50-400 OL

9/10/84 I-J.I.-23

9/10/84

EXHIBITS TO BE OFFERED INTO EVIDENCE BY JOINT INTERVENORS
for Applicants' Panel III and NRC Staff Panel

Panel III:
Other exhibits previously identified or placed into evidence

'85 JAN -8 P3:51

OFFICE OF SECRETARY
DOCKETING & SERVICE

NRC Staff:
Enforcement Action (EA) letters, inspection report numbers, and CP&L response for civil penalties

1) IE Report 50-324/75-10; CP&L responses
2) IE Reports 50-324/80-15 and 50-325/80-18; EA-80-41; CP&L response
3) IE Reports 50-324/80-11 and 50-325/80-12; EO-80-26; CP&L response
4) IE Report 50-324 and 325/81-16; EA-81-77; CP&L response
5) IE Report 50-324 and 325/82-02; EA-82-75; CP&L response
6) IE Reports 50-324 and 325;82-28; EA-82-106; CP&L response
7) IE Report 50-324 and 325/83-11; EA-83-88; CP&L responses
8) IE Report 50-261/81-10; EA-81-46; CP&L responses
9) IE Report 50-261/81-24; EA-82-07; CP&L response
10) IE Report 50-261/83-22; EA-83-94; CP&L response
11) IE Report 50-261/84-05; EA-84-14; CP&L response

Each of the above address CP&L civil penalties. They are listed more completely on pp. 7 - 8 of NRC Staff Further Response to Interrogatories (4/25/84)

Comparison between number and levels of violations and deficiencies in the SALP Reports (I - IV)

SECY 81-617 Preliminary Assesment of Organization and Management of CP&L (in response to 1980 Commission Order CLI-80-12, 11 NRC 514).

Portions of the transcript to the ACRS meetings (January 16, 1984) may be used

NUCLEAR REGULATORY COMMISSION

Docket No. 50-400 Official Exh. No. JI 23
In the matter of Sheron Harris #1

Staff ____ IDENTIFIED ✓
Applicant ____ RECEIVED ✓
Intervenor ✓ REJECTED ____
Cont'g Off'r ____ DATE 9-10-84
Contractor ____ Witness ____
Other ____

Reporter WRB

John Runkle
counsel for
Joint Intervenors

JI 23

FINAL DRAFT

-INVESTIGATION-
CAROLINA POWER AND LIGHT COMPANY
BRUNSWICK STEAM ELECTRIC PLANT

FEBRUARY 1982

A. RONALD JACOBSTEIN

prepared for:

STATE OF NORTH CAROLINA PUBLIC STAFF

UTILITIES COMMISSION

TABLE OF CONTENTS

1.0 INTRODUCTION

1.0 INTRODUCTION

The performance of Carolina Power and Light Company's Brunswick units has been deteriorating since 1979. In an effort to assess the causes of this and to better understand reasons and the future expectation for these units, the Public Staff of the North Carolina Utilities Commission requested that the operations of these plants be reviewed for the period subsequent to 1979.[1] This review was conducted by the author and is the subject of this report.

This report is divided into seven sections, including:

1.0 Introduction

2.0 Plant Description and Operating History

3.0 Past Outage Evaluation

4.0 Problem Systems and Equipment

5.0 Related Plant Procedures and Programs

6.0 Organization and Staffing

7.0 Conclusions

In conducting this review, several sources of data and information were utilized including that generated from regulatory bodies, the CP&L staff and other CP&L vendors.

SECTION 1.0 REFERENCES

1. Robert Fischback (NC Public Staff) letter to R. Jacobstein RE: Carolina Power and Light Company -- Brunswick Investigation, dated September 11, 1981 (Appendix A).

2.0 PLANT DESCRIPTION AND OPERATING HISTORY

2.0 PLANT DESCRIPTION AND OPERATING HISTORY

This section provides a brief general description of the Brunswick units and an overview of their operational history.

The Brunswick plant consists of two essentially identical operating generating units, each with a rated MNDC of 790 MWe. These units were placed in commercial operation as follows:

Unit 2 - November, 1975

Unit 1 - March, 1977

Each reactor building houses a single cycle, forced circulation General Electric Boiling Water Reactor (BWE) nuclear steam supply system (NSSS) and its auxiliaries. During operation, steam is supplied to a General Electric, direct-driven turbine generator rated at 850 MW. Both unit turbines are located in a common building referred to as the turbine building. Heat rejection from the main condensers is via a once-through circulating water system drawing from the Cape Fear Estuary and discharging to the Atlantic Ocean via a discharge canal and discharge system.*

Since startup, the capacity of factors from Units 1 and 2 have averaged 56% and 46%, respectively. Table 2-1 is a presentation of capacity factors by calendar year. On the average, the performance of Unit 2 is well below the industry norm, while that of Unit 1 agrees with the industry expectation. Most perplexing, however, is the downward trend of both units as opposed to the general industry trend of improved performance with plant age.

Although the reasons for forced outages and curtailments are well documented, the root causes are much more subtle and difficult to

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* For a more complete description of the Brunswick Nuclear Power Station, refer to the Brunswick Final Safety Analysis Report (FSAR).

identify. The focus of this investigation has been to delve into the significant plant upsetting events and, if possible, uncover and report on the root cause problems. Tables 2-2 and 2-3 provide a summary of upsetting key events that impacted plant availability and capacity factors during the period 1978-1981 (part).

TABLE 2-1

BRUNSWICK UNIT CAPACITY FACTORS (%)

Year	Unit 1	Unit 2
1977	46	35.2
1978	74	69.3
1979	45.8	52.8
1980	56.8	26.9
1981(Proj.)	33	45
1982(Proj.)	43	50

Source: B. J. Furr (CP&L).

TABLE 2-2

SUMMARY OF KEY UPSETTING EVENTS - UNIT I

DATE	TYPE	DURATION	CAUSE
1978			
1-1	SD	5	Drywell O_2 level 4%.
1-6	C		Condenser cleaning and tube plugging (A-N).
1-13	SD	57	Condenser hotwell drain line leak; steam tunnel tem. switch.
1-19	SD	65	Steam leaks on control, bypass & main steam valves; maintenance to correct original workmanship.
2-4	C/S	29	Condenser cleaning; reactor feed pump problem.
2-8	C	0	Condenser leaks (A-N).
2-13	S	335	Electrical Problem - B Bus. Caused other equipment failures. "B" - Recirc. Pump seal; RWCU pump seal; and 1B hogging pump - Replaced both Recirc pump seals; cleaned condensers, repaired feedwater heaters.
2-27	SD	28	Safety relief valve 13H.
3-9	C	0	Condenser leaks (A-N).
3-13	S	39	Main Stm. leak detector, spurius - Safety relief valve 13F.
4-4	S	52	Stator cooling problem - spurius.
4-7	S	7	Stator cooling problem.
4-8	S	11	Blown fuse.
4-30	S	8	Loss of RFP-"B" while shifting strainers.
5-1	SD	34	Safety relief valve 13H.
5-9	C	1	"4A" Feedwater heater (740 mw to 598 mw).
5-19	SD	105	Recirc. pump seals; 3 safety relief valves.
5-27	SD	8	"A" Recirc. discharge valve packing leak.

SUMMARY OF [illegible] UPSETTING EVENTS - UNIT I
(Cont.)

DATE	TYPE	DURATION	CAUSE
6-9	C	9	Rod swap and valve testing.
6-27	S	34	Turbine vibration instrumentation malfunction.
7-26	S	27	Instrument calibration - Rx level.
7-29	S	12	Reactor Feed Pump problem.
8-8	S	13	During testing.
8-10	C	5	Master trip solenoid fault.
9-8	C	23	Condenser cleaning and tube repair (B-S).
9-10	C	13	Condenser leaks (B-S).
9-15	C	80	Condenser leaks (B-S).
9-24	SD	147	Snubber inspection; replaced recirc. pump seals; recirc. riser safe-end inspection.
10-5	C		Stator cooling filters clogged; RFP-"A" problems.
11-2	S	18	Operator error
11-11	S	28	Conductivity and level control problem.
11-17	SD	52	Recirc. safe-end reinspection.
1979			
1-12	SD		Refueling - scheduled - 86 days/actual - 93 days.
5-1	S	67	Instrument problem.
5-16	C	9	Condenser leaks (A-N).
5-20	C	2	Rod sequence change.
5-21	C	6	Fish problems.

SUMMARY OF KEY UPSETTING EVENTS - UNIT
(Cont.)

DATE	TYPE	DURATION	CAUSE
5-26	SD	372	Hanger problems, 79-14 inspection; 41 hanger mods.
6-13	C	0	Valve testing and control rod sequencing.
6-21	C	0	Condenser leaks.
7-28	S	13	Recirc. pump MG set and water level problems.
8-4	S	15	Turbine control valve.
8-9	S	16	Turbine control valve.
8-19	S	12	Vessel water level instruments.
9-8	SD	215	Snubber inspection; H_2 seals.
10-8	S	18	Loose fuse.
10-19	S	141	Main stm. High Radiation caused by cleanup resin injection - NRC delay three days for investigation.
11-2	S	219	Electrical problems.
11-5	S	262	Testing feedwater control system.
12-1	SD	78	Recirc. packing leaks; Recirc. pump staging flow valve problem.
12-12	SD	215	Snubber inspection; safety relief valve modification; Rx. recirc. pump seals.
12-21	SD	2	Relief valve repair.
1980			
1-4	C	7	Rod sequence change.
1-10	C	7	Rod sequence change.
2-23	C	5	Rod sequence change.

SUMMARY OF KEY U[illegible]TTING EVENTS - UNIT I
(Cont.)

DATE	TYPE	DURATION	CAUSE
3-4	C	31	Condenser leaks (B-N) none found.
3-8	C	24	Condenser leaks (B-N).
3-23	S	44	Operator error; subsequent cooldown due to failure of drywell O_2 monitor.
3-26	SD	40	Valve packing leaks; problems with N_2 inerting - aux. boiler shutdown
3-31	S	62	Failure of "1D" Bus; Rx water level instrumentation.
4-3	C	42	HPCI problems.
4-5	S	30	Turbine trip during valve test; drywell leakage-instrument problem.
4-8	S	125	Electrical grounds.
4-15	S	50	Electrical grounds.
4-22	C	35	Condensers (A-S leaks) (B-N no leaks).
4-26	SD	20	Valve packing leak.
5-8	C	5	Condenser cleaning (A-N).
5-9	C	14	Condenser celaning (A-S).
5-14	C	281	Condenser leaks (B-N) - none found.
5-26	SD		Refueling - planned 38 days; actual 85 days.
9-12	SD	71	Main generator bearing.
10-14	S	43	Operator error.
10-17	C	23	Condenser leaks (B-N) none found.
10-19	C	40	Condenser leaks (B-N).
11-5	C	14	Rod sequence change.
11-8	C	42	Condenser leaks (B-N).

SUMMARY OF KEY UPSETTING EVEN !T I
(Cont.)

DATE	TYPE	DURATION	CAUSE
12-12	C	10	Bypassed 4A/5A Feedwater heaters.
12-28	SD	225	Feedwater heater repairs; snubber inspection.
1981			
1-20	S	40	Rx water level low - RIP valve shut.
1-26	C	38	Condenser leaks.
1-30	S	38	"A" RFP trip - no explanation.
2-2	C	127	Condenser leaks (A-N).
2-8	C	51	Condenser leaks (A-N, A-S, B-N).
2-12	S	24	Fish problems.
2-24	SD	13	High O_2 levels in drywell; N_2 pipe break.
3-25	C	28	MG set brush rigging.
3-07	C	21	Condenser leaks (A-N).
3-09	C	4	"1B" MG set brushes.
3-16	C	10	Condenser leaks (A-S).
3-17	C	6	Instrumentation.
3-20	C	31	Condenser leaks (A-S).
3-29	S	201	MSIV problem; HPCI pipe hanger repairs; burned coil in MG set.
4-10	C	179	MSIV closed.
4-17	SD	313	RHR Heat exchanger-oyster shells.
5-1	SD		Planned outage - scheduled 57 days/actual 165 days.
9-24	SD	18	Turbine trip due to power'load unbalance signal.

TABLE 2-3

UMMARY OF KEY UPSETTING EVENTS - UNIT

DATE	TYPE	DURATION	CAUSE
1978			
1-1	C		2A RFP bearing and spped control.
1-1	SD	20	Steam leaks on main steam bypass valves; HPCI speed control probs.
1-2	S	22	Operator error - select rod insert.
1-4	C		Tip system failure.
1-6	S	81	Rx. water level/operator error. Repaired HPCI spd. control and steam leaks.
1-17	S	17	Relay crew error.
1-31	S	26	EHC system calibration/operator error.
2-11	C	12	Condenser leaks (B-S).
2-19	C		Condenser leaks (B-S).
3-3	C		Condenser leaks (B-S).
3-5	S	25	Rx water level/operator error.
3-13	S	25	Inst. cal/operator error.
3-23	C		Turbine Bldg. HVAC probs.
3-24	S	7	Generator trip due to grounds/TB HVAC probs.
3-26	S	5	Generator trip due to grounds/TB HVAC probs.
3-28	S	6	Generator trip due to grounds/ TB HVAC probs.
3-29	S	144	Generator trip due to grounds/TB HVAC probs. Partial ground on generator bus leads, dehumidifier installed incorrectly; "B" recirc. pump seal replaced.
4-9	S	15	Electrical mod. design problem (relay failure).

SUMMARY OF KEY UPSETTING EVENTS - UNIT
(Cont.)

DATE	TYPE	DURATION	CAUSE
5-17	S	22	Operator error.
5-23	S	13	Rx. water level/operator error.
5-31	C	6	Htr. drain deaerator LL switch failure; MSR leaks.
6-2	SD	214	Generator hydrogen leaks; "A" recirc. pump seal; 4 - CRD's replaced.
6-11	SD	247	"A" recirc. pump thermal barrier failure.
7-3	S	85	Stop valve tests in progress - no explanation; "A" recirc. pump seal, "4A" Feedwater heater.
7-18	S	24	APRM upscale/recirc. pump controller - no explanation.
8-5	C	9	MSIV Limit switch repair.
8-18	SD	81	"A" recirc. discharge valve packing leak; prob. with backweat - jury-rigged.
9-6	S(M)	423	Conductivity - failure of extraction steam exp. joints and condenser tube damage. Inspected recirc. riser safe-ends.
10-7	C	0	MSIV testing; condenser cleaning (A-N & A-S).
11-6	S	193	Generator lockout/broken shield cable investigation. Recirc. seal failure.
11-30	S	19	Rx. water level/operator error - investigation.
1979			
1-27	C	14	Condenser leaks (B-N).
1-29	S	14	APRM Hi flux/MSIV "A" closed-stem separation. Continued operation at 50% reduced perver.
2-3	C	35	Valve testing. Power remained at 47% for core management -- dispatcher request.
2-4	S	7	APRM spikes/instability during RFP testing; EHC & FW control tuned.
3-2	SD		Refueling estimated 64 days/actual 78 days.

SUMMARY OF KEY OPERATING EVENTS - UNIT II
(Cont.)

DATE	TYPE	DURATION	CAUSE
5-21	S	32	Rx. water level/operator error.
5-23	S	14	RFP testing/operator error.
5-25	SD	419	Pipe support inspection and modification (47 mods).
6-29	SD	126	Pipe support inspection and snubber testing. TAR 78-085 -- Mechanical snubber evaluation.
7-19	SD	42	Safety relief valve 13F.
7-31	S	70	Circulating water leak; HPCI valve motor.
8-31	SD	142	Pipe support inspection and mods; snubber inspection.
9-7	SD	21	Main steam drain line leak; motor limit switch failure.
9-12	SD	25	Nuc. service water leak.
9-14	S	17	Load rejection/EHC electronics problem.
9-22	SD	12	Tip system problem/tube dented.
10-18	SD	4	RHR heat exchanger/service water supply leak.
10-25	C	79	Condenser leaks (A-S, B-N, B-S) - leak in B-N could not be repaired.
11-9	C	35	Condenser leaks (A-S, B-N) - B-N not fixed, but near top.
11-19	S	52	Janitor jarred instrument panal.
11-30	C	35	Condenser leaks (A-N, B-N seam); B-N not repaired.
12-25	SD	250	Safety relief valve indication mods; repaired B-N waterbox; leak in recirc. test connection; snubber testing; prob. with boiler water purity.

SUMMARY OF KEY UPSETTING EVENTS - UNIT
(Cont.)

DATE	TYPE	DURATION	CAUSE
1980			
1-7	SD	52	Safety relief valves 13A & 13K.
2-12	C	9	Condenser leaks (A-S).
2-13	S	57	Calibration checks/Operator error.
2-19	C	8	"A" RFP control/TB HVAC.
3-1	SD		Refueling outage estimated 71 days/actual 200 days.
9-23	SD	77	Valve packing leaks (E51-F007); Valve body weld crack (FW-FV46).
10-11	S	54	Preventive maintenance/operator error.
10-28	S	23	Feedwater controller failure.
11-1	C	11	Heater drain pump.
11-11	C	18	Condenser leaks (A-S).
11-13	S	35	Reactor Protection System electrical fault.
11-15	SD	122	Leak in heater drain pumps.
11-18	S	37	EHC electronics failure.
12-5	SD	188	Feedwater heater leaks.
12-16	S	69	Loss of emergency Bus E-4.
12-20	C	133	Rx water conductivity.
12-26	S	107	RFP trip/trigger assy and dump valve problem.

SUMMARY OF KEY UPSETTING EVENTS - UNIT II
(Cont.)

DATE	TYPE	DURATION	CAUSE
1981			
1-3	C	43	Debris filter celaning.
1-7	SD	98	"A" RFP.
1-28	C	9	Condenser leaks.
2-1	C	320	MSIV F028C seat separation.
2-14	SD	190	MSIV maintenance.
2-24	SD	32	N_2 system pipe failure.
2-26	S	22	CIV #1 connector faulty.
3-5	SD	876	Snubber inspection - all units repaired. HPCI pipe supports repaired.
4-11	SD	10	RCIC control and valve probelms.
4-12	SD	125	Condensate conductivity - failure of fiber plugs.
5-3	SD	21	B32-F051 valve packing leak.
5-6	SD	618	Oysters in service water systems.
6-10	SD	37	Recirc. loop Hi delta-T due to shut recirc. valve.
6-22	S	130	"A" recirc. pump MG set - dirty.
7-3	S	33	MSIV F022C disk separation; loss of FW control-extended outage.
7-11	S	40	Unknown.
7-18	SD	227	MSIV repairs.
8-4	S	68	Operator error; relief valve failure.
8-12	C	52	Recirc. pump "A" vibration monitoring system malfunction.

