesel D-GVS switch automatically to Unit 2 MCC 235X-2.

The DG-2A D-GVS fan (2VD03C) is powered from 480 Vac MCC 236X-3. The MODs in this subsystem receive their power via a 480V/120Vac transformer off MCC 236X-2.

The DG-2B D-GVS fan (2VD01C) is powered from 480 Vac MCC 243-1. The MODs in this subsystem receive their power via a 480V/120Vac transformer off MCC 243-1.

Actuation

Electrical power for actuation of the fans is provided by a 480 V/120Vac transformer off the MCC power lines to each fan. Electrical power for MOD actuation is provided by the same 120 Vac source that powers the damper.

Control

Control power for the fans is obtained through the 480V/120Vac transformers off the MCCs powering them.

Component Cooling

The D-GVS vent fan motors are self-cooled. No external component cooling is required for the D-GVS subsystems.

10.2.2.3 Instrumentation and Control

System Actuation

Each D-GVS ventilation supply fan is controlled by a three position (STOP-AUTO-START) switch with a spring retvrn to AUTO. In AUTO, once the loading sequence starts, the supply fan starts, and the outside air, exhaust air, and return air dampers open and modulate as demanded by the DG room temperature controller. In STOP the supply fan will be tripped, and the outside air, exhaust air, and return air dampers will close.

The D-GVS subsystems can be operated manually, but the auto start signal from the operation of the diesel-generators overrides the manual switch.

Success-oriented logic diagrams for actuation of the D-GVS vent supply fans are shown in Figures 10.2-4 through 10.2-6.

Component Control

The actuation of the D-GVS fans and motor-operated dampers is described above. Once started the fans operate at full capacity until they are automatically shutdown.

Regardles of the fan switch position the fans and MODs will be interlocked in the tripped/shut condition if the following combinations of signals are received: An initiation from the CO2 fire protection system or a combination of a stop D-G loading sequence and room temperature less than 104F.

The MODs in a D-GVS subsystem are positioned continually as dictated by a common bridge control circuit. The bridge is unbalanced by resistance elements which change with temperature in the D-G room. The outside air MOD (fan intake) in each ventilation system is the master damper and the return air and exhaust air dampers are slaves.

Instrumentation

Fans

All D-GVS fans have indicator lights at local indicator panels only. The ESF display and a control room alarm indicate fan trip due to overload.

Supply Filters

Differential pressure across the filter is indicated locally only (0-1 inch water). High DP (above 0.4 inch water) is alarmed locally and in the control room.

D-G Room Temperature

Diesel-generator room temperature indication (50-150o F) is provided in the control room for all three D-G rooms. High room temperature (about 130o, increasing) alarms in the control room.

10.2.2.4 Operator Actions

The initiation of the D-GVS is completely automatic. No operator action is assumed. The primary responsibility of the operator is to verify system operability following an initiation.

10.2.2.5 <u>Technical Specification Limitations</u>

There are no LaSalle Technical Specifications limitations pertaining directly to the D-GVS.

10.2.2.6 Tests

The tests that check the operability of D-GVS components are summarized in Table 10.2.2. The checks actually only verify the fact that the vent supply fans start automatically on D-G startup and the ventilation supply filter differential pressure is below its limit. However due to the extended period of time that the D-Gs operate during the tests, inoperability of, for example, an MOD is likely to be indicated by a high room temperature alarm.

No LaSalle Unit 2 tests were found that render an D-GVS subsystem inoperable.

Although it is not a test, daily surveillance verifies that D-G room temperatures are within specified limits (65F to 122F).

10.2.2.7 Maintenance

No scheduled maintenance which disables D-GVS components while the plant is at power is planned. Unscheduled maintenance is permitted on system components provided applicable safety controls can be satisfied. Unscheduled maintenance activities expected during plant operation include:

Replacement or repair of actuation and control circuitry

Electrical maintenance on motor driven components
Mechanical maintenance on the fans and motor-operated dampers.

A summary of unscheduled maintenance acts allowed on the Diesel-Generator Facilities Ventilation System while the plant is in full power operation is given in Table 10.2.3. Not included in this table is expected unscheduled maintenance on the feed circuit breaker in the power supply lines for each motor-operated fan and damper.

10.2.3 System Operation

10.2.3.1 Normal Operation

During normal plant operation the D-GVS subsystems are in standby. The tank room vent fans draw a nominal quantity of air through the fuel storage tank cubicles to prevent vapor buildup.

10.2.3.2 Abnormal Operation

When each diesel-generator loading sequence starts the associated D-GVS subsystem supply fan is automatically actuated and the MODs open and modulate as demanded by the room temperature controller. These automatic actions override any manual control.

The conditions under which each D-GVS subsystem shuts down are given in Section 10.2.2.3.

10.2.4 System Fault Tree

10.2.4.1 Description

Simplified diagrams of the three D-GVS subsystems showing the mechanical components included in the fault tree models are shown in Figure 10.2-7.

The complete Diesel-Generator Facilities Ventilation System fault trees are included at the end of this appendix.

There are four developed events in the D-GVS fault trees. They are all transfers from the electric power fault trees - the 480 Vac MCC's 235X-2, 236X-2, 236X-3, and 243-1.

The data for the basic events in the D-GVS fault trees are presented in Table 10.2.4.

