CAROLINA POWER & LIGHT COMPANY

ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

FOR OPERATING LICENSE AMENDMENT PROCEEDING

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CAROLINA POWER & LIGHT COMPANY

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I. BACKGROUND

In the current NRC licensing proceeding with respect to the replacement of the Robinson Unit 2 steam generator lower assemblies, the Hartsville Group contends (see Appendix A) that retirement of Robinson 2 would be more cost-beneficial than the proposed steam generator repair. In mid-1983, Carolina Power & Light Company performed an economic analysis to compare the costs and benefits of repairing the Robinson Unit 2 steam generators and continuing its operation, with the costs and benefits of retiring the unit and relying on replacement power.

II. SUMMARY AND CONCLUSIONS

The Company performed an economic analysis to compare the cost and benefits of two primary scenarios regarding the Robinson 2 steam generator replacement. One scenario - the Replacement Case - considered the costs and benefits of replacing the steam generator lower assemblies (SGLAs) in an extensive outage in 1984. Replacement of the SGLAs is expected to allow Robinson 2 to return to full-rated power operation, without frequent periodic steam generator inspection outages.

The second scenario - the Retirement Case - postulated that the Robinson 2 steam generators would not be repaired and that the unit would be permanently retired at the end of 1984. This scenario reflected the costs associated with retirement and the costs of replacing the Robinson 2 generation from other sources.

The study revealed that over the 15-year study period from 1984 through 1998, the Replacement Case would save CP&L customers approximately $830 million when compared with the cost of the Retirement Case.

In addition to the two primary scenarios, the study also included sensitivity analyses of certain factors, including O&M cost, capital cost, load growth, and capacity factor. All sensitivities continued to show a net savings to CP&L customers for the Replacement Case scenario. A detailed discussion of the sensitivity analyses and other results is provided in Section IV - Study Results. Also, a discussion of the bases for the study is provided in Section III - Study Assumptions.

Based on the study results, including the sensitivity analyses, it is concluded that there will be considerable benefit to CP&L's customers resulting from replacement of the steam generator lower assemblies and continuation of Robinson Unit 2 operation.

III. STUDY ASSUMPTIONS

This section provides the various assumptions which were used in the study for each scenario, including the sensitivity analyses.

A. GENERAL

The following are general assumptions which were used as a basis for all study cases.

1. Two primary study cases were considered:

   a. Replacement Case - Replace the steam generator lower assemblies in 1984.

   b. Retirement Case - Retire Robinson Unit 2 at the end of 1984.

   See Appendix B for a schedule of the primary and sensitivity study cases.

2. Study Period: 1984-1998 (15 years)

   The 15-year study period (1984 through 1998) was chosen for two basic reasons: 1) that time period was considered long enough to reflect the effect of the steam generator repairs and payback period and to show the effects of retiring Robinson 2 on December 31, 1984, and 2) the use of any longer period would require increasingly speculative assumptions regarding costs and other data necessary for such calculations. The use of a longer study period should not change the conclusions resulting from the 15-year study.

3. Cost Components

a. Operating Costs:

1) System fuel costs were determined by the production cost simulation model, PROMOD, which is generally used by the Company for planning, forecasting and study purposes. See Appendix C for a description of the PROMOD model. Appendix D provides the annual estimates of Robinson 2 fuel and spent fuel disposal costs which were used in the study.
2) O&M costs were based on the Company's 1983 long-term projections as provided in Appendix E.
3) Power purchases were used as necessary to maintain a 20% annual planning reserve margin. All other purchases were economy or emergency purchases. Purchased Power cost assumptions, upon which the power purchases were based, are provided in Appendix F. Also, projected system resources, loads and reserves as used in each of the study cases are provided in Appendix G.

b. Capital Costs:

1) Only the capital cost of Robinson 2 was considered. The capital costs and associated revenue requirements for other generating units required under the Retirement Case were not included.
2) The financial factors were based on the capital structure and cost of capital as originally requested in the Company's 1983 North Carolina Rate Case (Docket E-2, SUB 461), as follows:

Type	Ratio	Cost	Weighted Cost
Long-Term Debt	49.5	9.59	4.747%
Preferred Stock	12.5	8.96	1.120%
Common Equity	38.0	15.50	5.890%
Overall Rate of Return			11.757%

Tax Rate = 49.24%

Discount Rate = 9.420% (11.757% overall rate of return, net of tax)

No adjustment was made for future changes in the capital structure or cost of capital due to inflation or other economic impacts. This structure was assumed to remain constant throughout the study period.