SUMMARY OF KEY UPSETTING EVENTS - UNIT II
(Cont.)

DATE	TYPE	DURATION	CAUSE
8-28	C	30	Condenser leak (A-N).
9-12	C	3	Condenser leak (waterbox).

3.0 PAST OUTAGE EVALUATION

3.0 PAST OUTAGE EVALUATION

3.1 OVERVIEW

A major portion of the BSEP capacity loss is attributable to a poor record of excessive extensions of planned plant outages. Although on several occasions the extensions were somewhat unavoidable, there are methods by which their ultimate effects could have been mitigated. Table 3-1 is a brief summary of comparative outage lengths for the periods 1979-1981.

Table 3-1 - Outage Summary

		Unit 1	Unit 2
1979	Planned	86 Days	64 Days
	Actual	94 Days	78 Days
1980	Planned	31 Days	74 Days
	Actual	89 Days	200 Days
1981	Planned	65 Days	----
	Actual	82 Days	----
		163 Days (including turbine failure)	

3.2 1981 - UNIT 1 MAINTENANCE OUTAGE(3-1)

This outage differed from a routine outage in that it did not include a refueling but addressed a relatively large scope of maintenance and plant modification activities. This was the result of deferred work items remaining from the 1980 refueling outage. The original schedule called for plant shutdown on March 7, 1981 with an estimated duration of sixty-five (65) days. Major planned work activities included:

- Safety/Relief Valve Replacement
- Seismic Hanger Rework
- Digital/Analog Conversion
- Snubber Rework
- IEB 79-01B Inspection and Repair
- Inservice Inspection
- RWCU Heat Exchanger Seal Welds
- Service Water Pipe Replacement
- Turbine-Generator Overhaul
- Amertap/Debris Filters Installation
- TMI Related Modifications
- Integrated Leakrate Test
- Diesel Generator Load Test

In actuality, the outage began on April 18, 1981 after three successive 2-week delays. These delays are attributed to the unexpected forced outage of Unit 2 for snubber testing and overhaul. The length of the outage was a total of 82 days, followed by an additional 88 days for the ensuing oil flush and turbine repair program. The major additions to the scope of work was that associated with the service water system cleaning and the repairs to the RHR heat exchangers. Each major outage task is discussed below.

Safety/Relief Valve Replacement. This involved modification of all eleven safety/relief valves to remove the existing three-stage base assembly and install a new, improved two-stage design. Several problems were experienced with defective solenoid valves; however, the task was completed with no apparent impact on the critical path or other outage activities.

Seismic Hanger Rework. In response to regulatory requirements (IEB79-02, 79-04, and 79-14), CP&L was required to inspect and rework several pipe supports on safety-related systems. Short-term fixes (those requiring immediate attention) involved approximately 60 hangers, 30 of which were inside the drywell. All drywell work was completed by day 48 while the remaining work was completed by day 77. The actual time duration for the project was lengthened by manpower reductions in response to the needs of other outage projects and efforts to adapt modifications details to the as-built conditions found in the field. Later in the outage, on June 28, 1981, as a result of an overview of the short-term program, several oversights were identified resulting in additional modifications and design evaluations. At that time, the hanger work activities became critical path for a short period and would have resulted in a three day delay had other problems not occurred.

Digital/Analog Conversion. This included installation of the additional reactor vessel reference leg and several other conversions through plant systems including the HPCI and RCIC level-pot installations. It was not apparent that this impacted the overall outage schedule although some delays were encountered due to water levels on the -17 elevation, welding problems encountered in the drywell, and interference with the RWCU seal modification.

Snubber Rework. As a result of gross snubber failures on Unit 2, plant management decided to forego the routine partial testing of the Unit 1 snubbers and undertake a rebuilding and modification program in order to upgrade the units; thus precluding the generic failure characteristic of the Unit 2 snubbers. A total of 607 snubbers were removed, modified offsite, and reinstalled with no significant impact on the outage length.

IEB 79-01B Inspection and [illegible] air. This included an inspection and limited rework of a [illegible] of 239 electrical items in the

drywell and other normally inaccessible areas in response to NRC IEB 79-01B. Inspections were conducted by NPED with five two-man teams and was completed on June 17, 1981. This presented little impact on the overall outage schedule even though it was not completed within the original time schedule.

Inservice Inspection (ISI). Representative samples of welds in several components and piping systems were inspected in accordance with the overall ISI program. All inspections were completed on time.

RWCU Heat Exchanger Seal Welds. This modification consists of installing a welded seal ring at the juncture of the flanged heads of the heat exchanger to prevent flange seal leakage that, in the past, has adversely affected system operation. The work was originally scheduled to be done in 46 days. Actual duration of the job was 69 days. A similar scope of work was accomplished in 84 days on Unit 2 during the 1980 outage. This modification continually followed closely the critical path activities of the service water maintenance work. Key elements causing delays included:

- Failure of isolation valve G31-F044 required shutdown of the decontamination system.
- As of day 9 of the outage, the RWCU work was 6 days behind schedule suggesting a questionable schedule from the beginning.
- Worked stopped as a result of a broken hose connection and resin spill while transferring RWCU system resin (4/29/81).
- Work stopped due to high exposure. Hydrolasing was prohibited due to radwaste limitations (5/3/81).
- Limited work force was permitted on 50' elevation of the reactor building due to high levels of contamination (5/4/81).
- Work stoppage due to shortage of dosemeters (5/4/81).

- Machining delayed due to improper set-up of equipment -- unqualified workers. Resulted in some tube damage (5/9/81).

- Channel head gouged as a result of accident (5/12/81). Cracked weld on "1C" tube bundle.

- Delay caused by inoperable welding machines (5/30/81).

- Problems with weld quality (6/11/81).

- Continuing problems with high temperatures breathing air (6/5/81).

- Lack of manpower.

Service Water Pipe Replacement. The original work scope included the replacement of four sections of concrete-lined service water piping with essentially identical spools fabricated from a copper-nickel alloy. An evaluation of the time duration and delays encountered in completing these modifications is not necessarily meaningful since, with the advent of the Unit 2 shutdown and service water "unusual event", all prior schedules become obsolete and virtually useless. However, during the total service water work scope, several key events are of interest, namely:

- Excessive leakage between the Unit 1 NSW and CSW systems was identified on 4/21/81. There is no evidence this was taken into account in future schedules.

- Heavy oyster growth was identified in Unit 1 CSW header early in the outage. It did not seem that this problem was adequately addressed or related to potential problems in the NSW and Unit 2 service water headers.

- The repair work on the RHR heat exchanger waterboxes was troubled by an apparent lack of productivity and supervision.

- There were recurring delays encountered in the RHR heat exchanger baffle plate replacement work as a result of successive machining errors. Additional problems encountered by the contractor included lack of proper equipment for weld prepping, improper handling (and damage) to the baffle plate, and improper machining of "1B" RHR flange faces.

- On 5/10/81, the outage coordinator's comments raise significant questions regarding the planning and scheduling of the service water work.

- Continual problems were encountered with the RHR heat exchanger nozzle clad welding as a result of poor welder technique. This resulted in abandonment of the modification for those affected pipe sections and new sections of concrete-lined steel pipe was reinstalled.

- Occasionally there was an apparent shortage of qualified welders.

- Even though leaky isolation valves were identified as a potential problem early in the outage, there did not seem to be much in the way of an integrated contingency plan to accommodate it in a timely fashion.

- The technical specification requirements for system operability complicated the work sequencing.

- Service water work was manpower limited from the onset of the outage.

- The water level in the radwaste tunnel delayed service water work due to a lack of available ventilation -- radwaste became critical path.

Since the original and updated schedules are unavailable, it is extremely difficult to reconstruct a detailed description of this part of the outage and thus arrive at any quantitative analysis. However, based on the Unit 2 estimate and work experience, a 21 day work period would be required for cleaning both headers per unit or 42 days for successive outages; thus, had work begun on April 28 when the problem was initially identified, it could conceivably have been completed by June 9 -- with a possible savings of 2-3 weeks of outage time resulting in other outage tasks being on the critical path.

Turbine Generator (TG) Overhaul. The work on the TG consisted of several inspection and routine corrective maintenance activities as part of the planned maintenance program. Key items that were included in the 1981 work scope included:

- Main Generator Inspection (Major)
- Generator, Exciter and Thrust Bearings
- All Major Valves
- Moisture Separator Reheaters
- "A" Coupling Alignment Check
- Front Standard Inspection
- Cleaning of Main Oil Tank
- Non-return Valves

The planned work scope was completed with considerable complications and events that ultimately extended the outage by approximately eleven weeks. Problems were encountered even before the unit was shutdown. Prior to the original outage date, considerable resources were expended in preparing for the overhaul, including assembling a qualified and trained crew for the job. However, during the six week delay period, several key elements of the accummulated labor force were lost including the G.E. technical representative, 3 qualified welders, 2 QPI foremen, and 10-15 QPI millwrights, all of whom, for the most part, had worked at Brunswick in the past and were familiar with the equipment and plant practices (i.e., HP, security, etc.). As a result, when the outage began, there was an insufficient number of qualified workers on hand to properly conduct the overhaul. Throughout the period of the work, several related problems affected the schedule, and apparently, the quality of the job, including:

- Problems obtaining a vendor technical representative and after his arrival, several questions arose regarding his judgement.
- A general shortage of labor throughout the overhaul period -- particularly those with the experience and skills required for the work. This was also true, for the most part, of the first line supervision (foremen).

As the work proceeded, several problem areas were identified that are not generally expected during a routine turbine inspection. A chronology of events follows.

4/25/81	#8 bearing seat and ring galled - Reason suggested that this was a result of past maintenance.
4/30/81	#8 bearing found badly scored and H_2 seal damaged. G.E. made the recommendation to inspect all TG bearing since the cause appeared to be dirty lube oil.
5/3/81	Thrust bearing scored - G.E. suggested replacement.
5/4/81	#2 bearing and journal badly scored -- #2 lift pump strainers and thrust bearing strainers clogged with debris. Decided to inspect all bearings.
5/5/81	A suggestion was made that an oil flush should be conducted. Black deposits found on #5 and #6 bearings.
5/9/81	The subject of lube oil flush was discussed at a meeting with the plant staff. Apparently it was ultimately decided to do some "local" flushes in problem areas.
5/13/81	Began oil flush of thrust bearing -- strainers clogged approximately 45 minutes.
5/15/81	Several workers laid off -- unreliable or unqualified for work.
5/16/81	Small "flaky" metal particles found near #8 bearing.
5/18/81	Report possible sabotage of TG lube oil system.
5/27/81	Main oil tank inspected -- very dirty with a large quantity of debris; fine mesh return screens cut. Began discussions of large scale lube oil flush. The initial estimate called for completion by June 28 -- pressures to revise this resulted in a June 18 estimated completion date (3 weeks duration). A decision was made to use a high velocity flush but not the recommended G.E. erection flush.
6/1/81	Main oil pump discharge check valve lever arm reversed.
6/4/81	Commenced oil flush.
6/11/81	#2 bearing and dowel damaged by mishandling.

6/11/81	Thrust bearing L/H improperly installed. Oil flush completed.
Ongoing	Several comments were logged regarding the lack of qualified workers and poor work practices.
6/19/81	Generator failed air-leak test. Estimated completion date for TG - 6/23/81.
6/24/81	Turbine on turning gear.
7/8/81	Main turbine rolled - Startup aborted due to main lube oil pump discharge valve - operating arm reversed (note 6/1/81 entry).
7/9/81	Metallic particles found in MLO sump. In the ensuing days, multiple problems were identified including general bearing failure.

After the massive bearing problem was discovered, all contract labor was replaced by CP&L workers (including foremen) and preparations commenced to conduct an additional flush of the lube oil system. This time the flush was to be done according to the G.E. procedure. It appears that this flush was conducted in an expeditious manner and the unit was ready for operation on September 20 and synchronized on September 23.

The cause of the bearing failure on July 9 cannot easily be identified as an isolated event. Several factors could have caused the problem or contributed to the severity of the damage. Among these are:

- The suspected sabotage event on or before May 18.
- The poor quality of the work force used throughout the outage.
- A shortage of labor and of CP&L personnel to supervise and monitor the work.
- Obvious problems and errors during reassembly of several parts of the machine.
- Original oil contamination problems related to original erection and pre-outage conditions compounded by earlier flushing activities. During the 1979 outage, it was noted that several bearings had been damaged by metallic particles and apparently dirty oil[4].

- Potential contamination from the clean lube oil tank and used drums used for storage during the June oil flush. A similar problem was noted during the 1979 outage.[4]

While the turbine lube oil system was undergoing its final flush (July 10 - September 25), the plant mobilized forces and took advantage of the outage time by conducting several other plant modifications and maintenance activities. Many of these will likely have the effect of reducing the workload during future Unit 1 outages by approximately 43,000 manhours or a theoretical savings of 3-4 days of outage time. The major accomplishments during this time include:

- PM 79-188: Torus Modification - 15 of 16 overhead supports installed.
- PM 79-264: Torus Monorail - Installed monorail and relocated four air and water lines (less final tie-in of two noninterruptible instrument air lines).
- PM 80-032A: TMI Mod - Containment Hydrogen Monitoring.
- PM 79-124: Anchor Bolt Inspection.
- PM 81-073: CRD Hangers Inside Drywell - eight gang supports installed.
- PM 81-205: Cleaned, inspected, installed filters and balanced drywell ventilation.
- MSIV: Pinning of two MSIVs.
- PM 79-269: A/D modifications (packages A, C, E, F, and H) - 24 instruments were installed.
- PM 77-208: Replaced all ECCS room cooler water boxes with Cu-Ni water boxes.
- PM 81-088: RCIC auto reset.
- PM 79-152A: Reactor recirc. pump trip - 16 core bores completed.
- PM 81-075: CRD hangers outside the drywell - nine scram discharge volume hangers installed.
- PM 81-218G: "IB" circ. water discharge valve.

- PM 81-082: CFD/CDD flow element replaced.
- Service Water: SW V3 and V4 repaired, "1C" CSW discharge elbow repaired, vital header valve repaired.

Amertap/Debris Filters. This included extensive work related to the circulating water inlet and outlet piping and a considerable quantity of other unrelated but interfering piping that required temporary removal. The work appeared to go well despite a late start as a result of excessive water in the condenser pits and crane availability problems.

Integrated Containment Leak Rate Test (ILRT). Several problems were incurred during the conduct of the ILRT. As late as June 5, there were revisions to the procedure required as a result of NRC concerns. On June 9, pressurization of the drywell was begun and on June 11, a problem with excessive leakage was identified. The test was held up until these leaks were found. The source was mainly in the CAC system and were the result of several valve packing and seat leaks and apparently several valves that were not properly closed. These conditions were corrected and ILRT was successfully completed on June 12.

Diesel Generator (DG) Load Test. This test was similar to other tests conducted on the DGs since plant startup that generally took a nominal period of time to complete (approx. 3-4 days). However, during this outage, the duration of the tests were in excess of 17 days. This can be attributed to the problem of conducting a plant integrated test while major systems and equipment are inoperable as a result of maintenance and construction activities. Apparently, during the latter stages of the outage there was a large amount of work underway due to the fact that much of the non-critical path items had been lagging their schedule or had been deferred earlier due to manpower limitations. The DG testing was finally completed on July 2.

SUMMARY

The first part of the outage -- extending from April 18 through July 9 -- lasted a total of 82 days as compared to the planned length of 65 days for an overrun of about 26% (17 days). Although the service water cleaning project added additional scope to the overall outage effort, there was enough time from the initial discovery of the problem to complete much of the work in parallel with other outage activities. It appeared that in mid-May, the complexities of the concurrent Unit 1 outage and the Unit 2 shutdown, along with the existing manpower problems, tended to exasperate planning and scheduling efforts. Due to the limited sophistication of the scheduling mechanisms available to the plant staff, they were unable to adequately coordinate the ongoing activities, thus resources and time were probably not exploited to the utmost. As a result, the RWCU and service water work lasted longer than they should have and, toward the end of June, a large quantity of small, tail-end type of tasks remained to be completed. Also less than adequate plant staff and engineering followup of scheduled work could have had an effect as was commented on in the outage coordinator's log. Thus, even after the service water work was completed, it took almost two weeks to prepare the plant for startup. Another contributing factor was a shortage of auxiliary operators due to prescheduled vacations that perhaps could have been negotiated with those involved to relieve this problem. Other generic problems are discussed in Section 3.3 of this report.

3.3 OUTAGE PERFORMANCE FACTORS

An outage at a nuclear power plant is a complex operation demanding considerable efforts of planning, coordination, and close supervision. This is made even more complex by the fact that the other unit on the Brunswick site, which is not totally independent, must remain in operation -- usually on a priority basis.

As discussed earlier, over the past three years the outage performance at the Brunswick station has been relatively poor. Although this cannot be attributed to any specific problems, a study of past outage reports and summaries (Refs 1, 2, 3, 4, and 5) identifies several contributing factors that, in concert, make the difficult task of outage management at BSEP even more troublesome. Each of these issues is discussed below.

Outage Preparation. In most cases, outage planning began approximately four (4) months prior to the beginning of the outages. This is inadequate. Generally, most utilities begin planning for an outage a minimum of six (6) months before the outage. Several actually begin immediately after the prior outage is completed. A CP&L document discussing the reliability improvement program mentioned that this is the policy at H.B. Robinson (a single nuclear unit). A longer planning period allows a more detailed schedule to be developed and permits more study and fine tuning -- a process needed to ensure adequate coordination, interfacing, and resource utilization. This also forces those persons responsible for individual outage tasks to, early on, provide detailed schedules for procurement, training, procedure development, worker qualifications, operational evaluation, etc.

Spare/Replacement Parts. The availability of spare parts was a recurring problem particularly those required for the turbine generator and its associated auxiliary equipment. On several occasions, the unit was reassembled using parts that were marginal or questionable due to the lack of replacements. Although there has been no obvious impact on plant operations as a result of this problem, there are effects in the additional manpower needed to rework damaged parts, additional deferred outage work and the increased probability of equipment malfunction or excessive downtime caused by a part that is not available and cannot be reworked or repaired.

