PDR (41)

TECH. ENGR.

DISTRIBUTION

X Original, Responsible Section Head Action

___ File Copy, Master File

T-9216

COPIES TO BE MODIFIED FOR IMMEDIATE IMPLEMENTATION
1-SS 1 ODS Eng 1 TIC
1-CTRM 1 Tech Sec. 1 ASD
4 CR Files 1 MPS 1 Study Rm

DAVIS-BESSE NUCLEAR POWER STATION - UNIT 1
TEMPORARY MODIFICATION REQUEST
ED 6926

SECTION 1

PROCEDURE TITLE AND NUMBER

Trip Recovery, PP 1102.03.14

REASON FOR CHANGE

The station house power readings are no longer on Sheet 11. Also Standing Order # 20 has been VOIDED and its information incorporated in SP 1107 02

CHANGE

1) Void T-9043

2) Change step 4.19.2 to read

Take station house power readings as listed on Daily Reading Sheet 8. Per SP 1107 02, Station Transformer Auxiliaries System Procedure, step 11 3 1 3, the three KWH meters and the totalizer inputs and outputs must be read as soon as possible (within one-half hour) after a shutdown or trip

IS PROCEDURE REVISION REQUIRED Yes [x] No [ ] If no, this modification is valid until ______

PREPARED BY Lynn Richter	DATE 5/14/85
APPROVED BY G. Lemmon	DATE 5/14/85
APPROVED BY Lynn Richter	DATE 5/14/85
SUBMITTED BY (Section Head) WOE	DATE 5/20/85
RECOMMENDED BY (SRB Chairman) D. W. Briden	DATE MAY 22 1985
QA APPROVED BY (Manager of Quality Assurance) N/A	DATE
APPROVED BY (Station Superintendent) [signature]	DATE MAY 22 1985

Op

8507300261 850522
PDR ADOCK 05000346
P PDR

TECH. ENGR.

T-9186

DISTRIBUTION

X Original, Responsible Section Head Action

___ File Copy, Master File

COPIES TO BE MODIFIED FOR IMMEDIATE IMPLEMENTATION

1 Shift Sup 3 CTRM File
1 Ops Eng
1 CTRM Bck

DAVIS-BESSE NUCLEAR POWER STATION - UNIT 1
TEMPORARY MODIFICATION REQUEST
ED 6926

SECTION 1

PROCEDURE TITLE AND NUMBER

TRIP RECOVERY PP 1102.03.14

REASON FOR CHANGE

A commitment was made to the NRC that engineering would walkdown the AFPT steam piping after any operation of the AFPT's.

CHANGE

ADD STEP 21 and 22 to Attachment 7, SFRCS Initiation Recovery Guideline.

__ 21. Nuclear Facility Engineering has been notified to walkdown the AFPT 1-1 and 1-2 steam piping after any operation of the AFPT's.

__ 22. Nuclear Facility Engineering has approved the steam piping for AFPT 1-1 and 1-2.

Engineer __________ Time ______ Date ______

IS PROCEDURE REVISION REQUIRED Yes [ ] No [X] If no, this modification is valid until NRC commitment is lifited.

PREPARED BY Donald C. Rising	DATE 5-1-85
APPROVED BY [signature]	DATE 5-1-85
APPROVED BY John Johnson	DATE 5/1/85
SUBMITTED BY (Section Head) [signature]	DATE 5/6/85
RECOMMENDED BY (SRB Chairman) D. W. Briden	DATE MAY 8 1985
QA APPROVED BY (Manager of Quality Assurance) N/A	DATE
APPROVED BY (Station Superintendent) [signature]	DATE MAY 8 1985

Davis-Besse Nuclear Power Station

Unit No. 1

Plant Procedure PP 1102.03

TRIP RECOVERY

NUCLEAR SAFETY RELATED

Record of Approval and Changes

Prepared By	Louis Simon, William T. O'Connor	2/4/76 Date
Submitted By	Terry D. Murray — Section Head	5/2/76 Date
Recommended By	Jack Evans — SRB Chairman	5/17/76 Date
QA Approved	N/A — Quality Assurance Director	Date
Approved By	Jack Evans — Station Superintendent	6/7/76 Date

Revision No.	SRB Recommendation	Date	QA Approved	Date	Sta. Supt. Approval	Date
11	[signature]	12/8/83	N/A		T D Murray	12/20/83
12	[signature]	4/11/84	N/A		T. D. Murray/SMQ	4/19/84
					Plant Manager Approval	
13	D. W. Briden	10/16/84	N/A		[signature]/WO	11/9/84
14	[signature]	DEC 12 1984	N/A		[signature]	12/29/84

1. PURPOSE

1.1 Section 4 provides the steps to make the transition from the plant conditions in EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture, to the initial conditions required for Section 5.

1.2 Section 5 provides the steps to take the plant from post trip hot standby conditions to the conditions required for entry into either the plant startup or the plant shutdown and cooldown procedure.

2. PRECAUTIONS AND LIMITATIONS

2.1 RX startup is NOT permitted unless the cause of the RX trip is known and corrected. Attachments 1 and 3 must be completed for every reactor trip. If any Technical Specification Safety Limit (Section 2.0) has been exceeded, operation shall not be resumed until authorized by the Commission as per 10 CFR 50.36 Section C. A review of the Computer Post Trip Review is a useful guide in determining the cause of the RX trip.

2.2 Steam Generator limitations are:

The maximum cooldown rate is 100°F/hr.

When cooling down or depressurizing a steam generator, do "NOT" exceed a differential temperature between the RCS cold leg and the steam generator upper downcomer temperature of 25°F.

The minimum temperature limits of the main and auxiliary feedwater nozzles are 90°F and 40°F, respectively, at hot standby conditions. For filling SG, refer to SG Secondary Fill, Drain, and Layup SP 1106.08. A minimum feedwater temperature of 185°F is recommended at RCS temperatures exceeding 280°F. Max. ΔT between SG downcomer and feedwater temperature is 350°F.

For operation below 5 percent power, the main feedwater nozzles must be supplied with a continuous minimum feedwater flow of $\geq$22 gpm to reduce thermal cycling. SG level must be maintained between 18" and 348" on the startup range level indication when the RCS is in Mode 4 or above.

2.3 The startup feedpump may be operated during the trip recovery provided special requirements outlined in SP 1106.27, Startup Feedpump Operating Procedure, are followed.

2.4 The CRD Safety Group 1 will always be at its upper limit during dilution except during performance of approved physics testing. All subcritical boron concentration changes in the RCS will be verified for each predicted change of 30 ppm boron.

(TS 3.4.9) 2.5 The PRZR heatup and cooldown shall NOT exceed 100°F in one hour (1.67°F per min.). The PRZR spray shall not be used if the temperature difference between the PRZR and the spray fluid is greater than 410°F.

2.6 Control Rod Safety Group 1 shall be withdrawn to provide tripable reactivity prior to the addition of positive reactivity from a change in reactor coolant temperature, the motion of the APSR's (Group 8), or motion of the control rods (Groups 5-7). The following exceptions to this may be applied:

2.6.1 The RCS has been borated to the hot standby boron concentration as given in Figure 13 of PP 1101.02, Reactor Operator Curve Book, (or greater) and the unit is being maintained in the hot standby condition (Tave ~530°F).

2.6.2 The RCS has been borated to the cold shutdown boron concentration given in Figure 16 of PP 1101.02 (or greater) and the unit is being cooled down.

2.6.3 Group 1 Control Rods need NOT be withdrawn prior to cooling down from ~550 to 530°F provided the cooldown is within the time to reach equilibrium Xe from Figure 1. This time limit is to assure that xenon worth is sufficient to provide the necessary shutdown margin. If the cooldown is NOT started within 10 hours, the Group 1 Rods should be pulled unless the boron concentration, adjusted for the current xenon worth, is greater than the hot standby boron concentration shown in Figure 13 of PP 1101.02. Note that the boron concentration is mathematically adjusted by adding 100 ppm boron for each 1% $\Delta K/K$ of worth of xenon. For example, if boron concentration is 950 ppmB and xenon worth is -2.4% $\Delta K/K$, the adjusted worth would be 950 + 240 = 1190 ppmB.

NOTE: Whenever possible, it is desirable to maintain the safety group 1 at its upper limit as an additional safety margin.

2.7 At least two licensed operators shall be present in the CTRM during recovery from reactor trips.

2.8 Notify the Technical Section after a Reactor Trip so that data from the station computer (that is transferred and stored in a 24 hour rotating file in the DBAB computer) can be printed before the file cycles and the data lost.

2.9 When the condenser is unavailable for steam dump, (circulating water flow less than 100,000 gpm is either circulating water

loop or condenser pressure greater than 16.9 inches Hg A or MSIV's less than 90% open) the atmospheric steam vent valves must be used for steam header pressure/RCS cooldown rate control.

2.10 Ensure gland sealing steam and auxiliary steam loads are shifted from the main steam header to the Auxiliary Boiler after reactor shutdown to prevent cooldown of the RCS. With a low decay heat load present high steam usage from the main steam line could reduce steam line pressure and result in high RCS cooldown rates. If Auxiliary Boiler is lost, the main steam reducing station can be used to prevent loss of condenser vacuum but steam usage must be limited.

2.11 During operation with a positive moderator temperature coefficient and with boron concentration greater than 1200 ppm, added caution should be used when changing Tave in order to prevent a Tave transient.

2.12 The RCS (except PZR) temp. and press shall be limited in accordance with the limit lines shown on Figures 1 and 2 PP 1101.01, during heatup, cooldown, criticality, and inservice leak and hydrostatic testing with:

a. A max heatup or cooldown of 100°F if any one hour period per Technical specifications.

CAUTION: For heatup below 532°F and cooldown below 550°F, in addition to the Tech spec limit of 100°F/hr heatup or cooldown rate a further resistriction is imposed for allowable number of heatup and cooldown cycles considerations. Whenever the rate is greater than 15°F/hr the heatup rate should be trended (trend pen with 100°F/hr grease per line or similar tracking device) OR manually plotted every five minutes. The rate should be maintained less than 1.67°F per minute. If the temperature deviates by more than 15°F from the temperature which would occur at that point in time assuming the rate was maintained at 1.67°F per minute the temperature must be restored to a point between the 100°F per hour heatup line and 15°F limit point by holding and maintaining the RCS tempeature. In addition a DVR must be submitted for documentation to ensure a specific evaluation to determine the impact upon the allowable number of heatup and cooldown cycles is performed. This limit applied to all RCS components (including the PZR). For further guidance refer to Standing Order #23.

2.13 Seal injection water flow is required to all reactor coolant pumps when reactor coolant temperature and pressure are above 150°F and 150 psig except when operating in the loss of injection mode.

