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DENTON,H.R. Office of Nuclear Reactor Regulation, Director

SUBJECT: Forwards emergency operating procedures generation package in response to NUREG-0737,Suppl 1.

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TENNESSEE VALLEY AUTHORITY

CHATTANOOGA, TENNESSEE 37401
400 Chestnut Street Tower II

June 22, 1984

Mr. Harold R. Denton, Director
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Mr. Denton:

In the Matter of the	)	Docket Nos. 50-259
Tennessee Valley Authority	)	50-260
		50-296

Enclosed is the Emergency Operating Procedures (EOPs) generation package for the Browns Ferry Nuclear Plant units 1, 2, and 3. This submittal is made in response to NUREG-0737 Supplement 1, item No. 7.2.b.

If you have any questions regarding the enclosed, please get in touch with us through the Browns Ferry Project Manager.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

L. M. Mills

L. M. Mills, Manager
Nuclear Licensing

Subscribed and sworn to before
me this 22nd day of June 1984.

Paulette H. White

Notary Public
My Commission Expires 9-5-84

Enclosure
cc (Enclosure):
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Region II
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7920 Norfolk Avenue
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BROWNS FERRY NUCLEAR PLANT (BFN)
PROCEDURES GENERATION PACKAGE (PGP)

The PGP is being submitted in response to NUREG-0737, supplement 1, item 7.2b and will form the basis for upgrading Emergency Operating Instructions (EOIs) for BFN. The upgrading process will take place in several stages, incorporating more considerations with each succeeding stage. This process is scheduled to begin with operator training on EOIs based upon the attached package. It is scheduled to be complete by April 1, 1986, when implementation of EOIs is complete based on revision 3 of the BWR Owners' Group Emergency Procedure Guidelines (EPGs) excluding secondary containment control and radiation release considerations. These additional items and subsequent EPG revisions will be addressed as maintenance items.

I. Plant Specific Technical Guideline

The attached guideline will form the basis for the EOI steps in the first stage of implementation. It consists of BWR Owners' Group EPGs, revision 3 with changes to the cautions and with the guidance for ATWS events, secondary containment control considerations, and radiation release events removed. The guideline is presented in the same format in which the generic EPGs were submitted with change bars delineating any differences. These particular considerations are not included in the initial stage of implementation in order to minimize the negative impact associated with preparation, training, and actual use of EOIs markedly different from those previously used. The guideline will be augmented as more considerations are incorporated into the EOIs.

The "Caution" section has been changed to remove the destinction of general and specific cautions. Cautions will be addressed at the applicable procedure step or in operator training where appropriate.

II. Writers' Guide for EOIs

The attached writers' guide will provide instructions on writing EOIs using good writing principles. It will also promote consistency among various parts of the EOIs which may evolve over a long period of time or be prepared by different persons.

III. EOP Verification and Validation Program

The attached verification and validation program describes the methods which will be used to ensure that the EOIs (1) perform the intent of the technical guidelines, (2) are applicable to the plant in terms of equipment available and calculation of graphs and action levels, and (3) can be performed by the operator.

IV. EOP Training Program

The attached training outline will be used as guidance for training on the EOIs. Since they will be implemented in several stages of increasing scope, training on each successive stage will be commensurate with the steps which were added with that stage.

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT

PLANT SPECIFIC TECHNICAL GUIDELINE

INTRODUCTION

Based on the various BWR system designs, the following generic symptomatic emergency procedure guidelines have been developed:

- RPV Control Guideline
- Primary Containment Control Guideline

The RPV Control Guideline maintains adequate core cooling, shuts down the reactor, and cools down the RPV to cold shutdown conditions. This guideline is entered whenever low RPV water level, high RPV pressure, high drywell pressure, or a condition which requires MSIV isolation has occurred.

The Primary Containment Control Guideline maintains primary containment integrity and protects equipment in the primary containment. This guideline is entered whenever suppression pool temperature, drywell temperature, containment temperature, drywell pressure, or suppression pool water level is above its high operating limit or suppression pool water level is below its low operating limit.

Table I is a list of abbreviations used in the guidelines.

Brackets [ ] enclose plant unique setpoints, design limits, pump shutoff pressures, etc., and parentheses ( ) within brackets indicate the source for the bracketed variable. Illustrated in these guidelines are variables for a typical BWR/4 or BWR/6 as appropriate.

At various points throughout these guidelines, precautions are noted by the symbol $\boxed{\#}$. The number within the box refers to a numbered "Caution" contained in the Operator Precautions section. These "Cautions" are brief and succinct red flags for the operator. Where the basis for the "Caution" or a step is not completely evident from the text, a full discussion of the basis is contained in Appendix A. Other system details which pertain to the guidelines are also included in this appendix.

The emergency procedure guidelines are generic to GE-BWR 1 through 6 designs in that they address all major systems which may be used to respond to an emergency. Because no specific plant includes all of the systems in these guidelines, the guidelines are applied to individual plants by deleting statements which are not applicable or by substituting equivalent systems where appropriate. For example, plants with no low pressure injection system will delete statements referring to LPCI, and plants with Low Pressure Core Flooding will substitute LPCF for LPCI.

At various points within these guidelines, limits are specified beyond which certain actions are required. While conservative, these limits are derived from engineering analyses utilizing best-estimate (as opposed to licensing) models. Consequently, these limits are not as conservative as the limits specified in a plant's Technical Specifications. This is not to imply that operation beyond the Technical Specifications is recommended in an emergency. Rather, such operation may be required under certain degraded conditions in order to safely mitigate the consequences of those degraded conditions. The limits specified in the guidelines establish the boundaries within which continued safe operation of the plant can be assured. Therefore, conformance with the guidelines does not ensure strict conformance with a plant's Technical Specifications or other licensing bases.

The entry conditions for these emergency procedure guidelines are symptomatic of both emergencies and events which may degrade into emergencies. The guidelines specify actions appropriate for both. Therefore, entry into procedures developed from these guidelines is not conclusive that an emergency has occurred.

TABLE I

ABBREVIATIONS

ADS	-	Automatic Depressurization System
APRM	-	Average Power Range Monitor
CRD	-	Control Rod Drive
ECCS	-	Emergency Core Cooling System
HCU	-	Hydraulic Control Unit
HPCI	-	High Pressure Coolant Injection
HPCS	-	High Pressure Core Spray
HVAC	-	Heating, Ventilating and Air Conditioning
IC	-	Isolation Condenser
LCO	-	Limiting Condition for Operation
LOCA	-	Loss of Coolant Accident
LPCI	-	Low Pressure Coolant Injection
LPCS	-	Low Pressure Core Spray
MSIV	-	Main Steamline Isolation Valves
NDTT	-	Nil-Ductility Transition Temperature
NPSH	-	Net Positive Suction Head
RCIC	-	Reactor Core Isolation Cooling
RHR	-	Residual Heat Removal
RPS	-	Reactor Protection System
RPV	-	Reactor Pressure Vessel
RSCS	-	Rod Sequence Control System
RWCU	-	Reactor Water Cleanup
SBGT	-	Standby Gas Treatment
SLC	-	Standby Liquid Control
SORV	-	Stuck Open Relief Valve
SPMS	-	Suppression Pool Makeup System
SRV	-	Safety Relief Valve

OPERATOR PRECAUTIONS

CAUTION #1

Monitor the general state of the plant. If an entry condition for a [procedure developed from the Emergency Procedure Guidelines] occurs, enter that procedure. When it is determined that an emergency no longer exists, enter [normal operating procedure].

CAUTION #2

Monitor RPV water level and pressure and primary containment temperatures and pressure from multiple indications.

CAUTION #3

If a safety function initiates automatically, assume a true initiating event has occurred unless otherwise confirmed by at least two independent indications.

CAUTION #4

Whenever RHR is in the LPCI mode, inject through the heat exchangers as soon as possible.

CAUTION #5

Suppression pool temperature is determined by [procedure for determining bulk suppression pool water temperature]. Drywell temperature is determined by [procedure for determining drywell atmosphere average temperature]. Containment temperature is determined by [procedure for determining Mark III containment atmosphere average temperature].

CAUTION #6

Whenever [temperature near the instrument reference leg vertical runs] exceeds the temperature in the table and the instrument reads below the indicated level in the table, the actual RPV water level may be anywhere below the elevation of the lower instrument tap.

Temperature[*]	Indicated Level	Instrument	
[any	617 in.	Shutdown Range Level	(500 to 900 in.)
107°F	-107 in.	Wide Range Level	(-150 to +60 in.)
310°F	19 in.	Narrow Range Level	(0 to +60 in.)
545°F	168 in.	Fuel Zone Level	(200 to 500 in.)]

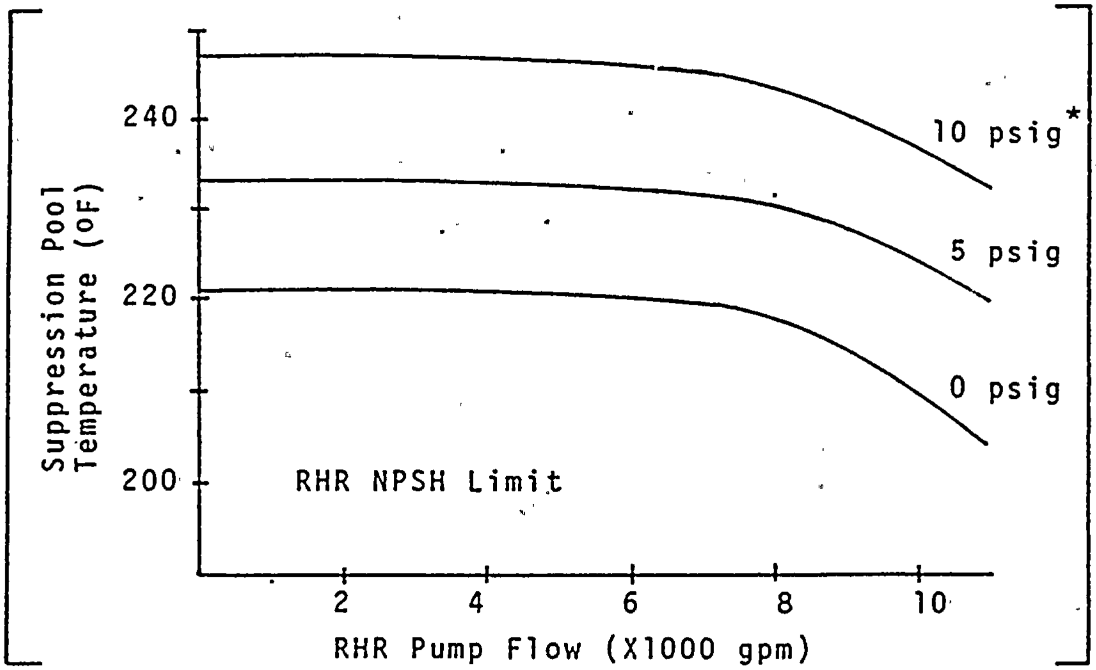
[*List in order of increasing temperature.]

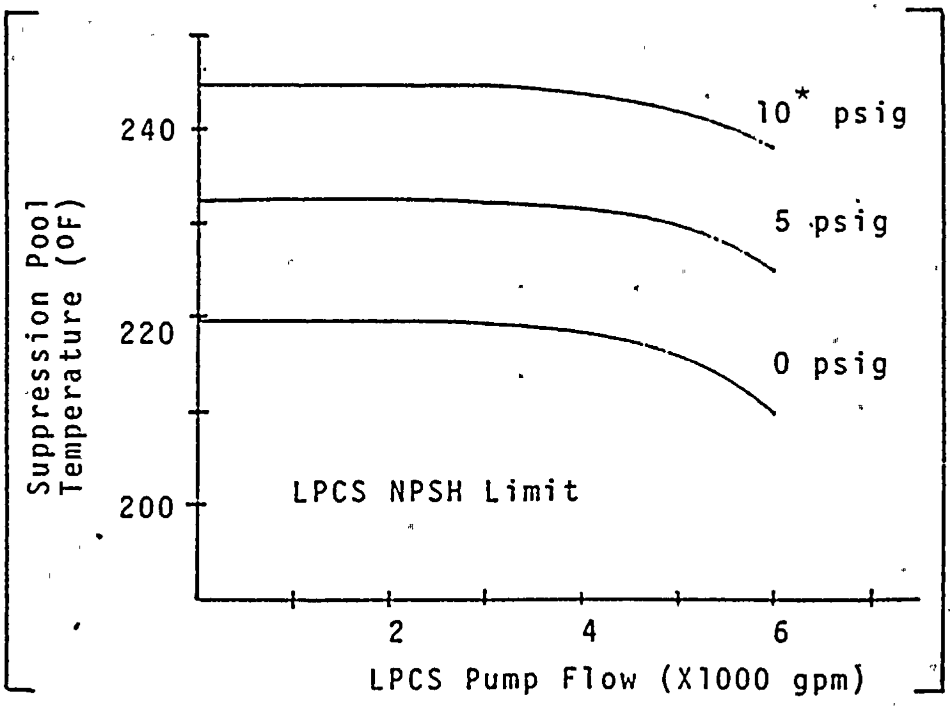
CAUTION #7

[Heated reference leg instrument] indicated levels are not reliable during rapid RPV depressurization below 500 psig. For these conditions, utilize [cold reference leg instruments] to monitor RPV water level.

CAUTION #8

Observe NPSH requirements for pumps taking suction from the suppression pool.





*Suppression chamber pressure
Suppression pool at normal water level

CAUTION #9

If signals of high suppression pool water level [12 ft. 7 in. (high level suction interlock)] or low condensate storage tank water level [0 in. (low level suction interlock)] occur, confirm automatic transfer of or manually transfer HPCI, and RCIC suction from the condensate storage tank to the suppression pool.

CAUTION #10

Do not secure or place an ECCS in MANUAL mode unless, by at least two independent indications, (1) misoperation in AUTOMATIC mode is confirmed, or (2) adequate core cooling is assured. If an ECCS is placed in MANUAL mode, it will not initiate automatically. Make frequent checks of the initiating or controlling parameter. When manual operation is no longer required, restore the system to AUTOMATIC/STANDBY mode if possible.

CAUTION #11

If a high drywell pressure ECCS initiation signal [2.0 psig (drywell pressure which initiates ECCS)] occurs or exists while depressurizing, prevent injection from those LPCS and LPCI pumps not required to assure adequate core cooling prior to reaching their maximum injection pressures. When the high drywell pressure ECCS initiation signal clears, restore LPCS and LPCI to AUTOMATIC/STANDBY mode.

CAUTION #12

Do not throttle HPCI or RCIC systems below [2200 rpm (minimum turbine speed limit per turbine vendor manual)].

CAUTION #13

Cooldown rates above [100°F/hr (RPV cooldown rate LCO)] may be required to accomplish this step.

CAUTION #14

Do not depressurize the RPV below [100 psig (HPCI or RCIC low pressure isolation setpoint, whichever is higher)] unless motor driven pumps sufficient to maintain RPV water level are running and available for injection.

CAUTION #15

Open SRVs in the following sequence if possible: [SRV opening sequence].

CAUTION #16

Bypassing low RPV water level [ventilation system and] MSIV isolation interlocks may be required to accomplish this step.

CAUTION #17

Cooldown rates above [100°F/hr (RPV cooldown rate LCO)] may be required to conserve RPV water inventory, protect primary containment integrity, or limit radioactive release to the environment.

CAUTION #18

If continuous LPCI operation is required to assure adequate core cooling, do not divert all RHR pumps from LPCI mode.

CAUTION #21

Elevated suppression chamber pressure may trip the RCIC turbine on high exhaust pressure.

CAUTION #22

Defeating isolation interlocks may be required to accomplish this step.

CAUTION #23

Do not initiate drywell sprays if suppression pool water level is above [17 ft. 2 in. (elevation of bottom of Mark I internal suppression chamber to drywell vacuum breakers less vacuum breaker opening pressure in feet of water)].

CAUTION #24

Bypassing high drywell pressure and low RPV water level secondary containment HVAC isolation interlocks may be required to accomplish this step.

RPV CONTROL GUIDELINE

PURPOSE

The purpose of this guideline is to:

- Maintain adequate core cooling,

- Shut down the reactor, and

- Cool down the RPV to cold shutdown conditions ([100°F < RPV water temperature < 212°F (cold shutdown conditions)]).

ENTRY CONDITIONS

The entry conditions for this guideline are any of the following:

- RPV water level below [+ 12 in. (low level scram setpoint)]

- RPV pressure above [1045 psig (high RPV pressure scram setpoint)]

- Drywell pressure above [2.0 psig (high drywell pressure scram setpoint)]

- A condition which requires MSIV isolation

OPERATOR ACTIONS

RC-1 If reactor scram has not been initiated, initiate reactor scram.

Irrespective of the entry condition, execute [Steps RC/L, RC/P concurrently.

RC/L Monitor and control RPV water level.

RC/L-1 Confirm initiation of any of the following:

- Isolation
- ECCS
- [• Emergency diesel generator]

Initiate any of these which should have initiated but did not.

> If while executing the following step:
>
> - RPV water level cannot be determined, RPV FLOODING IS REQUIRED; enter [procedure developed from CONTINGENCY #6].
> - RPV Flooding is required, enter [procedure developed from CONTINGENCY #6].

RC/L-2 Restore and maintain RPV water level between [+ 12 in. (low level scram setpoint)] and [+58 in. (high level trip setpoint)] with one or more of the following systems: #9 #10 #11

- Condensate/feedwater system [1110 - 0 psig (RPV pressure range for system operation)]
- CRD system [1110 - 0 psig (RPV pressure range for system operation)]
- RCIC system [1110 - 50 psig (RPV pressure range for system operation)] #12

- HPCI system [1110 - 100 psig (RPV pressure range for system operation)]

- LPCS system [425 - 0 psig (RPV pressure range for system operation)]

- LPCI system [250 - 0 psig (RPV pressure range for system operation)]

If RPV water level cannot be restored and maintained above [+12 in. (low level scram setpoint)], maintain RPV water level above [-164 in. (top of active fuel)].

If RPV water level can be maintained above [-164 in. (top of active fuel)] and the ADS timer has initiated, prevent automatic RPV depressurization by resetting the ADS timer.

If RPV water level cannot be maintained above [-164 in. (top of active fuel)], enter [procedure developed from CONTINGENCY #1].

If Alternate Shutdown Cooling is required, enter [procedure developed from CONTINGENCY #5].

RC/L-3 Proceed to cold shutdown in accordance with [procedure for cooldown to cold shutdown conditions].

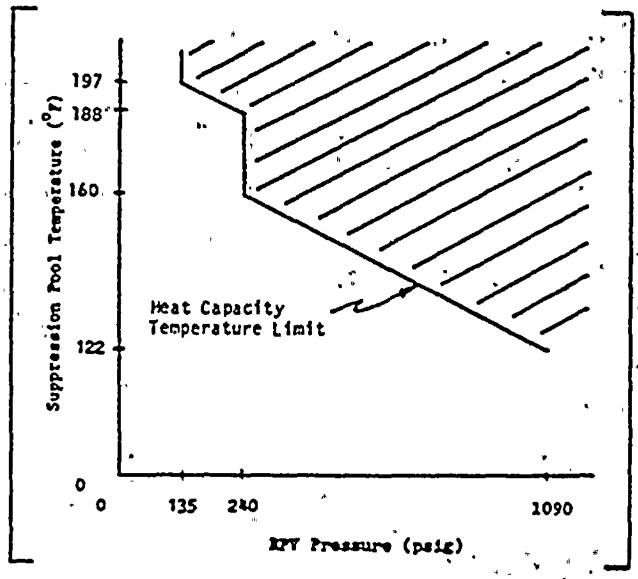
RC/P Monitor and control RPV pressure.

If while executing the following steps: • Emergency RPV Depressurization is anticipated, rapidly depressurize the RPV with the main turbine bypass valves. #13 • Emergency RPV Depressurization or RPV Flooding is required and less than [7 (number of SRVs dedicated to ADS)] SRVs are open, enter [procedure developed from CONTINGENCY #2]. • RPV Flooding is required and at least [7 (number of SRVs dedicated to ADS)] SRVs are open, enter [procedure developed from CONTINGENCY #6].

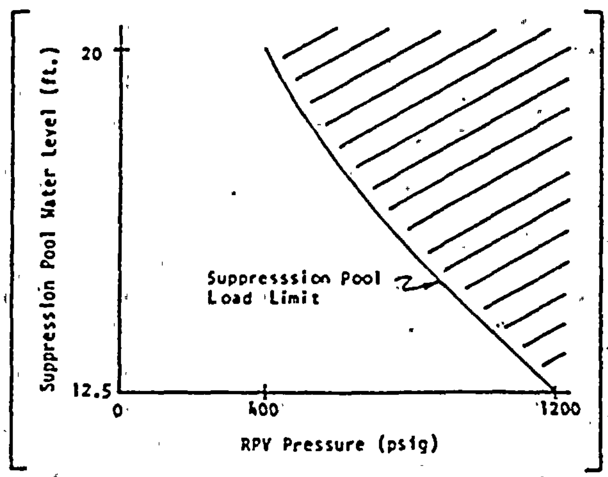
RC/P-1 If any SRV is cycling, manually open SRVs until RPV pressure drops to [935 psig (RPV pressure at which all turbine bypass valves are fully open)].

If while executing the following steps:

- Suppression pool temperature cannot be maintained below the Heat Capacity Temperature Limit, maintain RPV pressure below the Limit. #8 #13 #14



- Suppression pool water level cannot be maintained below the Suppression Pool Load Limit, maintain RPV pressure below the Limit. #13 #14



- Steam Cooling is required, enter [procedure developed from CONTINGENCY #3].

RC/P-2 Control RPV pressure below [1090 psig (lowest SRV lifting pressure)] with the main turbine bypass valves. #14

RPV pressure control may be augmented by one or more of the following systems:

- SRVs only when suppression pool water level is above [4 ft. 9 in. (elevation of top of SRV discharge device)]. If the continuous SRV pneumatic supply is or becomes unavailable, depressurize with sustained SRV opening. #15
- HPCI #12
- RCIC
- [Other steam driven equipment]

- RWCU (recirculation mode) if no boron has been injected into the RPV.

- Main steam line drains

- RWCU (blowdown mode) if no boron has been injected into the RPV. Refer to [sampling procedures] prior to initiating blowdown.

RC/P-3

depressurize the RPV and maintain cooldown rate below [100°F/hr (RPV cooldown rate LCO)]. #14, #17

RC/P-4 When the RHR shutdown cooling interlocks clear, initiate the shutdown cooling mode of RHR. #18

If the RHR shutdown cooling mode cannot be established and further cooldown is required, continue to cool down using one or more of the systems used for depressurization.

> If RPV cooldown is required but cannot be accomplished
>
> , ALTERNATE SHUTDOWN COOLING IS REQUIRED; enter [procedure developed from CONTINGENCY #5].

RC/P-5 Proceed to cold shutdown in accordance with [procedure for cooldown to cold shutdown conditions].

PRIMARY CONTAINMENT CONTROL GUIDELINE

PURPOSE

The purpose of this guideline is to:

- Maintain primary containment integrity, and
- Protect equipment in the primary containment.

ENTRY CONDITIONS

The entry conditions for this guideline are any of the following:

- Suppression pool temperature above [95°F (most limiting suppression pool temperature LCO)]
- Drywell temperature above [135°F (drywell temperature LCO or maximum normal operating temperature, whichever is higher)]
- Containment temperature above [90°F (containment temperature LCO)]
- Drywell pressure above [2.0 psig (high drywell pressure scram setpoint)]
- Suppression pool water level above [12 ft. 6 in. (maximum suppression pool water level LCO)]
- Suppression pool water level below [12 ft. 2 in. (minimum suppression pool water level LCO)]

OPERATOR ACTIONS

Irrespective of the entry condition, execute [Steps SP/T, DW/T, PC/P, and SP/L] concurrently.

SP/T Monitor and control suppression pool temperature.

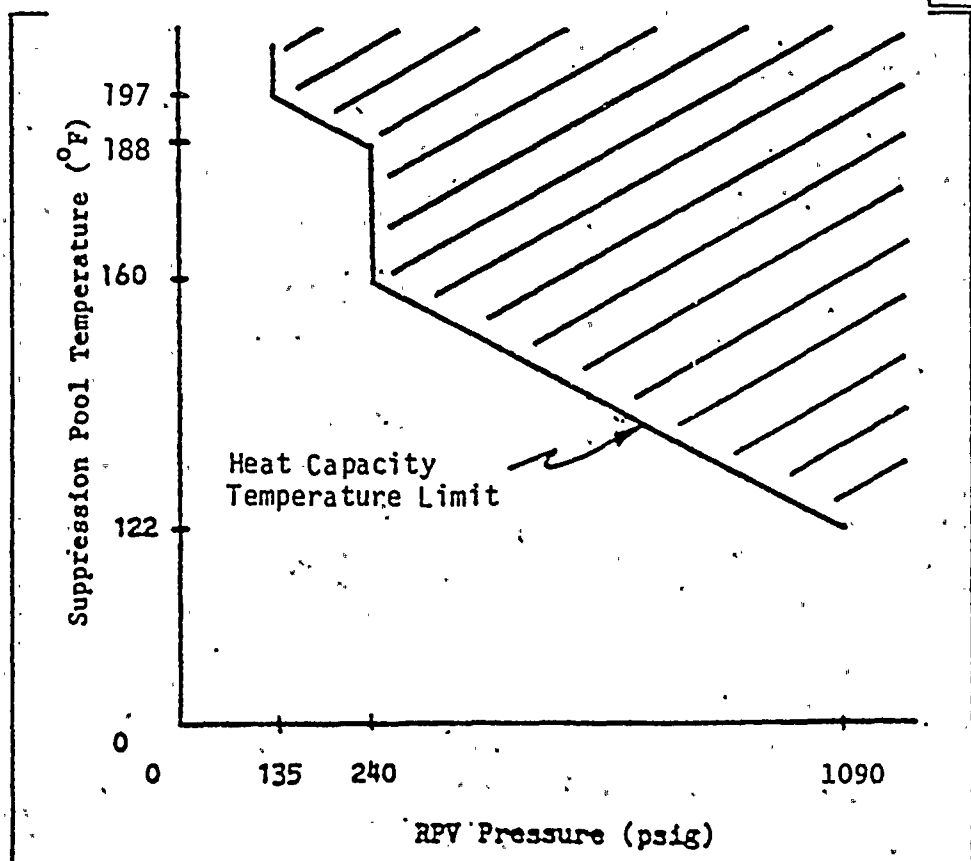
SP/T-1 Close all SORVs.

If any SORV cannot be closed [within 2 minutes (optional plant-specific time interval)], scram the reactor.

SP/T-2 When suppression pool temperature exceeds [95°F (most limiting suppression pool temperature LCO)], operate available suppression pool cooling. #18

SP/T-3 Before suppression pool temperature reaches [110°F], scram the reactor.

SP/T-4 If suppression pool temperature cannot be maintained below the Heat Capacity Temperature Limit, maintain RPV pressure below the Limit. #8 #13 #14



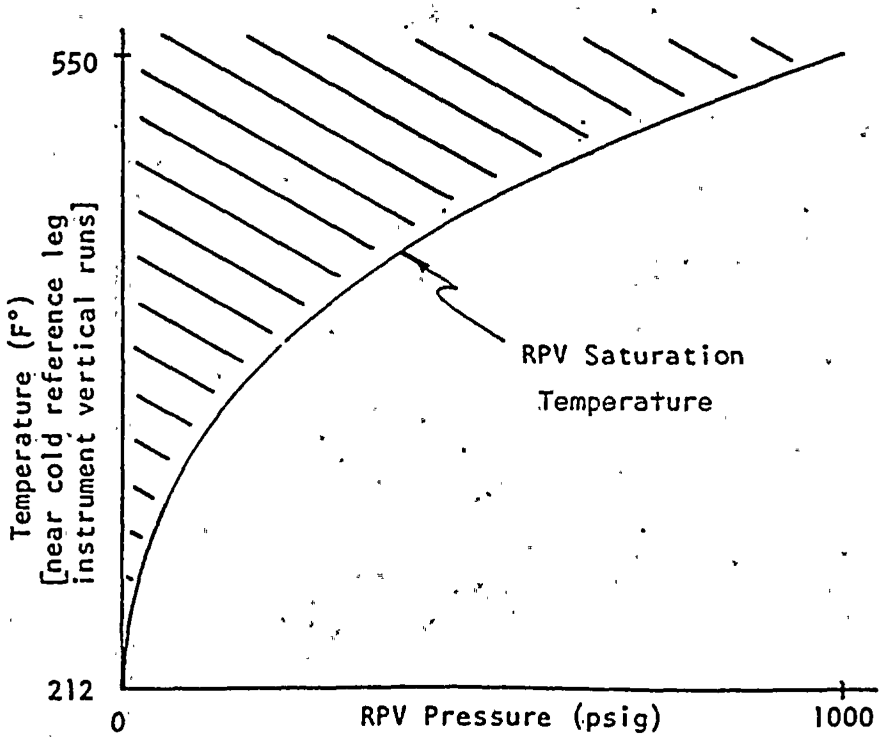
If suppression pool temperature and RPV pressure cannot be restored and maintained below the Heat Capacity Temperature Limit, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED; enter [procedure developed from the RPV Control Guideline] at [Step RC-1] and execute it concurrently with this procedure.