10.2.4.2 Success/Failure Criteria

Each of the independent D-GVS subsystems is successful if its vent supply fan starts and runs at full capacity, drawing outside air through the ventilation filter and circulating it through its associated D-G room as long as the D-G is in operation. An D-GVS subsystem fails if one of the following occurs:

1. One of the electro-thermal link dampers inadvertently closes (spurious fire protection signal).

2. Either the outside air or exhaust air MOD fails to open.

3. The return (recirc) air MOD fails completely open.

4. The supply fan fails or the ventilation filter plugs.

The top events of the D-GVS fault trees look like:

ROOM ROOMRRR COOLING OR VENTILATION SYSTEM FAULTS where ROOMRRR is one of the D-G room names.

10.2.4.3 Assumptions

Model Related

In addition to the general assumptions regarding fault tree development (listed at the beginning of the appendix), the following assumptions specific to D-GVS were made:

1. The main D-G vent supply fan must operate in order to adequately cool the diesel-generator. Operation of the fuel storage tank room fan alone is insufficient. (The later draws 4200 cfm compared to the 50,000 cfm air capacity of the main fan.)

2. The fire damper at either the inlet or outlet side of the D-G room will prevent adequate air flow from circulating through the room if it closes.

3. The exhaust air MOD must be open in order for adequate cooling air flow to occur in the D-G room. This assumes that secondary exhaust paths (e.g. via the day tank room or tank room) are too restricted to provide adequate D-G room exhaust.

4. Failure of the return air damper in a closed position does not affect successful cooling of the D-G room. This assumes "over-cooling" of the D-G will not fail it.

5. Failure of the return air damper in a fully open position does fail D-G room cooling. In this position approximately 45,800 cfm of the 50,000 cfm total flow is redirected back to the vent supply fan intake. The resultant outside air intake of 4200 cfm is assumed inadequate for successful room cooling.

6. Failure of the fuel storage tank room ventilation portion of a D-GVS subsystem is not a significant contributor to subsystem failure. The fuel tank vent fan draws a nominal quantity of air through the fuel tank rooms to prevent vapor buildup. Should the fan fail, the rooms are still open at two locations so that some dissipation is likely. Even with vapor buildup in the rooms the possibility of an explosive ignition that fails the diesel-generator when it's in operation appears remote.

7. The circulated air in the D-GVS subsystems is conveyed in what are essentially concrete passageways. For this reason duct rupture is not assumed to be a potential system failure mode.

Quantification Related

To be added.

Table 10.2.1 D-G Facilities Ventilation System Interface FMEA

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Ef (Sub) System System Funct
4160V <u>BUS 241Y</u>						
480Vac MCC 235X-2	OVD01C driven fan	Motor-	FTS/FTR	Fan indicated locally. Room temp. indicated/ alarmed in control room.	Loss of DG-O (swing diesel) room cooling	
	OVD01Y	Motor-op. damper	FC	Room temp indicated/alarmed in control room	Fan intake blocked. Loss of DG-O room cooling	
	OVD02Y	"	FO	"	Most of room air is recirculated-insufficient cooling air.	
	OVD03Y	"	FC	"	Room exhaust path blocked. Loss of DG-O room cooling	Fails DG-O r
4160V <u>BUS 242Y</u>						
480 Vac MCC 236X-3	2VD03C	Motor-driven fan	FTS/FTR	Fan indicated locally. Room temp. indicated/ alarmed in	Loss of DG-2A room cooling	
480 Vac MCC 236X-2	2VD09Y	Motor-op. damper	FC	Room temp. indicated/alarmed in control room	Fan intake blocked. Loss of DG-2A room cooling.	
	2VD10Y	"		"	Most of room air is recirculated-insufficient cooling air.	

Table 10.2.1 D-G Facilities Ventilation System Interface FMEA (Continued)

Support (Sub) System Failure	System Component Affected Identifier	Type	System Component Failure Mode	Detection or Recovery Potential	System Component Failure Effect on System Operation (Assuming No Recovery)	Summary - Ef (Sub) System System Funct
4160V <u>BUS 243Y</u>						
480Vac MCC 243-1	2VD01C	Motor-driven fan	FTS/FTR	Fan indicated locally. Room temp. indicated/ alarmed in control room.	Loss of DG-2B (HPCS) room cooling	
	2VD01Y	Motor-op. damper	FC	Room temp indicated/alarmed in control room	Fan intake blocked. Loss of DG-2B room cooling	
	2VD02Y	"	FO	"	Most of room air is recirculated-Insufficient cooling air.	
	2VD03Y	"	FC	"	Room exhaust path blocked. Loss of DG-2B room cooling	Fails DG-2B

Table 10.2.1 D-G Facilities Ventilation System Component/System Test Summary

Test Procedure Number	Type of Test	Component/ Subsystem Affected by Test	Component Type	Component/Subsystem out of Normal Alignment for Test	Automatic Return upon Initiation	Test Frequency (Mo)	Te Ou
LOS-DG-M1	D-G Operability	OVD01C	Motor-driven fan	No	No	---	
		OVD01F	Vent filter	"		---	
LOS-DG-M2	D-G Op.	2VD03C	Motor-driven fan	"		---	
		2VD02F	Vent filter	"		---	
LOS-DG-M3	D-G Op.	2VD01C	Motor-driven fan	"		---	
		2VD01F	Vent filter	"			