Labor Availability and Competence. During each major planned outage there was a shortage of qualified workers and first line supervision. It is apparent that the restriction on total site manpower (1,800 per day) has resulted in the inability to properly man the outage work scope. In addition to the number of workmen, those that were on site did not have the training and skills needed to carry out the tasks in a proper and expedient manner. Specific problems incurred were:

- Poor welding that resulted in schedule delays, excessive rework and extra radiation exposure -- primarily related to the RWCU, RHR heat exchanger, HPCI seal pot, and reference leg tasks;
- Errors and poor work habits related to the turbine generator overhaul;
- Lack of effective first line supervision (foremen) to provide consistent work quality and worker productivity; and,
- Inadequate reserve labor force that is needed to address the additional work scope and contingency requirements that are characteristic of nuclear plant outages.

Project Direction. At the outset of an outage, the critical path (CP) projects are identified and afforded a priority higher than parallel tasks to ensure the outage remains bounded. During the Brunswick outages, there appears to be an inordinate amount of concentration on the CP items and an effort to keep other selected activities off the CP -- with relatively little concern for individual project schedules. Three problems have arisen as a result of this. There were frequent incidences of mutual interference between concurrent activities, competition for services such as health physics, quality assurance, cranes, etc., overcomplicated the job of the outage coordinator, and project completion and closeouts were delayed until late in the outage, thus causing a peak workload for final QA checkoff, system turnover, and system lineups -- ultimately extending the startup time.

Job Coordination. There have been several problems regarding the relationship between the various groups on the site (i.e., maintenance, operations, construction, etc.). Apparently, there is not usually a single individual designated to orchestrate the efforts involved in accomplishing all the tasks associated with each individual project. In reading the logs, one is led to the conclusion that this task is left to the outage coordinator who should not be project oriented as much as maintaining an overview perspective.

Carelessness and Accidents. The 1981 Unit 1 maintenance outage was subjected to several incidents that caused work stoppages and extra work as a result of worker oversight or negligence. In this category are successive oil spills in the turbine building, radioactive water and resin spills in the reactor building, and incidents of mistakes that lead to large quantities of salt water dumping causing an overtaxing of the radioactive waste processing systems.

SECTION 3.0

REFERENCES

3-1. Carolina Power & Light Co. - Brunswick Steam Electric Plant, Unit No. 1, 1981 Spring Maintenance Outage Report - April 18, 1981 - July 6, 1981; File No. B10-13910 dated 1/7/82.

3-2. Brunswick Steam Electric Plant, Unit No. II Refueling/ Maintenance Outage/Unit No. I Refueling Outage, Spring/ Summer 1981 Rev. 1 (Prepared by General Electric)

3-3. Carolina Power and Light Company Brunswick Steam Electric Plant Unit Nos. 1 and 2 Refueling/Maintenance Outage Report, March 1, 1980 - September 17, 1980; File No. B10-1390 dated 1/7/82.

3-4. Carolina Power and Light Co., Brunswick Steam Electric Plant, Unit 1 Refueling Outage Report - January 13, 1979 - April 16, 1979. Revision 1 dated 12/22/81.

3-5. Carolina Power and Light Company - Brunswick Steam Electric Plant, Unit 2 Refueling Outage Report, March 3, 1979 - May 19, 1979, Revision 1 dated 12/22/81.

4.0 PLANT MATERIAL AND DESIGN

4.0 PLANT MATERIAL AND DESIGN

Many of the problems associated with the rather poor capacity factors of the BSEP units have been linked to the material condition of the plant and inherent design deficiencies of key systems and components. From an overall perspective, the units do not appear to have experienced any specific problems uncharacteristic of other nuclear and fossil power plants when subjected to similar circumstances. However, collectively the impression presented by the spectrum of issues and problems may lead one to believe the situation is perhaps worse than it really is. The two units were started up and began operating during a period when the NRC began resolving many of the long-standing design questions, when many of the first-generation BWR plants were identifying generic mid-term operational problems, and under the added complexity of the TMI issues. These plus an understaffing of engineers and maintenance personnel generated a large ever-increasing backlog of backfit and maintenance requirements during the 1979-1981 period. This section discusses, briefly, the key problems that have caused the poor performance and relatively large construction workload.

4.1 MAIN STEAM ISOLATION VALVES (MSIVs)

Each unit has a total of eight (8) MSIV's installed, two in each of the main steam lines, four inside the primary containment (FO22X) and four on the outside (FO28X). On several occasions the valves have failed by separations of either the main disc from the piston or of the stem disc from the stem, resulting in isolation of the respective steam line and a corresponding reduction of power (95% min) or a reactor scram. A history of valve failures is as follows:(4-1)

<u>July 30, 1976</u>: The main disc dropped in 2-B21-FO22D. The main disc had unscrewed from the piston. Failure was attributed to

improper pin installation as the single pin was not fully inserted into the disc.

January 29, 1979 (outage): 2-B21-FO28D failed LLRT. The valve was disassembled and the stem to stem-disc pin was found to be deformed.

January 29, 1979 (outage): The main disc and piston assembly separated in 2-B21-FO22A. The stem to stem-disc pin had sheared due to fatigue crack development. Additionally, the main disc-piston assembly was deformed in a manner indicating excessive torque.

January 15, 1981: The main disc separated on 2-B21-FO28C. The main disc unscrewed from the piston assembly. There was no evidence that the pin had ever been installed in the piston to main disc assembly, i.e., no tack weld.

March 30, 1981: The main disc and piston assembly dropped on 1-B21-FO22C. The stem to stem-disc pin had failed. The pin was not recovered, but evidence of a broken tack weld and hole damage indicated that it was installed at one time.

July, 1981: The main discs and piston assemblies dropped on 2-B21-FO22C and 2-B21-FO22D. In FO22C, the stem to stem-disc pin was present but rounded off instead of beveled as a new pin would normally be. On 2-B21-FO22D, the main disc tack weld was intact, but there was no pin. There was a small groove worn above the hole on the threaded inner surface of the main disc. The stem to stem-disc connection had no apparent problem, but approximately 1/32" of play was noticed between stem and stem-disc. Further investigation of the main disc and piston revealed thread damage on both the piston and main disc. The inside diameter of main disc was measured and found to be 6.598" and that of the outside diameter of the piston was 6.581", which indicated inadequate thread engagement as the probable failure mode.

August, 1981: 1-B21-FO22D and 1-B21-FO28B were disassembled for inspection. Both valves exhibited looseness between the main disc and piston. The stem to stem-disc assembly on FO22D had the pin hole in the stem in a position approximately 90 degrees from the pin. As a result, the pin was placed directly on the stem threads. No looseness was observed on this assembly. The FO28B stem to stem-disc assembly did exhibited looseness and thread wear was evident on the stem-disc.

September 8, 1981: 1-B21-FO22B was disassembled after failing a LLRT. There was looseness between the stem and stem disc, but not between the main disc and piston. The threads above the pin hole of the stem disc were worn uniformly and there was no deformation of the pin.

Investigations into the failures have revealed that the separations were clearly a result of failure of the threaded connections due to some combination of the following:

- Poor thread engagement caused by improper tolerances of mating parts;
- Poor assembly methods and quality control;
- Marginal design conditions with respect to maintaining proper thread preload; and
- The aggravation of turbulent steam flow conditions through the inboard valves and as a result of steam pipe geometry.

In response, the Brunswick plant engineering staff has issued a modification package consisting of several minor modifications of the threaded connections along with an increase level of quality control. Two of the Unit 1 valves have been modified and the remaining valves are planned for modification during the next refueling outages. This should eliminate any future forced outages or curtailments arising from the disc separation problem. However, the potential for future problems still exists since the

valve vendor continues to insist that the prevailing cause of the problem still exists -- that of steam flow turbulence. In order to solve the flow problem, major modifications to the steam lines would be required, which is considered imprudent at this time. Other possibilities include redesigning the stem-disc assembly by manufacturing the parts from single pieces of stock or using welded connections vs. threaded and pinned connections.

A quick study of the history of these valves leads to two conclusions and obvious actions that could minimize future operational impacts:

- Lack of quality control, both in the manufacturing and assembly operations has lead to valve failures. It is clear that CP&L and the vendor must apply an effective quality control program to ensure all parts conform to design requirements and that the valves are assembled under "strict" controls. This has been addressed by CP&L in their current procurement activities.

- It appears that failures occur on a frequency of 3-4 years -- even when quality control problems exist. CP&L might consider a program of inspection of the inboard valves to determine the effectiveness of the corrective measures taken.

4.2 STRESS-CORROSION CRACKING IN PIPING SYSTEMS

The occurrance of stress-corrosion cracking of austinetic stainless steel pipes has been a continuing problem in boiling water reactor systems. It has been the subject of several studies on the part of General Electric, EPRI, owners' groups, ACRS, and the NRC. In February, 1981 the NRC issued NUREG-0313, Revision 1 "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Bounding Piping." This required all licensees to provide the following:

- A program for replacement of service sensitive lines and welds;

- A program for augmented inservice inspection of susceptible piping system;
- A program for improving the reactor system water chemistry environment; and
- Incorporation of adequate leak detection capability.

The majority of the piping installed at the Brunswick plant in the systems in question does not meet the material standards set forth by the NRC. Exceptions to this are a small segment of recirculation piping in Unit 2 in which cracks were found, thus requiring pipe replacement, and several sections of the core spray piping and safe-ends in both units that have been replaced as a result of cracks and indications found during inservice inspection activities in 1977 and 1979. There have been no other occurrances of cracking since then in either unit.

The Brunswick plants are currently in compliance with NUREG-0313, Revision 1 and there are no plans for replacement of any piping in the near future.[4-2] The near-term impacts of this NUREG are manifested in additional inspection requirements and a more severe limitation on the allowable unidentified leak rate in the drywell. The welds in all of the non-conforming piping have been inspected and will continue to be inspected at the rate of 10% per refueling outage and 100% over each 80-month period as compared to 10% of the welds over a 40-month interval that is normally required. This will result in additional demands on the already overtaxed manpower pool with the increased probability of locating an indication or crack that would require repair or pipe replacement with the associated complication of that particular outage. The more limiting leakage specification could result in premature plant shutdowns needed to repair relatively minor system leaks; thus impacting plant availability.

In the G.E. Advanced Maintenance Planning Service (AMPS) program document for Brunswick, Unit 1, Reload 3, several issues are raised that are relevant to the Brunswick units. In particular,

this report cites another G.E. report (NEDO-21000) that discusses the cracking problem. They point to a correlation between the number of incidences of pipe cracking and the number of plant shutdowns extending greater than 24 hours or more. The theory is that during a shutdown, water chemistry is severely affected in that large increases in dissolved oxygen levels normally accompany shutdowns and startups. They point to chemistry control as the most effective approach toward minimizing the occurrances of stress-corrosion cracking. Also, the frequency of cracking increases with plant service time. All of these factors lead one to believe that the Brunswick units could experience problems in the future since they do have considerable quantities of sensitive piping welds, have experienced a relatively large number of cycles as a result of frequent forced shutdowns in the past 2-3 years, and have been plagued by problems associated with plant water chemistry control.

For planning purposes, G.E. has identified several recommendations for consideration by CP&L for the Brunswick units. These include:

- Conduct inservice inspections early in the outages to allow the maximum time for repairs without impacting the outage critical path;
- Develop a contingency package for replacing the RWCU piping sections if problems arise. There have been 39 incidents of cracks in this piping in other BWRs. This package would include all documentation and enough Type 316 stainless steel piping components to affect replacement for both units. CP&L stated that a package is available for recirculation pipe replacement and a similar package for RWCU systems is under evaluation for procurement; and
- Install oxygen control systems to control the amount of dissolved oxygen in the reactor water systems in an optimum range. This may also result in a reduction in the rate of increase of radiation levels throughout the system. This is currently under evaluation by the CP&L engineering staff.

There is a reasonably high probability that from time to time unplanned pipe replacement will be required that will adversely affect future outage lengths and plant availability.

4.3 SERVICE WATER SYSTEMS

The only significant forced plant shutdown directly related to the service water systems (conventional and nuclear) was a result of a buildup of oyster shells discussed in Sections 3.0 and 4.4 of this report. However, since startup, both Brunswick units have been plagued with pipe and valve corrosion and associated leakage. Brackish water leakage into the reactor and turbine building sumps has created significant problems in radioactive waste processing systems and can adversely effect plant operation.

The original piping was specified to be carbon steel with an internal lining of cement. Apparently, those internal parts of the piping system that are not cement lined by virtue of their geometry or where the cement has cracked or come loose, have been subjected to severe corrosion attack to the extent that through-the-wall leaks have developed. The CP&L staff has recognized that this type of piping is unsuited to this service when considering the character of the cooling water and the inability of gaining access to repair the internal lining of smaller diameter piping. In response, they have decided to replace all of the smaller diameter carbon steel/concrete-lined piping in the reactor building with segments made of copper-nickel -- a highly corrosion-resistant and anti-fouling alloy.

The modification consists of prefabricating flanged spool-pieces of pipe segments and installing them at convenient times. Implementation of this modification is quite complex since the service water systems are needed at all times and isolation valves between redundant trains generally suffer from excessive leakage. Additional isolation valves are being installed to mitigate this problem in the future.

The modification program is separated into three phases. Phase I is directed toward rectifying known problems where leakage exists, piping has been "patched," or areas that are suspect as a result of failures on similar sections of piping on other trains or in the other unit. There are approximately 50 individual packages associated with this phase with eleven of these completed. Current plans call for completion of the outage-related segments of this phase to be completed during the forthcoming 1982 scheduled refueling outages with the remainder done on an "as available" basis at the convenience of the construction force (relatively low priority).

Phase II consists of an inspection and survey program aimed at determining priorities and sequences for completing the balance of the project. This has been completed providing input for developing the Phase III Plan -- which addresses completion of the full scope of work. The engineering for Phase III will probably take place during 1982 with construction following in 1983.

Some issues regarding this program remain outstanding, including:

- Modification of the underground, large bore service piping. -- The philosophy is that the interior surfaces of this piping can be accessed by personnel and, thus, the lining can be repaired. It should be noted that similar problems have been experienced in the circulating water piping which also was cement lined. In that case, several sections of the cement lining was removed and replaced with a fiberglass coating. Since failure of the service water supply headers could ultimately result in an NRC-mandated shutdown and emergency repair program, the decision to leave this piping "as-is" should be based on sound engineering judgement and a permanent-fix philosophy.

- Modification of the turbine building service water piping. -- Turbine service water piping was fabricated to the same specifications as that of the reactor building service water systems and, thus, will exhibit a similar mode of failure. Although its failure does not connote the reactor safety issues as does that in the reactor building, nevertheless, it is an important

factor with respect to the issues of plant reliability and radwaste loading. CP&L should review the decision to omit this part of the service water system in light of cost-benefit, reliability, and radwaste issues. Considering the relatively rapid deterioration of other sections of the service water and circulating water systems, it is likely that the turbine building service water system will demand more and more repairs at an increasing frequency until ultimately replacement will be required.

4.4 CHLORINATION AND MARINE GROWTH IN SERVICE WATER SYSTEMS

(4-3) On April 18, 1981, Unit 1 was shutdown to begin a scheduled maintenance outage. Soon after shutdown, "1B"RHR heat exchanger was drained and inspected as per a prior commitment to the NRC relating to an earlier failure (LER-2-80-30). At that time, the baffle plate dividing the water boxes was found to have failed allowing water to bypass the heat exchanger tubes. Soon thereafter, cooling water flow through the "1A" RHR heat exchanger was initiated. An apparent degraded cooling capacity in this heat exchanger then led the plant operator to start an additional service water pump. It is believed at this time the "1A" heat exchanger was then damaged in a similar manner -- thus, the plant experienced a total loss of residual heat removal capability. The plant cooldown was then continued using a less conventional method with the main condenser used as a heat sink.

An investigation determined that the damage was the result of an accummulation of oyster shells and shell fragments blocking the tube inlets and eventually creating an excessive differential pressure (DP) across the divider plate. The code allowable stress for this design would be attained at a D.P. of approximately 1.4 psid, however, apparently the plant operators have experienced D.P.'s in excess of 30 psid with no apparent damage to the plate. As a result of these findings, the Unit 2 heat exchangers were inspected. The "2A" heat exchanger was found to be undamaged, but experiencing a higher than normal differential pressure, while "2B" was determined to have a displaced baffle plate. At

that time, both heat exchangers were declared inoperable and the unit was shutdown. A summary of RHR heat exchanger problems is as follows:

- "1A" RHR Heat Exchanger

April 25, 1981 Lack of heat transfer noted by Operations. Heat exchanger was drained and flow channel head removed. A 6 to 9-inch deflection was noted and the plate was jacked into position. Bracing stays were welded to the back of the plate for temporary support. The heat exchanger head was reinstalled and returned service April 27, 1981.

June 2, 1981 Exchanger drained and lower channel head was removed. Permanent repairs replaced baffle plate and inlet and outlet elbows per PM 79-231T. Work was completed on June 13, 1981. Awaiting reinstallation of inlet isolation valve (removed for vessel hydro) before returning to service.

- "1B" RHR Heat Exchanger

April 19, 1981 Heat exchanger drained and inspected. A deflection of 8 to 9 inches was noted on baffle plate. Plate was replaced along with inlet and outlet elbows via PM 79-231G. Work was completed on May 31, 1981 and returned to service.

June 3, 1981 High differential pressure was noted across the baffle plate. Channel head was removed to clean shells.

- "2A" RHR Heat Exchanger

Spring 1980 Heat exchanger was inspected and inlet and outlet elbows replaced (PM 79-232T). Baffle plate inspected and no degradation noted.

13 May 1981	Heat exchanger drained. Baffle plate was inspected with no signs of deformation. Exchanger cleaned of shells and put back into service May 14, 1981.
June 3, 1981	High DP noted across baffle plate. Exchanger cleaned of shells, no signs of deformation. Returned to service June 4, 1981.