DW/T Monitor and control drywell temperature.

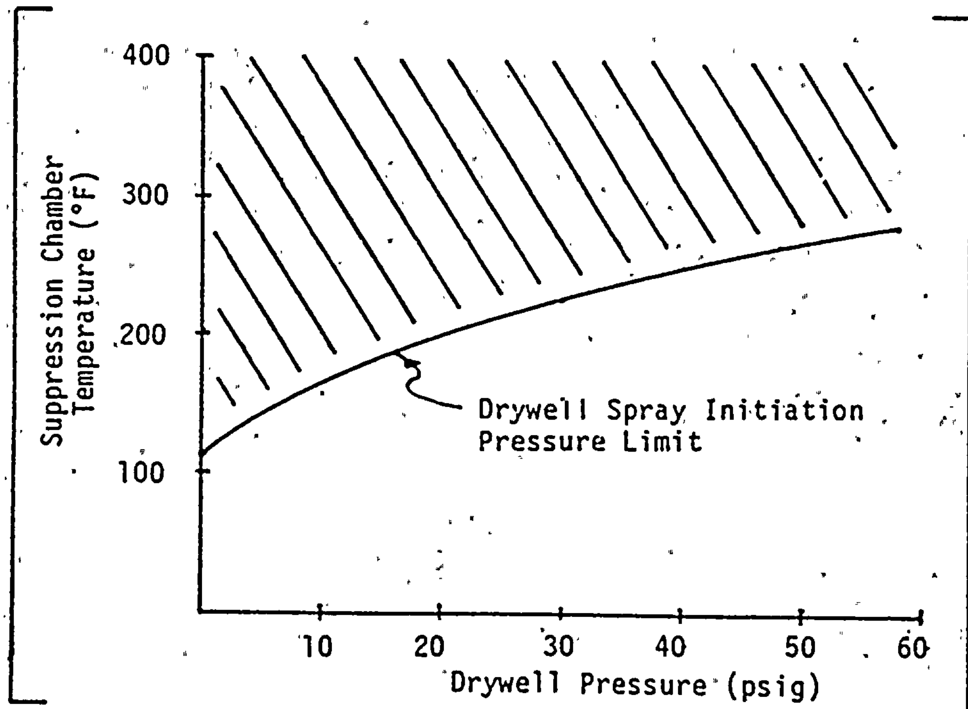
DW/T-1 When drywell temperature exceeds [135°F (drywell temperature LCO or maximum normal operating temperature, whichever is higher)], operate available drywell cooling. #6

Execute [Steps DW/T-2 and DW/T-3] concurrently.

DW/T-2 If drywell temperature [near the cold reference leg instrument vertical runs] reaches the RPV Saturation Temperature, RPV FLOODING IS REQUIRED; enter [procedure developed from the RPV Control Guideline] at [Step RC-1] and execute it concurrently with this procedure.



DW/T-3 Before drywell temperature reaches [340^{o}F (maximum temperature at which ADS qualified or drywell design temperature, whichever is lower)] but only if [suppression chamber temperature and drywell pressure are below the Drywell Spray Initiation Pressure Limit], [shut down recirculation pumps and drywell cooling fans and] initiate drywell sprays [restricting flow rate to less than 720 gpm (Maximum Drywell Spray Flow Rate Limit)]. #18



If drywell temperature cannot be maintained below [340^{o}F (maximum temperature at which ADS qualified or drywell design temperature, whichever is lower)], EMERGENCY RPV DEPRESSURIZATION IS REQUIRED; enter [procedure developed from the RPV Control Guideline] at [Step RC-1] and execute it concurrently with this procedure.

PC/P Monitor and control primary containment pressure.

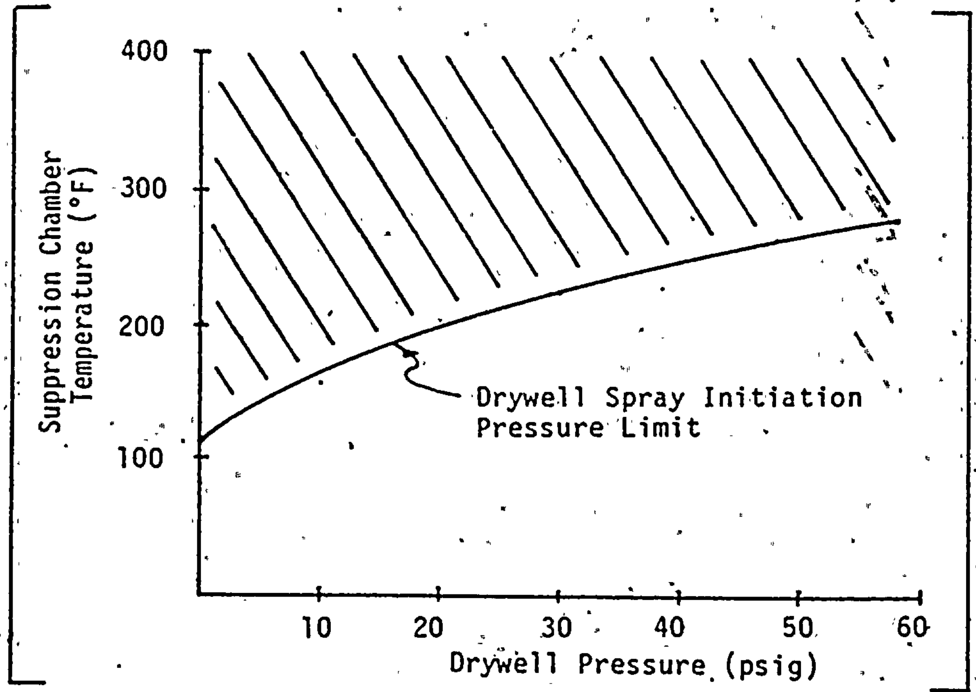
PC/P-1 Operate [the following systems, as required:

- Containment pressure control systems. Use containment pressure control system operating procedure.]

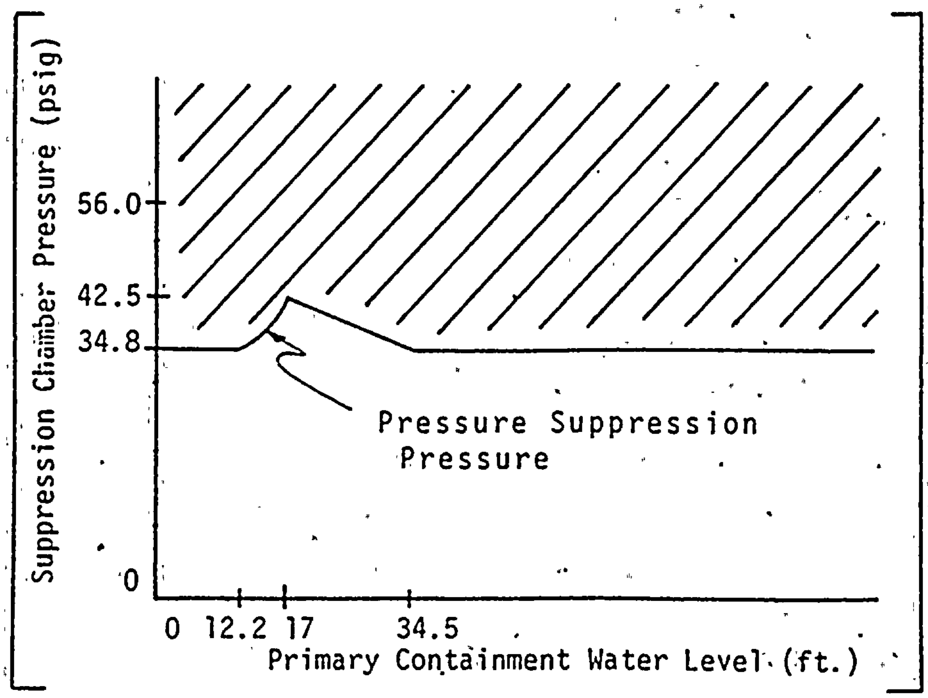
[•] SBGT [and drywell purge], only when the temperature in the space being evacuated is below [212°F (Maximum Noncondensible Evacuation Temperature)]. Use [SBGT and drywell purge operating procedures]. #21

PC/P-2 Before suppression chamber pressure reaches [the Pressure Suppression Pressure] [17.4 psig (Suppression Chamber Spray Initiation Pressure)], but only if [suppression chamber pressure is above 1.7 psig (Mark III Containment Spray Initiation Pressure Limit)] [suppression pool water level is below 24 ft. 6 in. (elevation of suppression pool spray nozzles)], initiate suppression pool sprays. #8, #18

PC/P-3 If suppression chamber pressure exceeds [17.4 psig (Suppression Chamber Spray Initiation Pressure)] but only if [suppression chamber temperature and drywell pressure are below the Drywell Spray Initiation Pressure Limit], [shut down recirculation pumps and drywell cooling fans and] initiate drywell sprays [restricting flow rate to less than 720 gpm (Maximum Drywell Spray Flow Rate Limit)]. #18

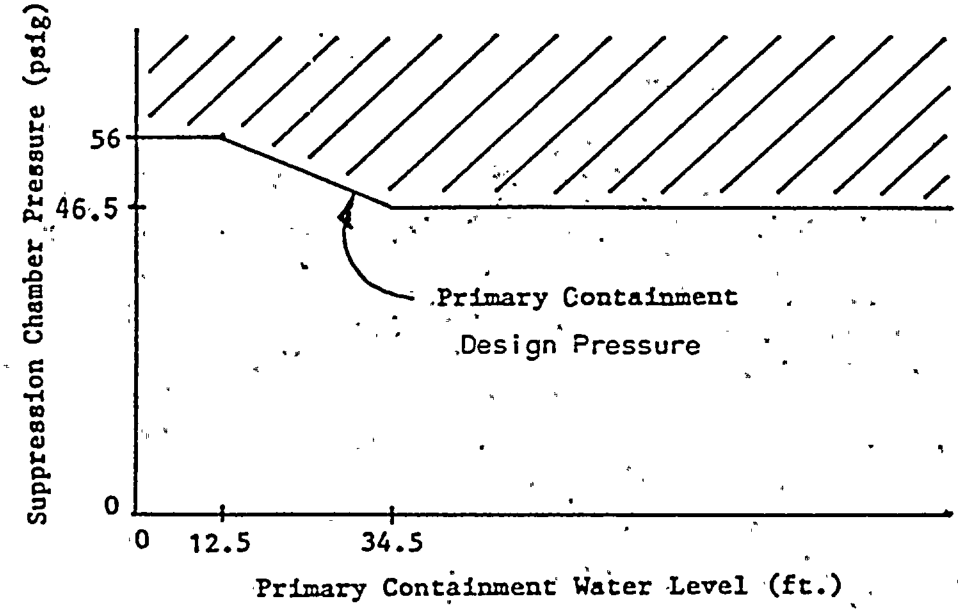


PC/P-4 If suppression chamber pressure cannot be maintained below [the Pressure Suppression Pressure], EMERGENCY RPV DEPRESSURIZATION IS REQUIRED.



PC/P-5 If suppression chamber pressure cannot be maintained below [the Primary Containment Design Pressure], RPV FLOODING IS REQUIRED.

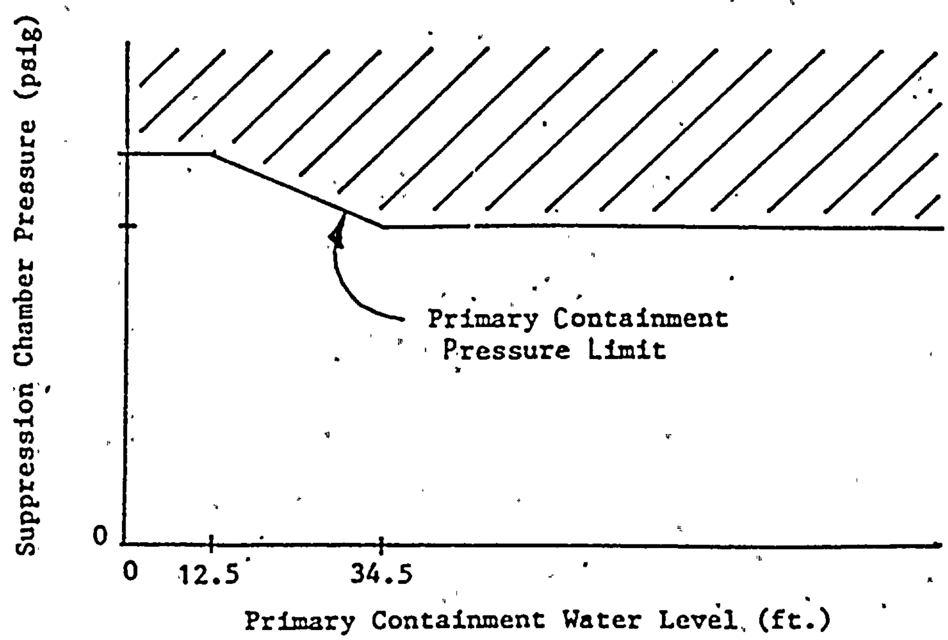
[



]

PC/P-6 If suppression chamber pressure cannot be maintained below the Primary Containment Pressure Limit, then irrespective of whether adequate core cooling is assured:

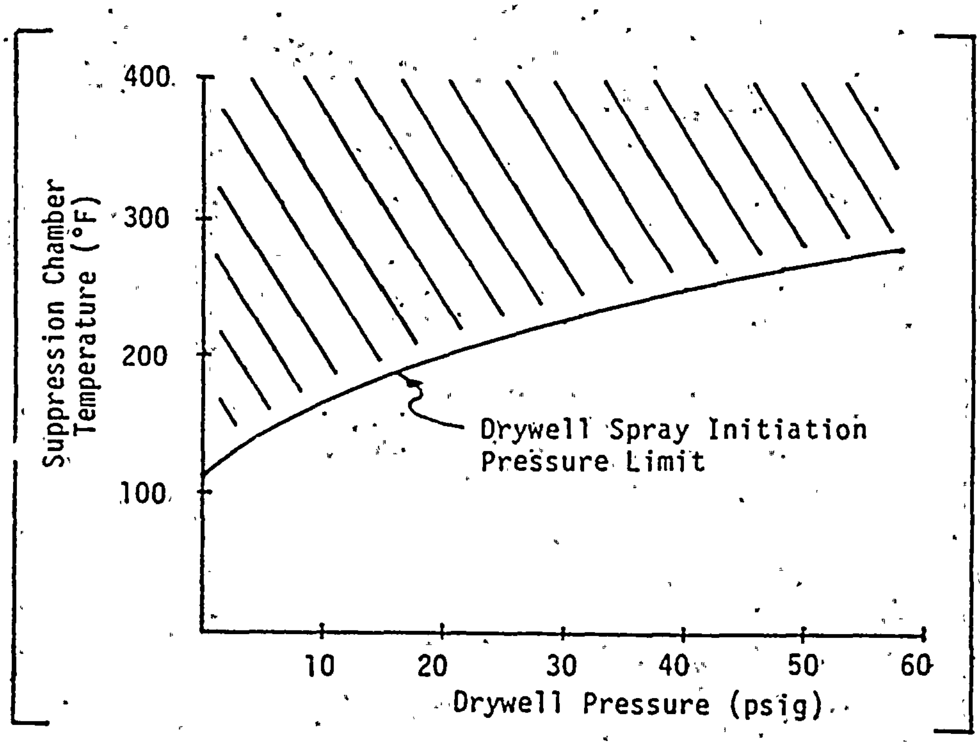
[



]

- [If suppression pool water level is below 24 ft. 6 in. (elevation of suppression pool spray nozzles),] initiate suppression pool sprays.

- If [suppression chamber temperature and drywell pressure are below the Drywell Spray Initiation Pressure Limit], [shut down recirculation pumps and drywell cooling fans and] initiate drywell sprays [restricting flow rate to less than 720 gpm (Maximum Drywell Spray Flow Rate Limit)].



PC/P-7 If suppression chamber pressure exceeds the Primary Containment Pressure Limit, vent the primary containment in accordance with [procedure for containment venting] to reduce and maintain pressure below the Primary Containment Pressure Limit. #22

SP/L Monitor and control suppression pool water level.

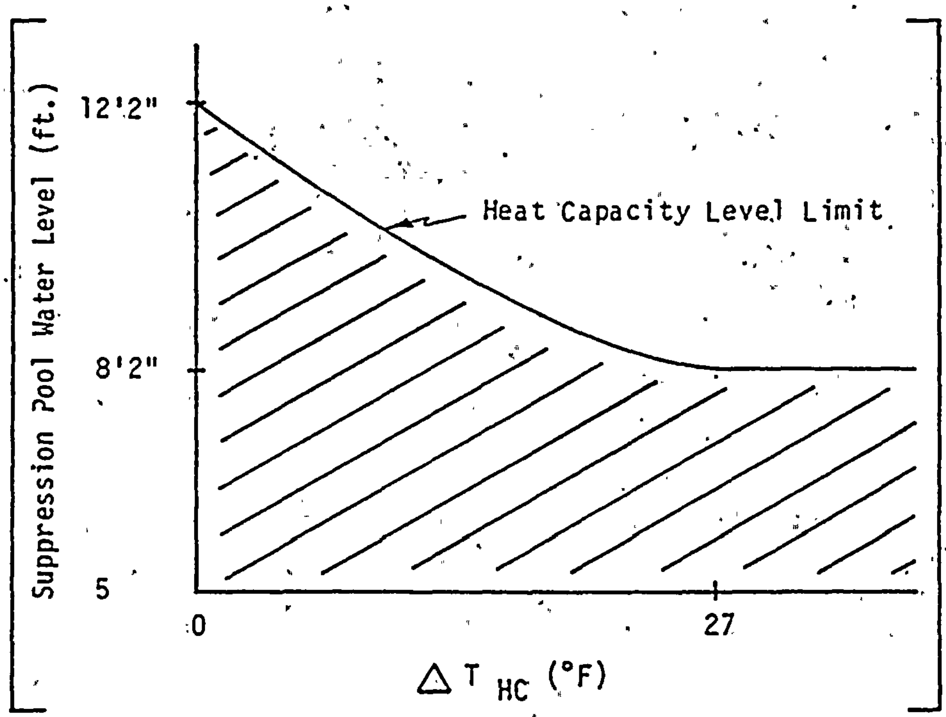
SP/L-1 Maintain suppression pool water level between [12 ft. 6 in. (maximum suppression pool water level LCO)] and [12 ft. 2 in. (minimum suppression pool water level LCO)]. Refer to [sampling procedure] prior to discharging water. #8, #9

If suppression pool water level cannot be maintained above [12 ft. 2 in. (minimum suppression pool water level LCO)] execute [Step SP/L-2].

If suppression pool water level cannot be maintained below [12 ft. 6 in. (maximum suppression pool water level LCO)] ([23 ft. 9 in. (SPMS initiation setpoint plus suppression pool water level increase which results from SPMS operation)] if SPMS has been initiated), execute [Step SP/L-3].

SP/L-2 SUPPRESSION POOL WATER LEVEL BELOW [12 ft. 2 in. (minimum suppression pool water level LCO)]

Maintain suppression pool water level above the Heat Capacity Level Limit.



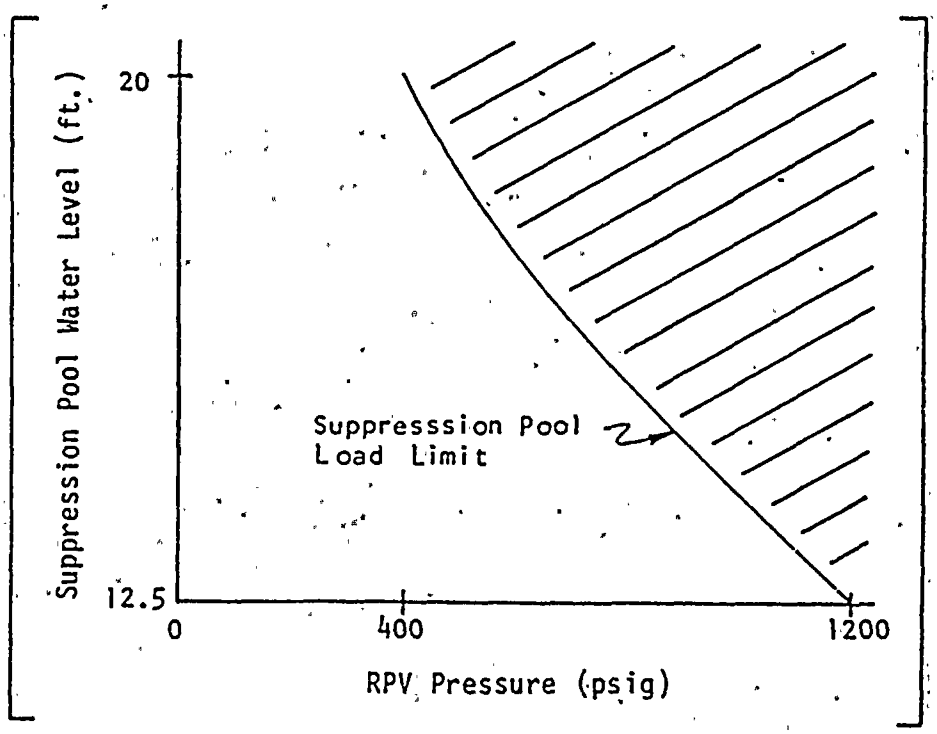
Where ΔT_{HC} = Heat Capacity Temperature Limit minus suppression pool temperature

If suppression pool water level cannot be maintained above the Heat Capacity Level Limit, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED; enter [procedure developed from the RPV Control Guideline] at [Step RC-1] and execute it concurrently with this procedure.

SP/L-3 SUPPRESSION POOL WATER LEVEL ABOVE [12 ft. 6 in. (maximum suppression pool water level LCO)] ([23 ft. 9 in. (SPMS initiation setpoint plus suppression pool water level increase which results from SPMS operation)] if SPMS has been initiated)

Execute [Steps SP/L-3.1 and SP/L-3.2] concurrently.

SP/L-3.1 Maintain suppression pool water level below the Suppression Pool Load Limit.



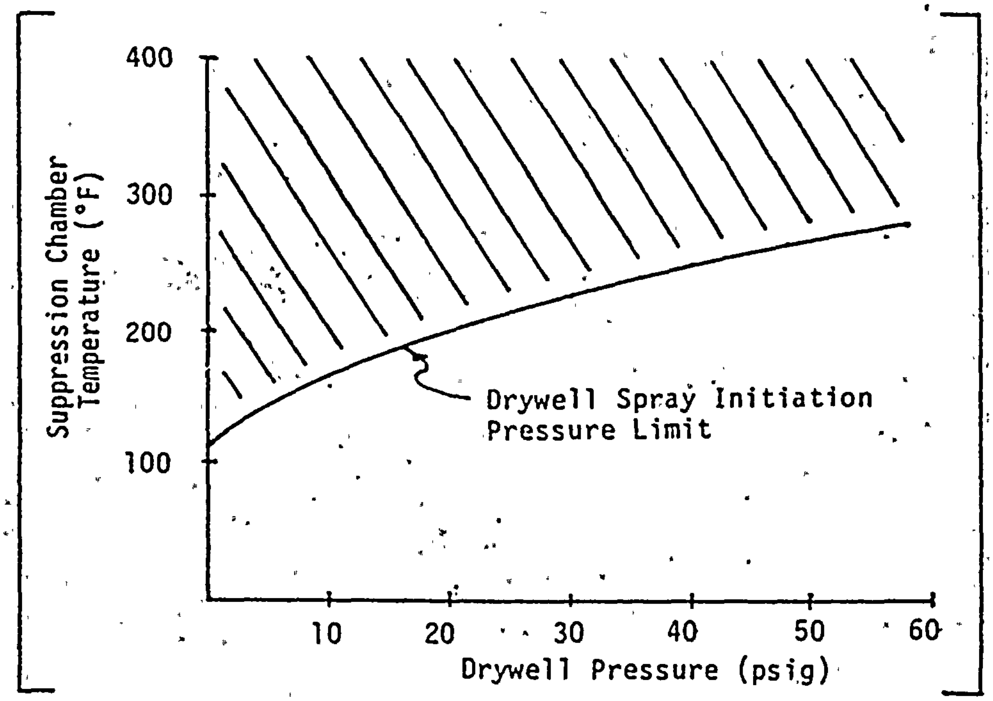
If suppression pool water level cannot be maintained below the Suppression Pool Load Limit, maintain RPV pressure below the Limit. #13 #14

If suppression pool water level and RPV pressure cannot be maintained below the Suppression Pool Load Limit but only if adequate core cooling is assured, terminate injection into the RPV from sources external to the primary containment except from boron injection systems and CRD.

If suppression pool water level and RPV pressure cannot be restored and maintained below the Suppression Pool Load Limit, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED; enter [procedure developed from the RPV Control Guideline] at [Step RC-1] and execute it concurrently with this procedure.

SP/L-3.2 Before suppression pool water level reaches [17 ft. 2 in. (Maximum Primary Containment Water Level Limit or elevation of bottom of Mark I internal suppression chamber to drywell vacuum breakers less vacuum breaker opening pressure in feet of water, whichever is lower)] but only if adequate core cooling is assured, terminate injection into the RPV from sources external to the primary containment except from boron injection systems and CRD.

1. When suppression pool water level reaches [17 ft. 2 in. (elevation of bottom of Mark I internal suppression chamber to drywell vacuum breakers less vacuum breaker opening pressure in feet of water)] but only if [suppression chamber temperature and drywell pressure are below the Drywell Spray Initiation Pressure Limit], [shut down recirculation pumps and drywell cooling fans and] initiate drywell sprays [restricting flow rate to less than 720 gpm (Maximum Drywell Spray Flow Rate Limit)]. #18



2. If suppression pool water level exceeds [17 ft. 2 in. (elevation of bottom of Mark I internal suppression chamber to drywell vacuum breakers less vacuum breaker opening pressure in feet of water)], continue to operate drywell sprays [below 720 gpm (Maximum Drywell Spray Flow Rate Limit)]. #23

3. When primary containment water level reaches [104 ft. (Maximum Primary Contrainment Water Level Limit)], terminate injection into the RPV from sources external to the primary containment irrespective of whether adequate core cooling is assured.

SECONDARY CONTAINMENT CONTROL GUIDELINE

RADIOACTIVITY RELEASE CONTROL GUIDELINE

CONTINGENCY #1

LEVEL RESTORATION

If while executing the following steps: • RPV water level cannot be determined, RPV FLOODING IS REQUIRED; enter [procedure developed from CONTINGENCY #6]. • RPV Flooding is required, enter [procedure developed from CONTINGENCY #6].

C1-2 Line up for injection and start pumps in 2 or more of the following injection subsystems:

- Condensate

- LPCI-A
- LPCI-B

- LPCS-A
- LPCS-B

If less than 2 of the injection subsystems can be lined up, commence lining up as many of the following alternate injection subsystems as possible:

- RHR service water crosstie
- Fire system
- Interconnections with other units
- ECCS keep-full systems
- SLC (test tank)
- SLC (boron tank)

C1-3 Monitor RPV pressure and water level. Continue in this procedure at the step indicated in the following table.

RPV PRESSURE REGION

[425 psig][1] [100 psig][2]

		HIGH	INTERMEDIATE	LOW
RPV LEVEL	INCREASING	C1-4	C1-5	C1-6
RPV LEVEL	DECREASING	C1-7		C1-8

[1](RPV pressure at which LPCS shutoff head is reached)
[2](HPCI or RCIC low pressure isolation setpoint, whichever is higher)

If while executing the following steps:

- The RPV water level trend reverses or RPV pressure changes region, return to [Step C1-3].
- RPV water level drops below [-146 in. (ADS initiation setpoint)], prevent automatic initiation of ADS.

C1-4 RPV WATER LEVEL INCREASING, RPV PRESSURE HIGH

Enter [procedure developed from the RPV Control Guideline] at [Step RC/L].

C1-5 RPV WATER LEVEL INCREASING, RPV PRESSURE INTERMEDIATE

If HPCI and RCIC are not available and RPV pressure is increasing, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED. When RPV pressure is decreasing, enter [procedure developed from the RPV Control Guideline] at [Step RC/L].

If HPCI and RCIC are not available and RPV pressure is not increasing, enter [procedure developed from the RPV Control Guideline] at [Step RC/L].

Otherwise, when RPV water level reaches [+12 in. (low level scram setpoint)], enter [procedure developed from the RPV Control Guideline] at [Step RC/L].

C1-6 RPV WATER LEVEL INCREASING, RPV PRESSURE LOW

If RPV pressure is increasing, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED. When RPV pressure is decreasing, enter [procedure developed from the RPV Control Guideline] at [Step RC/L].

Otherwise, enter [procedure developed from the RPV Control Guideline] at [Step RC/L].

C1-7 RPV WATER LEVEL DECREASING, RPV PRESSURE HIGH OR INTERMEDIATE.

