Enclosure 2

September 24, 1981
L-81-420

Office of Nuclear Reactor Regulation
Attention: Mr. Darrell G. Eisenhut, Director
Division of Licensing
U. S. Nuclear Regulatory Commission
Washington, D. C. 20555

Dear Mr. Eisenhut:

Re: St. Lucie Unit 2
Docket No. 50-389
Final Safety Analysis Report
Requests For Additional Information

Attached are Florida Power & Light Company (FPL) responses to NRC staff requests for additional information which have not been formally submitted on the St. Lucie Unit 2 docket. These responses will be incorporated into the St. Lucie Unit 2 FSAR in a future amendment.

Very truly yours,

Robert E. Uhrig
Vice President
Advanced Systems & Technology

REU/TCG/ah

Attachments

cc: J. P. O'Reilly, Director, Region II (w/o attachments)
Harold F. Reis, Esquire (w/o attachments)

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Attachment to L-81-420
September 24, 1981

A. Minutes to Power Systems Branch meeting held on September 25, 1981.

B. Appendix 15C.4 (Station Blackout Analysis).

C. Minutes to fire protection meeting held on September 23, 1981.

E. Revise response to Question #430.64.

F. Revised Pressure isolation valves submittal (Initially submitted on September 9, 1981, L-81-394).

G. Minutes to Emergency Planning meeting held on September 24, 1981.

H. Response to Human Factor Engineering Control Room Design Review/Audit Report, St. Lucie Unit 2.

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Enclosure 2

APPENDIX 15C-4

STATION BLACKOUT ANALYSIS

The station blackout event is outside of the design basis for St. Lucie Unit 2. Nonetheless, an analysis was performed as requested by the NRC in response to the decision of ALAB-603. This analysis shows that St. Lucie Unit 2 can successfully endure a complete loss of AC power for at least 4 hours. However, it is expected that AC power would be restored within 30 minutes to one hour as a result of either one of the following corrective actions:

1. Offsite power is restored;

2. One or both of the St. Lucie Unit 2 diesel generators are started.

Maintenance of natural circulation during this event is assured by operator action, starting 30 minutes after event initiation, to keep the coolant in the RCS piping at subcooled conditions.

The results of this analysis have shown that:

1. Natural circulation and core cooling can be maintained;

2. The reactor core remains in a subcritical condition;

3. There is no fuel failure;

4. The RCS coolant pressure remains within limits; and,

5. The resulting radiological doses are within limits.

Therefore, this analysis shows that St. Lucie Unit 2 can successfully endure station blackout event. Florida Power and Light will implement operator training and emergency procedures to ensure that plant operators would take appropriate actions to assure maintenance of natural circulation.

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15C.4 Total Loss of AC Power (Station Blackout)

15C.4.1 Identification of Event and Causes

The Station Blackout event results from a loss of offsite power followed by failure of both standby diesel generators to start.

For Unit 2, this event results in a loss of all onsite AC power except that supplied by inverters from the two safeguards batteries. This provides power to the 120 VAC (safeguards) instrument power and other required DC loads.

15C.4.2 Sequence of Events and Systems Operation

Table 15C.4-1 shows a chronological list of the timing of systems actions from the initiation of a station blackout event to the time that offsite power is restored (4 hours). A description of the sequence of events* is given below for each safety function :

Reactivity Control:

As a result of the loss of power to the reactor coolant pumps, an automatic reactor trip signal is generated by the RPS on low reactor coolant system flow, as measured by steam generator delta-pressure (ΔP). The reactor trip signal interrupts power to the reactor trip switchgear which in turn releases the CEA's to drop into the core. The negative reactivity inserted by the CEAs is sufficient to maintain the core subcritical throughout the rest of the transient.

Reactor Heat Removal:

Following coastdown of the reactor coolant pumps, flow through the reactor is maintained by natural circulation. Heat is transferred to the secondary system through the steam generators.

Primary System Integrity:

A Power Operated Relief Valve (PORV) opens to limit the RCS pressure increase following turbine trip. Steam released from the PORV is contained in the quench tank. Letdown is isolated by the closing of the letdown control valve on loss of offsite power. Late in the transient, the Safety Injection Tanks provide borated water to the RCS increasing RCS inventory and helping to maintain subcooling in the hot leg.

Secondary System Integrity:

A turbine trip signal (TTS) is generated following the loss of offsite power and causes the turbine stop valves to close. The Main Steam Safety Valves (MSSVs) open to limit the pressure increase.

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*Those safety actions necessary to maintain the plant in hot shutdown.

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Auxiliary feedwater is automatically actuated on low steam generator level. Flow is provided by the turbine driven pump which derives all its control power from the station batteries. The operator opens the Atmospheric Dump Valves (ADVs) and regulates them from the control room to maintain steam generator pressure below the setpoint of the MSSVs and to reduce the primary system temperature to maintain subcooling in the hot leg.

Restoration of AC power:

Although the analysis which follows shows acceptable results assuming no AC power for 4 hours, in actuality AC power would be restored to the plant prior to this time (within 30 minutes to one hour) by either one of the following corrective actions.

1) Offsite power is restored and the onsite buses are manually connected to the startup transformers. Equipment is manually loaded on these buses, according to plant emergency procedures, or

2) One (or both) Unit 2 diesel generators is started and safeguards loads are manually sequenced onto its 4.16 KV bus.

15C.4.3 Analysis of Effects and Consequences

A. Mathematical Models

The NSSS response to a Station Blackout was simulated using the CESEC-III computer program.

B. Input Parameters and Initial Conditions

The initial conditions assumed for this event are contained in Table 15C.4-2. These conditions were chosen to provide the largest and most rapid depletion of RCS inventory and shutdown margin. The highest initial pressurizer pressure, least negative Doppler coefficient and most positive moderator temperature coefficient maximize the power and RCS pressure early in the transient resulting in inventory loss through the PORV. The major contributors to the RCS depressurization are the pressurizer heat losses and RCS leakage. Maximum values of these parameters were selected based on technical specifications, plant operating data and reactor coolant pump test results. The lowest initial pressurizer water volume minimizes the available RCS inventory. Initial core inlet temperature, core mass flow rate and pressurizer pressure have a negligible impact on the primary system depressurization. The evaluation of shutdown margin depletion was performed using the most negative moderator temperature coefficient and the least negative CEA worth for trip. This minimizes the shutdown margin remaining at the end of the transient.

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The disposition of normally operating systems is given on Table 15C.4-3. The utilization of safety systems is given on Table 15C.4-4.

C. Results

The dynamic behavior of important NSSS parameters following a Station Blackout is presented in Figures 15C.4-1 to 15C.4-12. Table 15C.4-1 summarizes some of the important results of this event and the times at which the minimum and maximum parameter values discussed below occur. The loss of all AC electrical power initiates, among other things, a simultaneous loss of feedwater, loss of load, and loss of forced reactor coolant flow. As indicated in Figure 15C.4-1, the core power increases initially due to positive reactivity feedback and reaches a maximum value within a few seconds. Subsequent to loss of power to the reactor coolant pumps, the primary coolant flow decreases and a low flow reactor trip occurs as indicated in Table 15C.4-1. Reactor coolant flow vs. time is shown on Figure 15C.4-7. Subsequently, due to the insertion of large negative reactivity by the scram rods, the core power decreases very rapidly and approaches the decay heat value. Departure from nucleate boiling does not occur and therefore no fuel damage is predicted. See Figure 15C.4-8.

During the initial few seconds prior to reactor trip, the reduced steam generator heat rejection capability leads to a rapid increase in both the primary and secondary fluid temperatures. The volumetric expansion due to these increases in temperature produces sharp increases in primary and secondary pressures as well as an insurge of primary coolant into the pressurizer. The variations of the primary and secondary pressures are illustrated in Figures 15C.4-3, and 15C.4-9. The initial rapid increases in both pressures are terminated by the opening of the PORV and MSSVs. The primary relief valve closes rapidly, as the primary system pressure decreases below the setpoint value within a few seconds after opening of the valve. The secondary safety valves cycle open and closed until the operator opens the atmospheric dump valves. MSSV and ADV flow vs. time are shown on Figures 15C.4-11 and 15C.4-12, respectively.

The steam generator liquid level decreases during the transient and reaches a minimum value after auxiliary feedwater flow is automatically actuated using the steam-driven auxiliary feedwater pump. Steam generator level increases until normal water level is reached. The operator subsequently controls auxiliary feedwater to maintain normal level. See Figure 15C.4-6.

The RCS pressure and temperature gradually decrease at fairly constant rates in the long term as a result of pressurizer heat loss, RCS leakage, low heat transfer rates at the steam generators, and ~~due to~~ the operator manually reducing secondary side pressure. Since the RCS pressure decreases at a higher rate than the RCS temperature, the pressure approaches the saturation pressure.

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Saturation occurs in the reactor vessel head. Continued primary pressure drop without a significant decrease in primary temperatures would result in saturated conditions in the hot leg. Credit is taken for operator action to maintain at least 10°F subcooling in the hot leg. This is accomplished by further opening the atmospheric dump valves to reduce the secondary system pressure and temperature. The increased heat removal in the steam generators caused by the larger ΔT across the steam generator tubes reduces the primary system temperatures. Voiding is restricted to the vessel head and natural circulation is not adversely impacted for more than 4 hours.

The Safety Injection Tanks (SITs) provide borated water to the RCS after RCS pressure is reduced below their discharge pressure. No credit is taken for the negative reactivity added as a result of this discharge.

At 4 hours, sufficient AC power is assumed to be restored to provide power to the charging pumps and pressurizer heaters. These will be used to pressurize the RCS and to continue hot leg subcooling.

Operability of the turbine driven auxiliary feedwater pump requires at least 50 psia secondary pressure. At 4 hours after the initiation of the event, the secondary pressure will be greater than 300 psia. Less than 100,000 gallons of auxiliary feedwater are used during the event. The condensate storage tank capacity is greater than 300,000 gallons.

15C.4.4 Conclusions

The maximum RCS pressure is 2541 psia (including reactor coolant pump and elevation heads). This is well below 110% of design pressure.

Natural circulation is maintained for at least the 4 hour period that offsite AC power and diesel generator power are assumed unavailable. During this time voids are restricted to the reactor vessel head and subcooling is maintained in the hot leg.

The radiological release due to a Station Blackout results in no more than a 0.4 rem 4 hour inhalation thyroid dose at the exclusion area boundary.

The average RCS temperature at 4 hours is above 430°F. This is above the temperature at which the shutdown margin would be depleted. Therefore, the core remains subcritical following reactor trip for the duration of the event.

No fuel damage occurs during this event.

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Table 15C.4-1

SEQUENCE OF EVENTS, CORRESPONDING TIMES AND SUMMARY OF RESULTS FOR THE STATION BLACKOUT EVENT

Time (Sec)		Event	Setpoint or Value
0.0		Loss of all on - and off-site AC power	---
1.5		Low Primary Coolant Flow Reactor Trip, %	93
2.0		Auxiliary Feedwater Actuation Signal, % of Narrow Range Tap Span	5
2.4		Power Operated Relief Valve Opens, psig	2385
2.6		Maximum Core Power, %	104.8
5.5		Maximum RCS pressure, psia	2541
6.0		Maximum pressurizer pressure, psia	2460
6.3		Main Steam Safety Valves Open, psig	995
8.5	1.	Power Operated Relief Valve Closes, psig	2361
	2.	Total Primary Relief Valve Release, lbm	554
12.2		Maximum Secondary System Pressure, psia	1038
182.0		Auxiliary Feedwater reaches Steam Generators, gpm	500
1800.0	1.	Operator Opens and Controls Atmospheric Dump Valves, psia	900
	2.	Main Steam Safety Valves close, psig	945
	3.	Total Main Steam Safety Valve Release, lbm	116630

Table 15C.4-1 (continued)

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Time (Sec)		Event	Setpoint or Value
2258.0		Voiding Occurs in Reactor Vessel Head	---
8600.0		Operator Begins to Reduce Steam Generator Pressure to Maintain Hot Leg Subcooling	---
11785.0		Main Steam Isolation Valves close, psig	435.0
12540.0		Safety Injection Tanks actuated, psia	583.0
14400.0	1.	Operator Restores AC Power	---
	2.	Total Atmospheric Dump Valve Release, lbm	363300.0

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TABLE 15C.4-2

ASSUMED INITIAL CONDITIONS FOR
STATION BLACKOUT ANALYSIS

PARAMETER	ASSUMED VALUE
Initial Core Power Level, MWt	2630
Core Inlet Coolant Temperature, °F	551
Core Mass Flow Rate, 10^6 lbm/hr	133.9
Pressurizer Pressure, psia	2350
Initial Pressurizer Water Volume, % Level	40
Steam Generator Water Level, % of Narrow Range Tap Span	70
Doppler Coefficient Multiplier	0.85
Moderator Temperature Coefficient, 10^{-4} $\Delta\rho$/°F	
To determine initial power transient, 0- 10 seconds	+0.4
To determine degree of shutdown margin depletion	-2.7
CEA Worth for Trip, 10^{-2} $\Delta\rho$	6.68
Pressurizer Heat Loss, 10^6 BTU/hr	0.546
Primary Coolant Leakage, gpm:	16
Identified Leakage, gpm	
a) Technical Specification Steam Generator Tube Leakage	1
b) Primary Safety Valve Leakage	3
c) Other Identified Leakage	6
Unidentified Leakage	1
RCP Controlled Bleedoff	4
RCP Seal Leakage	1
	16

TABLE 15C.4-3
DISPOSITION OF NORMALLY OPERATING SYSTEMS FOR STATION BLACKOUT

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SYSTEM	NORMAL AUTOMATIC MODE THROUGH-OUT TRANSIENT	MANUAL MODE THROUGH-OUT TRANSIENT	NORMAL AUTOMATIC MODE INOPERATIVE ON LOSS OF A.C.	MANUAL MODE INOPERATIVE ON LOSS OF A.C.	FAILURE ASSUMED WITHIN SYSTEM	ASSOCIATED NOTES
1. Main Feedwater System			X			
2. Turbine-Generator Control System	X					
3. Steam Bypass Control System				X		
4. Pressurizer Pressure Control System				X		2
5. Pressurizer Level Control System				X		
6. Control Element Drive Mechanism Control System	X					
7. Reactor Regulating System				X		
8. Reactor Coolant Pumps				X		1
9. Chemical and Volume Control System				X		2
10. Condenser Evacuation System				X		
11. Turbine Gland Sealing System				X		
12. Component Cooling Water System						2
13. Turbine Cooling Water System				X		
14. Intake Cooling Water System						2
15. Condensate Transfer System				X		
16. Circulating Water System				X		
17. Spent Fuel Pool Cooling System				X		2
18. AC Power (Non-Safety)			X			
19. AC Power (Safety)					X	3
20. D. C. Power		X				
21. Power Operated Relief Valves	X					
22. Instrument Air System			X			2
23. Waste Management-Liquid				X		

NOTES:
1. RCP bleedoff is not isolated during this event.
2. Portions of these systems, powered by the safety bus on loss of AC, are not available due to the failure of both diesel generators.
3. Only the AC power supplied through the inverters is available.

TABLE 15C.4-4

UTILIZATION OF SAFETY SYSTEMS

FOR STATION BLACKOUT

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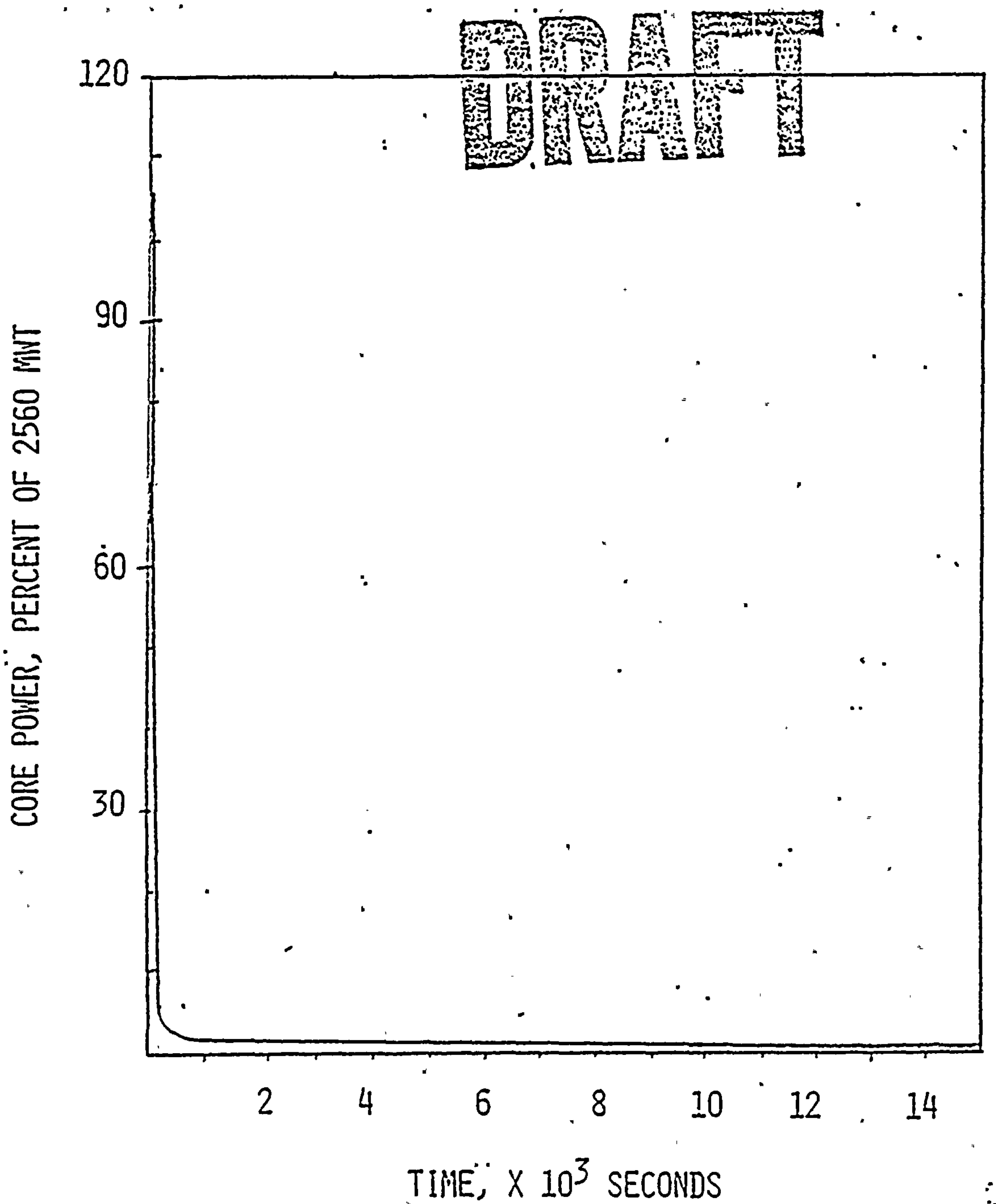
	ACTUATED AND REQUIRED	ACTUATED BUT NOT REQUIRED	SAFETY GRADE BACKUP TO NONSAFETY GRADE SYSTEM	FAILURE ASSUMED WITHIN SYSTEM (SEE NOTES)	ASSOCIATED NOTES
1. Reactor Protection System	X				
2. Engineered Safety Features Actuation Systems					2
3. Diesel Generators and Support Systems				X	1
4. Reactor Trip Switch Gear	X				
5. Main Steam Safety Valves	X				
6. Pressurizer Safety Valves			X		
7. Main Steam Isolation Valves		X			2
8. Main Feedwater Isolation Valves			X		
9. Auxiliary Feedwater System	X				2,4
10. Safety Injection System		X			3
11. Shutdown Cooling System (CCW & ICW)					
12. Atmospheric Dump Valve System	X				5
13. Containment Isolation System		X			6
14. Containment Spray System					
15. Iodine Removal System					
16. Containment Combustible Gas Control System					
17. Containment Cooling System					

Notes:
1. Both diesel generators fail for this event.
2. Only those portions powered from the safeguard batteries are available.
3. Safety Injection Tanks are available.
4. Auxiliary Feedwater is automatically actuated. Only the turbine driven pump is available.
5. ADVs can be manually operated from the control room.
6. Portions of this system are actuated on loss of instrument air.

Systems not checked are not utilized during this event.



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ST. LUCIE PLANT UNIT 2

CORE POWER VS TIME
FIGURE 15C.4-1

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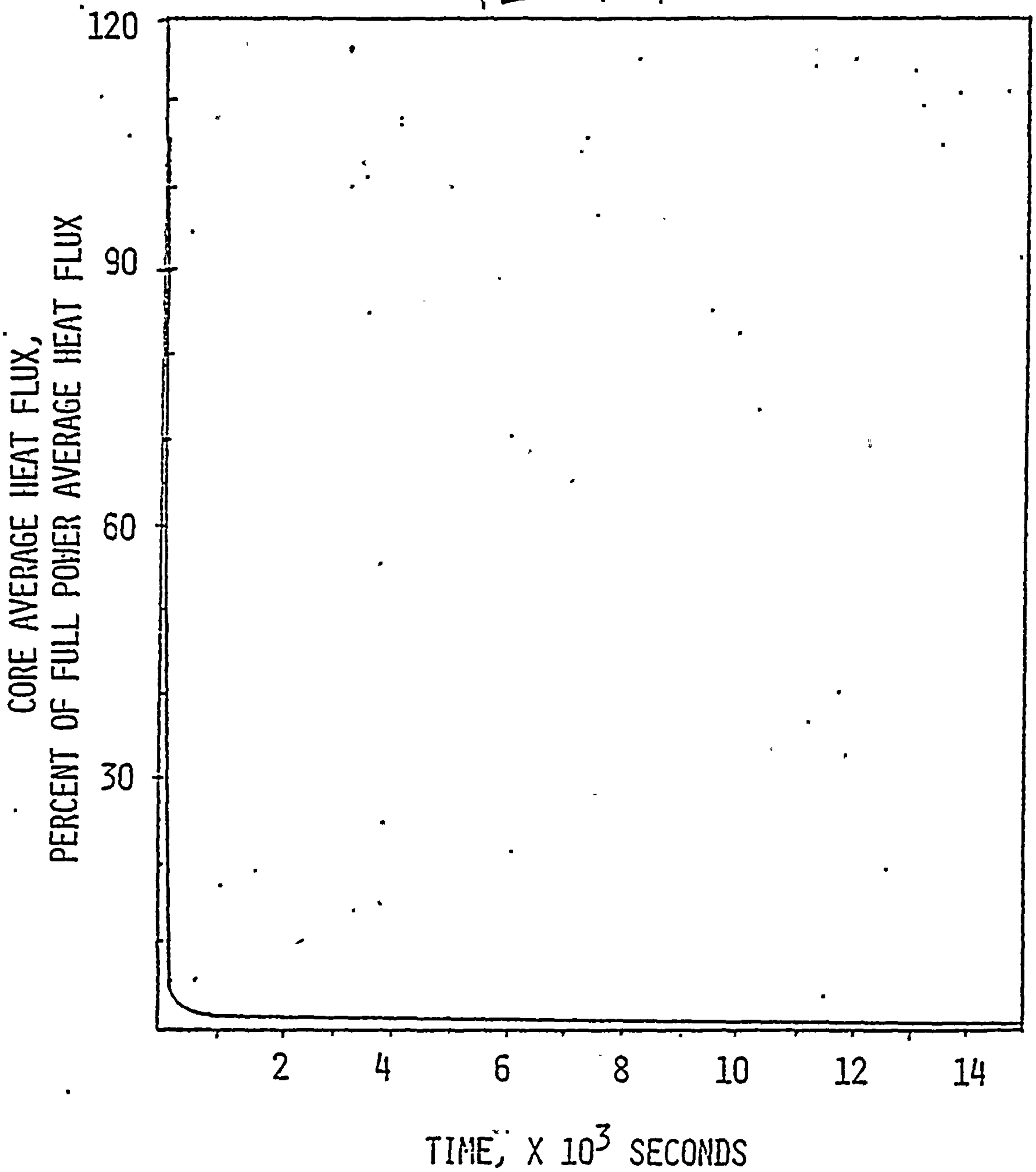

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CORE AVERAGE HEAT FLUX VS TIME

FIGURE 15C.4-2

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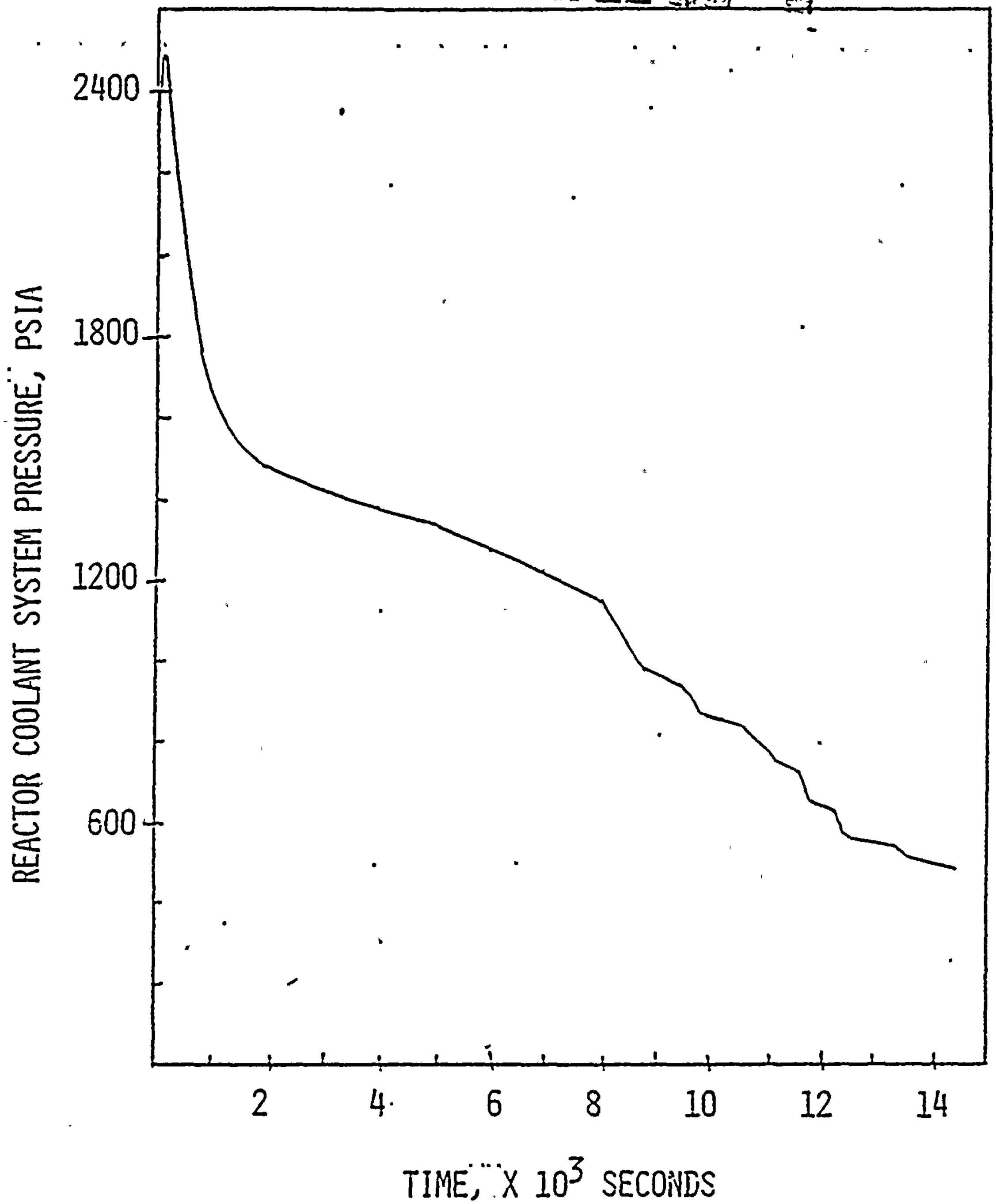