- "2B" RHR Heat Exchanger

Spring 1980	Heat exchanger inspected and 9-inch deflection discovered in baffle plate. Vertical plate attachment welds cracked approx. 33 inches. Baffle plate and elbows replaced per PM 79-232S and returned to service.
May 6, 1981	Exchanger drained and inspected. A 3-inch deflection of baffle plate was noted. Fillet welds along side walls showed a 2-inch crack. Baffle plate was removed and heat exchanger bolted up and put back into service on May 9, 1981. Unit used as flow path without place for flushing with heavy chlorination of service water system.
May 16, 1981	Exchanger drained and lower channel head once again removed so that baffle plate replacement work could begin. Work completed on May 24, 1981 and returned to service.

Further examinations of the service water systems were conducted in 1981 with the following results:

- The 30-inch concrete lined nuclear and conventional headers were completely covered with marine growth, the most common species being the American Oyster.

- The accumulation of marine growth decreased proportionally with the distance from the intake.
- Generally, piping that is normally isolated was found to be clean.
- Small quantities of shells were found throughout the system.

As a result of these problems, the plant entered into an extensive program of cleaning and flushing these systems along with appropriate repairs to the heat exchangers.

In perspective, it appears that this problem is primarily a result of an oversight on the part of the plant operating staff as to the importance of chlorination and control of marine growth. A chlorination program began in the spring/summer of 1975, which called for continuous chlorination of the service water systems except during those times when the screen wash pumps were operating. In June, 1977, a study of chlorination and biofouling was conducted by CP&L Company(4-4) in response to problems with the main condensers identified in 1974. At that time, organisms were found to be blocking and damaging the main condenser tubes. There was apparently little emphasis placed on the service water systems perhaps due to their relatively high flow characteristics.

Table 4-1 is chronology of chlorination system outages since the beginning of 1980. The system had been essentially inoperable for a period of approximately 14 months from February 1980 through May 1981, at which time it was started up just prior to the heat exchanger damage incident. It is clear that this incident was a direct result of the lack of system chlorination as so stated by Mr. Furr, CP&L Vice President, Nuclear Operations:

> "The occurrence of shell growth is not a new issue at Brunswick. The present problems were a result of our loss of capability to continuously and effectively chlorinate the service water systems due to electrical and mechanical problems with the system and the need to stop chlorine carry--over into the screen wash system due to environmental concerns."(4-5)

TABLE 4-1

Chronology of Chlorinator Outages

February 22, 1980 - Train #4 shutdown due to mechanical and electrical problems.

March 15, 1980 to September 21, 1980 - Units 1 and 2 outages.

September, 1980 - Restart of chlorinator system failed due to electrical problems with heaters and controls.

October, 1980 - Restart of chlorinator system revealed holes in the evaporators. Evaporators were replaced.

October 31, 1980 - The chlorinator system was run for three days. The system was shut down because of fish kill.

November, 1980 - Attempts were made to operate the system in a manner that would not kill fish.

December, 1980 - Contacts were made with involved groups to resolve the problem of chlorine in the screen wash.

January, 1981 - Trouble ticket submitted to have dam installed.

March, 1981 - A second trouble ticket was submitted.

April, 1981 - The dam was installed in "1A" service water bay.

May, 1981 - System line-up was completed. Held up startup due to oysters in heat exchangers.

May 10, 1981 - Restarted chlorination.

To preclude similar occurrences in the future, CP&L Company plans the following actions:

- Periodic measurements of RHR heat exchanger differential pressure (NRC commitment).
- Periodic internal inspection of the RHR heat exchangers (NRC commitment).
- Maintain continuous chlorination with a daily sampling frequency (5 days per week). Residual level to be maintained at 1 ± 0.5 ppm. free chlorine.
- Modifying the chlorination system to provide for chlorine injection at the pump suctions.
- Lease a third chlorine tanker to ensure an adequate inventory is maintained on site.

An area of major concern is the assignment of responsibility for the operation and maintenance of the chlorination system. In the past, the system has been operated and maintained by the Environmental and Radiation Control (E&RC) Group, except for electrical maintenance that was conducted by the plant maintenance staff. As a result, it is likely that it was afforded the status of a "poor cousin" to other plant systems and given minimal priority. Furthermore, there is no formal preventive maintenance program for the system other than those actions done at the discretion of the system operators. Although there are redundant trains, due to personnel safety considerations, it is unlikely that major maintenance can be performed on part of the system during operation and any extended system shutdown could result in future shell growth. Current plans include shifting operational and maintenance responsibility to the plant staff. Without a comprehensive preventive maintenance program it is, however, possible that a recurrence of the Spring 1981 incident could occur.

Although the NRC has not issued any specific orders, as a result of an ongoing study on their part,(4-3) several additional requirements could eventually arise, including:

- A need for justifying the continued use of the copper-nickel baffle plates or replacement with a stronger material.

- Improved performance monitoring and increased surveillance of other safety-related heat exchangers including pump auxiliaries, etc.

- Evaluation of the effects of internal coatings and deposits on service water systems during a seismic event.

4.5 REACTOR BUILDING CLOSED-COOLING WATER (RBCCW) SYSTEM

The RBCCW system, although not considered a "safety-related" system, is important and necessary for the operation of the plant. It provides cooling to essential equipment and systems, without which the plant could not operate. In fact, operations and maintenance even during shutdown periods would be severely impaired without this system. Equipment served by the RBCCW system include reactor recirculation pumps, drywell coolers, fuel pool cooling, cleanup system, etc.

The auxiliary operators' log entries for the past 1-1/2 years indicate problems exist in both Units 1 and 2. These are discussed below.

Unit 1: The Unit 1 RBCCW system has experienced a relatively large demand for makeup -- almost continuously. Estimates of the outleakage have been as high as 38 gpm. It is suspected that the RBCCW heat exchanger tubes have deteriorated and are leaking. Plant personnel stated that the cause is probably related to shell debris impingement and errosion. Since the waterbox internals are constructed, for the main part, of a copper-nickle alloy, there is no need to open and inspect as there is in Unit 2 where carbon steel parts require corrosion protection and periodic inspection. Thus, it is possible to establish an inventory of shells and debris that could cause tube damage. In any event,

there has been little done to resolve this problem other than some tube plugging during the latter stages of the 1981 extended outage that was only marginally successful. Due to the critical nature of these heat exchangers (there are 3 total per plant), and the degraded condition of each, if remedial action is not taken in a timely manner in the near future, it is quite likely that the problem will ultimately result in a forced outage or cause complications or extension of an unrelated planned outage.

Unit 2: Unit 2 has a somewhat different problem than that of Unit 1 and is identified by a net in-leakage to the system. The plant staff believes the source to be one of the fuel pool cooling heat exchangers (unit not known). Again, this has been known for an extended time but no action has been taken in resolution. The extent of the leakage is not known for sure since undetected outleakage may be moderating the extent of system drainage needed. At the present time, this does not cause any operational problems and is considered somewhat of a nuisance; however, it will eventually require repair. Efforts are currently underway to inspect the affected heat exchanger and repair the leak. Delaying this work could result in:

- Untimely failure due to leakage increasing beyond acceptable operational or regulatory limits;
- excessive radiation exposure during repair caused by increasing radiation levels in the vicinity of the heat exchangers; or
- increased contamination levels of the RBCCW system and the potential of contamination throughout the plant causing considerable maintenance headaches.

4.6 REACTOR SAFETY/RELIEF VALVES

Each unit has eleven (11) safety/relief valves mounted on the primary steam piping. In the event that reactor vessel internal pressure reaches a predetermined setpoint, one or more of these

valves will open and relieve the excess pressure to the suppression pool (torus). On at least six occasions, a plant shutdown was required as a result of malfunction of one or more of these valves causing them to open prematurely and fail to reclose. This was a generic industry-wide problem identified with this particular type of valve until the vendor redesigned the valve topworks (actuator section). The modification was made to the Unit 1 valves in 1981 with apparently good results (no failures to date). Current plans are to complete a similar modification on the Unit 2 valves during the forthcoming outage in 1982. These measures should eliminate the problems associated with this failure mode in the future.

An additional generic problem with insulation placement on safety-relief valves was identified by the NRC in their Circular No. 79-18. The CP&L engineering staff is cognizant of the contents of this circular and the Brunswick units comply with its intent and directive.

4.7 REACTOR RECIRCULATION PUMPS

The reactor recirculation pumps on both units have had a troublesome history since startup. On several occasions, the plant was shutdown or a forced shutdown was extended due to failure of the pump seals or thermal barrier. Several early modifications to the thermal barrier proved to be of marginal value and problems persisted until 1980 when the vendor developed what appears to be an improved stuffing box design that eliminates the thermal barrier and utilizes a cartridge-type of seal assembly. It is believed that this modification will reduce the frequency of seal failures and possibly eliminate the need for forced outages to effect repairs to these seals. In 1980, the improved stuffing box was installed in both of the Unit 2 pumps[4-6] and since that time, they have performed well. Current plans call for installing new stuffing boxes in the Unit 1 pumps during the 1982 refueling outage.

In the future, recirculation pump seal failures should not be a key contributor to either units' forced outage rate, assuming that they are properly maintained during the planned maintenance periods.

4.8 UNIT 1&2 SUPPRESSION POOLS (TORI)

In the course of performing large-scale testing of an advanced design containment, in early 1975 General Electric (G.E.) identified new stresses that could develop in the suppression pools of earlier designs during certain plant transients. The NRC staff, after reviewing the G.E. data, determined that affected plants could continue operation as long as existing designs or modifications to those provided a margin of safety of at least a factor of two, while a long-term comprehensive program was conducted to resolve any safety concerns.[4-7, 4-8] In July 1980, the NRC issued a long-term evaluation report [4-9] that set forth generic criteria for the plant-unique assessments. In the same timeframe, G.E. and the BWR owners group were developing generic approaches toward modifying the standard G.E. torus designs to meet the anticipated demands of the NRC. On January 13, 1981, the NRC issued an order establishing that the Brunswick units were to be modified by February 1982 and November 1981 for units 1 and 2, respectively.

The NRC demands were most likely based somewhat on the premise that the industry (G.E. and the owner's group) had a basic modification package at hand and implementation was a function of mobilizing a construction force. However, the Brunswick units have a torus design considerably different from the other G.E. plants. CP&L retained United Engineers and Construction (UE&C), the orginal plant architect/engineer, to undertake the development of a plant-unique modification package for the Brunswick units. Actually, in anticipation of these requirements, this

design effort was begun in 1979. In addition, CP&L applied for and received relief on the deadline dates such that modifications could be delayed until the 1982-83 timeframe (subsequently delayed until 1983-84). The total modification package from UE&C is essentially complete at this time.

During the Spring, 1980 refueling outage, Unit 2 planned to install those parts of the modification that were identified and designed at that time. An outage length of 59 days was allotted for completing these modifications. During the outage, the torus project was beset with several problems that extended the outage to 102 days. In addition to relatively uncontrollable elements that were encountered (e.g., snowstorms, contamination control, and labor walkouts), several design problems were encountered,[4-10] namely:

- The interferences and layout of the torus interior were not completely provided for in the new designs;
- The complete work scope was not adequately addressed in the original schedule. The quantity of unanticipated work was not appreciated prior to or even during the construction period;
- In some cases, interferences were so extensive that the design concept was no longer viable and redesign was required;
- The original schedule did not address the time and work force necessitated by the close tolerances required for some aspects of the design;
- Radiography was not a requirement in the initial scope but was added at a later date; and
- Six additional restraints were required but were not originally anticipated.

It is clear that a major issue was the lack of appreciation of the extent of the interferences between the modification and the "as-built" configuration of the torus. The Brunswick torus design is a reinforced concrete structure with a steel plate

lining providing a leak-proof containment. This type of construction is characterized by liberal tolerances, such that design drawings cannot, for the most part, be relied upon for determining design details. This is not true, however, for internal piping and structural details that should closely follow the applicable construction drawings.

In any event, a substantial portion of the total torus modification package was completed during this outage. In discussing this issue with CP&L personnel, appropriate measures have been taken to ensure that similar problems will be minimized in the future work needed to complete the modifications in both Units 1 and 2.

The current plans call for completion of all related torus modifications by 1984. The actual list of items to be accomplished is quite lengthy and a discussion of each is outside the scope of this report. However, it should be noted that the torus work will likely control the length of the following outages:

- Unit 2, 1982 Refueling (April-June, 1982); and
- Unit 1, 1982-83 Extended (August-December, 1982).

Following these outages, major work scope items will remain to be completed in Unit 1 in 1984 while all Unit 2 items will be complete except for some minor items. CP&L should consider completing all required major work in the Unit 1 torus during the extended outage in 1982, since the large scope of work being accomplished throughout the plant will likely result in an outage extension (historical perspective). This would preclude the possibility of another long Unit 1 outage in 1984.

Most of the suppression pools in the United States are coated with an epoxy paint system for corrosion protection. Due to the size and complexity of a torus, painting would normally encompass

a period in excess of nine weeks to complete -- to the exclusion of all other work in the torus. As a result of the scope of the Brunswick modifications, repainting would certainly be a requirement due to the effects of traffic, welding, etc. In July, 1981, UE&C provided, at CP&L's request, an evaluation of the need for recoating the Brunswick tori.[4-11] The results of this analysis stated that the corrosion allowance in the Brunswick torus design is large enough that, at the expected corrosion rate, the integrity of the liner wall and structure will not be jeopardized by corrosion over the expected lifetime of the plants given that there was no coating on the steel surfaces. As such, they recommended removal of the existing coating below the water line and a continuing surveillance program to monitor the actual corrosion rate. This is the approach that CP&L is planning to take. If this decision were to be changed in the future as a result of later findings or regulatory demands, a considerable outage impact will result at that time.

4.9 SEISMIC RESTRAINTS (SNUBBERS)

The failure of hydraulic snubbers has been a generic industry problem since the early 70's. At the Brunswick units, snubber failures and associated testing, inspection, and maintenance activities have accounted for a considerable amount of outage time. This is amplified by technical specifications requirements that increase the inspection and testing frequencies as a function of the number of failures identified each time one or the other is conducted.

The snubber failures at Brunswick have been a result of three mechanisms. Each of these is discussed below.

Seal Leakage: In order for a snubber unit to remain functional, an adequate supply of hydraulic oil must be maintained within the cylinders. As a result of aging, the rubber seals in the snubber tend to deteriorate and eventually allow the oil to leak from the

unit and, thus, become "technically" inoperable when the leakrate is such that adequate oil replenishment is not possible at the existing inspection frequency. Since all of the snubbers are essentially the same age and are generally similar in design, it is likely that massive snubber failure will occur at intervals equal to that time required for seal deterioration and failure. Current estimates are that the seal materials now in use for most seals have an operational lifetime of approximately five (5) years. CP&L has no existing program of periodic sampling or re-building of these units nor for other plant equipment having components that are subject to aging and deterioration (see Section 5.0 of this report for a further discussion of this issue). An evaluation of this issue is currently being conducted by the CP&L engineering staff.

Poppet Valve Wear: Several snubbers in both Brunswick units failed as a result of wear of the control valve poppets and spring guides. In 1981, all of the Unit 1 snubber control valves were rebuilt using an improved design that should not be susceptible to this problem. Earlier, all Unit 2 snubbers were rebuilt but the modified version was not available at that time. Current plans call for modifying the Unit 2 snubbers during the forth-coming 1982 refueling outage.

This problem is directly related to vibration of the associated piping systems. Although the improved design will make the units more resistant to wear and failure, it is not certain that the problem is resolved. Generally, snubbers are not designed to tolerate continuous vibration, even at low amplitudes. As a result, it is likely that snubber failures will continue to occur in the future, albeit at some reduction in frequency.

Severe Transients: There have been several cases of snubbers being damaged as a result of water hammer in the associated piping systems. In the case of the HPCI and RHR systems, this was related to the lack of a reliable system to keep the piping full of water

-- a necessity for preventing water hammer. Plant modifications have been installed to accomplish this in the future and their operation is currently pending a routine change in the technical specifications. In the interim, surveillance of the keep-fill systems has been increased to ensure proper operation. The failures of snubbers on the safety/relief valve discharge piping has been linked to the original plant design allowing common usage of a single discharge path to the torus for two relief valves. The torus modifications in progress will rectify this condition.

4.10 TURBINE GENERATORS

During the 1981 outage, the Unit 1 turbine generator was subjected to an attempted sabotage event followed by a gross failure of the unit's bearings and hydrogen seals. A detailed description of the event is provided in Section 3.0 of this report.

In reviewing the history of this unit, it was discovered that it has experienced bearing and seal problems as far back as 1979, (earlier records not reviewed). During the 1979 outage,[4-12] General Electric (G.E.) reported that bearings 1 through 4 were damaged as a result of dirty oil, as was the thrust bearing and perhaps the hydrogen seals. Additionally, the oil tank was found to be dirty and corroded and the fine mesh return screens ragged and torn. During the same period the hydraulic oil tank was also found to be "quite dirty" as well as the coolant side of the stator coolers. Since this was the first major outage since commercial operation and the generator repair in April, 1977, it can be assumed that contaminants were not removed from the turbine generator auxiliary systems during these evolutions. Another possible source of contaminants in the main lubricating system was identified by G.E. to be the clean oil storage tank. Apparently, there was confusion as to the cleanliness of oil stored there resulting in dirty oil being used to refill the MLO sump

after the sump was cleaned. This problem was again identified in 1981 when it was decided to modify the system such that oil from the clean lube oil tank was conditioned during transfer to the main sump. It should be noted that, although the Unit 2 turbine has had relatively few bearing problems, similar problems with dirty oil were identified in 1979 and 1980.[4-13, 4-14]

In April 1981, the unit was inspected again during the refueling outage. At that time, bearings No. 2, 8, and the thrust bearing were found to be severely damaged as were the hydrogen seals. In all cases, damage was believed to be caused by dirty lubricating oil.[4-15, 4-16] At that time, it was decided to inspect all turbine generator bearings and consideration was given to conducting an oil flush (low velocity). The sump was also inspected and found to contain a large quantity of trash and debris.

Following the three successive flushes and the gross bearing failure (see Section 3.0), the unit was placed in service on September 25, 1981 and has been in operation since that time. Although the unit appears to be operating satisfactorily, there continue to be problems with hydrogen leakage[4-17, 4-18, 4-19] and lubricating oil contamination. Subsequent to the final flush, significant quantities of dirt and debris were found in the lift pump strainers and on the lube oil return screens and lube oil samples indicate particle levels exceeding the manufacturer's specifications.