If HPCI or RCIC is not operating, restart whichever is not operating.

If no injection subsystem is lined up for injection with at least one pump running, start pumps in alternate injection subsystems which are lined up for injection.

When RPV water level drops to [-164 in. (top of active fuel)]:

- If no system, injection subsystem or alternate injection subsystem is lined up with at least one pump running, STEAM COOLING IS REQUIRED. When any system, injection subsystem or alternate injection subsystem is lined up with at least one pump running, return to [Step C1-3].

- Otherwise, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED. When RPV water level is increasing or RPV pressure drops below [100 psig (HPCI or RCIC low pressure isolation setpoint, whichever is higher)], return to [Step C1-3].

C1-8 RPV WATER LEVEL DECREASING, RPV PRESSURE LOW

[If no HPCS subsystem is operating,] start pumps in alternate injection subsystems which are lined up for injection.

If RPV pressure is increasing, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED.

When RPV water level drops to [-164 in. (top of active fuel)], enter [procedure developed from CONTINGENCY #4].

C1-3 MONITOR RPV PRESSURE AND WATER LEVEL. CONTINUE IN THIS PROCEDURE AT THE STEP INDICATED IN THE FOLLOWING TABLE:

<table>
<tr><td rowspan="2">RPV WATER LEVEL</td><td colspan="3">RPV PRESSURE REGION
[425 PSIG (*)]   [100 PSIG (*)]</td></tr>
<tr><td>HIGH</td><td>INTERMEDIATE</td><td>LOW</td></tr>
<tr><td>INCREASING</td><td><u>C1-4</u>
ENTER [PROCEDURE DEVELOPED FROM THE RPV CONTROL GUIDELINE] AT [STEP RC/L].</td><td><u>C1-5</u>
IF HPCI AND RCIC ARE NOT AVAILABLE AND RPV PRESSURE IS INCREASING, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED. WHEN RPV PRESSURE IS DECREASING, ENTER [PROCEDURE DEVELOPED FROM THE RPV CONTROL GUIDELINE] AT [STEP RC/L].

IF HPCI AND RCIC ARE NOT AVAILABLE AND RPV PRESSURE IS NOT INCREASING, ENTER [PROCEDURE DEVELOPED FROM THE RPV CONTROL GUIDELINE] AT [STEP RC/L].

OTHERWISE, WHEN RPV WATER LEVEL REACHED [+12 IN. (LOW LEVEL SCRAM SETPOINT)], ENTER [PROCEDURE DEVELOPED FROM THE RPV CONTROL GUIDELINE] AT [STEP RC/L].</td><td><u>C1-6</u>
IF RPV PRESSURE IS INCREASING, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED. WHEN RPV PRESSURE IS DECREASING, ENTER [PROCEDURE DEVELOPED FROM THE RPV CONTROL GUIDELINE] AT [STEP RC/L].

OTHERWISE, ENTER [PROCEDURE DEVELOPED FROM THE RPV CONTROL GUIDELINE] AT [STEP RC/L].</td></tr>
<tr><td>DECREASING</td><td colspan="2"><u>C1-7</u>
IF HPCI OR RCIC IS NOT OPERATING, RESTART WHICHEVER IS NOT OPERATING.

IF NO INJECTION SUBSYSTEM IS LINED UP FOR INJECTION WITH AT LEAST ONE PUMP RUNNING, START PUMPS IN ALTERNATE INJECTION SUBSYSTEMS WHICH ARE LINED UP FOR INJECTION.

WHEN RPV WATER LEVEL DROPS TO [-164 IN. (TOP OF ACTIVE FUEL)]:

• IF NO SYSTEM, INJECTION SUBSYSTEM OR ALTERNATE INJECTION SUBSYSTEM IS LINED UP WITH AT LEAST ONE PUMP RUNNING, STEAM COOLING IS REQUIRED. WHEN ANY SYSTEM, INJECTION SUBSYSTEM OR ALTERNATE INJECTION SUBSYSTEM IS LINED UP WITH AT LEAST ONE PUMP RUNNING, RETURN TO STEP C1-3].

• OTHERWISE, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED, WHEN RPV WATER LEVEL IS INCREASING OR RPV PRESSURE DROPS BELOW [100 PSIG (HPCI OR RCIC LOW PRESSURE ISOLATION SETPOINT, WHICHEVER IS HIGHER)], RETURN TO STEP C1-3].</td><td><u>C1-8</u>
[IF NO LPCS OR LPCS SUBSYSTEM IS OPERATING,] START PUMPS IN ALTERNATE INJECTION SUBSYSTEMS WHICH ARE LINED UP FOR INJECTION.

IF RPV PRESSURE IS INCREASING, EMERGENCY RPV DEPRESSURIZATION IS REQUIRED.

WHEN RPV WATER LEVEL DROPS TO [-164 IN. (TOP OF ACTIVE FUEL)] ENTER [PROCEDURE DEVELOPED FROM CONTINGENCY #4].</td></tr>
</table>

IF WHILE EXECUTING THE FOLLOWING STEPS THE RPV WATER LEVEL TREND REVERSES OR RPV PRESSURE CHANGES REGION, RETURN TO (STEP C1-3).

*RPV PRESSURE AT WHICH LPCS SHUTOFF HEAD IS REACHED. +HPCI OR RCIC LOW PRESSURE ISOLATION SETPOINT, WHICHEVER IS HIGHER.

CONTINGENCY #2

EMERGENCY RPV DEPRESSURIZATION

C2-1 #13, #14

C2-1.2 If suppression pool water level is above [4 ft. 9 in. (elevation of top of SRV discharge device)]:

- Open all ADS valves.
- If any ADS valve cannot be opened, open other SRVs until [7 (number of SRVs dedicated to ADS)] valves are open.

C2-1.3 If less than [3 (Minimum Number of SRVs Required for Emergency Depressurization)] SRVs are open [and RPV pressure is at least 50 psig (Minimum SRV Re-opening Pressure) above suppression chamber pressure], rapidly depressurize the RPV using one or more of the following systems (use in order which will minimize radioactive release to the environment): #22

- Main condenser
- [Other steam driven equipment]
- Main steam line drains
- HPCI steam line
- RCIC steam line
- Head vent

If RPV Flooding is required, enter [procedure developed from CONTINGENCY #6].

C2-2 Enter [procedure developed from the RPV Control Guideline] at [Step RC/P-4].

CONTINGENCY #3

STEAM COOLING

C3-1

If while executing the following steps Emergency RPV Depressurization is required or any system, injection subsystem, or alternate injection subsystem is lined up for injection with at least one pump running, enter [procedure developed from CONTINGENCY #2].

When RPV water level drops to [-272 in. (Minimum Zero-Injection RPV Water Level)] or if RPV water level cannot be determined, open one SRV.

When RPV pressure drops below [700 psig (Minimum Single SRV Steam Cooling Pressure)], enter [procedure developed from CONTINGENCY #2].

CONTINGENCY #4

CORE COOLING WITHOUT LEVEL RESTORATION

C4-1 Open all ADS valves. #13

If any ADS valve cannot be opened, open other SRVs until [7 (number of SRVs dedicated to ADS)] valves are open.

C4-2 Operate and LPCS subsystems with suction from the suppression pool.

When at least one core spray subsystem is operating with suction from the suppression pool and RPV pressure is below [310 psig (RPV pressure for rated LPCS or flow, whichever pressure is lower)], terminate injection into the RPV from sources external to the primary containment.

C4-3 When RPV water level is restored to [-164 in. (top of active fuel)], enter [procedure developed from the RPV Control Guideline] at [Step RC/L].

CONTINGENCY #5

ALTERNATE SHUTDOWN COOLING

C5-1 Initiate suppression pool cooling.

C5-2 Close the [RPV head vents,] MSIVs, main steam line drain valves, and HPCI and RCIC isolation valves.

C5-3 Place the control switch for [one (Minimum Number of SRVs Required for Alternate Shutdown Cooling)] SRV[s] in the OPEN position.

C5-4 Slowly raise RPV water level to establish a flow path through the open SRV back to the suppression pool.

C5-5 Start one LPCS or LPCI pump with suction from the suppression pool.

C5-6 Slowly increase LPCS or LPCI injection into the RPV to the maximum.

C5-6.1 If RPV pressure does not stabilize at least [94 psig (Minimum Alternate Shutdown Cooling RPV Pressure)] above suppression chamber pressure, start another LPCS or LPCI pump.

C5-6.2 If RPV pressure does not stabilize below [172 psig (Maximum Alternate Shutdown Cooling RPV Pressure)], open another SRV.

C5-6.3 If the cooldown rate exceeds [100°F/hr (maximum RPV cooldown rate LCO)], reduce LPCS or LPCI injection into the RPV until the cooldown rate decreases below [100°F/hr (maximum RPV cooldown rate LCO)] [or RPV pressure decreases to within 50 psig (Minimum SRV Re-opening Pressure) of suppression chamber pressure, whichever occurs first].

C5-7 Control suppression pool temperature to maintain RPV water temperature above [70°F (RPV NDTT or head tensioning limit, whichever is higher)].

C5-8 Proceed to cold shutdown in accordance with [procedure for cooldown to cold shutdown conditions].

CONTINGENCY #6

RPV FLOODING

C6-1 If at least [3 (Minimum Number of SRVs Required for Emergency Depressurization)] SRVs can be opened or if or motor driven feedwater pumps are available for injection, close the MSIVs, main steam line drain valves, HPCI, RCIC

C6-3 If RPV water level cannot be determined:

C6-3.1 Commence and increase injection into the RPV with the following systems until at least [3 (Minimum Number of SRVs Required for Emergency Depressurization)] SRVs are open and RPV pressure is not decreasing and is at least [77 psig (Minimum RPV Flooding Pressure)] above suppression chamber pressure.

- LPCS
- LPCI
- Condensate pumps
- CRD
- [RHR service water crosstie
- Fire System
- Interconnections with other units
- ECCS keep-full systems
- SLC (test tank)
- SLC (boron tank)]

C6-3.2 Maintain at least [3 (Minimum Number of SRVs Required for Emergency Depressurization)] SRVs open and RPV pressure at least [77 psig (Minimum RPV Flooding Pressure)] above suppression chamber pressure by throttling injection.

C6-4 If RPV water level can be determined, commence and increase injection into the RPV with the following systems until RPV water level is increasing:

- LPCS
- LPCI
- Condensate pumps
- CRD
- RHR service water crosstie
- Fire System
- Interconnections with other units
- ECCS keep-full systems
- SLC (test tank)
- SLC (boron tank)

C6-5 If RPV water level cannot be determined:

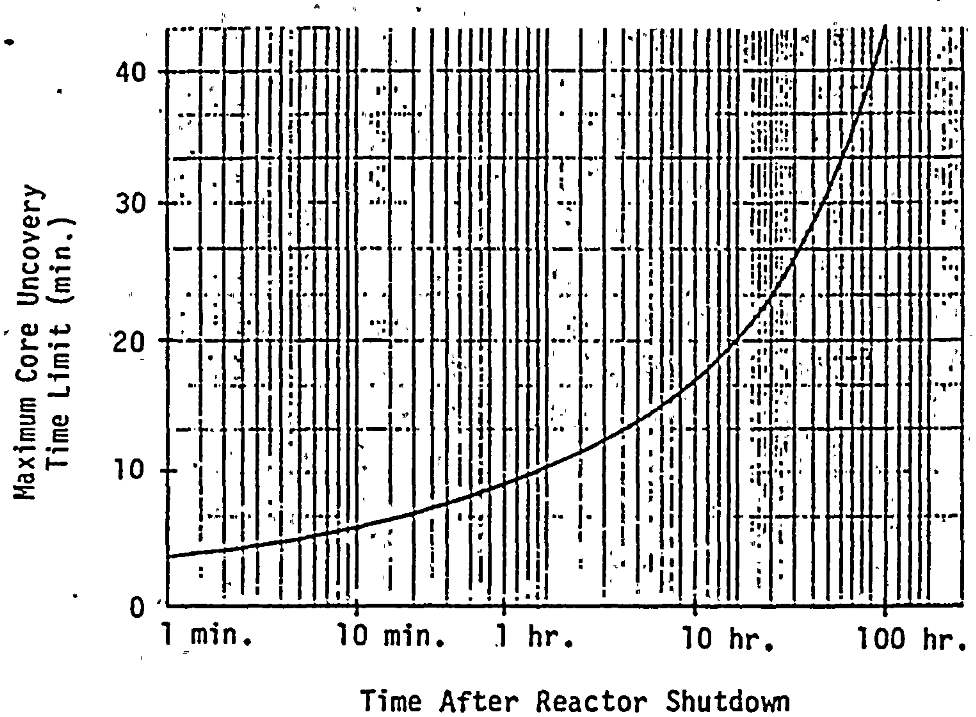
C6-5.1 Fill all RPV water level instrumentation reference columns.

C6-5.2 Continue injecting water into the RPV until [temperature near the cold reference leg instrument vertical runs] is below 212°F and RPV water level instrumentation is available.

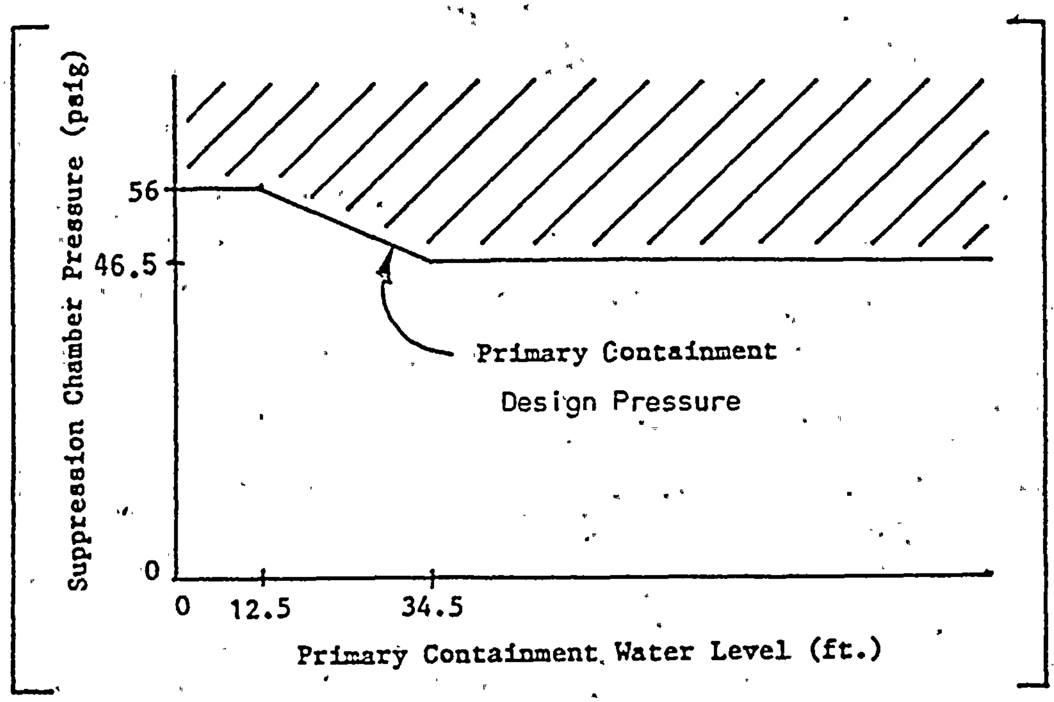
If while executing the following steps, RPV water level can be determined, continue in this procedure at [Step C6-6].

C6-5.3 If it can be determined that the RPV is filled or if RPV pressure is at least [77 psig (Minimum RPV Flooding Pressure)] above suppression chamber pressure, terminate all injection into the RPV and reduce RPV water level.

C6-5.4 If RPV water level indication is not restored within the Maximum Core Uncovery Time Limit after commencing terminaton of injection into the RPV, return to [Step C6-3].



C6-6 When suppression chamber pressure can be maintained below the Primary Containment Design Pressure, enter [procedure developed from the RPV Control Guideline] at [Steps RC/L and RC/P-4] and execute these steps concurrently.



CONTINGENCY #7

LEVEL/POWER CONTROL

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT

Writer's Guide
for
Emergency Operating Instructions

Writers Guide for Emergency Operating Instructions

Table of Contents

BFNP WRITER'S GUIDE FOR EMERGENCY OPERATING INSTRUCTIONS (EOIs)

I. SCOPE

The purpose of this writer's guide is to provide administrative and technical guidance on the preparation and maintenance of all emergency operating instructions at Browns Ferry Nuclear Plant.

II. PROCEDURE IDENTIFICATION

A. COVER SHEET AND TITLE PAGE

1. Each EOI shall be preceded by the standard cover sheet used for all plant procedures (Attachment B in Standard Practice BF 2.1). The primary purposes of this cover sheet are to:

   a. Identify the EOI by title and number designation for document control

   b. Identify the unit and facility to which the procedure applies

   c. Provide a place for review and approval signatures

   d. Provide a list of revision dates in chronological order and the page numbers to which they apply

   e. Provide a remarks section in which the reason for the most current revision is stated.

2. A title page shall immediately follow the cover sheet as page 1 of the EOI and contain the following information:

   a. A capitalized, descriptive title of the EOI

   b. The designation EOI followed by its assigned procedure number

   c. A table of contents listing the title and number of each section of the procedure.

B. PAGE IDENTIFICATION AND NUMBERING

1. Each page of the procedure will be identified by:

   a. The procedure designator and number (i.e. EOI-1)

   b. The unit number specified as "UNIT ______"

c. The revision date of the page

d. The page number specified as "Page____of____".

2. All of the above information will be together at the top right corner of the page.

C. REVISION IDENTIFICATION

1. The date of the latest revision will appear both on the cover sheet and on the page where the revision(s) was made.

2. To identify revisions to the text of an EOI, an asterisk to the left of the word "revision" will be located in the bottom left corner of the page (i.e. *REVISION).

3. If a new page is generated due to a revision, the page number will have an asterisk to the left of it, and the word "addendum" will appear at the bottom left corner of the page with an asterisk to the left of it (i.e. *ADDENDUM).

III. FORMAT

The following format is to be applied consistently for all EOIs.

A. PAGE FORMAT

1. A single-column format will be used.

2. All instruction steps, notes, and cautions will be written in complete sentences using a word order common to standard American English usage.

a. Short, simple sentences should be used in preference to long, compound, or complex sentences.

b. Sentences which require the operator to do something or observe something should be written as a directive.

c. Instructional steps should deal with only one idea.

d. For instructional steps that involve an action verb relating to three or more objects, the objects will be listed with space provided for operator checkoff.

3. Each instructional step and sub-step will be single spaced. Double spacing will be used to separate the following:

a. Section headings from instructional steps

b. Instructional steps from sub-steps

c. Sub-steps

d. Cautions and notes from instructional steps or sub-steps

e. Separate cautions from each other when they appear successively

f. Separate notes from each other when they appear successively

g. Separate notes and cautions from each other.

4. Margins shall be as follows:

   a. The right hand margin will be no less than ½ inch

   b. The bottom margin will be no less than ½ inch

   c. The left hand margin will be no less than 1 inch to ensure that no information is obscured due to the binding of the procedure

   d. The page identifiers (see section II.B) will be no less than 3/8 inch from the top of the page.

5. Each subprocedure (or subsection) of an EOI will begin on a new page.

6. Each action step will be wholly contained on a single page.

B. OVERALL EOI LAYOUT

1. Each EOI shall contain the following sections in the order shown below:

   a. SCOPE - Should be a brief statement describing what the procedure is intended to accomplish

   b. ENTRY CONDITIONS - List the conditions under which the procedure should be used

   c. AUTOMATIC ACTIONS - Should provide the operator with an indication of which safety systems should activate automatically, without operator intervention, and at what value for a given parameter this should be expected to occur.

   d. IMMEDIATE OPERATOR ACTIONS - Provide the operator actions to be taken as soon as possible, when there are indications of an emergency, to stop further degradation of existing conditions, mitigate the consequences of those conditions, and allow the operator to evaluate the situation

e. SUBSEQUENT OPERATOR ACTIONS - These actions should accomplish the following:

1) Ensure all immediate operator actions have been taken

2) Ensure proper notification of plant personnel

3) Direct the operator to the proper subprocedure (subsection) necessary to return the plant to a normal, stable, or safe steady-state condition

f. APPENDIX - Should contain all material which could aid the operator in efficiently carrying out the actions in the EOI, but which does not directly deal with the intent of the instruction and should therefore not be placed in the bulk of the procedure.

C. SECTION, SUBPROCEDURE (SUBSECTION), AND INSTRUCTION STEP NUMBERING

NOTE: Due to the difference between Level Control and Containment Control in the way the procedure is used, they will each be addressed separately here. (Refer to section VI for EOI use)

1. Arabic numerals will be used for numbering sections and subsections (subprocedures) in the following decimal format for Level Control:

a. 1.0 - 7.0 Section Numbers

b. Subprocedures under section 6.0 will be numbered 6.1 (Subprocedure 1), 6.2 (Subprocedure 2), etc.

2. The Containment Control EOI will be numbered as follows:

a. 1.0 - 6.0 Section Numbers

b. Subsections of section 5.0 are considered part of the subsequent operator actions and are numbered as such.

3. Instruction steps in a section or subprocedure (subsection) will be numbered and indented as follows:

1.0 Section or subprocedure (subsection title)

1.1 Instruction step (level 1 information)

1.1.1 Instruction sub-step (level 2 information).

4. Charts and tables will have the same number as the step in which they are referenced.

D. CAUTION AND NOTE STATEMENTS

1. Cautions will be used to attract attention to essential or critical information that addresses conditions, practices, or procedures which must be observed to avoid personal injury, loss of life, a long-term health hazard, or damage to equipment.

2. Notes will be used to present important supplemental information to aid in job performance and operator training, and facilitate decision making.

3. Neither notes nor cautions should contain action steps, if at all possible.

4. Cautions and notes will be written to preclude confusion as to which step or evolution they refer.

5. Cautions will immediately precede the step to which they refer.

6. Notes and cautions will not be interrupted by intervening steps or page turning.

E. CHARTS, TABLES, AND DIAGRAMS

1. Charts will be located on the opposite page from the step in which they are referred, if at all possible.

   a. If a calculation must be done to use a chart, (i.e. CHART 5.6.4 HEAT CAPACITY LEVEL LIMIT - EOI-2), the calculational procedure will be placed next to the chart to which it applies.

2. The step number and title of each chart will be centered above the chart.

3. Charts will be prepared in a 3" x 5" size according to standard graphics practices.

4. Logic diagrams will be used only for presentation of diagnostics.

5. The values used in charts and tables must correspond to the values the operator will obtain from plant instrumentation and to the written instructions in the procedure.

6. Tables will directly follow the step or caution in which they are referenced.

   a. They shall be presented in a columnar format with each column having a title expressing its contents centered above it.

F. OPERATOR CHECKOFFS

1. Operator checkoffs will be used as placekeeping aids and be located at the right hand margin of the following:

   a. All cautions, tables, instruction steps, and sub-steps under Subsequent Operator Actions.

   b. All subprocedure (subsection) cautions, tables, instruction steps and sub-steps.

G. BINDING AND TABBING

1. Use standard size ring notebooks (for $8\frac{1}{2}$" x 11" paper).

2. Arrangement of procedures will be as specified in Figure 1.

3. Color coded tabbing will be used to divide EOI-1 subprocedures and appendix as follows:

   a. Subprocedure 1 - RED

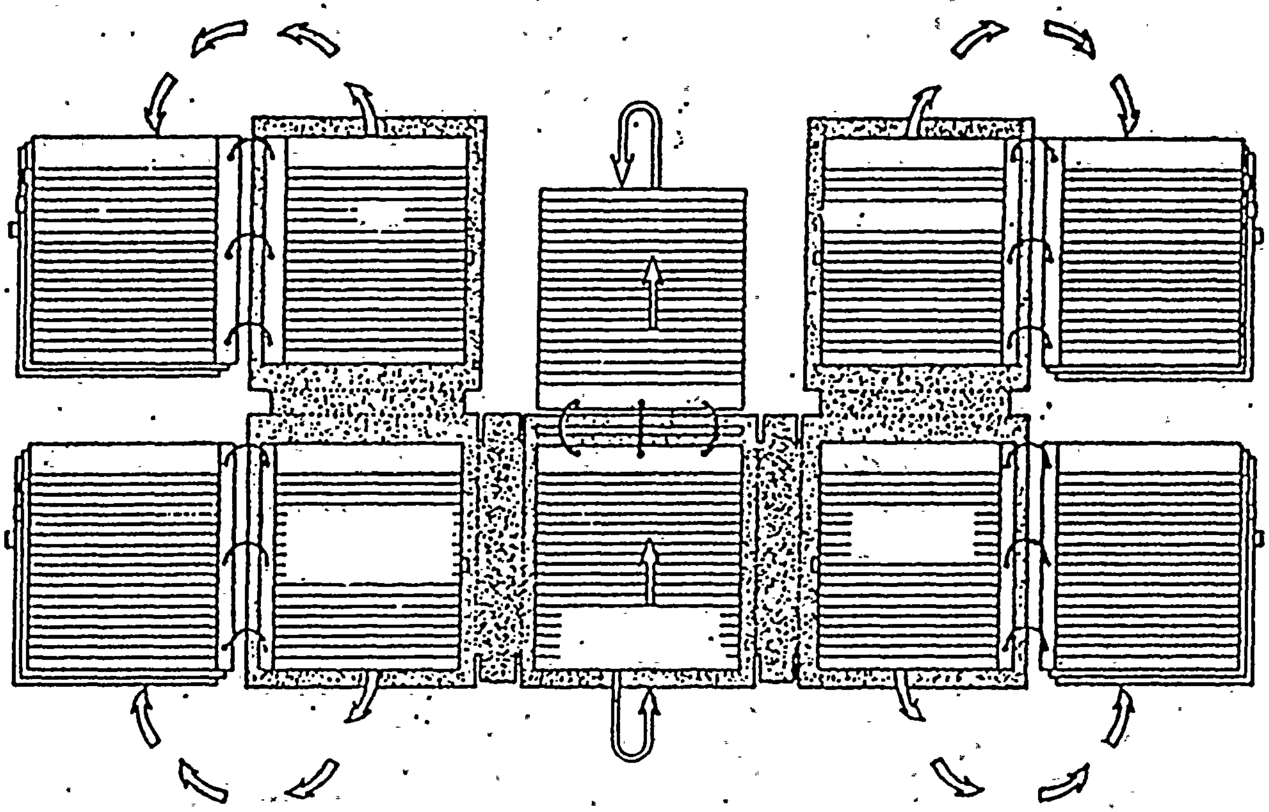
   b. Subprocedure 2 - WHITE

   c. Subprocedure 3 - GREEN

   d. Subprocedure 4 - YELLOW

   e. Subprocedure 5 - BLUE

   f. APPENDIX - PINK



BFNP EOI ARRANGEMENT

Figure 1

IV. STYLE OF EXPRESSION AND PRESENTATION

A. EMPHASIS

1. Underlining will be used for the following:

   a. All section and subprocedure (subsection) titles

   b. All "caution" and "note" headings

   c. All table headings or table column headings

   d. All logic terms (refer to IV. F. of this guide)

   e. Miscellaneous words needing special impact

2. Capitalization should conform to standard American English, but will also be used as a technique for emphasizing certain words or phrases as follows:

   a. The title of the EOI will be all capital letters whenever it appears in the procedure

   b. Headings appearing above charts and tables will be all capital letters

   c. All logic terms will be in capital letters

   d. The words "caution" and "note" will be in capital letters

   e. The first letter of each word, (excluding conjunctions), in section and subprocedure (subsection) titles will be capitalized

   f. Abbreviations of systems and procedures will be in capital letters

   g. The words "increasing" or "decreasing", when used in a section or subprocedure (subsection) title will be in capital letters

   h. The first letter in the abbreviation of "reactor" will be capitalized

3. Notes and Cautions

   a. Notes and cautions shall be emphasized and differentiated from each other as shown:

****

CAUTION

Elevated torus pressure may trip RCIC on high exhaust pressure.

****

NOTE: If at any time Rx. pressure or water level trend reverses or Rx. pressure changes region, return to step 6.1.4.

b. Successive cautions need only one heading and should appear together between the asterisk lines.

B. VOCABULARY

1. Use short words and words that are common in ordinary conversation.

2. Use nomenclature and idioms that the operator is trained to use and which are standard in the nuclear power industry.

3. Use concrete and specific words that describe precisely what the operator is to do or observe.

4. Use words and meanings consistently throughout the procedures.

5. Avoid using adverbs that are difficult to define in a precise manner (e.g. frequently, slowly).

C. ABBREVIATIONS, ACRONYMS, AND SYMBOLS

1. Abbreviations, acronyms and symbols should be those readily familiar to the operators so there is no need to consult a glossary in order to identify them.

2. The use of abbreviations, acronyms, and symbols should be consistent throughout the EOIs.

D. PUNCTUATION

1. Use the rules of punctuation for standard American English.

2. Use punctuation only as necessary to aid reading and prevent misunderstanding.

3. Select word order which requires a minimum of punctuation.

4. Use a comma after conditional phrases for clarity and ease of reading.

Example: <u>IF</u> HPCI or RCIC is not operating, <u>THEN</u> restart whichever is not operating.