2.14 The following valves have wedges that may stick in their seats if closed when they are hot and subsequently cooled down:

MU-1A, MU-1B, MU-2B, RC-10, RC-11

To prevent separation of the wedge from the valve stem when a valve is closed hot and then cooled down, perform steps as follows:

1. Exercise the valve once for every 100°F cooldown, or

2. If available, isolate the line with a manual valve and then reopen the Velan valve and continue cooldown in a normal manner.

3. If 1 or 2 above can't be performed, attempt to open the valve manually after cooldown. DO NOT ATTEMPT ANY EXCESSIVE FORCE. If valve does not open manually, contact Maintenance for assistance.

2.15 Nuclear instrumentation operation and intermediate/source range channel overlap should be checked during shutdown. At 5 x 10^{-10} amps on the intermediate range, the source range detectors are energized. When the intermediate range reaches 10^{-10} amps, the source range indication should be decreasing to provide a minimum of one decade overlap.

2.16 The Rapid Feedwater Reduction (RFR) portion of the ICS will target feedwater flow to above 4% and bias MFPT speed in the increase direction on a RX trip. If a RX trip occurs from low power levels, this system may NOT bring the SG's levels to low level limits in the approximately 2 1/2 minutes as intended. A timer in the system will then release FW valve control to tracking normal ICS demand. The MFPT speed control will remain biased upwards (if MFPT is in Auto). The net result of this control should bring the SG levels down to low level limits, however, it will take longer than if the Rx trip was from a high power level. The RFR is armed if the defeat switch in the ICS (Cab 5, Row 2, Module 8) is on, a MFPT is reset and all four FW control valves are in auto.

3. REFERENCES

(TS) 3.1 Davis-Besse Technical Specifications

3.2 NSSS Plant Limits and Precautions, PP 1101.01

3.3 NSSS Setpoints, PP 1101.02

3.4 EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture

3.5 Operational Chemical Control Limits, PP 1101.04

3.6 Plant Prestartup Check, PP 1102.01 (Prestart Checklist)

3.7 Reactor Coolant System Operating Procedure, SP 1103.00 Series

3.8 Auxiliary System Operating Procedures, SP 1104.00 Series

3.9 Instrumentation and Control Systems Procedures, SP 1104.00 Series

3.10 Steam System Operating Procedures, SP 1106.00 Series

3.11 Electrical System Operating Procedures, SP 1107.00 Series

3.12 AD 1839.00, Station Operations

3.13 USAR Section 6 and 7

3.14 Boron Control, SP 1103.04

3.17 Reactivity Balance Calculation

4. PLANT POST TRIP SUPPLEMENTAL ACTIONS

NOTE: Some steps in this section may not be applicable to the plant conditions for all trips. They should be marked N/A after getting the Shift Supervisor's concurrence. Include a brief explanation of the reason the step is N/A.

_____4.1 If the SFAS has initiated, perform Attachment 6 for SFAS equipment recovery guidelines, in parallel with the remainder of Section 4.

_____4.2 If the SFRCS has initiated for any trip except for loss of four RCP's perform Attachment 7 for SFRCS recovery guidelines, in parallel with the remainder of Section 4.

_____4.3 If all four RCP's are stopped, initiate steps to restart idle RCP's. Refer to SP 1103.06, RC Pump Operating Procedure.

If SFRCS has initiated only on loss of four RCP's the AFW pumps may be shutdown when RC flow is reestablished. Refer to SP 1106.06, Section 7, AFP Operating Procedure.

NOTE: If a cooldown is expected, only 3 RCP's need to be running.

_____4.4 If the reactor power shows any sign of an increase, initiate boron addition.

_____4.5 Stop all but one of the running Condensate Pumps as condensate system flow allows.

_____4.6 When S.G. levels reach 35" or when the rapid feedwater reduction 2.5 minute timer completes its cycle, verify the ICS controls at low level limits or take manual control of the feedwater system.

RFR may need to be defeated by going to off on RFR switch in ICS cabinet, Cabinet 5, Row 2, Module 8.

_____4.7 If both MFP's are running, stop one of the running MFP's.

_____4.8 After the generator field circuit breaker trips, open the exciter field circuit breaker.

_____4.9 <u>WHEN</u> <u>BOTH</u> of the following conditions are indicated:

_____1. Tave within the post trip range of 550° to 555°F, <u>OR</u> stabilized outside the post trip normal range.

<u>AND</u>

_____2. Control of pressurizer level and RCS pressure has been recovered.

<u>THEN</u> perform the following steps:

_____1. Set pressurizer level setpoint at present pressurizer level.

_____2. Return letdown to service.

_____3. Shift MU pump suction back to MU tank if transferred.

_____4. Stop the second MU pump.

_____5. Maintain MU tank level between 55" and 87" by batch additions equivalent to the present RCS boron concentration.

_____4.10 Verify that the turbine bypass valves are attempting to maintain 1015 psig. If not, take manual control of turbine bypass valves. Pressure is controlled by the individual Steam Generator Outlet pressure if the turbine stop valves are closed.

NOTE: If one or more Main Steam Safety Valves/Atmospheric Vent Valves continue to relieve with SG pressure less than 1015 psig, or if all the TBPV's remain closed immediately following a trip, lower the TBPV's setpoint to get on TBPV control and reset Main Steam Safety Valves/Atmospheric Vent Valves. After a reactor trip, a + 145 psi bias will be added to the setpoint on the controller. Pay close attention to the SG levels and the pressurizer level during this process.

_____4.11 Perform the following at the turbine control console (C5713).

1. Start the following pumps before they are started automatically.

   a) Motor Suction Pump with the T-G MSP Control Switch (HIS-2400).

   b) Turning Gear Oil Pump with the TGOP Control Switch (HIS-2401).

14| _____4.12 Ensure that the steam seals remain on the turbine as long as vacuum exists in the condenser. The steam seal header pressure should be 2.5 to 4.5 psig as read on the TURB STM SEAL HDR PRESS Indicator (PI-2340) located on the MSR and Heater Drains Panel (C5722). If the turbine steam seals are lost, immediately open the condenser vacuum breakers by using COND VACM BRKR (HIS-634) located on the Feedwater Panel (C5721).

NOTE: Do NOT break vacuum, except during emergency conditions, until the unit is below its critical speed (900 - 1200 RPM). Examples of emergency conditions are loss of steam seals, loss of lube oil, etc.

_____4.13 Perform Attachment 4 for equipment on the Feedwater Panel (C5721) and the MSR and Heater Drain Tank Panel (C5722).

_____4.14 Perform Attachment 5 for the feedwater heater and deaerator extraction steam non-return valves.

_____4.15 Assign an Equipment/Auxiliary Operator to monitor turbine lube oil temperature. As the turbine speed decreases, the bearing oil temperature should be reduced so that it's 80° to 90°F when rotation stops.

_____4.16 Verify that the source range nuclear instrumentation is activated when the intermediate range nuclear instrumentation indicates 5 x 10^{-10} amps.

_____4.17 Enter in the Operator's Log the last available criticality

information including time, rod position, boron concentration, power level, and RCS average temperature.

_____4.18 When the reactor decay heat load has reduced enough that the feedwater requirements are within the range of the SUFP, place the SUFP in service and the running MFP in standby. Refer to SP 1106.27 for placing SUFP in service.

_____4.19 Restore the 345 KV switchyard to the ring bus configuration.

_____1. Request that the Load Dispatcher open ABS 34620.

_____2. Take station house power readings for Daily Reading Sheet 11 AND for Standing Order 20.

_____3. Dispatch an operator to pull close fuses for ABS 34620 if requested by Load Dispatcher.

_____4. Open the disconnect on TD3 B03-94 AMXG Generator Anti-Motoring to allow a ring bus with the turbine tripped.

_____5. Reset generator XFMR lockout with Load Dispatcher concurrence. Do NOT reset any lockout other than 86-1A (2A) (3A) (4A) GX until the cause of the lockout has been determined and load dispatcher concurrence.

Verify ABS 34620 is open, reestablish a ring bus by closing the generator breakers.

_____ACB 34560 closed
_____ACB 34561 closed

_____4.20 Shift RIM 600 and RIM 609 (MS Line Radiation Monitors) from the analyze mode to the gross mode.

NOTE: When the Rx is shutdown there will be no N-16 gamma present in the RCS, so the MS Line Rad Monitors must be in the gross mode in order to provide early detection of an OTSG Tube Leak.

_____4.21 Instruct C&HP to take a sample of the letdown water between 2 and 6 hours after the trip (per T.S. Table 4.4-4). An isotopic analysis for iodine must be performed (per T.S. Table 4.4-4) and if possible, a gross activity determination should also be performed.

_____4.22 Perform Section 7.2, Shutdown After a Turbine Trip From Power, of SP 1106.15, Moisture Separator Reheater Operating Procedure.

_____4.23 At least two (2) licensed Reactor Operators must be present in the Control Room and at least one licensed Senior Reactor Operator must be present at this unit.

NOTE: The SRO License may be one of the two individuals in the Control Room.

_____4.24 Proceed with Section 5.

5. STABILIZING THE PLANT AT HOT STANDBY CONDITIONS AND INCREASING THE SG LEVELS

NOTE: Some steps in this section may NOT be applicable to the plant conditions for all trips. They should be marked N/A after getting the Shift Supervisor's concurrence.

NOTE: Exact sequence NOT required except for Steps 5.9 through 5.16 which must be done in the sequence listed.

Normally conditions will be as follows:

4 RCP's on
RCS pressure controlled at 2155 psi
PRZR level 100" to 200"
Turbine header pressure being controlled at 1015 psig
Tavg approximately 548°F to 555°F
(This will vary if the trip was from <25% FP)
MU tank level ≥55"
SG's on low level limits
Investigation of the cause of RX trip initiated
Startup Transformers supplying house power
GE Air Dump has closed FW Htr Extraction Non-return valves and opened extraction line drains
One MFPT or SUFP is in operation
Both Htr Drain Pumps are off
Motor Suction Pump, TGOP and Lift Pumps are on
Generator Field Circuit breaker open
One Condensate Pump on

5.1 Place the auxiliary boiler in service per SP 1106.04, Auxiliary Boiler Operating Procedure. Continue with this procedure as the auxiliary boiler is being placed on. When auxiliary boiler is on perform substeps below.

_____1. Transfer Auxiliary Steam Loads to the aux boiler per SP 1106.25, Section 7, Auxiliary Steam System Procedure. Ensure trap header and flash tank vent is shifted.

_____2. Shutdown the flash tank pumps locally.

_____3. Slowly increase pegging steam to the main deaerators to maintain ~ 2.5 psig steam blanket on deaerator.

_____4. Establish a drain path from the deaerators to the condenser by opening FW 104 and throttling FW 33 to maintain enough condensate flow to prevent water hammer in the deaerator and connecting lines. Keep the flow low enough to prevent exceeding auxiliary boiler capacity for pegging the deaerator.

