REFERENCE 3

2-70-0 EMERGENCY SHUTDOWN FROM POWER

BASIS

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Discussion

This document explains the operator actions associated with a reactor trip. A reactor trip is required for any transient that causes (or is about to cause) a plant parameter to exceed its RPS setpoint.

An emergency shutdown may result from either operator or Reactor Protective System (RPS) action. The RPS will trip the reactor whenever any of the following parameters exceed their safety setpoint:

a) High Reactor Power Level
b) High Rate of Change of Power
c) Low Reactor Coolant Flow
d) Low Steam Generator Level
e) Low Steam Generator Pressure
f) High Pressurizer Pressure
g) Low Pressurizer Pressure (below TM/LP setpoint)
h) High Containment Pressure
i) High Symmetric Offset

These automatic reactor trips will also cause the turbine to be tripped.

In addition to the RPS trips listed above, the reactor will trip as a result of a turbine trip, if reactor power level is greater than 15%. The following conditions will result in a turbine trip:

a) Overspeed
b) Low Vacuum
c) Low Bearing Oil Pressure
d) High Thrust Bearing Oil Pressure
e) High Heater Drain Receiver Level
f) High Steam Generator Level
g) Loss of EHC Fluid Pressure
h) Loss of Auto Stop Oil Pressure
i) Loss of EHC Power Supply
j) Actuation of the Generator Protective System
k) Any Reactor Trip

An emergency shutdown of the reactor and the turbine may also be manually initiated by the operator in response to conditions which indicate that an automatic shutdown is imminent or which require the plant to be shut down immediately.

1.0 ENTRY CONDITIONS

1.1 Automatic reactor trip due to a RPS parameter exceeding its setpoint.

1.2 Automatic Reactor trip due to a turbine trip with power greater than 15%.

1.3 Any event which leads the operator to manually trip the plant.

BASIS

The conditions indicate automatic or manual actions which tell the operator that the reactor has tripped.

Plant parameters after a trip will normally trend as follows:

a) reactor power - will decrease due to control rod insertion. Startup rate will be negative.

b) pressurizer pressure - will decrease due to thermal shrink. The expected minimum value is 1900 psig. See figure 1 for a typical pressure trace.

c) RCS temperature - will decrease because the steam dump/turbine bypass system removes more heat from the RCS than is being supplied by the reactor.

d) pressurizer level - will decaease due to thermal shrink...The reactor coolant contracts as it is cooled and the pressurizer void space enlarges. Typically, the pressurizer level drops to about 24% following a trip (see figure 3). Immediately after a trip the CVCS acts to restore level.

e) steam generator pressure - will increase to 900 psig due to:

   1) the closing of the turbine stop valves and

   2) control by the steam dump/turbine bypass system

f) steam generator level - will decrease due to reduction in feed flow and collapsing of voids as pressure is increased.

2.0 INITIAL ACTIONS

2.1 Manually trip reactor

2.2 Manually trip turbine.

BASIS

Steps 2.1 and 2.2 ensure that all reactor and turbine trip functions have been initiated.

3.0 REACTIVITY CONTROL

3.1 IMMEDIATE

1) - Ensure reactor trip breakers open
- Ensure all trippable CEA's inserted
- Ensure power decreasing

3.2 REMEDIAL

1) Only 1 CEA fails to insert:
- Open MG set output breakers
- Proceed to Section 4.0

2) 2 to 10 CEA's fail to insert:
- Open MG set output breakers
- Initiate EOP 2-70-5, Emergency Boration

3) 11 or more CEA's fail to insert:
- Open MG set output breakers
- Initiate EOP 2-70-5, Emergency Boration
- Reenergize CEDM's and drive rods

BASIS

The actions in Step 3.1 ensures that normal shutdown margin is established by CEA insertion and that reactor power is decreasing as expected. Decreasing power is indicated by decreasing neutron flux and a negative start up rate.

Power should be decreasing rapidly. If some of the CEA's do not insert, shutdown margin will be reduced. If many CEA's do not insert, the reactor may remain critical at a significant power level. This is a potentially serious situation.

The actions in Step 3.2 are taken to regain proper reactivity control.

1) Opening the CEDM motor generator (MG) set output breakers interrupts power from the MG sets. This deenergizes the gripper coils causing the rods drop into the core.

Maine Yankee is designed for a hot safe shutdown with one rod stuck out. Since this is not considered to be a serious condition, no remedial action is necessary.

2) When more than (1) CEA fails to insert, emergency boration is initiated. The seriousness of this event depends on the exact circumstances. Usually this will only mean a reduction in shutdown margin. If a rapid cooldown occurs, however, a return to power is possible.

3) With 10 rods out, the reactor will still shut down under any anticipated transient condition. This includes anticipated transients which occur at end-of-life and from 100% power. If more than 10 rods stick out, the reactor could remain critical. In the worst case, full power output could continue.

4.0 RCS INVENTORY CONTROL

4.1 IMMEDIATE	4.2 REMEDIAL
1) Ensure pressurizer level 20-34% (gradually lower setpoint to 34%)	1) Less than 20% and not recovering a) - Increase charging - Reduce letdown b) - Prevent unnecessary cooldown c) - Initiate Safety Injection (EOP 2-70-1)

CAUTION

DO NOT ATTEMPT TO REDUCE INVENTORY IF A PRESSURIZER STEAM SPACE LEAK IS APPARENT BY INDICATED HIGH PRESSURIZER LEVEL AND DECREASING PRESSURE

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2) Greater than 34% and not decreasing

a) - Reduce charging
- Increase letdown

b) - Prevent unnecessary heatup

c) - Utilize alternate letdown

BASIS

Step 4.1 ensures that the Pressurizer Level Control System (PLCS) restores pressurizer level.

RCS inventory must be maintained to ensure core heat removal. If pressurizer level drops below 28% the pressurizer heaters trip off. Pressurizer level usually drops below 28% following a trip. The operator should act quickly to restore pressurizer level.

Normally, the PLCS setpoint is established manually; therefore, it will be necessary to lower the PLCS setpoint to its no load value (34%). 34% has been chosen as the zero power setpoint because it represents the best compromise between maintaining a level above the pressurizer heaters and leaving a volume available for thermal expansion. Low level can be caused by either rapid RCS cooling or a LOCA. Since low level threatens pressure control, a serious inventory transient could result in safety injection. 57% is the full power setpoint. Levels higher than this are unnecessary, and threaten an overpressure transient. Low level is the more likely problem.

Step 4.2 restores normal inventory control.

1) Low Pressurizer Level

By manually maximizing charging, the operator attempts to regain inventory control without resorting to safety injection.

Excessive cooldown will cause the reactor coolant to shrink and indicate a false reduction in inventory. This shrink can hinder pressure control by blocking heaters.

If decreasing pressurizer level cannot be combated using manual control of the CVCS, safety injection is inevitable. Safety margins are widened by initiating safety injection early.

2) High Pressurizer Level

High level can be caused by rapid thermal expansion, excessive charging, or unjustified safety injection. The preferred way of reducing level is through manual operation of the CVCS.

Allowing the reactor coolant to heat up will cause it to expand and raise pressurizer pressure. This could result in PORV opening and loss of inventory. The loop drain system is the alternate letdown path.