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REACTOR COOLANT SYSTEM
PRESSURE VS TIME

FIGURE 15C.4-3

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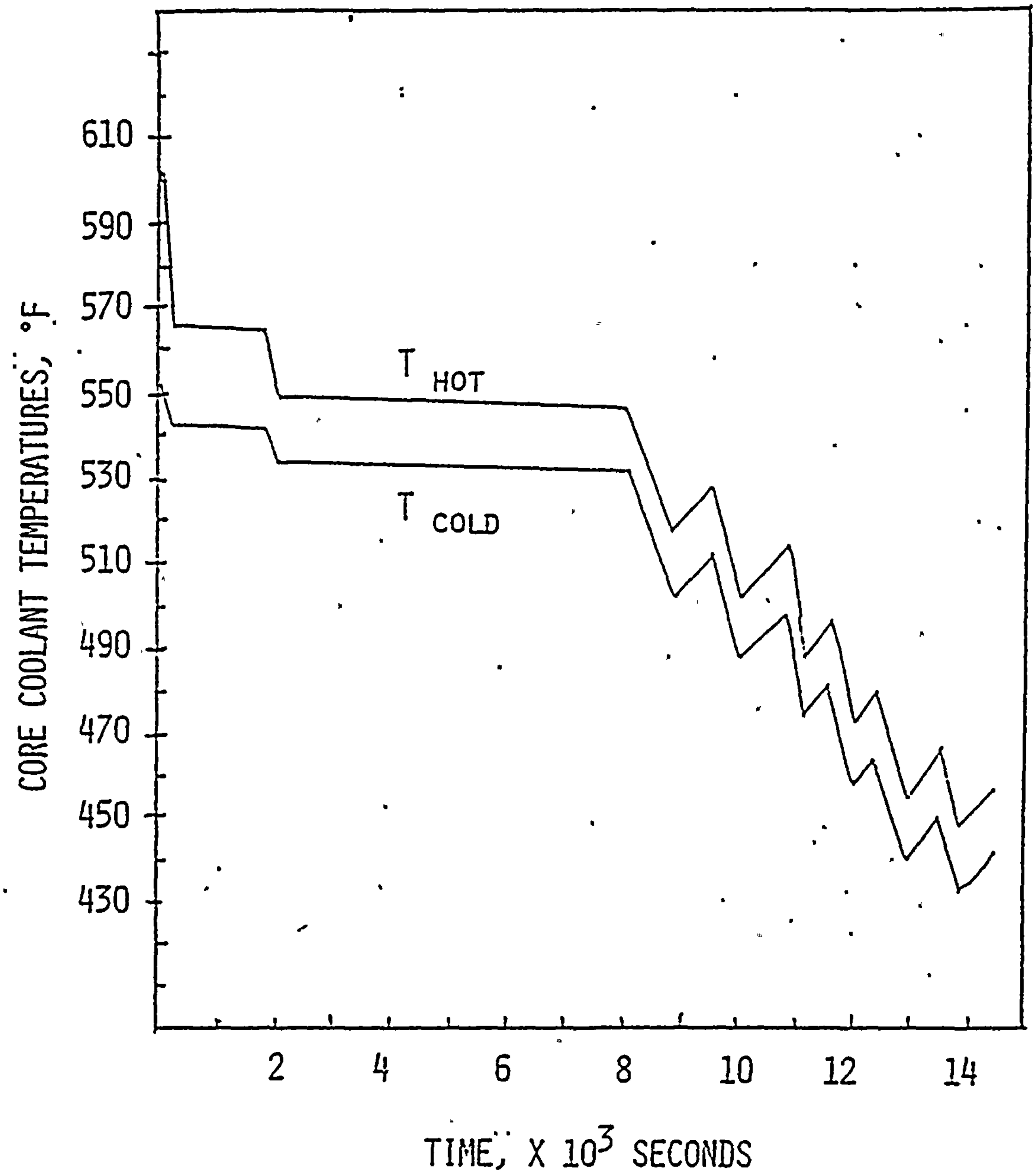

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CORE COOLANT TEMPS VS TIME
FIGURE 15C.4-4

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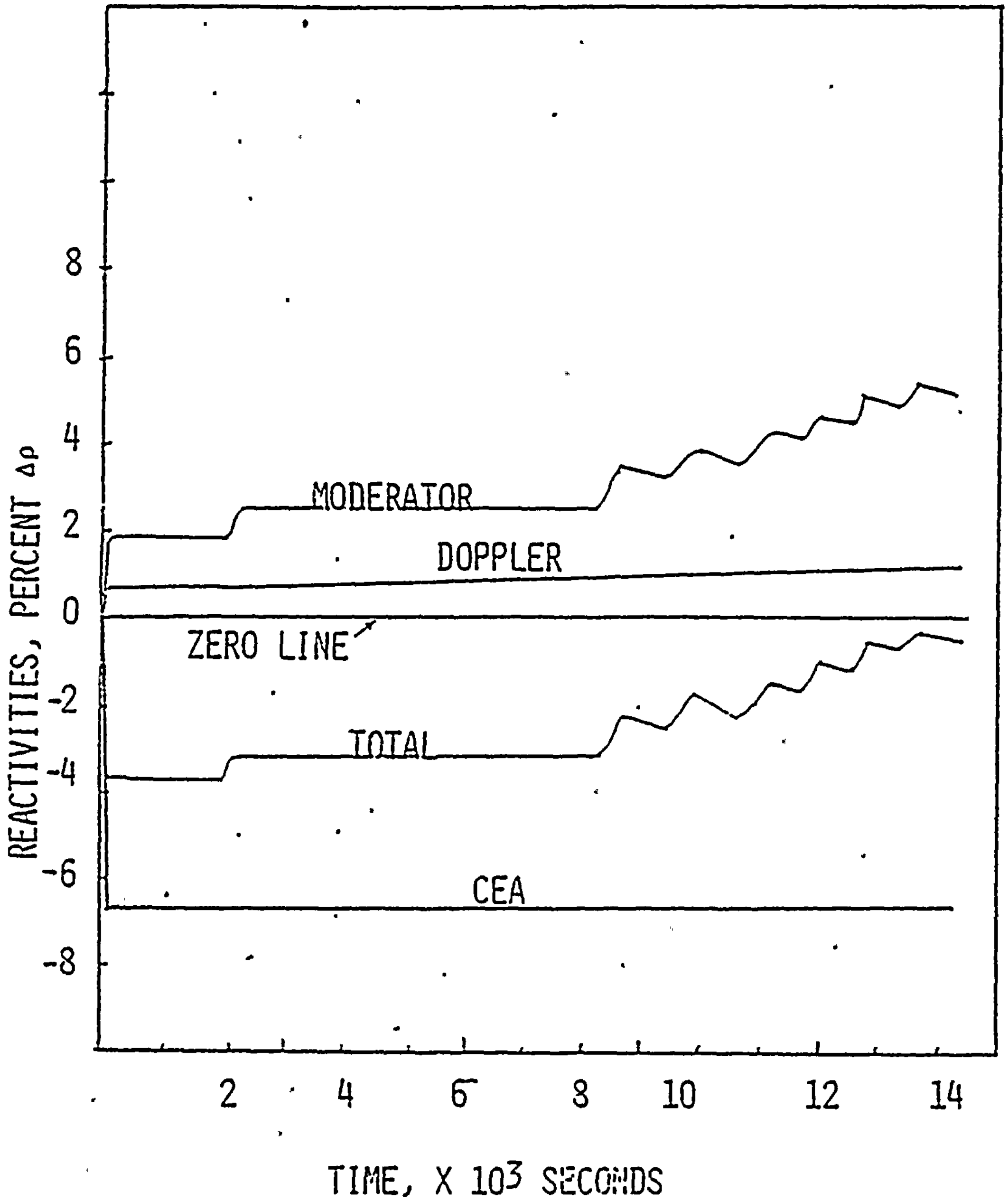

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REACTIVITIES VS. TIME
FIGURE 15C.4-5

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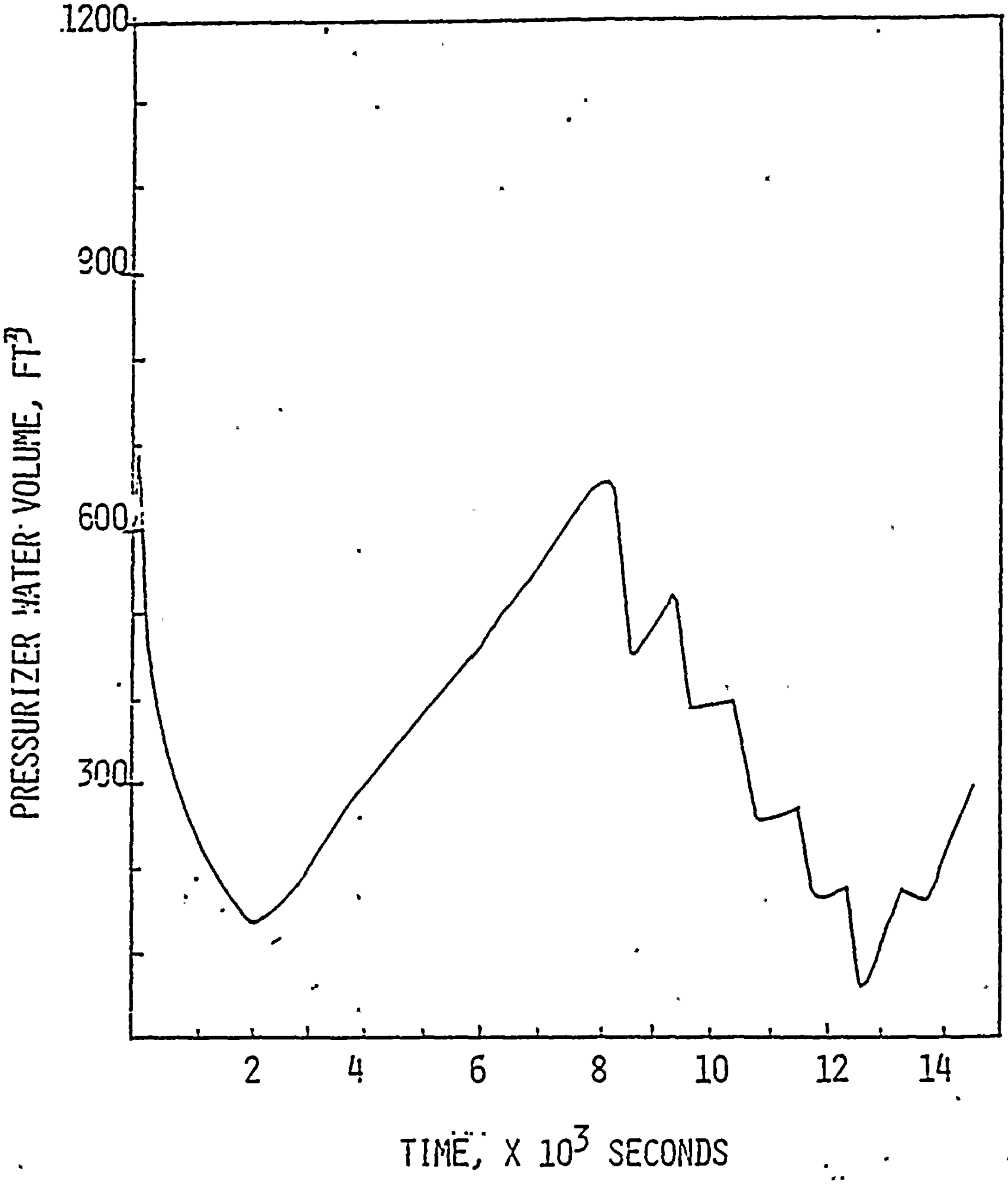

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PRESSURIZER WATER VOLUME VS. TIME
FIGURE 15C.4-6

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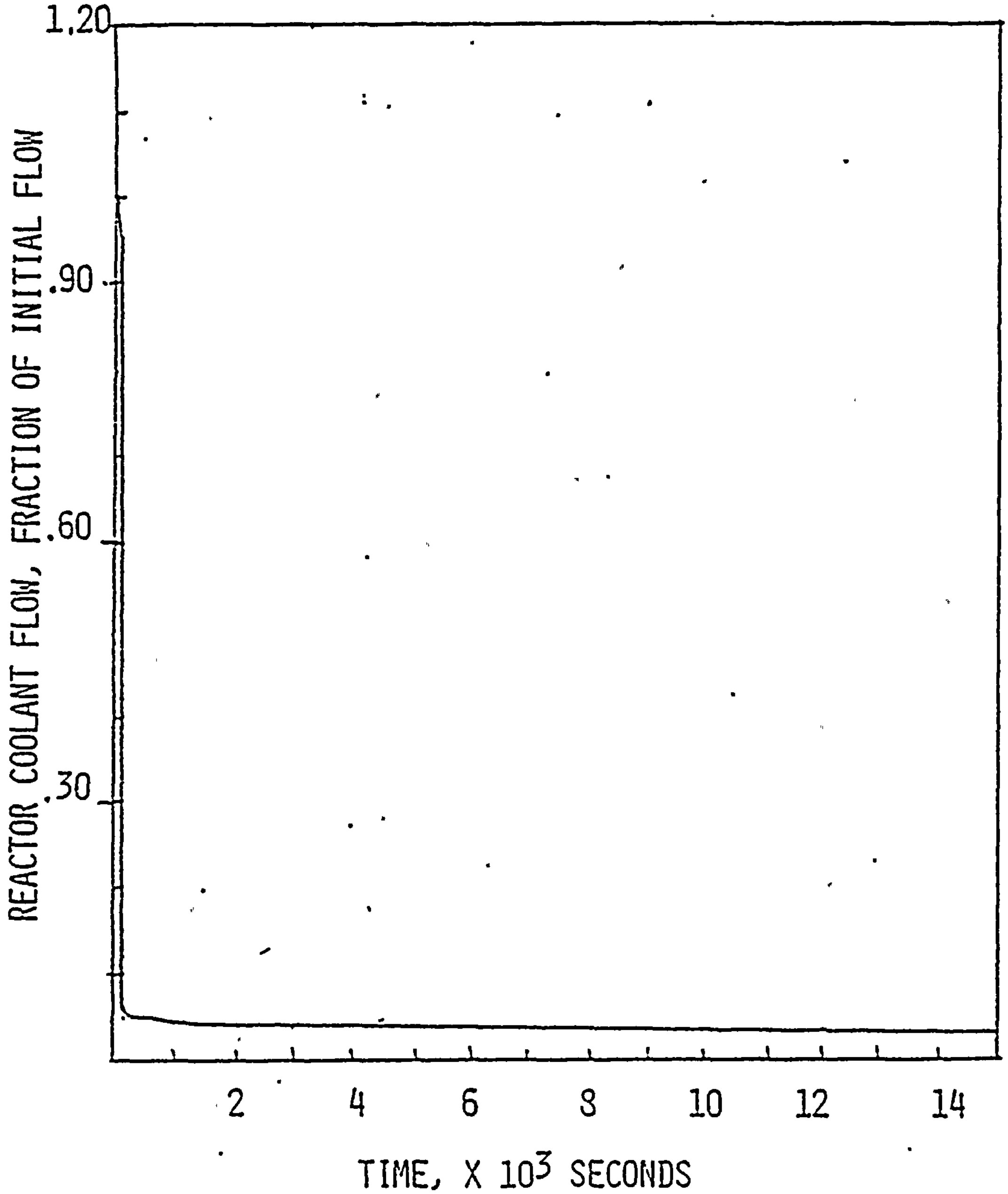

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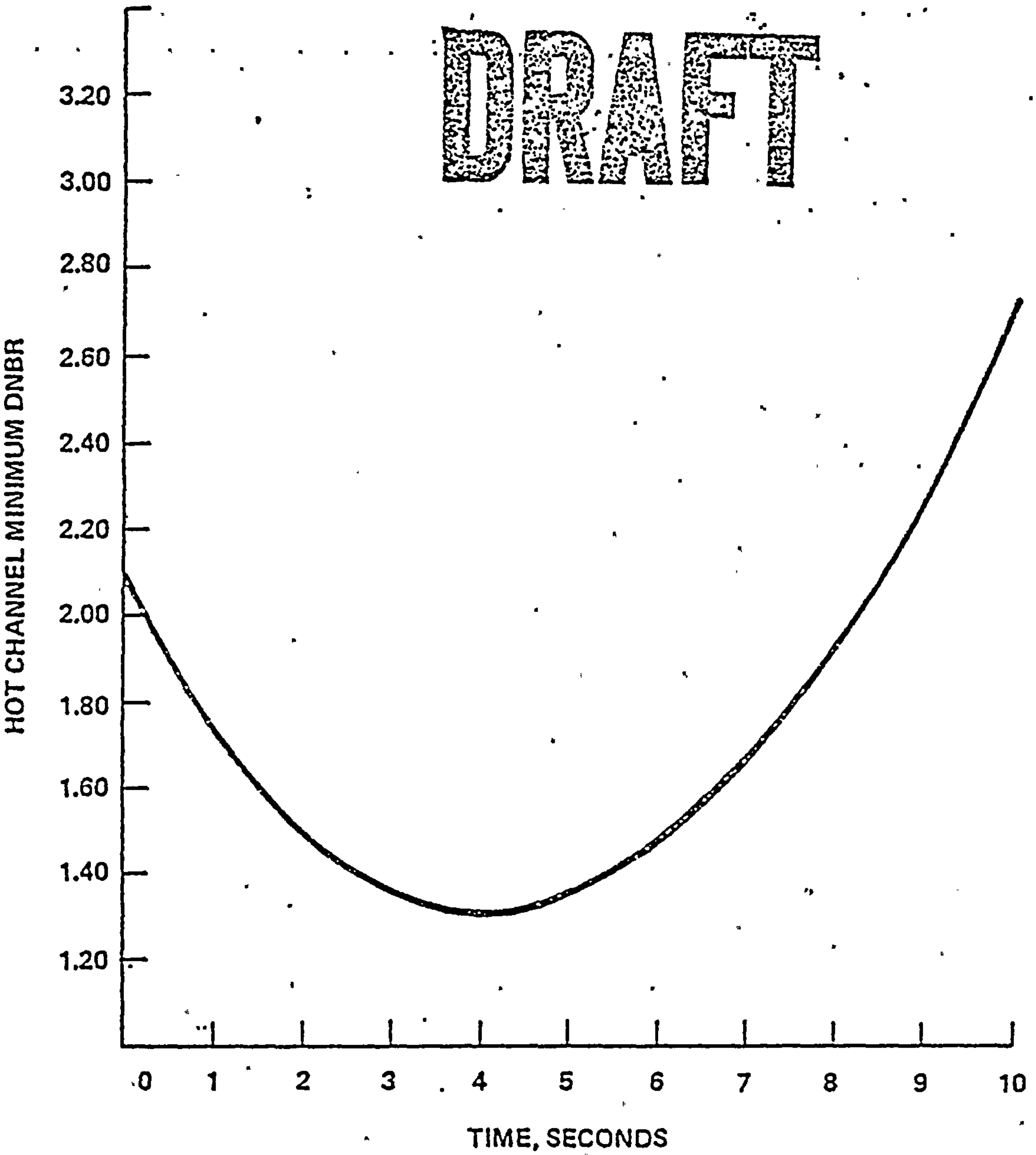
REACTOR COOLANT FLOW VS. TIME
FIGURE 15C.4-7



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HOT CHANNEL MINIMUM DNBR
VS. TIME
FIGURE 15C.4-8

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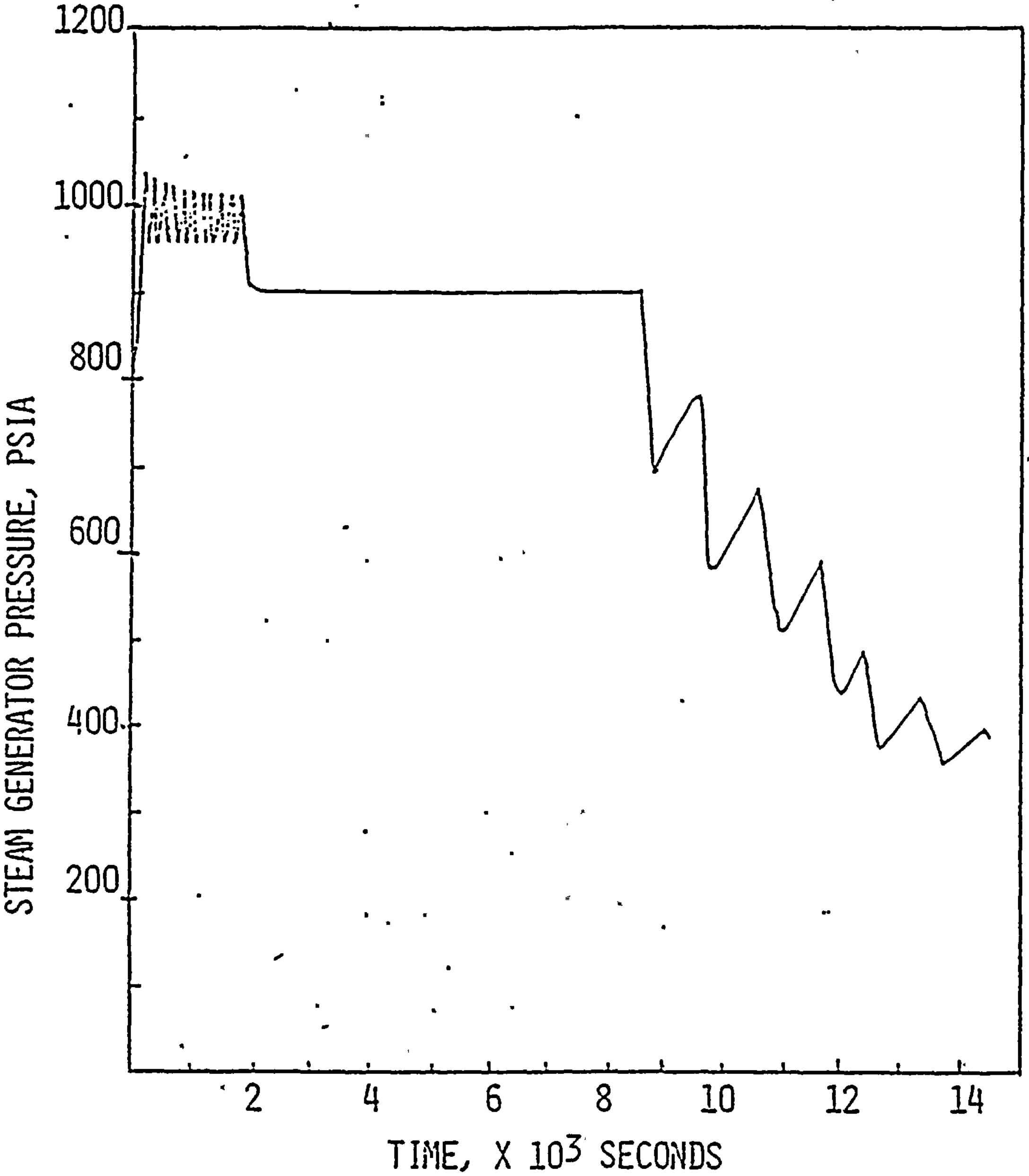

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STEAM GENERATOR PRESSURE VS. TIME

FIGURE 15C.4-9

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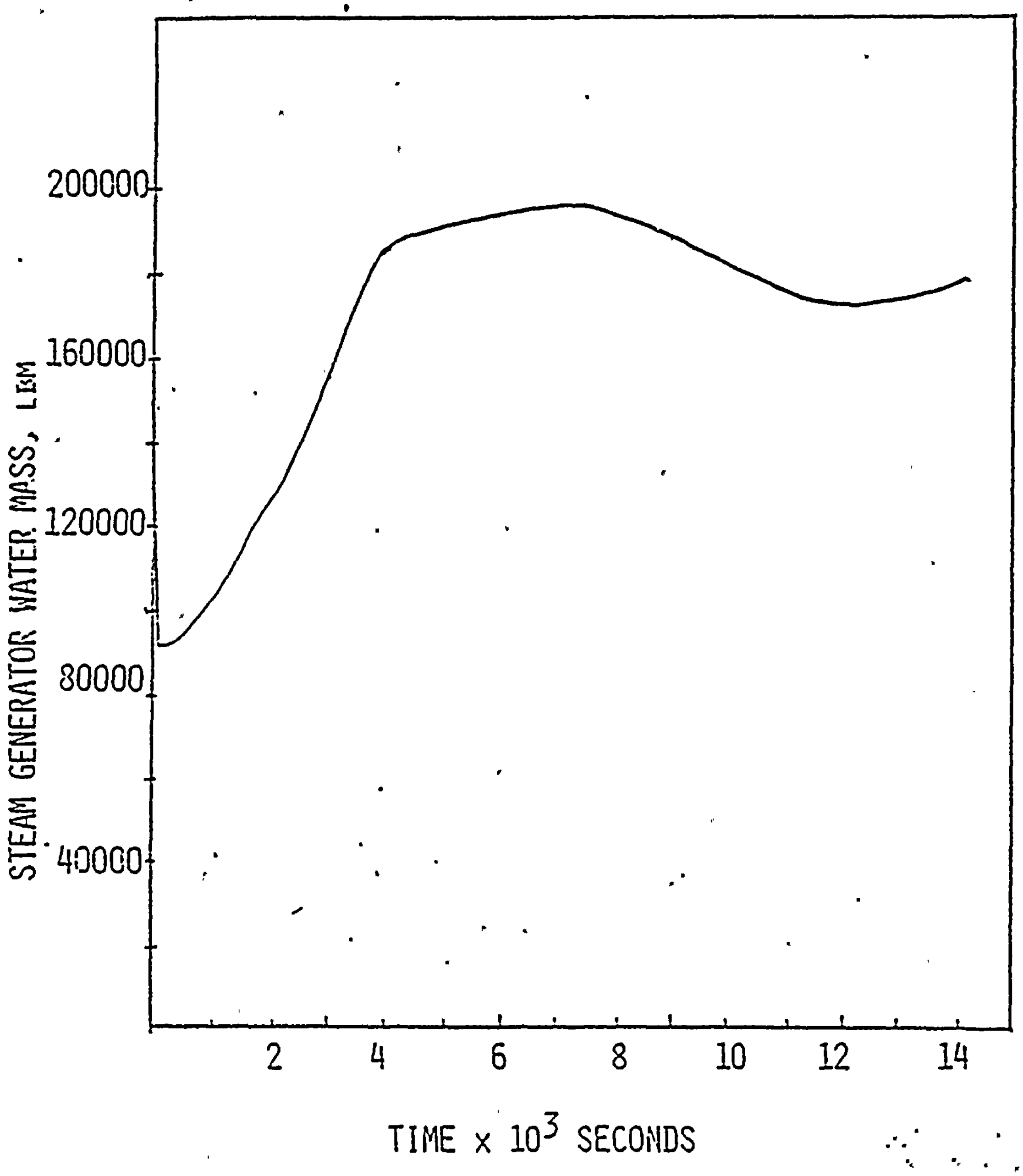