Table 10.2.3 D-G Facilities Ventilation System Unscheduled Maintenance Summary

Component/ Subsystem	Type	Type of Maintenance	Components out of Normal Alignment for Maintenance with no Auto-Return	Allowed During Plant Operation?	Frequency	Outage
0VD01C, 2VD03C, 2VD01C	Motor-driven fans	Mechanical/ electrical	Fan circuit breaker	Yes		
0VD01Y/2Y/3Y 2VD09Y/10Y/11Y 2VD01Y/2Y/3Y	Motor-operated dampers	Mechanical/ electrical	Fan circuit breaker	Yes		

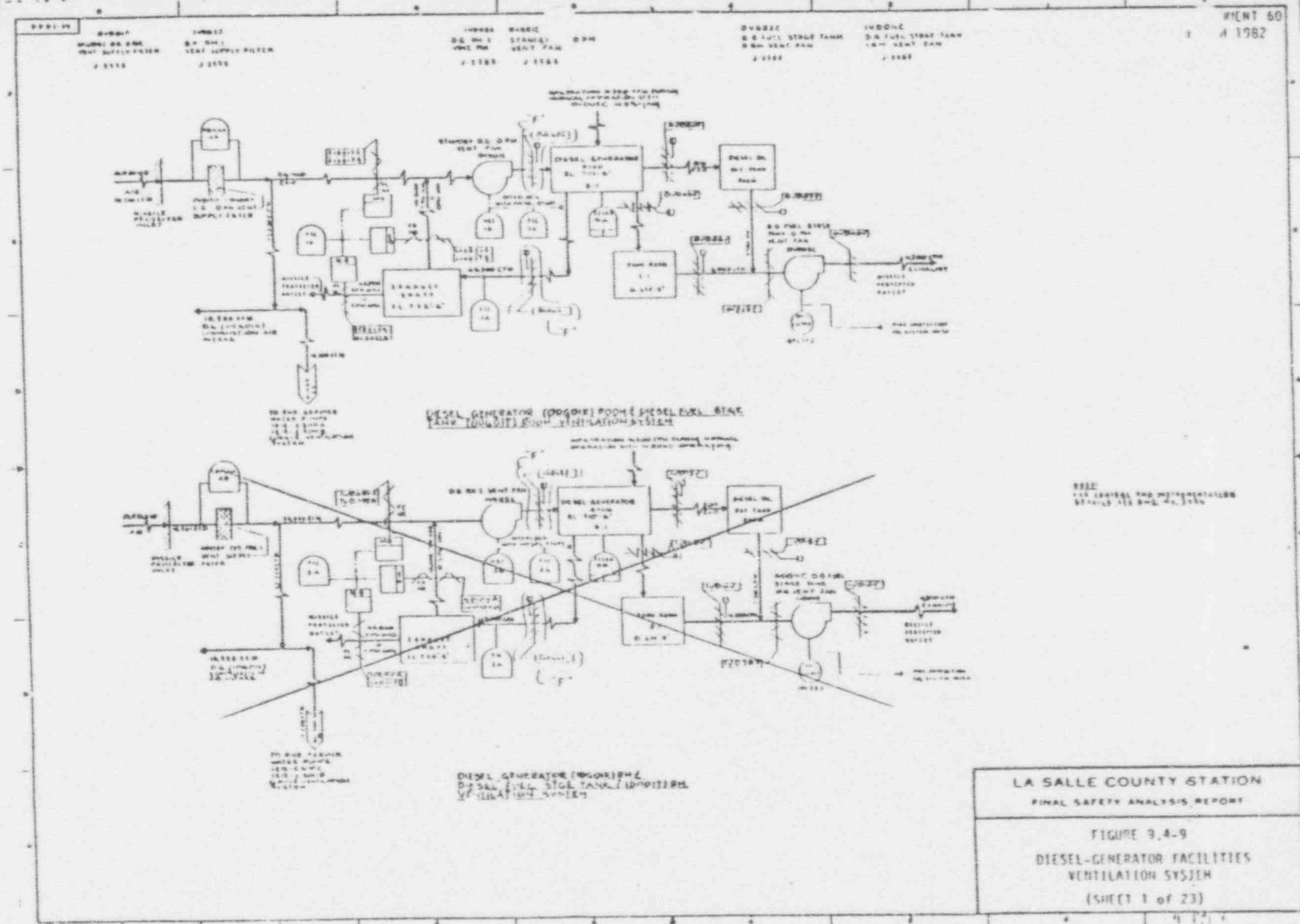


FIGURE B.X-1 D-G FACILITIES VENTILATION SYSTEM
(SWING DIESEL ROOM)