NOTE

POST TRIP RCS PRESSURE WILL NORMALLY BE BETWEEN
1800 and 2260 PSIG

5.0 RCS PRESSURE CONTROL

5.1 IMMEDIATE

1) Ensure subcooling 50-150°F

5.2 REMEDIAL

1) Less than 50°

a) - Increase charging
- Reduce letdown

b) - Prevent unnecessary heatup

c) - Energize heaters when level greater than 28%

d) - Reduce spray:

- close spray valve or isolate

- trip RCP's (last resort)

e) - Close PORV
- Close block valve

f) - Initiate SIAS (EOP 2-70-1)

2) Greater than 150°

a) - Heaters off

b) - Prevent unnecessary cooldown

c) - Reduce pressure to bring subcooling less than 150°F

d) - (Pressure above 2285 psig) Spray on

e) - (Pressure above 2385 psig) PORV's and block valves open

f) - (Pressure above 2485) check safeties open by accoustic accelerometer.

BASIS

Section 5.0 directs immediate and remedial actions to maintain proper RCS subcooling . Proper pressure control is specified in terms of subcooling to allow use of consistent criteria for all plant operating and accident conditions.

Subcooling is the difference between RCS temperature and saturation temperature for a given RCS pressure.

Subcooling is normally controlled by changing RCS pressure since pressure responds faster to operator actions than temperature.

The safe operating band for RCS subcooling protects against two unsafe fluid system conditions:

1. Bulk Boiling of the Reactor Coolant
2. Pressurized Thermal Shock.

Bulk boiling in the core can seriously degrade heat transfer from the core to the steam generator.

Pressurized Thermal Shock is a threat to reactor vessel integrity under the following conditions:

Conditions Necessary for a Real Challenge to Reactor Vessel

- Highly embrittled reactor vessel region
- Flaw or crack in the vessel of sufficient size
- Large induced thermal stresses
- High pressure in the primary system

(The first three conditions: At Critical Location)

Normal post trip subcooling is 90°F to 120°F. The 50°F to 150°F range specified provides reasonable assurance that bulk boiling limits and vessel integrity limits will not be exceeded. These limits account for uncertainties in pressure and temperature instruments under most conditions. It is best to operate near the 50°F subcooling condition.

Subcooling Less than 50°F

If subcooling is lost, voiding may result. RCS voiding outside the pressurizer can seriously degrade heat transfer from the core to the steam generator.

The pressurizer heaters and pressurizer spray normally work together to maintain pressurizer pressure. After a trip, the heaters will usually trip off on low pressurizer level.

Increased charging and reduced letdown will increase pressure by squeezing the bubble in the pressurizer. It will also speed the level recovery needed to regain use of the heaters.

Reducing pressure in the RCS increases the chance of boiling within the system. Heat removal actions are covered in section 6.0.

Any time level drops below 28%, the pressurizer heaters trip off. When level recovers to greater than 28%, the heaters may be reset. This action should be done quickly, since the heaters are vital to normal pressure control.

Loss of pressure control may be due to a stuck open spray valve. Control may be regained by closing spray valves or spray isolation valves. Tripping the RCP's will greatly reduce the differential pressure across the core. This will cause spray flow to be greatly reduced. To stop all spray flow, all RCP's must be tripped, even if only one spray valve is open since spray flow is proportional to core dp.

The PORV's could be the cause of loss of subcooling. Closing or isolating the PORV's will not remove all high pressure protection since the code safeties remain.

If subcooling is high, the operator should take action to lower it to prevent pressurized thermal shock (PTS) to RCS components.

<u>Subcooling Greater than 150°F</u>

If the above actions fail to restore subcooling or regain pressure control, safety injection will be required.

Pressurizer heater raises RCS pressure and subcooling by increasing the temperature of the saturated pressurizer fluid. If subcooling is too high, pressurizer heater power should be off.

Unnecessary cooldown could change the properties of some RCS components increasing the danger of PTS. The major component of concern is the irradiated reactor vessel. Heat removal controls are specified in section 6.0.

In the event of a cooldown transient, the operator must reduce pressure manually to prevent PTS. Specific directions are given in the procedures for Steam Line Break, LOCA, and Steam Generator Tube Rupture. These transients may cause cooldown by injection of cold HPSI water.

Pressure may be reduced to bring subcooling down to the desired level by use of the spray valves auxiliary spray valves, or PORV's. Values are given for automatic activation of these systems and the pressurizer safeties.

6.0 HEAT REMOVAL

6.1 IMMEDIATE	6.2 REMEDIAL
1) Ensure RCP's operation	1) Not operating: - Initiate EOP 2-70-7, Natural Circulation
2) Ensure core exit thermocouples decreasing toward 532°F	2) Not decreasing toward 532°F: - attempt to increase heat removal - Attempt to restore secondary sink
	3) Exceeds 800°F OR secondary heat sink unavailable: - Initiate SIAS (EOP 2-70-1) - Open PORV's, PORV block valves, and drain valves if needed to increase ECCS flow
3) Ensure the following valves have closed: - turbine stop valves - governor valves - intercept valves - reheat stop valves	4) Turbine steam supply cannot be isolated AND SG pressure falls below 500 psig: -close EFCV's
4) Ensure SG pressures 890-910 psig	5) Not 890-910 psig: - check proper operation of steam dump/turbine bypass system
	6) Less than 400 psig: - EFCV's auto close : - Initiate EOP 2-70-4, Steam Line Break

6.0 HEAT REMOVAL (cont'd)

6.1 IMMEDIATE (CONT'D)

5) Ensure operation of main condenser and steam dump/turbine bypass system

6) Ensure proper FW operation:

- check SG levels increasing
- check 1 main feed pump running
- check main feed reg valves closed
- check bypass valves 32% open
- throttle aux feed flow

6.2 REMEDIAL (CONT'D)

7) Main condenser or steam dump/turbine bypass not operable:

- Open atmospheric steam dump valve and isolation MOV
- Return MOV isolation switch to neutral

8) Main feed reg valves fail to close

a) - Close MFRV MOV's (FW-M-104, 204, 304)

b) - (last resort)

- Trip main FW pumps
- Trip heater drain pumps
- Trip condensate pumps
- Initiate auxiliary FW if not on

9) Normal feed flow not available

a) - Initiate EOP 2-70-6 Loss of Feedwater

BASIS

Section 6.0 directs actions to control heat removal from the core and the RCS.

Heat must be removed from the core to maintain fuel integrity and prevent unnecessary radioactive releases. Most of the post trip heat generation comes from the decay of fission products. Cooling the reactor coolant system too far too fast can overstress certain system components. The reactor vessel is of special concern here.

The preferred method of removing decay heat begins with forced circulation transferring heat from the core to the steam generator. Heat is then transferred from the steam generator to the condenser through the steam dump and turbine bypass system. Heat is removed from the condenser by the circulating water system.

Step 6.1 controls this preferred method of heat removal.

If the reactor coolant pumps fail or are required to be tripped, natural circulation will remove decay heat loads. In this mode dumping steam to the condenser is still the preferred mode of removing heat from the SG..

Use of the ECCS system and PORV's to remove decay heat should be used only when all attempts to cool the RCS with the steam generator have failed.

The 800°F action point was selected because:

- it is positive indication that the cooling method in use is not working,
- significant boiling and voiding is taking place in the core. Saturation temperature for 2485 psig is 668°F,
- starting this primary "feed and bleed" cooling method at 800°F gives enough margin to prevent massive core damage. The failure mechanisms, we are trying to prevent are:
    - Zirconium - water reaction of fuel clad at about 1600°F
    - Clad melt at about 3000°F
    - Fuel melt at about 4800°F

Present thermocouple indication on the MCB is limited to a high reading of 700°F. Higher readings can be read from the computer or input to the computer with a bridge device.