5. Ensure the use of punctuation remains consistent throughout the procedure.

E. NUMERICAL VALUES, TOLERANCES, AND CALCULATIONS

1. Arabic numerals should be used.

2. Numerals (representing values of parameters or equipment designations) should be written in a style familiar to the operator.

3. Numerals should correspond to those designated on panels so that the operator can recognize and locate the panel designation immediately.

4. When numerals and units of measure are used to refer to instrumentation readings, the operator should be able to immediately relate them to those used on the instrumentation, without conversion, translation or manipulation.

5. Minimize the need for calculations and use of formulas.

6. Provide a space for calculations and keep them as simple as possible.

7. Tolerances should be used to bound numerical values and to avoid approximations.

8. The units in which tolerances are expressed should be the same as the units on the display or instrument to which they refer.

F. CONDITIONAL STATEMENTS (LOGIC TERMS AND SEQUENCES)

1. The logic terms AND, OR, NOT, IF, IF NOT, THEN, and WHEN should be used to describe precisely a condition, set of conditions, action, or sequence of actions.

   Example: IF not all ADS valves are open, THEN open MSRVs until 6 valves are open.

2. Write conditional statements so that the description of the condition appears first, followed by the action instruction.

3. Construct conditional statements using the principles and techniques of formal logic so that they are logically correct, unambiguous, and complete.

4. Ensure the logic approach used remains consistent throughout the procedure.

V. CONTENT PRESENTATION

A. SEQUENCING AND VERIFICATION

1. Tasks and action steps should be sequenced according to technical necessity.

   - Closely follow the outline and basis of the BWR Owners Group Emergency Procedure Guidelines.

2. Physical layout and organization of the control room should be considered when sequencing tasks and actions, but technical necessity will remain the overriding consideration.

3. Mandatory sequence of steps is assumed unless otherwise stated.

4. Proper sequencing, operator checkoffs, and presenting alternative steps or sequence of steps are methods used in combination to provide a means for verifying that:

   a. An action has resulted in a positive indication that the equipment has or has not responded to a command

   b. An operator has correctly performed an action or has carried out a series of steps

   c. The objective of a given sequence has been accomplished.

B. CONCURRENT STEPS

1. Explicitly indicate which steps are concurrent so that operators can easily refer to both (or all) sets of steps.

2. Ensure that the maximum number of concurrent steps does not go beyond the capability of the control room staff to perform them.

C. REFERENCING

1. Be specific when referencing another procedure or section of a procedure.

2. If a sequence of actions is covered completely by another existing procedure and if the original procedure is to be re-entered, reference the procedure.

3. If the information to be referenced can be included in a section of the EOI without greatly increasing its length, a reference should not be used.

4. Minimize references as much as possible.

5. If several different levels of the same parameters must be looked at to determine what section of a procedure is required, use a logic diagram rather than a reference step.

D. LOCATION INFORMATION

1. Provide information on the location of equipment, controls, and displays that are infrequently used, are in out-of-the-way places, or are otherwise difficult to find.

   a. Consider operator experience, the tasks, and the equipment involved to determine whether location information would aid the operator in the efficient performance of the procedure.

2. Location information should be evaluated for adequacy during operator walk-throughs of the procedure.

E. CONTROL ROOM STAFFING AND DIVISION OF RESPONSIBILITIES

1. Structure the EOIs so that a unit operator and SRO can efficiently carry out specific actions, concurrent actions, and other responsibilities.

2. During an emergency, the SRO will be responsible for reading aloud the required procedures, utilizing the operator checkoffs, and ensuring the operator clearly understands and correctly performs the applicable action steps.

3. The STA will be available for support as needed.

VI. <u>USE AND MAINTENANCE</u>

A. USE

1. To ensure the proper execution of the procedures, the following standard notes will appear in Subsequent Operator Actions and subsections.

EOI-1 . . . .

NOTE: Upon entrance into the L.C. procedure proceed through the procedure as directed by procedure steps, being in only one section of the procedure at any given time. If directed into the L.C. procedure from the C.C. procedure, go to that step of the L.C. procedure and proceed from that point.

EOI-2 . . . .

NOTE: For <u>each</u> of the following entry conditions that are exceeded, enter appropriate step of this procedure and execute appropriate steps concurrently with one another. If at any time an entry condition for a containment parameter is exceeded, enter that procedure step and execute. When a containment parameter returns to normal, exit from that procedure section is appropriate.

B. MAINTENANCE

1. Handling and updating of EOIs will be in accordance with BROWNS FERRY STANDARD PRACTICE BF 2.1 (CONTROLLED DOCUMENTS).

2. Review and approval process for the instructions will be in accordance with BROWNS FERRY STANDARD PRACTICE BF 2.3 (REVIEW, APPROVAL, AND USE OF INSTRUCTIONS).

3. Due to the frequent use of the instructions, either at the plant, or in training, no scheduled review is required. This is in accordance with BROWNS FERRY STANDARD PRACTICE BF 2.14 (REVIEW OF PLANT INSTRUCTIONS).

4. All instruction changes are reviewed by each licensed RO and SRO per the NRC requirement specified in BROWNS FERRY STANDARD PRACTICE 4.8 pg. 34.

5. The Nuclear Engineer will verify the technical accuracy of all EOI changes and sign TVA Form BF5 (Permanent Instruction Change Form).

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT

Validation/Verification Program
for
Emergency Operating Instructions

BFNP VALIDATION/VERIFICATION PROGRAM FOR EMERGENCY OPERATING PROCEDURES

I. SCOPE

The purpose of the validation/verification program at Browns Ferry is to ensure the adequacy of the new sympton-based EOIs from both a technical and human engineering standpoint.

To accomplish this prior to implementation, control room walk-throughs, Browns Ferry simulator exercises, and desk top reviews will be applied to attain the following objectives:

1. The EOIs are technically correct, i.e., they accurately reflect the technical guidelines.

2. The EOIs are written correctly, i.e., they accurately reflect the plant-specific writer's guide.

3. The EOIs are usable; i.e., they can be understood and followed without confusion, delays, errors, etc.

4. There is a continuity between the procedures and the control room/plant hardware, i.e., control/equipment/indications that are referenced are available (inside and outside of the control room), use the same designation, the same units of measurement, and operate, as specified in the procedures.

5. The language and level of information presented in the EOIs are compatible with the minimum number, qualifications, training, and experience of the operating staff.

6. There is a high level of assurance that the procedures work, i.e., the procedures guide the operator in mitigating transients and accidents.

II. DESCRIPTION

NEW PROCEDURES REVIEWED IN VALIDATION/VERIFICATION PROGRAM

1. EOI-1 LEVEL CONTROL
2. EOI-2 CONTAINMENT CONTROL
3. GOI-100-11 REACTOR SCRAM
4. GOI-100-12 OPERATIONS NECESSARY FOR NORMAL SHUTDOWN FROM POWER TO COLD SHUTDOWN CONDITION

The first draft of the new EOIs at Browns Ferry was written based on revision 1B of the BWROG's Emergency Procedure Guidelines in October, 1981. Upon the completion of the draft, a desk top review by the writers was performed to verify (1) that the EOIs were usable, and (2) the procedures would mitigate transients and accidents and the consequences of transients and accidents. At this time Contingency #5 (Alternate Shutdown Cooling) of the EPGs was made a separate procedure and placed in the abnormal section of the plant cooldown procedure GOI-100-12.

Following the initial desk top review, an Emergency Procedures Evaluation Worksheet was prepared to document the test batteries used to validate the EOIs. In addition, a standard scenario evaluation sheet was developed to provide a comprehensive, constructive means of verifying that the procedures would meet the objectives outlined in NUREG 0799 throughout each scenario. Test battery #1 was executed on the Browns Ferry simulator during the week of December 7, 1981, by one shift engineer and two unit operators familiar with the procedures. Following evaluation of the scenarios, modifications were made to Level Control and Containment Control and to the Emergency Procedures Evaluation Worksheet. During the week of December 14, 1981, test battery #2 was executed on the simulator using one experienced and one inexperienced operator. Neither operator was familiar with the procedures. Minor modifications were again incorporated into the procedures as a result of the remarks documented on the scenario evaluation worksheets.

During the week #1 requalification training, which began January 11, 1982, all licensed operations personnel participated in desk-top reviews, and simulator walkthroughs and scenarios. At the conclusion of the training all operator input was reviewed and minor revisions made accordingly.

In the interim period between week #1 and week #2 requalification training, the operations procedure section issued an information manual for each unit control room containing the following:

1. LETTER FOR ALL OPERATIONS PERSONNEL
2. EOI-1 LEVEL CONTROL
3. EOI-2 CONTAINMENT CONTROL
4. EOI-3 REACTIVITY CONTROL
5. GOI-100-11 REACTOR SCRAM
6. GOI-100-12 OPERATIONS NECESSARY FOR ATTAINING COLD SHUTDOWN
7. REVISION 1B of the BWROG Emergency Procedure Guidelines
8. BASES FOR STEPS CONTAINED IN EPGs

At a meeting held in Dallas, Texas during April, 1982, the BWROG made a formal presentation of the EPGs. Using the clarification given at the meeting, and the operator input from the information manual and week #2 requalification training, minor modifications were again incorporated into the procedures.

Following the approval of revision 2 of the EPGs by the NRC, Level Control and Containment Control were updated to reflect the newer revision. Because the change from Rev. 1B to Rev. 2 of the EPGs was minor, (i.e., augment Rx. pressure control, reword ATWAS procedure, add and/or change graphs in Containment Control), the validation/verification test batteries and scenarios developed from Rev. 1B remained applicable and adequate. A desk top review, control room walkthroughs, and the test batteries scenarios using the procedures based on the plant technical guidelines will be completed by the procedure writers before implementation. An independent engineering section will perform a documented engineering review of the procedures for technical accuracy against the plant technical guidelines before implementation. In addition, the operator information manual and its introductory letter requesting operator input will be updated to reflect the newer revision and reissued to each unit control room. This information package, and any revisions made as a result of the simulator validation, will be in place before the beginning of operator training on the new procedures.

The type of validation/verification process described herein will remain ongoing for all major modifications made to the EOIs (i.e., Combustible Gas Control, Secondary Containment Control). Minor modifications considered maintenance items will be verified as specified in the Use and Maintenance section of the BFNP Writer's Guide for EOIs.

TENNESSEE VALLEY AUTHORITY

BROWNS FERRY NUCLEAR PLANT

Training Outline

for

Emergency Operating Instructions

TRAINING OUTLINE FOR EMERGENCY OPERATING INSTRUCTIONS

I. TRAINING PRIOR TO IMPLEMENTATION

Training began with the first draft of the new procedures which were based solely on Rev. 1B of the BWROG Emergency Procedure Guidelines. The purpose of training at this initial stage of development was to orient the operators to the new approach of symptom based vs. event based emergency procedures. A week of training divided equally between classroom discussions and simulator scenarios/control room walkthroughs was included as part of operator annual retraining at the Power Operations Training Center, and was documented as such.

Training on the EOIs based on the plant technical guidelines developed from Rev. 3 of the EPGs will begin during week #2, 1984 retraining for all licensed personnel. A broad overview of the procedures will be presented in a classroom session encompassing the history of the EOI program, the change in structure and format from the old event based procedures, and the planned schedule for training and final implementation.

An additional week of retraining for licensed personnel and STAs has been structured specifically for the new procedures. The training will be divided equally between classroom discussion and simulator scenarios/control room walkthroughs. Classroom discussion will include the bases for action steps and cautions, the use of charts and tables, and a review of appendixes. Classroom evaluation of the operator's ability to describe specific aspects of the EOIs will be by written tests administered by training center personnel. The simulator training staff will utilize scenarios designed to exercise the operator's ability to use the procedures both separately and/or concurrently, and will also include a review of control room instrumentation used to monitor key parameters referenced in the action steps and cautions of the procedures. Documented evaluations during the simulator training will be done by training center personnel, through the use of simulator evaluation worksheets, for each operator.. The documentation will be maintained in each employee's training file at the plant site. Operator recommendations for procedure improvements will be submitted to the operations procedure section for review.

Reactor Operator license candidates after 1984 will be trained on the new procedures as part of the license training program. In addition, they will also receive one week of simulator training designed specifically for new procedure review. Before a new procedure is implemented, all licensed personnel will have received training in that new procedure.

II. TRAINING FOLLOWING IMPLEMENTATION

As outlined in Standard Practice BF 4.8 (Training For Nuclear Plant Operator Positions at Browns Ferry Nuclear Plant), each licensed RO and SRO shall be supplied periodically with design changes, procedure changes, and facility license changes. Each licensee is required to read and sign a documentation sheet attesting to review of the changes. This documentation sheet is placed in the requalification training file of the individual. In addition, each licensee is supplied monthly with a list of emergency operating instructions and the abnormal section of operating instructions. After reviewing the assigned instructions, the licensee signs a documentation sheet. This documentation sheet is kept in the plant files. Training on major modifications made to the EOIs following implementation will be as outlined in the Validation/ Verification section of this Procedures Generation Package.

Assistant Unit Operators will be trained on the manual system alignments addressed in the Level Control procedure appendix during their annual retraining. Evaluation and documentation of this training is by written examination.

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INTRODUCTION
BROWNS FERRY INTEGRATED SCHEDULE

TVA has submitted several revisions to the integrated schedule for Browns Ferry Nuclear Plant since the Fall of 1981. As dicussed with your staff in the past, any additional modifications required or a redefinition of priorities in general could cause significant perturbations within our integrated schedule and require new deferrment requests.

As presented in my letter to you dated March 27, 1984, we have instituted a Regulatory Performance Improvement Plan (RPIP) to improve our regulatory compliance at Browns Ferry. The RPIP, coupled with pipe replacement in accordance IE Bulletin 83-02 inspections, forces TVA to request of NRC significant deferrments of items that have been included in former integrated schedule submittals.

Enclosed is a series of eight enclosures which explain in detail the methodology utilized and defines the current revision of the Browns Ferry integrated schedule. We have met with members of your staff in a working meeting on May 23, 1984, and believe that those individuals involved in the meeting have a good understanding of what we are requesting of NRC in the way of deferrments.

This requested amendment organizes the commitment work items into Categories 1, 2, and 3. Category 1 are those NRC requirements enforced by regulation, orders, or license conditions. Category 2 are NRC requirements not enforced by order or regulation. Category 3 items are items mandated by agencies other than NRC or TVA-initiated plant improvement/maintenance type items. Category 1 changes may not be made without prior NRC approval in accordance with established NRC procedures. Category 2 items can be changed without NRC approval; however, TVA must notify the NRC Browns Ferry Project Manager

Also, enclosed is a program description of how TVA proposed to conduct future scheduling discussions with the NRC.

LIST OF ENCLOSURES
BROWNS FERRY NUCLEAR PLANT
INTEGRATED SCHEDULE SUBMITTAL

ENCLOSURE 1

BASES FOR BROWNS FERRY INTEGRATED SCHEDULE REVISION

ENCLOSURE 1

THE BFN INTEGRATED SCHEDULE HAS BEEN REVISED TO BE CONSISTENT WITH THE REGULATORY PERFORMANCE IMPROVEMENT PLAN (RPIP) PRESENTED TO NRC REGION\II BY TVA. THIS REVISED OUTAGE SCHEDULE IS BASED ON THE FOLLOWING OBJECTIVES:

1. REPLACE/REPAIR RECIRCULATION SYSTEM PIPING AND OTHER ASSOCIATED STAINLESS STEEL PIPING AFFECTED AS A RESULT OF NRC IE BULLETIN 83-02 INSPECTIONS, IN A TIMELY MANNER.

2. MINIMIZE THE LENGTHS OF THE OUTAGES, CONSISTENT WITH (1) ABOVE, IN ORDER TO MINIMIZE DERATING OF THE OPERATING UNITS OR TO PREVENT OVERLAP OF UNIT OUTAGES.

3. COMPLETE NRC COMMITMENT - RELATED MODIFICATIONS IN AN ORDERLY AND TIMELY MANNER WITH PARTICULAR EMPHASIS ON THOSE MODIFICATIONS WHICH TVA HAS IDENTIFIED AS 'CATEGORY 1' COMMITMENTS.

4. LIMIT THE AMOUNT OF WORK IN THE REACTOR BUILDING (AND IN PARTICULAR ON ELEVATION 565) TO A SAFE AND CONTROLLABLE LEVEL DURING THE REFUELING OUTAGES.

5. REPAIR/REPLACE ALL UNIT LOW-PRESSURE TURBINES AS SOON AS POSSIBLE TO PREVENT FAILURE DUE TO STRESS FRACTURE OF THE DISCS.

6. SCHEDULE AT LEAST 60 DAYS BETWEEN REFUELING OUTAGES IN ORDER TO PROPERLY PREPLAN FOR THE SUBSEQUENT OUTAGE, TO ALLOW FOR PREFABRICATIONS, TO REVIEW DESIGNS AND INVENTORY MATERIALS, AND TO REFRESH THE WORK FORCE.

7. CONTINUE TO PERFORM ALL PREVENTIVE MAINTENANCE AND INSPECTIONS PER LOCAL AND OTHER DIRECTIVES.

THE REVISED SCHEDULE WHICH FOLLOWS OPTIMIZES THESE OBJECTIVES AT THE EXPENSE OF PERFORMING PLANT IMPROVEMENT MODIFICATIONS WHICH HAD PREVIOUSLY BEEN SCHEDULED. IT ADDITIONALLY WAS NECESSARY TO PLAN IMPLEMENTATION OF SEVERAL LARGE-SCALE MODIFICATIONS INTO WORK SEGMENTS, EACH OF WHICH WOULD BE PERFORMED DURING SEVERAL SUBSEQUENT REFUELING OUTAGES FOR A PARTICULAR UNIT.

A MODIFICATION SCOPE REDUCTION REVIEW IS PLANNED IN AN EFFORT TO ELIMINATE UNNECESSARY WORK. SUCCESSFUL REDUCTION IN WORK SCOPES WILL EXPEDITE THE COMPLETION OF THE BACKLOG OF MODIFICATIONS.

THE UNIT 2 CYCLE 5 REFUELING OUTAGE IS SCHEDULED TO BE PERFORMED IN 120 DAYS. THE CRITICAL PATH ACTIVITY FOR THIS OUTAGE IS THE INSPECTION AND REPAIR/REPLACEMENT OF LP 'A' AND 'C' TURBINES, IF NECESSARY. THE PLANNED START DATE FOR THIS OUTAGE HAS BEEN DEFERRED IN ORDER TO AVOID A POSSIBLE TWO-UNIT OUTAGE. DERATING OF UNIT\2 DURING OPERATING CYCLE 5 IS IN PROGRESS TO SUPPORT THE DELAYED SHUTDOWN.

THE UNIT 1 CYCLE 6 REFUELING OUTAGE DURATION IS BASED ON REPLACEMENT OF RECIRCULATION SYSTEM AND OTHER PRIMARY COOLANT SUPPORT SYSTEMS STAINLESS STEEL PIPING.

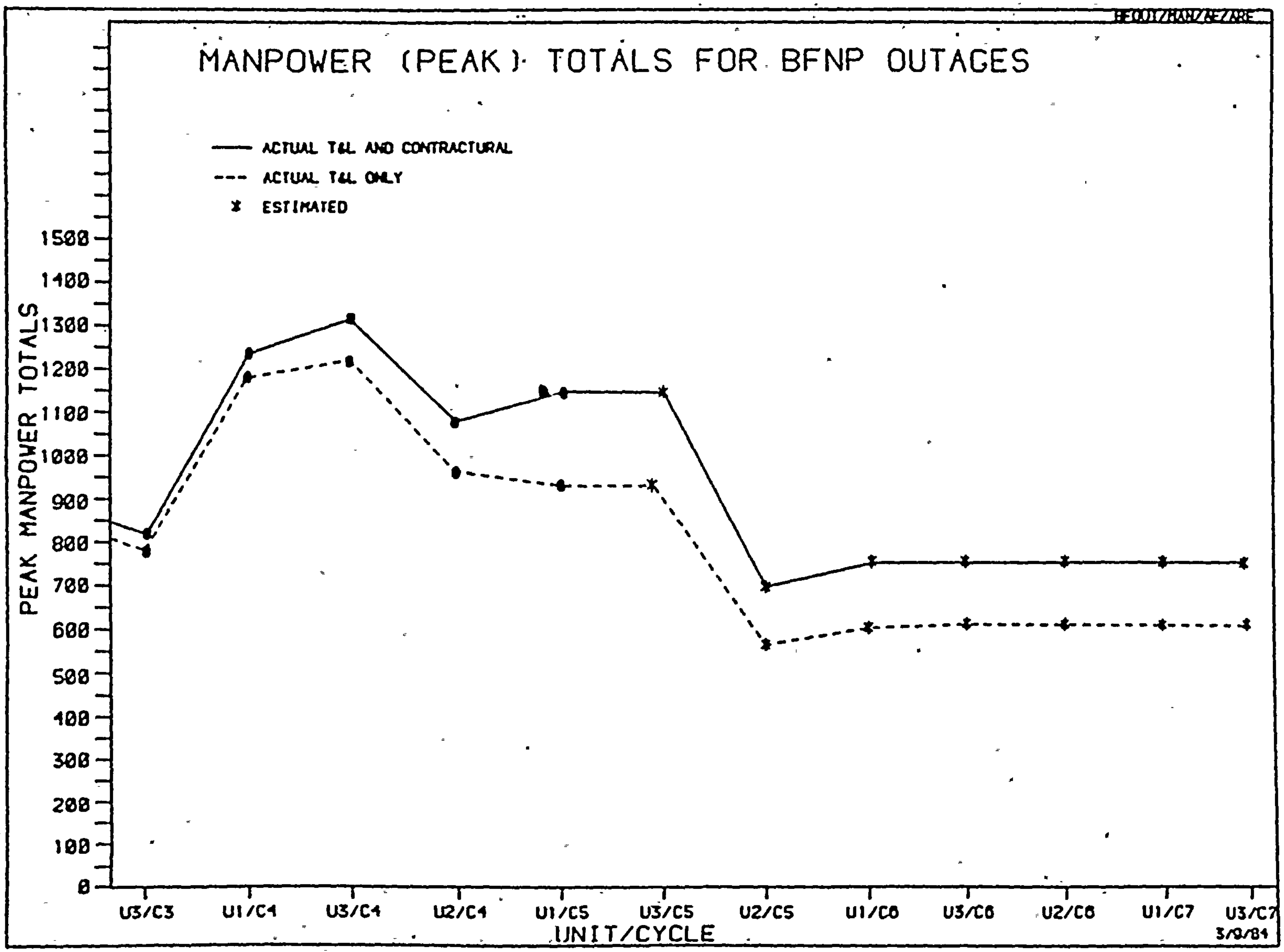
THE SCHEDULED UNIT 3 CYCLE 6 REFUELING OUTAGE DURATION IS 90 DAYS IN ORDER TO ALLOW FOR REINSPECTION OF STAINLESS STEEL PIPING IN ACCORDANCE WITH NRC\IE\BULLETIN\83-02. THIS OUTAGE DURATION IS LIMITED SINCE LENGTHENING IT WOULD HAVE SEVERE IMPACT ON THE DURATION OF THE UNIT\2 CYCLE\6 REFUELING OUTAGE.

REFUELING OUTAGES FOLLOWING THE UNIT 3 CYCLE 6 OUTAGE HAVE BEEN PLANNED BASED ON NO FURTHER REPLACEMENTS OF STAINLESS STEEL PIPING IN ANY UNIT. THE SCHEDULED OUTAGE DURATIONS, HOWEVER, REFLECT A 'WORST CASE' SCENARIO, I.E., CONTINUED PIPE AND DRYWELL PENETRATION REPLACEMENTS. SHOULD PIPE REPLACEMENT NOT BE REQUIRED DURING THESE SUBSEQUENT OUTAGES, THE SCHEDULED DURATIONS WILL BE ADJUSTED TO RELECT LOW PRESSURE TURBINE REPAIRS AND CATEGORY 1 COMMITMENT MODIFICATIONS AS CRITICAL PATH. HOWEVER, SHOULD PIPE AND PENETRATION REPLACEMENTS BE REQUIRED, THE SCHEDULED WORK WILL BE ADJUSTED TO REFLECT PERFORMANCE OF COMMITMENT-RELATED MODIFICATIONS, IN ORDER OF PRIORITY, BASED ON AVAILABLE RESOURCES REMAINING AFTER THOSE RESOURCES REQUIRED TO SUPPORT THE PIPE CHANGEOUTS HAVE BEEN CREDITED AGAINST TOTAL RESOURCES AVAILABLE.

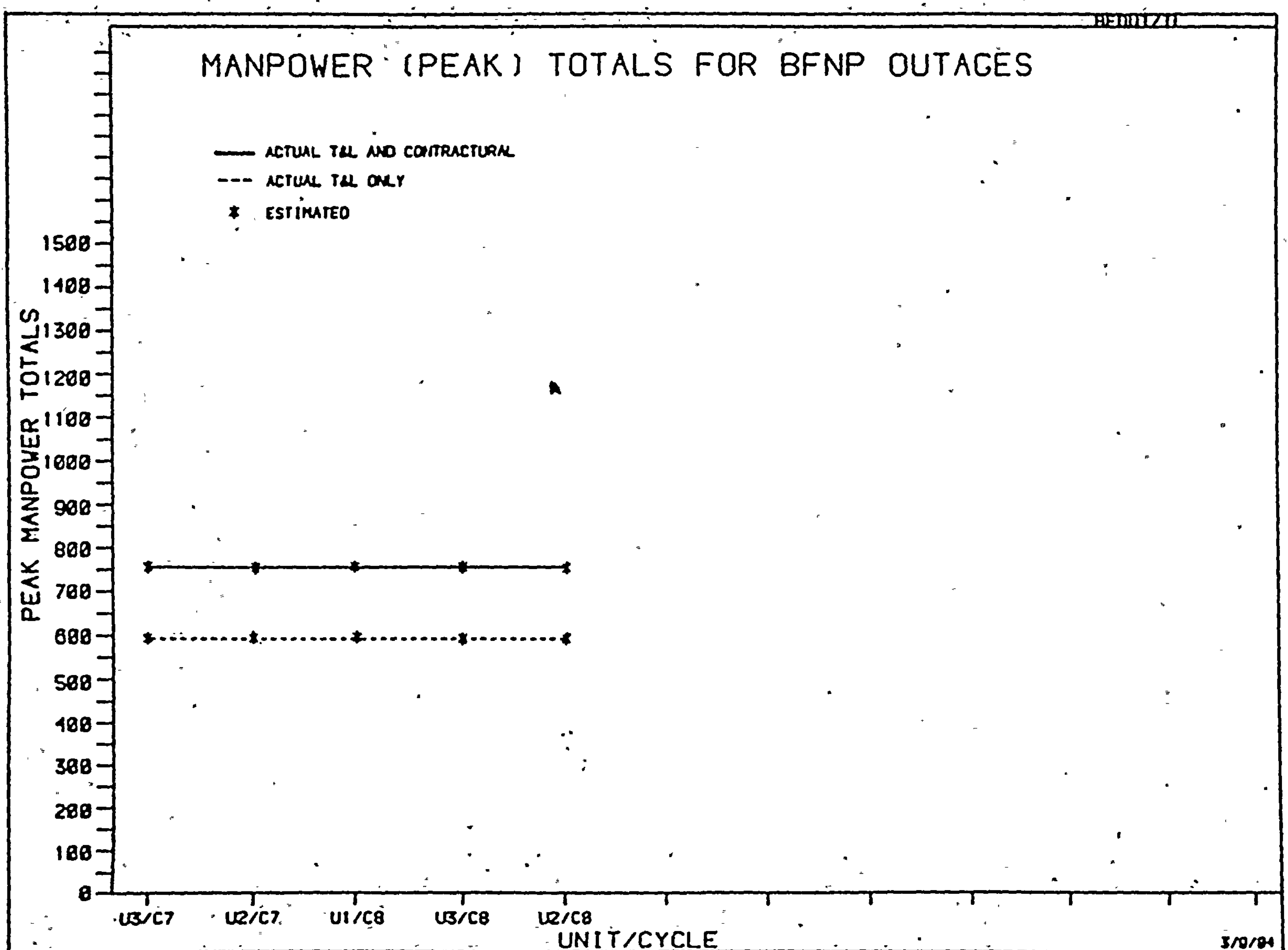
ENCLOSURE 2

GRAPHS OF MANPOWER (PEAK) TOTALS FOR
BROWNS FERRY OUTAGES

ENCLOSURE 2



7/82 3/83 9/83 8/84 3/85 12/85 5/86 1/87 7/87



7/87 4/88 9/88 5/89 11/89

ENCLOSURE 3

DEFINITION AND LISTING OF COMMITMENTS
BY CATEGORIES

ENCLOSURE 3

ALL NRC COMMITMENT ITEMS HAVE BEEN REVIEWED AND GROUPED INTO CATEGORIES 1, 2, AND 3 ACCORDING TO TVA'S CONCEPT OF PRIORITY. THE CATEGORIES ARE DEFINED AS FOLLOWS:

1. COMMITMENTS REQUIRED BY REGULATORY AGENCIES AND ENFORCED BY THE CODE OF FEDERAL REGULATION OR CONFIRMATORY ORDERS. FOR EXAMPLE: TORUS MODS, APPENDIX R, IE\BULLETIN\79-01B, 10 CFR RULES OR THOSE ITEMS TVA CONSIDERS TOP NUCLEAR SAFETY CONCERNS, SUCH AS PIPE CHANGEOUT.