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STEAM GENERATOR WATER MASS, VS. TIME
FIGURE 15C.4-10

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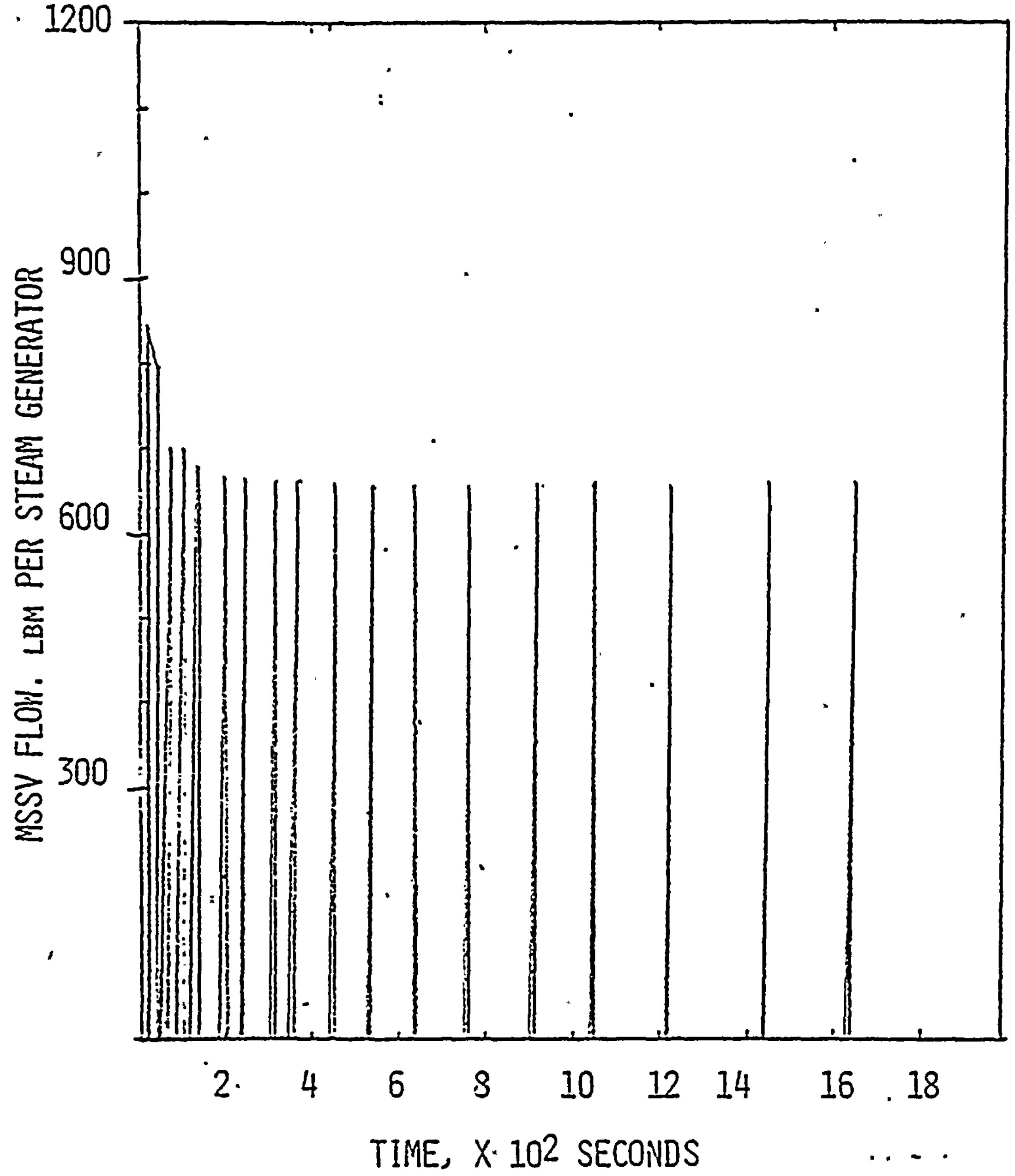

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MSSV FLOW VS. TIME
FIGURE 15C.4-11

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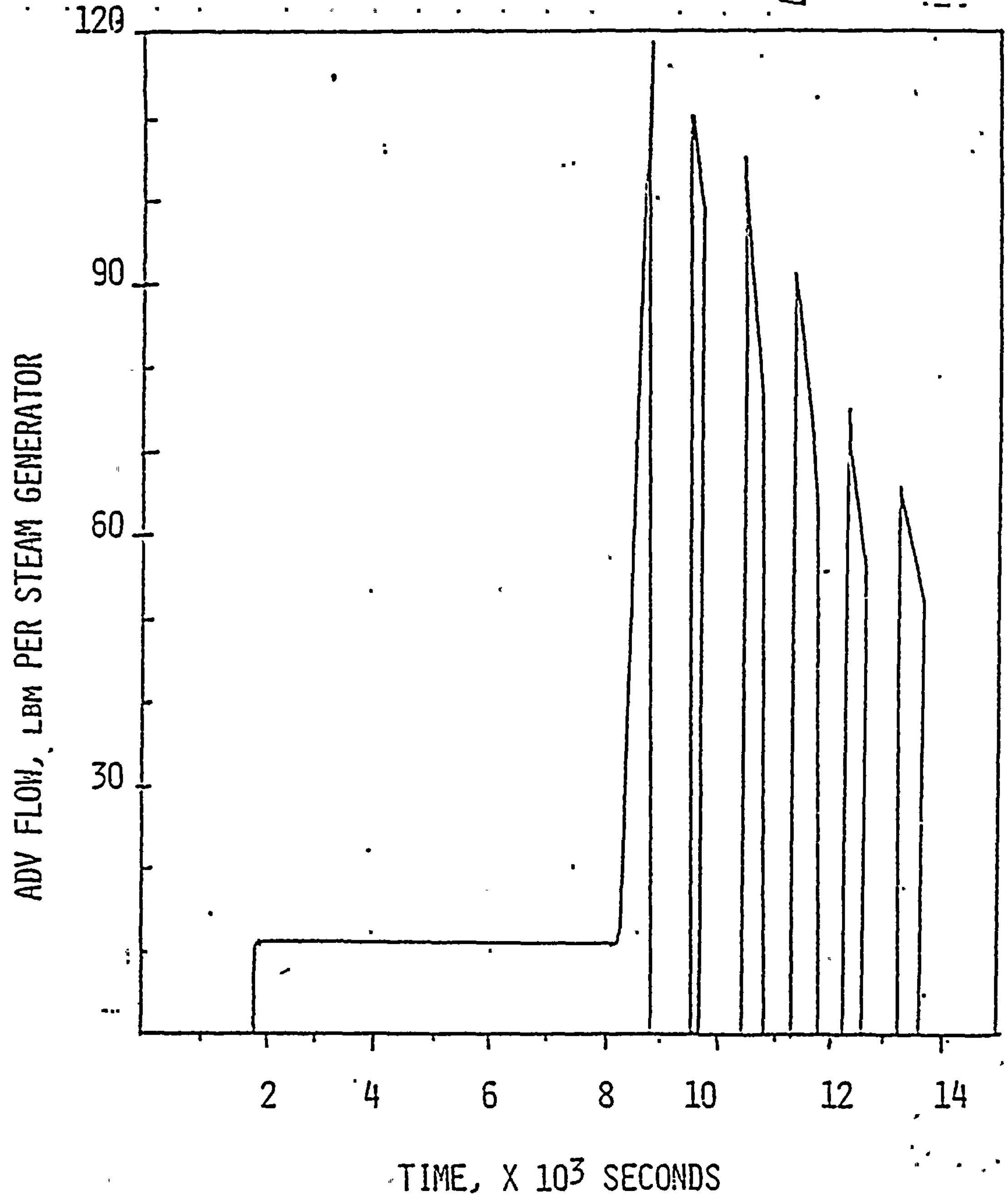

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ADV FLOW VS. TIME
FIGURE 15C.4-12

FLORIDA POWER & LIGHT CO.
ST. LUCIE UNIT 2

BLACKOUT OPERATION

REV.	FRG.	DATE
APPROVAL	PLT. MNGR.	DTD.

Emergency Procedure
2-0120042 Rev.0

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FLORIDA POWER & LIGHT COMPANY
ST. LUCIE UNIT 2
EMERGENCY PROCEDURE NUMBER 2-0030140
REVISION 0

Draft 1
06/12/81 dps

1.0 SYMPTOMS

.1 Alarms associated with the loss of operating plant components.

.2 Loss of normal control room lighting and DC lighting energized.

.3 Reactor and turbine trip.

.4 Emergency diesel generators start

.5 Reactor coolant pump trip and steam generator feed pump trip.

.6 Reactor Power decrease

.7 Przr. pressure decrease

.8 T Ave decrease

.9 Przr. level decrease

10 Stm. Gen. Press increase

11 Stm. Gen. level decrease

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EMERGENCY PROCEDURE NUMBER 2-0030140
REVISION 0

2.0 IMMEDIATE OPERATION ACTION

2.1

IMMEDIATE	EQUIPMENT	POSITION
Trip	Turbine/REactor Push Buttons	Tripped
Ensure	Full Length CEA's	Inserted
Ensure	Reactor Trip Breakers	Open
Ensure	Turbine Valves	Closed
Ensure	240W40349, 240W40352, Gen. Bkrs.	Open
Close	Reheater Control TCV's MV-08-4, 6, 8, 10	Closed
Ensure	D.G. 2A, 2B	Running
	AND	
Ensure	Bkrs. 20211, 20401	Closed
Open	S.U. Brkrs. 20102, 30102, 20101, 30202	Open
Ensure	T Ave	Decreasing
Ensure	Atmospheric Steam Dump	Operating
Close	S/G Blowdown Valves	Closed
Start	*1. Aux. FDWTR. (Steam Driven)	Start
Ensure	2. Automatic Actions per. sect. 3.0	Actuated
	2. Or Table 8.3-2 (Dies. Gen. Sequence)	Running

NOTE:

*1. If aux. fdwtr. pps have started due to the auto start feature, the motor driven pumps may be secured 30 sec. after they start .

2. Manually initiate any auto action that does not occurr.

3. If vital indications and/or controls are lost refer to OP.Proc. 2-0970020, 2-0970021 (120V-AC.) or 2-0960020, 2-0960022 (120V-DC.)

EMERGENCY PROCEDURE NUMBER 2-0030140
REVISION 0

2.0 IMMEDIATE OPERATION ACTION: (Cont.)

2.2 IMMEDIATE AUTO ACTION — Check

Reactor and turbine trip, generator lockout ________

Generator breakers open. 240W40349, 240W40352 ________

Incoming feeder breakers open to 6900 V and 4160 V buses. ________

Tie breakers between Normal 4160 buses 2A2 and 2B2 and the emergency 4160 V buses (2A3 and 2B3) open. ________

Ties between essential and non-essential sections of emergency 480 V MCC's open. ________

Breakers open for the following non-safety related loads which are normally fed from emergency buses. ________

NOTE: These loads can be manually reconnected to the emergency buses as needed.

* Charging Pump ________

* B. A. Makeup Pumps ________

* Instr. Air. Comp. ________

Przr. heater transformers 2A3 and 2B3

Fire pump 1A and 1B

CEA Drive M.G. 2A & 2B

Fuel Handling 480 V MCC 2A8, 2B8

Reactor Cavity sump pump

Reactor building elevator

Electrical equipment room hoist

120/208 power panel 121 transformer

Lighting panel transformers 110, 112, 114, 117, 125, 126

2.0 IMMEDIATE OPERATION ACTION: (Cont.)

2.2 Immediate Auto Action: (Cont.)

Incoming feeder from 2A2 & 2B2 4160V buses

RCP oil lift pumps (B pumps only - A pumps running)

Airborne radioactivity removal fans HVE-1&2

Przr. relief isol valves 1404 & 1405

CVCS heat tracing transformer 2A & 2B

480V Lighting panel 2A, 2B & 2C

Waste management heat tracing transformers 2A & 2B

Air conditioner 2HVA/ACC-3C.

Power panel 120

Lighting panels 113, 116, 109, 115, 130

Refueling equipment

Refueling water to charging pumps V-2504

Boric Acid batching tank heaters

Fire siren

All loads on emergency buses are tripped except the following:

Emergency lighting ____________

Class I power panels ____________

RCP oil lift pumps (A pumps only - B pumps off) ____________

Diesel fuel transfer pump. ____________

Diesel generators A & B start and energize 4160 V emergency buses 2A3, 2B3, and 2AB and loads listed above ____________

EMERGENCY PROCEDURE NUMBER 2-0030140
REVISION 0

2.0 IMMEDIATE OPERATION ACTION: (Cont.)

2.2 Immediate Auto Actions: (Cont.)

Subsequent loads are started at 3 second intervals. See Table 8.3.2, Emergency Diesel Generator Loading Sequence.

Auxiliary Feedwater auto start sequnce initiates when the first steam generator level decreases to 34%.

NOTE: Pump start and flow initiation is delayed for 3 minutes. Pumps may be started by the operator AT ANY TIME.

TABLE 8.3-2

DIESEL GENERATOR LOADING SEQUENCE[5]

Item	Automatic Starting Equipment (4)	Per Diesel Generator Quantity	Nominal Load or Nameplate HP	Starting KVA	Timing Sequence	Running Load (kW): Shutdown With Loss of Off-Site Power (LOOP)	Running Load (kW): LOCA (Recirculation) With Loss of Off-Site Power (LOOP)	Running Load (kW): Main Steam Line Break With Loss of Offsite Power (LOOP)
1	High Pressure Safety Inj Pump	1	400	2422.0	0 Sec	–	373	373
2	Motor Operated Valves	Lot	40	Later	0 Sec	40	8 (1)	80
3	Emergency Lighting	Lot	–	–	0 Sec	70	70	70
4	Power Panels	Lot	–	–	0 Sec	30	30	30
5	Diesel Oil Transfer Pumps	1	3	21.5	0 Sec	3	3	3
6	RCP Oil Lift Pumps	4	10	66.85	0 Sec	19	19	19
7	Uninterruptible Power Supply	1	–	–	0 Sec	20	20	20
8	HVAC Dampers	Lot	–	–	0 Sec	4	4	4
9	HVAC Valves	Lot	–	–	0 Sec	3	–	3
10	Elec Equip. Room Exhaust, 2-HVE-11	1	50	244.7	0 Sec	47.5	47.5	47.5
11	Elec Equip. Room Exhaust, 2-RV-3	1	5	34.22	0 Sec	5	5	
12	Battery Room Roof Ventilator, 2-RV-1	1	0.75	8.5	0 Sec	.75	.75	.75
13	Low Pressure Safety Inj. Pump	1	400	2183.3	3 Sec	–	–	361
14	Containment Fan Coolers	2	125/83	828.4	3 Sec	160	116	116
15	Elec Equip. Room Supply	1	100	584.12	3 Sec	95	95	95
16	Component Cooling Water Pump	1	450	2491.2	6 Sec	400	400	400
17	[illegible]	1	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
18	Shield Bldg Heaters	Lot	–	–	6 Sec	–	37.5	37.5
19	Intake Cooling Water Pump	1	600	3709.0	9 Sec	527	527	527
20	Containment Spray Pump	1	500	2892.6	12 Sec	–	450	450
21	Hydrazine Pump	1	3	21.5	12 Sec	1	1	1

TABLE 8.3-2 (Cont'd)

Item	Automatic Starting Equipment (4)	Per Diesel Generator Quantity	Nominal Load or Nameplate HP	Starting KVA	Timing Sequence	RUNNING LOAD (kW) Shutdown With Loss of Off-Site Power (LOOP)	LOCA (Recirculation) With Loss of Off-Site Power (LOOP)	Main Steam Line Break With Loss of Offsite Power (LOOP)
22	Auxiliary Feedwater Pump	1	350	1951.4	15 Sec	297	297	297 (2)
23	Boric Acid Heat Trace	Lot	Lot	-	18 Sec	5	5	5 (3)
24	Control Room Air Conditioning	1	60	-	18 Sec	57	57	57
25	Control Room Emerg Filter Fan	1	10	62.0	18 Sec	9.5	9.5	9.5
26	RAB Supply Fan	1	150	900.1	18 Sec	142.5	142.5	142.5
27	ECCS Area Exhaust Fan	1	60	358	18 Sec	57	57	57
28	Reactor Cavity Supply Fan	1	20	124.15	18 Sec	19	-	-
29	Reactor Supports Cooling	1	40	234.76	18 Sec	38	-	-
30	Intake Bldg Cooling Fan	1	7.5	44.0	18 Sec	5	5	5
31	Battery Charger	1	3	-	-	73.5	73.5	73.5
32	Charging Pumps	2	125	1656.8	Manual load	237.5	237.5	-
33	Boric Acid Make-Up Pump	1	25	124.1	Manual load	23.75	23.75	-
34	Low Pressure Safety Inj. pump	1	400	2183.3	Manual load	309	-	-
35	Instrument Air Compressor	1	60	340.6	Manual load	57	-	-
36	Fuel Pool Cooling Pump	1	40	234.76	Manual load	38	38	-
37	Hydrogen Recombiner	1	-	-	Manual load	-	75	-
				Total		3144.0 kW	3274.25 kW	3335.53 kW

Notes:

1) Actuated on RAS
2) Started if operating prior to LOOP
3) Approximate kW required for temperature maintenance
4) Items 32 to 37 inclusive are manual loads
5) Items identified as "Later" will be supplied in a future amendment.

Page 2 of 4

3.0 SUBSEQUENT ACTIONS:

3.1 Ensure adequate natural circulation flow

(a.) Loop T is less than full power T (<44^{0}F)

(b.) T_c is constant or decreasing

(c.) T_h is stable or decreasing

(d.) No adnormal differences between T_c-RTD's and core exit thermocouples.

3.2 If natural circulation is not assured

(a.) Check RCS Temperature/Pressure to ensure subcooling.

(b.) Ensure aux. feed flow to the S/G has been initiated, steam dump to atmosphere is functioning. __________

3.3 Start one RCP in each loop, as soon as offsite power is available.

3.4 Start or stop equipment in Table 8.3-2 as required __________

CAUTION:

Do not overload diesel generators when starting additional equipment. (3685 KW max. cont. rating.

3.5 If one diesel fails to start, then

(a.) Attempt manual start

(b.) Send operator to investigate locally check alarms, overspeed trip, local manual start. CHECK

Refer to Op. Procedure 2-2200020, 2-2200050 __________

3.6 Locally OPEN (Condenser vacuum brkrs)

MV 10-1A __________

MV 10-1B __________

EMERGENCY PROCEDURE NUMBER 2-0030140
REVISION 0

3.0 SUBSEQUENT ACTIONS: (CONT.)

CHECK

3.7 Locally CLOSE (M.S.R. Main Steam Block Valves)

MV-08-4 ________

MV-08-6 ________

MV-08-8 ________

MV-08-10 ________

3.8 MSR Warm-up valves closed or close manually

MV-08-5 ________

MV-08-7 ________

MV-08-9 ________

MV-08-10 ________

3.9 Verify one (1) set of cavity and support cooling fans operating, or start.

3.10 Lock out automatic equipment that is not in service. ________

3.11 Manually open all breakers on any non-vital bus or motor control center that is to be energized. ________

3.12 Reset lockout relays for each required bus to allow closing of feeder breakers. ________

3.13 Energize 4160V buses 2A2, 2B2 as follows:

Strip non-vital 4.16 KV bus brkrs.
(All should be opened automaticlly)
Insert sync. plug.

Close 2-20109 ________
Close 2-20309 Hold and ________
Close 2-20209 ________
Close 2-20411 ________

EMERGENCY PROCEDURE NUMBER 2-0030140
REVISION 0

3.0 SUBSEQUENT ACTIONS: (Cont.)

3.14 Energize non-vital load centers 2A1, 2B1 as follows:

	CHECK
Strip load centers 2A1, 2B1	____
Close 2-20110	____
Close 2-20310	____

3.15 Energize 480V-MCC's 2A1, 2B1,2A4, 2B4, 2C as follows:

Strip MCC's, 2A1, 2B1, 2A4, 2B4, 2C	
Close 2-40115	____
Close 2-40410	____
Close 2-(later)	____
Close 2-(later)	____
Close 2-40119 or 40409	____

3.16 At MCC-2C Close breakers for:

Turning gear - 42510	____
Bearing oil pump - 42506	____
Air side seal oil pump - 42507	____
Hydrogen side seal oil pump-42504	____

3.17 Place turbine TCW pp in operation	____
3.18 Align TCW system to the instrument air compressor back to normal	____
3.19 Place turbine drain valve control to the open position.	____

3.20 Before turbine bearing oil pressure drops to 12 psig.

Start - bearing oil pump, IF oil pressure drops to 10 psig.	____
Start - emergency D.C. oil pump Do not run both pumps simultaneously.	____

3.21 Remove the following components from service.

a.) Steam jet air ejectors	____
b.) Priming ejector	____
c.) Aux. Priming ejector	____
d.) Aux. Steam to R.A.B.	____
e.) Gland Seal	____

3.0 SUBSEQUENT ACTIONS: (Cont.)

3.21 (Cont.)

CAUTION:

Consider equipment starting requirements. Alternate operation of equipment may be required to avoid overloading the diesel generators (3685 KW. max. cont. rating)

		CHECK
3.22	Start CEDM cooling fans A or B	________
3.23	Start reactor support cooling fans A & B	________
3.24	Close breakers for pressurizer heater buses	
	2-20204	________
	2-20403	________
3.25	At approx. 600 RPM turbine speed	
	Bearing oil lift pump - start	________
3.26	Start - turbine lube oil vapor extractor	________
	generator oil vapor extracktor	________
3.27	At approx. 0 RPM turbine speed verify turning gear operation or initiate manually.	________
3.28	Reduce turbine oil temperature to 95-100^{0}F.	________
3.29	Isolate TCW to the hydrogen coolers.	________

3.30 If additional CST water is required and sufficient power is available, place the water treatment plant in service.

NOTE: Refer to OP.Proc. 2-0030142

3.31 Place the spent fuel cooling system in operation as necessary.

NOTE: With 3 1/3 fuel cores stored, it will take 5 hours without cooling before reaching the boiling point.

EMERGENCY PROCEDURE NUMBER 2-0030140
REVISION 0

3.0 SUBSEQUENT ACTIONS: (Cont.)

	CHECK
3.32 Sample and analyze the RCS to determine if fuel element failure has occurred	______

NOTE: Periodically verify oil storage and transfer operations.

3.33 Determine expected duration of power outage. If unable to do so or the outage is to be extensive, borate the RCS to cold shutdown concentration.	______

3.34 If the outage will exceed 4 hours and the RWT is available, proceed to cold shutdown conditions utilizing thermal circulation, atmospheric steam dump, and feedwater addition. Place S.D. cooling in service when conditions permit. Proceed to step 4.43.

CAUTION

DO NOT BEGIN PLANT COOLDOWN UNTIL COLD SHUTDOWN B_c IS VERIFIED.

3.35 If the outage will exceed 4 hours and the RWT is not available, the S.I.T.'s should be used for makeup to the RCS. Make the following preparations.

3.36 Verify operation of the instr. air systems.

	CHECK
3.37 OPEN 480V A.C. brkrs for:	
MV-2504-	______
MV-2501-	______
3.38 OPEN and lock	
S.I.T test line return to RWT V-07009	______
S.I.T test line return to RWT V-3463	______
S.I.T test line tie to VCT V-03920	______

EMERGENCY PROCEDURE NUMBER 2-0030140
REVISION 0

3.0 SUBSEQUENT ACTIONS: (Cont.)

CAUTION:

Insure that one BAMT remains in service as a source of borated water in Mode 5.

3.39 Borate the RCS to cold shutdown B_c.

3.40 Proceed to cold shutdown conditions utilizing thermal circulation, atmospheric dump and aux. fdwtr addition.

	CHECK
3.41 Select a S.I.T. to use as a makeup source to the VCT. Operate the appropriate fill and drain valve, 2A1, -AOV-3621, 2A2, -AOV-3611, 2B1, -AOV-3631, 2B2, -AOV-3641	______

CAUTION:

USE ONE S.I.T AT A TIME. Insure RCS is >1750 PPM.

3.42 Place shutdown cooling in service when appropriate temperatures and pressures are reached.

3.43 If przr. cooldown cannot be accomplished satisfactorily by ausiliary spray, proceed with the alternate positive means of depressurization as follows:

	CHECK
a.) Place power operated relief valve V1402 and V1404 switches in: overide	______
b.) Initiate a high przr. pressure trip signal on two RPS channel trip units.	______
c.) Place either power operated relief valve (V1402 or V1404) switch in normal range position.	______
NOTE: This will vent the pressurizer to the quench tank.	
To close valve, place switch in override	______
d.) Control rate of cooldown/depressurization by selective operation of power operate relief valves in this mode, until cooldown vie the aux. spray valves can be initiated	______

EMERGENCY PROCEDURE NUMBER 2-0030140
REVISION 0

3.0 SUBSEQUENT ACTIONS: (Cont.)

3.44 When normal AC power is available

	CHECK
a.) Restore bus sections to normal supply	______
b.) Place diesel generator system in standby per 2-2200020	______
c.) Restore all systems to normal	______

4.0 PRECAUTIONS:

A. Monitor diesel oil storage tank levels.

B. Verify operation of the fuel oil transfer system.

C. Do not overload the diesel when starting additional equipment (3685 KW-max. continuous rating)

D. Insure that one BAMT remains in service to use as a source of borated water while in mode 5.

E. If an S.I.T. is to be used as a make-up source, use only on at a time. Insure RCS is at >1750 PPM before using a second S.I.T.

5.0 PURPOSE AND DISCUSSION:

This procedure provides the action to be taken in the event of a complete loss of off site electrical power concurrent with a turbine trip.

Discussion

A loss of power to the 4160 V buses, results in a loss of power to all 480 V load centers and motor control centers and to all instrumentation not fed directly or indirectly from the station battery. A reactor trip will occur from a low reactor coolant flow rate signal due to the loss of power to the 6900 V buses supplying the reactor coolant pumps and will be accompanied by a turbine trip and generator lockout.

Steam dump to atmosphere must be used to remove reactor decay heat. Initially, steam generator safety valves may actuate to augment the steam flow and to help control steam generator pressure immediately after the trip.

5.0 PURPOSE AND DISCUSSION: (Cont.)

On site power will be supplied by Emergency Generators.

A rapid reduction in steam generator water levels will occur due to the reduction of the steam generator void fraction on the secndary side and also because steam flow will continue after normal feedwater flow stops. Auxiliary feedwater flow will automatically initiate 3 minutes after the irst steam generator level reaches 34% (2/4 logic).

Core decay heat removal is accomplished by natural circulation in the reactor collant loops.

Core damage is not expected as a result of a loss of power condition as the steam generators are maintained as a heat sink and no loss of water occurs from the pressurizer.

If operating under blackout conditions and an engineered safety features actuation signal occurs, any non emergency loads that are running will be automatically tripped and the required emergency loads will be automatically started.

6.0 REFERENCES:

6.1 FSAR, Section 15

6.2 FSAR, Section 8

6.3 Operating Procedure #0030130, Shutdown Resulting From Reactor/Turbine Trip

6.4 Operating Procedure #0210020, Charging and Letdown

6.5 Operating Procedure #0330020, Turbine Cooling Water Operation

6.6 Operating Procedure #0250031, Boron Concentration Control, Off-Normal

6.7 Operating Procedure #1010040, Loss of Instrument Air

6.8 Operating Procedure #1540020, Water Plant Startup and Shutdown

6.9 Operating Procedure #2200020, Emergency Diesels - Standby Lineup

6.10 Operating Procedure #0700022, Aux. Feedwater System Operation

6.11 Operating Procedure #0030142, RCS Cooldown During Blackout

EMERGENCY PROCEDURE NUMBER 2-0030140
REVISION 0

7.0 RECORDS/NOTIFICATION:

Normal Log Entries.

Notify Duty Call Supervisor.