Failure of the turbine steam supply to isolate after a trip, will result in excessive heat removal.

The EFCV's can be used to isolate the turbine if the turbine stop valves remain open. Since this will also isolate the steam dump valves the SG pressure will increase and the safety valves will lift. The safety valves will then be removing decay heat and protecting the SG from overpressure.

The steam dump and turbine bypass system controls SG pressure between 890 and 910 psia. 900 psia SG pressure corresponds to a SG temperature of 532°F. 532°F is the desired value of Tave immediately following a plant trip since RCS cooling below 532°F will cause a reactivity insertion. As reactor power diminishes after a trip, Tave approaches the SG temperature; therefore, controlling SG pressure controlls Tave.

If the condenser is not available, the atmospheric dump valve can be used to aid heat removal. The atmospheric dump valve cannot relieve all initial decay heat; therefore, the safety valves will lift.

If a steam line break occurs and pressure drops below 400 psig in any SG, all EFCV's will trip closed and all feed valves associated with the affected generator will close.

The MFWRV's are designed to supply feed at full power conditions. When the plant is shut down, much less feedwater is required. If the MFWRV's remain open and continue to supply feed, excessive feed flow could result. Overfeeding the SG's can cause undue stress on the SG's and the main steam piping. It may also cause excess cooldown.

7.0 CONTAINMENT

7.1 IMMEDIATE	7.2 REMEDIAL
1) Ensure containment pressure less than 5 psig	1) Greater than 5 psig: - Ensure actuation of CIS/SIAS - Check safeguards light boxes - If individual CIS/SIAS valves fail to operate, attempt to manually operate valves from control room
	2) Greater than 20 psig: - Ensure actuation of CSAS
2) Ensure containment radiation levels normal	3) Containment radiation levels high AND Containment purge operating: - Secure containment purge

BASIS

Section 7.0 directs action control direct radioactive material releases.

Containment integrity is defined in the definition section of the Technical Specifications. It is threatened any time any one of the following conditions exist.

1) high containment pressure (greater than 5 psig)

2) high containment temperature (greater than 125°F)

3) high containment radiation (monitors are alarming)

These conditions are all very unusual and indicate an increased probability for radioactive release. The operators should verify that, for the given conditions, the appropriate engineered safety feature automatic actions have taken place. Containment conditions are also important in determining the operational status of systems inside containment.

The CIS setpoint is 4.25 to 4.75 to ensure actuation below the 5 psig containment pressure Tech. Spec. limit.

If CIS does not actuate as expected, it may be manually initiated from the MCB. Both trains of CIS valves must be actuated. This is done by placing both CIS switches in manual.

Each CIS valve can be closed from the control room.

If CSAS does not acutate as expected, it may be manually actuated from the MCB. Either train of CSAS may be actuated by placing its respective control switch in manual.

Containment purge must be isolated on high radiation inside containment. This prevents uncontrolled releases to the environment via the 42 inch purge exhaust duct.

8.0 VITAL AUXILIARIES

8.0 IMMEDIATE | 8.2 REMEDIAL

NOTE:

Upon a turbine trip with the main generator connected to the 345 KV switchyard and station service power supplied by the unit breakers, 9 automatic transfer to reserve and disconnect of the main generator should occur within 2 minutes

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CAUTION

Do not open the main generator output breakers (KG-1, KG-1/375 T1H) until station loads have been transferred to reserve power

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1) Ensure automatic transfer to reserve power
   - reserve breakers closed (1R, 2R, 3R, 4R)
   - unit breakers open (1U, 2U, 3U, 4U)

2) Automatic transfer to reserve power does not occur within 2 minutes of trip:
   - Manually transfer to reserve power

8.0 VITAL AUXILIARIES

8.0 IMMEDIATE (CONT'D)	8.2 REMEDIAL (CONT'D)	
2) Ensure the main generator is disconnected - KG-1 OPEN - KG-1/375 OPEN - T1H OPEN - exciter breaker OPEN	2) Generator does not automatically disconnect: - Open KG-1, KG-1/375, T1H - Open exciter breaker - Close MS-M-100, 101	
3) Ensure proper operation of vital auxiliaries according to the following criteria:	3) At least one vital auxiliary is lost or is operating in a degraded mode: - Initiate the indicated procedure:	
Vital Auxiliary		
PCC less than 95°F and greater than 70 psig (not in alarm)	AOP 2-33	LOSS of PCC
SCC less than 95°F and greater than 70 psig (not in alarm)	AOP 2-32	LOSS OF SCC
Service Water check header pressure alarms	AOP 2-31	SW HEADER RUPTURE
Control Air (all headers) greater than 70 psig	AOP 2-28	LOSS OF CONTROL AIR
Offsite Power all buses properly energized through the reserve breakers	EOP 2-70-9	LOSS OF OFFSITE POWER

BASIS

Section 8.0 ensureS availability of vital auxiliaries necessary for plant control.

Vital auxiliaries include emergency power, component cooling water, and control air. Failure of any of these systems is addressed by a separate procedure.

To ensure a reliable power supply for station service loads following a reactor and turbine trip normal load transfer takes place as follows:

1) On 4 of 4 turbine stop valves indicating closed, KG-1, KG-1/375 and T1H will open and power will automatically switch over to the reserve breakers (86P relay).

2) Opening both ring bus breakers or T1H will prevent the auto transfer in (1).

3) If any turbine stop valve indicates open, 86P will not fire but 86BU will fire after a one minute delay (and accomplish the same function as 86P).

4) Unit breakers trip.

5) Reserve breakers close.

6) Loss of voltage on either emergency bus for one second will cause an autostart of its respective diesel generator.

Breakers KG-1, KG-1/375, and T1H open to guarantee that the generator is disconnected from the ring bus. If the breakers do not open automatically, manual action must be taken to prevent damage to the turbine due to backfeeding.

The note in this section indicates the logic which starts the automatic transfer. Care should be taken to allow the backup relay 86BU to perform its function before attempting manual actions.

Primary Component Cooling (PCC) and Secondary Component Cooling (SCC) are needed to cool the ECCS pumps and RHR heat exchanger when operating in the ECCS mode after an accident. These heat exchangers become the primary heat removal system following a Recirculation Actuation Signal. PCC and SCC temperatures are located on the A section of the Main Control Board. A temperature alarm is set at 89°F. Alarms will indicate when PCC or SCC pressure drops below 55 psig and reset at 70 psig. These will alarm in windows W-1-3 PCC pump auto start and W-1-4 SCC pump auto start.

Service water is required to cool the PCC and SCC heat exchanger. This system is the ultimate heat sink in the recirculation mode following a LOCA.

Control air is used to operate valves in the major fluid systems required to control a transient.

9.0 STA/MANAGEMENT/E-PLAN

9.1 IMMEDIATE ACTIONS

1) Notify the STA and DCO

2) Initiate Emergency Plan Procedure 2.50.0, Declaration and Catorization of Emergency Condition.

- potential or acutal degradation of plant safety

- events which will arouse public interest (e.g., noise nuisance)

BASIS

Section 9.0 specifies those actions to gain technical and management assistance and to insure proper emergency response.

10.0 SUBSEQUENT ACTIONS

CAUTION

Rapid feeding/overfeeding of SG's could cause RCS cooldown

BASIS

Feedwater is colder than SG water itself. High feed rates tend to decrease SG temperatures and, therefore, increase the rate of RCS heat removal.