It is unlikely that the unit will experience a gross bearing failure as was encountered during the 1981 outage as a result of increased security and other measures taken by CP&L regarding lube oil quality. In the future, CP&L should consider other actions for both turbine generator units to ensure a high level of performance, including:

- Complete implementation of the recommendations set forth by G.E. for turbine lube oil systems;[4-20]

- Develop a qualified, competent and experienced crew (including foremen) for future generator work;

- Implement a QA/QC program for turbine generator overhaul;

- Resolve the hydrogen seal leakage problems; and

- Consideration of conducting an oil flush of the Unit 2 main lube oil system as per G.E.'s recommendation.[4-21]

In an unrelated matter, in 1979 the NRC issued Information Notice 79-37--Keyway and Disc Cracks in Low Pressure Turbines. Until recently, this was thought to be a problem related only to Westinghouse turbines. However, earlier this year, G.E. found cracks in the low pressure turbine (5th stage) hub discs at another BWR plant. As a result, G.E. is planning to submit a report to the NRC in the near future recommending ultrasonic inspection of all G.E.-supplied L.P. turbine rotors at 6-year operating intervals. G.E. believes that only stages 4, 5, and 6 are susceptible to cracking and inspections will be limited only to these areas. It is estimated that the complete inspection for one rotor can be accomplished in 10 weeks.

In response to this situation, CP&L is planning to inspect both L.P. rotors of both units during the 1982 refueling outages. This will probably result in a delay of the planned inspection of the H.P. turbine in Unit 2 and a likely outage extension. Should cracks be detected, the affected row of blades can be removed and the turbine reassembled with some moderate loss of efficiency pending receipt of a replacement.

4.11 MASONRY WALLS

In May, 1980, the NRC issued IE Bulletin No. 80-11 regarding the questionable design and construction of masonry walls at nuclear

power plants and their concern that these walls could endanger adjacent safety-related plant systems in the event of an upsetting occurrance (e.g., earthquake). This bulletin required that utilities review their installations to ensure adequacy with respect to the criteria provided by this bulletin and 10 CFR 50.

As a result of this survey, CP&L identified approximately 20 walls which had not been constructed in accordance with the details shown on the construction drawings.[4-22] These deviations ranged from details such as angles and clips missing to, in one case, a 5'x6' opening filled with non-mortered blocks that was not shown on the drawings.

CP&L arranged the findings of the survey into two categories:

(1) Those where wall failure and subsequent damage to important equipment would, theoretically, occur during a seismic event; and

(2) Others that are characterized by code deviations of the wall construction but not to the extent that they would experience failure under seismic conditions.

Approximately half of these walls are being modified such that they meet design and code requirements. The remainder of the walls are the subject of waiver request to the NRC to permit them to remain "as-is." Justification for this comes from an analysis completed by UE&C that shows that the walls are structurally sound in their present configuration and that the scope of work needed to correct these deficiencies is quite large due to interfering plant systems, structures, and components.

The potential of reoccurrance of this problem as a result of future plant modifications still remains. In October, 1980, this was identified by the plant staff[4-23], however, there is no evidence that the engineering or plant instructions provide specific guidance in this regard.

4.12 SEISMIC PIPE SUPPORTS

In 1979, as a result of findings at other nuclear plants, the NRC issued three bulletins associated with the support of Class I seismic piping. These were:

- IEB 79-02: Requiring inspection and testing of concrete anchor bolts used to attach seismic structural members to the plant's concrete structures.
- IEB 79-07: Requiring a review of the programming and computational techniques used for analyzing the piping installations and associated support structures.
- IEB 79-14: Requiring an examination of all seismic Category I piping and support structures to ensure compliance with the applicable design drawings and correlation with the piping analysis.

Over the past two years, the CP&L staff has conducted essentially all of the inspections required under these bulletins and, with the assistance of United Engineers and Construction, have re-analyzed the affected piping systems. As a result of these reviews and analyses, approximately 1,000 supports (in both units) were found to be deficient to varying degrees and required modifications to correct these problems.

To establish the proper priorities, the fixes were split into two categories -- "short-term" fixes and "long-term" fixes.

> "Short-term" fixes relate to those items that would fail (yield or tensile stress exceeded) during the design-basis event. These required immediate remedial attention.
>
> "Long-term" fixes relate to those items that would not necessarily fail under the design-basis event, but where the code-allowable material stresses were exceeded. For this group, the NRC permitted extended operation with a firm commitment for modification. In the case of the Brunswick plant, this was agreed upon to be 1982.

During 1979 and 1980, all short-term fixes and some long-term fixes were apparently the cause of several outage extensions. For many of the short-term fixes, this was a result of insufficient time available for planning and pre-job preparations along with NRC pressure to complete fixes in a relatively short time frame.

As of this date, all short-term fixes have been completed. UE&C has completed reviews and modification packages for all supports and restraints other than those associated with the control rod drive (CRD) system which are being reviewed by another contractor. CP&L staff reviews are expected to be completed in February 1982 and all packages should be issued to construction in a time frame that will permit completion of all work in both units in 1982.

The CRD piping is being reviewed by EDS Nuclear, the original designer. Any modifications to the existing systems that may be required will be developed by the CP&L engineering staff and implemented accordingly. Again, current plans call for closing out this item in 1982. The potential exists that the Unit 2 modifications could impact the length of the 1982 refueling outage.

The only piping systems included in these programs are those related to the NRC reactor safety issues. It should be noted that, from a plant reliability standpoint, hangers and supports in the remainder of the plant may be suffering from similar deficiencies or may be susceptible to operational-related failures. CP&L representatives stated that there is no intention to conduct any extensive inspection of the non-safety related pipe supports nor to periodically inspect pipe supports (other than those identified in the ISI Program) in the future. It would be prudent of CP&L to reconsider this approach in order to reduce the probability of an untimely pipe support failure that could result in a forced outage and subsequent regulatory requirements for unplanned inspections and surveys.

4.13 RADWASTE SYSTEMS

The problems associated with the radwaste processing facility are legion and, thus, an in-depth investigation of the radwaste systems is beyond the scope of this study. However, in 1980, CP&L retained a consultant to review the radwaste problem and develop recommendations for improving current conditions[4-24]. A spot check of recent log books as well as discussions with CP&L personnel indicate that conditions have improved slightly since then. As the first step to develop a three-year plan toward improving conditions in radwaste, an in-house task force was organized. A few projects have been undertaken including improvements in the instrument air system and the development of a reverse-osmosis purifying unit for low-quality waste. These will have some near-term effect on the performance of the radwaste systems. One of the most important projects involves the overhaul of the 50 gpm evaporator. This will provide an effective method of processing regeneration wastes and contaminated salt water which will vastly improve conditions in radwaste and the other plant facilities. Other issues to be addressed include:

- Material compatibility. Gross changes in mechanical components (i.e., piping, valves, etc.) are required to provide materials more resistant to corrosion caused by the makeup of the waste streams. Several valves have been replaced with a corresponding marked improvement in radwaste conditions and performance.

- Waste generation rate. Plant log entries and discussions with management indicated that efforts to reduce inleakage are not completely effective. The level of concern does not appear to be of such as to imply that a program of leak reduction could be successful at this time. It should be noted that reduction of inleakage is <u>key</u> to radwaste performance improvement.

- Waste stream quality. Again, indications are that the program of chemical and oil control, if it exists, is not effective. Frequent spills of oil and salt water continue to burden the already overloaded processing systems.

- Preventive maintenance (PM) program. A plant PM program is currently under development, however, implementation is just beginning. It is likely that, due to the high level of construction activity and the large backlog of repair items, any progress toward a broad-based PM program will be limited in the near term (2-3 years).

- General housekeeping and work practices. This continues to be a problem area.

Although plant management claimed that radwaste processing limitations have not adversely affected plant operation, certainly it is a factor in numerous opreational and maintenance decisions, the effects of which are difficult to quantify. For example, during the Unit 1, 1981 maintenance outage, on several occasions critical path activities were held up due to radwaste limitations and excessive water in the RHR rooms and the pipe tunnels. In any event, the potential <u>does</u> exist for radwaste limitations to adversely affect future plant availability.

Some near-term improvement may be recognized as a result of some of the actions already completed or planned for the near future along with a recent change in policy that would stabilize the radwaste operating crew.

4.14 UNIT 1 AND 2 MAIN CONDENSERS

The BSEP condensers in both units have experienced severe problems with tube leakage and saltwater intrusion since plant startup. Frequent power curtailments and outages needed to effect condenser repairs have been a major negative impact on the overall performance of the units. Significant problems with reactor chemistry and the radwaste systems are also linked to the condenser leakage.

Various failure modes have been identified as the source of the leaks. These include inlet-end erosion, sulfide corrosion, steam

impingement, debris-related erosion, and failure of the tube-to-tubesheet joints. CP&L conducted several investigations into the root cause of these problems and resolved that the condensers were unservicable with respect to long-term reliability goals.(4-25)

The key problem is related to the design and condition of the tube sheets and poor quality control during erection. Specifically, the thickness of the tubesheet material, as specificied by UE&C, is inadequate to prevent excessive deformation during operation. As a result, the tube-to-tubesheet joints are overstressed and eventually fail. In addition, the tube and tubesheet material choices are questionable with respect to compatibility, original tubesheet fabrication errors caused oversized holes, and there was a lack of quality control during initial and subsequent tube rolling. In light of the foregoing conditions, the staff recommended rebuilding the condensers with the highest quality materials and state-of-the-art design. The new tubes will be titanium and the tubesheet a new integrally-grooved type. Titanium tubing provides the best resistance available to corrosion, errosion, and steam impingement. The integrally-groved tube sheet design will allow continued operation in the event of a tube-tubesheet leak. Any joint failure would result in leakage of clean, demineralized water into either the waterbox or the condenser hotwell -- thus, precluding seawater intrusion. Other design changes include modifications to steam and hot water dumps to the condenser that will prevent future steam impingement damage, protective baffles for the upper periforal tubes, additional stiffiners and support plates to account for tube vibration associated with the replacement tubing and other minor alterations.

The majority of the engineering effort involved in these modifications has been done by the CP&L staff. In addition to the

basic concept, several other related design efforts were addressed, including:

- Reanalysis of the thermal and structural characteristics of the new installation;
- Evaluation of titanium tube vibration and modifications needed to eliminate this as a future source of tube damage; and,
- Due to the choice of tube and tubesheet materials, excessive corrosion of the tubesheet is possible, thus, requiring design and installation of a reliable corrosion protection system.

In the interim, the plant staff took several actions immediately to alleviate the conditions causing failures and to minimize the impact of condenser leakage. Among these are:

- Installation of AMERTAP and debris filters to reduce foreign object impingement and erosion and to improve cleanliness;
- installation of baffles in the inlet waterbox to control inlet-end erosion; and,
- Employing a high-sensitivity helium leak detector to increase the efficiency of locating small leaks.

Some other issues related to the condenser rebuilding are discussed below.

Quality Assurance/Quality Control (QA/QC). As discussed earlier, quality control during fabrication and erection of the existing condensers contributed to the problems now being experienced at the plant. This does have CP&L management attention and is being addressed under the current refurbishment program. CP&L has contracted with inspection organizations for essentially fulltime coverage for both the fabrication of the tubesheets and other internals and for the tube manufacture. This is quite extreme and exceeds normal industry practice, thus, the potential

for fabrication errors will be extremely small. The requirement for similar QA/QC coverage during field operations has been identified and the current intentions are to address it to the extent normally expected of nuclear-related systems.

Tube-Tubesheet Joint. There is some disagreement between the design of the tube-tubesheet joint as suggested by the tubing manufacturer,[4-26] and that specified by CP&L[4-27] The manufacturer recommends adherance to the standards established by the Tubular Exchanger Manufacturers Association (TEMA) that is more restrictive for tubesheet hole size, whereas CP&L has specified the standards of the Heat Exchange Institute (HEI). Below is a comparison of these standards.

	TEMA	HEI
96% of holes	≤1.014"	≤1.018"
100% of holes	≤1.022"	≤1.024"

Thus, statistically, the tubing will require more expansion with the HEI standards with an increased probability of tube or joint failure.

Tube Rolling Procedures. Proper rolling technique is extremely important to ensure a reliable installation[4-27] -- particularly for the new design. The titanium tubing is susceptible to work hardening and splitting. Also, since the tubing has a higher yield point than the tubesheet, there is a danger of plastic deformation of the tubesheet, an unacceptable condition. CP&L intends to conduct procedure qualification tests to ensure that the procedures are correct; however, there are no existing plans to extend these tests to the "worst case" tube-tubesheet fit conditions, nor are there intentions to conduct metallurgical or non-destructive examinations of test joints to identify latent defects that could result in future tube or joint failure.

Construction Workmanship. The condenser assembly and rolling activities are key to the ultimate quality of the final product. Past history identifies serious concerns as to the caliber of the available workforce at the Brunswick station. CP&L is aware of the problem and is evaluating three options: 1) using local labor with CP&L supervisors and a contracted consultant; 2) contracting a firm to supervise and manage the work with local labor; and, 3) contracting a "turn-key" type of operation.

Schedule/Manpower Constraints. There has been a tendency at Brunswick for projects to be undermanned as a result of site manpower restrictions. The character of this project is such that it will require a relatively large crew working at a steady pace in order to meet the prevailing schedule and quality demands. Some compromise of existing restrictive policies will be required if this project is to be completed properly.

Current plans call for the rebuilding the Unit 1 condenser in late 1982 and Unit 2 in 1983. This will result in a marked improvement of plant performance assuming the project progresses as designed. It should be noted that this combination of tubesheet design and material is relatively new with little service history. Therefore, it is difficult to predict the future performance. Theoretically, it represents the best possible design available for this type of installation.

4.15 REACTOR VESSEL NOZZLES

Cracking of the feedwater and CRD return line nozzles is a generic problem identified by the industry. In 1980, the NRC issued NUREG 0619[4-29] requiring all BWR licensees to inspect and make some modifications to the nozzles and associated reactor pressure vessel internals. The status of this is as follows:

Unit 1 - Feedwater Nozzles(4). These were inspected in 1979 and no indications or cracks were found on any of the accessable surfaces of the nozzles. Since the sparger and thermal sleeve are of the welded type -- generally acceptable to the NRC, there are no current plans for replacement of the sparger or for clad removal. Inspection requirements will probably continue into the near future (next 2-3 refueling outages).

Unit 1 - Control Rod Drive (CRD) Return Line Nozzle. This was inspected in 1979 and several cracks were found in the nozzle and the associated thermal sleeve. All cracks were removed from the nozzle by grinding and the thermal sleeve was not reinstalled. Since this particular piping is no longer needed in the G.E. design for the CRD system, the isolation valves were shut and the line isolated. During the next refueling outage, the piping will be removed and the nozzle capped. No further action will be required.

Unit 2 - Feedwater Nozzles(4). In 1970, accessible portions of the nozzles were inspected and no problems were found. However, the spargers were not removed. Unit 2, being an earlier design, has a slip-fit type of sparger. Attempts to remove it failed due to the extremely tight fit. During the 1982 refueling outage, the accessible portions of the nozzle will again be inspected. If no problems are identified, then sparger replacement and nozzle clad removal will be deferred until 1983. CP&L has contingency plans and replacement spargers on hand should removal be required in 1982 by the NRC (a strong possibility). This could result in a dramatic extension of the 1982 refueling outage if it occurs.

Unit 2- Control Rod Drive Return Line Nozzle. The status is essentially the same as that of Unit 1, except nozzle cracking was not observed.

In a related matter, General Electric has undertaken a thermal cycling study for the feedwater nozzles. This is intended to provide a more meaningful and credible lifetime evaluation of the integrity of these nozzles over the life of the plant. It is anticipated that results of this study will not be more restrictive than the existing technical specification guidelines.

4.16 ELECTRICAL EQUIPMENT QUALIFICATION

Throughout the period 1978-1980, the NRC issued I&E Circular, I&E Bulletin 79-01 and several associated documents. These required all licensees to review their installation with respect to accident survival capability and compare the results to newly developed standards. As a result of this review, several I&C components will require replacement (relatively minor impact). A major task remains to be resolved -- that of the containment electrical terminals.[4-30] The design of the plant was such that most cables within the drywell are terminated at an intermediate terminal board. This was designed to facilitate cable servicing without disburbing the associated penetration. CP&L is now tasked with qualifying and installing some encapsulation of the terminal board or terminal box or taking on a program of splicing the affected cables (approximately 1000 per unit). In any event, the NRC will insist that all work is performed within the timeframe of the next two refueling outages.

Currently, a vendor has been tasked with identifying and testing an encapsulation material with no results to date. Encapsulation will probably be relatively simple to implement with a substantial savings of manpower, cost, and radiation exposure. If splicing is ultimately required, due to the time-consuming nature of the operation, the limited work area, and anticipated test requirement, it could result in being the critical path activity of a refueling outage or at least a complicating factor for outage coordination.

4.17 FEEDWATER HEATERS

The 4A and 4B feedwater heaters on both units have been troublesome since soon after startup. On several occasions, tube leaks have necessitated isolation of the 4 and 5 string of heaters thus reducing plant efficiency and output by about 40-50 MWe or more.

Inspections and tests of the affected heaters have identified the failure mechanism to be a combination of corrosion and erosion, possibly caused by steam and particle impingement or erratic level control. Problems of this type are typical in the power industry today. A consultants' report[4-31] and vendor's recommendations suggest three options available to address the problem. These include:

- Installing an external flash tank;
- Additional baffles inside the heaters; and,
- A general upgrade or replacement of the heaters.

Proposals have been received from the original heater manufacturer. Option 2 is the only short-term alternative (approximately 18 weeks procurement time). The first opportunity for implementation is during the 1982 Unit 1 refueling outage. A management decision is pending regarding the preferred approach. There is also some effort underway to develop a short-term fix for Unit 2 to be implemented this spring. In addition, the level control system is under evaluation with no apparent milestones or goals established.

This issue is considered an open item and it can be anticipated that feedwater heater problems will plague the plant operators for the next 2-3 years until a final fix is installed or the heaters are replaced.

4.18 ANALOG/DIGITAL INSTRUMENTATION

There are two problems related to the original digital-type instrumentation. The first is the large number of licensee-event reports caused by setpoint drift. Although this is a maintenance and reporting headache, there is little impact on overall plant performance. However, related to this is the installation of an additional reactor vessel level reference leg. This will serve to eliminate the spurious reactor scrams experienced in the past during instrument calibration.