3) Fixed charge rates were based on the above capital structure and cost of capital. Separate sets of fixed charge rates were developed for both the initial capital cost and post commercial capital additions. These fixed charge rates reflect a 25-year depreciable life for all capital costs.

4. Sensitivity Analysis:

In order to assess the effects of changes in various study components, sensitivity analyses were performed on values of the capacity factor of Robinson 2, system load growth, Robinson 2 O&M cost, and capital additions for Robinson 2. Specific sensitivity parameters are described under the individual study case assumptions and are also shown in Appendix B.

B. REPLACEMENT CASE

The following are assumptions specific to the Replacement Case.

1. The steam generators were assumed to be replaced in 1984 during a 43-week replacement outage starting January 21, 1984.

2. It was assumed that Robinson 2 would maintain an operating capacity factor of 70 percent until it is removed from service for the replacement outage. An operating capacity factor of 85 percent was used for Robinson 2 thereafter. For clarification, an "operating capacity factor" is an average capacity factor which excludes periods of scheduled outage. For example, assuming a projected 85% operating capacity factor and 15 weeks of scheduled outage time would result in a projected annual capacity factor of approximately 60%. However, for Robinson 2, this annual capacity factor would be somewhat higher because of the difference in summer and winter seasonal capability. Appendix H provides projections of operating capacity factor, scheduled outages, annual capacity factor, and energy generation for the Replacement Case for each year of the study period.

3. The Company's nuclear outage schedule in effect at the end of March 1983 was used as a basis for outage scheduling and operating capacity factors. See Appendix H for a list of the Robinson 2 scheduled outages used in the study.

4. For additional system generating capacity needed during the study period, the Company's current construction schedule was used, plus additional undesignated units, as follows:

Unit	Unit Size (MW)	In-Service Date
Harris 1	900	1986
Harris 2	900	1990
Mayo 2	720	1992
Undesignated 1	690	1996
Undesignated 2	690	1998

Appendix G provides the system reserves associated with the above capacity additions. Additional generating capacity was used for determining production cost only. The capital costs associated with these units were not considered, as a conservative approach for the comparison with the Retirement Case.

5. Capital Cost:

a. The capital costs of projected Robinson 2 additions and modifications estimated for the entire study period were based on the Company's 10-year construction program. The estimates incorporated those modifications included in

the Company's 1983 Construction Budget. Appendix I provides the estimated annual capital cost of Robinson 2 additions and modifications which were used in the study for the Replacement Case.

b. The capital cost of the replacement steam generators was depreciated over 25 years using straight-line depreciation.

c. The existing steam generators were retired by appropriately adjusting the depreciation reserve.

6. Decommissioning:

Decommissioning revenues were provided based on estimates supporting current rate recovery. These revenue projections were provided from a decommissioning revenue computer program, and were based on the current plans adopted by the North Carolina Utilities Commission (NCUC) and the South Carolina Public Service Commission (SCPSC), which use a retirement date of April 13, 1997. (Note: This retirement date is used only for decommissioning revenue collection and is not the Company's proposed retirement date).

It was assumed that the existing steam generator lower assemblies will be stored on site and decommissioned at the same time the unit is decommissioned. Interim storage was assumed in an on-site tomb; the cost of this tomb is included in the 1983 Construction Budget and reflected in this study. Ultimate disposal cost is considered negligible since the radiation level of that equipment should be insignificant at the time of unit decommissioning.