2. COMMITMENTS TVA VOLUNTARILY MADE IN RESPONSE TO REGULATORY AGENCIES. FOR EXAMPLE: NUREG-0737, IE\BULLETINS AND NOTICES AND RESPONSES TO NRC QUESTIONS WHICH ARE NOT ENFORCED BY THE CFR OR CONFIRMATORY ORDERS.

3. CATEGORY 3 ITEMS ARE ITEMS MANDATED BY AGENCIES OTHER THAN NRC OR TVA-INITIATED PLANT IMPROVEMENT/MAINTENANCE TYPE ITEMS.

NRC COMMITMENT ITEMS IN EACH CATEGORY HAVE BEEN EVALUATED AND ARE PRIORITIZED BELOW.

PLEASE REALIZE THAT THIS LIST DOES NOT INCLUDE THOSE REGULATORY AGENDA ITEMS THAT ARE IN THE INFORMATION STAGE NOW OR THAT CAN BE FORESEEN AS REQUIRED IN THE FUTURE. ITEMS SUCH AS THE ATWS RULE, MECHANICAL QUALIFICATION OF EQUIPMENT, UNRESOLVED SAFETY ISSUES RESOLUTION, ETC., WILL HAVE A MARKED EFFECT ON THIS LIST IN THE COMING MONTHS.

TVA'S APPROACH TO SCHEDULING THESE ITEMS FOR IMPLEMENTATION WILL BE SUCH THAT ALL CATEGORY 1 ITEMS WILL BE SCHEDULED FIRST. THE CATEGORY 1 ITEMS WILL BE SCHEDULED IN ORDER OF DECREASING PRIORITY. THIS APPROACH TO SCHEDULING WILL BE CONTINUED FOR THE ITEMS CONTAINED IN CATEGORY 2.

IN COMPLIANCE WITH THE REGULATORY PERFORMANCE IMPROVEMENT PLAN, THE MAN-DAY ESTIMATES ASSOCIATED WITH EACH ACTIVITY HAVE TAKEN INTO ACCOUNT REDUCED MODIFICATION SCOPES.

CATEGORY 1				
		MAN-DAYS		
MODIFICATION	Requirement	UNIT 1	UNIT 2	UNIT 3
RECIRCULATION PIPING				
IEB-83-02 Inspection and Repair	Bulletin		424	424
Replacement (Does not include contractor work)		13,000	13,000	13,000
IEB-80-17 CRD SDIV & PIPING				
Modify scram discharge system. Replace Delta P. transmitters with RDS.	Bulletin	Complete	776	3,825
*IEB 79-01B QUALIFIED INSTRUMENTATION	Bulletin			
IEB 79-01B ECNs P3XXX.		2,067	2,430	2,371
Evaluate and increase the HVAC capacity for level 1C (E1.593.0) in the control bay.		(Common) Total	843	
Replace switches with transmitter and associated trip unit.		1,850	2,100	2,450
Modify existing RPS to provide fully redundant class 1E protection at the interface of the nonclass 1E power supplies and the RPS.		Complete	195	195
Upgrade drywell temperature and pressure instrumentation.		145	145	145
*TORUS	NUREG - Orders			
Long-term torus integrity modifications--piping--PSC.		Complete	12,723	12,723
Long-term torus integrity modifications piping--MSDs.		Complete	15	15
Design, procure, and install a torus temperature monitoring system consisting of 16 sensors (1-inch or less thermowells per unit.		Complete	493	493
Modifications for long-term torus integrity program.		Complete	15	15
*NOTE: Items in each major heading are of equal priority.				

CATEGORY 1				
MODIFICATION	Requirement	MAN-DAYS		
		UNIT 1	UNIT 2	UNIT 3
***TORUS (Continued)**				
Install new hinge arm, hinge shaft, bearing and associated components to increase the strength of the vacuum breaker valves, etc.		Complete	140	140
***NUREG-0737**	NUREG			
II F.1.1 Noble Gas and II F.1.2 Iodine		38	2,038	38
II F.1.3 Containment Hi Radiation		340	1,030	1,030
II F.1.4 Containment Pressure		Complete	320	320
II F.1.5 Containment Level		75	879	879
***APPENDIX R**	10 CFR Part 50, APPR			
Install emergency lighting units with an 8-hour battery power supply in all areas for operation of safe shutdown equipment, in access and egress routes.		Complete	Complete	544
Rework electrical backup controls to comply with 10 CFR-50, appendix R.		429	429	429
Upgrade or add circuit protection to comply with 10 CFR-50, appendix R.		25	25	25
Modify conduit and cable runs to existing equipment (install, reroute, and wrap) to comply with 10 CFR-50, appendix R.		7,982	7,982	7,982
Install preaction sprinkler system on entire floor elevation 550 of the intake pumping station and add a water spray system.		2,730	2,730	2,730
Install a 3-hour fire barrier in shutdown board rooms, A, C, E, and RX building, elevation 621, etc.		4	4	4
Modify existing fire suppression and detection system.		58	58	58

CATEGORY 1				
MODIFICATION	Requirement	MAN-DAYS		
		UNIT 1	UNIT 2	UNIT 3
*APPENDIX R (Continued)				
Seal the annular space between the exterior of the pipe or conduit and the penetration sleeve such that the fire rating for the seal is equivalent to the fire rating of the wall.		44	44	44
Add backfeed switches to each unit to reduce the number of breaker manipulators required of unit operation, etc.		225	225	225
Install fire dampers at each penetration (HVAC ducts) in fire walls.		225	225	225
UNDERVOLTAGE MODIFICATIONS				
Instrument and control bus problems.	NRC/TVA Concern	Complete	214	214

CATEGORY 2				
MODIFICATION	Requirement	MAN-DAYS UNIT 1	UNIT 2	UNIT 3
MSIV Modifications	NRC/TVA Concern	178	255	178
MSIV Modification		177	255	177
Process computer system for each unit.	NUREG-0737 S1	848 (296 common)	848	848
Install redundant air supply to the drywell from plant control air and drywell control air system.	NUREG-0737	Complete	254	254
IEB-79-14 Modify Hangers	Bulletin	22,198	26,111	21,403
NRC IE Bulletin 79-02	Bulletin	1,063	1,027	2,125
IEB-79-14 Modify Hangers	Bulletin	115	115	115
IEB-80-11 Masonry Walls	Bulletin	230	230	230
Feedwater nozzle temperature - NUREG-0619.	NUREG	Complete	383	383
Modify FCV 76-18 and -19 to allow the flange side that cannot be isolated from primary containment to be testable (to be worked in conjunction conjunction with DCR 2859).	APP. J	Complete Complete	42.5 42.5	42.5 42.5
Valves 64-17, -18, -19, -20, -21, -29, -30, -31, -32, and -33. Modify seating surface on each side by welding stainless steel onto seating area of the disc.	APP. J	120	120	120

CATEGORY 2				
		MAN-DAYS		
MODIFICATION	Requirement	UNIT 1	UNIT 2	UNIT 3
Modify valves FCV-64-18, -19, -20, -21, and -31 to allow the flange side that cannot be isolated from primary containment to be testable (to be worked in conjunction with DCR 2893R1).	APP. J	Complete	120	120
Modify valves FCV-84-88A through D to allow the flange side that cannot be isolated from primary containment to be testable.	APP. J	Complete	60	60
NUREG 0737 IIK3.13 RCIC restart.	NUREG	45	45	45
NUREG 0737 IIB.3 - PASF	NUREG	1,823 (Common	2,130 1,653)	1,775
NUREG 0737 IIE4.1 - dedicated H2 penetrations.	NUREG	1,922	1,922	1,922
NUREG 0737 IIIA.1.2 - Emergency support.	NUREG	816	816	816
Provide a safety-grade, long-term depressurization capability to the ADS by installing a line from each of the 2 CADs nitrogen supply trains, etc - NUREG-0737, Item II.K.3.28	NUREG	230	230	230
Rewire diesel generator protective circuitry to enable diesel generator loss of field trip to be bypassed when in emergency mode.	Bulletin		Complete	
IEB-79-18 Emergency evacuation.	Bulletin	2,986	2,986	2,986
Provide substitute for Walter Kidde Model FT200, CPD 1212, and CPD 1201 smoke detectors.	LER	21	21	21
Replace vent and drain line restraints.	LER	566	566	N/A
Install instrument and HPCI (special test procedure) (plant perform).	LER	N/A	N/A	33

CATEGORY 2				
		MAN-DAYS		
MODIFICATION	Requirement	UNIT 1	UNIT 2	UNIT 3
Provide a circuit change to the RPS shutdown scram reset interlocks which prevents the backup manual scram capability to the Rx mode switch from being bypassed upon loss of power with subsequent restoration.	Info. Notice	12	12	12
Install permanent wind monitor recorders.	Insp. Report	40	40	40
Rx building water seepage.	NRC Concern	Scope undefined		
Investigate soil settlement condition the south side of the reactor building.	NRC Concern	Scope undefined		
Provide postaccident monitoring status of barriers, etc. Provide a remote multiplexed data acquisition system, etc.	NUREG	1,000	1,000	1,000

CATEGORY 2				
		MAN-DAYS		
MODIFICATION	Requirement	UNIT 1	UNIT 2	UNIT 3
Replace the magnetic pickups and flexible conduit on RCIC with self-enclosed pickups having rigid conduit connections.	LER	35	35	35
Add devices in the sample lines for panels 25-340, 25-341.	LER	65	65	65
Provide for distinct annunciation in control room for process radiation monitor (scheduled with ECN P0254).	LER	700	700	700
Install pressure switch on oil feed line to HPCI pump to give alarm in control room panel 9-3 on low pressure to bearings.	LER	120	120	120
Heat trace and insulate sample lines and chamber to CAM-90-250.	LER	10	10	10
Replace existing sensing panels with solid state speed sensing panels on all eight diesel generators.	LER	103	103	206
Install throttle valves, transition pieces, and support same as required, upstream in the EECW supply to all diesel generator cooling water heat exchangers.	LER	35	35	70

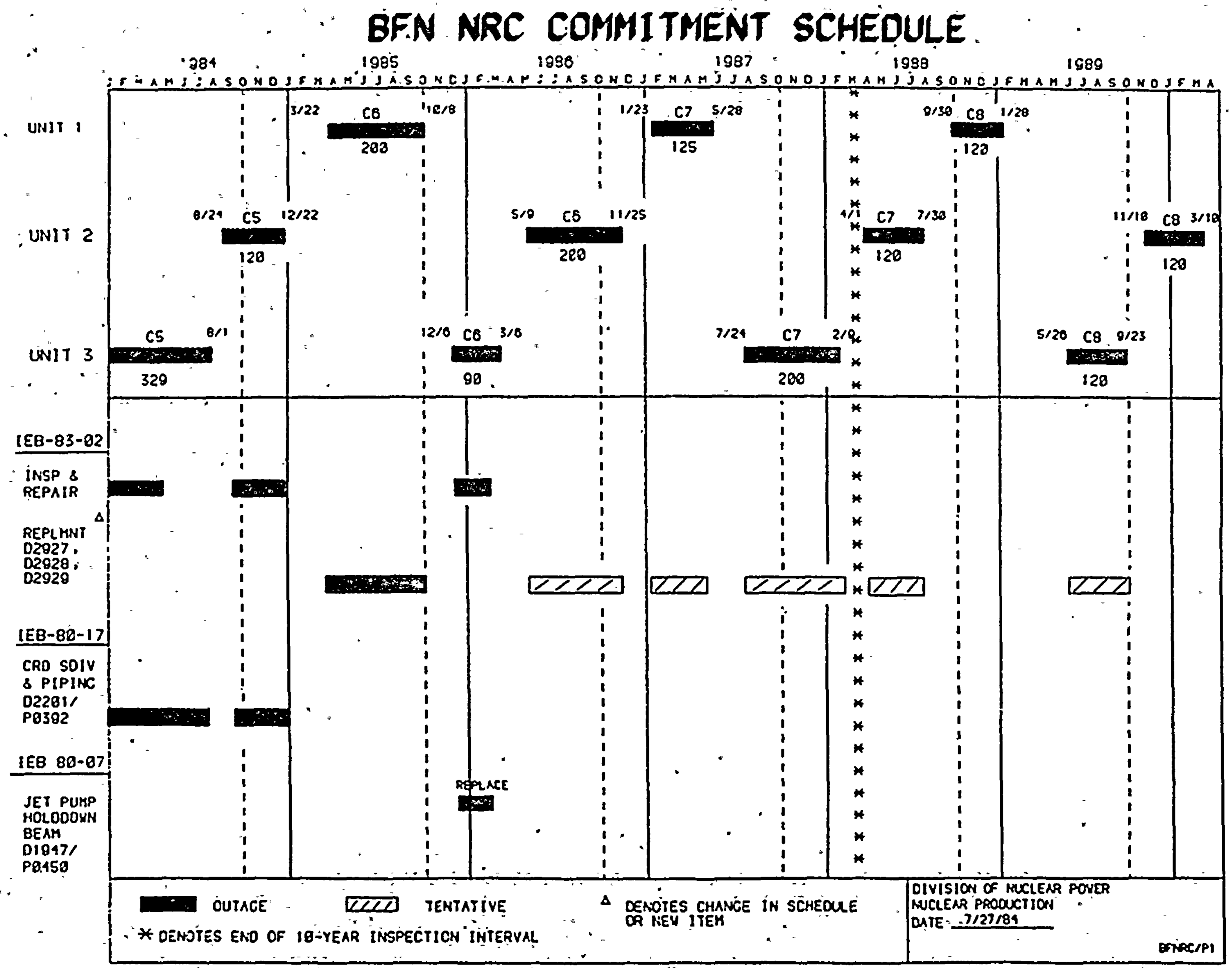
CATEGORY 3 - MAJOR ITEMS FOR UNIT 2 CYCLE 5 ONLY*

ECN NO.		ITEM
P0588	-	LIS-2-30, -38, and -49. Replace existing switches with ITT Barton switches of same range.
N/A	-	Turbine Rebuild - replace 1 HP and 2 LP rotors (10,000 man-days)
P0596	-	Replace FCV-85-11A, 11B with an improved design valve.
P0609	-	Substitute Westinghouse UX-252 meter movement for existing GE-180 meter movement.
P0611	-	MSRV - Machine gasket surfaces between bases and bodies of Target Rock model 7567F for installation of larger gaskets.
P0612	-	Install 1/2-inch stainless steel line from control air permanent line to solenoid control of MSRVs.
P0621	-	MSIVs - Install new locking tabs; modify limit switch mounting plates; install gate valves on test connections; add hangers to test connections.
P0622	-	Replace flow element and transmitter. Replace FE-66-111A and -111B, FT-66-111A and -111B.
P0631	-	Move RHRSW and RCW inline detectors, wells and assoc., cables to south end of service water tunnels.
P0632	-	Modify 4-KV common boards A and B so that their normal feeds are from the unit station service transformers and their alternate feeds are from the start bases.
P0636	-	Replace EHC coolers as required with Young model SSF-810-AR-2P fixed tube bundle heat exchangers.
P0639	-	Cut splitters away from impeller eye on reactor feed pumps.
P0651	-	Replace FCV-73-45 with pneumatic-operated soft-seated check valve.
P0652	-	Replace FCV-71-40 with pneumatic-operated soft-seated check valve.
P0732	-	Modify existing sewage treatment facility.

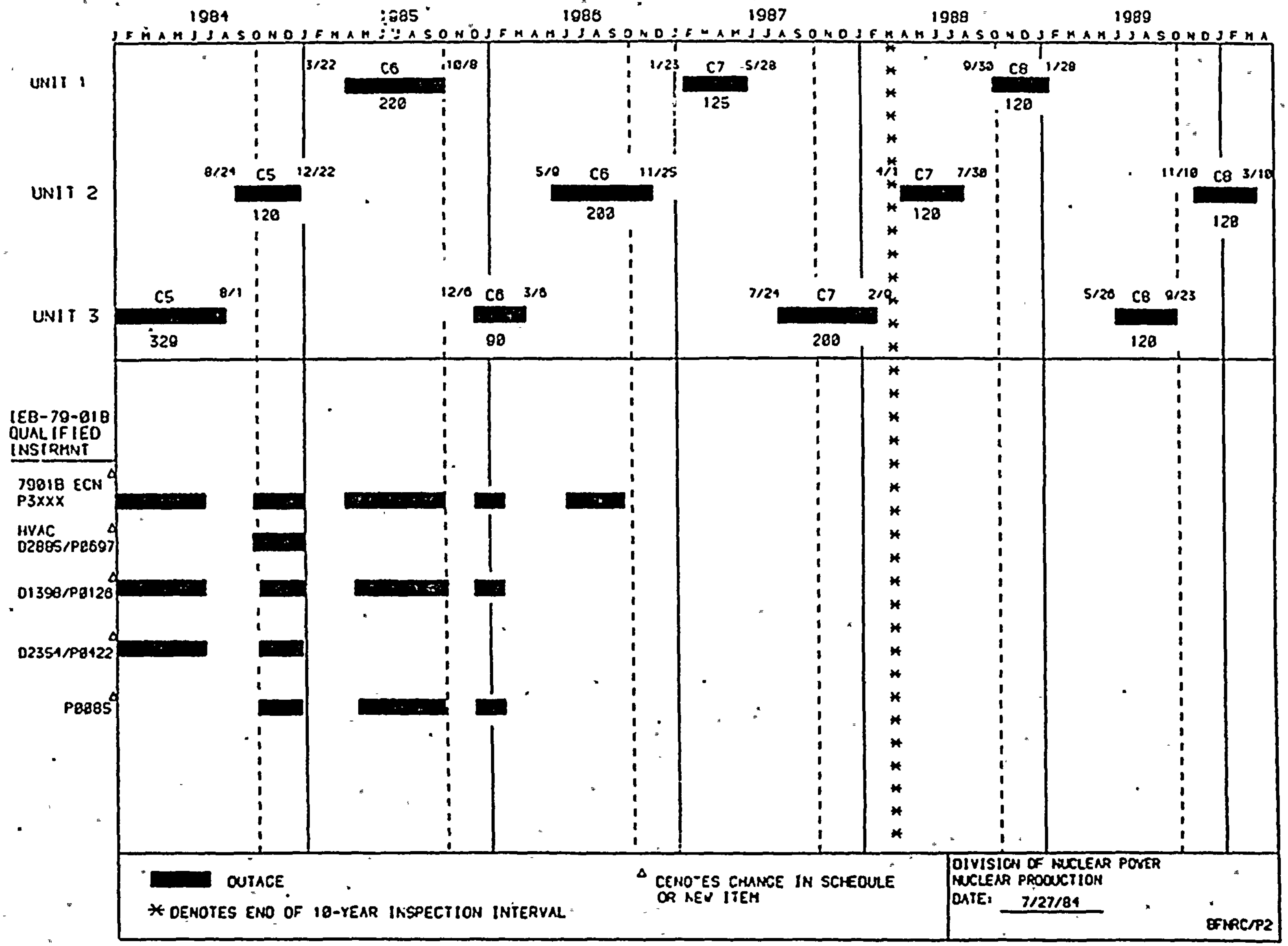
*Many small maintenance/plant improvement items are not listed. Also, because of the sheer number of these items, it is not feasible to include these in this submittal.

ENCLOSURE 4

BROWNS FERRY NUCLEAR PLANT
INTEGRATED SCHEDULE


BFN NRC COMMITMENT SCHEDULE
1984
1985
1986
1987
1988
1989
UNIT 1
3/22 C6 10/8
200
1/23 C7 5/28
125
9/30 C8 1/28
120
UNIT 2
8/24 C5 12/22
120
5/9 C6 11/25
200
4/1 C7 7/30
120
11/18 C8 3/10
120
UNIT 3
C5 8/1
329
12/6 C6 3/6
90
7/24 C7 2/9
200
5/26 C8 9/23
120
IEB-83-02
INSP & REPAIR
REPLMNT D2927, D2928, D2929
IEB-80-17
CRD SDIV & PIPING D2201/ P0392
IEB 80-07
JET PUMP HOLDDOWN BEAM D1947/ P0450
REPLACE
OUTAGE
TENTATIVE
DENOTES CHANGE IN SCHEDULE OR NEW ITEM
* DENOTES END OF 10-YEAR INSPECTION INTERVAL
DIVISION OF NUCLEAR POWER
NUCLEAR PRODUCTION
DATE 7/27/84
BFNRC/P1

BFN NRC COMMITMENT SCHEDULE



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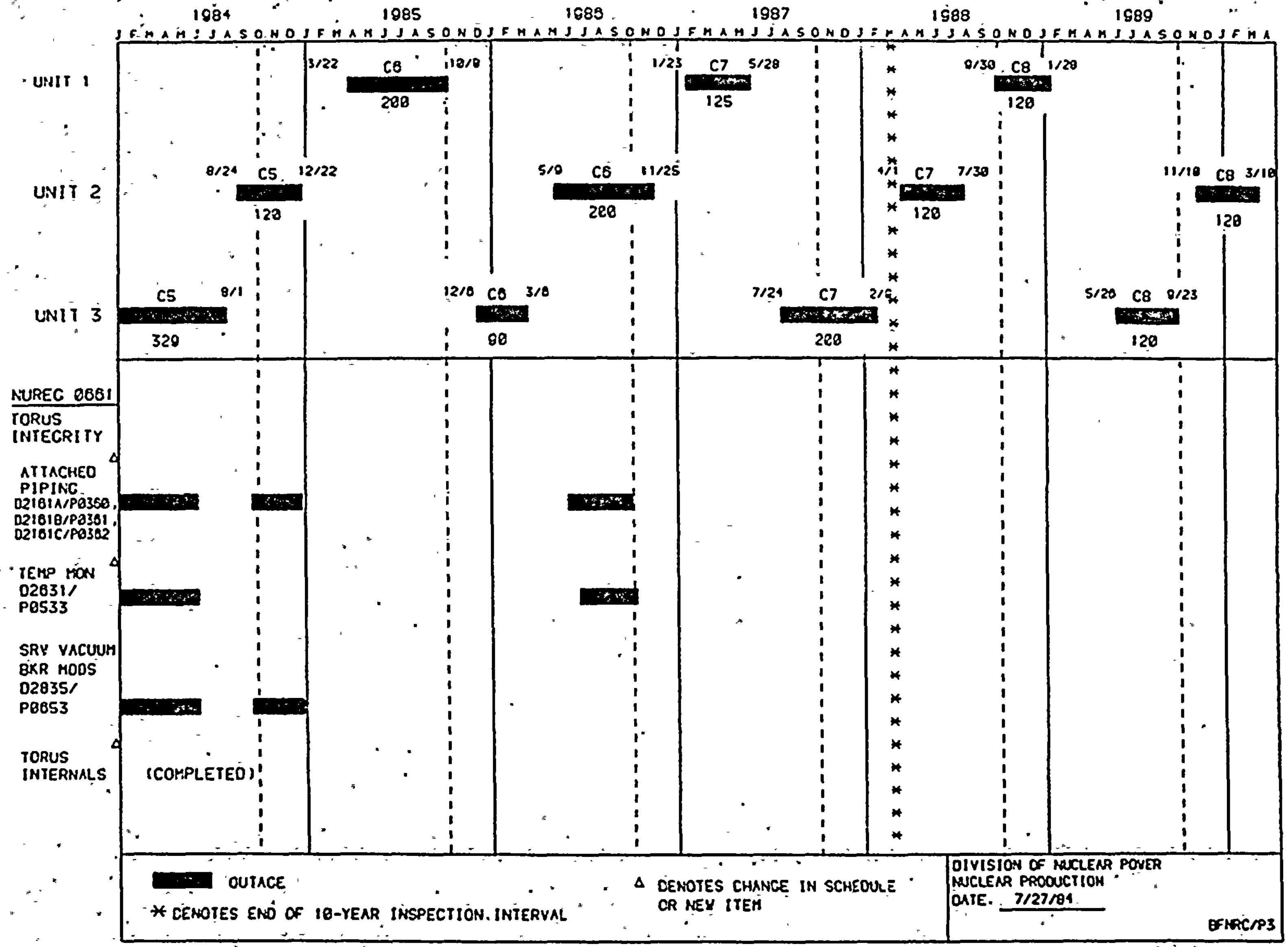

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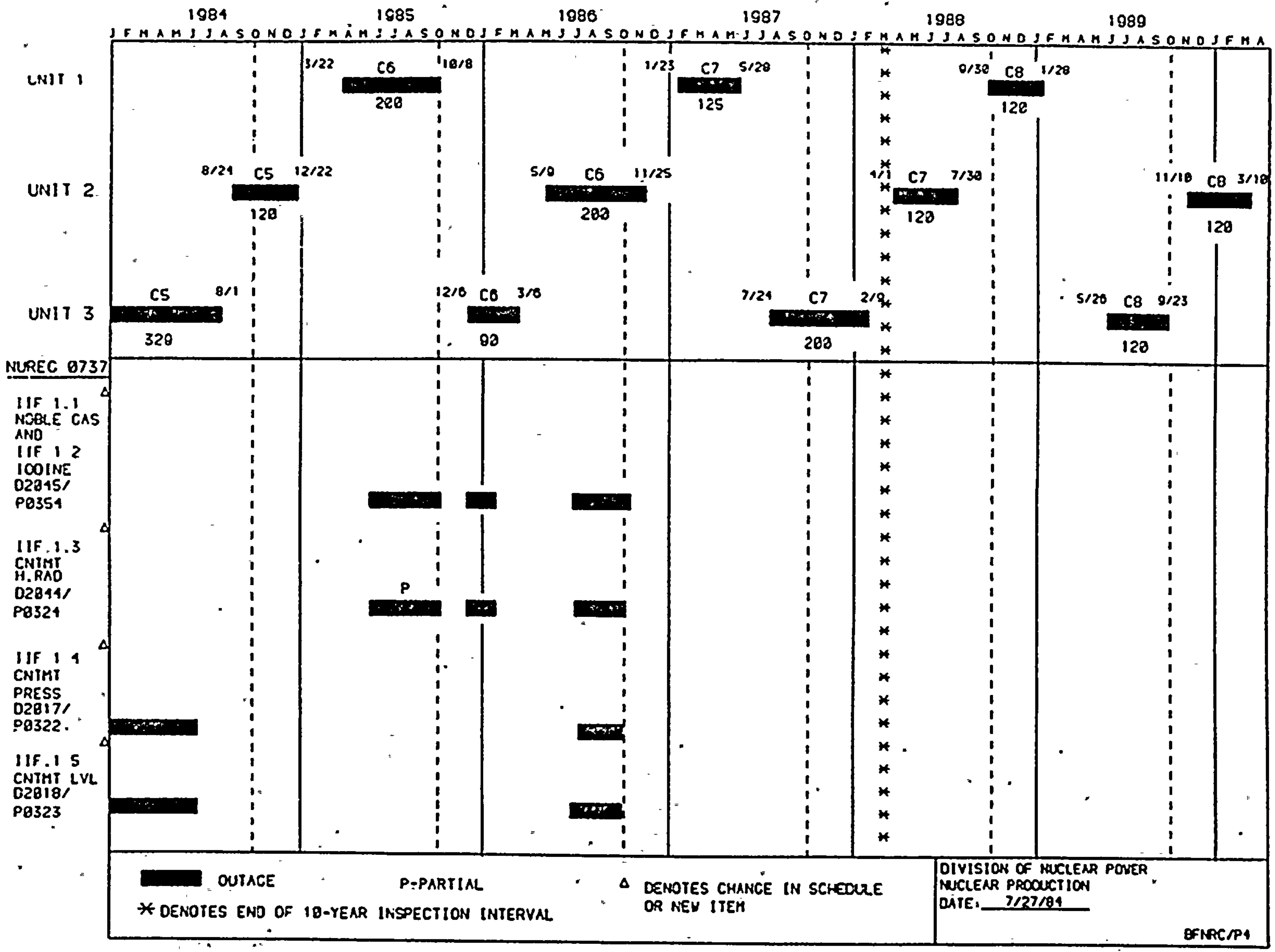