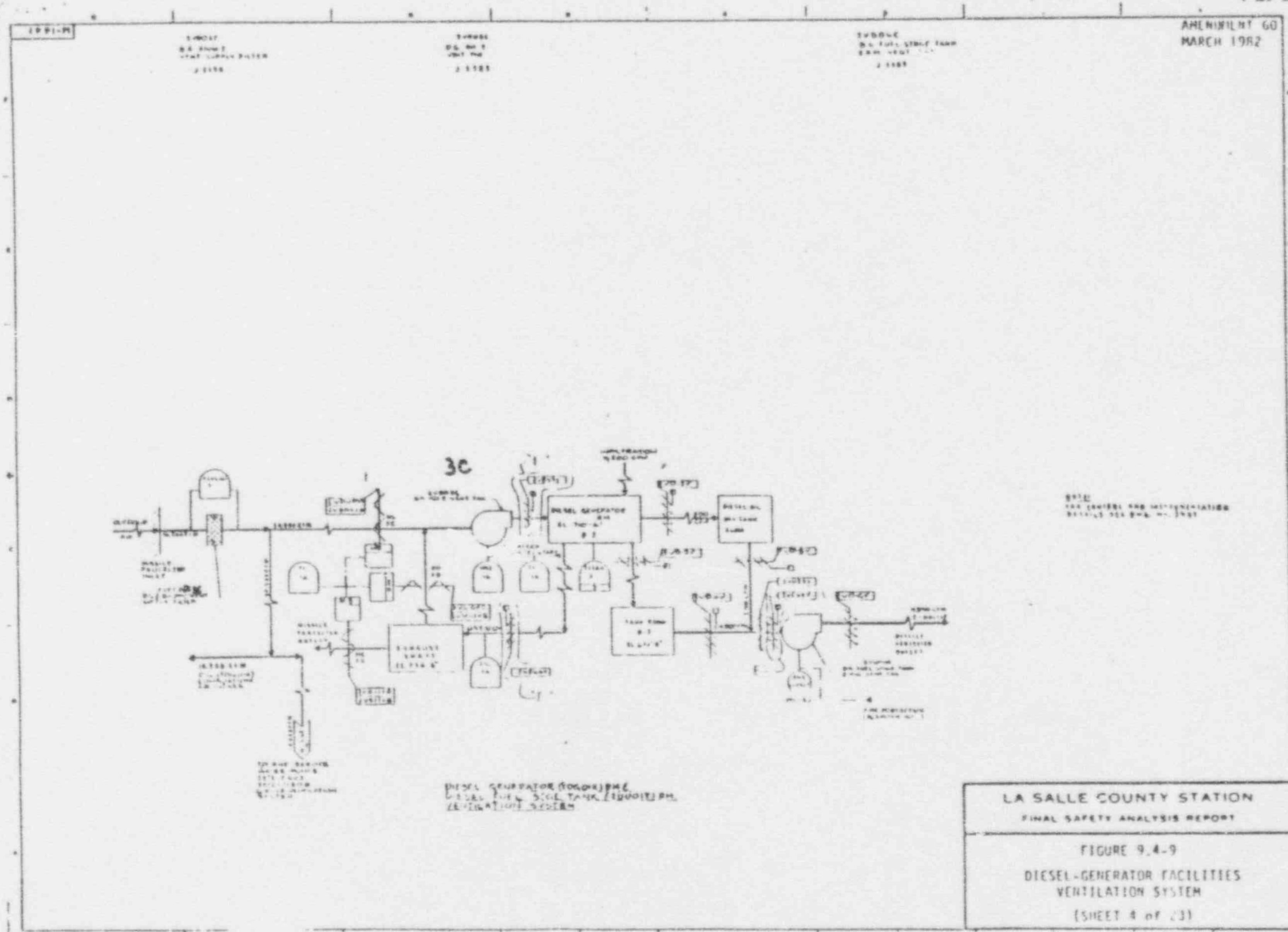


FIGURE B.X-2 D-G FACILITIES VENTILATION SYSTEM
(DG-2A ROOM)