_____5.2 If a MFP is still supplying feedwater, when RX decay heat load has reduced the SG feed requirements to within the range of the SUFP, place the SUFP in service and place the MFP in standby. Refer to SP 1106.27 for placing the SUFP in service.

5.3 Shift the gland seal steam supply from the main steam header to the auxiliary steam header by performing the following from CTRM Panel C5722:

_____1. Open the auxiliary steam supply to Gland Steam System drain valve, AS 1934, using HIS 1934.

_____2. Open the auxiliary steam supply to Gland Steam System, GS 2380, using HIS 2380.

_____3. Close main steam supply to Gland Steam System, GS 2384, using HIS 2384.

_____4. Close auxiliary steam supply to Gland Steam System Drain Valve AS 1934.

5.4 When the turbine has come to rest (approximately 90 minutes with Vacuum), perform the following.

_____1. Verify the turbine is on gear.

_____2. Lockout the Motor Suction pump.

_____3. If the shutdown is expected to last more than 24 hours, activate blanketing steam per SP 1106.15, MSR procedure.

_____4. Shift H_2 purity analyzer to vent and verify flow is 1 scfm.

_____5. Verify lube oil temperature is 80°F.

_____6. With the generator at rest or on turning gear, there is no positive ventilation of the exciter house. EITHER degas the generator as a safety measure during long duration outages OR have temporary fans installed to ventilate the

exciter house AND have daily checks made for Hydrogen leakage into the exciter house. Contact the Operations Engineer for guidance.

_____5.5 Check the EHC first hit panel to determine the cause of the turbine trip.

CAUTION: Never reset the EHC trip system before the cause of the trip has been clearly established and the responsible malfunction has been corrected.

_____5.6 Verify both OTSG's on low level limits and place Steam Generator/ RX Demand, and RX Demand ICS Stations in hand and run down to minimum.

_____5.6.1 Place ΔTc controller in manual set demand @ 50%.

_____5.6.2 Place both feedwater loop demands to zero. AND verify feedwater flow remains constant.

_____5.6.3 The operating MFP may be put in manual as needed to prevent OTSG level oscillations.

5.7 Determine from Boron Concentration Control Procedure, SP 1103.04, the feed solutions required to maintain RCS Boron Concentration at its' present value (from primary plant status board and boronometer) while adding the contraction volume required during RCS cooldown to 530°F.

_____5.7.1 Maintain PZR Level @ 100 inches if a Rx startup is planned. If a cooldown is expected, maintain PZR level @ 200 inches. Any volume above the 100" level required for plant startup can be used as contraction volume during the cooldown from post trip Tave to 530°F.

_____5.7.2 Increase MU tank level to 86". Record the batch sizes and sources below.

B_1__________gal B_2__________gal
from________ from________

_____5.8 If a cooldown is planned, begin degasing per SP 1102.12, Hydrogen Addition and Degasification Procedure to the limits given in SP 1102.12.

_____5.9 In preparation for withdrawing CRA Safety Rod Group 1, reset ARTS and then RPS as follows:

NOTE: If the control rods cannot be withdrawn or if the RPS and/or ARTS cannot be reset at this time, refer to Step 2.6.3.

To reset ARTS, perform the following steps at each channel:

_____1. Obtain keys to the ARTS cabinet from the Shift Supervisor.

_____2. If both MFPT's are tripped, obtain the four test trip bypass switch (TTBS) keys from the Shift Supervisor for all four ARTS channels. Place all four TTBS in the MFP position to block the trip signal from the ARTS to the RPS.

_____3. Verify the 1/5 lights are off.

_____4. Press the reset button and verify the TRIP light goes off.

To reset the RPS, perform the following steps at each channel when the conditions causing the trip have cleared.

_____5. Obtain keys to the RPS Cabinet from the Shift Supervisor.

_____6. Reset the appropriate trip bistables and output memory bistables for the parameter(s) that caused the RX trip by depressing the "Reset" toggle switch.

_____7. Reset the Reactor Trip Module (location 2-2-7) by depressing the "Reset" toggle switch on the Reactor Trip Module. The "Channel Trip" lamp should go dim.

_____8. Reset the"Output Memory" lamp on the Source Range SUR Bypass/High Voltage Shutoff from NI-3 (NI-4) Bistable (Channel 3 and 4; location 1-2-9).

_____9. Reset the "Output Memory" lamp on the Flux 10% Bistable (Channel 1 and 2: location 1-7-12: Channel 3 and 4, location 1-8-12).

_____10. Close and lock RPS Cabinet doors and return keys to the Shift Supervisor.

_____Channel 1 _____Channel 2 _____Channel 3 _____Channel 4

_____5.10 Verify component cooling water flow of at least 122 GPM supplied to CRDMs.

CAUTION: Prior to resetting the Control Rod Drive System, ensure the Turbine Bypass Valve H/A stations are in hand, ICS 12A & B, as the +145 psi bias will be removed from their setpoint.

_____5.11 After verifying the TBV H/A stations are manual, reset the Control Rod System, latch safety rod groups 1 through 4, reset the Relative Position indication and withdraw safety group 1 as per Control Rod System Procedure, SP 1105.09, Section 4.1.

NOTE: Observe count rate while withdrawing control rods.

_____5.12 Using either the turbine bypass valves (PIC ICS 12A & B) in manual or the turbine header pressure controller setpoint (PIC ICS 10), slowly reduce turbine header pressure to 870 psig.

NOTE: Step 5.14 can be performed at the same time as this step for a smoother cooldown to 530°F.

_____5.13 Monitor RCS temperature and pressure during cooldown to verify TS 4.4.9.1.1. while cooling down; log the time and pressure and temperature every 1/2 hr during cooldown in the RO Log.

_____5.14 As turbine header pressure is lowered (and SG level increased if Step 5.16 is done at the same time as this step), RCS temperature will decrease from approximately 546°F. Add borated water per Boron Concentration Control Procedure, SP 1103.04, to maintain Makeup Tank level at 55 inches if necessary.

_____5.15 Place the turbine bypass valve ICS station in Auto (PIC ICS 12A and B), with the header pressure setpoint at 870 psig (45%) on PIC ICS 10.

_____5.16 Place the Main Feedwater and Startup Feedwater Control Valves (FIC ICS 35A & B and FIC ICS 33A & B) in hand control and slightly increase feedwater flow to both SG's. Minimize the amount of cooldown to the reactor coolant system unless this step is being performed at the same time as header pressure is being reduced. Increase the SG's level to 250 ± 50" on the startup range.

NOTE 1: This step may be performed with Step 5.14.

2. If reactor startup is expected within ~10 hours, it is permissible to remain on low level limit control with Feedwater Valves in AUTO. If the return to power is delayed or if necessary to improve Steam Generator chemistry, S/G levels should be increased to 250 ± 50".

_____5.17 If possible, perform an inspection of containment at full temperature and pressure. This inspection will identify leaks and other potential problems. If a cooldown is planned, this inspection is highly desirable. As a minimum the inspection should include the pressurizer valve room, the top and bottom of BOTH "D" rings, the Letdown Cooler area, the incore closure seals and the Decay Heat Valve pit area. The inspection should be made by a team consisting of representatives from Operations, Maintenance and Chemistry and Health Physics. The list of identified problems should be turned in to each department's supervisor.

_____5.18 Update the Shift Supervisor status board for the due date and time for ST 5061.05.

_____5.19 If the water in the Steam Generators is out of spec, start the following sequence: fill, soak (approximately two hours), and drain Steam Generators. Continue this procedure until the water in the SG's is within spec. If the chemistry is out of limits after eight hours, the system must be cooled to less than 400°F.

LIMITS:	Cl	1.0 ppm max
	Sodium	2.0 ppm max
	Cation Conductivity	10.0 μmho/cm
	Silica	2.0 ppm max

_____5.20 If the time since the reactor trip approaches the time required to reach equilibrium xenon (from Figure 1), a determination should be made as to whether or not the plant is to be cooled down. This is required to assure a 1% shutdown margin after the trip.

1. If a cooldown is <u>NOT</u> expected, <u>THEN</u>

   borate the RCS to the value given in Figure 13 of PP 1101.02

   <u>OR</u>

   If it desired to have a boron concentration below the value given in Figure 13 (for a quick restart), obtain an Estimated Critical Boron (ECB) calibration from the START program and maintain the RCS boron concentration equal to or about the boron concentration given in the ECB calculation for that hour. When all the Xenon decays, the ECB boron concentration value will be equal to the value given in Figure 13.

   NOTE: If an adjusted boron concentration is used, put an information Tag near the batch controller indicating how long the boron concentration is good for.

2. <u>IF</u> a cooldown is expected, <u>THEN</u>

   borate the RCS to the value given in Figure 15 of PP 1101.02.

   NOTE: If Figure 15 is used, put an Information Tag on the Diamond T-handle indicating that the boron concentration only allows CRA Group 1 to be pulled and still maintain the reactor 1% $\Delta k/k$ shutdown (1% $\Delta k/k$ <u>SHUTDOWN VALUE</u>).

_____5.21 Complete Attachment 3, Post Trip Review.

_____5.22 If plant cooldown is expected, de-energize the generator core monitor as per Generator, SP 1106.09.

_____5.23 If plant cooldown is planned, proceed to Plant Shutdown and Cooldown Procedure, PP 1102.10, Section 5 (Cooldown of NSSS from Hot Standby Condition).

_____5.24 If it is desired to return the reactor to power from the reactor trip, complete Attachment 1, Checklist for Return to Power Following a Reactor Trip. Then proceed to Plant Startup Procedure, PP 1102.02, Section 7, with the exception that the MODE 2 and MODE 1 checklist need not be completed. Successful completion of the Checklist for Return to Power Following a Reactor Trip will satisfy MODE 2 and 1 requirements.

At the completion of this section the following conditions should normally exist.

- RCS pressure 2155 PSIG
- T_{ave} approximately 532°F
- Pressurizer level 100 inches. If return to power, 200" if cooldown planned
- RCP combination 2/2
- RCS boron concentration as necessary to maintain the reactor greater than 1% $\Delta K/K$ subcritical
- Group 1 Rod fully withdraw, Groups 2 through 7 fully inserted, and Group 8 at its previous position
- Normal Letdown in Service
- Main feedpump or startup feedpump in service
- OTSG level maintained at 35 to 70% or at low level limits
- Decay Heat being removed by dumping steam to the condenser
- Deaerator pegging steam heating feedwater
- Auxiliary boiler supplying Auxiliary Steam

Section 5 completed by______________________________Date__________

Checklist for Return to Power Following a Reactor Trip

The following checklist must be completed for each reactor trip from power prior to restart.

_____1. Attachment III, "Post Trip Review" has been completed or an SRB review of the trip has been performed.

2. Without actually filling out the checklist, look through Mode 2 and Mode 1 Startup Checklists in PP 1102.01, Prestartup Checklist. Verify the status of these systems is in a condition such that a startup can be made.