This modification is currently underway for all non-GEMAC instruments in both units. The status is as follows:

Unit 1 - Approximately 45 of 75 instrument loops have been completed including the reference leg portion. The total scope will be completed in 1982.

Unit 2 - All cabling, racks, and reference leg piping is installed. Current plans call for completing approximately 2/3 of the loops in 1982 and the remainder in 1983.

4.19 CONTAINMENT INERTING

For reactor safety reasons, the technical specifications require that the containment (drywell) be inerted with nitrogen such that the oxygen content remains below 4%. Exceeding this value would normally require plant shutdown with some time allowances.

A liquid nitrogen system is installed for the purpose of supplying gaseous nitrogen to both units for initial purge and occasional makeup. From time to time during operation, additional nitrogen must be transferred to the containment to account for inleakage from the instrument air system. On several occasions, plant

availability has been jeopardized by the inability to provide nitrogen to the drywells. The reasons include vaporizer problems, lack of auxiliary steam and in one case, an insufficient inventory of liquid nitrogen available for startup.

Current plans call for replacing the existing steam-heated vaporizer with a more reliable, electrically-powered, fan-ambient vaporizer. In addition, automatic controls have been installed to preclude discharge of liquid nitrogen from the vaporizer -- a condition that has caused pipe rupture in the past. The problem associated with the nitrogen inventory was linked to a management oversight. The plant staff claimed that this has been solved by an administrative adjustment. No consideration has been given to locate a local distributor with a portable, pumper-vaporizer unit.

There was some engineering expended to evaluate and develop a pump-back system whereby an additional instrument air compressor would be installed with its intake piped from the drywell itself. This would virtually eliminate the need for periodic nitrogen makeup. However, it was decided that the modification involved more than the staff was willing to attempt at this time due to higher priority items. Subsequently, the plans were shelved.

If current plans are carried out, it is unlikely that nitrogen inerting will have any further impact on plant availability.

4.20 REACTOR WATER CLEANUP (RWCU) SYSTEM

The RWCU system is designed to maintain the reactor water chemistry within designated specifications in order to preclude undesirable corrosion effects and to minimize the sources of residual radiation within the reactor coolant systems. There have been considerable problems with the reliability of the system at BSEP that have been responsible for plant shutdown in addition to interfering with outage tasks.

In 1981, members of the CP&L staff visited several other BWR plants to identify system differences and any changes to systems or procedures that might be appropriate at Brunswick.[4-32] This confirmed the validity of many of the actions already planned by CP&L. In addition, the study pointed out the importance for careful and high quality maintenance, particularly with respect to the recirculation pump performance.

CP&L has undertaken a program to upgrade the RWCU system in an effort to improve operations. Modifications have been made to the recirculation pumps and non-regenerative heat exchangers of both units. During the 1982 refueling outages, current plans include:

- Replacement of several valves with a more reliable design;
- Relocation of the backwash receiving tank to provide better access for maintenance;
- Modification or replacement of the system process controller;
- Rearrangement of piping runs to facilitate future access for maintenance; and,
- Several other minor items included in a group considered "general upgrade."

These actions should go far toward improving the future performance of the system and it should not be a significant factor affecting overall plant performance or availability in the future.

4.21 VALVE-PACKING (VARIOUS)

On several occasions, plant shutdown was required due to excessive valve leakage inside the drywell (technical specification requirement). Many of these leaks have been attributed to failure

of valve stem packing. This is especially true of Unit 2, where pre-operational conditions are thought to be the cause of many packing failures. In Unit 1, a program of repacking was undertaken just prior to startup in order to avoid a similar problem. In addition, many of the troublesome valves (i.e., recirculation, main steam isolation, etc.) have been repacked with an improved grafite type of material that appears to be more reliable than the older asbestos type.

Another contributing factor to packing failure identified by the plant staff is related to the lack of a rigorous mechanical maintenance training program. Since valve packing procedures are usually somewhat general in nature, heavy reliance is placed on the training and experience of the specific mechanic assigned to the task. Thus, it is not unlikely that some percentage of past packing failures were caused by improper technique during repacking. The relatively high personnel turnover rate adds significance to this situation. This particular issue is to be addressed in the newly expanded CP&L corporate training program now being implemented.

The actions planned by CP&L discussed in this section should do well in reducing thes frequency of packing failures in the future. These, along with an effective perventative maintenance program, could eliminate this as a reason for forced outages.

4.22 MISCELLANEOUS ITEMS

Augumented Offgas (AOG) System

Attempts to operate the Brunswick offgas system in 1976 were aborted due to successive detonations and general design details. A subsequent analysis was conducted by the CP&L staff and it was determined that the cryogenic system with the pelletized-catalyst recombiners was neither safe nor economical when compared to

improved systems including ribbon-type recombiners and charcoal absorber beds. Thus, the systems were abandoned and efforts were initiated to design and procure an improved system. The current plans call for installing recombiners in Units 1 and 2 in 1982 and 1983, respectively. Installation plans for the charcoal beds have not yet been established although regulatory pressure will likely force the schedule into the 1983-1984 time frame. (Not outage related.)

Normally, this has little effect on plant capacity factors, however until the current load of 7 x 7 fuel bundles is discharged from Unit 2, there is a power restriction that could have been mitigated had the AOG system been operable.

Service Air System

The service air system suffers from a lack of sufficient capacity to meet the current needs of the plant. Efforts are underway to upgrade the existing system including:

- New cyclone separators in the radwaste air supply header;
- An additional 1200 CFM air compressor for each unit; and
- Doubling of the air dryer capacity in each unit.

This should help to eliminate many of the problems experienced in the 1981 outage that were related to the service air system.

Local Power Range Monitors (LPRMs)

During the last Unit 1 outage serious concern was raised regarding the poor reliability of the LPRMs. This was particularly true of the newer model supplied by General Electric. Failure of a large number of LPRMs could force a premature outage or extend a planned

outage due to the time-consuming nature of LPRM replacement activities. CP&L and G.E. are currently evaluating the problem.

Nuclear Fuel

The earlier 49 pin design of the G.E. fuel (7 x 7) was susceptible to operational damage and cladding failure ultimately resulting in excessive offgas releases and corresponding plant operating restrictions. The nature of the reactor core is such that once the fuel is used, it is not technically, or economically, feasible to simply remove the faulty fuel and replace it with the new design.

Currently Unit 2 is restricted by approximately 10-15% due to fuel failures until after the 1982 outage when plans call for removal of the last 7 x 7 bundles of fuel. (None of this type is loaded in Unit 1). Thus, restrictions due to offgas is not expected in the future and it should not be a reason for reduced capacity factors.

Fuel Pools

Both fuel pools are suspected of having liner leaks of some "small" magnitude. Although this does not pose any immediate operational problems, repair of the leaks could interfere with future plans to increase the capacity of the pools by re-racking. Currently efforts are underway using divers for inspecting the pools and locating the leaks. Approximately one-half of each pool has been inspected to date but no leaks have been found. The remaining areas of the pools are somewhat unaccessible until additional temporary fuel storage racks are installed in the pools to allow reshuffling of fuel bundles. CP&L did not have a time schedule for these activities.

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5.0 PLANT PROGRAMS AND MANAGEMENT ISSUES

5.0 PLANT PROGRAMS AND MANAGEMENT ISSUES

There are many management issues that have direct impact on plant capacity factor and overall reliability. At Brunswick, several of these have played a key role in establishing plant performance patterns in the past and affecting it for a considerable time period into the future. For the purpose of this report, the issues of interest include:

- Engineering and Design Control;
- Equipment Lubrication;
- Efficiency and Reliability Program;
- Health Physics;
- Preventive Maintenance;
- Outage Management; and
- Training.

Each of these is discussed briefly in the following sections. These discussions are pragmatic in nature and attempt to view the factual data available in the context of generally prevailing conditions at the Brunswick site.

5.1 ENGINEERING AND DESIGN CONTROL

During the construction phase of a power plant, the architect/engineer and constructor are tasked with ensuring that the final plant configuration reflects the engineering drawings and plans and meets the required codes, standards, and regulations as well as the philosophies and concepts of the individual engineers responsible for the design. This includes the scope of other lower-tier organizations such as vendors and subcontractors. Theoretically, when plant systems are turned over to the plant operator or owner, they conform to basic design documents and

records or exceptions are noted. It then becomes the responsibility of the plant engineering staffs to ensure that the plant remains in a "conforming" condition. The details of such a program are set forth in the recognized standard ANSI N45.2.11.[5-1]

At the Brunswick station, United Engineering and Constructors (UE&C), the plant architect/engineer (A/E) was tasked with the detailed design of the units. Within their organization, they maintained a system of design control such that all designs, and changes thereto, were reviewed and issued in accordance with strict guidelines. At the plant site, Brown and Root Co. was the constructor, basically responsible for implementing the design as set forth in drawings and plans provided by UE&C. Frequently during construction, designs must be altered for a variety of reasons. To control such changes, the constructor or A/E establishes a design change procedure to ensure that these changes are afforded the same controls as that of the original design. Apparently, during the construction of the Brunswick units, many of the design change notices that were generated either did not go through the complete review process or were not ultimately included in the details of the governing plant drawings. Thus, anyone using the plant drawings for operational or engineering reasons could not be sure that they reflected the actual configuration of the plant. This was apparent in the problems associated with the torus modifications, the seismic restraint and hanger surveys and the masonary wall evaluations, all of which are discussed in Section 4 of this report. It may be even more of a problem in those parts of the plant considered "balance of plant" and non-safety-related systems and components (i.e., main condensers, floor drains, main turbine systems, etc.). In these cases, a minimal amount of design control was required during construction and documentation is probably not available for all changes and deviations from the original designs.

Carolina Power and Light (CP&L) recognized this problem and has instituted a program aimed at updating the plant drawings to the

"as-built" conditions. UE&C has been actively working on this since 1979 and will continue until all documented plant changes are reflected in the respective plant plans and drawings. There are, however, no plans to comprehensively survey the entire plant for conformance to the drawings, with the exception of those elements mandated by the Nuclear Regulatory Commission (NRC) -- i.e., seismic supports, masonry walls, etc. -- or required as part of modifications (main condensers, torus, service water piping, etc.).

As discussed earlier, the plant and corporate engineering staffs have the responsibility of design control as it applies to future changes in the plant systems and structures. Prior to 1980, and to a large extent even at the present time, the plant engineering staff was responsible for most of the smaller and moderate-sized design projects. Engineers working for a plant staff (at any facility) will generally, under management and workload pressures, tend to minimize the depth of analysis of a design or maintenance problem in order to respond to the plant operational demands. This is especially true at the Brunswick station when a related situation was noted by the NRC in their Performance Appraisal Team (PAT) Inspection.[5-2] During that inspection, the inspector noted that although the engineers were technically qualified, their workload was excessive and the quality of their engineering was questioned. Design control measures were also found to be deficient during a later inspection conducted in October, 1980.[5-3] As a result of this, during the period prior to 1981 when the engineering staff began to expand, the plant probably suffered from several related effects. Some important aspects of this include the following:

- Regulatory Demands. During this phase, plant management was surely aware of the potential impact the NRC could have on plant available. Thus a considerable portion of the limited engineering capability was devoted to regulatory issues versus "real" plant engineering problems.

- Plant Operational Concerns. Any remaining engineering resources were applied to solving the immediate maintenance problems experienced by the units while they were suffering from basic design and construction deficiencies. As the maintenance backlog continued to increase, the engineers were quick to arrive a short-term fixes in lieu of more expansive root-cause corrections that demand considerably more resources.

- Priority Assessment. Sensitive to the engineering and maintenance limitations as well as perhaps management directives, the plant operators were and continue to be somewhat resigned to the fact that the plant, as it was constructed, has limitations and problems. In response, they adopted a somewhat cavalier attitude toward the operation of plant equipment. This was demonstrated during the events leading up to the radioactivity release incident on February 22, 1980, involving the auxiliary boiler tube rupture.

- Maintenance Controlled Modifications. In the event that a component equipment failure was identified to be a result of a minor design deficiency, there is a tendency for the plant maintenance staff to modify the item by using a maintenance instruction, thus, effectively bypassing the engineering control system. Although this occasionally may have occurred on Q-designated equipment, it was probably more widespread in other areas and systems of the plant.

- Limited Design Review. ANSI N45.2.11 requires that all designs and changes thereto be subjected to an "independent" design review to ensure that the final design takes into account the proper inputs and that the assumptions, calculations and other aspects of the analyses are proper and logical. It is unlikely that, considering the staff makeup and limitations, the rigor of the reviews that were conducted met the intent of the standard. This increased the probability of error and likely resulted in difficulties during or after implementation.

- Lagging Update of Plant Documents. Under the pressures of high priority engineering work, the updating of plant documents including procedures, training instructions, drawings, etc., which is the responsibility of the plant engineers, generally takes on a lower priority after the construction and installation work is completed and the associated system(s) is operational. This was identified as a problem at Brunswick and is addressed in the existing plant modification procedure.[5-4] The Engineering Data Coordinator is now responsible for ensuring all followup documentation is completed.

Over the past year or two, the CP&L engineering capability has increased both in numbers and in maturity (see Section 6). Thus, in the future the quality of the modification packages generated by the engineering staffs will improve resulting in more efficient implementation of the modifications and better, long-term resolution of problems. However, to be effective, this effort must address the lower priority engineering requests as well as those directly related to plant availability. Many of the low priority items create operational and maintenance difficulties and inconveniences that will ultimately affect plant availability. There appears to be a tendency for the CP&L engineering staff to underemphasize the lower priority items and concentrate their efforts on those engineering tasks considered by management to be more important. Another current weakness was noted in the lack of rigor involved in the plant-generated modifications. It is suggested that this is a hold-over from past practices.

5.2 EQUIPMENT LUBRICATION

Maintaining proper equipment lubrication is a key element of any effective maintenance program. The lack of proper lubrication will eventually lead to premature failure and complicated, extensive repairs. The 1981 Unit 1 turbine bearing failure underscored this fact.

Last summer (1981), an in-house review of the plant lubrication sampling program was conducted. It was determined that the program was ineffective and could have been a contributing factor in the turbine bearing failure. Prior to that, several inspection reports cited dirty lubricating oil as the probable cause of failure of bearings in the turbine-generator and main feed pumps as well as the generator hydrogen seals.(5-5, 5-6, 5-7) Before July 1981, the responsibility for equipment lubrication was assigned to a "designated" foreman as a collateral duty. It is apparent that under the extensive workload during the period 1978-1980, the

lubrication program was afforded a relatively low priority. Oil samples were taken periodically, but the system for documentation and control of these samples was poor -- thus the results of any analysis conducted of the oil could not be correlated and were of little value. Basically, the auxiliary operators were called upon to ensure sumps and sight glasses were at the proper levels and equipment was operating without obvious lubrication failure.

In July 1981 the PTPM group was established as part of the plant maintenance department with a permanent foreman designated as its supervisor. This group has the primary responsibility for equipment lubrication as well as special equipment tests (i.e., snubbers, valve operators, etc.). In addition, a plant procedure was issued in September 1981 to control the sampling and analyses of lubricating oils.[5-8] Samples from critical oil sumps are drawn on a monthly basis and sent to the New Hill Laboratory for analysis. A three-day turnaround is required for all samples. On a quarterly basis, additional samples are provided to the oil vendor for further analysis. Results of the New Hill analyses are teletyped to the E&C Project Specialists Group for review and then sent to the plant maintenance engineers and the PTPM foreman. Corrective actions are decided upon at that level.

Several areas of concern are identified with regard to the implementation of this program, namely:

- Plant upper management does not have the responsibility for routinely reviewing analysis results.
- Data is not presented in a format to provide trend analysis.
- There is no audit requirement for the program.
- Standards for equipment other than the turbine-generator do not exist; thus, oil analyses for many plant components are of marginal value. In several instances, recent results of lube oil tests did not meet the published specifications and were apparently ignored based on the belief that these standards are too restrictive.

- There is no requirement for frequent checks (by the PTPM group) of equipment and sumps in the plant nor for periodic checks and cleaning of filters and strainers. The auxiliary operators are depended upon to alert the maintenance group as he observes problems developing.

5.3 EFFICIENCY AND RELIABILITY PROGRAM

In June 1978, CP&L management initiated the plant Efficiency and Reliability Program. This was intended to stem the steady decline of the total system equivalent availability since 1972[5-9] The key elements of this program called for a formalizing and modernizing plant management activities including:

- Management monitoring and control procedures aimed at those management activities directly related to improvements in plant reliability and availability;
- Reviews and analyses of plant operating data;
- Evaluation of operating procedures with respect to the specifications and instruction set forth by the plant designers and equipment vendors;
- Monitoring and improved control of equipment; and,
- Investigation of all forced outages.

A Reliability Steering Committee was formed to establish guidelines for program implementation. In December 1978, this committee developed the first six of these guidelines and requested the plants to implement these by July 1, 1979.[5-10] The topics of these guidelines followed along the same thrust of the program, namely:

- Management control of reliability projects;
- Review and analysis of routine operating data;
- Assurance of operating equipment parameters and limits;
- Trouble alarms, control system, and instrument calibration and maintenance;

- Forced and forced-partial outage investigation and correction; and

- Outage planning.

On January 16, 1979, the steering committee met and documented concerns related to the lack of available resources for implementing this program.(5-11) In the meeting minutes, they stated:

> "Many problems are expected on implementing these guidelines. The major one being the lack of personnel assigned to develop and implement these guidelines. It was expressed that other, more important things that need to be done, could be deferred to implement these guidelines. The concern was that the bottom line of the operating plants would suffer, and that the plants had to be kept operating. It was expressed that the plants needed to work on known problems and not on developing procedures."
>
> "The fact that developing and implementing the Reliability Program is going to cost personnel time has not been accepted. Management must allocate resources to correct reliability problems and to implement the Reliability Program."

At that time, it was apparent that the program was not being afforded a high priority in light of the existing, more immediate, problems facing plant management. Implementation of these guidelines continued to slip until November 1979, when Mr. Furr, in a memo to the nuclear plant managers, underlined the importance of such a program in light of public attitude and political and economic issues pertaining to the nuclear power industry as a whole.(5-12) He also suggested that consideration be given to use contract engineering to assist with the task.