8.0 APPROVAL:

Reviewed by Plant Nuclear Safety Committee October 15 1974
Approved by K. N. Harris Plant Manager October 25 1974

Rev. 19 Reviewed by FRG February 1981
Approved by C. M. Wethy Plant Manager March 10 1981

Purpose or Discussion:

"L A S T P A G E"

Attachment to L-81-468
October 27, 1981

A. Minutes of meeting held on October 23, 1981 on the topic of Compaction Piles at St. Lucie Plant.

B. Response to the items mentioned in the meeting minutes of October 23, 1981 on the topic of Compaction Piles.

C. Minutes of meeting held on October 23, 1981 on the topic of Electrical SER open items.

D. Final Submittal to (1) Adequacy of Station Voltages; (2) 90% motor starting.

E. Corrected Resubmittal of the Inadequate Core Cooling write-up submitted by Letter L-81-463.

F. Matrix Power Supply Isolation Devise Testing

G. Clarification to our final response to the NRC Control Room Audit Findings (refer to our submittal FP&L letter L-81-420, dated September 24, 1981).

F. Loss of Coolant Accident (LOCA)

G. Inadequate Core Cooling (ICC)

MEETING MINUTES
NRC & FPL
OCTOBER 23, 1981

Subject: Compaction Piles at St. Lucie Plant.

Location: C-E Conference Room, Triangle Towers Building, Bethesda, Maryland.

Attendees:

NRC	FPL	Ebasco
V. Nerses	E.W. Dotson	E. Zuchman
L. Heller	P.P. Carier	M.P. Horrell
R. Pichumani	W.F. Brannen	J.L. Ehasz
G. Lear (part-time)		W.F. Mercurio
		G. Coscia

Proceedings:

The NRC staff opened the meeting by reviewing their concerns related to a blockage of the plant's circulating water system intake structures by a land slide resulting from the liquefaction of subsurface soils during a seismic event. They noted that their concerns were still valid since it appeared that there was still a layer of in-situ soils that had not been densified by the compaction piles placed in the slopes north and south of the intake structures (see minutes for meeting of October 14, 1981).

Ebasco presented cross sections of each row of compaction piles which they had prepared since the meeting of October 14, 1981. The cross sections were based on the original pile driving logs and detailed:

1. Ground surface elevation for each pile.

2. Elevation of class II/in-situ soil interface.

3. Elevation to which each pile fell under its own weight.

4. Blow count per foot for each pile.

Using the cross sections Ebasco demonstrated that the majority of the piles were driven from a point above the class II/in-situ soil interface with significant blow counts and, therefore, densified the in-situ soil. They noted that the piles that fell into the in-situ soil were probably passing through a clay layer that lies between elevation -20 feet and -35 to -40 feet.

Ebasco also presented documentation which established an increase of 3% to 6% in the relative density of the in-situ soils as a result of driving the compaction piles. It was noted that this should yield a 76% to 79% average relative density for the in-situ materials. Ebasco also demonstrated factors of safety against liquefaction during a seismic event of 0.1g and 10 cycles ranging from 2.4 to 3.8.

The NRC noted that, based on the information presented, the compaction piles in the north and south slopes would be acceptable. They added that several items would have to be included in a docketed submittal:

1. The existance of the clay layer should be documented.

2. The fact that only one pass with an auger was made into the in-situ soils should be documented.

3. Details of the original excavation should be provided to justify the cross sections.

4. A reason should be provided for some of the piles following below the class II/in-situ interface.

5. An explanation as to why other piles hung up above the interface should be provided.

6. The effectiveness of compaction piles should be documented.

Ebasco agreed to revise the submittal to incorporate the above items by Wednesday, October 28, 1981.

INTRODUCTION

The following information has been prepared to document FP&L's position that the soils North and South of the Intake Structures is sufficiently dense to resist liquefaction: (1)elaborated on information presented in the compaction pile reports (noted below); (2) graphical presentation of depths that compaction piles were actually driven; (3) calculation of denisty increase due to pile-soil displacement and vibration effects (4) liquefaction analysis for 3 different cases: relative densities of 60.8%, 73.3% and 80%; (5) reference to other projects where compaction piles were successfully used for soil densification.

REFERENCE REPORTS

1) Ebasco Report - Compaction Pile Soil Stabilization Program - dated January 1976

2) Ebasco Report - Soils Foundation of the Emergency Wall - dated May 1976

Facts

1) Paragraph 5, on page 3 of January, 76 report makes comments with respect to removal of soil due to augering. This statement is the worst case that was experienced. Generally no material was brought to the surface. This paragraph should be changed to read:

> "An estimate of the amount of material removed from the hole during the established pre-drilling procedure was made for one of the 74 foot piles. This estimate was very conservative, reflecting the worst case, and is only indicative of this case. The estimated volume of material removed as a result of the drilling of this worst case pile was 95 cubic feet. The volume of a 74 foot long pile is 167 cubic feet which results in a material displacement of 57 percent of the pile volume. This material was removed from the upper half of the hole in the Class II fill. Very little material was removed from the insitu material portion of the hole, making the compaction effects of the pile effective in the insitu material where densification by material displacement was required by the NRC staff. Our visual estimate of material removal from other pile locations was essentially zero, and generally 1/2 to 1 cu. yd. of sand was used in backfilling adjacent to these piles."

These changes give a clearer picture of what happened when we performed the densification by compaction piles. It is our engineering judgement that the areas compacted in this manner now have an in-place relative density of 80% or better. This is based on the fact that: (1) these areas were pre-loaded during initial excavation and backfilling while dewatering was taking place, and (2) that the displacement and compaction of the insitu material occurred as a result of driving the compaction piles.

The St Lucie Unit 2 SER indicates some confusion with the information presented on compaction piles used to densify the soils beneath the UHS barrier wall and small triangular areas North of the Unit 1 Intake Structure and South of the Unit 2 Intake Structure. This is probably true because of varying statements in the two reports referenced on page one. This confusion can be cleared up by referring to a field trip report titled, Compaction Piles North of Unit 1 Intake and South of Unit 2 Intake, dated October 22, 1975.

The first area of confusion is in paragraph 4 , page 2 of the January 1976 report. The paragraph as written is not entirely correct. It should be revised to reflect the ideas in paragraph 3, of the October 22, 1975 memo. Thus, the January 1976 report, 4th paragraph, page 2 should read:

> "The final drilling-driving procedure established was to drill one pass with the auger to a depth of approximately 70 feet, to facilitate pore pressure relief in the insitu materials. Two additional passes would be made only to the bottom of the Class II fill, to relieve skin friction in the backfill and insure that the piles would be driven in the insitu material."

Paragraph 6, of page 2, of the same report should read:

> "In areas where hard drilling and driving was encountered, the number of auger passes was increased to no more that 5 but only to the bottom of the Class II fill. This was to ensure that the pile could be driven in the insitu material with only a minimum of skin friction in the backfill."

As stated in the St Lucie #2 FSAR Section 2.5.4.2, occasional discontinuous plastic clay seams were found in the upper part of the Anastasia formation, which extends from the surface to approximately El-150 feet. Several borings

in the vicinity of the areas where the compaction piles were installed show the existence of clay seams between El-20 feet and El-45 feet.

Of specific interest are borings B-103, B-104 and B-117, which indicate a seven to eight foot thick clay seam in the intake area occurring between El-22 feet and-43 feet. Additionally, borings AE-1, AE-13, AE-17 and AE-23 indicate a sandy clay seam varying in thickness from three to nine feet occurring between El-27 feet and El-43 feet. These clay seams have low SPT values, indicating a low shear strength. Although this clay was excavated beneath the main plant island, it is still present beyond the limits of the excavation. Thus, the clay seam intersects the sloping interface between the Class II backfill and the insitu soil. In the intake area, this intersection generally occurs between El-22 feet and El-43 feet.

The intent of pre-augering several times to the Class II fill-insitu soil interface was to minimize the amount of skin friction on the piles driven through the very dense Class II fill. However, in areas where as much as 75 feet of fill had to be penetrated to reach the insitu soils, pile driving began at elevations substantially higher than the interface (in particular, rows 4,5,11 and 12) because the pre-augered holes would not remain open for full insertion of the pile prior to driving and because skin friction from the fill could not be entirely eliminated. Rather than remove the pile and perform additional pre-augering to the interface (in excess of five auger passes), the piles were driven as placed in order to limit disturbance of the Class II fill.

In twelve cases, piles dropped up to ten feet below the Class II fill - insitu soil interface before driving began. These piles are located in areas where the thickest portions of the insitu soils to be densified occur

existed around each pile after driving. The cone was 3.5 to 4.0 feet across at the top and 9 feet deep. We estimate that the increase in relative denisty is 3 to 5%. Based on our original determination of Rd (relative density), we estimate that the original relative density prior to dewatering and pile driving was 73.3%. (See paragraph 4). Add to this the 3 to 5% increase. The after construction relative density is 76 to 78%, due to displacement only. The vibrational effects of pile driving also contributed to soil densification; however, due to the difficulties involved in evaluating this increase, vibrational effects have been neglected. Based on this increase in relative density, we believe that we have more than an adequate factor of safety against liquefaction.

4) The attached figure presents our calculation for factors of safety against liquefaction in the areas north and south of the intake structures, in the insitu soils. The factors of safety have been calculated for relative densities of 60.8, 73.3 and 80%. These relative densities were based on values obtained during our earlier investigation in the area. The 73.3% is the average relative density and 60.8% is one standard deviation less than the average. These values are presented in the SL2 PSAR Appendix 2G. In addition, we show the safety factor for a relative density of 80%. This 80% is a conservative lower bound based on the increase due to dewatering alone or due to compaction by pile diving alone. In any case, using the procedures outlined by H.B. Seed, the minimum safety factor against liquefaction in the insitu soil is greater than 2.2 for any depth for any possible relative density and ranges up to a value of 3.7 safety factor.

(and consequently, the overlying Class II fill is at a minimum thickness). In these areas the Class II fill-insitu soil interface occurs in the previously described clay layer. Since less Class II fill had to be penetrated to reach the insitu soil than in the other areas, the piles were able to be inserted close to the interface elevations prior to driving. However, due to the high static contact stress at the pile tip (approximately 6 TSF), the pile also penetrated the soft clay layer (which was further weakened when remolded by the one auger pass that extended into the insitu soil to relieve pore pressure), and driving began with the pile tip at the bottom of the clay. Since clays are not subject to liquefaction, densification was not required in the clay layer, and therefore the absence of pile driving through the clay did not detract from the overall quality of the compaction pile program.

2) The attached 14 figures present a plan of compaction pile locations and a cross section through the different rows of piles. The cross sections show the Class II fill and insitu soil interface as well as the depth the piles settled to and the driving records per foot of pile. As shown on these cross sections, the piles were driven through the insitu material as required. In fact, in most cases, the pile blow counts are very high. Based on these profiles and the length of pile that was driven, we are convinced that the insitu soils were densified by displacement and compaction.

3) We have calculated the density increase in the insitu soil based on the pile displacement and an estimate of the volume of soil that followed the pile down during pile driving. From the photos of the construction operation, we have calculated the volume of a cone of depression that

5) Various other projects have been documented in which driving of piles resulted in soil densification. Several of these are listed below:

(a) Dames & Moore Report prepared for Dairyland Power Cooperative, LaCrosse Boiling Water Reactor (March 21, 1980)

(b) Dames & Moore Report prepared for Dairyland Power Cooperative, LaCrosse Boiling Water Reactor (July 11, 1980)

(c) Liquefaction Potential Study, South San Francisco Medical Center, San Francisco, California, for Kaiser Foundation Hospitals (Dames & Moore, August 11, 1978).

(d) Basore, C.E., and J.D. Boitano, "Sand Densification by Piles and Vibroflotation," Placement and Improvement of Soils to Support Structures, ASCE Specialty Conference Proceedings (August 1968).

(e) Nakayama, J.,E. Ichimoto, H Kamada, S. Taguchi, "On Stabilization Characteristics of Sand Compaction Piles," Soils and Foundations, Vol. 13, No. 3 (September 1973).

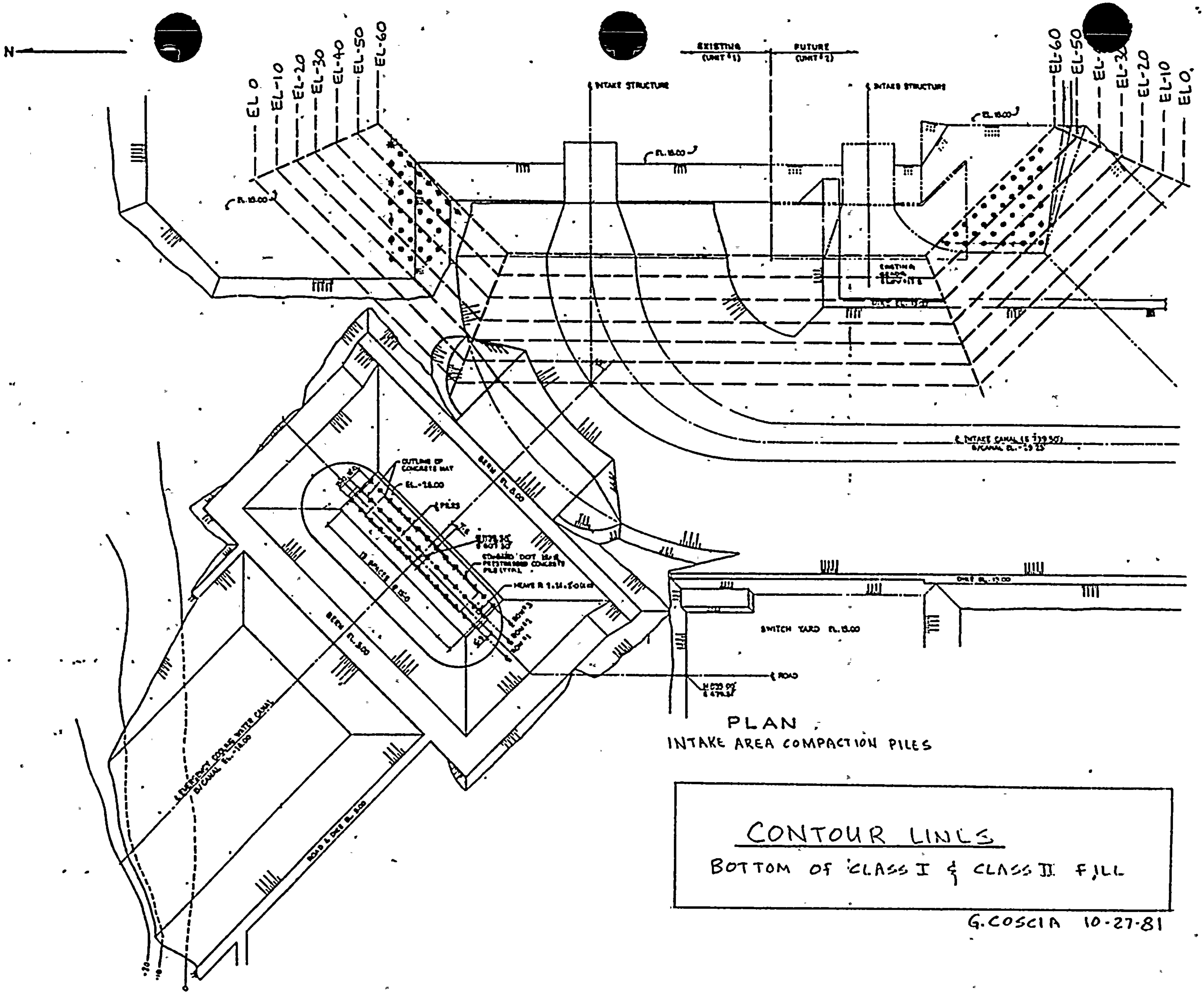
(f) Woodward-Clyde Consultants, Results and Interpreation of Pile-Driving Effects Test Program, Existing Lock and Dam No. 26, Mississippi River, Alton, Illinois, "Report to U.S. Army Corps of Engineers.

(g) Endo, M., "Relation Between Design and Construction in Soil Engineering--Deep foundations," Caissons and Pile Systems, Proceedings of Specialty Session No. 3 of 9th International Conference of Soil Mechanics and Foundation Engineering (1977).

(h) Dames & Moore Report No. 05676-008-07 for Sargent & Lundy Engineers, Bailly Nuclear Generating Station (1978)

Summary

We are convinced that the insitu soils at the St. Lucie site are dense and provide more than an adequate safety factor against liquefaction as noted above under items 1 through 4. We believe that both construction techniques (dewatering and compaction piles) have densified the insitu soil to relative densities greater than 80%.



PLAN
INTAKE AREA COMPACTION PILES

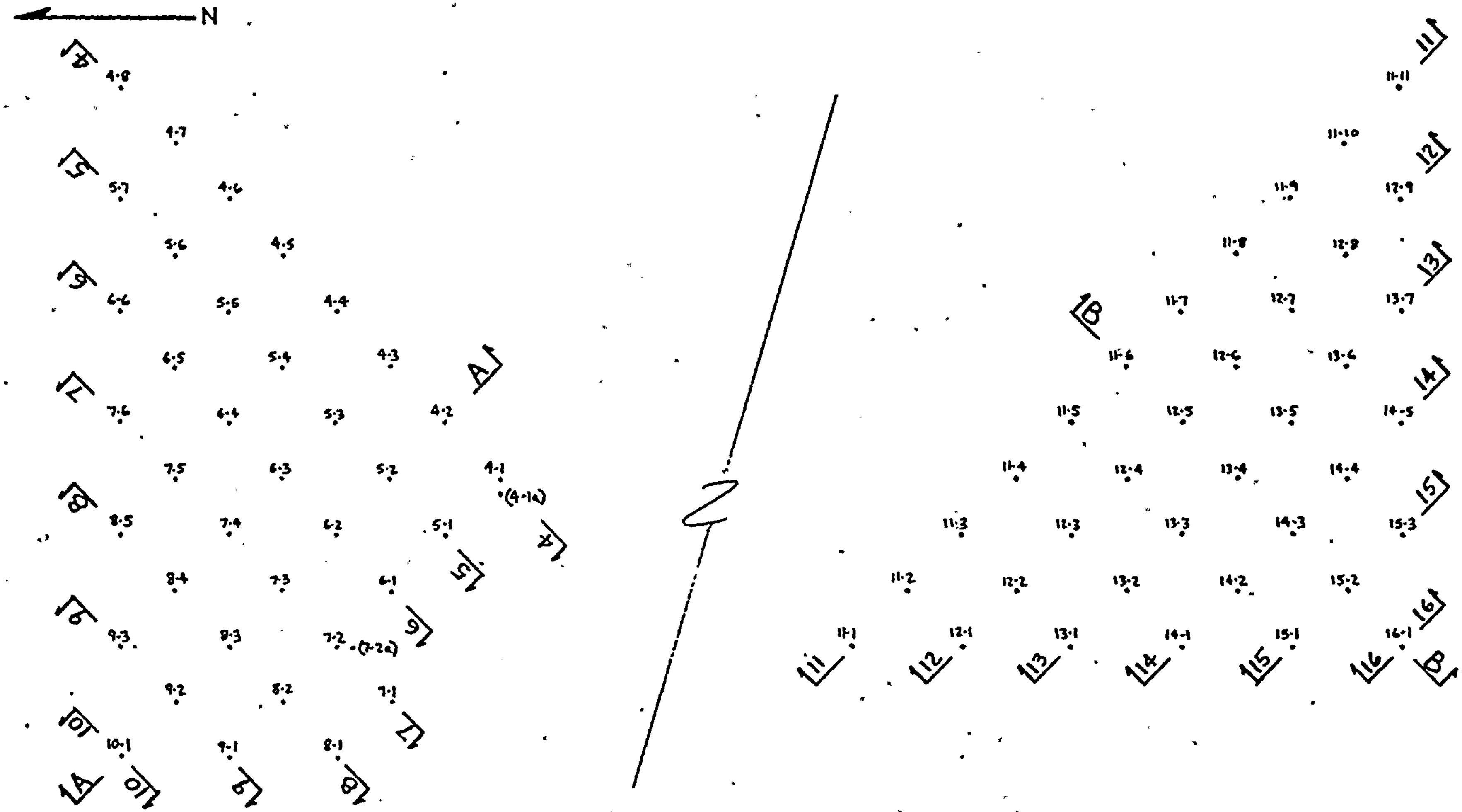
CONTOUR LINES
BOTTOM OF CLASS I & CLASS II FILL

G. COSCIA 10-27-81

EBASCO SERVICES INCORPORATED

CLIENT FPL
PROJECT SL2
SUBJECT INTAKE AREA COMPACTION PILES

OPS NO. 2524.902 DEPT. NO. 559
BY G. COSCIA DATE 10-14-81
CHECKED BY ______ DATE ______



PLAN - INTAKE AREA COMPACTION PILES
1" = 20'

CLIENT ____

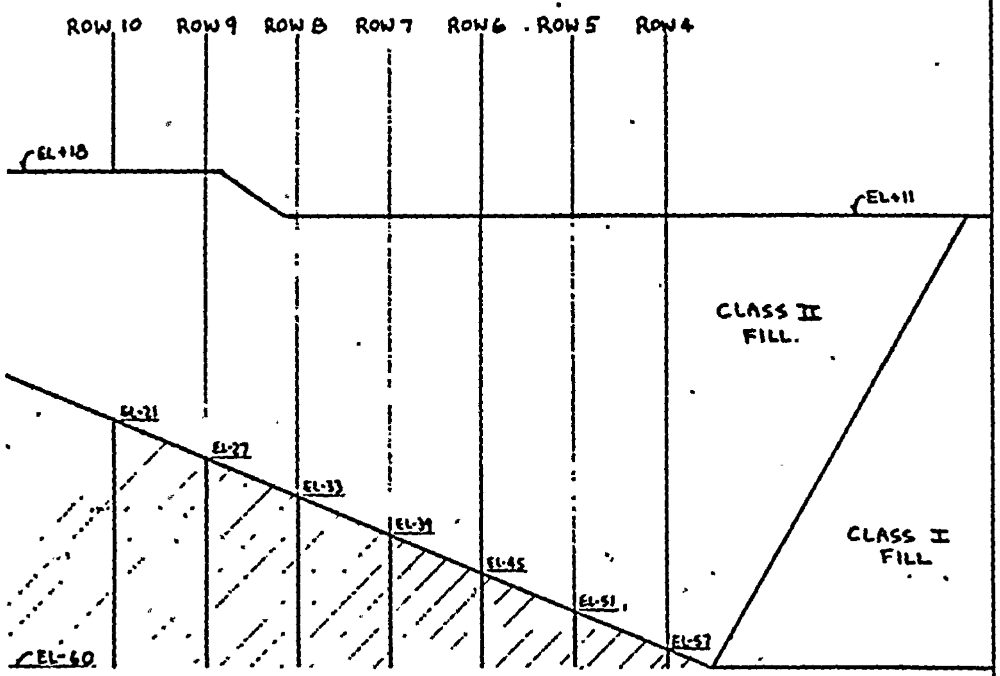
PROJECT ____

SUBJECT SECTION A-A & SECTION B-B

OPS NO. ____ DEPT. NO. ____

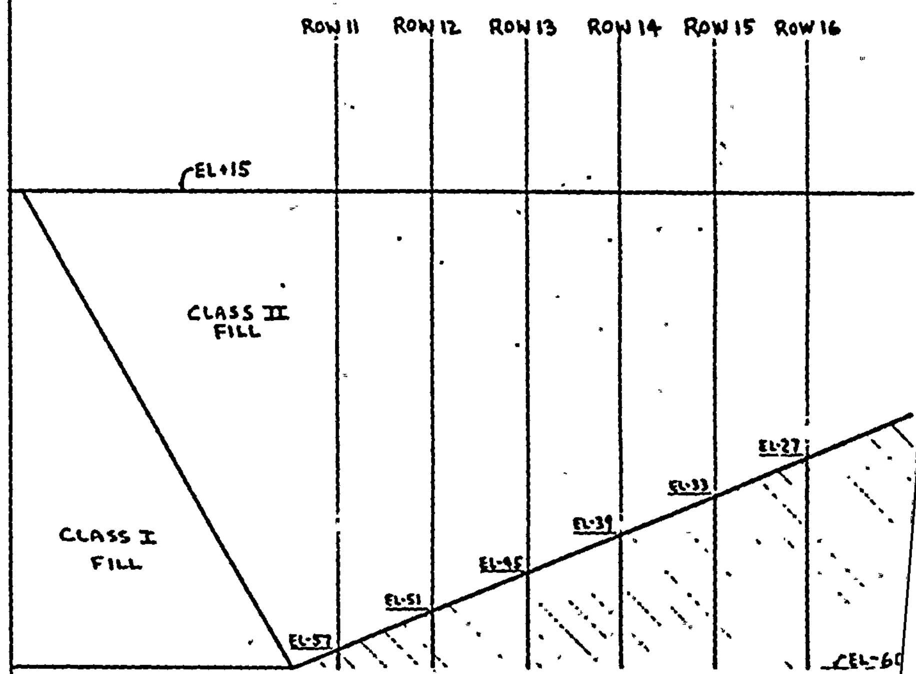
BY ____ DATE ____

CHECKED BY ____ DATE ____



SECTION A-A
1"=20'

NOTE: SHADED AREA IS INSITU MATERIAL TO BE DENSIFIED



SECTION B-B
1"=20'

NOTE: SHADED AREA IS INSITU MATERIAL TO BE DENSIFIED

EBASCO SERVICES INCORPORATED

CLIENT

PROJECT

SUBJECT SECTION 4

OFS NO.

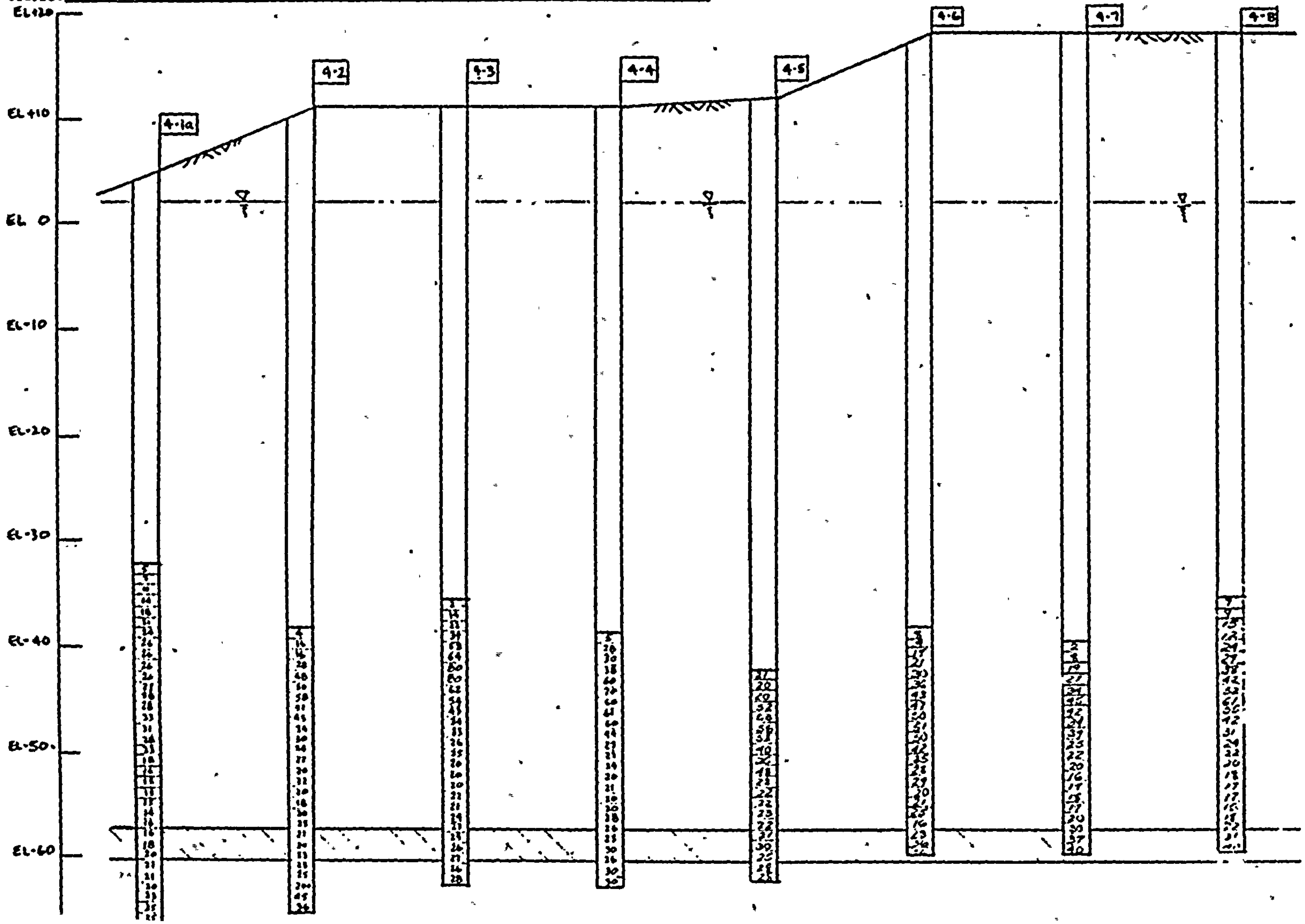
DEPT. NO.