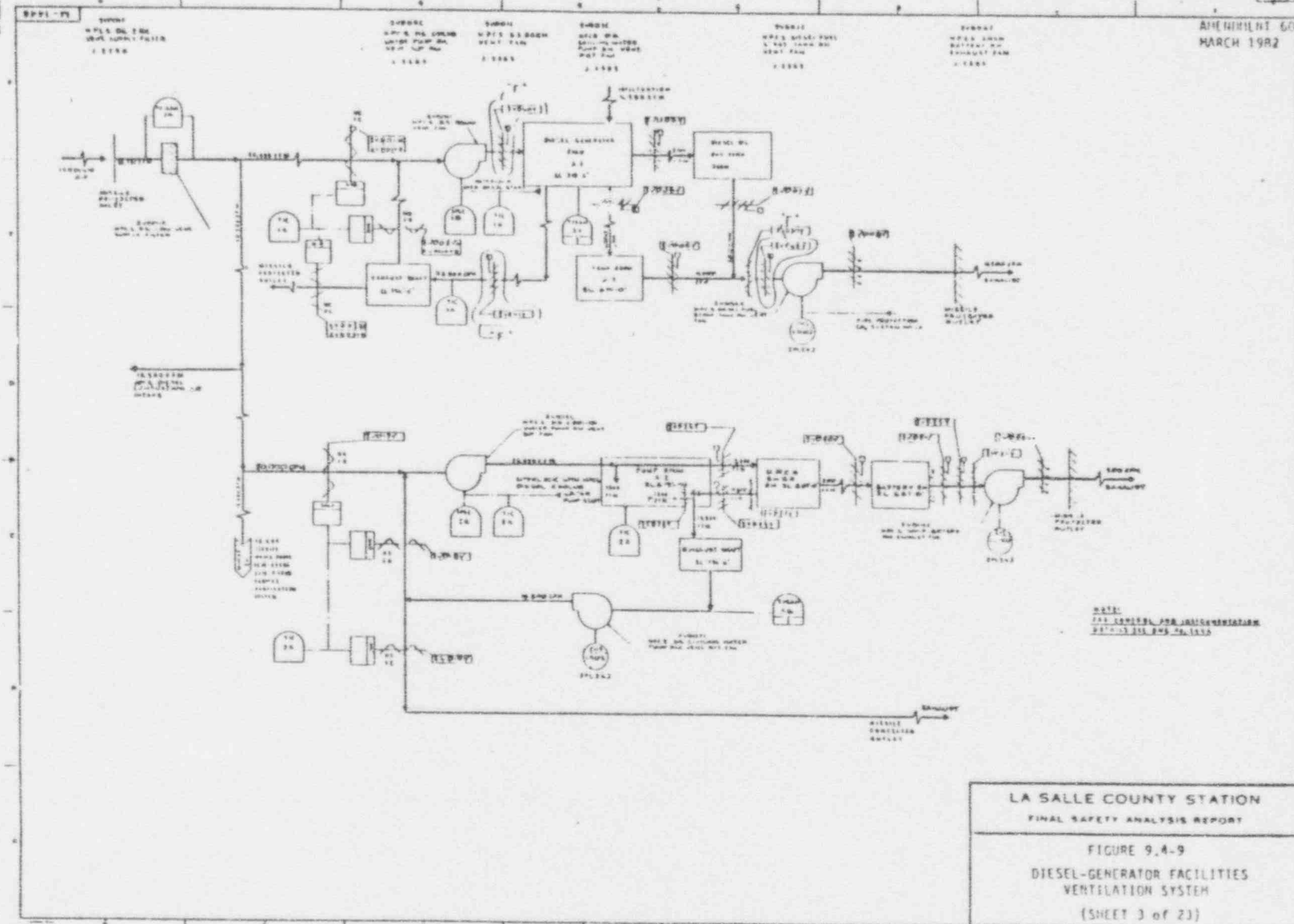


FIGURE B.X-3 D-G FACILITIES VENTILATION SYSTEM
DG-2B (HPCS DIESEL) ROOM

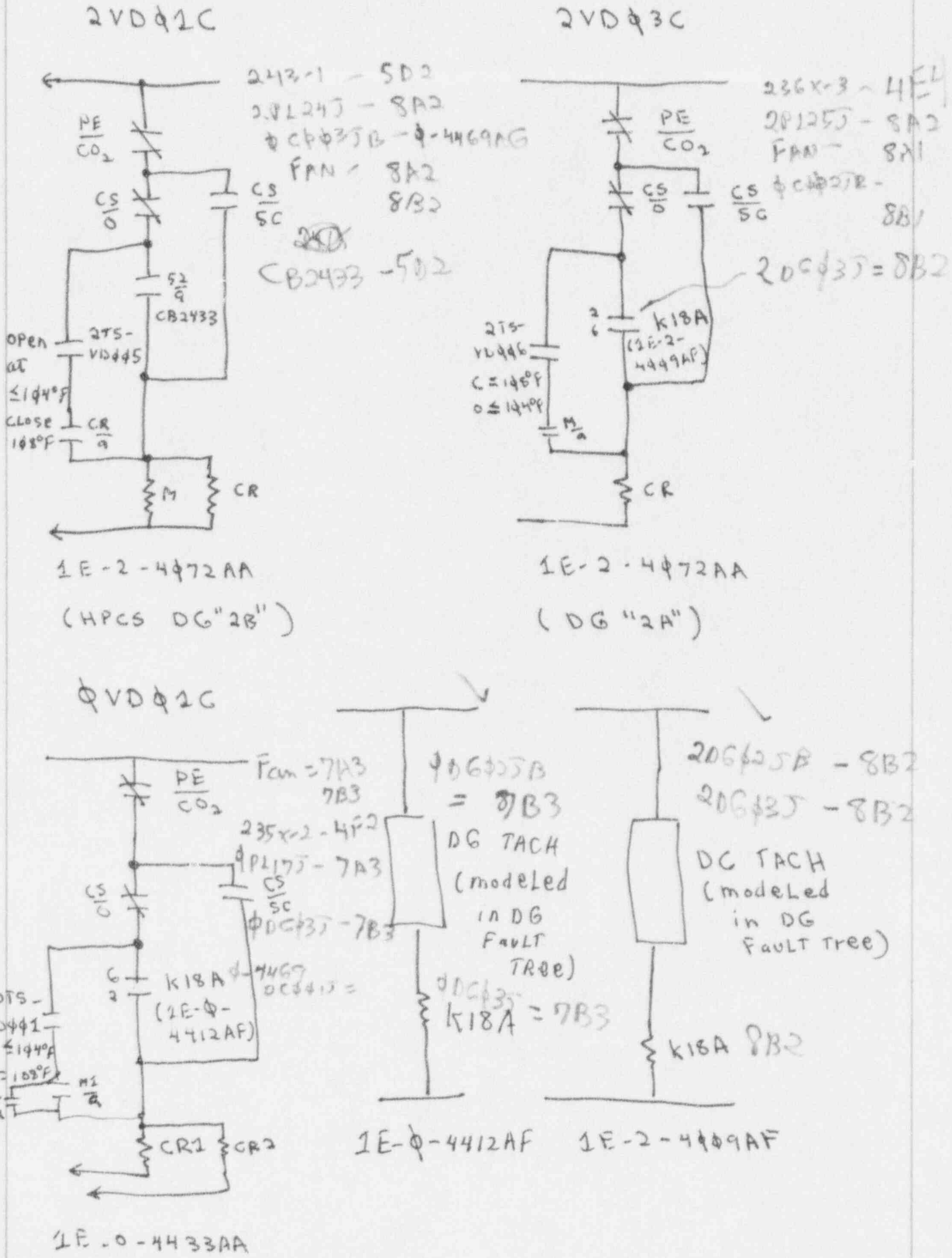


Figure B.X-2 DG Room Cooling Fans

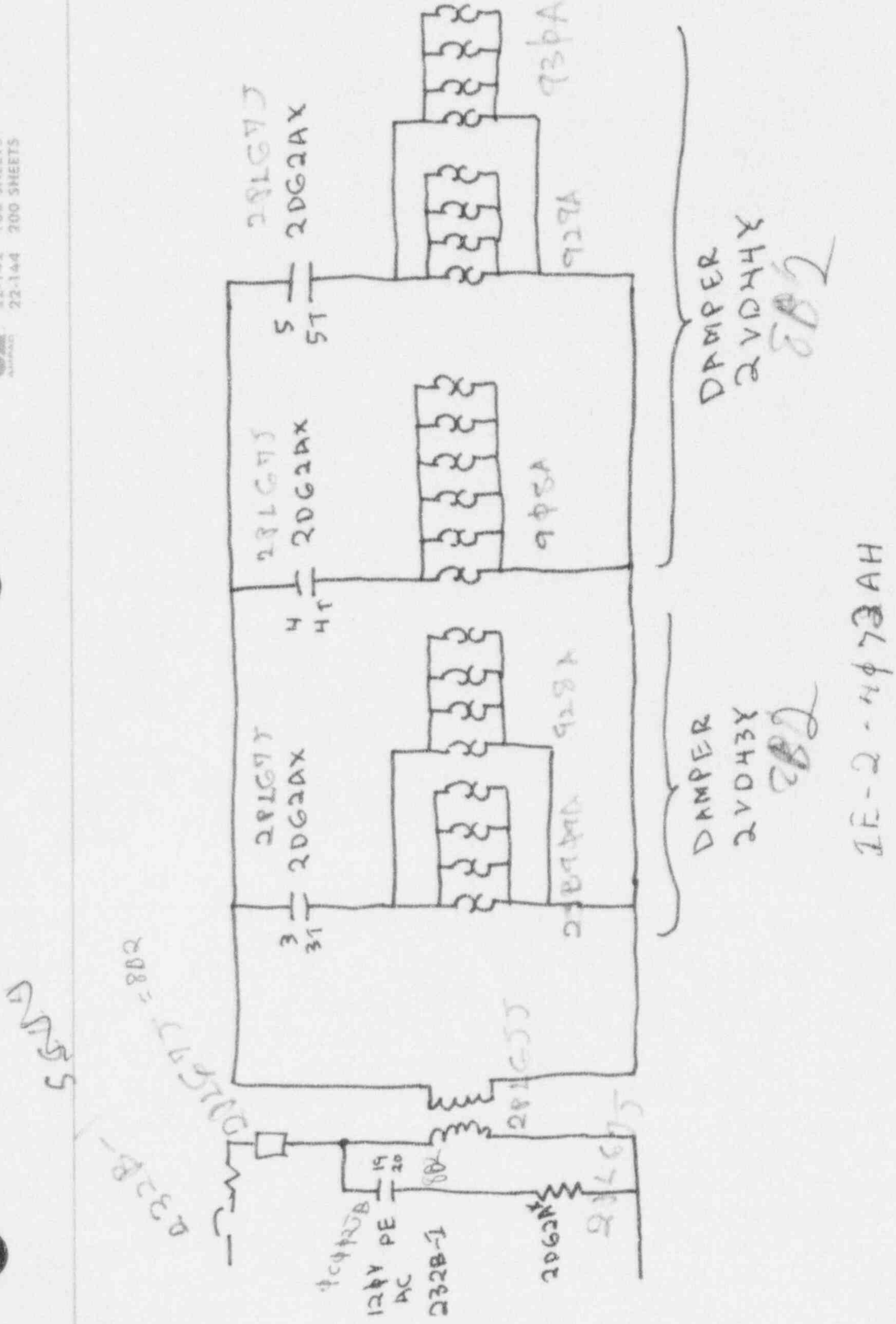