In 1980 some progress was made toward implementing the program. At Brunswick, however, several informal documents and notes indicate that, perhaps, the effort was somewhat superficial. The responsibility for the program, for the most part, fell on the engineering staff, with little or no involvement from the operations or maintenance staffs. The implication was that it held relatively low priority. Other relevant comments included:

- There was little done in the area of performance monitoring.
- Management involvement was minimal.
- There were no effective auditing or controls to ensure that the program was being carried out.
- Investigation of forced outages was ineffective.
- Critiques of planned outages were nominal or non-existent.
- Lines of communication and authority were confusing. The roles of the various management groups were especially questionable.
- Operational and maintenance priorities were established in a somewhat arbitrary manner.

On May, 14, 1981, after almost three years of implementation, relatively little had been accomplished in developing the reliability program at Brunswick as documented in a meeting between Mssrs. Hollowell and Strickland and Mr.Dietz, the newly appointed Brunswick plant manager.(5-13) Mr. Dietz stated that concepts presented in the program are good management practices that should be implemented and he agreed to accomplish as much as is feasible in the near future.

In light of the foregoing discussion, one can understand some of the aspects of the plant management during the years 1977-1981 that have led to the relatively poor performance of the units.

In August, 1981, the plant staff published a summary report of the status of the BSEP Efficiency and Reliability Programs.(5-14) Below are brief descriptions of those elements addressed in the summary report. The majority of these were implemented in 1981.

Efficient Operations Log. This provides the control operators with a tool for periodically monitoring the thermal performance of the units and to take steps to maximize plant output.

Daily Plant Performance Report. This report to plant management presents information on a daily basis describing the performance of the units.

Weekly Spot Data Report. Data on several key plant parameters and plant equipment availability is collected on a weekly basis and passed on to plant and corporate management for review.

Condenser Performance Testing. At least once each week, data is collected and the overall performance of each condenser is evaluated.

Monthly Operating Report. This report provides corporate management with information regarding unit heat rate, capacity factor, output factors, and other pertinent operating parameters needed to assess the overall operation of the unit during the month.

Annual Unit Heat Rate Predictions. These predictions are developed each year and, on a yearly basis, are reviewed and analyzed with respect to actual versus predicted to identify areas of potential improvement.

Instrumentation. Efforts are underway to identify and upgrade the operation and maintenance activities associated with plant performance. This appears to be an extension of the existing instrumentation program for those systems falling under the jurisdiction of the plant technical specifications.

Implementation of Manufacturer's Recommendations. All G.E. Service Information Letters and other manufacturer's recommendations regarding equipment for which these are operation or maintenance procedures are reviewed by way of an engineering work request to the appropriate engineering group who is responsible for evaluation and implementation, as required.

Outage Investigation. Each forced/forced partial outage is investigated, evaluated, and corrective actions recommended as appropriate in a Unit Outage Report.

MWH Loss Accounting. This results in a computation of MWH losses on an hourly basis as a result of any full or partial outage.

From the foregoing, it would appear that some progress is being made in this regard. However, the program, as it exists, remains limited to the participation of the Performance Engineering Group with little involvement of other plant management organizations. Because of this, it is likely that outputs and recommendations coming from the program will be somewhat lacking in perspective, credibility, and the support of other plant departments; thus, limiting the effectiveness of the program.

5.4 HEALTH PHYSICS (HP)

The plant HP program is an integral part of all site activities and it is often a key element in controlling the tenor of plant evolutions such as outages, tests, etc. The mark of a successful HP program is its ability to maintain the proper controls to ensure work is performed in a safe manner while not providing any added measure of difficulty to the effort. A review of several past NRC inspection reports (5-15, 5-16, 5-17) suggests that perhaps, due to other plant conditions, the latter of these goals was overemphasized.

After reviewing several descriptions of plant activities during the period 1978-1980, it is apparent that the conditions (radiation and contamination) under which the HP program was forced to function made the effort most difficult -- conditions that would challenge even the most experienced HP management. Some key elements in this regard are discussed below.

General Housekeeping. On several occasions the plant was sited by the NRC as having poor housekeeping habits. This also corresponds with several unsolicited comments in the plant logs. Relatively high levels of contamination and radiation in areas that in most BWR plants would be clean, became accepted as normal. Note: In November 1981, a force in excess of 100 workers were onsite for plant cleanup. Apparently, contamination control measures remain ineffective since this is an excessively large effort.

Maintenance/Operational Errors. During the 1981 refueling outage, there were several instances where errors, poor work planning, or minor accidents resulted in large quantities of oil and radioactive materials being indiscriminately released from plant systems. This can only be attributed to a lack of attention to detail and prudence in developing and monitoring work procedures.

Restrictive Contamination Level Limits. Apparently, due to regulatory influence, CP&L management reduced the defined contamination limit to 200 $\mu C/100\ cm^2$. This significantly increased the effort required to decontaminate plant surfaces and equipment as required to maintain areas in a "clean" condition. As a result, due to limited resources, it is likely that more areas remained classified as "contamination areas" and characteristically became more and more contaminated due to unrestricted traffic between these areas and those with more contamination. Thus, this restriction may have actually had a negative impact on the problem. This decision is in the process of being reversed and the limits will be reestablished at 1000 $\mu C/100\ cm^2$ -- the standard industry limit.

Plant Operational Problems. As discussed in Section 5.1 of this report, on several occasions the operators were likely to have been forced to operate equipment and systems in unusual or improper modes due to lingering engineering or maintenance problems. This eventually led, in many cases, to abnormal

radiation and contamination conditions that oftentimes are transient or change depending on plant status. Thus, the HP management was tasked with anticipating problems and reacting to various situations somewhat out of their control to ensure proper coverage.

Radwaste Limitations. Due to the limited capacity of the radioactive waste processing systems, large quantities of contaminated water were required to remain in sumps and pipe tunnels and on floors for extended periods of time. Under these conditions, the spread of contamination to other areas is predictable.

Work Planning. It would appear that, in the past, planning and scheduling activities assumed that HP coverage of planned work would be provided on a not-to-interfere basis; i.e., HP management would be tasked with providing support as was necessitated by the work schedule. Also changes to the schedule during outage periods were accomplished in such a manner that perhaps the available HP resources were not optimized.

All of these factors probably contributed to the apparent problems sited in the NRC inspections conducted during this time; culminating in an enforcement action and fine in 1980. In response, the plant staff was adjusted to provide for increased management attention directed toward the area of health physics. Also, additional staff and technician positions were established. Other significant upgrades of the program include:

- An improved training program for HP personnel;
- Implementation of a computerized exposure and radiation control record system including automated TLD reading and RWP generation systems;
- Initiation of the concept of a travelling HP supplemental support crew; and,
- Implementation of the ALARA program.

In addition, upper management placed an administrative limit on the gross number of people permitted to be onsite per day at 1800 until the plant staff can demonstrate that more workers can be adequately supported and protected. Although this is somewhat effective in that it limits the worker/technician ratio to an acceptable limit, it may also have a contradictory effect. Many of the projects that are directed toward plant improvement in the areas that would ease the HP burden have been deferred due to manpower shortages. Also, as was experienced during the Unit 1 1981 refueling outage, manpower shortages ultimately could have resulted in overcomplicating the outage or creating conditions in which shorthanded crews were prone to make costly errors. Thus, there is no assurance that this restriction is not really self-defeating.

In any event, it is likely that HP problems will ease in the future. Some overall improvement is implied in the NRC Health Physics Appraisal conducted on December 8, 1980.[5-18] Also, there was a substantial increase in HP personnel assigned to the site in 1981.

5.5 PREVENTIVE MAINTENANCE

The Reliability Improvement Program identifies effective preventive maintenance as a major factor in the potential success of the program. At Brunswick, some parts of a preventive maintenance (PM) system are in place including that for the majority of the key equipment in the classes of instrumentation/control and electrical. This is part of the computerized PTS system that has been in place for 3-4 years. However, implementation of such a program for the mechanical equipment is all but nonexistent. Preventive maintenance activities are accomplished on major mechanical equipment but there is no formalized system of documentation and tracking and most actions are conducted at the discretion of some individual or group. The plant staff has identified this

problem and is currently in the process of evaluating several vendor proposals for developing such a program. Plans include implementation of the PM program by 1985.

The timing of the mechanical equipment PM program is a significant factor with respect to plant reliability and availability. Each unit is approaching that stage where aging of component parts will have a considerable impact on failure rates as opposed to service or design-related effects. This is especially true for elastermeric materials (i.e., seals, o-rings, etc.) whose expected theoretical lifetime is 3-5 years. Near-term regulatory pressures are expected to address this problem as well, thus adding an additional level of complexity. Another concern is related to the manpower requirements for a PM program. It is certain that the program will draw upon the available labor resources that are already limited and burdened by a large maintenance backlog as well as support for the backfit and construction projects underway. If priorities are set such that the implementing dates slip substantially, then one can suspect an increase in the forced-outage rate in the mid-to-late 1980s or a significant impact on a selected outage caused by large-scale, unplanned maintenance activities.

5.6 OUTAGE MANAGEMENT

5.6.1 Planned Outages

CP&L has recognized serious shortcomings in the management of past outages. In response, a new planning and scheduling (P&S) group was added to the plant staff with the group director reporting directly to the plant manager. This group will have the responsibility of developing the overall plans and schedules for all outages. Basically, this group and the planning and scheduling staff at the central office, with inputs from other key organizations, develop a master project schedule that provides windows for each major job. From this, the plant P&S staff works

with the subunit coordinators to incorporate detailed schedule requirements. Eventually, a schedule depicting the critical path and the relationships of other major activities is generated. During the outage, shift outage coordinators are assigned from the P&S staff to monitor progress and ensure interfaces are efficiently maintained between the various organizations and project activities.

Prior to the recent plant reorganization, outage planning was done in a somewhat informal manner. Three or four months prior to the outage start date an outage coordinator (OC) was chosen from the operations engineering staff. There is a general policy that the outage coordinator should hold at least a reactor operator's license. During this pre-outage period, the OC had the task of collecting a list of outage items and, working with maintenance and construction representatives, developing an overall schedule. Initially, each individual project was assigned a "window" in which project work activities were scheduled. There was no requirement to incorporate all of the details of each work package into a single composite network. As the date for the beginning of the outage became closer, additional fine tuning and analyses were conducted to ensure a minimum of mutual interference existed between projects. Any special prerequisites and procurement actions were the responsibility of the cognizant individuals or departments for each project.

After an outage begins, characteristically many of the original assumptions become invalid for a number of reasons and schedules require modification to accommodate changing conditions. The amount and extent of change is a function of the quality and thoroughness of the original plans, contingency allowances and the validity of the original estimates. At BSEP the current management philosophy is to schedule the most optimistic approach -- factoring in little contingency. In order for this to be successful, additional emphasis must necessarily be placed on pre-planning and pre-outage investigation to ensure highly accurate input is provided to the planners.

It is apparent from the Brunswick outage reports and the consistent practices of deferring planned work and overrunning schedules that this approach did not work -- especially with the manpower constraint established at the plant site. In the event of major schedule interruptions or unplanned events, each individual project is perturbed and slippages occur. Since there is little contingency in these schedules incidental interferences are bound to develop. By this time, major schedule changes are impractical due to the time-consuming effort of rescheduling the large number of concurrent activities and the value of the original schedule is continually erroded. This was quite apparent in May 1981.

Note: The construction group has computerized scheduling capability; however, it was noted that the published schedule consistently was not credible since it usually lagged the problem and did not provide an up-to-date status of ongoing jobs. Also it is only used for the work under the cognizance of the construction group.

The new organization will handle outages in much the same manner except there will be a staff permanently assigned for outage coordination. Other improvements include:

- More organized and directed control of pre-outage planning including frequent meetings and planning sessions with sub-unit coordinators.
- Publication and maintenance of an up-to-date prerequisite status chart for all major projects and modifications.
- Implementation of a computer maintenance planning system.
- Publication and distribution of outage reports to ensure avoidable errors are not repeated in future outages.

Assuming CP&L management continues in the current direction of a more sophisticated and contemporary approach toward outage management, there should be some improvement in the future resulting in shorter and more predictable outages. This, however, is conditional

on overcoming several inherent weaknesses related to their current practices and improving their management by:

- Utilizing a composite schedule showing all outage activities and interrelationships including integration of the construction and plant-controlled schedules.
- Adherence to individual project schedules to eliminate "log-jams" at the end of the outages.
- Implementation of computer-assisted scheduling methods to permit efficient and reliable schedule manipulation as required.
- Maintaining an experienced and qualified team of planners.
- Development of the capacity to adjust labor forces to adequately cope with work-scope changes without adversely impacting other outage activities.
- Provision for direct personnel responsibility for individual outage projects.
- Development of the capability to integrate the site schedules (Units 1 and 2). As was demonstrated in 1981, the Units are not independent.
- Utilize fully the opportunity afforded by outage time. Generally the quantity of work accomplished at a power plant is defined by mutual interference problems; thus the amount of work accomplished is maximized. At Brunswick current management directives assert a manpower limitation that eventually will result in more outage time in the future.

5.6.2 Forced Outages

Prior to 1982 there was no established, consistent, and documented method of mobilizing and controlling forced or unplanned outages. Generally, whenever the plant was forced to shut down on short notice, a meeting was convened and plans developed with relation to the anticipated length of the outage. This probably resulted in less than optimum usage of the available time. In early-1982 CP&L plans to implement a program by which schedules and priorities are established for outstanding maintenance and PT items on a continuous basis. This will provide the capability of generating

a firm, highly credible schedule for a short outage (3-7 days) and be able to minimize the outage length, maximize the outage-time utilization, and react to unanticipated changes that may occur during the course of an outage. Since reliance remains on manual scheduling techniques, performance will not show marked improvement until personnel skills are more fully developed and/or automated scheduling techniques are utilized.

5.7 TRAINING

During the period 1978-1981 the NRC conducted several audits of the Brunswick overall training program. In the areas of operator training there were a few negative comments but, in general, it would appear that the licensed operator training program is acceptable. Not surprisingly, the findings with respect to the non-licensed personnel training were generally adverse. As a result, a maintenance training program was developed in 1980. It would appear from NRC records (5-19) that in October 1980, the program was not yet implemented. This is probably a result of the change of emphasis toward the centralized training program.

In 1980, CP&L began implementing company-wide training by establishing the Nuclear and Fossil Training Section -- in the Department of Technical Services. The responsibility of this section includes all related plant-oriented training for operators and maintenance personnel alike. Training sessions are held at the Harris facility as well as at the plant site -- depending on the nature of the instruction and the trainee group.

If the current corporate training plans are carried out, the training of plant personnel throughout the CP&L system should improve substantially -- meeting or exceeding the post-TMI requirements of NUREG-0585-TMI-2 Lessons Learned Task Force Final Report. The management and staff of the training section appear well qualified and capable of meeting the goals and objectives of the program assuming that the necessary resources are made available. There is, however, a potential problem with respect to the

extent to which Brunswick personnel are availed of training opportunities. With the close proximity of the training facility to the Harris plants (and even the Robinson unit) there will be a tendancy for more concentration on these units and less at Brunswick simply due to logistical limitations. CP&L management must institute controls to guarantee that the program efforts remain balanced and properly meet the needs of all generating stations.

SECTION 5.0 REFERENCES

5-1. American National Standards Institute (ANSI) Standard N45.2.11. Quality Assurance Requirements for the Design of Nuclear Power Plants.

5-2. NRC Inspection Report NO. 50-324/70-19 and 50-325/79-19 dated 8-21-79.

5-3. NRC I&E Report 50-325/80-42 and 50-324/80-39 dated January 7, 1980.

5-4. CP&L-BSEP Plant Modification Procedure-Engineering Procedure: ENP-03.

5-5. General Electric Steam Turbine Generator Inspection report, Brunswick No. 1 dated 3/7/79.

5-6. General Electric Turbine Generator Inspection Report for Brunswick #2 dated July 2, 1980.

5-7. CP&L Co. Brunswick Steam Electric Plant Unit No. 1, 1981 Spring Maintenance Outage Report dated 1/7/82.

5-8. CP&L Co. Brunswick Steam Electric Plant, Radiation Control and Test Procedure No. RC&T-1145 - Sampling and Analysis Schedule for Lubricating Oils, Rev. 000.

5-9. H.R. Banks and J.B. McGirt memo serial: GB-78-1684 dated June 22, 1978.

5-10. H.R. Banks and J.B. McGirt memo Serial: GD-78-3348 dated December 20, 1978.

5-11. H.R. Banks memo Serial GD-79-374 dated February 13, 1979.

5-12. B. Furr memo to Starkey/Tollison dated 11-9-78.

5-13. Trip Report BSEP E.G. Hallowell and E.G. Strickland dated May 14, 1981 RE: Power Plant Reliability Program (PPRP).

14. B.J. Furr memo to L.W. Eury dated August 25, 1981 RE: Summary Report on Maintenance Management System, Efficiency Program and Plan Reliability Programs.

5-15. V. Stello, Jr. (NRC) letter to J.A. Jones, Serial No. EA-80-26 dated June 11, 1980.

5-16. NRC I&E Inspection Report No. 50-325/80-12 and 50-344/80-11 dated June 13, 1980.

5-17. NRC I&E Inspection Report No. 50-325/80-18 and 50-324/80-15 dated August 4, 1980.

5-18. J.P. O'Reilly (NRC) letter to J.A. Jones, No. 50-325/80-45 -- 50-324/80-43 RE: Health Physics Appraisal dated April 27, 1981.

5-19. NRC I&E Inspection Report No. 50-325/80-42 and 50-324/80-39 dated January 7, 1981.

6.0 ORGANIZATION AND STAFFING

6.0 ORGANIZATION AND STAFFING

Over the past few years the CP&L organization has gone through significant changes, both at the corporate level and at the Brunswick plant site. Apparently, this was in response to several stimuli, including:

- Falling capacity factors of the system power generating stations;
- Increased regulatory and engineering demands placed on the generating stations;
- Regulatory pressures related to the licensing and construction of the Harris stations; and,
- The realization that the anticipated cumulative demands of the planned nuclear generating plants (7 total) could not be adequately supported by the existing organizations.

In any event, the existing organization, structurally and complement-wise, should be adequate for addressing the current and future problems facing the Brunswick station assuming that adequate flexibility and growth is provided in a timely basis to match the rate at which additional capacity is added to the system.