BY

DATE

CHECKED BY

DATE



NOTES:

(1) SHADED AREA INDICATES INSITU SOIL TO BE DENSIFIED.

(2) AREA ABOVE SHADED AREA IS CLASS II FILL.

(3) HORIZONTAL SCALE IS 1"=10'; HOWEVER, PILE WIDTHS ARE EXAGGERATED (BUT C-C PILE SPACING IS ACCURATE).

(4) VERTICAL SCALE IS 1"=10'.

(5) WATER LEVEL SHOWN IS GWL

(6) SLOPES SHOWN ARE APPROXIMATE.

(7) PILE DRIVING BLOWS PER FOOT ARE SHOWN ON EACH PILE, FOR EACH FOOT OF PILE DRIVEN.

(8) UNMARKED PORTION OF PILE REFLECTS THE AMOUNT OF PILE DROP THAT OCCURRED PRIOR TO DRIVING.

EBASCO SERVICES INCORPORATED

CLIENT

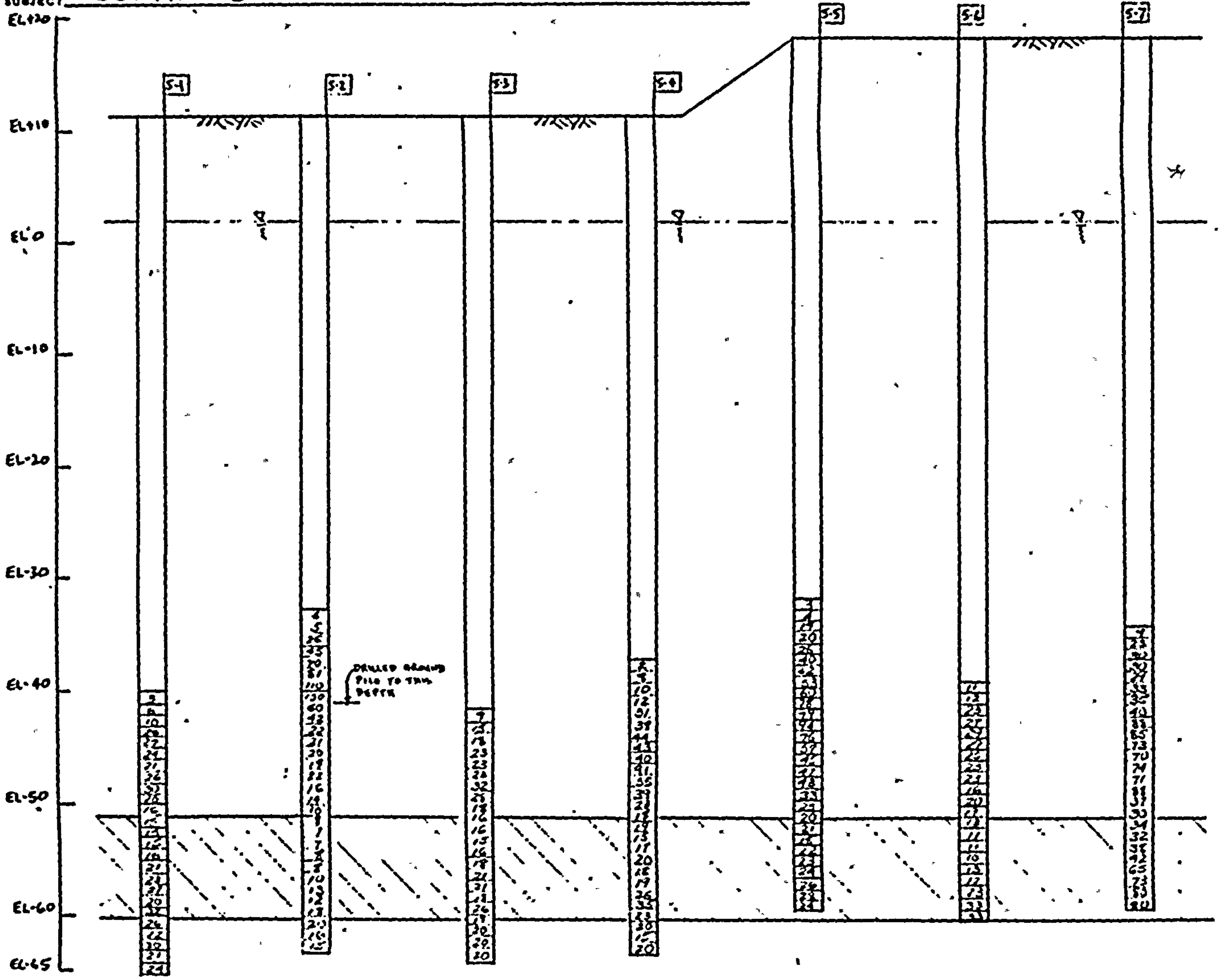
PROJECT

SUBJECT SECTION 5

OFS NO. DEPT. NO.

BY DATE

CHECKED BY DATE



NOTES:

FOR NOTES, SEE SH-3

EBASCO SERVICES INCORPORATED

CLIENT

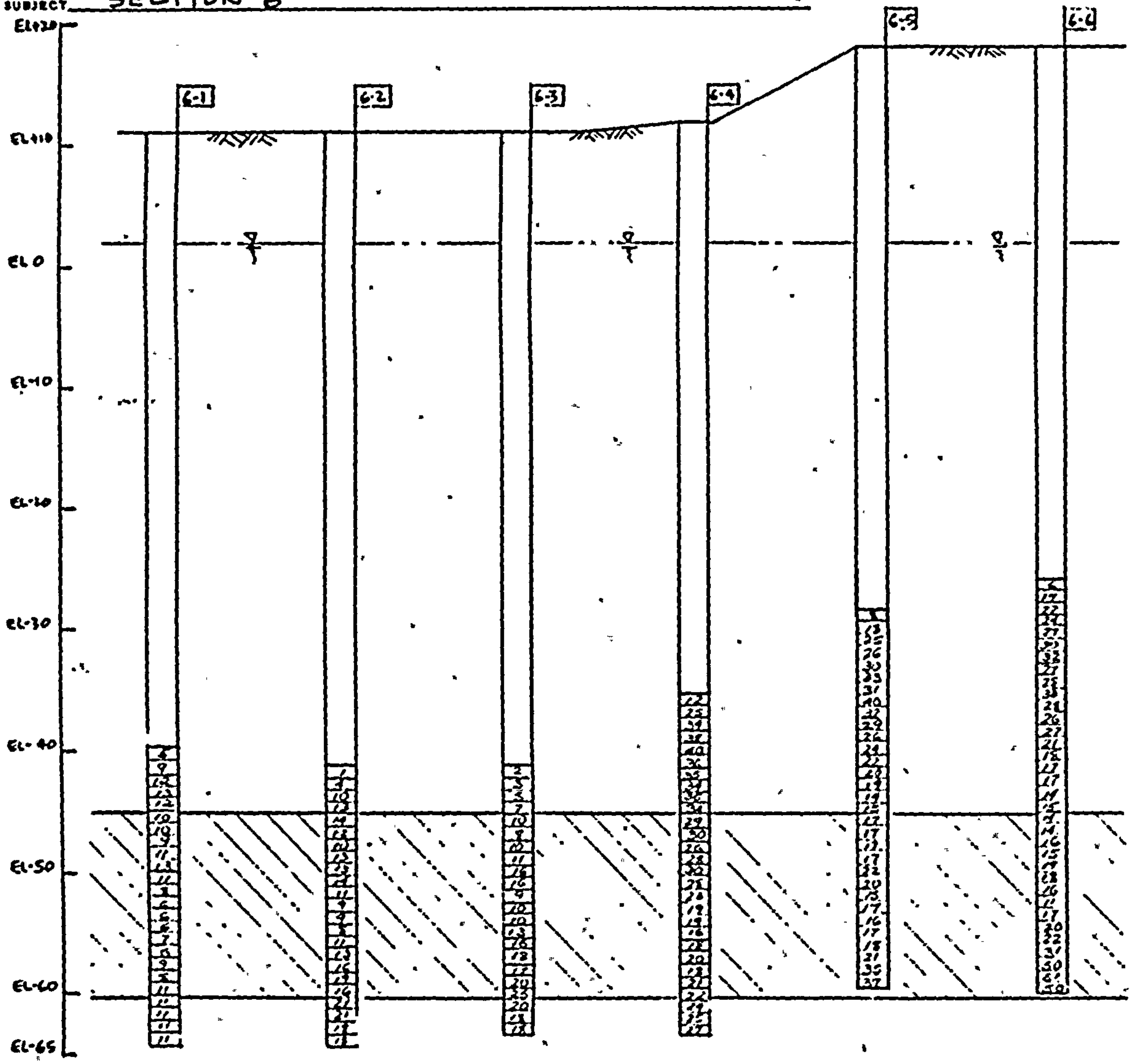
PROJECT

SUBJECT SECTION 6

OFS NO. DEPT. NO.

BY DATE

CHECKED BY DATE



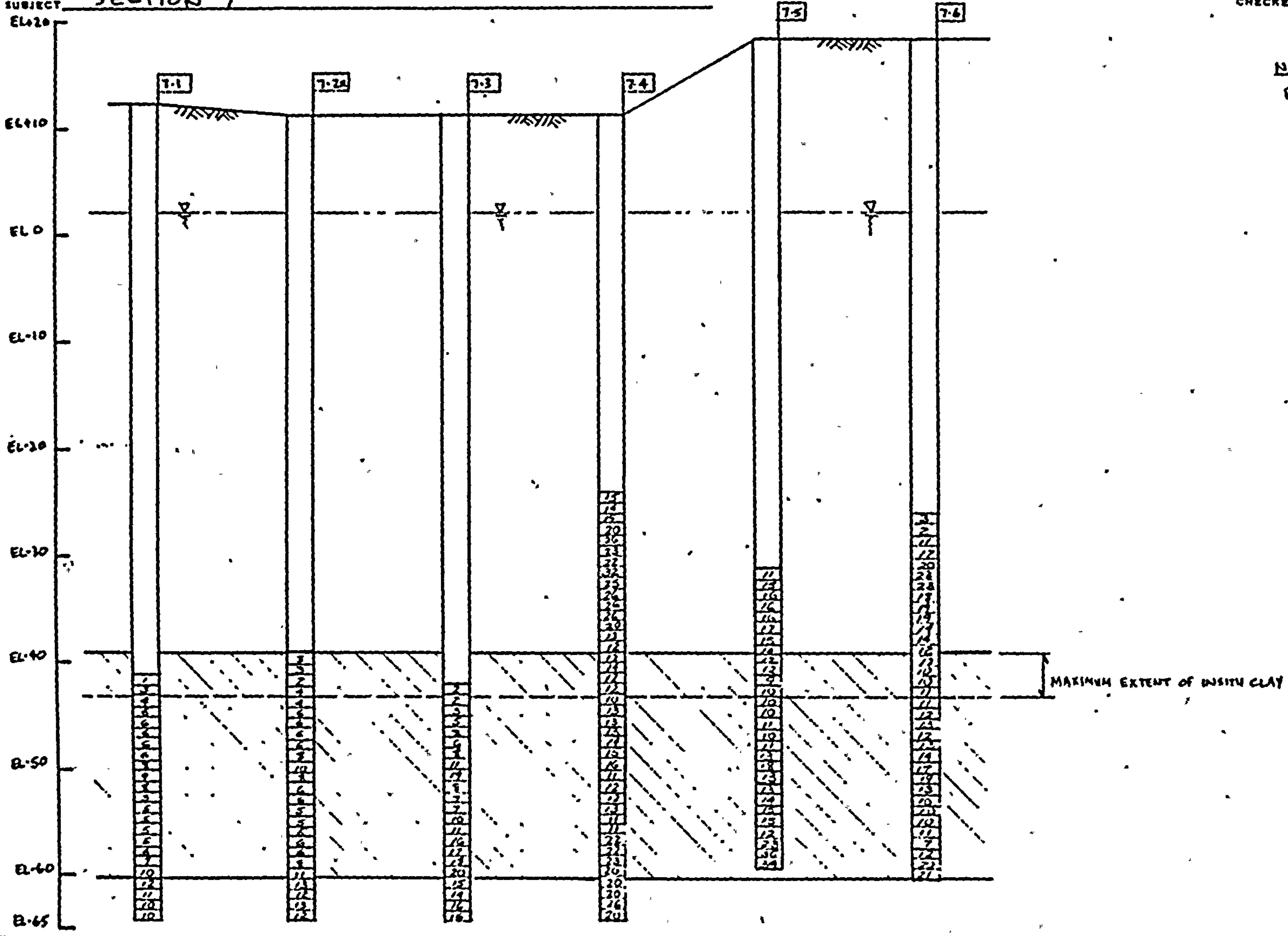
NOTES:

FOR NOTES, SEE SH. 3

EBASCO SERVICES INCORPORATED

CLIENT
PROJECT
SUBJECT SECTION 7

OPS NO. DEPT. NO.
BY DATE
CHECKED BY DATE



NOTES:
FOR NOTES, SEE SH. 3

EBASCO SERVICES INCORPORATED

CLIENT

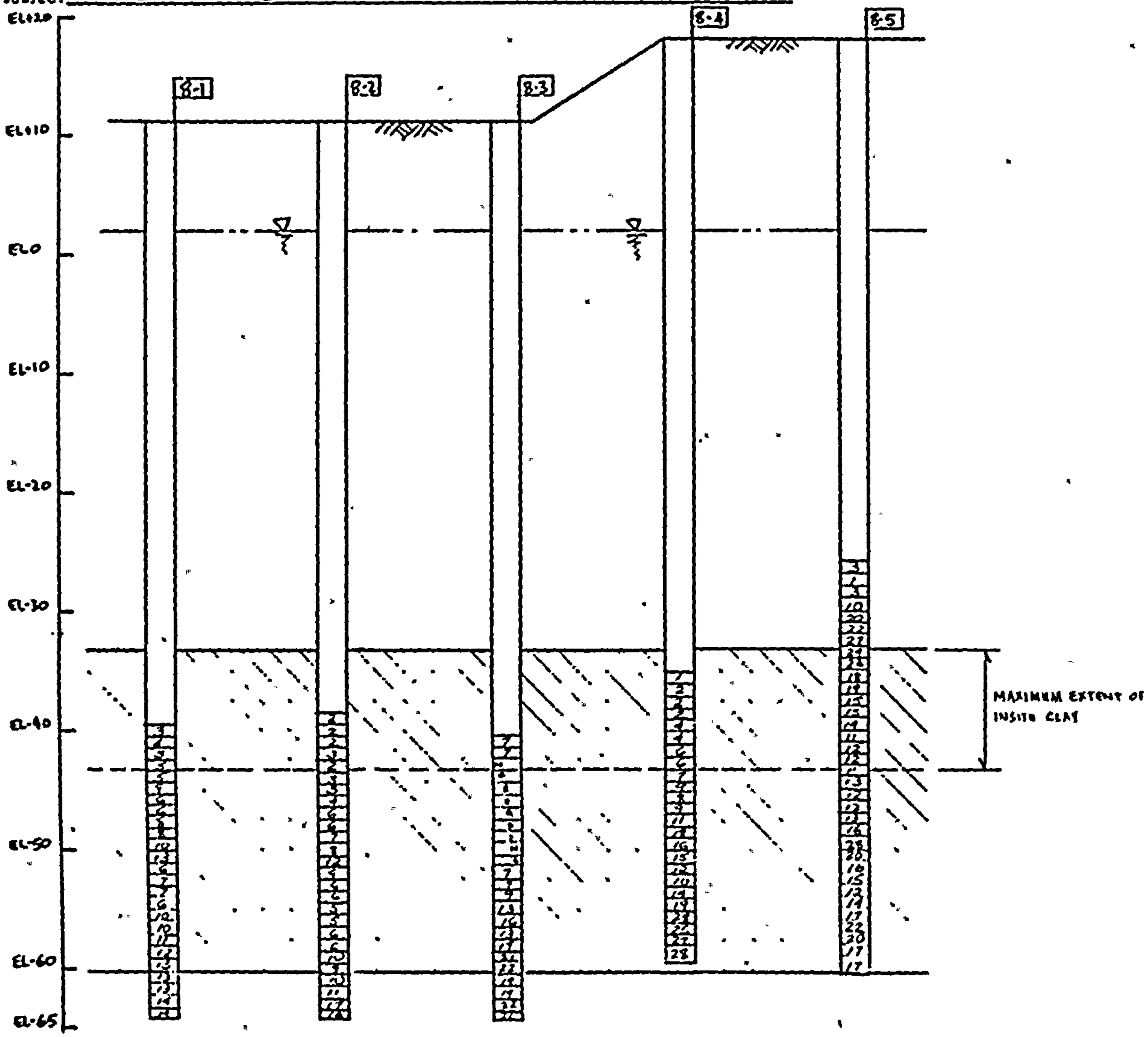
PROJECT

SUBJECT SECTION 8

OPS NO. DEPT. NO.

BY DATE

CHECKED BY DATE



NOTES:

FOR NOTES, SEE SH-3

EBASCO SERVICES INCORPORATED

CLIENT

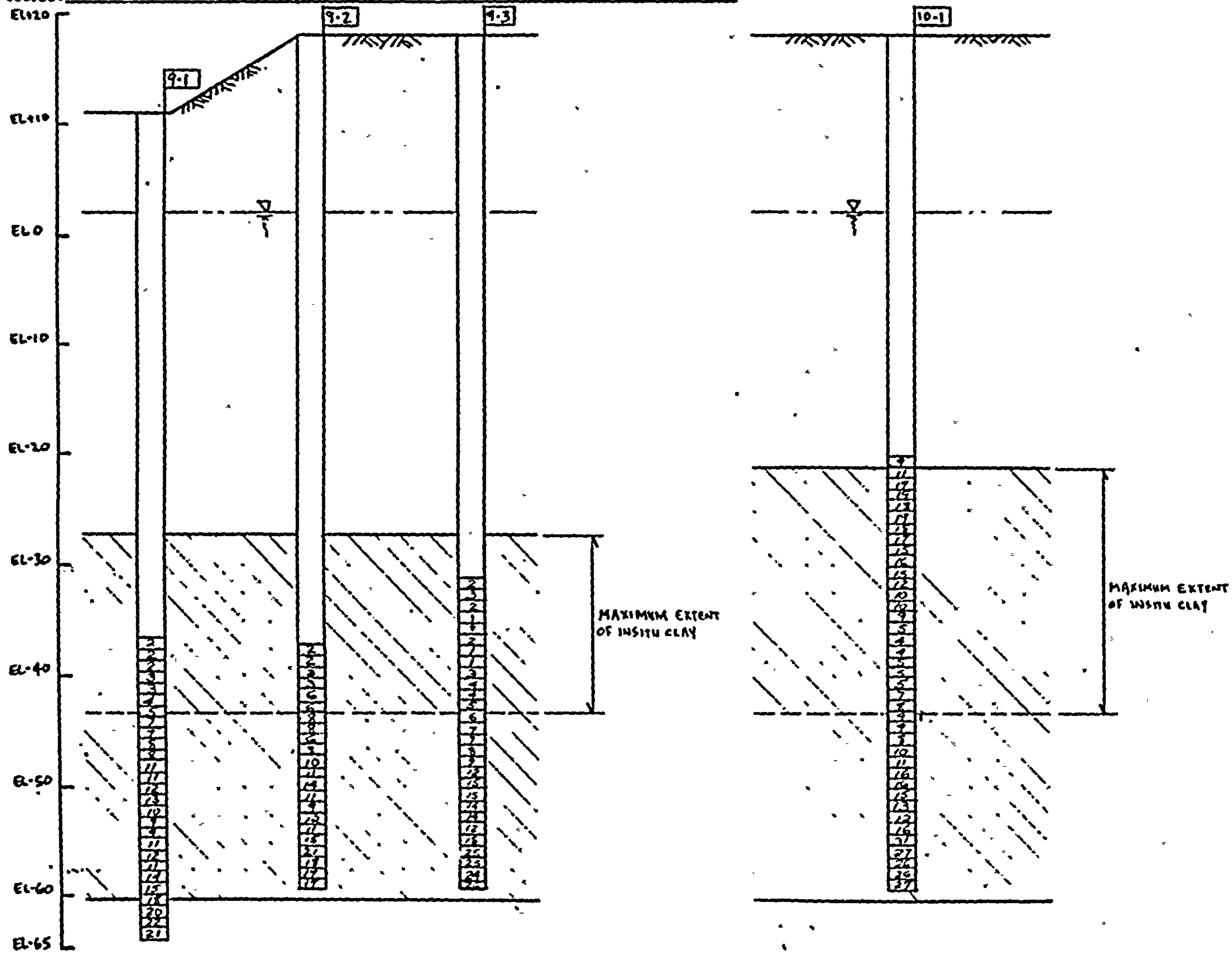
PROJECT

SUBJECT SECTION 9 & SECTION 10

OFS NO. DEPT. NO.

BY DATE

CHECKED BY DATE



NOTES:

FOR NOTES, SEE SH. 3

EBASCO SERVICES INCORPORATED

CLIENT ______________________

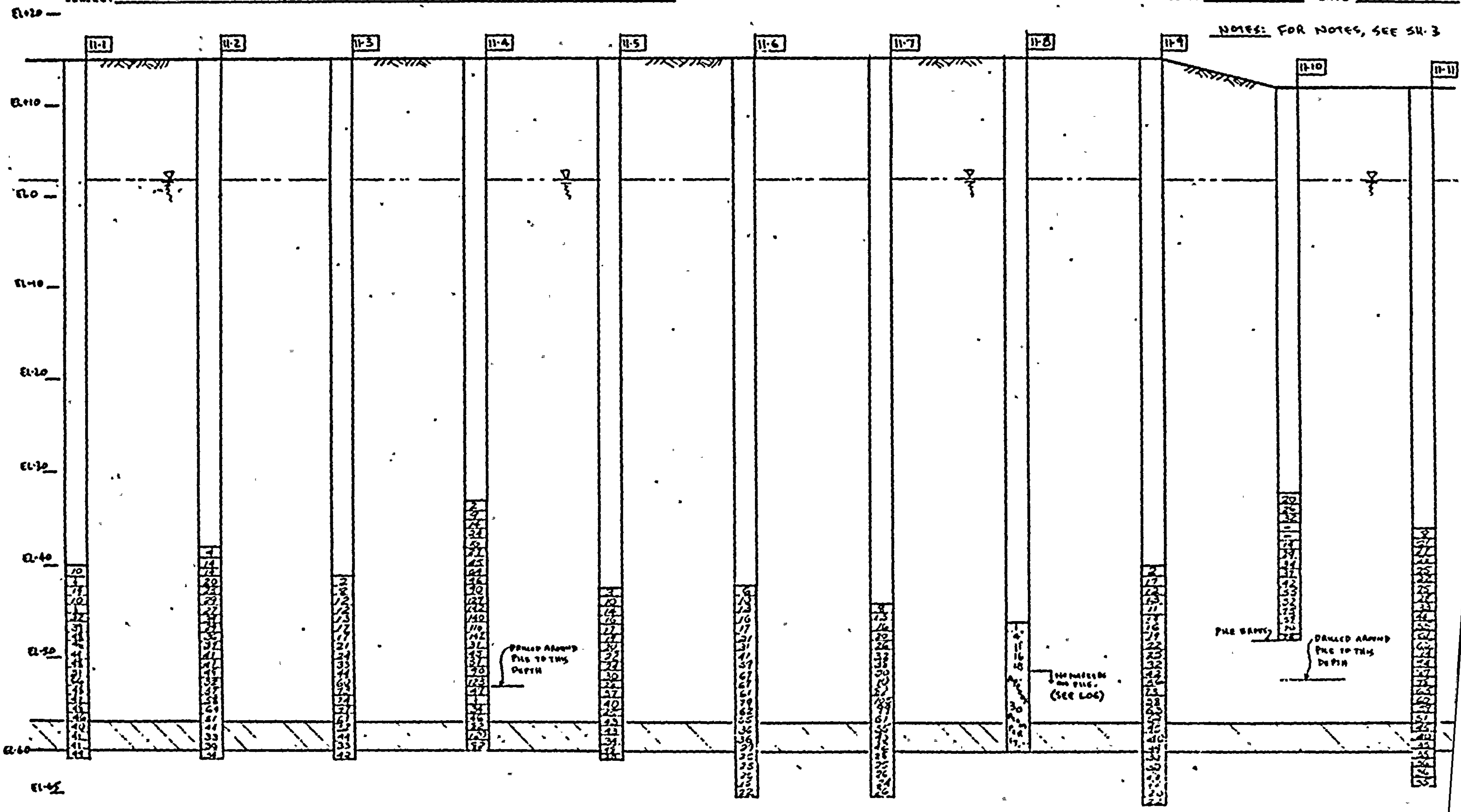
PROJECT ______________________

SUBJECT SECTION 11

OFS NO. __________ DEPT. NO. __________

BY __________ DATE __________

CHECKED BY __________ DATE __________



EBASCO SERVICES INCORPORATED

CLIENT

PROJECT

SUBJECT SECTION 12

OFS NO.

DEPT. NO.