10.1 When SG's are returned above 35% NR depress "OVERRIDE" buttons to restore auto control to MFWRV bypass valves.

BASIS

35% NR is the desired steam generator level. Once the plant has stabilized and SG levels have returned to normal, automatic level control can resume.

10.2 Check heater drain pumps tripped.

BASIS

The heater drain tank is no longer receiving flow; therefore, the pumps are no longer needed. Continued operation in the no-flow condition may cause pump damage.

10.3 Trim secondary plant to one FW pump and one condensate pump.

BASIS

Feedwater demand has been greatly reduced and the pumps are running at minimum flow. Minimum flow conditions are operationally inefficient and can be damaging to the pumps.

10.4 Open turbine drain valves:
(Valves marked with an "#" automatically open on Auto Stop Oil pressure).

Valve	Source
HD-A-299	TK-104A (Cross Under Drain Tank)
HD-A-300	TK-104B (Cross Under Drain Tank)
GS-F-55	HP Turbine
# GS-F-56	HP Turbine
# GS-F-57	HP Turbine
# GS-F-58	HP Turbine
# GS-F-59	HP Turbine

10.5 Check open extraction steam drain valves:
(All valves automatically open on low Auto Stop Oil pressure).

Valve	Associated Extraction Heater
HPD-A-299	E-11A (1st Point)
HPD-A-100	E-11B (1st Point)
SD-A-256	E-14B (4th Point)
SD-A-257	E-14A (4th Point)
SD-A-258	E-13B (3rd Point)
SD-A-259	E-13B (3rd Point)

10.6 Check closed MS-M-100 and MS-M-101.
(reheater isolation valves)

10.7 Close moisture separator/reheater temperature control valves using RESET button on control panel.

10.8 Check moisture separator/reheater manual valve controller at ZERO.

10.9 Turn main generator voltage regulator OFF.

BASIS

These steps protect equipment by controlling moisture buildup in the secondary plant.

10.10 Control RCS Temperature:

Dump steam to condenser
<u>OR</u>
Dump steam to the atmosphere using decay heat release system

<u>BASIS</u>

The amount of steam "dumped" is related to the amount of heat removed from the RCS... Dumping more steam will lower the SG temperature, increase the SG/RCS temperature gradient, increase the rate of RCS heat removal, and lower RCS temperature.

10.11 Obtain switching orders from the dispatcher

<u>BASIS</u>

Safety considerations require coordination with the dispatcher before conducting grid switching operations.

10.12 As the turbine coasts down, check proper operation of the following equipment:

<u>At 8 psi bearing oil pressure</u>

P-49 Turning Gear Oil Pump
P-88 Seal Oil Backup Pump

<u>At 600 rpm (decreasing)</u>

Bearing Lift Pump

<u>At zero speed</u>

Turning Gear

<u>BASIS</u>

These actions are specified by the Westinghouse Turbine Instruction Manual to prevent turbine "sag".

10.13 Ensure P-2C turning gear is operating.

<u>BASIS</u>

This is necessary to prevent turbine sag. See manufacture's manual.

10.14 Change scales on the wide range log chart to keep pens on scale.

<u>BASIS</u>

Self explanatory.

10.15 Verify normal decreasing count rate.

BASIS

Ensure reactivity control.

10.16 Initiate Procedure 1-6, Reactor Shutdown.

10.17 DELETED

10.18 Within one hour of a plant trip, initiate Procedure 1-106-1, Boiler Warmup.

10.19 Between 2 and 6 hours following a trip from above 15% thermal power a RCS sample must be taken for isotopic analysis of iodine.

10.20 Reference Procedure 1-26-1, Operational Event Reporting.

BASIS

These are routine procedures to bring plant to a normal shutdown mode.

Figures 1-8 show traces of plant parameter following typical uncomplicated plant trips.

FIGURE 1

PRESSURIZER PRESSURE
POST - TRIP
(TYPICAL)

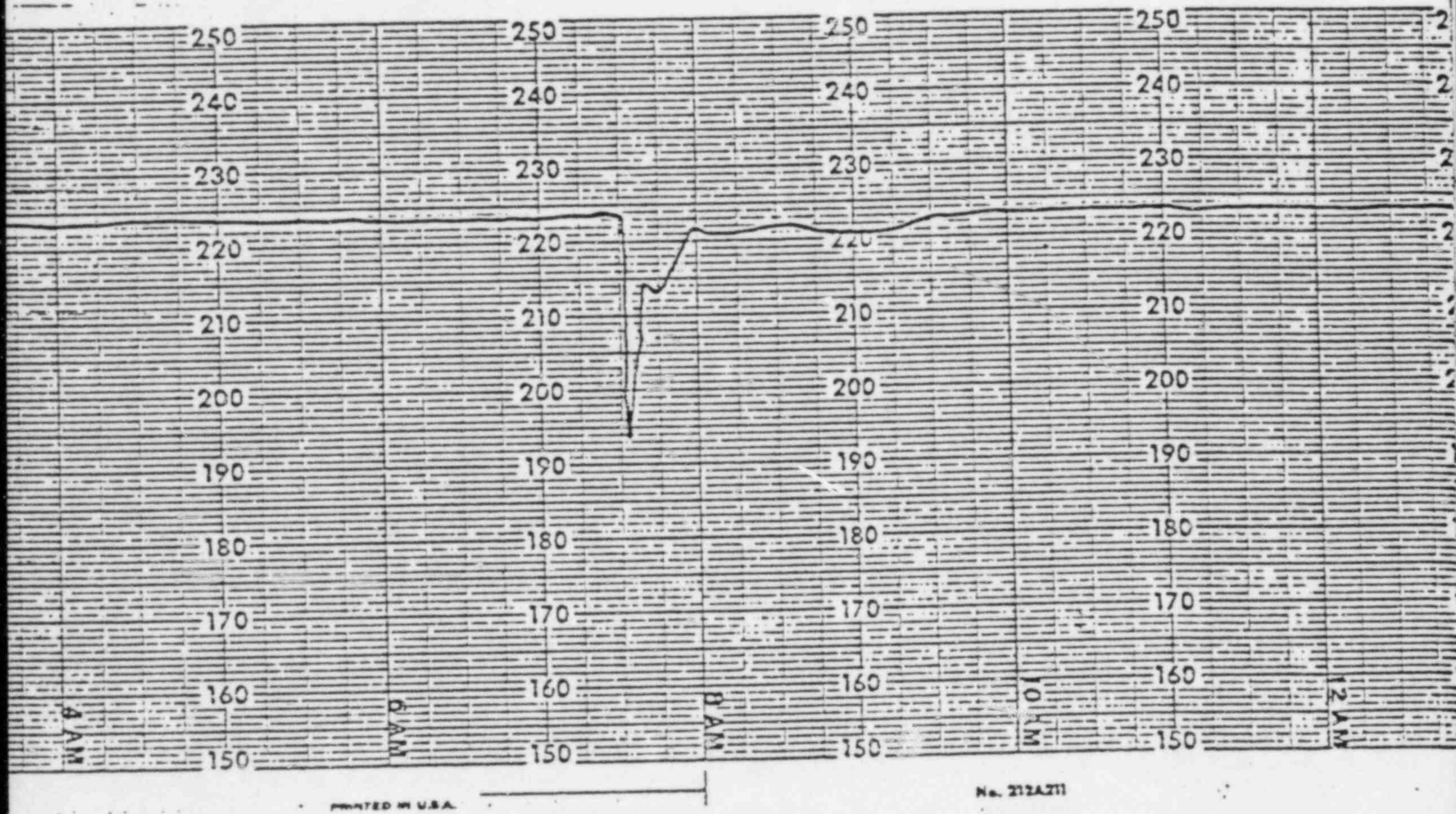


FIGURE 2

PRESSURIZER LEVEL
POST - TRIP
(TYPICAL)