NOTE: Refer to TS Table 4.3-1 for RPS surveillance requirements. Items 1, 10, 11, and 12 are required prior to each startup. Items 1, 10, 11 and 12 have a "Note 1," if not performed in previous 7 days.

Notify the I&C Engineer or the I&C Shop Foreman that the following Surveillance Tests must be completed prior to plant startup:

_____2.1 ST 5030.02 (Intermediate Range Only) must be done if required by the ST schedule.

_____2.2 ST 5030.17 (Intermediate Range Prestartup Functional Test) if not performed within previous 7 days.

_____2.3 ST 5091.01 (Channels 1 and 2, Source Range) if not performed within previous 7 days.

_____2.4 ST 5030.12 (Functional Test of the Reactor Trip Module Logic and Control Rod Drive Trip Breakers) if not performed within previous 7 days.

Operations personnel are to perform the following:

_____2.5 ST 5030.13 (Functional Test of Manual Reactor Trip) if not performed within previous 7 days.

_____2.6 ST 5073.01 (MSIV Valve Test) if not performed within previous 92 days.

_____2.7 ST 5013.04 (CRD exercising monthly) should be performed during rod withdrawal for startup.

_____3. Verify the unit is not in an ACTION statement of Technical Specifications which now would prevent re-entry into MODES 2 and 1.

NOTE: If 1, 2, or 3 cannot be verified, stop at this point in the checklist since the return to power cannot be made.

____4. Contact maintenance to replace canvas hoods on any main steam safety valves that may have lifted on the trip.

____5. If the Operations Engineer and the Technical Engineer have concurred to extend the 24 hour limit on this checklist, so document this extension by filling in the time allowed in addition to the original 24 hours. If no concurrence was given, place N/A in the blank.

Operations Engineer Notified By________________Date__________

Extension________Hours

Technical Engineer Notified By_________________Date__________

Extension________Hours

____6. At least two (2) licensed Reactor Operators must be present in the Cotnrol Room and at least one licensed Senior Reactor Operator must be present at this unit.

NOTE: The SRO License may be one of the two individuals in the Control Room.

Shift Supervisor____________________Date__________

____7. The Operations Engineer (or his designee) and the Plant Manager (or his designee) have given permission for restart.

Plant Manager Notified By_____________________Date__________

Operations Engineer Notified By________________Date__________

This form should be routed to the Operations Engineer for his review.

Reviewed By Operations Engineer__________________________Date__________

After the Operations Engineer completes his review, the completed form should be routed to the Technical Section for filing into the unit trip files.

Checklist completed: Shift Supervisor___________________Date__________

Isolation of Main Steam Line Drains and Loads to Permit
Pressure Equalization for Opening MSIV's

	Isolated By	Restored By
Main Steam Line No. 1 (MS 101)		
Located 623' Aux. Bldg.		
Isolate ST 39, MS 106		
Isolate ST 132, by 107A		
Located 603' Turb. Bldg.		
Close MS 710, MS Line 1 TBV Iso		
Close MS 710A, MS Line 1 TBV Iso Bypass		
Close MS 1299B or MS 846, w/u Line		
Located 585' Turb. Bldg.		
Close MS 706, MS Line 1 to MFPT 1-1		
Isolate ST 66, by MS 706		
Close MS 708, MS to AS Red. Sta.		
Close MS 2582, 2nd Stage R.H. S/U Drain		
Isolate ST 101, M.S. Line 1 Drain Trap		
Close MS 266 or MS 847, ST 101 Bypass		

NOTE: MS 101 may be opened when ΔP across the valve is less than 250 psid. Restore all valves and traps to normal S/U position as soon as possible after opening MS 101.

	Isolated By	Restored By
Main Steam Line No. 2 (MS 100)		
Located 623' Aux. Bldg.		
Isolate ST 125, by MS 107		
Isolate ST 121, by MS 106A		
Located 603' Turb. Bldg.		
Close MS 709, MS Line 2 TBV Iso		
Close MS 709A, MS Line 2 TBV Iso Bypass		
Close MS 840, MS to SG Iso		
Close MS 1299A or MS 843, MS Line 2 w/u Line		
Located 585' Turb. Bldg.		
Close MS 707, MS Line 2 to MFPT 1-2		
Isolate ST 67, by MS 707		
Isolate ST 100, MS Line 2 Drain Trap		
Close MS 138 or MS 841, ST 100 Bypass		

NOTE: MS 100 may be opened when ΔP across the valve is less than 250 psid. Restore all valves and traps to normal S/U position as soon as possible after opening MS 100.

Post Trip Review

The following review must be completed for each reactor trip (except normal tripping of CRD during heatups and cooldowns) even if a unit restart is not in progress.

1.1 Plant Pre-Trip Conditions (to be completed by the Shift Technical Advisor and Operations personnel after the plant stabilization is complete).

(A) Reactor power prior to the trip: _________%

Note any runback that occurred. ______________________________

____

____

(B) List any ICS stations in manual prior to the trip: __________

____

____

(C) List any testing in progress prior to the trip: ____________

____

____

(D) List any safety systems inoperable prior to the trip:

____

____

(E) List any other abnormal plant conditions contributing to the plant trip (inoperable main feedwater pump, high condenser vacuum, etc.).

____

____

Completed By_______________________________________Date__________

1.2 Plant Post Trip Conditions (to be completed by the Shift Technical Advisor and Shift Supervisor after the plant stabilization is complete).

(A) Did any of the following occur? (Use Control Room recorders, computer information, or operator observations.)

	No
Did the PORV actuate?	____
Did the pressurizer code safety valves actuate?	____
Did either steam generator level exceed 82.5%?	____
Did SG level go below 18"?	____
Was SFAS actuated?	____
Did pressurizer level decrease below 8 inches?	____
Did pressurizer level exceed 300 inches?	____
Was the Emergency Plan activated?	____
Did the SFRCS actuate?	____

If any of the above did occur, determine the cause and describe below:

____

____

____

____

____

____

____

(B) Write a short description of the cause of the trip, the ractor trip sequence of events which resulted in the trip, and any actions taken to prevent recurrence. (Review the Post Trip Review, Alarm Printout, and Sequence of Events Printouts, if available.)

____

____

____

____

____

____

____

Shift Technical Advisor______________________________Date__________

Shift Supervisor____________________________________Date__________

1.3 Safety Review of Transient (to be completed by Shift Technical Advisor and Shift Supervisor).

(A) Verify no safety concerns* have been identified in the review of the trip.

*A safety concern is defined as a safety related system not performing the design function for which it was intended.

Shift Supervisor________________________________Date__________

Shift Technical Advisor_________________________Date__________

(B) Verify no safety limits exceed during the transient (see Technical Specification 2.1). If any safety limits has been exceeded, operation shall not be resumed until authorized by the Commission as per 10CFR50.36 Section C.

Shift Supervisor________________________________Date__________

Shift Technical Advisor_________________________Date__________

If the cause of the unit trip cannot be determined, or the Sequence of Events for the reactor trip cannot be determined, or any safety concern identified, a unit restart cannot proceed until a Station Review Board review of the transient has been completed.

After this form is completed, it should be routed to the Operations Engineer for his review.

Operations Engineer______________________________________Date__________

After the Operations Engineer review, his attachment should be routed to the Technical Section to be included in the trip files.

1. Press open for main steam line NRV's.

   __________ HIS 209
   __________ HIS 210

2. Close HPT EXT to MSR 1 and 2 1st stage.

   __________HIS 197

3. Verify closed or close the following valves:

VALVE NO.		CONTROL SWITCH NAME	CONTROL SWITCH NO.
_____	ES278	HP FW HTR 1-4 LPT EXT VLV	HIS-278
_____	ES264	HP FW HTR 1-5 HPT EXT VLV	HIS-264
_____	ES377	HP FW HTR 2-4 LPT EXT VLV	HIS-377
_____	ES370	HP FW HTR 2-5 HPT EXT VLV	HIS-370
_____	GS346	LP FW HTR 1-1 SEAL REG VLV	HIS-346
_____	GS957	LP FW HTR 2-1 SEAL REG VLV	HIS-957
_____	AS958	CNDS FLSH TK 1 STM OUT MO/L	*HIS-958

*This switch will also open the Condensate Flash Tank Vent to 5 psig steam header valve (AS3748) if it was NOT automatically opened.

4. Verify open or open the following valves:

VALVE NO.		CONTROL SWITCH NAME	CONTROL SWITCH NO.
_____	ES308	FW HTR 1-5 & 2-5 HPT EX DR	HIS-308
_____	GS2167	STM SEAL REG DMP TO HP COND	HIS-2167

5. Stop Heater Drain Tank Pumps 1-1 and 1-2 using control switches HIS-318 and HIS-342, respectively.

   __________ HDP 1

   __________ HDP 2

6. Verify open or open the following valves:

	Valve No.	Control Switch Name	Control Switch No.
_____ _____	MS 2844 & MS 2845	MSR 1 MOIS SET IN X AROUND	HIS-2844
_____ _____	RD 2146 & RD 2148	MSR 1 MOIS SET DRN	HIS-2146
_____	MS 2842 & MS 2843	MSR 2 MOIS SET IN X AROUND	HIS-2842

	Valve No.	Control Switch Name	Control Switch No.
_____	RD 2150 & RD 2151	MSR 2 MOIS SEP DRN	HIS-2151
_____	TD 2382	STM LEAD DRN VLV 1	HIS-2382
_____	TD 2383	STM LEAD DRN VLV 2	HIS-2383
_____	TD 2368	STM LEAD DRN VLV 2	HIS-2368
_____	TD 2369	STM LEAD DRN VLV 4	HIS-2369
_____	TD 2381	COMBINED CTRL VLV	HIS-2381
_____	MS 138	MN STM 2 TRAP BYPASS	HIS-138
_____	MS 266	MS 1 STM TRAP	HIS-266
_____	ES 249	LPT 1 EXT TO FW HTR 1-2 DRN	HIS-249
_____	ES 415	LPT 1 EXT TO DEAR HTR 1-3	HIS-415
_____	ES 341	LPT 2 EXT TO FW HTR 2-2	HIS-341
_____	ES 411	LPT 2 EXT TO DEAR HTR 2-3	HIS-411
_____	ES 417	LPT 1 EXT TO FW HTR 1-4	HIS-417
_____	ES 252	HPT EXT TO FW HTR 1-6 DRN	HIS-252
_____	ES 409	LPT 2 EXT TO FW HTR 2-4	HIS-409
_____	ES 413	HPT EXT TO FW HTR 2-6	HIS-413

_____7. Depress the bearing lift pump RESET pushbutton (HS 2404A) and start the six (6) bearing lift pumps with the six BEARING LIFT PUMPS before they are started automatically. Control Switches (#1 HIS-2404; #2, HIS-2405; #3, HIS-2406; #4, HIS-2407; #5, HIS-2408; #6, HIS-2409).