BY

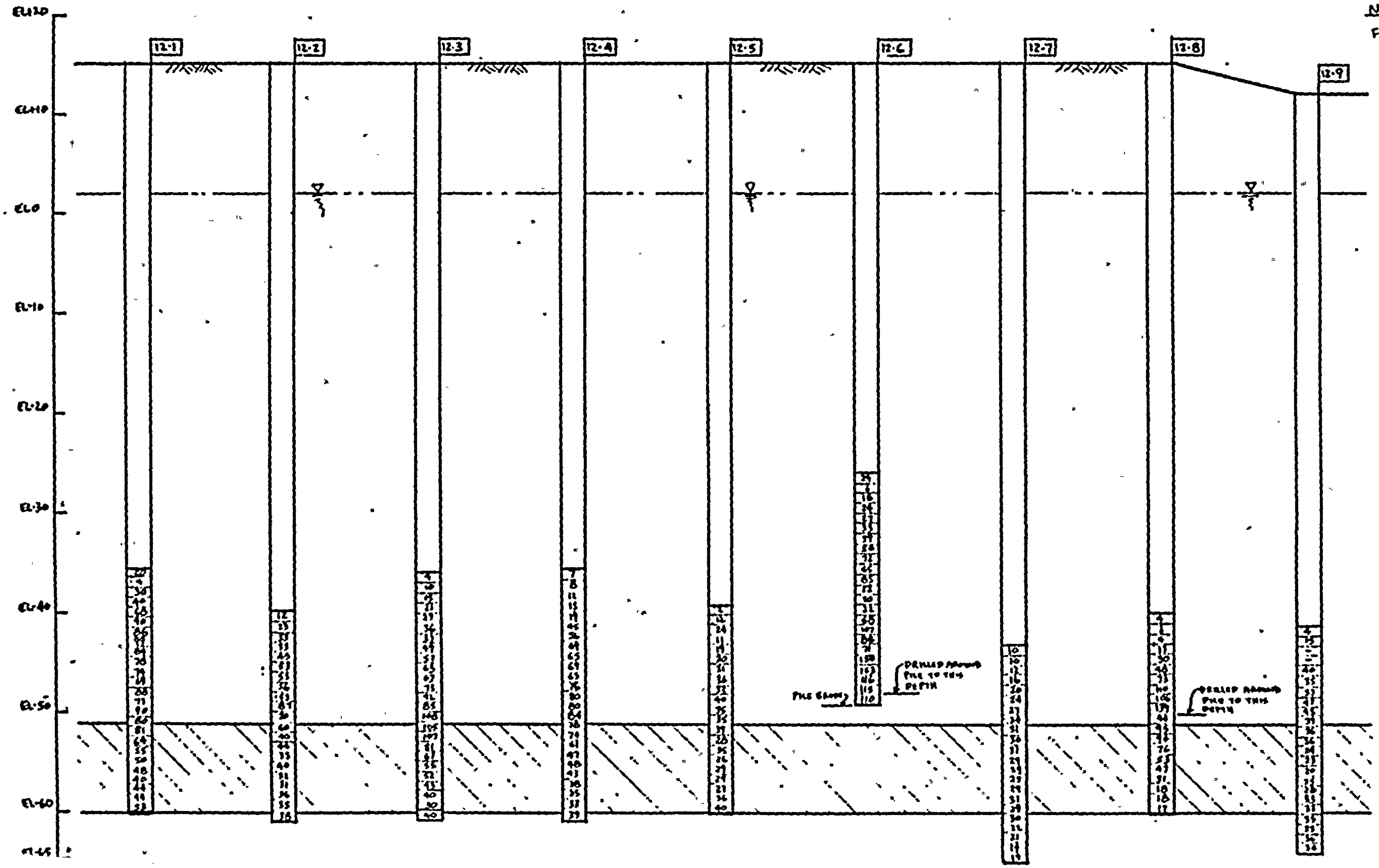
DATE

CHECKED BY

DATE

NOTES:

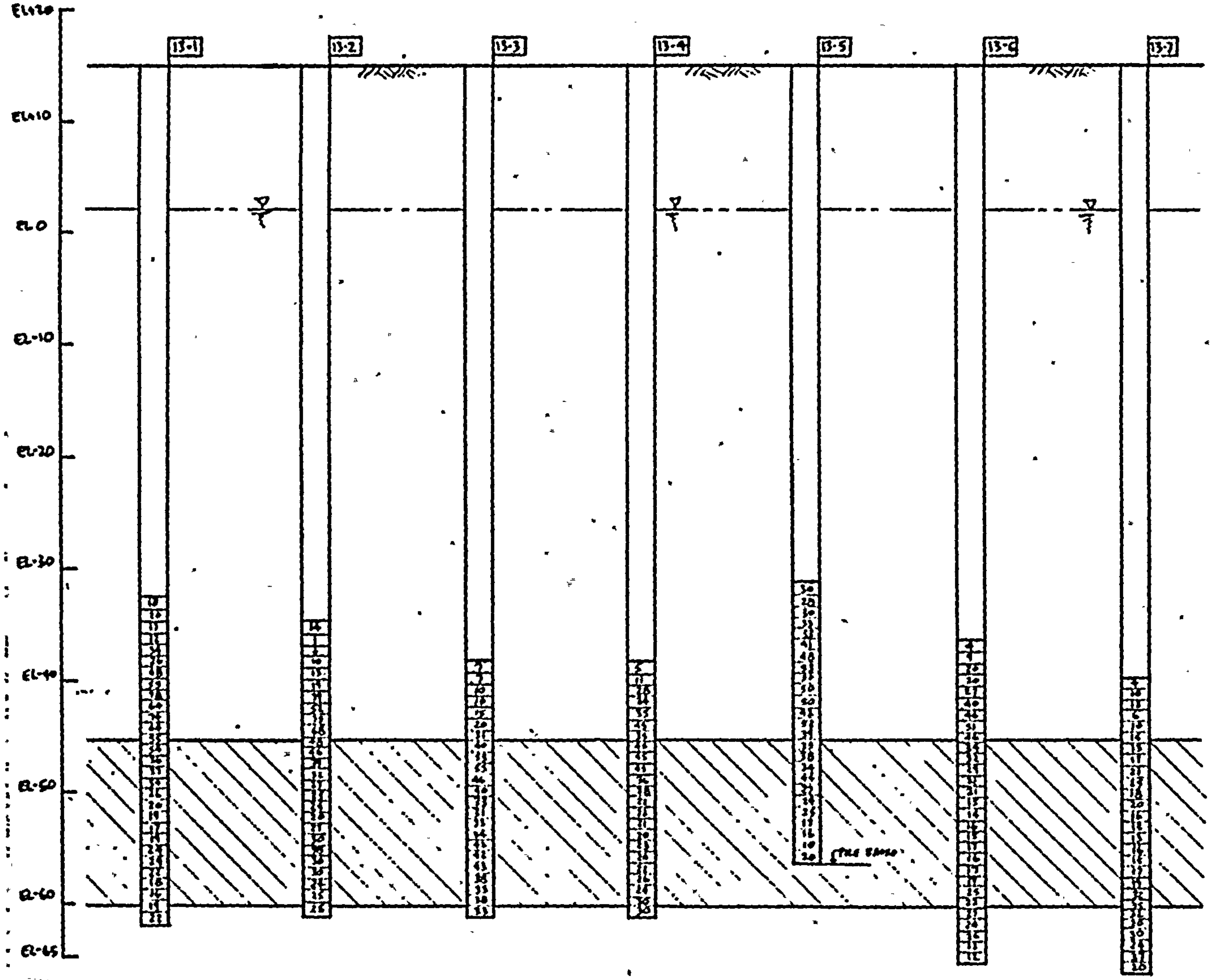
FOR NOTES, SEE SH 3



EBASCO SERVICES INCORPORATED

CLIENT ______
PROJECT ______
SUBJECT SECTION 13

OFS NO. ______ DEPT. NO. ______
BY ______ DATE ______
CHECKED BY ______ DATE ______



NOTES:
FOR NOTES, SEE SH. 3

EBASCO SERVICES INCORPORATED

SHEET 12 OF 13

CLIENT

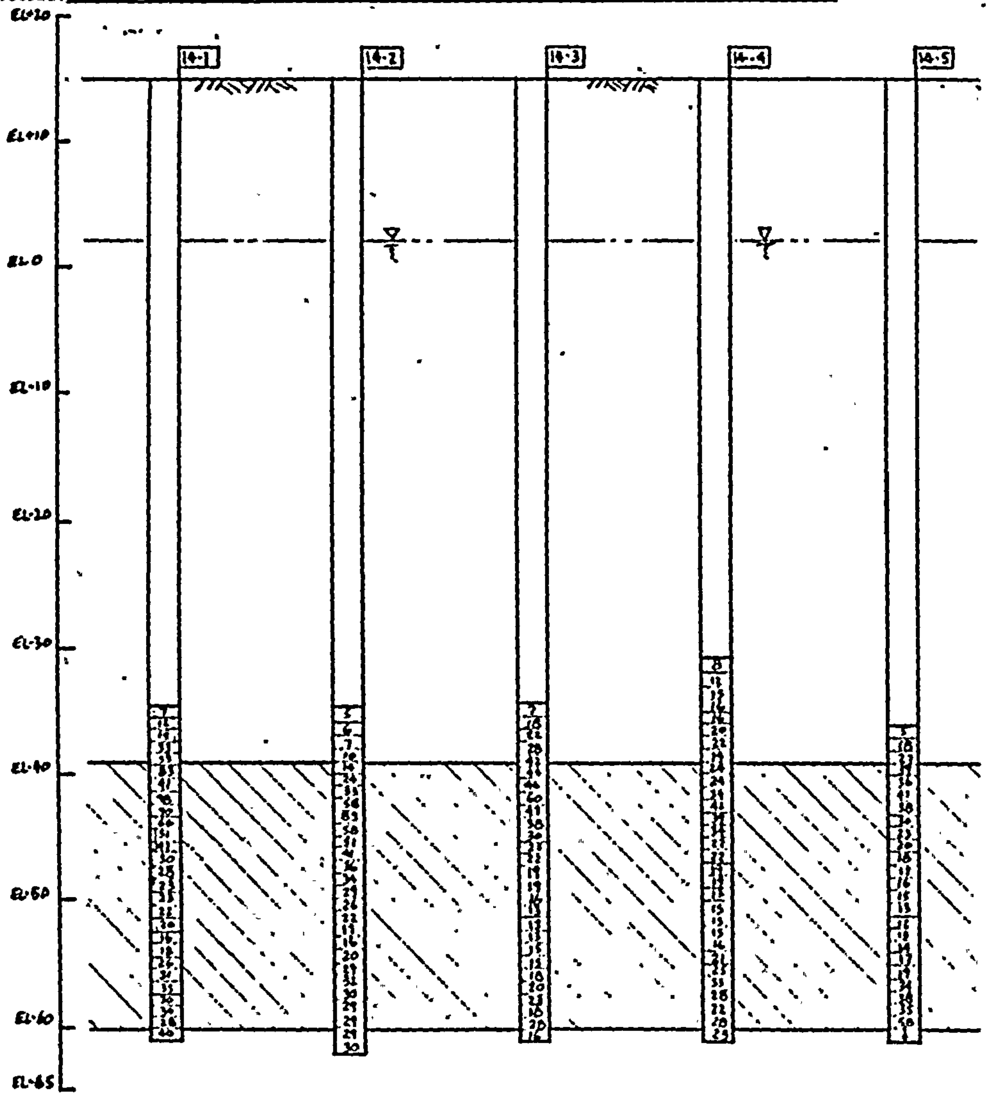
PROJECT

SUBJECT SECTION 14

OFS NO. DEPT. NO.

BY DATE

CHECKED BY DATE



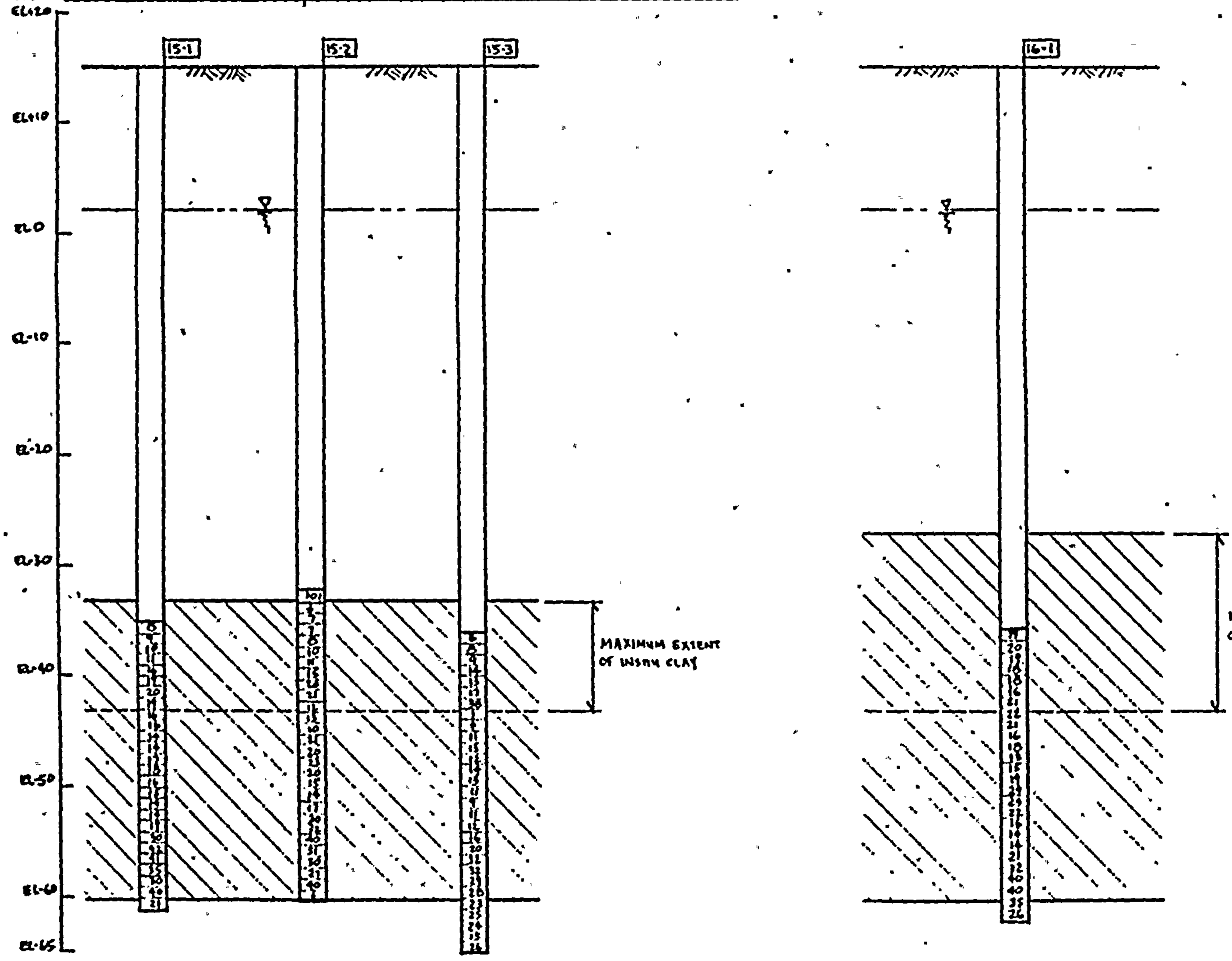
NOTES:

FOR NOTES, SEE SH 3

EBASCO SERVICES INCORPORATED

CLIENT
PROJECT
SUBJECT SECTION 15 & SECTION 16

OFS NO. DEPT. NO.
BY DATE
CHECKED BY DATE



NOTES:

FOR NOTES, SEE SH. 3

EBASCO SERVICES INCORPORATED

NEW YORK

BY G COSCIA DATE 10-22-81 SHEET 1 OF ____

CHKD. BY ____ DATE ____ OFS NO. ____ DEPT. NO. ____

CLIENT ____

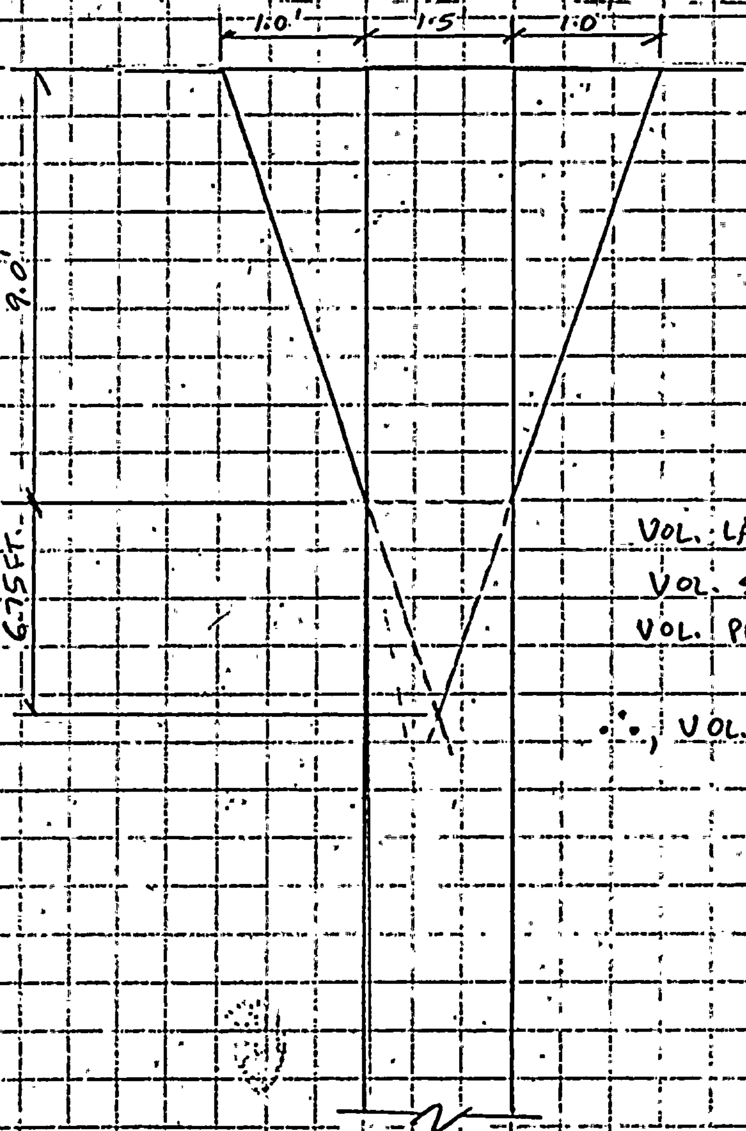
PROJECT ____

SUBJECT ____

ESTIMATE VOLUME OF CONE OF DEPRESSION:

DIA. APPROX. 4.5 FT.

DEPTH APPROX. 9 FT.



$\frac{9}{1.0} = \frac{X}{1.75}$ $X = 15.75$ FT

$X - 9 = 15.75 - 9 = 6.75$ FT

VOL. CONE $= \frac{1}{3}\pi r^2 h$

$= \frac{1}{12}\pi D^2 h$

VOL. LARGE CONE $= \frac{1}{3}\pi(1.75)^2(15.75) = 50.5$ FT^3

VOL. SMALL CONE $= \frac{1}{3}\pi(.75)^2(6.75) = 4.0$ FT^3

VOL. PILE $= 1.5^2 \times 9 = 20.3$ FT^3

∴ VOL. CAVITY $= 50.5 - 4.0 - 20.3 = 26.2$ FT^3

$= \approx 0.97$ YD^3

EBASCO SERVICES INCORPORATED

NEW YORK

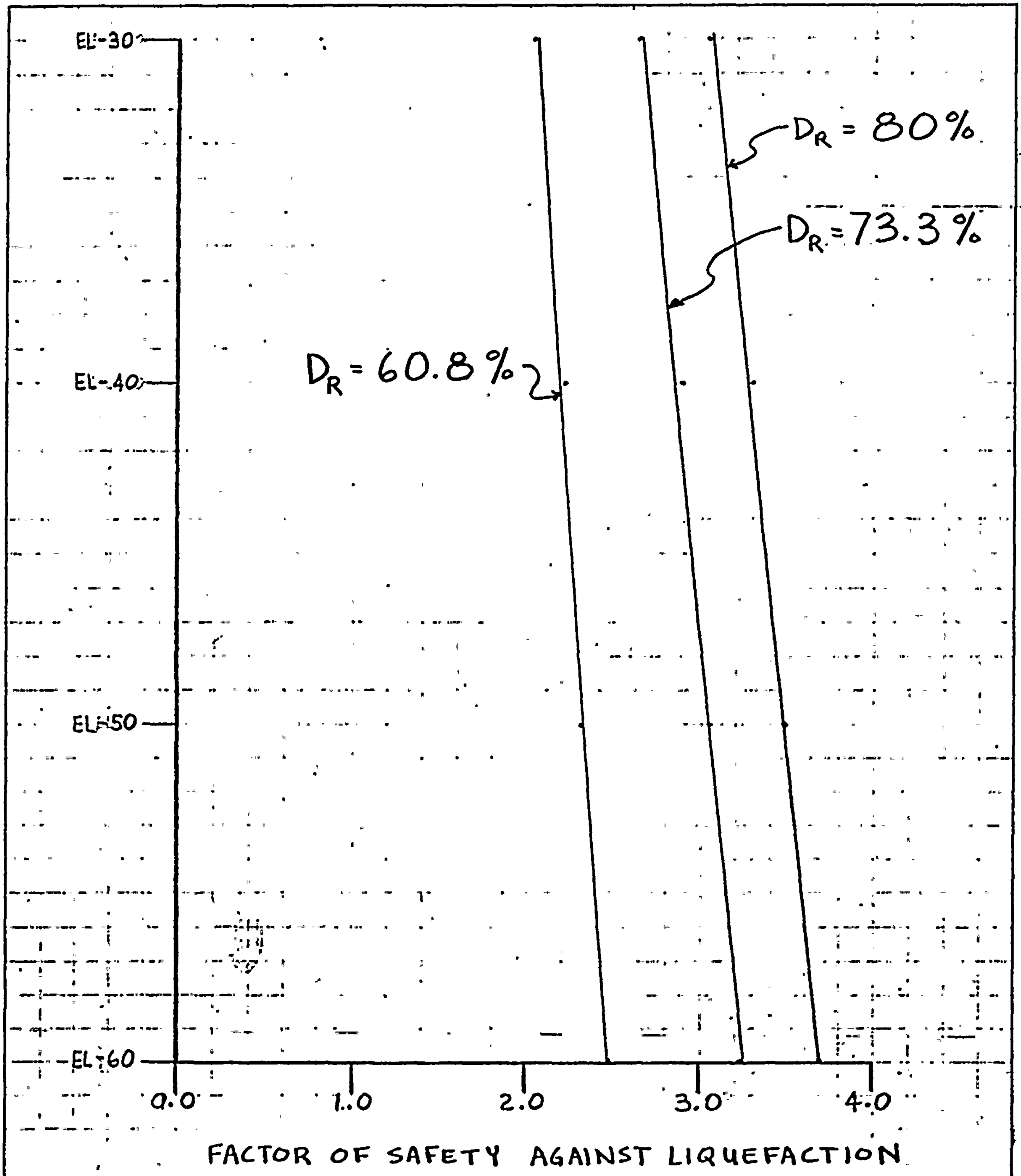
BY ________ DATE ________ SHEET 9 OF ________

CHKD. BY ________ DATE ________ OFS NO. ________ DEPT. NO. ________

CLIENT ________

PROJECT ________

SUBJECT ________



FLORIDA POWER & LIGHT COMPANY
St. Lucie Unit 2
NRC-FPL-Ebasco
Meeting on Electrical SER Open Items
October 23, 1981

Those present at the meeting were:

FPL	NRC	Ebasco
E. Dotson*	V. Nerses	E. Zuchman*
J. Franklin	A. Ungaro	G. Attarian
P. Carier	O. Chopra	* part-time

The purpose of this meeting was to present FPL responses to SER electrical open items:

1. 90% starting of 460VAC motors
2. Adaquacy of station voltages.

FPL and Ebasco presented draft responses to item 1 above and reviewed the methodology of the analysis. The NRC found the response acceptable and considered the item closed pending formal submittal of the response.

FPL and Ebasco presented a draft response to item 2 above and reviewed the methodology of the analysis. Following lengthy discussions several modifications to the draft response were agreed upon. The NRC found the modified draft acceptable and considered the items closed pending formal submittal of the response.

A concern was raised by FPL regarding the SER description and Technical Specification requiremetns for the safety related AB bus the breakers.

The SER requires in several places that the Technical Specifications include the requirement that these tie breakers be locked open (except for normally closed breakers) during plant operation FPL stated that the tie breakers presently have electrical interlodes and that breaker misalignment alarms are provided in the control room. The SER requirement, if interpreted as meaning pad locks on the breakers, would be detrimental to safety since an operator would be required to leave the control room during the loss of a safety train to remove the padlocks and realign the swing (AB) bus.

To provide an added measure of security for tie breaker operation FPL proposed that captive key switches be provided on the RTG boards in place of the standard switches.

The NRC agreed that this would meet their concerns, eliminate the need for a Technical Specification and provide control room operability of the tie breakers. The NRC has agreed to modify the appropriate paragraph of the SER to clearly indicate the means of locking open the AB tie breakers would be via captive key switches on the RTG board and delete the Technical Specifications requirements.

FPL agreed to change the RTG board control switches for the AB bus tie breakers to capture key type.

Response to SER Open Item: Adequacy of Station Voltages

Branch Technical Position PSB-1 requires that two levels of undervoltage protection be provided for the Class 1E busses.

In accordance with PSB-1 the first level of undervoltage protection is provided to detect a loss of offsite power. One Type CV-2 inverse time voltage relay is provided for each Class 1E division and is set at time dial 2 which will provide undervoltage tripping in accordance with the relay characteristic curve provided in Figure 2998-PSB1-E. The tap voltage value is set at 105VAC which produces a tripping characteristic of approximately 12 seconds at 79% voltage.

Each Class 1E division is provided with one Class 1E relay as described above mounted in the Class 1E 4.16KV switchgear. Upon detection of a loss of voltage condition this relay automatically indicates diesel generator starting and disconnection of the offsite source on a loss of offsite power.

Branch Technical Position PSB-1 requires that a second level of undervoltage protection be provided for the Class 1E busses. Flordia Power and Light meets the requirements of the position for St. Lucie Unit 2 by providing for each Class 1E division, a coincident logic protection scheme consisting of three definite time relays, ITE Type 27D or equivalent set at 92.5% of 4.16KV and provided with a 10 second time delay. The relay logic actuates control room annunciation to alert the operator to a degraded voltage condition and aligns the trip circuitry associated with the undervoltage logic such that subsequent occurance of a safety injection actuation signal (SIAS) will separate the Class 1E system from the offsite power system automatically.

To evaluate the acceptability of the relay setting an analysis of station electric system voltages was performed under steady state conditions with the full plant running loads and minimum design main generator voltages supplying the on site system through the Unit Auxiliary Transformers. The results of this analysis were shown on Figure 299B-PSB1-A which demonstrate that voltages on Class 1E systems at the 4.16KV level, the 480VAC level and the 120VAC level with the exception of PP247, remain above the design limits of the equipment.

The most limiting equipment was considered to be the 460VAC motors rated at 90% of nameplate operating voltages. Inspection of Figure 2998-PSB1-A reveals that in this condition, on the worst case 480VAC the operating voltage remains above 90.8% of 480VAC which corresponds to 94.7% of motor nameplate voltage, safety above the 90% operating limit.

The voltage level on the 4.16KV busses remains above 94.5% of 4.16KV which insures that the alarm and SIAS alignment relays described above are not picked up during this steady state operating condition.

To meet the requirement of Branch Technical Position PSB-1 section B.1.6(2) a second set of ITE-27D or equivalent definite time relays will be provided in a coincident logic arrangement for each Class 1E division. These relays will be set at 90% of 480VAC and located downstream of the 480VAC powercenter 2A5 and 2B5 reactors. The output of the relay logic will enable a CV-2 inverse time relay having a time voltage characteristic shown in Figure 2998-PSB1-E. The inverse time relay will separate the Class 1E system from the offsite source in accordance with the selected time dial setting should the operator fail to restore system voltages.

The setting of the definite time coincident logic relays at 90% of 480VAC. insures positive operation within the defined region of the operating curve of the inverse time relay. The operating characteristic of the inverse time relay assures that under the worst case starting transient which is the 4.16KV condensate pump, when generator voltage is at its expected minimum or switchyard voltage is at its expected minimum, inadvertent relay actuation will not occur.