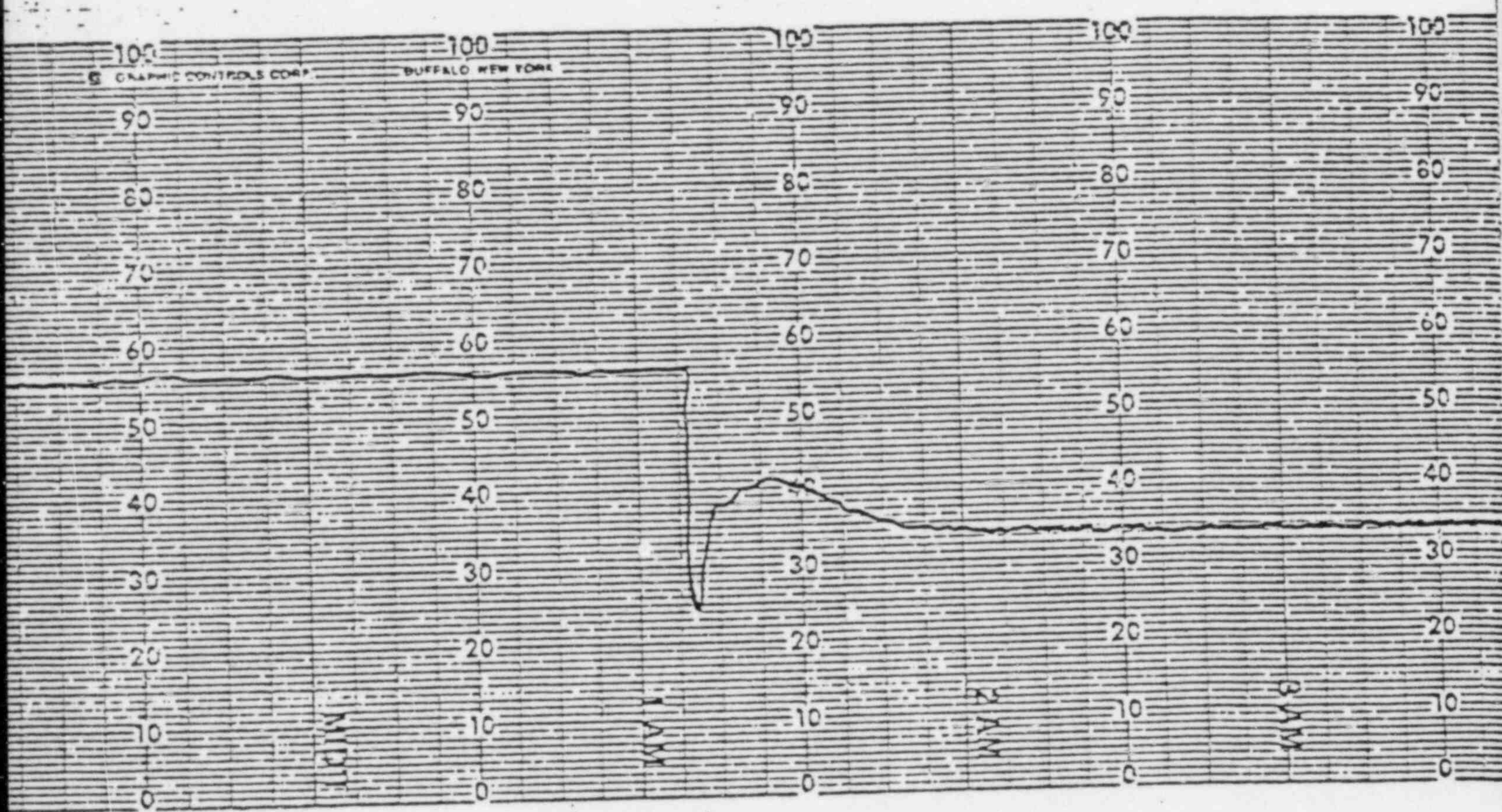


FIGURE 3

LOOP T_C
POST - TRIP
(TYPICAL)

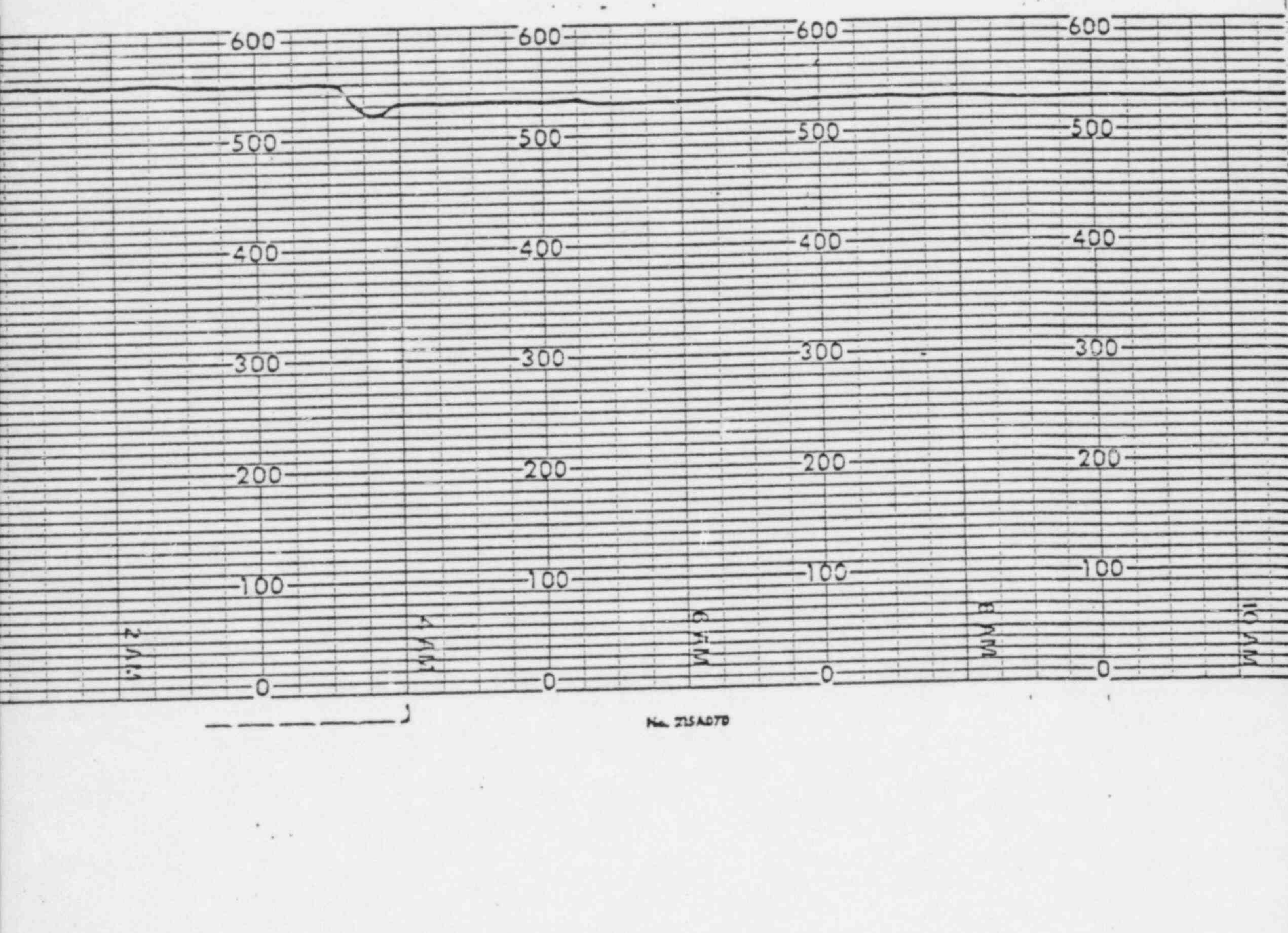


FIGURE 4

MAIN STEAM PRESSURE
POST - TRIP
(TYPICAL)