1. Verify that the following valves have automatically closed. This must be done using either the respective computer points or by local verification. If these valves have not closed, close them using the local control switch.

	Valve No.	Computer Pt.	Local Control Switch Name	Local Control Switch No.
____	ES 256	Z517	HPT 1ST EXT T/E NRV, FW HTR 1-6	NV-256A
____	ES 349	Z515	HPT 1ST EXT G/E NRV, FW HTR 2-6	NV-349A
____	ES 298A&B	Z586	DEAER HTR 1-1-3 LP TURB 1-1 EXT	NV-298A
____	ES 9845	N/A	DEAR HTR 1-1-3 LP TURB 1-1 EXT	NV-9845
____	ES 325A&B	Z602	DEAR HTR 1-2-3 LP TURB 1-2 EXT	NV-325A
____	ES 9846	N/A	DEAR HTR 1-2-3 LP TURB 1-2 EXT	NV-9846
____	ES 264	Z493	HP EXT NRV FW HTR 1-1-5	NV-264A
____	ES 377	Z600	LPT 3RD EXT NRV FW HTR 1-2-4	NV-377A
____	ES 278	Z585	LPT 3RD EXT NRV FW HTR 1-1-4	NV-278A
____	ES 370	Z495	HPT EXT NRV FW HTR 1-2-5	NV-370A

SFAS INITIATION RECOVERY GUIDELINE

The purpose of this section is:

- To ensure that the SFAS is in the most relible operational condition at all times.

- To act as a guide for recovery from any incident level after a real or erroneous SFAS actuation.

This section is written strictly as a guide for the operator and is in no way intended to be detailed in actions to be taken. No real detail can be provided since the plant conditions at the time of the incident are in themselves unpredictable. The intent of this procedure is to remind or instruct the operator how to evaluate the incident, what general actions need to be taken, what problems to look for, and what detailed procedures will be needed for recovery from the various situations. The conditions of the reactor, primary and secondary systems, the operator actions during SFAS actuation, and the failure of components or systems during SFAS actuation will also determine the required actions for recovery.

The purpose of the Safety Features Actuation System (SFAS) is to automatically prevent or limit fission product and energy release from the core, to isolate the containment vessel and to initiate the operation of the ESF equipment in the event of a Loss of Coolant Accident (LOCA). To accomplish this purpose, SFAS actuated equipment shall NOT be blocked or overridden except as allowed by EP 1202.01, Specific Rule 4.

Blocking to re-initiate system operations should be avoided when possible. The desired method for re-establishing system operations after an erroneous trip is to reset the SFAS trips first. In this way, any subsequent SFAS trips can actuate the appropriate equipment as needed.

Following a real or erroneous trip of any SFAS incident level, the status of the associated equipment is dependent mainly on the incident level(s) actuated. Therefore, this section is divided into subsections by which incident levels occurred. The subsections are:

1. Incident Level 1 Occurrence
2. Incident Levels 1 and 2 Occurrence
3. Incident Levels 1, 2, and 3 Occurrence
4. Incident Levels 1, 2, 3, and 4 Occurrence

The corrective action steps listed in the sections do not have to be completed in the order given except as noted. In fact, it would be better if the steps listed were divided among personnel on shift at the time to speed their completion.

1. Incident Level 1 Occurrence

   An Incident Level 1 Occurrence will automatically initiate when

high radiation (2 times background at 100% power) is detected by two out of four containment radiation detectors, or by one out of three detectors when one has been declared inoperable and has been placed in the tripped condition.

CAUTION: Prior to any restoration of systems, ensure that the conditions warranting this actuation have been cleared, the plant is in a stable and controlled condition or the fault causing the automatic initiation has been determined and corrected.

The trip can be determined to be real or erroneous by comparing all four SFAS channels radiation levels and by noting any unusual RCS conditions which would indicate a leak exists. Containment radiation can also be checked on the wide range indicators on the Post Accident Indicating Panels.

1.1 SFAS Equipment Recovery From Real Initiation

(A) If a real high radiation condition does exist, it is probably indicative of a small RCS leak. Follow AB 1203.29, Small RCS Leaks.

(B) After the unit is shutdown, no specific recovery is required from Incident Level 1. Restore actuated equipment listed on Table 1 as required after approval, but do not open closed containment isolation valves unless required by plant conditions.

1.2 SFAS Equipment Recovery From Erroneous Initiation

(A) Reset the SFAS cabinets in accordance with SP 1105.03, "SFAS Operating Procedure", Section 5. This may require placing one of the channels with the erroneous input in the tripped condition. Do not reset the SFAS until the fault causing the actuation is cleared.

(B) Re-establish the Containment Gas H_2 Analyzer System per SP 1105.15, Section 7.

NOTE: Blocking will not be required as per Step 7.1.1 of SP 1105.15 if Step (A) above has been completed.

(C) Secure the Emergency Ventilation System per SP 1104.15, Section 4.

(D) Restart the Control Room Ventilation System per SP 1104.14, Section 4, as required.

(E) Re-establish ECCS Rooms Ventilation per SP 1104.16, Section 4. Steps 4.3.14 through 4.3.16.

(F) Secure the Containment Purge System per SP 1104.21, Section 6; or restart per Section 4 as required.

(G) Restore other SFAS actuated equipment as listed on Table 1 to normal as directed by the Shift Supervisor.

2. Incident Levels 1 and 2 Occurrence

A combined occurrence of Incident Levels 1 and 2 will automatically initiate when primary plant pressure drops to less than 1650 psig or containment vessel pressure raises to greater than 18.4 psia.

CAUTION: Prior to any restoration of systems, ensure that the conditions warranting this actuation have been cleared, the plant is in a stable and controlled condition, or the fault causing the automatic initiation has been determined and corrected.

The trip can be determined to be real or erroneous by comparing all four SFAS channels for the parameter which tripped the SFAS as indicated by the annunciators. If RCS pressure has reduced to 1985 psig, the independent RPS pressure transmitters would have tripped the reactor. Also, if enough reactor coolant was released into containment to provide 18.4 psia, radiation levels should have increased and pressurizer water level should have dropped. The Post Accident Indicating Panels also contain indication of containment wide range pressure, water level, and radiation as well as normal sump level, all of which can be used for comparison.

NOTE: If an SFAS Level 2 Trip has occurred and the EDG's are supplying C-1 and D-1 busses DO NOT reset SFAS until offsite power is restored. If SFAS is reset and subsequently actuated with an existing loss of offsite power the EDG sequencer will not be reset and all loads will be instantaneously placed on the EDG, overloading the unit. The sequencer logic will only be reset by closing the essential bus feeder breaker or cross-tie.

2.1 SFAS Equipment Recovery From Real Initiation

Recovery from this situation will generally be conducted after the establishment of cooldown and depressurization per EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture.

The primary concern during this recovery is the assurance of no further release of fission products or energy from the core and continued integrity of the containment vessel. To ensure this, the plant must be in a shutdown condition with a reliable source of cooldown and depressurization in progress.

After approval:

(A) Return both Emergency Diesel Generators to normal standby conditions per SP 1107.11, "EDG Operating Procedure" if not required for emergency power.

(B) If the condition causing the trip has cleared, reset the SFAS cabinets per SP 1105.03, (SFAS), Section 5.

NOTE: Resetting of the SFAS cabinets will not change the status of the actuated equipment.

(C) If the SFAS cabinets have been reset, restore other SFAS actuated equipment as listed on Table 1 to normal. Do not open containment isolation valves unless necessary.

2.2 SFAS Equipment Recovery From Erroneous Incident Levels 1 and 2 Trip

After approval from the Shift Supervisor:

(A) Reset the SFAS cabinets per SP 1105.03, "SFAS Operating Procedure", Section 5. This may require placing one of the channels with the erroneous input in the tripped condition. Do not reset the cabinets until the fault causing the actuation is cleared.

(B) Re-establish letdown when necessary for RCS inventory control.

(C) Stop both HPI Pumps and close all four injection valves HP2A, B, C, and D.

(D) Return both Emergency Diesel Generators to normal standby conditions per SP 1107.11, "EDG Operating Procedure".

(E) Re-establish the Containment Gas H_2 Analyzer System per SP 1105.15, Section 7.

NOTE: Blocking will not be required as per Step 7.1.1 of SP 1105.15, if Step (A) above has been completed.

(F) Secure the Emergency Ventilation System per SP 1104.15, Section 4.

(G) Re-start the Control Room Ventilation System per SP 1104.14, Section 4, as required.

(H) Re-establish ECCS Rooms Ventilation per SP 1104.16, Section 4.

(I) Restore the Containment Purge System per SP 1104.21.

(J) Restore other SFAS actuated equipment as listed on Table 1.

(K) If an SFRCS trip has occured in parallel with the SFAS trip such that the OTSG level control setpoint has been changed to the "HIGH" value, return the setpoint to the "LOW" value by pressing "LOW" on HIS SP9B for SG1 and HIS SP9A for SG2. Switches located on the SFAS valve panel.

3. Incident Levels 1, 2, and 3 Occurrence

A combined occurrence of Incident Levels 1, 2, and 3 will automatically initiate when primary plant pressure drops to 450 psig or containment pressure of 18.4 psia. A comparison of the RCS pressure reading in each SFAS Channel will determine if the trip is from a real incident or from erroneous instrumentation. Also, the RPS has separate RC pressure transmitters that will trip the reactor if RCS pressure drops to 1985 psig. If the event is indeed due to a LOCA, containment pressure and radiation levels would be elevated. The Post Accident Indicating Panels also contain indication of containment wide range pressure, water level, and radiation as well as normal sump level, all of which can be used for comparison.

CAUTION: Prior to any restoration of systems, ensure that the conditions warranting this actuation have been cleared, the plant is in a stable and controlled condition, or the fault causing the automatic initiation has been determined and corrected.

NOTE: If an SFAS Level 2 Trip has occurred and the EDG's are supplying C-1 and D-1 busses DO NOT reset SFAS until offsite power is restored. If SFAS is reset and subsequently actuated with an existing loss of offsite power the EDG sequencer will not be reset and all loads will be instantaneously placed on the EDG, overloading the unit. The sequencer logic will only be reset by closing the essential bus feeder breaker or cross-tie.

3.1 Recovery From Real Incident Levels 1, 2, and 3 Occurrence.

Recovery from this situation will generally be conducted after the establishment of cooldown and depressurization per EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture.

The primary concern during this recovery is the assurance of no further release of fission products, to keep the core cool, and the continued integrity of the containment vessel. To ensure this, the plant must be in a shutdown condition with a reliable source of cooldown and depressurization in progress.

After approval:

(A) High pressure injection may be stopped or throttled per the Specific Rules section of EP 1202.01.

(B) Return both Emergency Diesel Generators to normal standby condition per SP 1107.11, "EDG Operating Procedure" if not required for emergency power.