In can be seen from Figure 2998-PSB1-E that with a time dial setting in the range of 2 to 4 and with tap voltage selected such that a 90% tap voltage value corresponds to 90% of 480VAC, the condensate pump starting transient which dips the 480VAC bus voltage to a minimum of 80% with a recovery to 91.7% within 6 seconds, with generator voltage are at their expected minimums, will not produce inadvertant actuation of the protection feature.

Under steady state conditions with normal plant operating loads and with the switchyard or generator voltages at their expected minimum, 480VAC bus voltage remains above 90.6% of 480VAC which is above the setpoints of the definite time relays, preventing sperious actuation of the protection feature during steady state conditions.

Should 480VAC bus voltage decrease to 90% of 480VAC, voltage at the worst case motor control center will be at 90% of 460VAC or 86.2% of 480VAC. The definite time logic relays will pick up energizing the CV-2 relay which will transfer the Class 1E busses to the Diesel Generators in approximately 20 seconds. Should the 480VAC bus voltage continue to decrease the inverse time function of the relay will shorten the time to trip in accordance with the time dial setting selected..

The relays and all associated equipment are Class 1E and will be in the Class 1E switchgear. The capability for test and calibration during power operation will be provided.

Flordia Power and Light will provide test verification of the analysis performed to establish adequate station electric system voltages prior to fuel loading. Optimum relay setpoints will be determined and based on the test results.

The minimum acceptable operating voltage at the 120VAC level was established by equipment ratings to be 90% of 120VAC. Inspection of Figure 299B-PSB1-A reveals that for all 120VAC panels except PP247 the operating voltage remains above the 90% limit. The unacceptably low voltage of PP247 will be corrected prior to plant operation by load redistribution or other means such that under the defined operating conditions voltages of PP247 and all 120VAC power panels remain above 90% of 120VAC.

Analysis of station electric system voltages was also performed under steady state conditions with the full plant running load and minimum design switchyard voltage supplying the onsite system through the Start-up Transformers. The results of this analysis are shown in on Figure 2998-PSB1-B which demonstrates that, as shown in the analysis for the Unit Auxilary Transformer, all voltages on the Class 1E system with the exception of 120VAC panel PP247 remain above minimum acceptable design conditions. Modification to panel PP247 will be made as previously committed, to insure all voltages remain above the acceptable minimum.

The worst case starting transient was also analyzed for the most limiting conditons which occur on the 2A system since this is the most heavily loaded with all normal plant running loads on the busses, when the startup transformer is supplying the 2A system and offsite switchyard voltage is at the design minimum of 230KV. The results of this analysis are provided in igure 2998-PSB1-C. The analysis indicates that following the starting transient, voltages on all Class 1E busses remain at values above the acceptable design limits and that the voltage on the 4.16KV busses returns to above the relay setpoint of 92.5% within the timer setting of 10 seconds. In accordance with Branch Technical Position, PSB-1, relay actuation during the worst case motor starting transient does not occur.

The 10 second time delay is based on preventing the worst case motor starting transient, which is the 4.16KV condensate pump which accelerates to full speed upon the minimum voltage conditions expected on the main generator or switchyard in 6 seconds, from causing sperious alarms in the control room.

An additional analysis was performed on the onsite system to evaluate the impact of an SIAS and resultant fast dead bus transfer when the offsite source is at the minimum design voltage conditions. The results of this analysis are provided in Figure 2998-PSB1-D which demonstrate that the voltages on the 4.16KV level, 480VAC level and 120VAC level remain with acceptable design limits following the fast dead bus transfer.

The relays and all associated equipment will be Class 1E and will be located in the Class 1E switchgear.

Cabability for test and calibration of the relay scheme during power operation will be provided.

The above scheme meets the requirements of Branch Technical Position PSB-1 section B.1.6(1).

Response to SER Open Item: 90% Motor Starting

When ESF motors are sequenced onto the diesel generator the voltage at the motor terminals must be sufficient to start and accelerate the motor and driven equipment without damage to the motor or impact to the accident analysis. Motors that are supplied for St. Lucie 2 and that are rated 460 volts are designed as standard motors. (90% start) or specially designed for 75% starting voltage.

When the ESF motors are sequenced onto the diesel generator three motors experience starting voltages less than their 460 volt 90% start design. They are the Containment Fan Coolers, and the Shield Building Exhaust Fan.

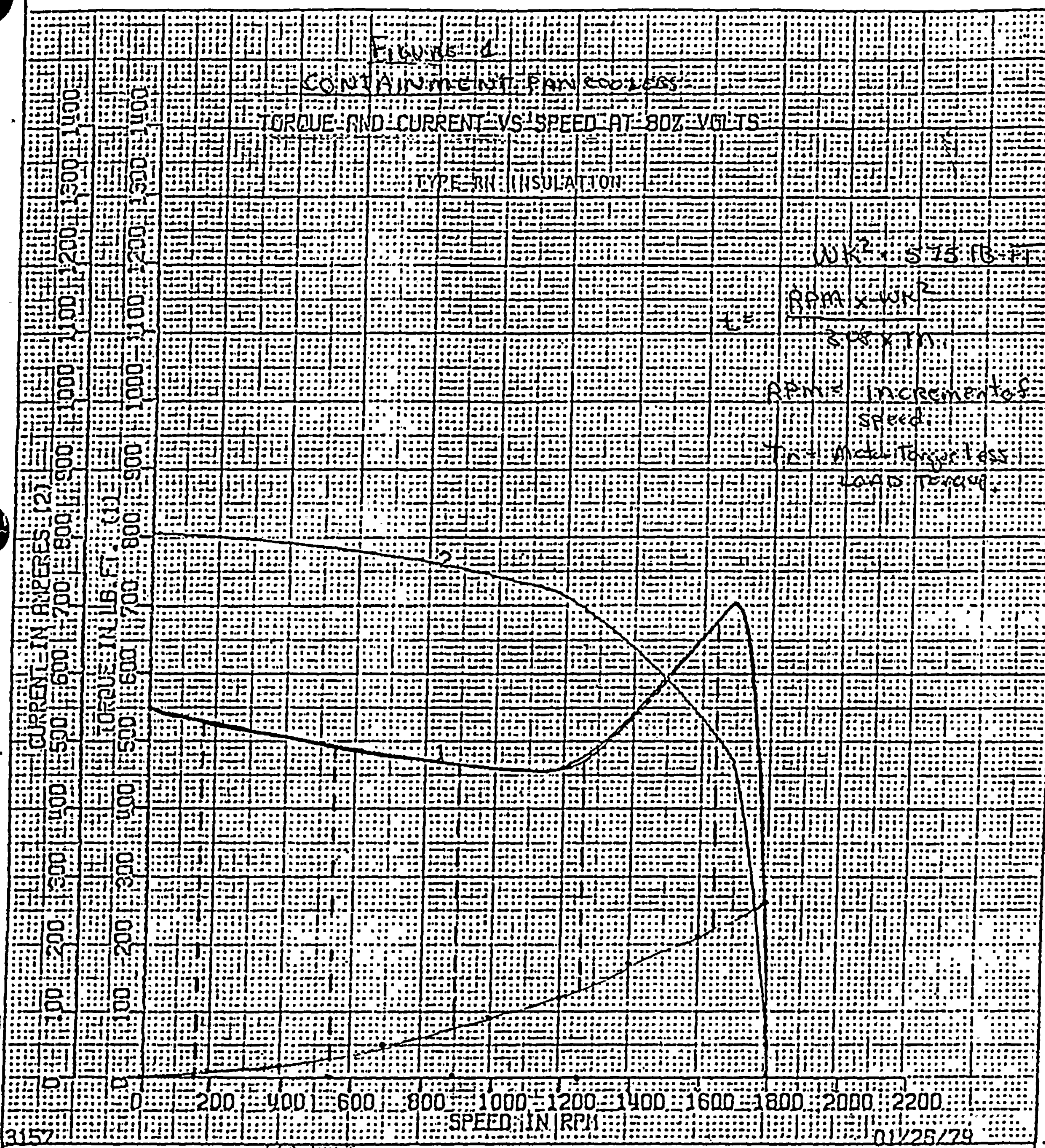
The voltage of the Containment Fan Cooler motor experiencing the worst starting transient is 84.4% of motor nameplate voltage at the instant that the motor is applied to the diesel generator. This voltage recovers to 94.4% of motor nameplate voltage as the result of the recovery of the diesel generator voltage brought about by the voltage regulator action. The next load block to be started by the diesel generator occurs in 3 seconds subjecting these motors to a motor terminal voltage of approximately 87% at the instant the load block is connected which recovers as a result of the diesel generator voltage regulator action to 91.8% motor terminal voltage.

To assure that the motor has sufficient torque to accelerate the driven equipment under this type of transient, the motor manufacturer supplied speed torque curves for motor acceleration considering a constant motor terminal voltage of 80% which is bounding to the starting transient described above. This curve is shown in Figure 1. From this curve net torque (motor torque minus loading torque) was determined at 20% speed intervals and the acceleration time of the motor was calculated to be 7.6 seconds. Comparing this acceleration time to the acceleration time measured in the accident analysis, 10 seconds, indicates that the motor is accelerated in sufficient time as to not impact the accident analysis. To assure that the motors are not damaged during this starting transient, the motor acceleration time was compared to the safe stall time of the motor. From manufacturer's data applied, the safe stall time at 100% starting voltage is 11 secs. (hotstart). The acceleration time of 7.6 secs. is less than 11 seconds and therefore motor damage will not occur. It must be noted that the safe stall time of a motor increases as a result of lower starting voltage since the inrush current is less. Therefore, by comparing the acceleration time at the lower voltage (7.6 seconds) to the safe stall time at the higher voltage (11 seconds) is very conservative. Actual manufacturers data for starting transients such as described above indicates that the safe stall time is increased to 15 seconds.

During the third diesel generator load block and the acceleration of the containment fan coolers, the Shield Building Exhaust Fan is started. The voltage at its motor terminals is approximately 87% of motor nameplate voltage. Since this motor is 90% motor, the motor load was analyzed

in a similar manner as the containment fan coolers described above utilizing the same conservative constant 80% motor terminal voltage. The speed torque curve, taken from manufacturers data for the motor and load is shown on Figure 2. The acceleration time is calculated for this motor is 4.9 seconds. Again comparing this time to the time assumed in the accident analysis, 10 seconds, and comparing this time to the safe stall time typical for motors this size, 11 seconds, indicate that the reduced voltage starting of this motor and load does not impact the safety analysis or damage the motor.

S.O.	-	RPM	1782/1186	S.F.	1.0	ROTOR	41495/-3611
FRAME	4491	VOLTS	460	NEMA DESIGN	A	TEST S.O.	171-882438
HP	125/83	AMPS	144/113	CODE LETTER	H	TEST DATE	1-18-79
TYPE	PH	DUTY	Cont.	ENCLOSURE	TEAO	STATOR RES. @ 25°C	.05222/.0794
PHASE/HERTZ	3/60	AMB°C/INSUL	50/H	E/S	501583		OHMS (BETWEEN LINES)



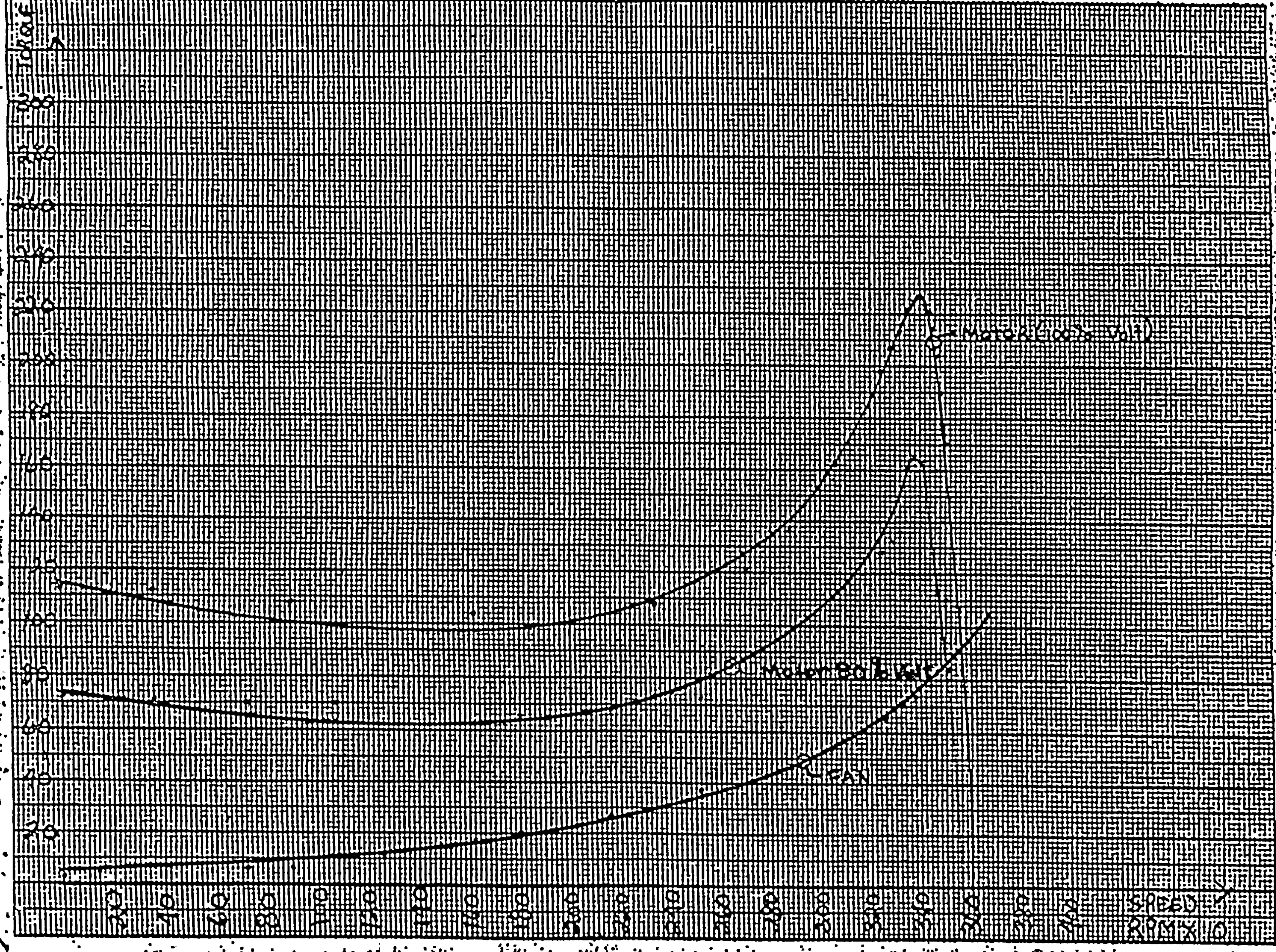
AMPERES SHOWN FOR 460 VOLT CONNECTION. IF OTHER VOLTAGE CONNECTIONS ARE AVAILABLE, THE AMPERES WILL VARY INVERSELY WITH THE RATED VOLTAGE. 4 POLE, 125 HP CONNECTION.

RELIANCE ELECTRIC CLEVELAND, OHIO 44117 U.S.A.	DR. BY ED CK. BY DAM APP. BY [illegible] DATE 1-30-79	A-C MOTOR PERFORMANCE CURVES	SK-50800-636-5 ISSUE DATE 1-30-79

RE 1572VB2 Printed in U.S.A.

2HVE-6A

FIGURE 2. SHIELD BUILDING EXHAUST FAN



ATTACHMENT "A"

Response to NRC Questions on Inadequate Core Cooling Instrumentation

ATTACHMENT A

Response to NRC Questions on Inadequate Core Cooling Instrumentation

(1-13) Responses to questions (1-13) were responded to on a generic basis by the C-E Owners Group. These responses were provided in CEN-181-P, "Generic Responses to NRC Questions on the C-E Inadequate Core Cooling Instrumentation", which was transmitted in a letter from K. P. Baskin (Chairman C-E Owners Group 1 to D.M. Crutchfield dated September 15, 1981. That letter also transmitted CEN-185, "Documentation of Inadequate Core Cooling Instrumentation for Combustion Engineering Nuclear Steam Supply Systems", which is applicable to the St. Lucie-2 ICC instrumentation.

Question 14: Describe how the processor tests operate to determine that the sensor outputs are within range. How are the ranges selected?

Response: Analog signals are converted to digital form through a 12 bit resolution A/D converter. The input electrical ranges are preprogrammed to 0-10V, 1-5V, 4-20 ma, 10-50 ma, and a range suitable for Type K thermocouples.

Functionally, the analog signals are first converted into volts, then scaled to engineering units. The input variable is then compared to upper and lower out of range values to detect out of range inputs. If the variable is out of range, the display will clearly identify the variable as out of range. The out of range variables will be eliminated from algorithms.

Question 15: Describe the display measurement units.

Response: The primary ICC display will be in the Safety Assessment System. However, the QSPDS display will present the measured variables in engineering units. The engineering units will be in units most directly describing the process. For the ICC detection variables, the following units will be used:

FUNCTION	UNITS
1. Saturation/Subcooled Margin	- °F of PSIA (subcooled or superheat)
Inputs	- °F or PSIA
2. Reactor Vessel Level Above the Core	- % height above the core and discrete level displays
Inputs	- °F
3. Core Exit Thermocouple Temperature	- °F

Question 16: Describe which parameter or parameters would need to be calculated from the sensor inputs. The description of the QSODS implies that such a calculation might or might not be required. When would it be required? When would it not be required?

Response: The following ICC detection parameters or variables require calculation from sensor inputs:

1. Saturation or subcooled margin - The maximum of the temperature inputs and the minimum of the pressure inputs are compared to the saturation temperature or pressure to determine the temperature and pressure margin to saturation. Superheat will be calculated up to the difference between the range of the inputs and the saturation temperature.

2. Reactor vessel level above the core - The HJTC sensor differential temperature and the unheated temperature are compared to setpoints to determine if a liquid covered or uncovered condition exists at each sensor location. The corresponding level output is directly related to the number of sensors that detect liquid or an uncovered state.

3. Representative core exit thermocouple temperature - A temperature will be calculated to represent the number of core exit thermocouple temperatures across the core. This calculation has not been determined yet. It is anticipated to be an average calculation such as the averaging of the five highest temperatures.

Question 17: Specifically, describe the automatic on-line surveillance tests.

Response: The following on-line surveillance tests are performed in the QSPDS:

1. The temperature inside the QSPDS cabinet with a cooling system alarm on high temperature.

2. Power failure to the processor with alarm on failure.

3. Bad sensors and broken communication links with indication on the display.

4. CPU memory check and data communication checks with alarm and indication on the plasma display and digital panel meter on the cabinet. (These checks are performed periodically.)

5. Alalog input offset voltage with compensation performed automatically.

6. Inputs out of range with alarm (see Question 14).

7. Low HJTCS differential temperature with alarm.

Question 18: Describe the manual on-line diagnostic capability and procedures.

Response: The automatic on-line surveillance tests replace the need for a manual initiated on-line or off-line diagnostic test to be performed by the computer. A page displaying the status of the automatic surveillance tests will be provided to aid operator diagnostics.

Additionally, the following manual test capabilities are included in the design:

1. Calibration of the A/D boards (with automatic offset voltage compensation).

2. Reset of the system.

Question 19: Discuss the predetermined setpoint for the heated junction thermocouple signals and how it will be selected.

Response: A setpoint on each of two inputs determines the presence or absence of liquid at each HJTC senor location:

1. Differential temperature between the unheated and heated HJTC junctions, and

2. Unheated HJTC junction temperature.

When either of these two input temperatures exceeds the setpoint for the respective input temperature, the logic indicates that the liquid level has dropped to a level lower than the sensor location. The setpoint values are predetermined and are installed as part of the level logic software. The differential temperature setpoint is calculated (based on tests) to be low enough to obtain a good response time but high enough to assure liquid is not present. The unheated junction temperature setpoint is calculated to assure that liquid is not present at the sensor position.

ATTACHMENT "B"

Draft Responses to Appendix 1.9B

Section 3.1.1 Replacement

3.1.1 SATURATION MARGIN

Saturation Margin Monitoring (SMM) provides information to the reactor operator on (1) the approach to and existence of saturation and (2) existence of core uncovery.

The SMM includes inputs from RCS cold and hot leg temperatures measured by RTDs, the temperature of the maximum of the top three Unheated Junction Thermocouples (UHJTC), representative core exit temperature, and pressurizer pressure sensors. The UHJTC input comes from the output of the HJTCS processing units. In summary, the sensor inputs are as follows:

Input	Range
Pressurizer Pressure	0-3000 psia
Cold Leg Temperature	0-710°F
Hot Leg Temperature	0-710°F
Maximum UHJTC Temperature of top three sensors (from HJTC processing)	200-2300°F
Representative CET Temperature	200-2300°F

3.2 DESCRIPTION OF ICC PROCESSING

The following sections provide a preliminary description of the processing control and display functions associated with each of the ICC detection instruments in the AMS. The sensor inputs for the major ICC parameters; saturation margin; reactor vessel inventory/temperature above the core, and core exit temperature are processed in the two channel QSPDS and transmitted to the Safety Assessment System for primary display and trending.

3.2.1 SATURATION MARGIN

The QSPDS processing equipment will perform the following saturation margin monitoring functions:

1. Calculate the saturation margin

   The saturation temperature is calculated from the minimum pressure input. The temperature subcooled or superheat margin is the difference between saturation temperature and the sensor temperature input. Three temperatures subcooled or superheat margin presentations will be available. These are as follows:

a. RCS saturation margin - the temperature saturation margin based on the difference between the saturation temperature and the maximum temperature from the RTDs in the hot and cold legs.

b. Upper head saturation margin - temperature saturation margin based on the difference between the saturation temperature and the UHJTC temperature (based on the maximum of the top three UHJTC).

c. CET saturation margin - temperature saturation margin based the difference between the saturation temperature and the representation core exit temperature calculated from the CETs (Section 2.2.3).

2. Process sensor outputs for determination of temperature saturation margin.

3. Provide an alarm output for an annunciator when temperature saturation margin reaches a preslected setpoint (expected to be within 0°F to 50°F subcooled) for RCS or upper head saturation margin. CET saturation margin is not alarmed to avoid possible spurious alarms.

3.2.2 HEATED JUNCTION THEMOCOUPLE

The QSPDS processing equipment performs the following functions for the HJTC:

1. Determine collapsed liquid level above core.

   The heated and unheated thermocouples in the HJTC are connected in such a way that absolute and differential temperature signals are available. This is shown in Figure 2-6. When liquid water surrounds the thermocouples, their temperature and voltage outputs are approximately equal. The voltage $V_{(A-C)}$, on Figure 2-6 is therefore, approximately zero. In the absence of liquid, the thermocouple temperatures and output voltage become unequal, causing $V_{(A-C)}$ to rise. When V of the individual HJTC rises above a predetermined setpoint, liquid inventory does not exist at this HJTC position.

2. Determine the maximum upper plenum/head fluid temperature of the top three unheated thermocouples for use as an output to the SMM calculation. (The temperature processing range is from 100°F to 2300°F).

3. Process input signals to display collapsed liquid level and unheated junction thermocouple temperatures.

4. Provide an alarm output when any of the HJTC detects the absence of liquid level.

5. Provide control of heater power for proper HJTC output signal level. Figure 2-7 shows the design for one of the two channels which includes the heater controller power supplies.

3.2.3 CORE EXIT THERMOCOUPLE SYSTEM

The QSPDS performs the following CET processing functions:

1. Process core exit thermocouple inputs for display.

2. Calculate a representative core exit temperature. Although not finalized, this temperature will be either the maximum valid core exit temperature or the average of the five highest valid core exit temperatures.

3. Provide an alarm output when temperature reaches a preselected value.

4. Process CETs for display of CET temperature and superheat.

These functions are intended to meet the design requirements of NUREG-0737, II.F.2 Attachment 1.

3.3 SYSTEM DISPLAY

The ICC detection instrumentation displays in both the SAS (primary displays) and the QSPDS (backup displays) have an ICC summary page as part of the core heat removal control critical function supported by more detailed display pages for each of the ICC variable categories.

The summary page will include:

1. RCS/Upper Head saturation margin - the maximum of the RCS and Upper Head saturation margin.

2. Reactor vessel level above the core.

3. Representative core exit temperature.

Since the SAS has more display capabilities than the QSPDS such as color-graphics, trending, and a larger format, additional information may be added and with a better presentation than is available with the QSPDS. These variables are incorporated in other SAS system displays.

Since the SAS receives both QSPDS channels of ICC input, the SAS displays both channels of ICC information. The QSPDS displays only one channel of ICC information for each video display unit.

Although all inputs are accessible for trending and historical recall, the SAS has a dedicated ICC trend page for RCS/upper head saturation margin, reactor vessel level, and representative core exit temperature and core exit saturation margin. These are also available as analog outputs from the QSPDS cabinet.

Each QSPDS safety grade backup display also has available the most reliable basic information for each of the ICC instruments. These displays are human engineered to give the operator clear unambiguous indications. The backup displays are designed:

1. To give instrument indications in the remote chance that the primary display becomes inoperable.

2. To provide confirmatory indications to the primary display.

3. To aid in surveillance tests and diagnostics.

The following sections describe displays as presently conceived for each of the ICC instrument systems. Both primary and backup displays are intended to be designed consistent with the criteria in II.F.2 Attachment 1 and Appendix B.

3.3.1 SATURATION MARGIN DISPLAY

The following information is presented on the primary SAS and backup (QSPDS) displays:

1. Temperature and pressure saturation margins for RCS, Upper Head, Core Exit Temperature.

2. Temperatures and pressure inputs.

3.3.2 HEATED JUNCTION THERMOCOUPLE SYSTEM DISPLAY

The following information is displayed on the CFMS and QSPDS displays:

1. Liuqid inventory level above the fuel alignment plate derived from the eight discrete HJTC positions.

2. 8 discrete HJTC positions indicating liquid inventory above the fuel alignment plate.

3. Inputs from the HJTCS:

    a. Unheated junction temperature at the 8 positions.

    b. Heated junction temperature at the 8 positions.

    c. Differential junction temperature at the 8 positions.

2.3.4. CORE EXIT THERMOCOUPLE DISPLAY

The following information is displayed on the SAS display:

1. A spatially oriented core map indicating the temperature at each of the CET's.

2. A selective reading of CET temperatures.

3. The representative core exit temperature.

The following information is displayed on the QSPDS display:

1. Representative core exit temperature.

2. A selective reading of the CET temperatures (two highest temperatures in each quadrant)

3. A listing of all core exit temperatures.

Replacement Section
5.0 SYSTEM QUALIFICATION

The qualification program for St. Lucie-2 ICC instrumentation will be based on the following three categories of ICC instruments:

1. Sensor instrumentation within the pressure vessel.

2. Instrumentation components and systems which extend from the primary pressure boundary up to and including the primary display isolator and including the backup displays.

3. Instrumentation systems which comprise the primary display equipment.

The in-vessel sensors represent the best equipment available consistent with qualification and schedular requirements (as per NUREG-0737, Appendix B). Design of the equipment will be consistent with current industry practices in this area. Specifically, instrumentation will be designed such that they meet appropriate stress criteria when subjected to normal and design basis accident loadings. Seismic qualification to safe shutdown conditions will verify function after being subjected to the seismic loadings.