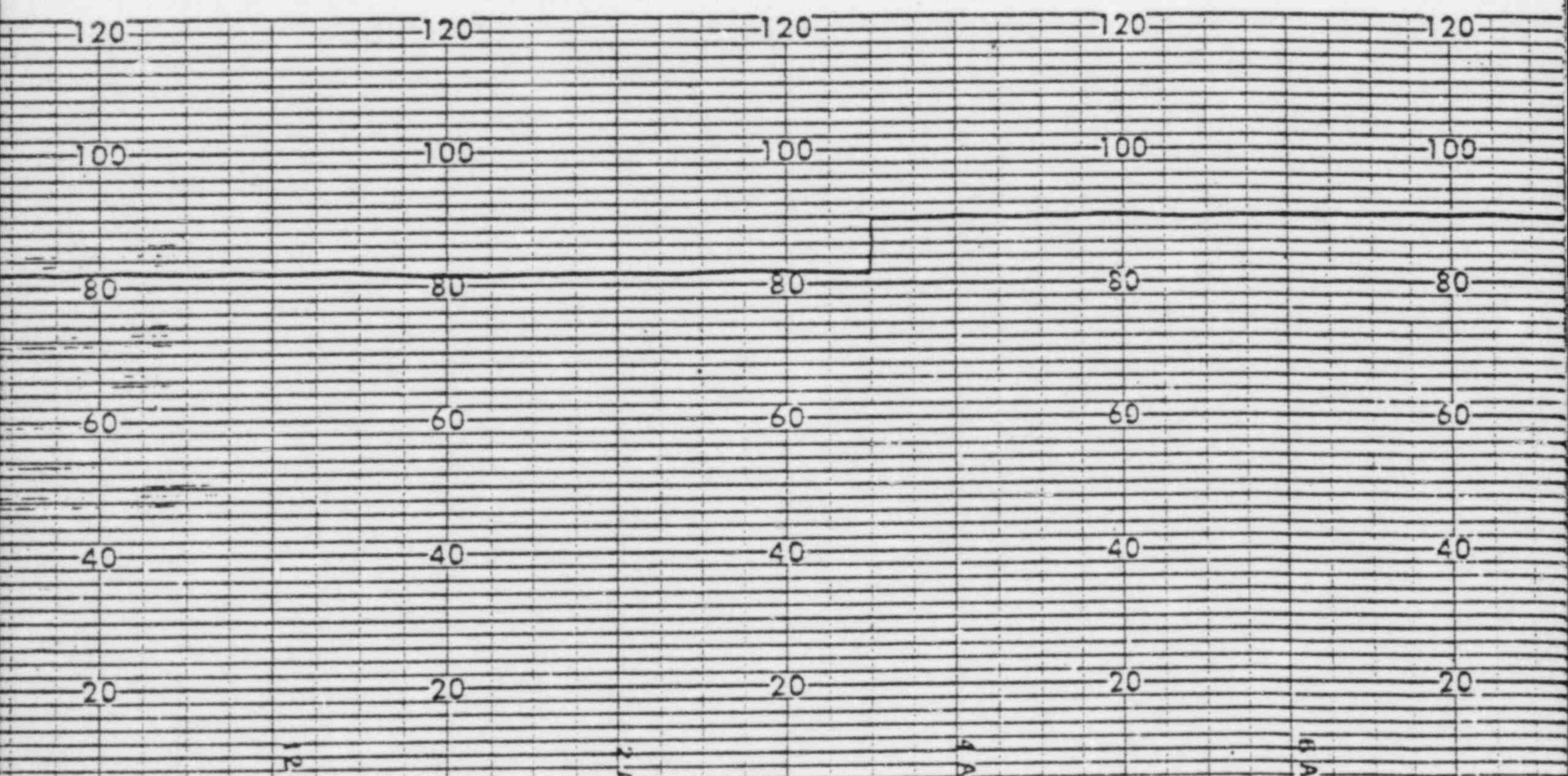


FIGURE 5

STEAM GENERATOR LEVEL
POST - TRIP
(TYPICAL)