(C) If the condition causing the trip has cleared, reset the SFAS cabinets per SP 1104.03, "SFAS Operating Procedure", Section 5.

(D) If the SFAS is reset, restore other SFAS actuated equipment as listed on Table 1 to normal. Do not open containment isolation valves unless necessary.

3.2 SFAS Recovery From Erroneous Incident Levels 1, 2, and 3 Occurrence

After approval from the Shift Supervisor:

(A) Reset the SFAS cabinets in accordance with SP 1105.03, "SFAS Operating Procedure", Section 5. This may require placing one of the channels with the erroneous input in the tripped condition. Do not reset the SFAS until the fault causing the actuation is cleared.

(B) Re-establish seal injection flow by:

(1) Re-open CC1460 to supply cooling water to the MU Pumps.

(2) Closing the seal injection flow control valve using FIC MU19.

(3) Reopen the RCP seal injection valves MU66C (D, A, B).

(4) Reopen MU19 until a flow of 3-5 GPM per seal is established. Open MU38, MU59C (D, A, B) and slowly establish approximately 32 GPM. Transfer hand/auto station to auto.

(5) Re-establish letdown when required for RCS inventory control.

(C) Stop both HPI Pumps and close all four injection valves HP2A (B, C, D).

(D) Stop both DH Pumps.

(E) Return both Emergency Diesel Generators to normal standby condition per SP 1107.11, "Emergency Diesel Generator Operating Procedure".

(F) Close CS Valves CS1530 and CS1531.

(G) Restore CCW to normal lineup and close the CCW to DH Coolers outlet valves CC1467 and CC1469.

(H) Re-establish the Containment Gas H_2 Analyzer System per SP 1105.15, Section 7.

NOTE: Blocking will not be required as per Step 7.1.1 of SP 1105.15, if Step (A) above has been completed.

(I) Secure the Emergency Ventilation System per SP 1104.15, Section 4.

(J) Restart the Control Room Ventilation System per SP 1104.14, Section 4 as required.

(K) Re-establish ECCS Rooms Ventilation per SP 1104.16, Section 4.

(L) Restore the Containment Purge System per SP 1104.21.

(M) Restore other SFAS actuated equipment as listed on Table 1 to normal.

(N) If an SFRCS trip has occured in parallel with the SFAS trip such that the OTSG level control setpoint has been changed to the "HIGH" value, return the setpoint to the "LOW" value by pressing "LOW" on HIS SP9B for SG1 and HIS SP9A for SG2. Switches located on the SFAS valve panel.

4. Incident Levels 1, 2, 3, and 4 Occurrence

A combined occurrence of Incident Levels 1, 2, 3, and 4 will automatically initiate when containment pressure increases to 38.4 psia. Since the only real incident that can cause this large increase in containment pressure is a major LOCA, by a quick observation of RCS pressure, pressurizer level, and containment radiation levels, the operator can determine if the incident is real or erroneous. The Post Accident Indicating Panels also contain indication for containment WR pressure which can be checked as a backup.

CAUTION: Prior to any restoration of systems, ensure that the conditions warranting this actuation have been cleared, the plant is in a stable and controlled condition, or the fault causing the automatic initiation has been determined and corrected.

If Incident Levels 1 through 4 are due to a real occurrence, the BWST level will drop within a matter of hours to the low level setpoint and the DH and CS Pumps suction will have to be transferred to the emergency sump. Therefore, the recovery from a real Incident Level 1 through 4 occurrence is the same as from an Incident Level 1 through 5 occurrence.

NOTE: If an SFAS Level 2 Trip has occurred and the EDG's are supplying C-1 and D-1 busses DO NOT reset SFAS until offsite power is restored. If SFAS is reset and subsequently actuated with an existing loss of offsite power the EDG sequencer will not be reset and all loads will be instantaneously placed on the EDG, overloading the unit. The sequencer logic will only be reset by closing the essential bus feeder breaker or cross-tie.

_____4.1 Recovery From Real Incident Levels 1, 2, 3, and 4 Occurrence

Recovery from this situation will generally be conducted after the establishment of cooldown and depressurization per EP 1202.01, RPS, SFAS, SFRCS Trip or SG Tube Rupture.

The primary concern during this recovery is the assurance of no further release of fission products, to keep the core cool and the continued integrity of the containment vessel. To ensure this, the plant must be in a shutdown condition with a reliable source of cooldown and depressurization in progress.

After approval:

(A) High pressure injection may be stopped or throttled per the Specific Rules section of EP 1202.01.

(B) If containment pressure has returned to below 18.4 psia, shut off both CS Pumps and close CS Isolation Valves CS1530 and CS1531.

(C) Return both EDG to normal standby condition per SP 1107.11, "Emergency Diesel Generator Operating Procedure" if not required for emergency power.

(D) If the condition causing the trip has cleared, reset the SFAS cabinets per SP 1105.03, "SFAS Operating Procedure", Section 5.

(E) If the SFAS has been reset, restore other SFAS actuated equipment as listed on Attachment 1 to normal. Do not open Containment Isolation Valves unless necessary. Do not close the containment emergency sump outlet valves if DH/CS suction is from the emergency sump.

4.2 SFAS Equipment Recovery From Erroneous Incident Levels 1 through 4 Occurrence

Since Incident Level 4 closes the MSIV's, the plant trip is a certainty. The operators efforts must be to stop both CS Pumps from spraying borated water into containment and reestablishing CCW to the containment header.

After approval from the Shift Supervisor:

(A) Push the block pushbuttons by the CS Pump control switch and stop both CS Pumps.

(B) Block and reopen the CCW Isolation Valves CC1407A and B and CC1411 A and B.

(C) Reset the SFAS cabinets in accordance with SP 1105.03, "SFAS Operating Procedure" Section 5. This may require placing one of the channels with the erroneous input in the tripped condition. Do not reset the SFAS until the fault causing the actuation is cleared.

(D) Clear any SFRCS trips present, open the MSIVs, and reestablish condenser vacuum per Attachment 7.

(E) Stop both HPI Pumps and close all four injection valves HP2A (B, C, D).

(F) Stop both DH Pumps.

(G) Return both Emergency Diesel Generators to normal standby condition per SP 1107.11, "Emergency Diesel Generator Operating Procedure".

(H) Close CS Injection Valves CS1530 and CS 1531.

(I) Restore CCW to normal lineup and close the CCW to DH Coolers Outlet Valves CC1467 and CC1469.

(J) Re-establish the Containment Gas H_2 Analyzer System per SP 1105.15, Section 7.

NOTE: Blocking will not be performed as per Step 7.1.1 if Step (C) above has been completed.

(K) Secure the Emergency Ventilation System per SP 1104.15, Section 4.

(L) Restart the Control Room Emergency Ventilation System per SP 1104.14, Section 4, as required.

(M) Re-establish ECCS Room Ventilation per SP 1104.16, Section 4.

(N) Restore the Containment Purge System per SP 1104.21.

(O) Restore other SFAS actuated equipment as listed on Table 1 to normal.

(P) If an SFRCS trip has occured in parallel with the SFAS trip such that the OTSG level control setpoint has been changed to "HIGH" value, return the setpoint to the "LOW" value by pressing "LOW" on HIS SP9B for SG1 and HIS SP9A for SG2. Switches located on the SFAS valve panel.

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 1

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
C30-1	M-029A	Emer Vent Fan 1	SA 111A	Start	Off
HV 5439	M-028B	ECCS Room 105 HV&AC Iso Vlv	SA 111B	Closed	Open
HV 5440	M-028B	ECCS Room 105 HV&AC Iso Vlv	SA 111C	Closed	Open
HV 5024	M-029A	Emer Vent Fan 1 Vlv from Aux. Bldg.	SA 111D	Closed	Various
HV 5716	M-028B	ECCS Room 115 Iso Dmpr	SA 111E	Closed	Various
C30-2	M-029A	Emer Vent Fan 2	SA 112A	Start	Off
HV 5441	M-028B	ECCS Room 115 HV&AC Iso Vlv	SA 112B	Closed	Open
HV 5442	M-028B	ECCS Room 115 HV&AC Iso Vlv	SA 112C	Closed	Open
HV 5025	M-029A	Emer Vent Fan 2 Vlv from Aux. Bldg.	SA 112D	Closed	Various
HV 5715	M-028B	ECCS Room 105 Iso Dmpr	SA 112E	Closed	Various
CV 5008	M-029A	CTMT Purge Out Iso Vlv	SA 121B	Closed	Closed
CV 5011A	M-029B	CTMT Air Sample Iso Vlv	SA 121C	Closed	Open
CV 5011B	M-029B	CTMT Air Sample Iso Vlv	SA 121D	Closed	Open
CV 5011C	M-029B	CTMT Air Sample Iso Vlv	SA 121E	Closed	Open
CV 5011D	M-029B	CTMT Air Sample Iso Vlv	SA 121F	Closed	Open
CV 5006	M-029A	CTMT Purge In Iso Vlv	SA 121G	Closed	Closed
CV 5009	M-029A	Mech Pent Room 4 Purge Vlv	SA 121H	Closed	Closed
CV 5016	M-029A	Mech Pent Room 4 Purge Vlv	SA 121I	Closed	Closed
CV 5011E	M-029B	CTMT Air Smpl Ret Iso Vlv	SA 121J	Closed	Open
S10-1	M-027A	CTMT Ret Fan & HV/AC Unit 1	SA 121L	Various	

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 1

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
CV 5010D	M-029B	CTMT Air Sample Iso Vlv	SA 122B	Closed	Open
CV 5004	M-029A	Mech Pent Room 3 Purge Vlv	SA 122C	Closed	Closed
CV 5021	M-029A	Mech Pent Room 3 Purge Vlv	SA 122D	Closed	Closed
CV 5005	M-029A	CTMT Purge In Iso Vlv	SA 122E	Closed	Closed
CV 5007	M-029A	CTMT Purge Out Iso Vlv	SA 122F	Closed	Closed
CV 5010A	M-029B	CTMT Air Sample Iso Vlv	SA 122G	Closed	Open
CV 5010B	M-029B	CTMT Air Sample Iso Vlv	SA 122H	Closed	Open
CV 5010C	M-029B	CTMT Air Sample Iso Vlv	SA 122I	Closed	Open
CV 5010E	M-029B	CTMT Air Sample Ret Iso Vlv	SA 122J	Closed	Open
S10-2	M-027A	CTRM Ret Fan & HV/AC Unit 2	SA 122L	Stop	Various