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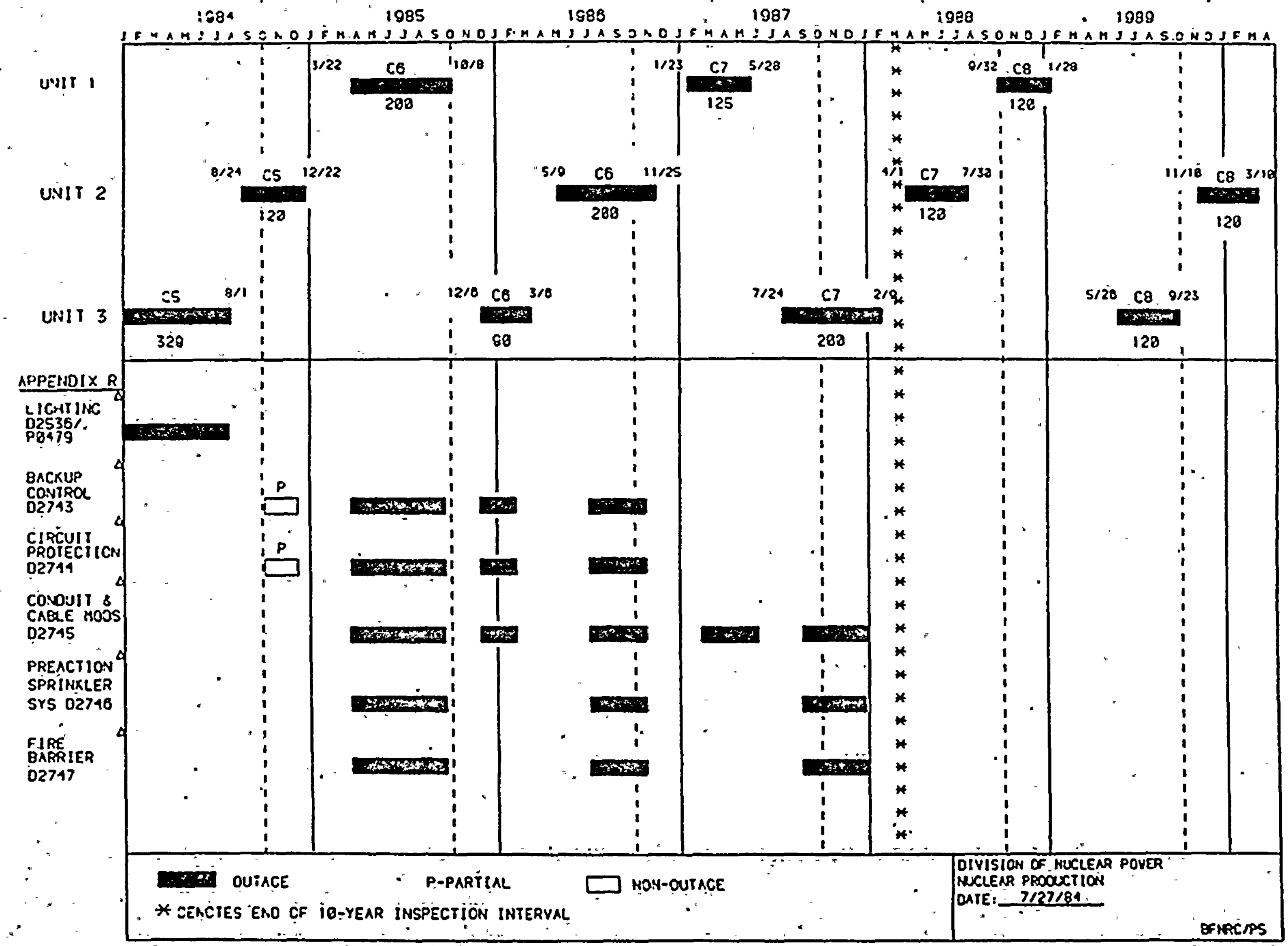

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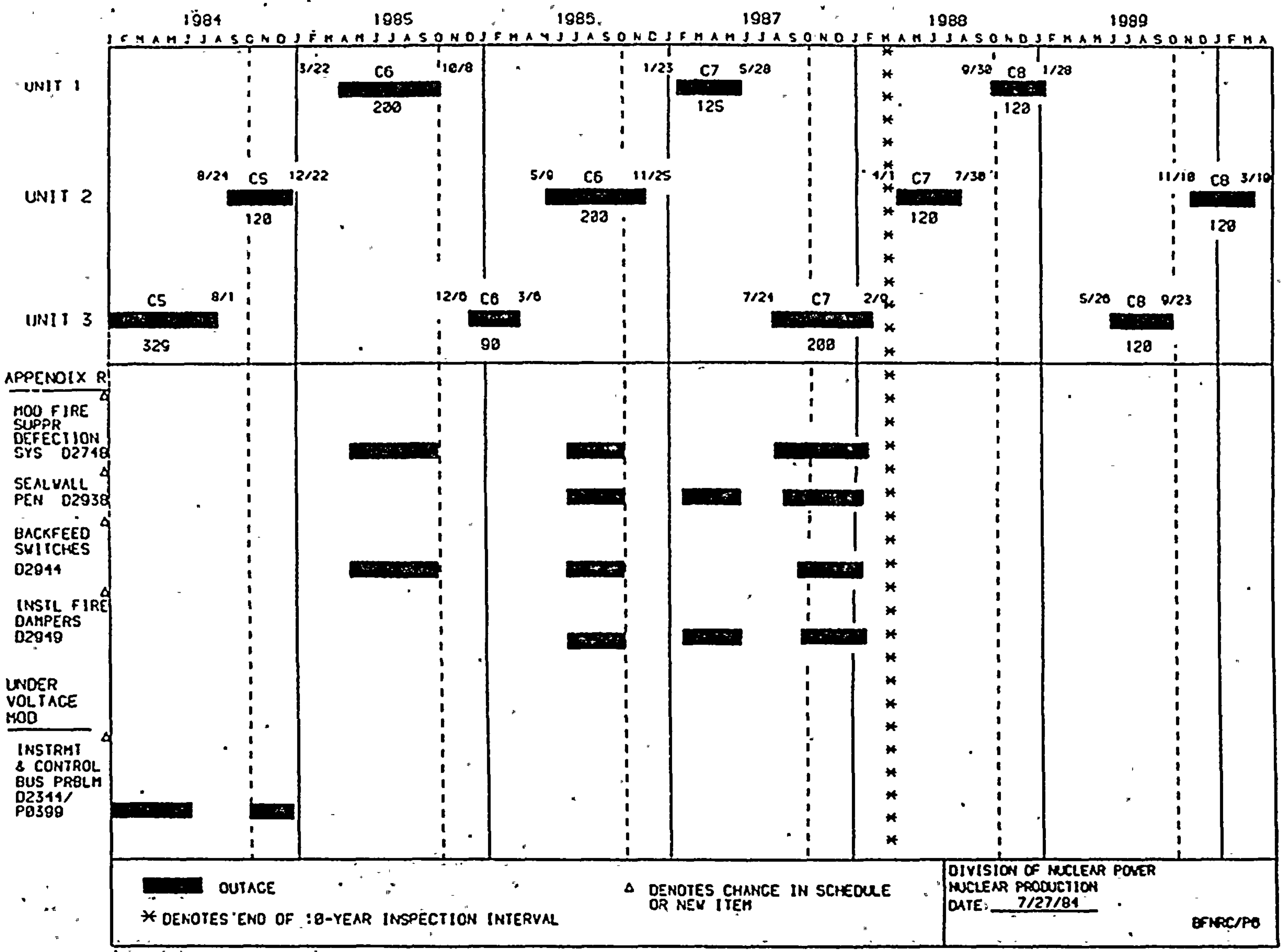

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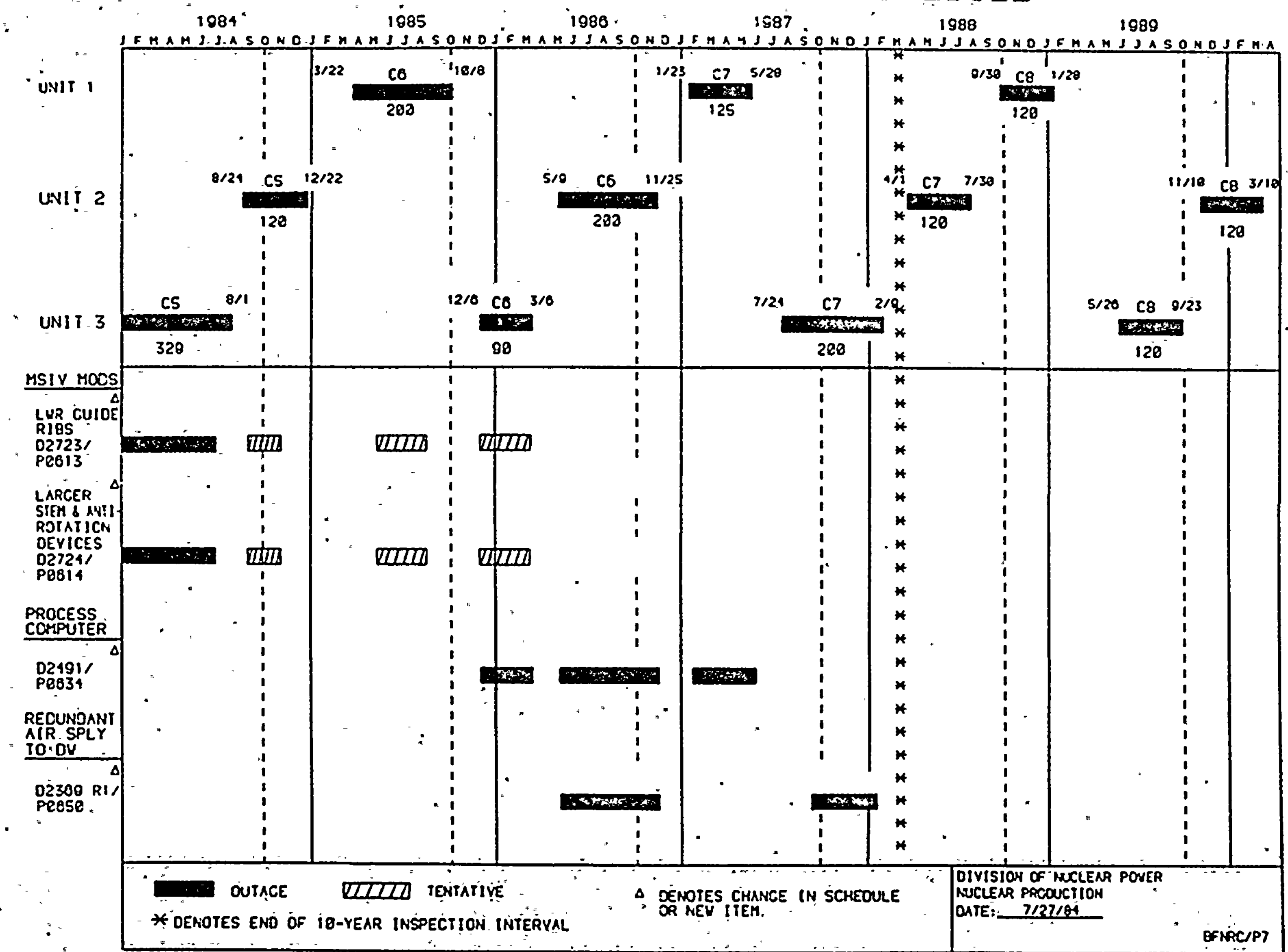

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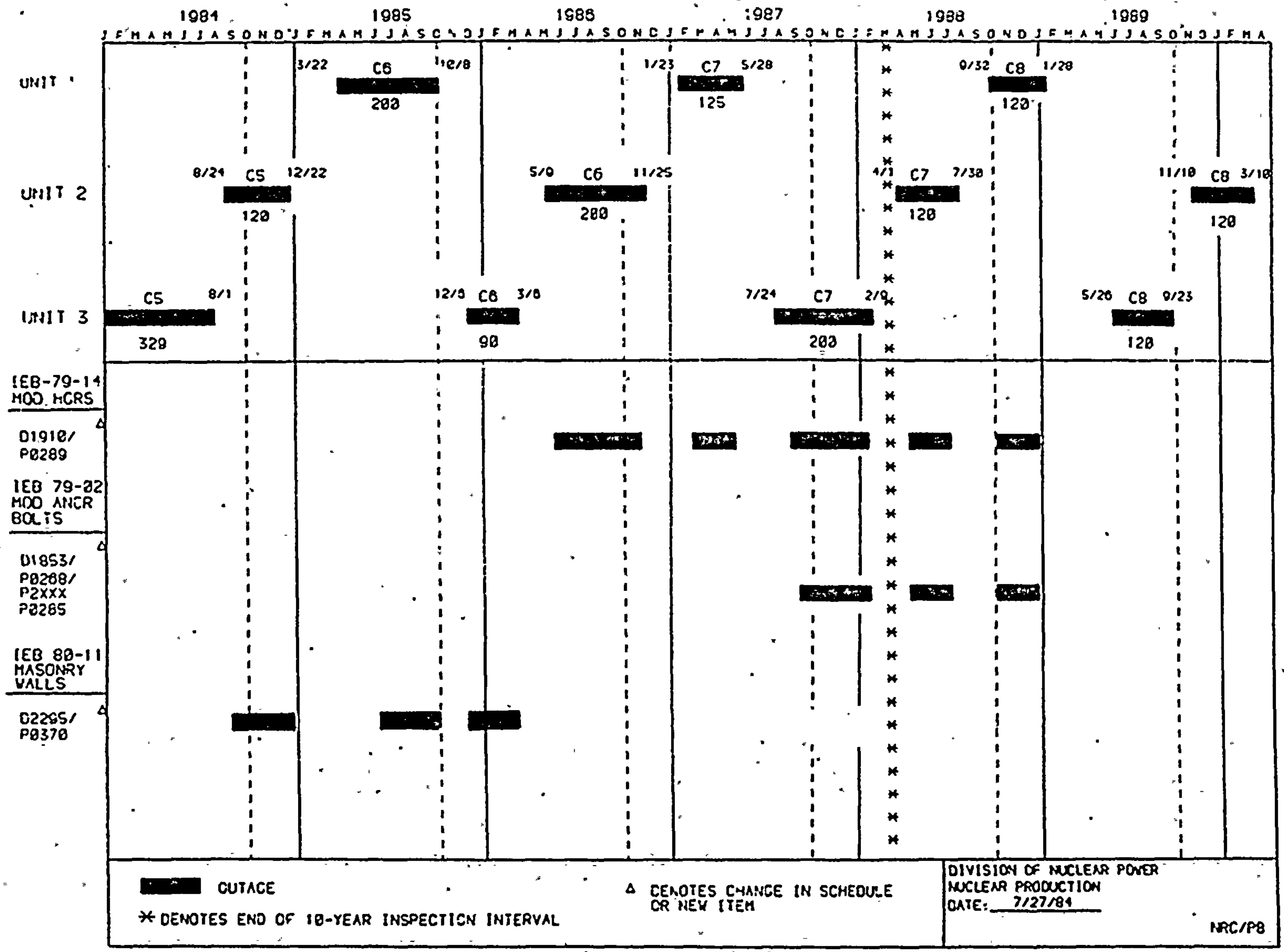

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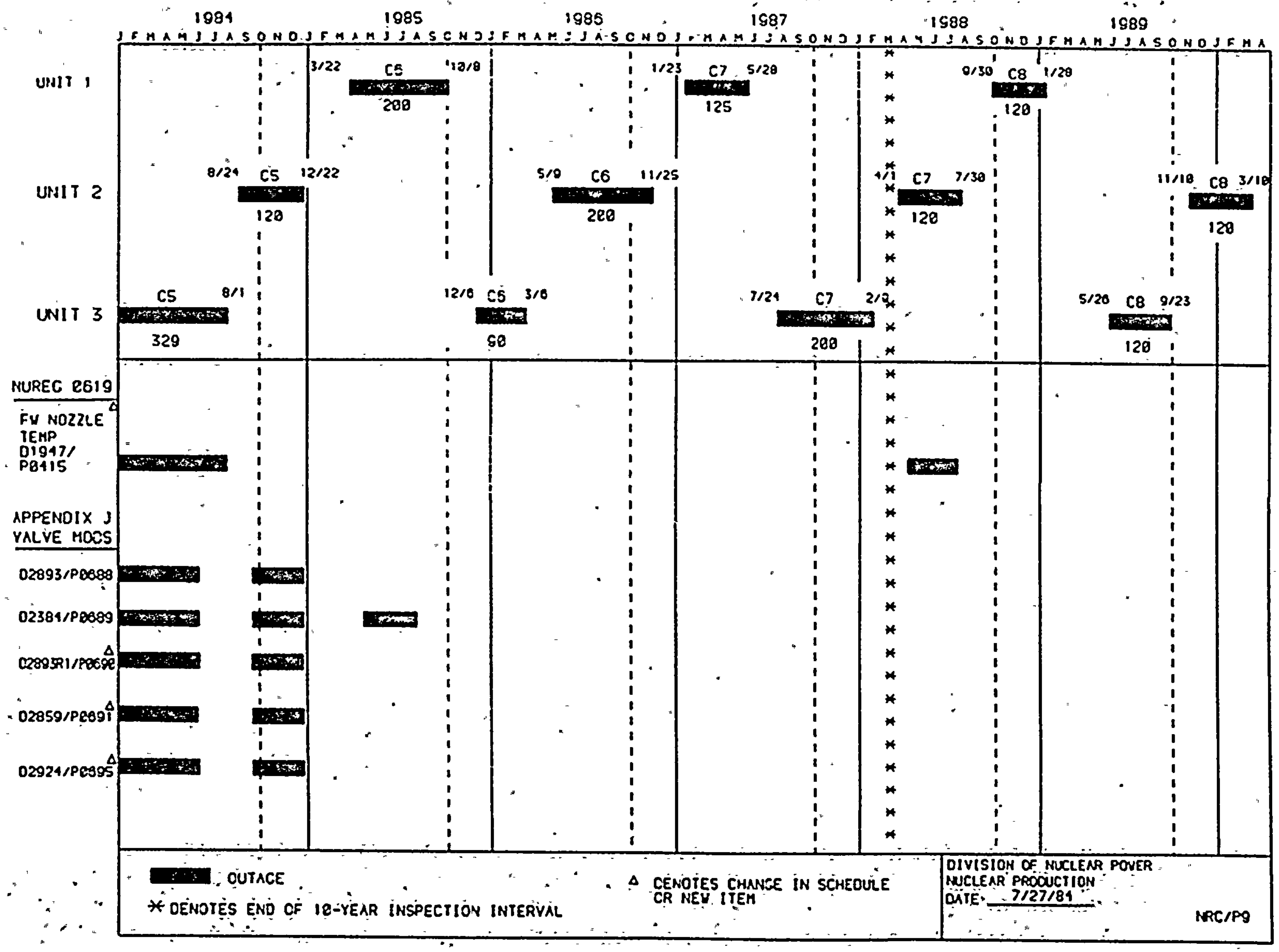

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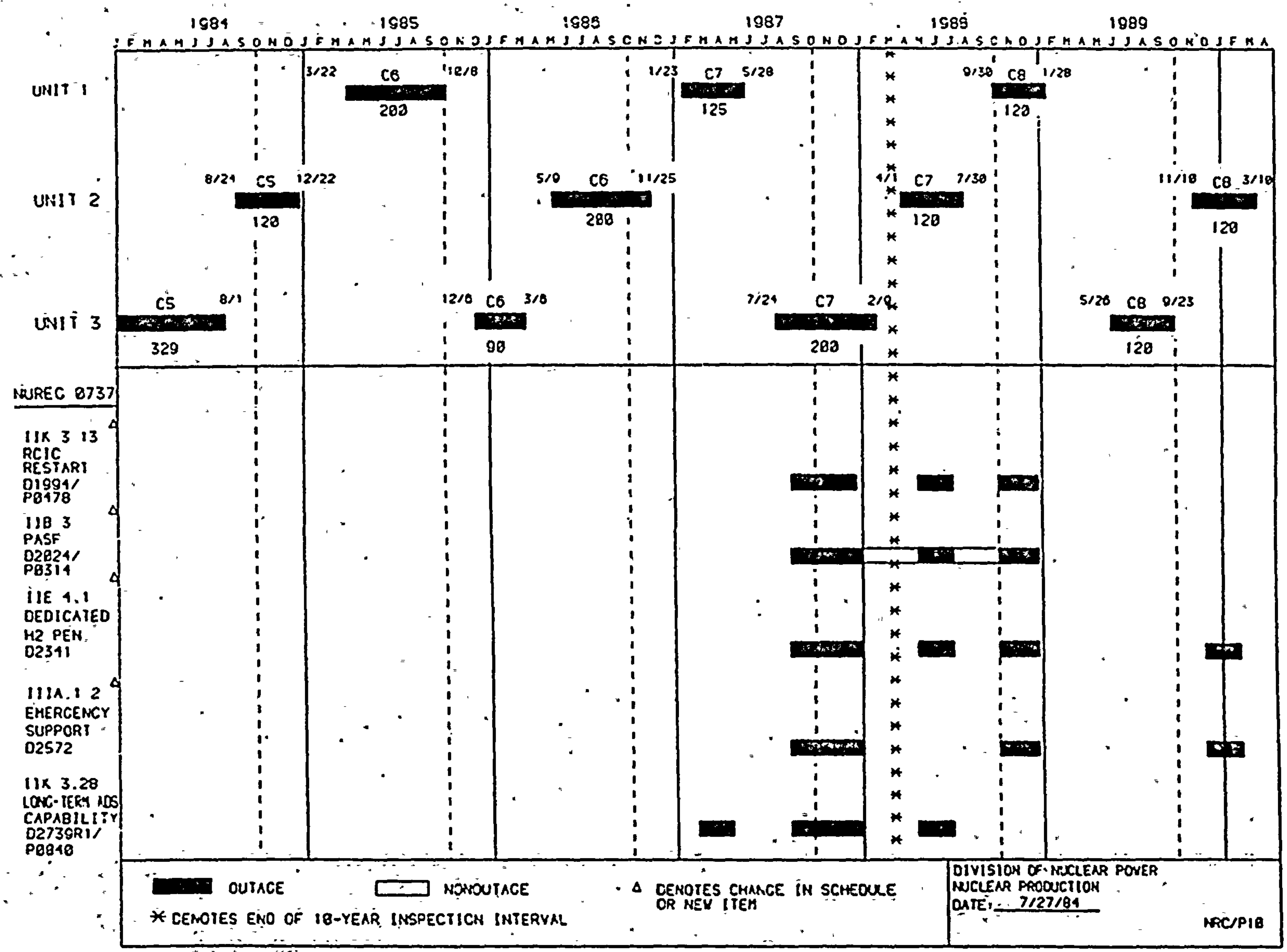

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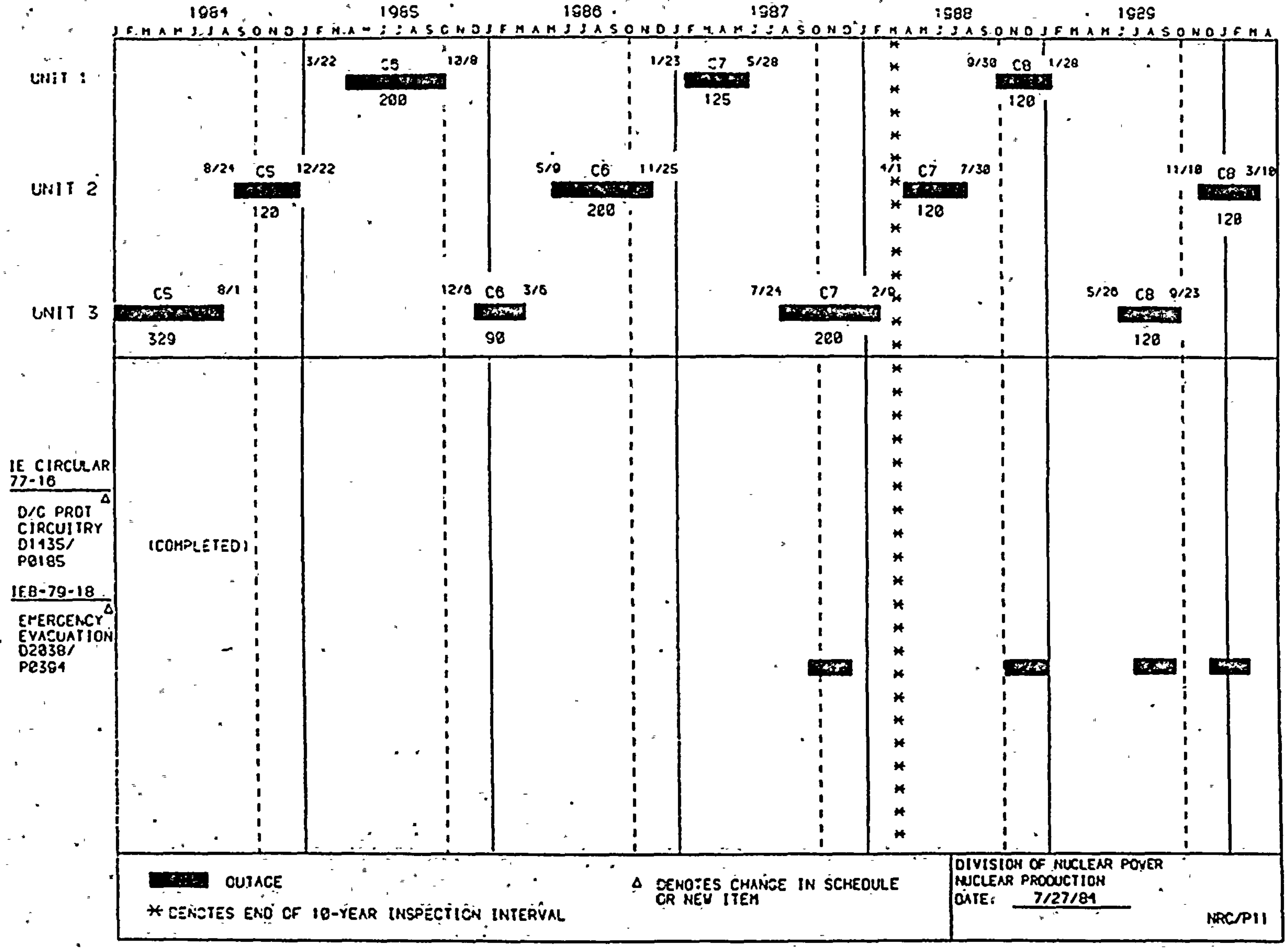

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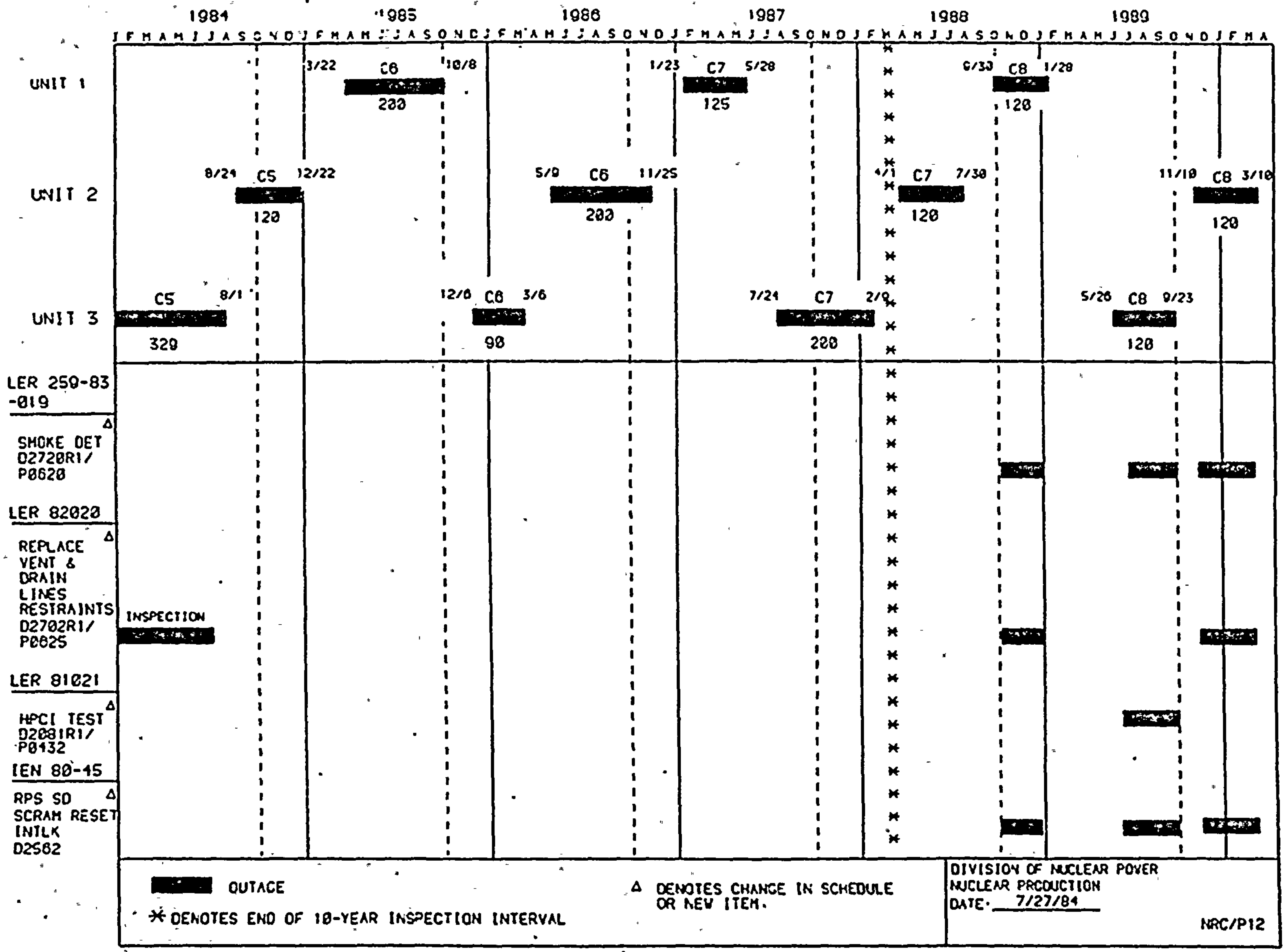