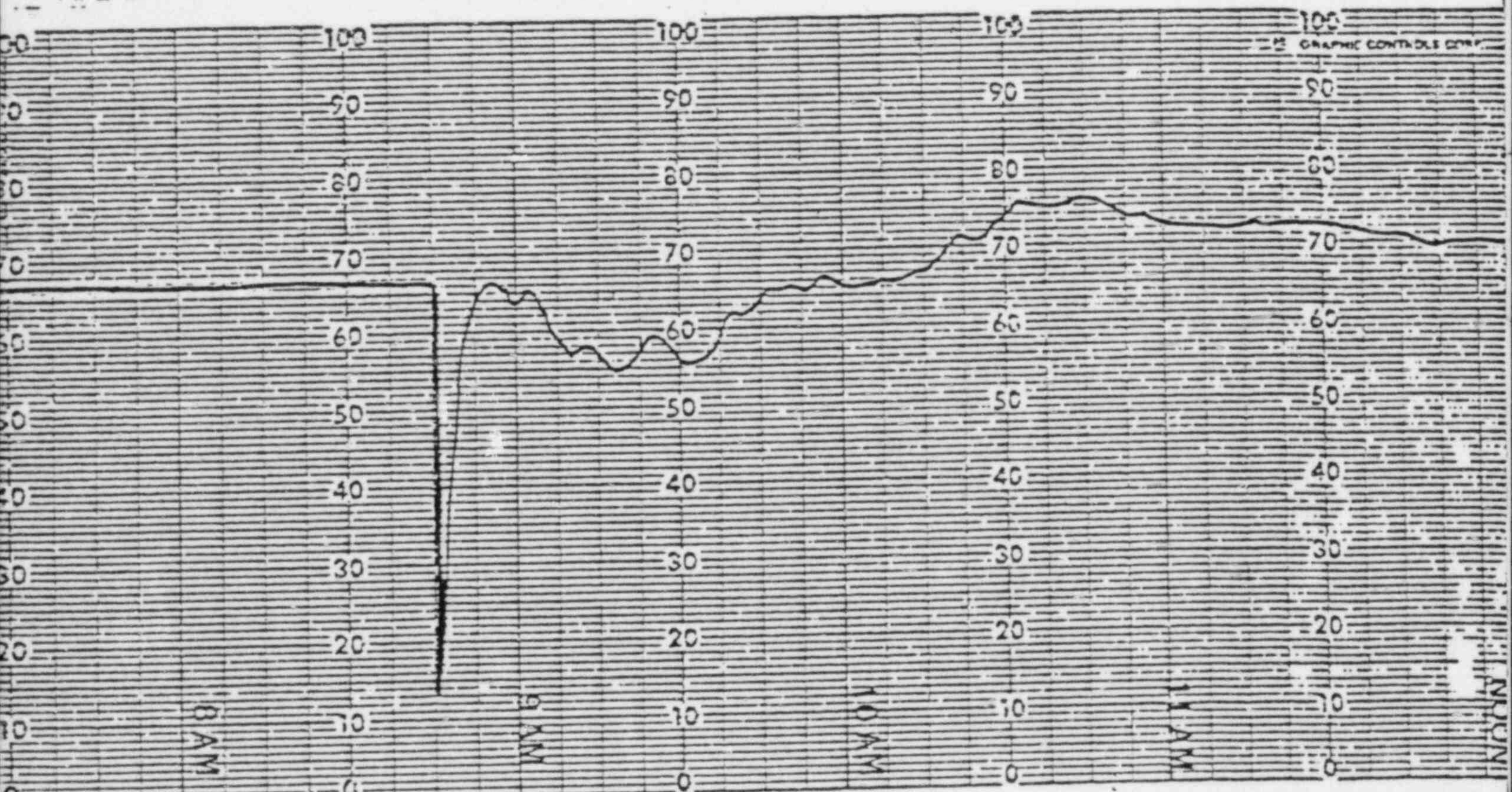


FIGURE 6

STEAM FLOW/FEED FLOW
POST - TRIP
(TYPICAL)

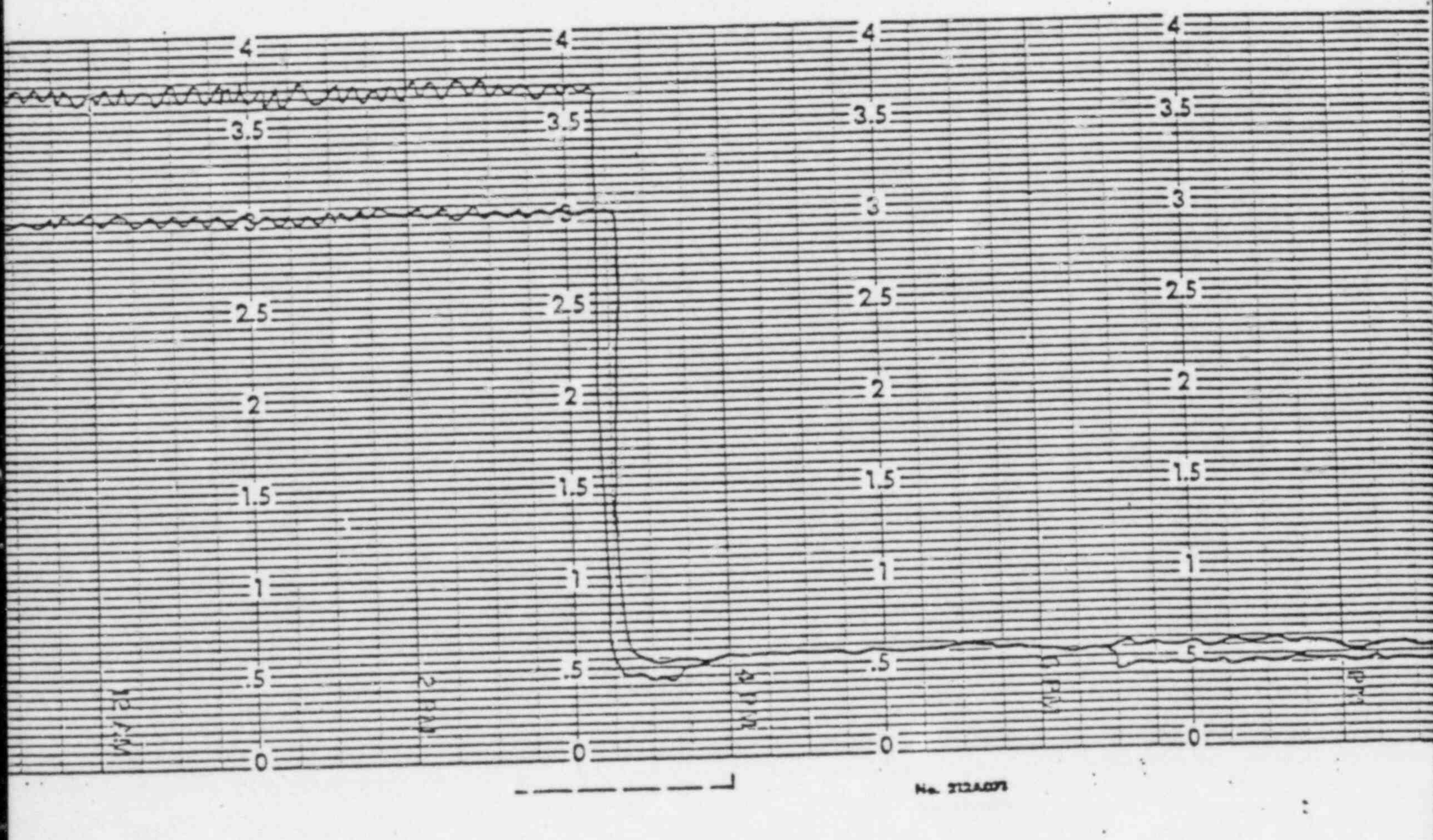


FIGURE 7

TAVE / TREF
POST - TRIP
(TYPICAL)