7. Sensitivity Analysis:

a. Capacity Factor: For sensitivity analysis purposes only, the operating capacity factor for Robinson 2 was assumed to be 70 percent for the entire study period. In addition to other scheduled outages, a four-week steam generator inspection outage was assumed to be required every three effective full power months (EFPM). No improvement in operating capacity factor was assumed after replacement of the SGLAs. Operating capacity factor is an average capacity factor which excludes periods of scheduled outage. Assuming a 70% operating capacity factor for Robinson 2; an annual refueling, maintenance and steam generator inspection outage; plus an additional steam generator inspection outage, the resulting annual capacity factor would be approximately 51%.

b. Load Growth: For sensitivity analysis purposes only, zero system load growth was assumed after the forecasted 1984 summer peak of 7043 MW. Using this peak will allow for the increase in additional Power Agency load, which is already under contract. This case was compared to a similar sensitivity under the Retirement Case.

c. O&M Cost: It was assumed, for sensitivity analysis purposes only, that the Robinson 2 O&M cost would be significantly higher than current projections. For 14 years of the study period, the sensitivity case O&M costs ranged from 41% to 95% higher than the Company's long-term O&M estimates which were used in the Replacement Case. During 1984, the year of the steam generator replacement outage, the sensitivity O&M costs were 15% higher than in the Replacement Case. The sensitivity case O&M costs averaged over

58% higher for the 15-year study period. Therefore, the sensitivity O&M cost values were substantially higher than the O&M costs based on historical actual costs and projections based on repair of the steam generators.

d. Capital Additions: For sensitivity analysis purposes only, the capital estimates for Robinson 2 additions and modifications beyond 1986 were arbitrarily increased by a factor of 4.

C. <u>RETIREMENT CASE</u>

The following are assumptions specific to the Retirement Case.

1. It was assumed, for study purposes only, that Robinson 2 would be permanently retired on December 31, 1984. This date was based on a qualitative review of the accelerating corrosion rates from the spring 1983 steam generator inspection outage and an extrapolated future corrosion rate. The actual date of retirement would depend on future actual operating experience and the point at which continued operation of the unit would not be economical. Any decision on retirement of the unit would be influenced by several factors, such as a continuous evaluation of the allowable thermal limits, any necessary reductions in power level, and the frequency of required inspection outages.

2. The operating capacity factor of Robinson 2 was assumed to be 70 percent until retirement on December 31, 1984.

3. The Company's nuclear outage schedule in effect at the end of March 1983 was used as a basis for outage scheduling and operating capacity factors, except as indicated herein.

4. Based on the results of the spring 1983 steam generator inspection outage, it was assumed that a four-week steam generator inspection outage would be needed every three EFPM, until retirement.

5. The retirement of Robinson 2, as assumed in the Retirement Case, would result in insufficient generating capacity on the CP&L system. For study purposes, construction of generating units planned or anticipated for the future was assumed to be accelerated to make up the deficiency created by the retirement of Robinson 2, as shown by the following table:

Unit	Unit Size (MW)	Assumed Accelerated In-Service Date	Assumed Schedule Acceleration
Harris 1	900	1986	No acceleration assumed*
Harris 2	900	1990	No acceleration assumed*
Mayo 2	720	1991	1 year
Undesign. 1	690	1994	2 years
Undesign. 2	690	1996	2 years
Undesign. 3	690	1998	2 years

*No acceleration of the in-service date of Harris 1 or 2 is assumed because of the current stage of construction, lead time requirements on equipment and construction, and regulatory schedules.

Appendix G provides the system reserves associated with the above capacity additions.

The benefit of the acceleration of the units, as shown in the above table, was included for determining production costs. However, the additional capital costs and associated revenue

requirements for constructing the replacement capacity, plus other financial impacts of accelerating construction of the above units, have not been included in the study cost comparisons, as a conservative approach. Inclusion of these costs would further increase the cost of Robinson 2 retirement, resulting in increased savings from continued operation of Robinson 2 after replacement of the SGLAs in 1984.

6. The decision date for accelerating the construction of new units was assumed to be January 1, 1984.

7. Capital Cost:

   a. The capital cost of Robinson 2 additions and modifications through December 31, 1984 was included.

   b. The unavoidable portion of capital cost commitments (such as "sunk" costs for materials and equipment, and work already performed) for future additions and modifications identified in the Company's 1983 Budget and 10-year construction program, was included.

   c. It was assumed that the undepreciated cost of Robinson 2 based on retirement on December 31, 1984 would be recovered over a 10-year period.