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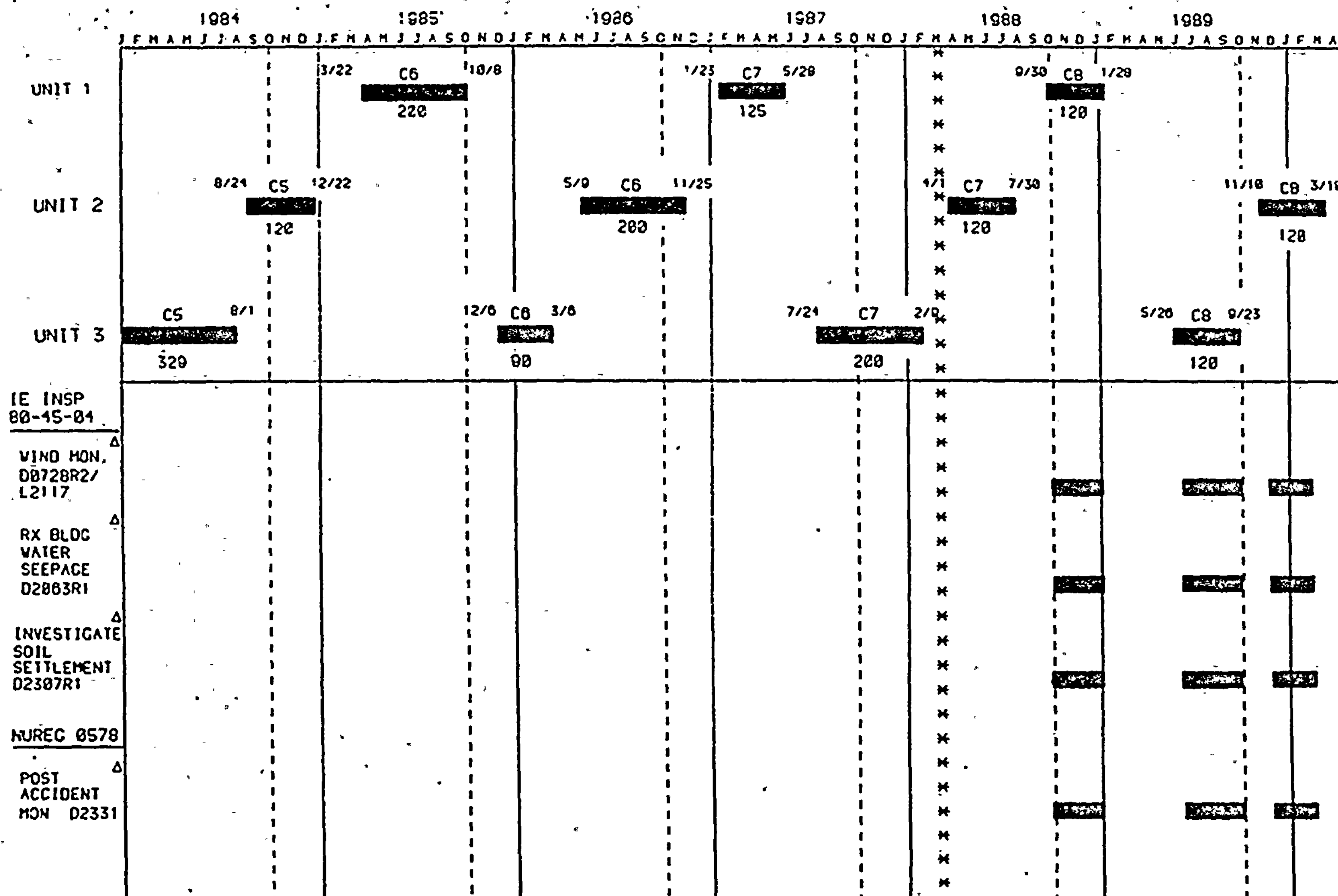


OUTAGE

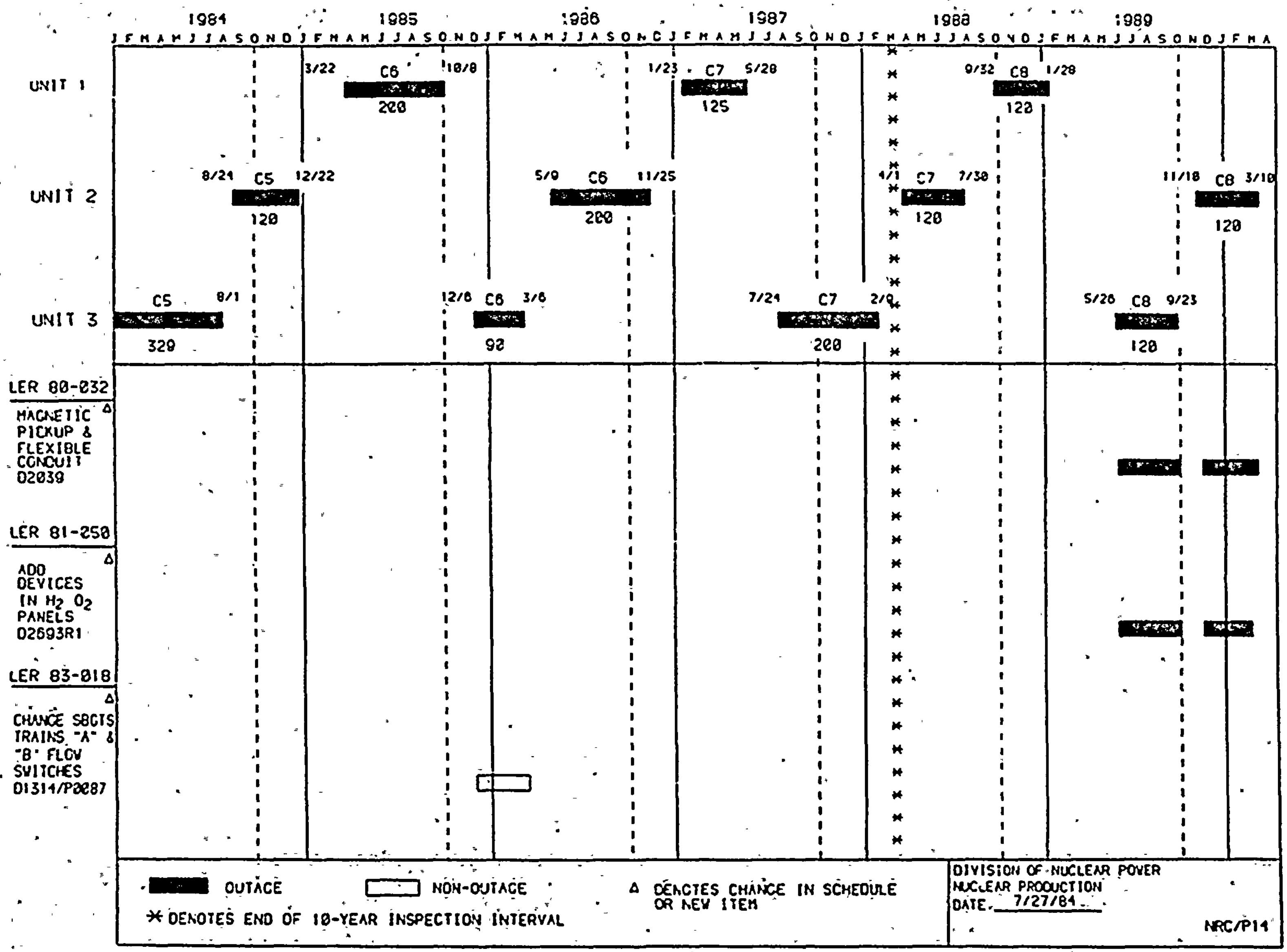
* DENOTES END OF 10-YEAR INSPECTION INTERVAL

Δ DENOTES CHANGE IN SCHEDULE OR NEW ITEM

DIVISION OF NUCLEAR POWER
NUCLEAR PRODUCTION
DATE: 7/27/84

NRC/P13

BFN NRC COMMITMENT SCHEDULE



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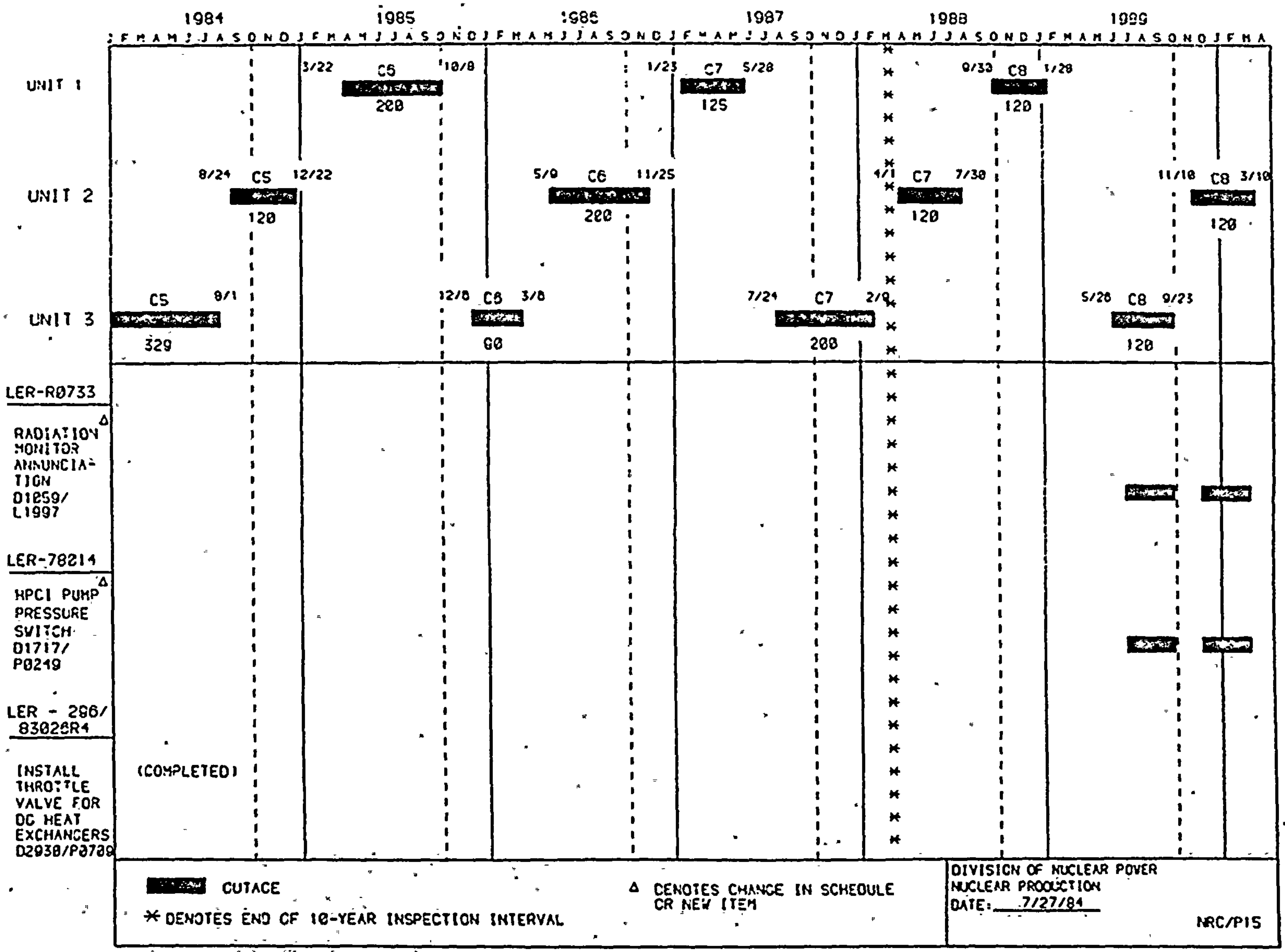

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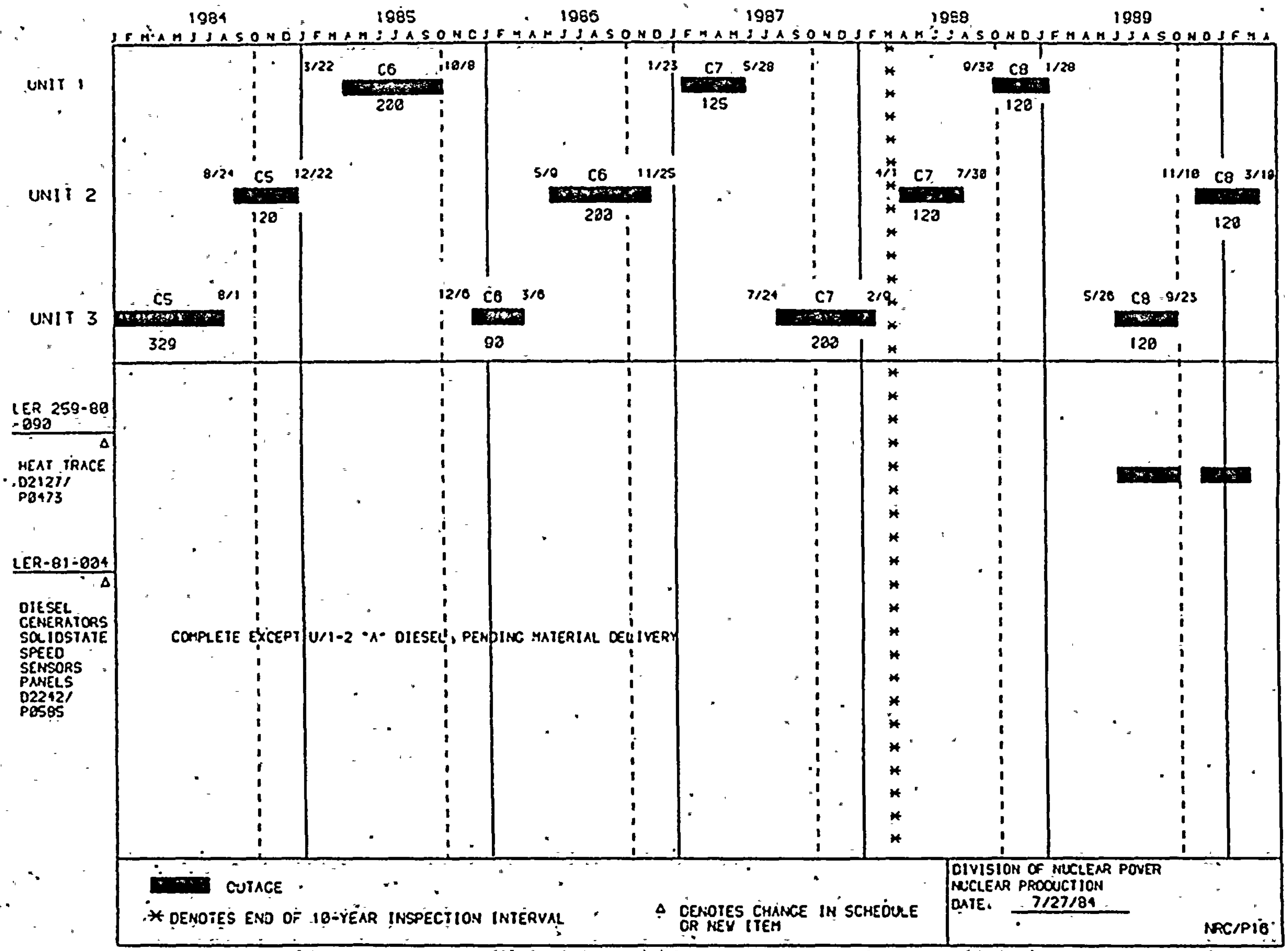
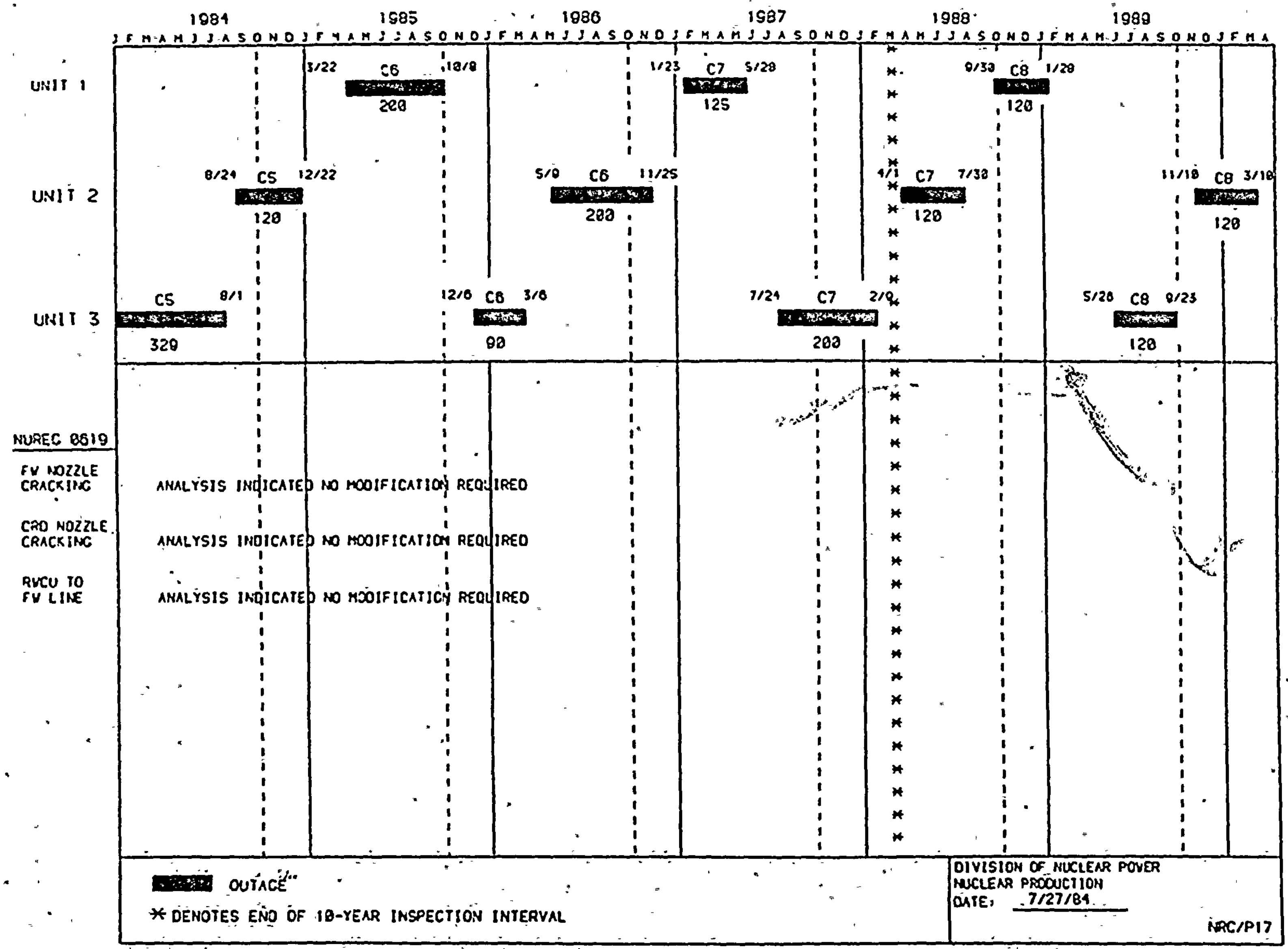


E4-16

BFN NRC COMMITMENT SCHEDULE



ENCLOSURE 5

METHODOLOGY FOR CALCULATING OUTAGE WORKLOAD MAN-DAY ESTIMATES

ENCLOSURE 5

BROWNS FERRY CRAFT STRENGTH CALCULATIONS USED

FOR PLANNING REFUELING OUTAGE WORKLOADS

1. MAN-DAYS OF WORK AVAILABLE (MD) FOR MODIFICATION AND MAINTENANCE WORK DURING EACH SCHEDULED REFUELING OUTAGE WAS USED TO CALCULATE HOW MANY MODIFICATIONS COULD BE PERFORMED. IT IS CALCULATED AS FOLLOWS:

$$MD = (DAYS - (3 + 15)) \frac{(12)}{(14)} ((CRAFT) (.7) (.95) (PF) - 150),$$

WHERE

DAYS = SCHEDULED OUTAGE DAYS

(3 + 15) = DAYS DURING WHICH MOST OF THE PRODUCTIVE WORK IS NOT PERFORMED (3 SHUTDOWN, 15 STARTUP DAYS)

$\frac{(12)}{(14)}$ = TWELVE OF EVERY FOURTEEN CALENDAR DAYS ARE WORKDAYS

CRAFT = ALLOWED CRAFT ONSITE PER RPIP

(.7) = 70% OF ALL WORK IS SCHEDULED--THE REMAINING 30% IS EMERGENT WORK.

(.95) = ACCOUNTS FOR 5% ABSENTEEISM

(PF) = PRODUCTIVITY FACTOR EXPECTED AS A RESULT OF RPIP

PRODUCTIVITY FACTORS (PF) ARE NORMALIZED TO ONE CONSISTENT WITH THE FACT THAT PRODUCTIVITY IS AT 'X' LEVEL PRESENTLY (i.e., 'X' = 1). THE PF IS THEN UTILIZED AS A MULTIPLIER FOR THE CYCLE OF OUTAGE WORK TO INDICATE AN OVERALL INCREASE OF PRODUCTIVITY THROUGH UNIT 3 CYCLE 8. FOR EXAMPLE:

PF OF 1 INDICATES PRESENT PRODUCTIVITY LEVELS

PF OF 1.1 INDICATES A 10 PERCENT INCREASE IN PRODUCTIVITY LEVELS

PF OF 1.2 INDICATES A 20 PERCENT INCREASE IN PRODUCTIVITY LEVELS

PF OF 1.3 INDICATES A 30 PERCENT INCREASE IN PRODUCTIVITY LEVELS

PF OF 1.4 INDICATES A 40 PERCENT INCREASE IN PRODUCTIVITY LEVELS

150 = CRAFT ALLOTED TO DIRECT SUPPORT ACTIVITIES

2. CONSISTENT WITH RPIP, THE RESULTANT PRODUCTIVITY FACTORS (PF) EXPECTED ARE AS FOLLOWS:

U2C5 - PF = 1

U1C6, U3C6 - PF = 1.1

U2C6, U1C7 - PF = 1.2

U3C7, U2C7, U1C8 - PF = 1.3

U3C8 - PF = 1.4

3. CONSISTENT WITH RPIP, SCHEDULED MAINTENANCE (EXCLUDING MAIN TURBINE MAINTENANCE) MAN-DAYS REQUIRED HAS BEEN REDUCED FROM 10,000 TO 7,500. THIS NUMBER WAS SUBTRACTED FROM MD TO YIELD MD AVAILABLE FOR MODIFICATIONS.

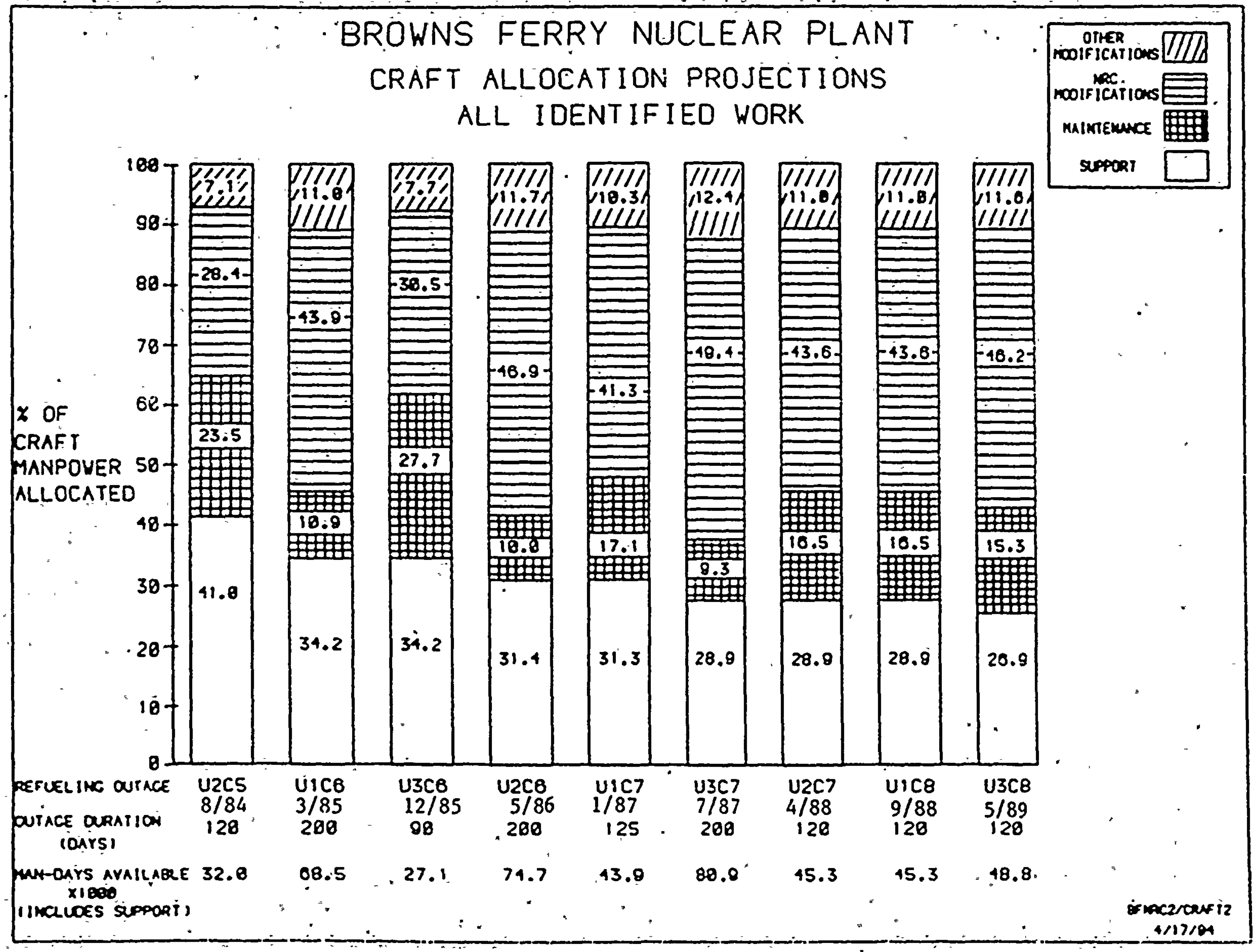
4. THE NUMBER OF MAN-DAYS AVAILABLE FOR MODIFICATIONS WAS MULTIPLIED BY 0.8 TO YIELD THE NUMBER OF MAN-DAYS AVAILABLE FOR NRC COMMITMENT-RELATED MODIFICATIONS, I.\E., 80% OF THE AVAILABLE MODIFICATION MAN-DAYS ARE DEDICATED TO NRC COMMITMENT-RELATED MODIFICATIONS.

NOTE: THE FOLLOWING ENCLOSURE GRAPHICALLY DEPICTS THE MAN-DAYS AVAILABLE FOR IDENTIFIED WORK DURING EACH REFUELING OUTAGE.

ENCLOSURE 6

GRAPH OF AVAILABLE MAN-DAYS
FOR EACH REFUELING OUTAGE

ENCLOSURE 6



E6-1

ENCLOSURE 7

DETAILED JUSTIFICATION/STATUS FOR BROWNS FERRY INTEGRATED SCHEDULE ITEMS

<u>NOTE:</u> The reasons for our schedular revisions and the methodology for prioritizing the various items on the schedule are provided in enclosures 1 and 3. The information in this enclosure provides additional justification and information regarding our schedules for the most significant Category 1 and 2 items.

If no additional information is provided on a particular item, the reasons are as follows:

1. The relatively low safety priority attached to the item.
2. The amount of work and time required to complete large scale items of much higher priority (i.e., IEB 79-01B, Appendix R, etc.)

RECIRCULATION PIPING REPLACEMENT
IE BULLETIN 83-02

Status

Unit 1 Cycle 6 (Currently Scheduled for March 1985)

- Piping replacement is scheduled.
- Stainless steel welds greater than four inches which are not being replaced will be selected for examination in accordance with the guidance given in Generic Letter 84-11.

Unit 2 Cycle 5 (Currently Scheduled for August 1984)

- One hundred-percent examination of the accessible stainless steel welds greater than four inches before induction heat stress improvement (IHSI).
- Twenty-five percent sample of the stainless steel welds (greater than four inches) following IHSI. The sample will be selected from those welds which require recording/evaluation of indications. Any additional welds needed to complete the 25-percent sample will be from weld locations shown to have the highest propensity for cracking.