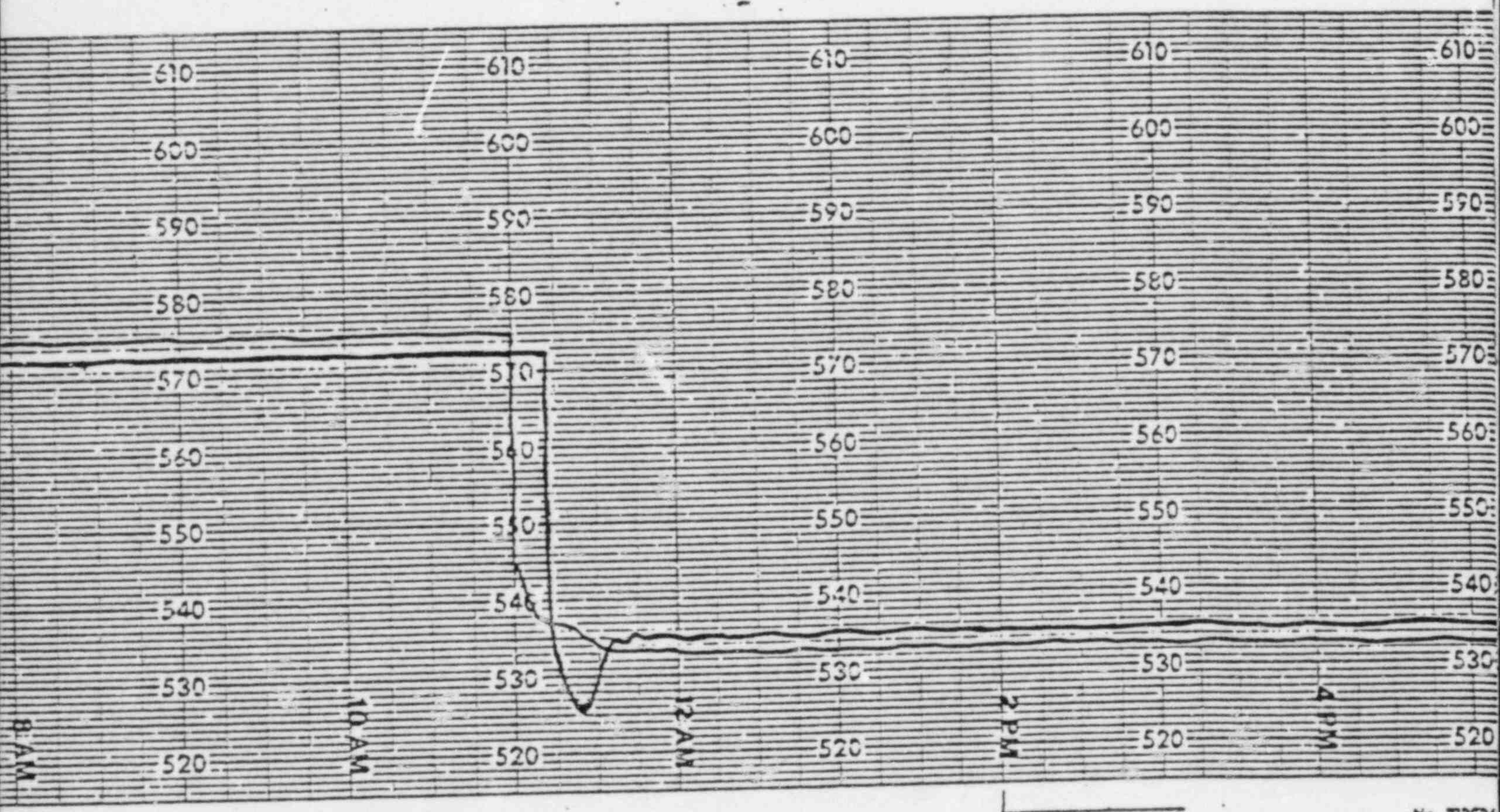
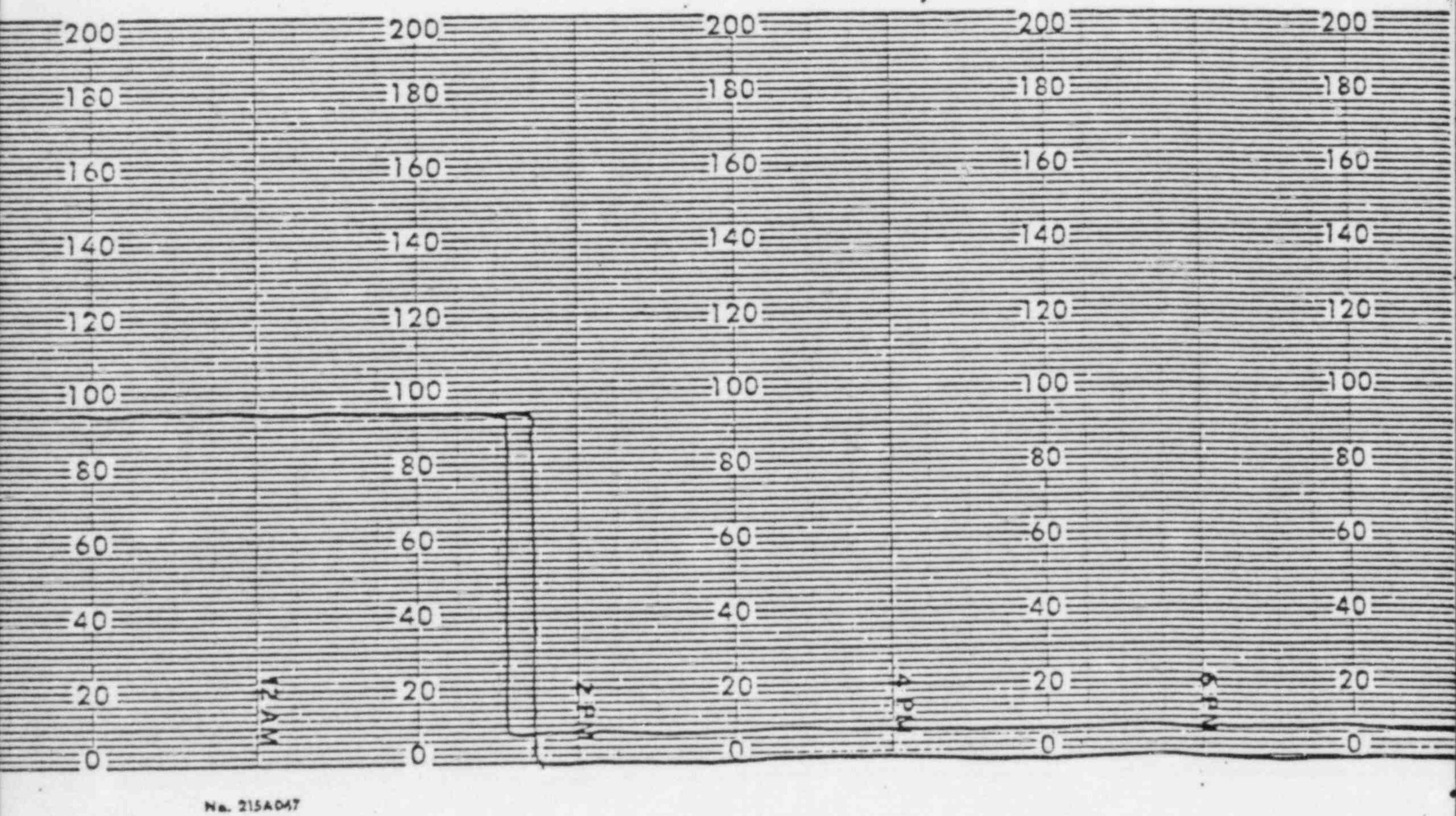


FIGURE 8

NUCLEAR POWER / dT POWER
POST - TRIP
(TYPICAL)



ENCLOSURE 3

MAINE YANKEE SCHEDULE FOR ICCI IMPLEMENTATION

10 CFR 50.54(f) - REQUEST 3

Each licensee is to develop and submit its own plant specific schedule which will be reviewed by the assigned NRC Project Manager. The NRC Project Manager and licensee will reach an agreement on the final schedule and in this manner provide for prompt implementation of these important improvements while optimizing the use of utility and NRC resources.

Response

The following key milestones remain to be completed and are submitted for consideration by the NRC Project Manager. The schedule for final installation and testing necessary to make the ICCI system operational is closely dependent upon Maine Yankee's schedules for Regulatory Guide 1.97 upgrades and development of the Maine Yankee SPDS.

TASK	PROJECTED COMPLETION DATE
°Install and Calibrate PITs Strip Chart Recorder	May 30, 1983
°Complete Subcooled Margin Monitor Upgrades	Startup from 1984 Refueling Outage
°Install Backup Core Exit Thermocouple Display	Startup from 1984 Refueling Outage
°Complete PITS Acceptance Data Recording Phase	Startup from 1984 Refueling Outage
°Complete Analysis to Predict PITS and entire ICCI Response During Accidents	Estimated one year from Startup from 1984 Refueling Outage
°Submit Analysis to USNRC For Review	Two months following Completion of Analysis
°ICCI System Fully Operational	Following Receipt of NRC Review and Approval
°Complete EOP Changes Based on PITS and ICCI Analysis	Within 180 Days of Receiving Final NRC Approval