8. Decommissioning:

   The assumption was made that upon early retirement, the unit will be entombed, with surveillance following for the next 30 years. At the end of the surveillance period, the unit would be dismantled and permanently disposed of. This amounts

to basically the current decommissioning cost-recovery plan, as approved by the NCUC and the SCPSC for ratemaking purposes, but accelerated for work to begin in 1985 rather than 1997. Escalation rates for projecting nominal costs were those adopted by the NCUC and the SCPSC for decommissioning cost collection. All decommissioning costs were assumed to be collected from customers in 1984 to make the fund whole and allow work to begin in 1985.

9. Sensitivity Analysis:

a. Capacity Factor: No sensitivity for Retirement Case capacity factor was performed.

b. Load Growth: For sensitivity analysis purposes, zero load growth was assumed after the 1984 summer peak of 7043 MW. Using this peak will allow for the increase of additional Power Agency load, which is already under contract.

c. O&M Cost: No sensitivity for Retirement Case O&M cost was performed.

d. Capital Additions: No sensitivity was performed in the Retirement Case for the cost of capital additions and modifications for Robinson 2.

IV. STUDY RESULTS

The Company's economic analysis to assess the benefit of steam generator repairs at Robinson 2 was based on comparing two primary scenarios. The Replacement Case considered the cost and benefits of replacing the Robinson 2 SGLAs in a 43-week outage beginning January 21, 1984. The Retirement Case assumed that the SGLAs would not be replaced, resulting

in the retirement of Robinson 2 on December 31, 1984. Both study cases considered the appropriate costs which would be incurred for each scenario. The costs considered included the fuel and O&M costs of operating the system, purchased power costs, nuclear liability insurance costs, the carrying charges on nuclear fuel inventory, and the capital costs associated with Robinson 2. The various assumptions upon which the economic analysis for each scenario were based are discussed in Section III - Study Assumptions.

The results of the study cost comparison show that replacement of the Robinson 2 SGLAs will save the Company's customers approximately $830 million in nominal dollars (or $343 million in 1983 dollars) over the 1984 through 1998 study period. Table 1 shows a comparison of estimated annual charges (including all of the above-mentioned cost components) for the two primary study cases. This table reflects the lower cost in 1984 which would be experienced by the Retirement Case below that of the Replacement Case because, under the Retirement Case, less outage time for Robinson 2 would be required in 1984. However, Table 1 also shows that the replacement alternative will provide net savings to customers for each year after 1984, accumulating to $830 million by the end of the study period (1998). Net savings are expected to continue to accrue for the remainder of the operating life of the unit.

The study, including the results revealed on Table 1, was based on the Company's best estimates of cost and other input available at the time the study was prepared. Therefore, these results are considered to reflect the most probable cost comparison. However, in order to assess the effect of possible changes in some of the key study assumptions, sensitivity analyses were performed. Assumptions upon which sensitivity analyses were performed include Robinson 2 O&M cost, the capital cost of Robinson 2 additions and modifications, system load growth, and Robinson 2 capacity factor.

For the sensitivity analysis, the Company's best estimate for each of these assumptions was separately replaced with a value that was generally considered to be a boundary or worst case assumption. The values used for each sensitivity analysis are described for each study case in Section III - Study Assumptions.

Table 2 provides the results of the various sensitivity analyses. As shown on Table 2, for each sensitivity cost comparison using generally boundary or worst case assumptions for the variable indicated, there remains a cost savings to customers for replacing the Robinson 2 SGLAs.

Considering all of the economic analysis and cost comparisons performed for the Robinson 2 SGLA replacement, the study shows that replacement of the Robinson 2 SGLAs will result in a net cost savings to Carolina Power & Light Company's customers.