SFAS Incident Level 2

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
P58-1	M-033	HP Inj PMP 1	SA 211A	Start	Off
HP2C	M-033	HP Inj 1-1 Vlv	SA 211B	Open	Closed
HP2D	M-033	HP Inj 1-2 Vlv	SA 211C	Open	Closed
P58-2	M-033	HP Inj Pmp 2	SA 212A	Start	Off
HP2A	M-033	HP Inj 1-2 Vlv	SA 212B	Open	Closed
HP2B	M-033	HP Inj 2-2 Vlv	SA 212C	Open	Closed
C 1-1	M-029A	CTMT Clr Fan 1	SA 221A	Start	Various
C 1-3	M-029A	CTMT Clr Fan 3	SA 221B	Slow	Various
C 1-2	M-029A	CTMT Clr Fan 2	SA 222A	Slow	Various
C 1-3	M-029A	CTMT Clr Fan 3	SA 222B	Slow	Various

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 2

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
P43-1	M-036	CC Pump 1	SA 231A	Start	Various
P43-3	M-036	CC Pump 3	SA 231B	Start	Various
CV 5070	M-029B	CTMT Vacm Rlf Iso Vlv	SA 231C	Closed	Open
CV 5071	M-029B	CTMT Vacm Rlf Iso Vlv	SA 231D	Closed	Open
CV 5072	M-029B	CTMT Vacm Rlf Iso Vlv	SA 231E	Closed	Open
CV 5073	M-029B	CTMT Vacm Rlf Iso Vlv	SA 231F	Closed	Open
CV 5074	M-029B	CTMT Vacm Rlf Iso Vlv	SA 231G	Closed	Open
P43-2	M-036	CC Pump 2	SA 232A	Start	Various
P43-3	M-036	CC Pump 3	SA 232B	Start	Various
CV 5075	M-029B	CTMT Vacm Rlf Iso Vlv	SA 232C	Closed	Open
CV 5076	M-029B	CTMT Vacm Rlf Iso Vlv	SA 232D	Closed	Open
CV 5077	M-029B	CTMT Vacm Rlf Iso Vlv	SA 232E	Closed	Open
CV 5078	M-029B	CTMT Vacm Rlf Iso Vlv	SA 232F	Closed	Open
CV 5079	M-029B	CTMT Vacm Rlf Iso Vlv	SA 232G	Closed	Open
P3-1	M-041	SW Pump 1	SA 241A	Start	Various
P3-3	M-041	SW Pump 3	SA 241B	Start	Various
SW 1424	M-041	SW From CC HX 1 Iso Vlv	SA 241C	Open	Various
SW 1429	M-041	SW From CC HX 3 Iso Vlv	SA 241D	Open	Various
P3-2	M-041	SW Pump 2	SA 242A	Start	Various
P3-3	M-041	SW Pump 3	SA 242B	Start	Various
SW 1434	M-041	SW From CC HX 2 Iso Vlv	SA 242C	Open	Various
SW 1429	M-041	SW From CC HX 3 Iso Vlv	SA 242D	Open	Various
CS 1530	M-034	CS 1 Iso Vlv	SA 251A	Open	Closed
CS 1531	M-034	CS 2 Iso Vlv	SA 252A	Open	Closed
K 5-1	E-3	Emer DG 1	SA 261A	Start	Off
K 5-2	E-3	Emer DG 2	SA 262A	Start	Off

TABLE 1
Sheet 3 of 7

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 2

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
MU2A	M-031	RC Letdown Delay Coil Out Vlv	SA 271A	Closed	Open
DR 2012A	M-046	CTMT Norm Sump Iso Vlv	SA 271D	Closed	Open
RC 240A	M-030	RC PRZR Sample Vlv	SA 271E	Closed	Closed
SW 1399	M-041	SW Iso Vlv to Clng Wtr	SA 271F	Closed	Open
RC 1773A	M-040A	RC DT Hdr Iso Vlv	SA 271G	Closed	Open
RC 1719A	M-040A	CTMT Vent Hdr Iso Vlv	SA 271H	Closed	Open
SS 607	M-007	SG 1 Sample Iso Vlv	SA 271I	Closed	Open
ICS 11B	M-007	SG 1 Atm Stm Vent Vlv	SA 271J	Closed	Open
SS 235A	M-040A	Przr Qnch Tk Sample Iso Vlv	SA 271K	Closed	Closed
CF 1544	M-034	CF Tk 1 H_2O and N_2 Fill Iso Vlv	SA 271L	Closed	Closed
MU 3	M-031	RC Letdown Hi Temp Vlv	SA 272A	Closed	Open
DR 2012B	M-046	CTMT Norm Sump Iso Vlv	SA 272C	Closed	Open
RC 240B	M-030	RC Przr Vapor Sample Vlv	SA 272D	Closed	Closed
CF 1542	M-034	CF Tk Vent Iso Vlv	SA 272E	Closed	Closed
SW 1395	M-041	SW Iso Vlv to Clng Wtr	SA 272F	Closed	Closed
RC 1773B	M-040A	RC DT Hdr Iso Vlv	SA 272G	Closed	Open
RC 1719B	M-040A	CTMT Vent Hdr Iso Vlv	SA 272H	Closed	Open
SS 598	M-007	SG 2 Sample Iso Vlv	SA 272I	Closed	Open
ICS 11A	M-007	SG 2 Atm Stm Vent Vlv	SA 272J	Closed	Open
SS 235B	M-040A	PRZR Qnch Tk Sample Iso Vlv	SA 272K	Closed	Closed
CF 1541	M-034	CF Tk 2 H_2O and N_2 Fill Iso Vlv	SA 272L	Closed	Closed
DH 9B	M-033	CTMT Emer Sump Vlv	SA 281A	Closed	Closed
DH 7B	M-033	BWST Out Vlv	SA 281G	Open	Open
NN 236	M-019	N_2 CTMT Iso Vlv	SA 281H	Closed	Open
RC 229A	M-040A	PRZR Qnch Tk Out Iso Vlv	SA 281I	Closed	Open
MS 394	M-003	Mn Stm Line 1 WU Drn Iso Vlv	SA 281J	Closed	Open

TABLE 1
Sheet 4 of 7

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 2

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
RC 232	M-040A	PRZR Qnch Tk In Iso Vlv	SA 282A	Closed	Open
RC 229B	M-040A	PRZR Qnch Tk Out Iso Vlv	SA 282B	Closed	Open
CC 1545	M-034	CF Tk Sample Vlv	SA 282D	Closed	Closed
DH 9A	M-033	CTMT Emer Sump Vlv	SA 282E	Closed	Closed
DH 7A	M-033	RWST Out Vlv	SA 282G	Open	Open
IA 2011	M-015	CTMT Instr Air Iso Vlv	SA 282H	Closed	Open
SA 2010	M-015	CTMT Serv Air Iso Vlv	SA 282I	Closed	Open
MS 375	M-003	Mn Stm Line 2 WU Drn Iso Vlv	SA 282J	Closed	Closed
CV 5065	M-029A	CTMT H_2 Dilution In Iso Vlv	SA 291A	Closed	Closed
DW 6831A	M-010B	RCP STDP Demin Wtr Iso Vlv	SA 291C	Closed	Open
CV 5038	M-029A	CTMT H_2 Dilution Out Iso Vlv	SA 291E	Closed	Closed
CV 5090	M-029A	CTMT H_2 Dilution In Iso Vlv	SA 292B	Closed	Closed
DW 6831B	M-010B	RCP STDP Demin Wtr Iso Vlv	SA 292C	Closed	Open
CV 5037	M-029A	CTMT H_2 Dilution Out Iso Vlv	SA 292E	Closed	Closed

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 3

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
P 42-1	M-033	DH Pump 1	SA 311A	Start	Various
HV 1467	M-036	CC From DH Clr 1 Out Vlv	SA 311C	Open	Various
HV 2733	M-033	DH Pump 1 Suct Vlv From BWST	SA 311D	Open	Various
HV DH14B	M-033	DH Clr 1 Out Vlv	SA 311E	Open	Various
HV DH13B	M-033	DH Clr 1 Bypass Vlv	SA 311F	Closed	Various
P 42-2	M-033	DH Pump 2	SA 312A	Start	Various
HV 1469	M-036	CC From DH Clr 2 Out Vlv	SA 312C	Open	Various
HV 2734	M-033	DH Pump 2 Suct Vlv from BWST	SA 312D	Open	Various
HV DH14A	M-033	DH Clr 2 Out Vlv	SA 312E	Open	Various
HV DH13A	M-033	DH Clr 2 Bypass Vlv	SA 312F	Closed	Various
HV 1495	M-036	CC Aux Equip In Vlv	SA 321A	Closed	Open
HV 1460	M-036	CC Vlv to Emer Inst Air Cmps	SA 322A	Closed	Open
MU 33	M-031	RC MU Iso Vlv	SA 331I	Closed	Open
MU 38	M-031	RCP Seal Ret Iso Vlv	SA 332F	Closed	Open
MU 66A	M-031	RCP 2-1 Seal In Iso Vlv	SA 332E	Closed	Open
MU 66B	M-031	RCP 2-2 Seal In Iso Vlv	SA 331J	Closed	Open
MU 66C	M-031	RCP 1-1 Seal In Iso Vlv	SA 331K	Closed	Open
MU 66D	M-031	RCP 1-2 Seal In Iso Vlv	SA 332G	Closed	Open
MU 59A	M-031	RCP 2-1 Seal Ret Vlv	SA 331E	Closed	Open
MU 59B	M-031	RCP 2-2 Seal Ret Vlv	SA 331F	Closed	Open
MU 59C	M-031	RCP 1-1 Seal Ret Vlv	SA 331G	Closed	Open
MU 59D	M-031	RCP 1-2 Seal Ret Vlv	SA 331H	Closed	Open

ACTUATED EQUIPMENT TABULATION

SFAS Incident Level 4

EQUIP NO.	P&ID NO.	EQUIPMENT DESCRIPTION	SA SIGNAL NO.	SA POSITION	NORMAL POSITION
		SFAS Incident Level 4			
P 56-1	M-034	CS Pump 1	SA 411A	Start	Off
P 56-2	M-034	CS Pump 2	SA 412A	Start	Off
CC 1411A	M-036	CC In Iso Vlv to CTMT	SA 421A	Closed	Open
CC 1407A	M-036	CC Out Iso Vlv from CTMT	SA 421B	Closed	Open
CC 1567A	M-036	CC In Iso Vlv to CRD	SA 421C	Closed	Open
CC 1328	M-036	CC CRD Booster Pump 1 Suct Vlv	SA 421D	Closed	Open
CC 1411B	M-036	CC In Iso Vlv to CTMT	SA 422A	Closed	Open
CC 1407B	M-036	CC Out Iso Vlv from CTMT	SA 422B	Closed	Open
CC 1567B	M-036	CC In Iso Vlv to CRD	SA 422C	Closed	Open
CC 1338	M-036	CC CRD Booster Pump 2 Suct Vlv	SA 422D	Closed	Open
MS 101	M-003	Mn Stm Line 1 Iso Vlv	SA 431A	Closed	Open
FW 612	M-007	Mn FW 1 Stop Vlv	SA 431C	Closed	Open
MS 100-1	M-003	Mn Stm Line 1 WU Iso Vlv	SA 431E	Closed	Closed
MS 100	M-003	Mn Stm Line 2 Iso Vlv	SA 432A	Closed	Open
FW 601	M-007	Mn FW 2 Stop Vlv	SA 432C	Closed	Open
MS 100-1	M-003	Mn Stm Line 2 WU Iso Vlv	SA 432E	Closed	Closed

SFRCS INITIATION RECOVERY GUIDELINE

The purpose of this section is to act as a guide to restore plant operation to the normal mode of MFW feeding the SGs and the TBVs dumping steam to the condenser. This will allow the AFW System to be returned to standby and termination of steam dumping to the atmosphere via the atmospheric vents. The assumptions used in writing this section were that the SFRCS actuated on a signal other than a MFW or MS rupture. If a rupture is suspected, it should be determined if it can be isolated and a normal cooldown conducted (possibly on one SG) or consideration should be given to conducting a cooldown on AFW and the AVVs. A rupture, or condition such as a stuck open MSSV which prevents restoring normal feed and steaming on one SG, will make the below steps on that SG non-applicable.