The out-of-vessel instrumentation system, up to and including the primary display isolator, and the backup displays will be environmentally qualified in accordance with IEEE-323-1974. Plant-specific containment temperature and pressure design profiles will be used where appropriate in these tests. This equipment will also be seismically qualifed according to IEEE-STD-344-1975. CEN-99(S), "Seismic Qualification of NSSS Supplied Instrumentation

Equipment, Combustion Engineering, Inc." (August 1978) describes the methods used to meet the criteria of this document.

FP&L is evaluating what is required to augment the out-of-vessel Class 1E instrumentation equipment qualification program to NUREG-0588. Consistent with Appendix B of NUREG-0737, the out-of-vessel equipment under procurement is the best available equipment. FPL expects to complete this evaluation by the end of the first quarter of 1982.

Revision to Section
6.2 PROTOTYPE TESTING

The Phase 3 test program will consist of high temperature and pressure testing of the manufactured prototype system HJTC probe assembly and processing electronics. Verification of the HJTC system prototype will be the goal of this test program. The Phase 3 test program is expected to be completed by the end of the first Quarter of 1982.

Revision to Setion
9.0 SCHEDULE FOR ICC INSTRUMENTATION INSTALLATION

Flordia Power and Light is actively pursuing, procuring and expediting equipment necessary to implement requirements for TMI item II.F.2, "Instrumentation for Inadequate Core Cooling". However, this commitment is predicated upon manufacturers and vendors meeting their scheduled delivery promises. When firm schedules are developed FPL will inform NRC of the most probable implementation date.

APPENDIX 1.9B Section 10 Will Be Deleted

Replacement Table
I.9B-2

TABLE 1.9B-2
EVALUATION OF ICC DETECTION
INSTRUMENTATION TO DOCUMENTATION
REQUIREMENTS OF NUREG-0737 ITEM
II.F.2

ITEM	RESPONSE
1.a.	Description of the ICC Detection Instrumentation is provided in Section 3.0. The instrumentation to be added includes the modified SMM, the HJTC Probe Assemblies, and Improved ICI (CET) Detector Assemblies.
1.b.	The instrumentation described in Section 2.0 will be the ICC detection instrumentation design for FPL.
1.c.	The planned modifications to the existing Unit 2 instrumentation will be made prior to fuel load. Modifications include changes to the SMM, design, procurement and installation of the HJTC probe assemblies, and improved ICI Detector Assemblies (which necessitate installation of improved ICI Nozzle Flanges). The final ICC Detection Instrumentation will be as described in Section 3.0.
2.	The design analysis and evaluation of the ICC Detection Instrumentation is discussed in Sections 2.0 and 4.0. and Appendix A. Testing is discussed in Section 6.0.
3.	The HJTCS has one remaining test phase. The Phase 3 test program will consist of high temperature and pressure testing of a manufactured production prototype system HJTC probe assembly and processing electronics. The Phase 3 test program will be executed at the C-E test facility used for the Phase 2 test and is expected to be completed by the first quarter of 1982. No special verification or experimental tests are planned for the hot leg and cold leg RTD sensors, the pressurizer pressure sensors, or the Type K (chromel-alumel) core exit thermocouples since they are standard high quality nuclear instruments with well known responses. For qualification testing, all out-of-vessel sensors and equipment, including the QSPDS up to and including the isolation to the SAS, will be environmentally qualified to IEE Std. 323-1974 as interpreted to CENPD-255 Rev. 01, "Qualification of C-E Instruments", as interpreted by CENPD-182, and seismically qualified to IEEE STd. 344-1975, "Seismic Qualification of C-E Instrumentation Equipment". The qualification to NUREG-0588 is being addressed by the C-E Owners' Group (See the response to item 1 in Table 3 for more information).

Table 1.9B-2 Continued

Necessary augmenting of out of vessel class 1E instrumentation to NUREG-0588 requirements will be addressed by the FPL evalation to be completed by the end of the first quarter of 1982.

4. This table evaluates the ICC Detection Instrumentation's conformance to the NUREG-0737, Item II.F.2 documentation requirements. Table 1.9B-3 evaluated conformance to Attachement 1 of Item II.F.2 Table 1.9B-4 evaluates conformance to Appendix B of NUREG-0737.

5. The ICC detection instrumentation processing and display consists of two computer systems; the 2 redundant channel safety grade microcomputer based QSPDS, and the SAS. The ICC inputs are acquired and processed by the safety grade QSPDS and isolated and transmitted to the primary display in the SAS. The QSPDS also has the seismically qualified backup displays for the ICC detection instruments. The software functions for processing are listed in Section 3.2, the functions for display are listed in Section 3.3.

The software for the QSPDS is being designed consistent to the recommendations of the draft standard, IEEE std. P742/ANS 4.3.2, "Criteria for the Application of Programmable Digital Computer Systems in the Safety Systems of Nuclear Power Generating Stations". This design procedure verifies and validates that the QSPDS software is properly implemented and integrated with the system hardware to meet the system's functional requirements. This procedure is quality assured by means of the C-E QADP. Since C-E has designed the only licensed safety grade digital computer system in the nuclear industry, C-E has the facilities and experience to design reliable computer systems.

The QSPDS hardware is designed as a redundant safety grade qualified computer system which is designed to the unavailability goal of 0.01 with the appropriate spare parts and maintenance support.

6. Section 9.0 discusses the schedule for installation and implementation of the complete ICC Detection Instrumentation.

7. Guidelines for use of the ICC Detection Instrumentation are discussed in Section 7.0.

8. A future amendment will discuss key operator actions in the current emergency procedures for ICC. The ammendment will be submitted prior to fuel load. Section 7.0 discusses the emergency procedures to be implemented upon incorporation of the complete ICC Detection System.

Table 1.9B-2 Continued

9. The following describes additional submittals that will be provided to support the acceptability of the final ICC Detection Instrumentation.

1) Environmental and Seismic Qualification of the instrumentation equipment. Additional evaluation to NUREG-0588 will be provided by June 1982.

2) Modifications to emergency procedures (prior to fuel load)

3) Changes to Technical Specifications (prior to fuel load)

TABLE 1.9B-3

EVALUATION OF ICC DETECTION INSTRUMENTATION

TO ATTACHMENT 1 of II.F.2

ITEM	RESPONSE
1	St. Lucie 2 has 56 core exit thermocouples (CETs) distributed uniformly over the top of the core, Section 3.1.3 has a discription of the CET sensors, Figure 1.9B-7 depicts the locations of the CETs.
2.	The SAS meets the primary display requirements for CET temperatures.
2.a.	A spatial CET temperature map is available on demand.
2.b.	A selective representative CET temperature will be displayed continuously on demand. Although not finalized, this temperature will be either the maximum CET temperature or the average of the five highest CET temperatures.
2.c.	The SAS provides direct readout of CET temperature with a dedicated display page. The line printer provides the hardcopy capability for recording CET temperatures.
2.d.	The SAS has an extensive trend and historical data storage and retrieval system. The historical data storage and retrieval system function allows all ICC inputs to be recorded, stored, and recalled by the operator. The operator (and other user stations) can graphically trend any CET value on the display screen. A dedicated ICC trend page which includes the representative CET temperature and representative CET saturation margin will be accessible to the users.
2.e.	The SAS has alarm capabilities and visually displayed value alarms on the system level pages.
2.f.	The SAS is an extensively human-factor designed display system which allows quick access to requested displays.
3.	ICC instrumentation QSPDS design incorporates a minimum of one backup display with the capability of selective reading of a minimum of 16 operable Thermocouples, 4 from each quadrant. All CET temperatures can be displayed within 5 minutes.
4.	The types and locations of displays and alarms are determined for the primary display by performing a human-factors analysis. The QSPDS also incorporates human factors engineering. The use of these display systems will be addressed in operating procedures, emergency procedures, and operator training.
5.	The ICC instrumentation was evaluated for conformance to Appendix B of NUREG-0737 (see Table 1.9B-4).

Table 1.9B-3 Continued

6. The QSPDS channels are Class 1E, electrically independent, energized from independent station Class 1E power sources and physically separated in accordance with Regulatory Guide 1.75 "Physical Independence of Electric Systems" January 1975 (R1) up to and including the isolation devices.

7. ICC instrumentation shall be environmentally qualified pursuant to C-E owners group qualification program. The isolation devices in the QSPDS are accessible for maintenance following an accident.

8. Primary and backup display channels are designed to provide the highest availability possible. The QSPDS is designed to provide 99% availability. The availability of the QSPDS will be addressed in the Technical Specifications.

9. The quality assurance provisions of Appendix B, Item 5, will be applied to the ICC detection instruments as described in the Appendix B evaluation in Table 1.9B-4.

Revision to Table 1-9B-4

ITEM	RESPONSE
5.	1.144 "Auditing of Quality Assurance Programs for Nuclear Power Plants".
6.	The ICC detection instrumentation outputs are continuously available on the QSPDS displays through manual callup of displays through manual callup of displays. Additionally, one channel of analog trend recording will continuously indicate the ICC summary variables.
7.	The ICC instrumentation is designed to provide readout display and trending information to the opeartor through the SAS and analog trend recording of the ICC summary variables. (See Section 3.3).
8.	The inadequate core cooling instrumentation is specifically and singularly identified so that the operator can easily discern their use during an accident condition.
9.	Transmission of signals from instruments of associated sensors between redundant IE channels or between 1E and non-1E instrument channels are isolated with isolation devices qualified to the provisions of Appendix B.
10.	The QSPDS consists of two redundant channels to avoid interruptions of display due to a single failure. If in the remote chance that one complete QSPDS channel fails, the operator has: 1) Additional channels of ICC sensor inputs for cold leg temperature, hot leg temperature, and pressuizer pressure on the control board separate from the QSPDS. 2) The HJTCS and CET have multiple sensors in each channel for the operator to correlate and check inputs. 3) The HJTCS sensor output may be tested by the operator reading the temperature of the unheated thermocouple and comparing to other temperature indications. 4) Other variables are available to the operator on the Main Control Board for verifying the ICC parameter.
11.	Servicing, testing and calibrating programs shall be consistent with operating technical specifications.
12.	The ICC instrumentation, including the QSPDS, are not intended to be removed or bypassed during operation. Administrative control will be necessary to remove power from a channel.
13.	The system design is such as to facilitate administrative control of access to all setpoints adjustments, calibration adjustments and test points.

Revision to Table 1.9B-4 Continued

14. The QSPDS is designed to minimize anomalous indications to the operator (see section 3.3).

15. Instrumentation is designed to facilitate replacement of components or modules. The instrumentation design is such that malfunctioning components can be identifed easily.

16. The design incorporates this requirement to the extent practical.

17. The design incorporates this requirement to the extent practical.

18. The system is designed to be capable of periodic testing of instrument channels.

MATRIX POWER SUPPLY ISOLATION DEVISE TESTING

Isolation within the Reactor Protective System is discussed in general within the response to NRC question 420.7. Below are excerpts from this response:

> "Each matrix is powered from the diode isolated power supplies located in two different channels of the RPS. Each power supply has with it an isolation circuit which limits the fault to acceptable values and prevents the fault from disturbing the independent vital buses.
>
> All isolation devices discussed above are qualified to 480V ac and 325V dc and tested to 600V ac and 400 dc. The entire system is also subjected to an EMI test in accordance with MIL-STU-461 'Electromagnetic Interference Characteristics Requirements for Equipment' for both conducted and radiated signals using test CS01, CS02, CS06, RS07 and RS03."

The following provides further definition on the method of qualifying the RPS matrix power supply (with associated isolation networks) to the requirements of IEEE-323-1974. Aging qualification requirements are not considered in this discussion.

A. Fault Isolation Qualification

The maximum credible fault is limited to 600 VAC and 400 VDC due to the following design separation and precaution described below:

- All cables routed from the respective instrument bus to various loads are classified as low level circuits and are routed in enclosed raceways with one exception. This cable is a control circuit whose cable route is through the cable vault area. Both instrumentation and control cables do not exceed a voltage of 480 volt.
- The cable spreading area and control room do not contain high energy equipment such as high energy switchgear, transformers over 480 volts, high energy rotating equipment, or potential sources of missiles or pipe whip, and are not used for storing flammable materials.
- High energy circuits are considered to be those with available fault currents in excess of the interrupting rating of the 480V motor control centers.
- Circuits in the cable spreading area and control room are limited to control functions, instrument functions and those power supply circuits and facilities serving the control room and instrument systems.

- D C Power supply feeders from redundant MA, MB, MC and MD instrument buses to the control room are installed in enclosed raceways that qualify as barriers.

- The instrument power supply system equipment is designed to meet seismic and environmental qualification requirements for class IE equipment.

- All cables are flame resistant and are qualified in accordance with IEEE Standard 383.

- Different parameter signal cables are in the same wireway as long as they do not belong to separate redundant channels; separate tray and conduct systems are provided for power and control and low level instrument systems.

- All cables are inspected by site quality control to assure that they are not damaged in the process of cable pulling. The inspection of these cables is documented and subject to random audit by quality compliance.

- All electrical raceways are seismically supported.

Matrix power supplies and isolation circuits are configured within the RPS as shown in Figure 1. The isolation test will consist of the application of a 600 Vac and 400 Vdc fault in the circuit in the common and transverse modes. The basis for the 600 Vac and the 400 Vdc test voltage is as follows:

- 600 Vac: The highest credible AC fault voltage which could appear within the RPS is 480 Vac. This voltage is increased by 10% to 528 Vac to account for normal voltage tolerances and then again increased by 10% to 581 Vac to account for IEEE-STD-323-1974 margin. This voltage is then rounded off to 600 Vac.

- 400 Vdc: The highest credible DC fault voltage which could appear within the RPS is 325 Vdc. This voltage is increased by 10% to 358 Vdc to account for normal voltage tolerances and then again increased by 10% to 394 Vdc to account for IEEE-STD-323-1974 margin. This voltage is then rounded off to 400 Vdc.

1. Common Mode Test

The common mode test is accomplished by applying a fault to the DC side of a matrix power supply between point (G) and the power supply chassis. The fault voltage and current are monitored to define the fault characteristics. Also, the 120 Vac line side of the power supply is monitored to document any effect as a result of application of the fault. All monitoring is by means of a light beam recorder. This same process is repeated for point (H) to the power supply chassis.

For the purpose of this test, it has been conservatively assumed that it is a fault appeared on vital bus B (points A or B to chassis ground in Figure 1) it

would propagate through the DC power supply (PS-B) and appear at points C or D. Since PS-B is directly connected to PS-A (through CR-1 and CR-2) the fault is assumed to appear at points G of H to ground. Therefore, it is required to show that when a fault is present on the BC side of a matrix power supply it does not propagate to the 120 Vac side of the power supply, thereby affecting more than one vital bus. It should be noted that complete propagation of a fault from power supply primary to secondary is a conservative fault circuit evaluation which would most likely not occur.

2. Transverse Mode Test

The transverse mode test is accomplished by applying the fault directly to the output terminals (E and F) of the isolation circuit. This fault voltage and current are monitored to define the fault characteristics. Also, the input side (G and H) of the isolation circuit and the 120 Vac line side (J and K) of the power supply is monitored to document any effects as a result of application of the faults. All monitoring is by means of a light beam recorder.

Similar to the common mode test, a fault appearing on vital bus B (Figure 1 points A and B) is assumed to propagate completely to points E and F. Therefore, it must be shown that application of a fault to the output of the isolation circuit (points E and F) does not propagate in the 120 Vac side of power supply A thereby affecting more than one vital bus. It should be noted that the isolation circuit clamps the fault voltage such that power supply damage does not occur, as discussed below:

- Clamp Circuit - The power supply fault clamp circuit is designed to limit or shortout a positive or negative fault. Figure 1 is a schematic of the fault clamp circuit which is connected to each matrix power supply. During normal operation VRI is in the open circuit condition, SCR-Q1 is deenergized and CR4 is reverse biased. The normal 28 Vdc output of the power supply will be seen between points E and F.

  The clamp circuit operates in the following manner. On the negative cycle, the fault is clamped or shorted out by CR4, causing F1 to open. On a positive cycle, the fault would cause VR1 to conduct upon reaching an amplitude to 47V (combined 28V PS volts and 19V fault).

  With VRI conducting, SCR-QI will energize, shorting out or clamping the fault and the power supply output, causing F1 and F2 to open.

3. Acceptance Criterion

The acceptance criterion for the above tests is that upon application of the fault the input power supply voltage does not vary more than ± 10% from the nominal voltage.

B. Surge Qualification

A surge test will be performed on the RPS according to the guidance of IEEE Standard 472-1974, to the extent practical. The test will be performed similar to that which was performed on the ANO-2 Plant Protection System (PPS) and subsequently approved by the NRC.

The test involves simulating (with identical equipment) a typical RPS matrix (Figure 2) including bistable trip units, bistable power supplies, matrix power supplies, matrix relays, and isolation relays. Vital bus power (120 Vac) is simulated by using two power isolation transformers. A 300 Vac surge (negative peak to positive peak) will then be superimposed on one vital bus. Thus, the test voltage from neutral to peak will be 337 volts (120 Vac + 10%) x 1.414 plus the neutral to peak surge 300V/2. The surge voltage is based on a calculation performed for the ANO-2 PPS which concluded that circuit damage or false operation would not occur provided the peak AC voltage is maintained below 400 Vac. Since the equipment within the St. Lucie Unit 2 PPS is similar (but not identical) to the ANO-2 PPS it is assumed that calculation conclusions are applicable to the RPS.

An ultra isolation transformer is being added to the vital bus inverter system in order to attinuate any line surges which may pass through the inverter system. The isolation transformer will be surge qualified in accordance with the guidelines of IEEE standard 472-1974. This will include application of the surge to the primary winding in both the common and transverse modes. The acceptance criteria for this test is that the transformer limits this surge on the secondary to a 50 Volt pulse. Note that the credible surge seen by the RPS is limited to 50 volts which is a factor of one third less than the surge being applied to the RPS. The transformer will also be qualified to the requirements of IEEE standard 344-1975 and IEEE standard 323-1974 (minus aging).

1. Common Mode Test (Figure 1)

The common mode test is accomplished by applying a surge to the AC side of the matrix power supply between point (A) and the power supply chassis. During surge application the simulated RPS circuit is operated to show proper function and accuracy. Also, the 120 Vac line of the associated power supply is monitored across points (J) and (K). The same process is repeated for point (B) and the power supply chassis.

2. Transverse Mode Test (Figure 1)

The transverse mode test is accomplished by applying a surge to the AC side of the matrix power supply between points (A) and (B). During application of the surge the simulated RPS circuit is operated to show proper function and accuracy. Also the 120 Vac line of the associated power supply is monitored across points (J) and (K).

3. Acceptance Criterion

The acceptance criterion for the above tests is that all circuits shall operate correctly and within their normal accuracy requirements. Also, the voltage observed at points (A) and (B) should not vary more than ± 10% of the nominal voltage.

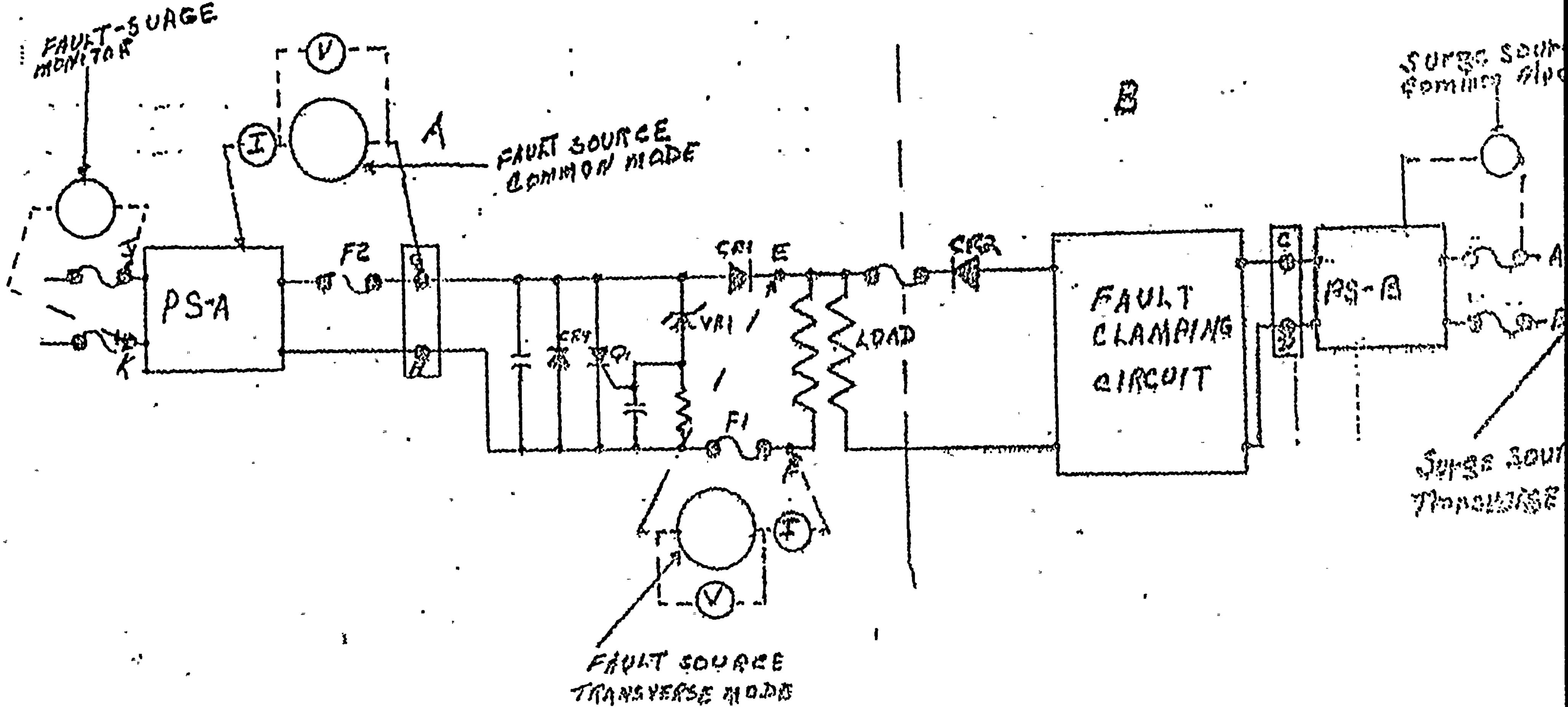
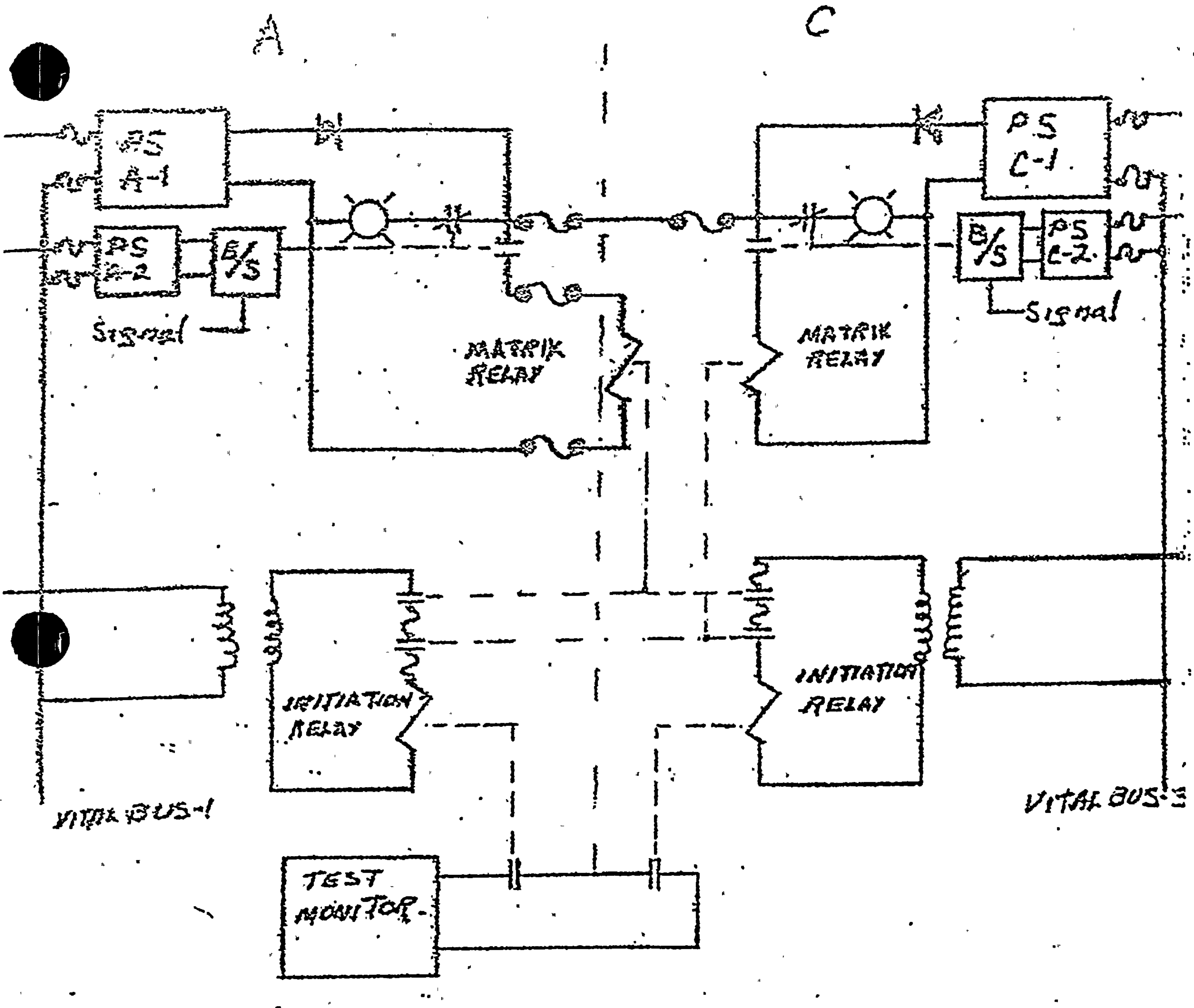

FAULT-SURGE MONITOR
A
B
FAULT SOURCE COMMON MODE
PS-A
F2
CR1
E
VR1
LOAD
F1
FAULT CLAMPING CIRCUIT
PS-B
FAULT SOURCE TRANSVERSE MODE

Figure - 1



B/S - Bistable

PS-A1 & C1 have clamp circuit.

Figure -2

<u>Clarification to Our Final Response to the NRC Control Room Audit Findings</u>

A meeting was held at the St. Lucie Site on Friday, October 30, 1981, with Joe Joyce of the Human Factors Engineering Branch of the NRC and representatives of Flordia Power & Light. Discussed were several clarifications to our final response to the NRC Control Room Audit Findings.

This letter is to document those clarifications. The page numbers and section numbers refer to our submittal, Florida Power & Light letter L-81-420, Attachment H, dated September 24, 1981.

Page 5 to 59 Section 1.12	Add - This item will be scheduled for implementation prior to issuance of an operating license.
Page 8 of 59 Section 2.1	Add - This item will be scheduled for implementation prior to issuance of an operating license.
Page 16 of 59 Section 4.1b	Replace first sentence with: The 2C pump is a swing pump used while either the 2A or 2B pump is out for maintenance. Add the word "The" in front of the second sentence.
Page 19 of 59 Section 4.11	After the word conventions insert "(teeth down)".
Page 27 of 59 Section 5.16	Replace the entire response with the following: A lighting color convention will be established with implementation scheduled prior to issuance of an operating license.
Page 30 of 59	The second sentence should be revised to read as follows: "The following method will be..." Replace 24.b with: Installing filament warning circuits to extend filament life. In 24.f replace the word "periodic" with the word "monthly".
Page 35 of 59 Section 6.12	Replace "NUREG" with "Reg. Guide".