TABLE 1

ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

COST COMPARISON OF REPLACEMENT CASE WITH RETIREMENT CASE

Year	REPLACEMENT CASE: Replacement of Steam Generator Lower Assemblies in 1984 (000s $)	RETIREMENT CASE: Retire Robinson 2 December 31, 1984 (000s $)	Savings of Replacement Case Over Retirement Case (Nominal 000s $)	Savings of Replacement Case Over Retirement Case (1983 000s $)
1984	761,828	719,514	-42,314	-38,671
1985	767,737	817,866	50,129	41,869
1986	847,616	894,338	46,722	35,664
1987	918,807	926,714	7,907	5,516
1988	1,101,398	1,118,362	16,964	10,815
1989	1,092,615	1,210,525	117,910	68,702
1990	1,189,124	1,214,104	24,980	13,302
1991	1,458,562	1,486,412	27,850	13,554
1992	1,441,645	1,514,283	72,638	32,307
1993	1,621,005	1,723,921	102,916	41,833
1994	1,934,101	1,990,309	56,208	20,880
1995	2,081,988	2,131,892	49,904	16,942
1996	2,315,034	2,435,528	120,494	37,386
1997	2,579,761	2,669,751	89,990	25,518
1998	2,868,250	2,956,285	88,035	22,814
TOTALS	$22,979,471	$23,809,804	$830,333	$348,431

TABLE 2

ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY
RESULTS OF SENSITIVITY ANALYSIS

SENSITIVITY ASSUMPTIONS	COST SAVINGS RESULTING FROM SGLA REPLACEMENT	
	NOMINAL 000s $	1983 000s $
BASE CASE	830,333	348,431
1) Increased Robinson 2 O&M Costs in Replacement Case by an average of over 58% for each year of the study period.	388,622	154,697
2) Increased Robinson 2 Capital costs in Replacement Case. Robinson 2 capital additions and modifications after 1986 were increased by a factor of 4.	676,522	292,126
3) No improvement in Robinson 2 operating Capacity Factor after replacement of the SGLAs, in the Replacement Case. Operating Capacity Factor held at 70%, and assumed a 4-week steam generator inspection outage every three EFPM.	497,325	190,149
4) Zero system load growth was assumed for both the Replacement and Retirement Cases. The forecasted 1984 summer peak load of 7043 MW was held constant for the remainder of the study period.	314,617	112,094

Under all sensitivity assumptions, the Replacement Case continues to show a significant cost savings.

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APPENDICES

HARTSVILLE GROUP CONTENTION 3

The Hartsville Group's Contention 3, as allowed for litigation by the Atomic Safety and Licensing Board (ASLB), is as follows:

"The Applicant's Evaluation of Alternatives incorrectly weighs the costs of retirement of Robinson. The cost-benefit balance should be struck against the repair of the steam generators in favor of retirement of Robinson as the most cost-beneficial alternative. The EIS should strike that balance. An analysis of the alternative of closing Robinson 2 is required by 102(2)(e) 42 USC 4332(2)(e).

"The cost-benefit analysis involving repairs to an aging nuclear plant like Robinson 2 is analogous to the analysis of major repairs to an aging automobile. Repairing the steam generators at Robinson 2 is like putting new tires on a car with bad main bearings.

"The Energy Systems Research Group of Boston found in an October 1982 study of Indian Point, The Economics of Closing the Indian Point Nuclear Power Plants, that the percentage impact on rates of closing those facilities would be less than 2%. Application of their Cost Assessment of Nuclear Substitution model to Robinson would show that the proposed steam generator repair to keep Robinson operating is not cost-effective. Robinson 2 is older than the Indian Point plants, and has continuing major equipment problems and reactor embrittlement which compounds the potential for Pressurized Thermal Shock, which may close Robinson 2 down within three to six years and/or result in significant derating. Non-oil fired make-up power is available to substitute for power that Robinson would have generated.

"The cost-benefit analysis should include not just the cost of repairs to Robinson 2, but other avoided future costs if Robinson 2 is retired, including expenditures on nuclear fuel, operating and maintenance expenses, and a portion of the costs of nuclear waste disposal.

"Because the Applicant cannot demonstrate that the proposed changes in the Model 44F steam generators will solve the problems which have led to tube leaks in the old Model 44F steam generators, the Applicant cannot rightly claim that occupational exposures to workers during testing and repair of the new steam generators will be reduced but should be required to assume that future exposures will be substantially the same as current exposures. As the staff's 'Steam Generator Status Report' of February 18, 1982 notes regarding earlier 'fixes': 'these fixes have met with varying degrees of success, but none of them is a panacea. Furthermore, short-term solutions to one problem may create other problems.'"