1. Take control of OTSG pressure using the atmospheric vents to stop secondary side safety valve lifting.

_____1.1 Place both atmospheric vent valves hand/auto stations in "hand" at zero demand.

_____1.2 Press both atmospheric vent valves block buttons (HIS-ICS-11D and HIS-ICS-11C).

_____1.3 Press "auto" on HIS-ICS-11B and HIS-ICS-11C.

_____1.4 Control OTSG pressure as desired to prevent lifting secondary side safety valves. The valves may be placed in "auto" if desired.

_____2. Trip both Main Feed Pump Turbines.

3. If condenser vacuum has been lost, open the condenser vacuum breakers and lockout the Mechanical Hogger.

_____3.1 Open the condenser vacuum breakers using HIS-634 on Panel C-5721.

_____3.2 Lockout the Mechanical Hogger using HIS-1005 on Control Room Panel C-5721.

4. Have an operator start up the Auxiliary Boiler and charge the Auxiliary Steam Header.

_____4.1 Start up the Auxiliary Boiler per SP 1106.04.

5. Locate and correct the cause of the loss of normal feedwater if possible. If loss of normal feed was due to a pipe rupture, ensure isolation of the rupture. The cause of loss of normal feed could be one of the following:

_____5.1 A feed line rupture.

_____5.2 Loss of both main feed pumps.

_____5.3 Inadvertent closure of Main Feedwater Control Valves, Startup Control Valves, or Main Feedwater Block Valves.

_____5.4 Inadvertent SFRCS actuation.

_____5.5 Loss of steam pressure control causing SFRCS actuation, i.e., a stuck open MSIV.

6. When the 235 psig steam header is on the Auxiliary Boiler, re-establish seal steam and condenser vacuum.

_____6.1 Establish gland steam per SP 1106.03.

_____6.2 Establish condenser vacuum per SP 1104.35.

7. Before normal feedwater control can be accomplished, the SFRCS low level manual trips must be reset. The SUFP must be started to clear the SFRCS steam to feed ΔP trips.

_____7.1 To reset the manual low SG SFRCS trip, push off buttons on SG LVL LOW TRIP BUTTONS (4869 and 4970) on SFRCS manual initiation selection of Control Room Panel C-5721.

_____7.2 Start the SUFP per SP 1106.27.

_____8. If normal feedwater cannot be established, a cooldown will have to be conducted using the Auxiliary Feedwater System and the atmospheric vents.

_____9. If cooldown using the AFPs is required for an extensive period such that the CST water is exhausted, the automatic shift to service water should be verified or manually initiated if CST level falls below three feet.

9.1 Four pressure switches (two for each AFP) automatically shift AFP suction to service water on low AFP suction of 2 psig. If manual initiation is necessary, open SW 1382 (SW to AFP 1-1 suction and SW 1383 (SW to AFP 1-2 suction) and close FW 786 (AFP 1-1 suction valve) and FW 790 (AFP 1-2 suction valve).

_____10. If the SFRCS trips could be reset, restore normal OTSG heat removal by continuing with the following steps

_____11. Place the turbine bypass valves in hand and close the turbine bypass valves.

12. Open the Main Steam Non-return Valves MS 209 and MS 210.

_____12.1 Press open on HIS 209 and HIS 210 on Control Room Panel C-5722.

13. Press the closed buttons for MSIV 100 and MSIV 101. Then reset the SFRCS solenoids for MSIV 100 and MSIV 101.

_____13.1 HIS 100 and HIS 101 are located on Control Room Panel C-5717.

_____13.2 The SFRCS resets for MSIV 100 and MSIV 101 are located on the north wall of the Control Room Cabinet Room. Both resets must be pushed for each MSIV.

_____14. Equalize pressure across the MSIVs by opening the MSIV Bypass Valves MS 100-1 and MS 101-1.

15. If the dP across the MSIVs is greater than 250 psig and stable, isolate the main steam line traps and drains per Attachment 2 of this procedure. Restore the lineup after MSIVs are open.

_____15.1 Main Steam Isolation Valve dP for Line 1 is determined by comparing OTSG 1 pressure SP12B to turbine header pressure SP16B on the front consoles.

_____15.2 Main Steam Isolation Valve dP for Line 2 is determined by comparing OTSG 2 pressure SP12A to turbine header pressure SP16A on the front console.

_____16. When the dP across the MSIVs is less than 250 psid, place the atmospheric vent valves in hand and then open MS 100 and MS 101.

_____17. Using the hand/auto stations, take control of steam generator pressure with the turbine bypass valves and close the atmospheric vent valves.

_____18. Place the main feedwater valves and startup feedwater valves ICS stations in hand and close them. Reset the main feedwater valves and startup feedwater valves SFRCS trips.

_____18.1 Reset the Startup Feedwater Valves SP7A and SP7B SFRCS trips by pushing the reset pushbuttons on the west wall of the Control Room Cabinet Room.

_____18.2 The Main Feedwater Valves SP6A and SP6B SFRCS trips are reset by pushing reset pushbuttons located 603' elevation, east wall of the Turbine Building at SP6A and SP6B.

_____18.3 Reset the MFW Block Valves FW 779 and FW 780 by placing their control switches to OFF then back to AUTO.

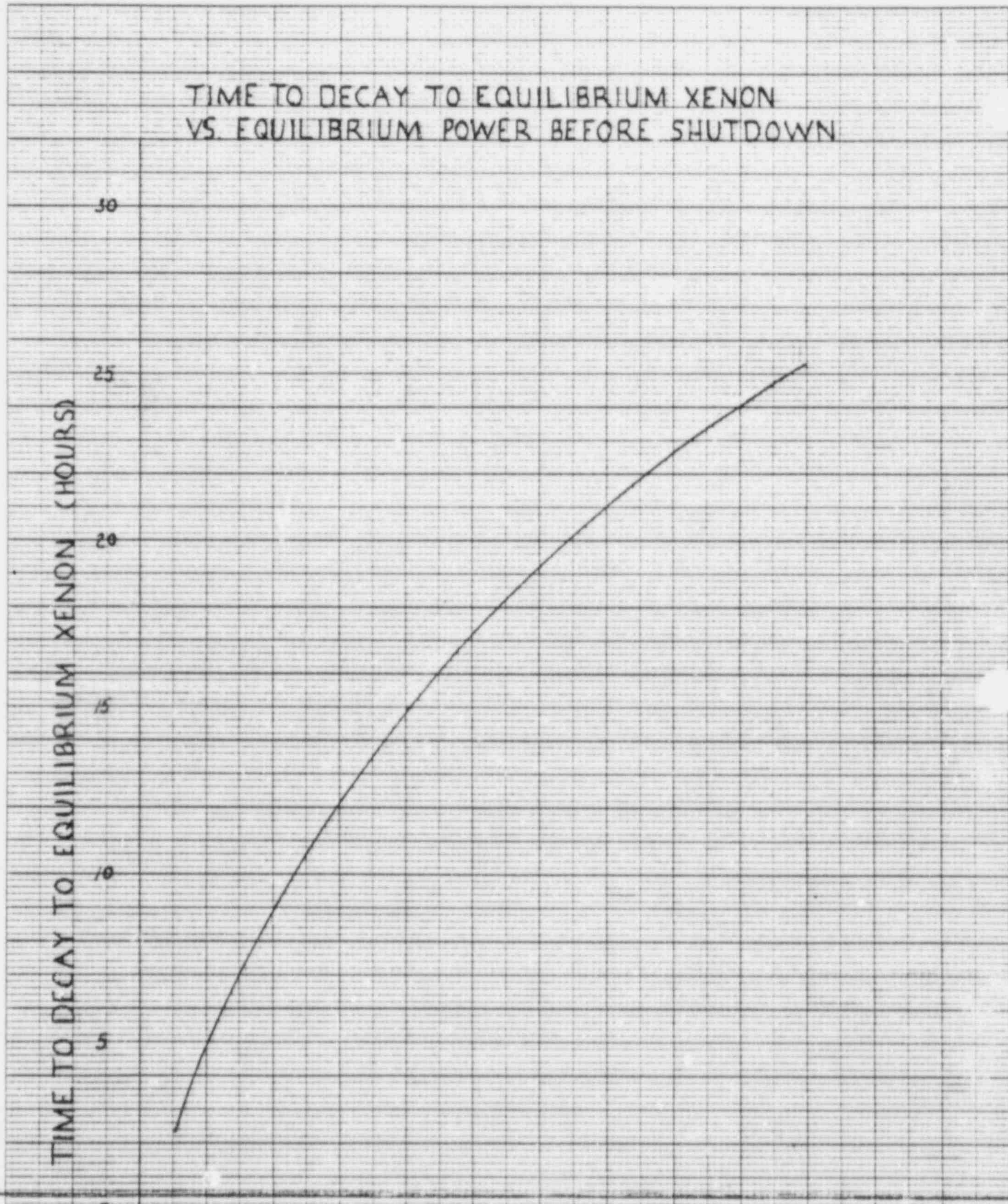
19. When the decay heat load is low enough to prevent running out to SUFP, establish main feedwater flow to the OTSGs. This may

require from one to two hours after reactor shutdown depending on the power history.

_____19.1 SUFP is rated for 300 gpm at 900 psig. Ensure AFW flow to both OTSGs is less than 300 gpm prior to shutting down AFPs.

_____19.2 Establish MFW flow to OTSGs by opening FW 601 and FW 612, Main Feedwater Stop Valves, and then throttling open SP7A and SP7B, Startup Feedwater Valves, from their ICS stations. Run the AFW governors to the low speed stops in manual.

_____20. When OTSG levels are being maintained by the SUFP alone, shutdown the AFPs per SP 1106.06, Section 7.



END

FIGURE 1
Sheet 1 of 1