Figure B.X-3 DG ROOM "2A" ELECTRO-THERMAL LINK DAMPERS

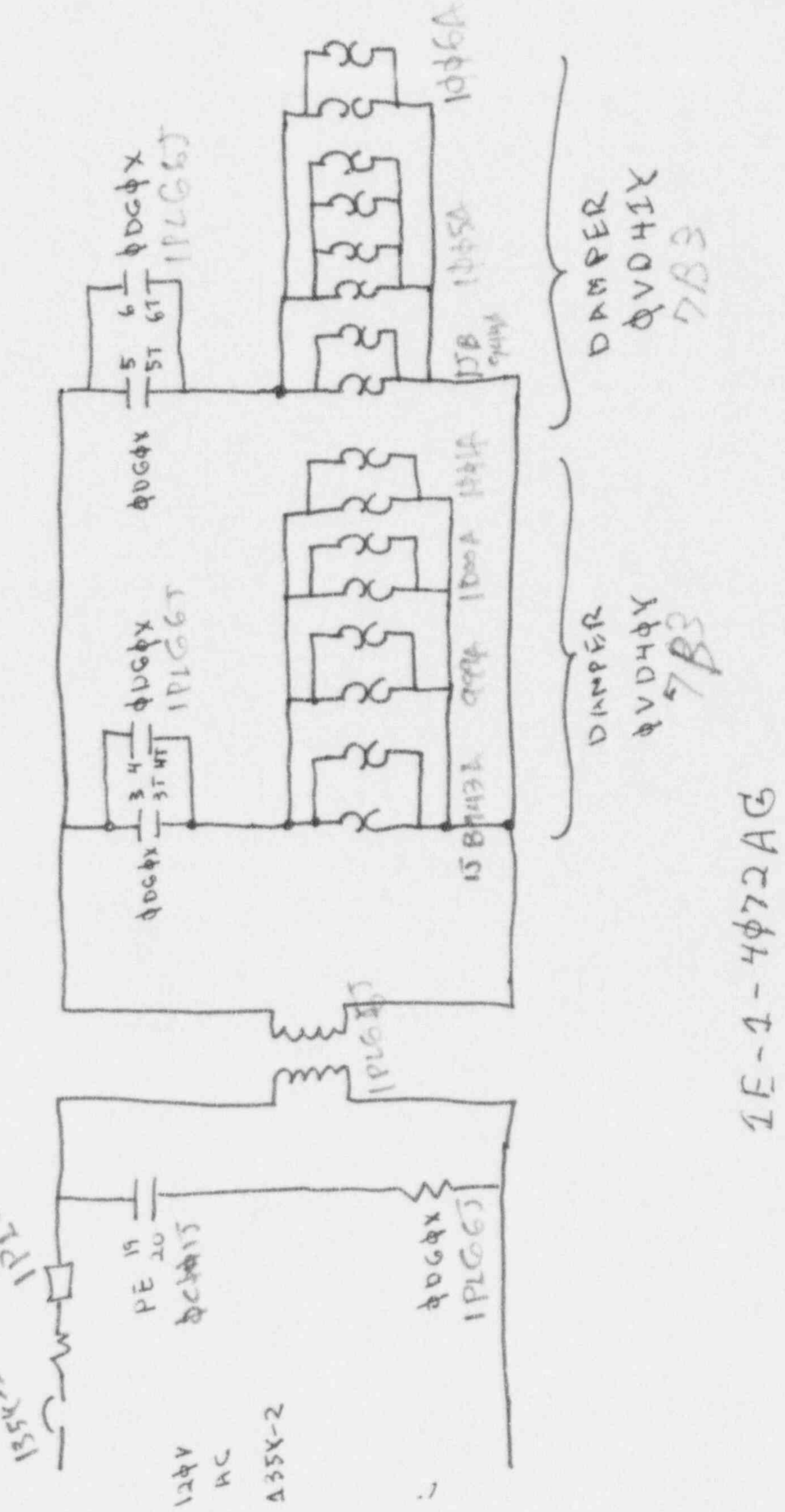


Figure B.X-4 D6 ROOM "O" ELECTRO-THERMAL LINK
DAMPERS

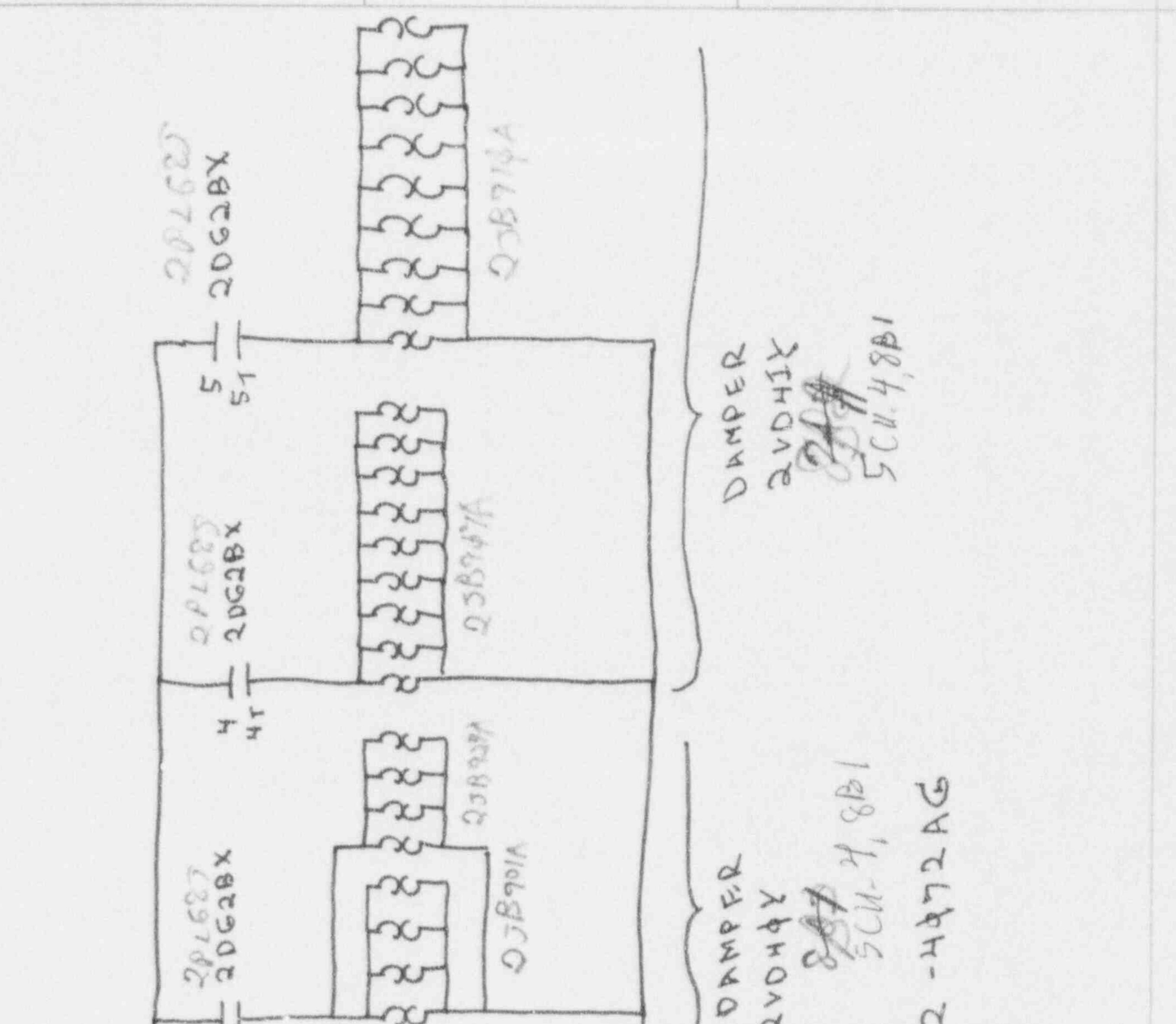