Unit 3 Cycle 5 (Currently in an Outage)

- One hundred-percent examination of the accessible stainless steel welds greater than four inches before IHSI.
- Twenty-five percent sample of the stainless steel welds (greater than four inches) following IHSI. The sample was selected from those welds which require recording/evaluation of indications (34 welds) and additional welds from locations shown to have the highest propensity for cracking (nine welds).

Unit 3 Cycle 6 (Currently Scheduled for December 1985)

- The sample will be in accordance with Generic Letter 84-11 with the exception of 100-percent examination following IHSI. The post-IHSI sample will be the 25-percent sample performed during unit 3 cycle 5.

The following is a description of special surveillance measures for primary system leak detection beyond those required by current technical specifications.

Leak detection and leakage limits that will be used at Browns Ferry Nuclear Plant are those described in the technical specifications for units 1, 2, and 3. Leakage detection and limits follow the requirements of attachment 1 to Generic Leter 84-11 with the following exceptions.

a. The containment air-monitor system has not been upgraded or calibrated to correspond to a particular leak rate. This is the system which promptly indicates an increase in leak rate.
b. Leakage rate is monitored at eight-hour intervals.
c. At least one sump leakage monitor must be operable or power operation is permissible only for the succeeding 72 hours.

10 CFR 50.49
ENVIRONMENTAL QUALIFICATION OF ELECTRICAL EQUIPMENT

Browns Ferry Nuclear Plant presently has a total of 1,475 components classified as applicable under 10 CFR 50.49. Calculations currently show that approximately 50 percent are fully equipped. This status is constantly changing as unit 3 is in the refueling mode and components are being relocated or replaced daily. The status of less than 10 percent of the components have their program still undetermined, that is, they are being tested or analyzed to see if they qualify.

Unit status is as follows:

Unit 1 - Qualified 232, to be relocated or replaced 211, undetermined 44.
Unit 2 - Qualified 234, to be relocated or replaced 221, undetermined 44.
Unit 3 - Qualified 238, to be relocated or replaced 207, undetermined 44.

Procurement and design problems are rapidly being resolved; the only things undetermined are the items in test. Other than the items requested in our letter dated March 27, 1984, for unit 3, the problem now becomes one primarily of manpower. Our integrated work schedule discussed with NRC in Bethesda, May 23, 1984, shows 10 CFR 50.49 components being completed with unit 2 cycle 6 whose outage starts mid-year 1986.

During the review of our program for this presentation, we have found other items to be added to our letter dated March 27. Our findings include a nonconformance report (NCR) identifying additional components to be in a harsh environment, one typing emission, and some limitorque components that will not meet the startup for unit 3. An updating of the March 27 letter will be upcoming shortly.

TORUS INTEGRITY MODIFICATIONS
NUREG-0661

The major torus integrity modifications have been installed. The remaining torus attached piping modifications are necessary to demonstrate both the piping and containment pressure boundary and structural integrity remain within specified margins when considering torus integrity long-term program analysis dynamic load combinations. However, the existing configuration for the unit 2 torus meets the criteria established for the short-term program. SRV testing which was conducted following the unit 2 cycle 4 torus modifications indicates that the contribution to piping loads from SRV actuation is actually less than was predicted by long-term program analysis.

The torus structural modifications have reduced the loads in the torus attached piping. The unit 2 SRV testing indicates all dynamic loads on attached piping may be lower than the loads predicted by the long-term program analysis.

The torus temperature monitoring system required by NUREG-0661 will upgrade the torus temperature monitoring capability. The existing torus temperature monitoring system will remain operational until the improved system is installed.

The remaining SRV tailpipe support modifications are relatively minor modifications which are located in the drywell. The major SRV tail pipe modifications, which are located in the torus and main vent pipe are complete.

NUREG-0737
ITEMS II.F.1.1, HIGH RANGE NOBLE GAS MONITORS AND
II.F.1.2, SAMPLING AND ANALYSIS OF PLANT EFFLUENTS

TVA is currently under Confirmatory Orders to install high range effluent gas monitors this outage (unit 2, cycle 6) according to NUREG-0737, II.F.1.1 and II.F.1.2. The high range noble gas monitors and sampling system is currently scheduled to start installation on the unit 1 cycle 6 outage (March 1985), and to be completed during the unit 2 cycle 6 outage. The modification will require 17,000 man-hours of work to complete.

TVA believes that with the lengthy outage currently planned for unit 2 (120 days) that the deferral is justified by the safety/benefit comparison with the earlier scheduled work and the current plant capability to perform the NUREG-0737 Items II.F.1.1 and II.F.1.2 requirements.

In the interim Browns Ferry has a system that can detect and measure noble gas releases out the stack during and following an accident (II.F.1.1). These monitors do not meet the NUREG-0737 upper range requirements set forth in NUREG-0737. The interim sample system can monitor radioiodine and particulates as required in II.F.1.2. Because the interim system is currently in place, TVA has put a relatively low safety priority on these items. TVA believes that the interim monitoring systems is satisfactory for the interim period and deferring the modifications constitutes no significant safety concerns.

NUREG-0737, ITEM II.F.1.3
CONTAINMENT HIGH-RANGE RADIATION MONITOR

TVA is currently under Confirmatory Orders to install redundant radiation monitors at Browns Ferry unit 2 during the upcoming outage to meet the requirements of NUREG-0737, Item II.F.1.3. While installing the equipment on unit 1 in late 1983, it was determined that the cable penetration connectors were not qualified. The reordered penetrations have not been received on site at this time. Therefore, if the monitors were installed at this time they would not meet the operability or environmental qualification requirements. In the interim Browns Ferry has a high-range containment monitoring system. These monitors do not meet the NUREG requirements because of their insensitivity to low energy gammas.

Because the interim system is currently in place and can detect radiation levels over most of the II.F.1.3 required range, TVA has put a relatively low safety priority on the high-range containment radiation monitors.

Therefore, TVA believes that the interim monitoring system is satisfactory for the interim period and deferring the modification constitutes no significant safety concern.

NUREG-0737, ITEM II.F.1.4
CONTAINMENT WIDE-RANGE PRESSURE INSTRUMENT

This commitment is a requirement of NUREG-0737, Item II.F.1.4. The modifications consists of pressure transmitters and control room instrumentation to indicate and record drywell pressure from zero to 300 psig. This modification requires deferral due to its contribution to the overall manpower requirements during unit 2 cycle 5 refueling outage.

The maximum design pressure of the containment is 62 psig with a yield pressure of approximately 120 psig. The existing pressure instrumentation covers the zero to 80 psia (-15 to 65 psig) range encompasses all expected design basis conditions. There is currently no operator action which is based upon a pressure greater than 62 psig and, therefore, monitoring pressure above that point would not result in any additional action taking place and would be for information purposes only. Deferral of this modification will not result in a reduction in safety.

NUREG-0737, ITEM II.F.1.5
CONTAINMENT WIDE-RANGE LEVEL INSTRUMENT

This commitment is required by NUREG-0737, Item II.F.1.5. It involves installation of water level transmitters and associated control room recorders and indicators to measure torus level from the bottom of the torus to 25 feet above the bottom. This modification requires deferral due to its impact on the overall manpower requirements.

The existing torus level instrumentation has a range from 24 inches below to 26 inches above normal water level. During design basis events it is possible for the torus level to increase above the range of the instrument, however, there is currently no operator action which is based upon a torus level outside the existing range. Therefore, the extended range provided by this modification will only provide additional information as to the status of the water level and will have a minimal effect on operator actions to correct the condition based upon this. Deferral of this modification will have a minimal impact on safety.

APPENDIX R - FIRE PROTECTION

To accelerate the Appendix R work schedule would require either the postponement of other regulatory mandated modifications, (such as IEB 79-01B Environmental qualification, IEB 83-02, Pipe Replacement) or require the significant delay of a unit's return to service beyond the present extended outage schedule. Either option could have a severe adverse impact. Therefore, TVA does not propose to accelerate the Appendix R modification schedule at the expense of other safety-related modifications of similar importance for the reasons outlined below.

Elevations 565 and 593 of the Reactor Building have complete automatic suppression provided by fixed water spray and preaction sprinkler systems. The accumulation of transient fire loads is rigidly controlled by administrative procedures currently in place and ignition sources are controlled by strict controls on all cutting, welding, and hot work operations.

Fixed water spray systems were installed where the trays of one division crosses the trays of the other division and where two cable tray runs of opposite divisions approach each other directly to within a few feet. In addition, they were also installed where nondivisional cable trays are within the boundary zone of both divisions.

Equipment which presents a special hazard to safety-related equipment in other areas of the Reactor Building are protected by fixed water spray or preaction sprinkler systems. Very few redundant circuits necessary to achieve and maintain hot and cold shutdown are located in other areas of the Reactor Building. With the protection provided for special hazards, strick controls on transient combustibles and ignition sources, and a well-trained and -equipped fire brigade, the possibility of a fire occurring in these areas is significantly reduced.

In addition, immediately following the completion of the unit 2 cycle 5 outage, the following compensatory measures will be initiated.

1. Reactor Building

A roving fire watch will be posted in each unit of the Reactor Building while the unit is operating. The fire watches will be provided until all required Appendix R modifications are completed for each specified area of that particular unit or the unit is in cold shutdown.

The fire watches will check the following areas of the Reactor Building during each hourly round:

a. Residual heat removal pump corner rooms (Elevations 519 and 541).

b. Area above the drywell access room, south of the drywell, Elevation 565.

c. Area below shutdown board rooms A, C, and E, Elevation 593.

d. Area around the unit 3 shutdown board room transformers, Elevation 621.

In addition to the provision of roving fire watches, administrative controls will be established to prohibit the storage of transient combustibles in the above areas until all required Appendix R modifications are completed for each specified area of that particular unit or the unit is in cold shutdown. The areas to be kept clear of the storage of transient combustibles will be clearly marked.

2. Intake Pumping Station

A roving fire watch will be posted in the intake pumping station, Elevation 550 while any unit is operating. The fire watch will be provided until all required Appendix R modifications are completed or unless all three units are in cold shutdown.

In addition to the provision of a roving fire watch, administrative controls will be established to prohibit the storage of transient combustibles in the pipe tunnel along the north wall of the intake pumping station.

3. Other Critical Areas

Administrative controls will be established to prohibit the storage of transient combustibles in the following areas until all required Appendix R modifications are completed for that particular area or the unit is in cold shutdown.

a. Shutdown board rooms A, C, and E, Elevation 621.25 - fixed combustible loading in these rooms is very low and access is strictly controlled.

b. Battery rooms and battery board rooms in the Control Building, Elevation 593 - automatic suppression and detection is provided in each complex and access is strictly controlled.

c. Auxiliary instrument rooms in the Control Building, Elevation 593 - suppression and detection is provided in the rooms and access is strictly controlled.

The compensatory measures outlined above provide an additional level of fire prevention in the areas which are critical to safe operation. These measures will provide adequate protection for health and safety of the public during the time required to complete the modifications necessary to meet the applicable requirements of 10 CFR 50, Appendix R.

REDUCED MAIN STEAM ISOLATION VALVE (MSIV) LEAKAGE PROGRAM

TVA is continuing its efforts to minimize misalignment of MSIV poppets when the valves are in the closed position. The efforts commenced during the unit 2 cycle 4 outage and have continued through the units 1 and 3 cycle 5 outages. The following work has been performed on MSIVs which failed leak rate test during each of the forementioned outages:

1. Machine the poppet and overlay the lower guide with stellite.
2. Check the poppet upper guide and weld buildup as necessary. Both guide concentricities were kept to within 0.001 inch, as were overall guide diameter tolerances.
3. Valve body machining was performed using a standard which consisted of a poppet mockup. After lapping its seating surfce, each valve body was measured with this standard. The upper bore was then honed as required and/or additional lapping was performed to ensure adequate clearance in the poppet upper guide area and to align the seat with the guides. The lower three inches of the guide was then built up and machined, and clearances were verified by reinstalling the mockup. The following valves were modified in the above manner:

   Unit 2 (cycle 4) 7 of 8 MSIVs (all except '2D' inboard)
   Unit 1 (cycle 5) 7 of 8 MSIVs (all except '1B' outboard)
   Unit 3 (cycle 5): 4 of 8 MSIVs (both '3A', '3C' outboard, '3A', '3D' inboard)

TVA additionally intended to install air boosters on the MSIV operators. However, this effort was discontinued due partly to vendor concerns and also due to the possibility that the previously mentioned modifications were adequate to control leakage. In order to prevent poppet rotation during closure, TVA changed the poppet stem to a two-inch diameter stem with an anti-rotation assembly. To accommoate the larger stems the bonnets were bored, the backseats were welded and remachined and several parts were replaced. This work was performed on of the unit 1 and unit 3 MSIVs which received the alignment modifications.

TVA has additionally provided MSIVs with a rebuilt control panel operator, modified limit switch mountings, and better locking tabs.

The craft effort required to perform these modifictaions to date has been approximately 30,000 man-hours.

TVA continues its efforts to limit MSIV leakage. MSIV leak rate testing during the unit 2 cycle 5 refueling outage should provide data regarding the success of realignment efforts. MSIV testing during the unit 1 cycle 6 refueling outage should additionally indicate the relative merit of installing anti-rotation devices. The data obtained from these two refueling outages should provide adequate information to determine which

modifications, if any, produced the desired results. In the interim, all of the forementioned modifications are scheduled to be performed on all MSIVs which fail leak rate testing and have not been previously modified.

TVA considers its MSIV improvement program to be a dedicated continuous effort which requires time for actual results of the modifications to be measured. As such, although a projected overall completion date associated with unit 1 cycle 7 refueling outage is proposed, the actual completion date will vary with both the degree of success of these modifications and with changes in the state-of-the-art design of MSIVs.

PIPING HANGER MODIFICATIONS
(IEB 79-14)
HANGER BOLT MODIFICATIONS
(IEB 79-02)

TVA has qualitatively evaluated all major piping systems and the associated supports to ensure they satisfy the originally specified configuration. All deficiencies have been prioritized in accordance with an established procedure, and the most critical deficiencies have been corrected.

Concrete anchors for these supports have been evaluated for IE Bulletin 79-02. Expansion shell anchors were repaired as necessary to meet at least a minimum safety factor of two (2) based on the original design loads. Therefore, the failure of the supports or anchors is not likely for the original design loading conditions.

Delay of these modifications will not significantly impact plant safety.

MODIFICATIONS TO REPLACE VENT AND DRAIN LINE RESTRAINTS

In response to LER BFRO-50-259/82020 (R2), an evaluation was conducted to verify that adequate supports existed on test, vent, and drain connections on safety-related piping systems. The purpose of this evaluation was to identify any connections which did not have adequate vibrational restraints. The need for additional restraints which have not been installed was identified in the recirculation, RHR, and HPCI systems for unit 1 and the HPCI system for unit 2.

The vibrations in these systems are not excessive during normal power operation. Most vibration problems in these systems have occurred when flow is throttled producing valve cavitation. Additional occurrences of vibration during shutdown cooling operation or system flow tests will contribute to the possibility of a failure of the connections until the additional restraints are installed.

Vibrations due to valve cavitation in the HPCI system are not expected during vessel injection. Vibration induced failures of connections on the HPCI piping are most likely to occur as a result of vibrations experienced during system flow testing which is an infrequent occurrence. However, if a failure of a connection should occur during vessel injection, an examination of the connections on the HPCI system indicates that the failure would not adversely affect redundant systems.

Vibrations due to valve cavitation in the RHR system are not expected during vessel injection except when flow is throttled following core reflood. However, failure of a connection at that time would have less adverse impact on system operation because RHR flow requirements are also reduced. Vibration problems may also occur when RHR flow is throttled during shutdown cooling operation. However, operational guidelines have been implemented to reduce vibration levels during RHR operation. Some vibration problems have been experienced during system flow tests to the torus for the RHR system. However, modifications have been made to the RHR test return line which greatly reduce piping vibration.

The net result of the measures taken to reduce vibration in these systems has been to reduce the probability of vibration induced failures of the connections on these piping systems. Therefore, a delay in the installation of additional restraints on these systems should not have a significant impact on system reliability.

NUREG-0737, ITEM II.K.3.13

RCIC AUTOMATIC RESTART

This commitment is a requirement of NUREG-0737, Item II.K.3.13. The modification involves logic changes to the RCIC system such that the automatic start feature is retained following a high water level trip of the turbine. Currently, operator action is required to perform this function. Deferral of this modification is required because of its impact or overall manpower for the unit 2 cycles 5 and 6 refueling outage. Currently, the HPCI system will auto-restart as is planned for the RCIC system. Therefore, a high pressure ECCS makeup system is available to maintain water level with no operator action. In case there is a break in the primary system, water level is maintained by the ADS system in conjuction with low pressure ECCS systems if the HPCI system fails to do so. In events where RCIC prevents core uncovery, the inventory loss must be less than the RCIC capacity of 600 gpm. With water level initially at the high level trip point for RCIC, an inventory loss of less than 600 gpm with no makeup allows sufficient time for operator action to restart RCIC prior to core uncovery. Therefore, the only effect of this modification is to avoid the need for operator action in cases where sufficient time is available for such action. Deferral of this modification will have negligable effect on safety.

NUREG-0737, ITEM II.B.3
POST-ACCIDENT SAMPLING FACILITY

In response to this item, TVA has procured and designed for installation of a common facility serving the three units. The facility represents a substantial modification on the order of 20 million dollars total expense. Much of the central analysis facility's structure has been completed, but considerable work is outstanding to erect the sample tube field runs, provide reactor and containment tie-ins, install electrical controls and valving. Estimated manpower for completion of the project is 58,400 man-hours. This item is proposed for deferral with work to start in 1987 during the unit 3 refueling outage.

It is evident that considerable resources will be involved in completing this project. Justification for deferral is generated by a resource/safety benefit comparison with the earlier scheduled work items. Furthermore, in response to NUREG-0578 and -0737 requirements, the plant developed a capability to sample and analyze reactor coolant and containment atmosphere following an accident. This capability was evaluated in 1981 by the NRC and determined to be fully adequate. The NRC and knowledgeable TVA personnel continuously audit and review this capability. Improvements are made as necessary based on the results of these audits and internal reviews. Also, existing containment radiation monitors provide alternative and timely indication of core damage progress.

No significant hazard is involved in maintaining our present post-accident analytic capability to allow priority to be given to modifications which minimize potential for an accident.

NUREG-0737, ITEM II.E.4.1
DEDICATED HYDROGEN PENETRATIONS

TVA examined the post-accident nitrogen injection and vent system in response to this NUREG item. There were two deficiencies on the vent side of the system for which we planned modifications. Neither deficiency seriously affects system operation. This proposition is further reinforced by the fact that for Browns Ferry the purge system is not the primary post-accident hydrogen gas control system. A relatively low safety priority has thus been established with modifications scheduled to begin in 1987.

TVA committed to install a leak detection system on all three Browns Ferry units. The systems are installed on units 1 and 3. TVA wants to delay the installation on unit 2 until the unit 2 cycle 7 refueling outage (March 1988). TVA believes that this is justified since General Electric Company's (GE) NEDE-21821-A showed by removing nozzle cladding and installing a GE triple sleeve feedwater sparger a low 40-year usage factor will be obtained when there is little or no secondary leakage. The triple sleeve sparger is presently installed in all three units and should prevent secondary seal leakage for a minimum of five years. Even if a crack is assumed to be present, its growth rate, based on NEDE-21821-A, will be limited to less than 3/8-inch total depth for approximately 10 years. Analysis shows that the growth of a crack will not be greater than one inch due to stresses from temperature variations and the startup and shutdown cycles during 40 years of the plant life based on a leak rate of 1 gpm. Therefore, TVA believes that with the triple sleeve sparger installed there is no significant safety concern by delaying the installation of the leak detection monitoring system on the feedwater nozzles.

INSPECTION AND ENFORCEMENT BULLETIN 79-18
PERSONNEL EVACUATION IN HIGH-NOISE AREA

The subject bulletin dealth with the audibility problems encountered on evacuation of personnel areas. TVA's original response dated February 12, 1980 to J. P. O'Reilly, NRC-Region II, from L. M. Mills, stated that several modifications were required to satisfy the requirements of IEB 79-18. Since that time, TVA has implemented procedural changes to the Radiological Emergency Plan (REP) which require specified personnel to verify that all personnel have exited areas that have been ordered evacuated. This personnel verification will ensure that all personnel in high-noise areas including pump-rooms, storage rooms, and feedwater heater rooms have exited the evacuated area. TVA has used this procedure several time in practice drills and has found that the manual personnel verification works. TVA, therefore, believes that the safety of the personnel is ensured with the current system and procedures and that it is not necessary to perform the modifications as originally stated in the referenced letter. TVA has determined that this bulletin is of no nuclear safety concern and that personnel safety is not compromised with the current system. TVA believes this modification should be taken off of the integrated schedule with the NRC's approval.

WATER ACCUMULATION IN H_2-O_2 MONITORS

This commitment involves a modification to the H_2-O_2 monitors to prevent water accumulation in the sensing lines and is a corrective action for the resulting License Event Reports (LERs). This problem does not jeopardize the post-accident operability of the H_2 monitor and has never actually caused it to become inoperable. LERs were originally generated because the monitor was removed from service to dry the lines, but new reporting requirements have eliminated further LERs due to this condition. The O_2 monitor has become inoperable due to water accumulation because of differences in its internal construction, but it is not required to be operable post-accident and is, therefore, only an operational problem. This modification requires deferral because of its impact on the overall design workload since design work is not yet complete. This modification is being deferred on the basis that it is an operational problem only, and that there is no indication that the equipment cannot perform its safety function.

IE BULLETIN 80-11

Inspection and Enforcement Bulletin 80-11 was released on May 8, 1980 identifying a problem with the structural integrity of masonry block walls due to seismic qualifications. The seismic analysis showed 19 walls were not qualified. Later tornado depressurization analysis was performed on the masonry walls and it was determined several walls needed to be reinforced because of this analysis. Two walls were identified as critical and modifications were immediately implemented. TVA currently has 17 walls that need to be modified due to either the seismic or tornado analysis.

Deferral of the unit 1 and unit 3 walls is required because of its impact on overall manpower for the unit 2 cycle 5 refueling outage. The unit 2 walls will be worked this outage. The unit 1 and unit 3 walls will be worked in their next respective refueling outage.

A reanalysis is currently being performed to reevaluate a case that was originally not included in the tornado evaluation to determine if they pose any significant threat to safety-related equipment. Based on the reanalysis performed to date, TVA has not identified any unacceptable consequences that might be a significant safety concern.

TVA believes it is justified in deferring the unit 1 and unit 3 wall work until their next refueling outage because of the low probability of either a seismic or tornado event and the acceptable consequences of the failure of all walls known to be effective.

ENCLOSURE 8
PROGRAM DESCRIPTION

I. Program Description

Upon completion of the complete work listing, TVA determined that detailed and integrated schedules were required for the major work items. Upon completing the comprehensive listing of major work items, the tasks were organized into categories 1, 2, and 3. All categories are briefly described below:

Category 1

All items which have implementation dates mandated by NRC rules, orders, or license conditons.

Category 2

Regulatory items (of either a generic or plant specific nature) identified by NRC which have implementation dates committed to by TVA and which would result in either (a) plant modifications, (b) procedure revisions, or (c) changes in facility staffing requirements, or items perceived by TVA as prospective NRC requirements or Licensee Event Reports (LER).

Category 3

All other major tasks resulting from mandates of agencies other than NRC and TVA-initiated system upgrades for availability improvement.

Category 1 dates may be modified only with the prior approval of NRC, in accordance with existing NRC procedures. Changes in Category 2 dates require written notification to NRC, as described in Section III.

Categories 1, 2, and 3, taken together, provide a basis for assessing the overall effects of changes to schedules and a departure point for discussion between NRC and the licensee regarding such changes, as discussed below.

II. Schedule Changes

An important aspect of TVA's planning effort is the recognition that the integrated schedules will need to be modified at times to reflect changes in regulatory requirements, to accommodate those activities that TVA finds necessary to improve plant efficiency and reliability,

and to take into account delays resulting from events beyond TVA's control. It is important that the procedure used by TVA for changing the schedules be documented. In addition, NRC must play a role in the oversight of the scheduling process (and must, in fact, judge the acceptability of proposed date changes in Category 1). Accordingly, it is important that NRC's role and the interaction between NRC and TVA be clearly defined as discussed below.

III. TVA Responsibilities

The integrated schedule requires that TVA monitor the progress of all work undertaken, manage its activities to maintain the schedule, and act promptly to take necessary actions when a schedule change is needed.

A. Periodic Updating

TVA will update schedule Categories 1, 2, and 3 semi-annually and submit the revised schedules to NRC, beginning six months following NRC concurrence in the plan. In addition to updating the schedules, TVA will:

1. Summarize progress in implementing NRC requirements concerning plant modifications.

2. Identify changes since the last report.

3. Summarize the reasons for schedule changes associated with regulatory requirements.

B. Changes to Schedules

Changes to the schedules may arise from a variety of reasons, such as new work activities; modifications in the scope of scheduled work problems in delivery; procurement, etc.; changes in NRC rules and regulations; or other NRC or TVA actions.

Where it is necessary to add a new work item or to change the schedule for an item, the following general guidance will be utilized to the extent appropriate:

1. Assess the priority of the work item and its safety significance.

2. Schedule the new or changed item to avoid rescheduling other items, if it can be reasonably achieved.

3. Alter Category 2 items before Category 1 items.

4. Select a schedule for the new or changed item which will help in maintaining an optimum integrated program of work.

As noted above, no changes will be made in the Category 1 schedule without prior NRC approval. Should a change become necessary, it will only be proposed after TVA has determined that rescheduling of non-NRC required work items either will not significantly assist in maintaining Category 1 without change; or that the safety, cost, or schedule penalties from rescheduling non-NRC required work significantly outweigh the change in a Category 1 completion date.

TVA will inform the NRC Project Manager when serious consideration is given to requesting a schedule change in a Category 1 item. If TVA determines that a change in Category 1 is necessary, it will submit a written request for NRC approval in accordance with applicable procedures.

Work items in Category 2 may be rescheduled or work items may be added to Category 2 by TVA without NRC approval; however, TVA will inform the NRC Project Manager when serious consideration is given to changing the schedule for item in Category 2.

In addition, at least 30 days (unless otherwise agreed to by the NRC Project Manager or unless circumstances beyond TVA's control arise within 30 days of the scheduled date) before TVA adopts a

change for an item in Category 2 (as defined in Section I above), it will provide NRC written notification thereof, including the reasons therefore, and any compensatory actions instituted. If not provided 30 days in advance, such notification will be provided by TVA as promptly as practicable. NRC may request further explanation or discussion concerning such change. In this event, discussions will be initiated with the NRC Project Manager; however, TVA changes in scheduled dates will be effective unless subsequently modified by TVA.

IV. NRC Review

As pointed out in Section II.B above, changes to the schedules are inevitable. Action required by NRC is discussed below:

A. TVA-Originated Changes

1. Upon receipt from TVA of a request for change of Category 1, NRC will act promptly (consistent with resource availability and priority of other work) to consider and decide on the request in accordance with applicable procedures.

2. If the request for a modification of Category 1 is denied, NRC shall promptly inform TVA and provide the reasons for denial.

3. NRC consideration of TVA changes in non-Category 1 items is covered by IV.B.

B. NRC-Originated Changes (Category 1)

It is recognized that formal NRC regulatory actions may: (1) impose a new regulatory requirement with a fixed date or (2) establish a firm date for a previously identified regulatory requirement. In taking any such action NRC, to the extent consistent with its overall regulatory responsibilities and, unless public health, safety, or interest require otherwise, will take into account the impact of such action on TVA's ability to complete effectively the items on Categories 1 and 2, and in in consulation with TVA, will try to minimize such impact. Although, any formal regulatory action taken by NRC will be effective in accordance with its terms without inclusion in Category 1, NRC and TVA recognize the desirability of incorporating such actions into Category 1, particularly in order to incorporate at the same time any other appropriate changes in the total integrated schedule program. Accordingly, once such formal regulatory action is taken (or earlier, if practicable), NRC will provide TVA a reasonable opportunity to propose overall changes in the total integrated schedule program which would most

effectively accommodate such requirements. Any resulting changes in items in Category 1, will be approved by NRC in accordance with established procedures, and will thereupon be reflected in a revised Category 1 submitted by TVA. TVA will inform NRC of any resulting changes in Category 2 in accordance with Section III above.

C. New NRC Issues (Category 2)

NRC may, from time to time, identify new regulatory issues which may result in (a) plant modifications, (b) procedure revision or development, or (c) changes in facility staffing requirements. For issues as to which NRC requests scheduling information, these issues may be included in Category 2 in accorance with the date commitment developed in discussions between TVA and the NRC staff. As for the case of NRC-originated changes to Category 1 items, NRC will provide TVA a reasonable opportunity to propose overall changes in the total integrated schedule program which would most effectively accommodate such issues. Any resulting changes in integrated program schedules will thereupon be reflected in a revised Category 2 schedule submitted by TVA.