6.1 CENTRAL OFFICE STAFF

It appears that in the past two years, the CP&L central office organization has gone through somewhat of a transformation. Prior to that, indications imply that the central office staff was oriented more toward the financial and engineering management aspects of plant construction and operation rather than involvement with day-to-day activities at the sites. Then in late-1979 and 1980, major changes in the central office staff were initiated. These included the following:

- Establishment of an engineering group separate from the construction group and focused toward supporting the operating plants (one group each for fossil and nuclear). Initially, the group included 56 engineers and provided incidental support to the plant staffs. Recently, the staff has been increased to 116 (150 estimated by 1983) and broadened their scope to full-scale modifications with particular emphasis on the larger projects. This has taken considerable burden off the plant staffs.

- Redirection of the Technical Service Group to support the Power Supply Group in March 1981. The focus of Technical Services now is toward establishing a centralized support function concentrating on the company's operating power stations. This group is developing the capability of providing a variety of support services including chemical and metallurgical laboratories, radiation control expertise, extensive training programs, and licensing support.

- The Quality Assurance management was centralized.

- The nuclear plant construction group was separated from the fossil groups and redirected toward the direct support of the operating nuclear stations. Along with this, the nuclear plant backfits are now implemented within a matrix-type organization with the construction group operating as somewhat of an autonomous entity.

6.2 BRUNSWICK PLANT STAFF

The Brunswick plant staff has experienced marked changes within the last year and, before that, during the time since 1978 (see Table 5-1). A study of Table 5-1 indicates that not only has the staff been increasing in size and complement, the emphasis is changing markedly as a result of several forces. In 1976, the staff was increased in all categories probably to support the startup and operation of Unit 1. Then, in response to growing maintenance needs, in 1978 the engineering and maintenance staffs were increased by 68 and 51 percent respectively. In 1979, probably somewhat in response to regulatory pressures and TMI issues, the operations and administrative staffs were bolstered and again the maintenance group was increased -- this time by 43 percent to meet increasing maintenance demands. Then, in 1981, in response to the conditions outlined in this report, CP&L management

ORGANIZATION

Year	MANAGEMENT	ENGINEERING	OPERATIONS	MAINTENANCE	ADMIN.	ENV. & RADCON	STARTUP	Q.A.	Total
1969	4	9	28	20	--	--	--	--	61
1970	4	9	28	20	--	--	--	--	61
1971	4	9	28	20	--	--	--	--	61
1972	1	18	36	50	10	--	--	--	115
1973	1	20	48	43	28	--	--	--	140
1974	1	12	48	55	36	32	--	--	182
1975	1	12	48	55	36	32	--	--	182
1976	10	19	64	81	41	49	25	6	295
1977	10	19	64	81	41	49	25	6	295
1978	10	32	76	123	54	48	--	6	349
1979	4	36	115	177	62	49	--	25	468
1980	4	36	115	177	62	49	--	25	468
1981	8	39	130	271	63	75	--	29	591

Note: These numbers do not reflect Harris-designated individuals at the BSEP site on temporary assignment.

Table 5-1: Plant Staffing Levels (Authorized)

identified weakness in the pre-1980 staffing and again increased the maintenance force, this time by 53 percent. Also, for the first time since 1976, the E&RC group was enlarged and almost doubled. It is interesting to note that the plant maintenance staff fraction has increased since 1977 when maintenance accounted for 27 percent of the plant staff to the present compliment where it represents 45 percent of the total staff.

In addition to the plant staff authorized positions, there are three other major groups located at the Brunswick site in a semi-permanent mode. These include:

- NPED - Engineering support unit consisting of approximately 100 contractors and 10 CP&L engineers.
- NPCD - Construction forces, including CP&L supervision and approximately 350 semi-permenant craft laborers.
- CP&L Travelling Maintenance Crew that, at the present time, is concentrated at the Brunswick (approximately 400 craft laborers).

Key changes in the plant organization should result in a marked improvement of plant management in the future (see Table 5-1). Included in these charges are:

- Adding the position of Manager-Plant Operations to provide improved management and coordination of plant activities.
- Streamlining the responsibilities of the Manager-Technical Support to relate directly toward regulatory and engineering matters apart from plant routine items.
- Adding the position of Director - Planning and Scheduling who has a staff dedicated to this function;
- Eliminating the QA functional responsibility from the plant staff. (QA is now directed under the corporate QA organization);
- Adding the position of Assistant to the General Manager; and,

- Adding nine (9) additional maintenance foremen and a reduction of maintenance crew size from 16 to 10. This should result in improving the quality of maintenance and reducing the frequency of costly errors.

In general, the existing staff appears to be adequate and capable of managing the Brunswick Plant in a satisfactory manner in the long term. However, success in the immediate future is dependent on the capability of the organization and staff members (especially those new additions) to maintain the momentum of the current plant improvement program and apply the increasing level of sophistication demanded of nuclear plant operators. CP&L management must routinely review staffing needs as future demands increase due to implementing new programs (i.e., preventive maintenance, training, etc.).

7.0 CONCLUSION

7.0 CONCLUSION

The focus of this investigation is to examine the key elements of the operation and maintenance of the Brunswick station in the past few years to better understand the reasons linked to the relatively poor performance of the units in 1979 and 1980 and to assess their potential for the near-future. It is difficult, if not impossible, to reconstruct the historical details leading up to the period in question. However, by reviewing plant logs and NRC inspection reports, along with discussions with plant personnel, an attempt is made to develop realistic scenarios to better understand the events and decisions of the past that effect present day plant performance.

This section of the report is formated to correspond to the issues raised by Mr. Fischbach's letter dated September 11, 1981 (See Appendix A).

7.1 MANAGEMENT RESPONSE TO POST-TMI REGULATORY REQUIREMENTS

Chapter 5 of this report discusses many of the CP&L plans and programs currently in place or being implemented. CP&L management has taken what appears to be a positive attitude toward programs aimed at meeting the regulatory and other demands anticipated for the 1980s. Particular emphasis has been placed on a centralized structure providing state-of-the-art programs in training, planning and scheduling, engineering, and laboratory services with a realistic staffing philosophy. The middle-level management staff directing these services is quite competent -- many being newly-hired from other parts of related industries. It is expected that these actions will result in excellent performance of CP&L's generating stations (both nuclear and fossil) during the mid- and late-1980s.

7.2 UNIT 1 - 1981 SUMMER OUTAGE

There were several reasons for the extended Unit 1 outage in 1981. The initial outage was lengthened by the additional scope as a result of oyster shell fouling in the service water systems. Because of this, the plant startup lagged the targeted date by approximately 4 weeks. During the startup period, the turbine-generator unit suffered massive bearing failure resulting in an additional 11 week delay for repairs and an extensive flush of the turbine-generator lube oil system.

Given the set of circumstances and restrictions that CP&L management was faced with during the conduct of the outage period, the conclusion is that they took reasonable steps to return the unit to service. There is, however, sufficient cause to believe that, with prudent management decisions and attention, the upsetting incidents experienced during the outage should have been avoided completely. The service water problem was a direct oversight of CP&L to recognize the importance of chlorinating the plant's cooling water systems. After identifying the problem, they were ill prepared to react in a timely manner due to restrictive manpower limitations (management imposed) and the inability to modify the existing schedules in such a manner that the available resources and time were optimized -- thus minimizing the impact on the overall schedule.

The cause of the turbine generator failure cannot be attributed to any one of the known factors identifed in Section 3, but one should note that all are directly related to management issues. The entire incident clearly could have been avoided with prudent and reasonable actions that should have been taken prior to the beginning of the outage. It should be noted that, subsequent to July 9, such measures were initiated to ensure that a similar occurrence would not happen again.

7.3 BSEP PERFORMANCE DURING 1980 and 1981

During this period, the Brunswick units were plagued with frequent forced outages and excessive overruns of planned outages. Sections 3 and 4 of this report discuss the reasons for these in detail and describes the corrective actions taken by CP&L.

One must realize that none of the activities associated with the operation and maintenance of a nuclear power plant is independent. This is particularly true of management directives. During the mid-1970s, CP&L management, perhaps under the influence of the relatively good record of the Robinson plant or for other unknown reasons, did not properly address the staffing needs of the Brunswick station. As a result, they were unable to respond to acute needs of BSEP during the period 1978-1980. A backlog of problems developed during this time that simply overwhelmed the existing staff. These included:

- Main condenser failure
- TMI-related modifications
- Massive snubber failures
- Torus modifications
- Pipe support evaluation and modification
- Radwaste failure
- Main Steam Valve and Recirculation Pump Problems.

Although many of these are design-related defects and taken individually are not necessarily significant in the context of the overall plant, the coincidental timing quickly overtaxed the available resources of CP&L. Because of this, many of the non-operationally restrictive items were afforded a lower priority and deferred.

In 1981, with an increase in the engineering and maintenance staff and an easing of new problem erruptions, the plant has been able to properly address many of the recurring and lingering equipment problems and to effectively reduce the backlog of maintenance items. This in itself will have a dramatic effect in the near-term by an overall reduction of the forced outage rate. The converse, however, is true for the planned outages. The additional engineering force was not matched by any responsive increase in the size of the construction force available for installing backfits. The management restrictions on manpower at the Brunswick site will inevitably result in measurably longer outages (as compared to industry norms) for the next 3-5 years. With this policy in place, outage time cannot be fully utilized and exploited to the greatest possible extent.

7.4 FUTURE PLANT PERFORMANCE

During this investigation, no unusual inherent plant deficiencies were identified that will significantly effect the performance of the Brunswick units in the future. There are, though, several specific items that will affect plant capacity factors and are somewhat out of the immediate control of the plant staff. Included are:

- NPDES permit -- This restricts plant cooling water flow at various times of the year. It is expected that this will effectively derate both units by an average of 2%.
- Main condenser modifications -- Replacing the existing copper-nickel tubing with those made of titanium alloy will reduce plant efficiency by approximately 1-1.5%.
- Nuclear Fuel Preconditioning -- This factor is unavoidable but is proportional to the plant forced-outage rate. It is expected, that this will account for approximately a 3% loss in total generation.
- Feedwater heaters -- For the next 2-3 years problems with the feedwater heaters in both units will result in a loss of approximately 4-5% capacity.

Based on these factors and the future extended outages related to the existing known workload, an estimate of plant capacity factors is presented in Table 7-1. Note that this is the best performance that can be expected, assuming CP&L continues with their current plans and programs and no additional major problems develop.

Table 7-1: Projected Unit Capacity Factors

Year	Unit 1	Unit 2
1982	51 %	[illegible] %
1983	63 %	68 %
1984	54 %	49 %
1985	61 %	79 %
Average	57 %	61 %

APPENDIX A

APPENDIX A

State of North Carolina
Public Staff
Utilities Commission
P.O. Box 991
Raleigh 27602

September 11, 1981

Robert Fischbach
Executive Director

Office of Executive
Director
(919) 733-2435

Mr. Ron Jacobstein
2401 H Street, N.W.
Suite 215
Washington, D. C. 20037

Re: Carolina Power & Light Company
Brunswick Investigation

Dear Mr. Jacobstein:

The Public Staff of the North Carolina Utilities Commission proposes to retain you to review the performance of Carolina Power & Light Company's nuclear power plants during the period subsequent to 1979. We are particularly interested in whether CP&L is adequately and timely responding to the management challenges presented by regulatory requirements, many of which arose after the Three Mile Island incident. In connection with this, you should assess the efforts being made by the company in the area of management staffing, training and scheduling. Areas in which you find improvements are needed should be noted, along with your assessment of the cost versus benefits of such improvements.

Your report should specifically address the following matters:

(1) The reasons for the extended outage this summer of the company's Brunswick No. 1 and whether the company made reasonable and prudent efforts to return the unit to service as quickly as possible.

(2) Factors contributing to the below-average performance of the Brunswick units during the past two years and the reasonableness of the company's plans and efforts to restore performance to a better level.

(3) Whether there are any inherent deficiencies in the plant's design or construction that are likely to impair the plant's ability to perform in the future at a more adequate level, and to the extent there are such deficiencies, the reasonableness of the company's efforts to correct them.

CP&L has assured us of its full cooperation and we would expect its plant management to help coordinate your investigation in a way that would not unduly interfere with continued efforts to repair the plant and maintain it in service.

Please respond by letter stating a time frame within which you feel this task could be completed and your fee therefor.

Sincerely,

Robert Fischbach

Robert Fischbach

RF/elw

APPENDIX B

NAME: A. Ronald Jacobstein

EDUCATION:

1966	U.S. Naval Submarine School, completed course in preparation for submarine assignment
1965-66	U.S. Naval Nuclear Power School, completed training in supervision and operation of Naval Nuclear Power Systems
1965	Columbia University, B.S., Electrical Engineering
1965	Miami University (Ohio), B.S., Engineering Physics

EXPERIENCE:

11/78 to present - International Energy Associates Limited, Washington, DC
- Associate Consultant

Developed the Inservice Inspection and Testing Program for Seismic Restraints (Snubbers) for the SNUPPS project.

Developed and implemented the EPRI Mechanical Component Evaluation and Inspection Program at Three Mile Island.

Analyzed the operation of a utility's based-loaded coal-fired power plants. Identified management and equipment related problem areas along with root causes. Developed qualitative and quantitative impacts of these problems as they relate to plant availability and heat rate along with recommended solutions.

Applications and market analyses for a new process for nuclear power plant ion-exchange and radioactive waste disposal.

Study of worldwide high-level radioactive waste plans and programs for the U.S. Department of Energy.

Coauthored a report on the status of programs and technology of nuclear spent fuel disposal for the U.S. Department of Energy.

Study for the U.S. Department of Energy assessing the perspectives, interests, and possible courses of action of utilities and intervenor groups with regard to the operation of a federally-sponsored AFR spent nuclear fuel storage facility.

Provided the Nuclear Safety Analysis Center (NSAC) routine, first-hand reports of the early stages of the Three Mile Island recovery program implementation.

Technical Integration Office interface for GPU -- managed the GPU organizational participation in the DOE-sponsored R&D programs at Three Mile Island.

General consulting to General Public Utilities for the Three Mile Island recovery program including planning, process engineering, radwaste, and general operations. Designed and spearheaded the procurement of SDS demineralizer vessels utilized to capture and contain the high level radioactive wastes.

Survey and study of U.S. utility approaches toward nuclear plant management including aspects of operation, maintenance, inspection, and regulatory interface.

Study identifying LWR plant alternatives and damage control options as adjuncts to LWR safeguards systems to deter and survive sabotage actions.

Study to evaluate power plant feedwater heater performance, to define problems and causes, and to propose steps needed for equipment and operational improvement.

1977 to 1978 - Nuclear Installation Services Co., Westmont, NJ
- Project Manager

Total job responsibility for the modification and repair of a steam generator at an operating PWR reactor power plant.

Project manager for the erection of the primary shield wall at a new BWR power plant.

Project manager/engineer for the design, fabrication, and installation of a major nuclear safety-related piping system at a two-unit nuclear power station.

1975 to 1977 - NUS Corporation, Rockville, MD
- Staff Engineer, Operating Services Division

Acted as the site engineering/design representative and general site project manager for a major ECCS backfit at a BWR plant. Coordinated the efforts of design engineers, plant personnel, client representatives, and construction contractor.

Assisted the internal NUS design group with the development of a device used for the volume reduction of BWR fuel channels in preparation for disposal.

Assigned for a period of 4 months to the position of Training Coordinator for a large, multi-unit PWR power plant with the responsibility for developing and implementing a comprehensive training program for all plant personnel.

Acted as site engineering design liaison engineer for a flyash system conversion (wet-to-dry) at a large coal-fired electric generating station.

Conducted a comprehensive fire hazard analysis for an operating BWR generating station and prepared the submittal concerning the plant fire protection program in response to NRC requirements.

Assigned as Installation Engineer for the replacement of spent fuel racks at several operating nuclear power plants. Included were procedure preparation, pool design interfaces, overall planning, and direct supervision during rack installation.

6/75 to 9/75 - Surfco-Metalweld, Inc., Philadelphia, PA
- Quality Assurance Manager

Wrote and implemented a quality assurance plan meeting the requirements of 10 CFR 50, App. B, for the application of special coatings to the interior surface of a nuclear containment vessel. Responsible for client acceptance of the QA plan, quality control inspections, vendor surveillance, and material control at the job site. General consulting for special coatings and their application.

1971 to 1975 - Jersey Central Power & Light Co., Morristown, NJ
- Project Engineer

Reponsible for multidisciplined engineering efforts relating to system engineering and project management at the Oyster Creek Nuclear Generating Station and company fossil power plants. Major accomplishments while in this position included:

- System Analysis and Design: Supervised and directed the fabrication and installation of a spent fuel cask drop protection system and the associated cask handling equipment. Developed numerous nuclear associated material and service specifications including such items as pumps, valves, piping, seismic restraints, etc. Conducted formal design reviews and nuclear safety analysis on proposed system modifications. Designed and supervised the installation of modifications to plant systems.

- Operation and Maintenance Support: Responsible for all activities associated with corrosion protection of the primary containment suppression chamber. Routinely assigned the direct responsibility for significant maintenance activities requiring close engineering support and failure evaluation.

- Supervisory: Leader of a team of 6 graduate engineers engaged in various engineering support activities. Directed nuclear refueling operations including fuel handling, inspection, failure testing, and other assorted refueling activities. Provided close support and supervision to vendor contractors involved in construction, maintenance, and inspection activities.

- Quality Assurance: Developed and implemented the JCP&L Generation Department procedure for the control of plant repair, modification, and design. Instrumental in the development of JCP&L Quality Assurance Plan. Developed the JCP&L Inservice Inspection procedure and directed the development of the associated ISI Plan for the Oyster Creek Nuclear Plant.

1965 to - U.S. Navy
1971 - Lieutenant

Assigned duty as Auxiliary Division Officer aboard a nuclear submarine supervising the operation and maintenance of the ship's auxiliary and life support systems. Trained the ship's control personnel and managed the quality assurance program.

Qualified for and assigned, on a regular basis, the additional duty of Engineering Officer of the Watch supervising the operation and maintenance of the nuclear propulsion and power generating plant.

Responsible for the quality assurance and quality control of the ship's essential, safety, and emergency systems.