Figure B.X-5 DG ROOM "2B" ELECTRO-THERMAL LINK DAMPERS

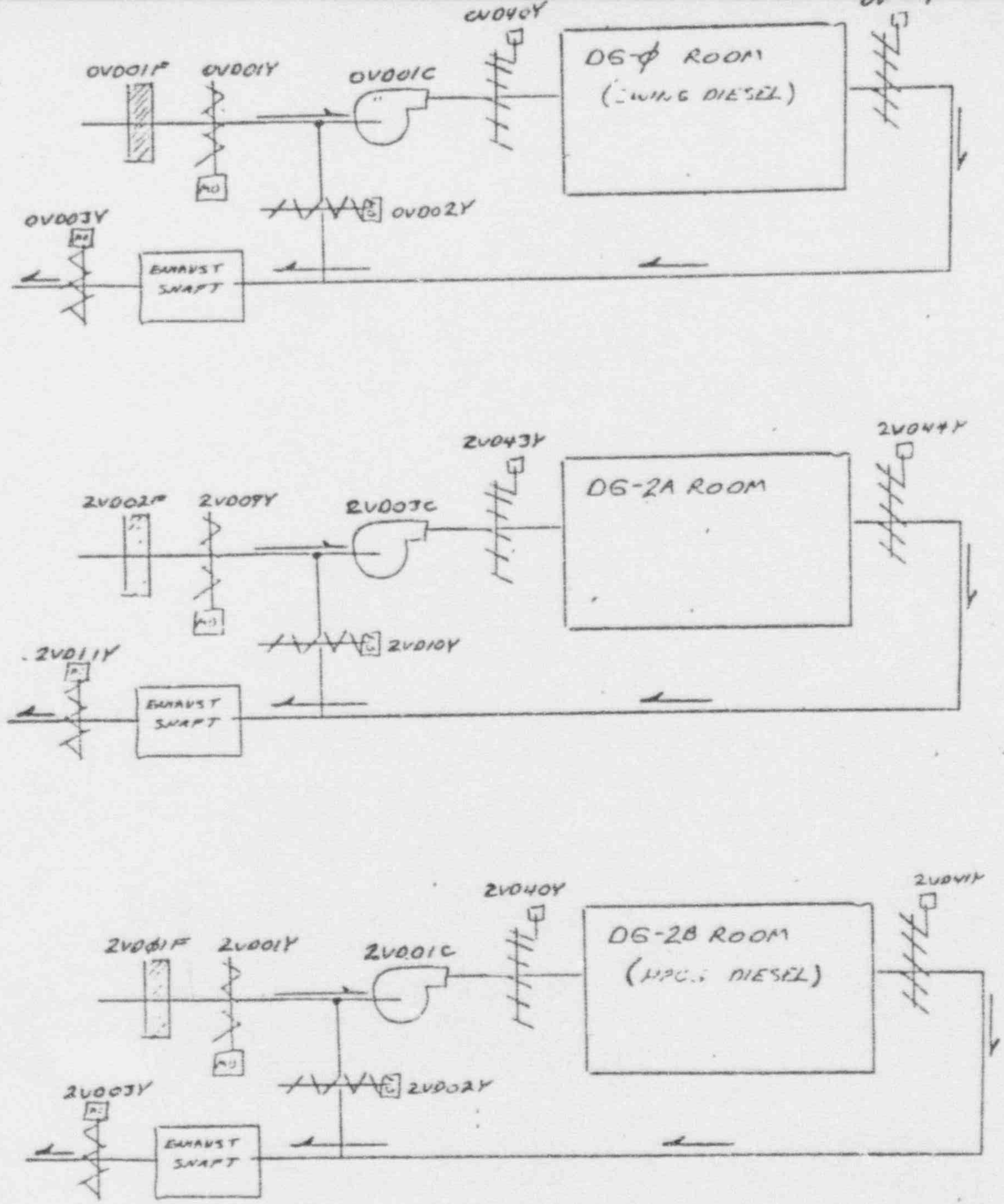


FIGURE B.X-7 D-G FACILITIES VENTILATION SYSTEM
SIMPLIFIED DIAGRAM

11.0 MISCILLANEOUS SYSTEM

11.1 (Deisel-Driven) Firewater System (FW or DFW)

11.2 Primary Containment Isolation System (PCIS)

11.3 Vapor Suppression System (VP)

11.4 Primary Containment Venting System (VENT)

11.5 Primary Containment Cooling System ()

11.6 Standby Gas Treatment System (SGTS)