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ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY
SENSITIVITY CASES

CASE NO.	ROBINSON 2	HARRIS 1	HARRIS 2	MAYO 2	UNDES. 1	UNDES. 2	UNDES. 3	ROBINSON 2 CAPACITY FACTOR	LOAD GROWTH	O&M COST	CAPITAL COST
Replacement (Base)	Replace SGLAs 1984	1986	1990	1992	1996	1998	-	(1)	Current	Base	Base
Retirement	Retire Unit 1984	1986	1990	1991	1994	1996	1998	(2)	Current	Base	Base
CF	Replace SGLAs 1984	1986	1990	1992	1996	1998	-	(3)	Current	Base	Base
LG-1	Replace SGLAs 1984	1986	1990	1992	1996	1998	-	(1)	0[(A)]	Base	Base
LG-2	Retire Unit 1984	1986	1990	1991	1994	1996	1998	(2)	0[(A)]	Base	Base
O&M Cost	Replace SGLAs 1984	1986	1990	1992	1996	1998	-	(1)	Current	+58%[(B)]	Base
Cap. Cost	Replace SGLAs 1984	1986	1990	1992	1996	1998	-	(1)	Current	Base	x4[(C)]

Robinson 2 Capacity Factor (CF) Assumptions

(1) Operating Capacity Factor* of 70% used until removed for Replacement Outage. Operating Capacity Factor* of 85% used thereafter.
(2) Operating Capacity Factor* of 70% used until Retirement. A four-week Steam Generator Inspection Outage was assumed every three EFPMs, until Replacement.
(3) Operating Capacity Factor* of 70% used for duration of the study. A four-week Steam Generator Inspection Outage was assumed every three EFPMs for study duration.

*Operating capacity factor is an average capacity factor which excludes periods of scheduled outage.

General Notes

(A) Zero load growth (LG) was assumed after the 1984 summer peak of 7043 MW. For this sensitivity case, all other parameters and results were the same as used in each primary study case.
(B) The Replacement Case was used as the basis for the sensitivity case for O&M costs. For this sensitivity case, all parameters and results were the same as the Replacement Case, except for Robinson 2 O&M costs, which were increased on the average by over 58% in each year over the 15-year study period.
(C) The Replacement Case was used as the basis for the sensitivity case for capital cost. For this sensitivity case, all parameters and results were the same as the Replacement Case, except for the capital cost of future additions and modifications. These capital costs were increased by a factor of 4 for this sensitivity case.

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ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

DESCRIPTION OF THE PROMOD COMPUTER MODEL

INTRODUCTION

PROMOD III is the primary computer software tool that CP&L uses for planning studies, forecasting fuel and purchased power requirements, and to perform economic analyses for consideration of various contingency scenarios. PROMOD III was developed by Energy Management Associates, Inc., from whom CP&L leases the right to use the model.

SUMMARY OF PROMOD III

The PROMOD III system simulates the economic operation of the system and determines the associated financial impact of fuel and purchased power. It is first and foremost a comprehensive production costing model for projecting future operating costs.

PROMOD III differs from conventional production costing programs in its treatment of generating unit forced outages. It is these random and unpredictable forced outages that comprise the major factor in the disruption of fuel budget forecasts, operating cost estimates, and projected utilization of high-cost peaking and mid-range equipment. PROMOD III employs a special mathematical technique to explicitly consider the impact of forced outages on fuel requirements and, thus, operating costs. A more detailed discussion of PROMOD III's treatment of forced outages is provided later in this discussion.

In addition to forced outages, PROMOD III considers the relative efficiencies (operating costs) of the generating units so that generator output will be matched with electric demand in the most economical manner. Other operating restrictions which impact CP&L operating costs include spinning and quick-start reserve requirements and import and export capability limitations of the transmission network. These as well as other considerations are explicitly modeled in the PROMOD III program. Its strength lies in the

combination of probabilistic production costing techniques with detailed modeling of operating considerations to produce realistic estimates of fuel consumption and operating costs.

PROMOD III INPUTS

The minimum basic data needed to make a CP&L PROMOD III study falls into five categories:

- Generating Unit Data - unit types, heat rates, fuel types, capacity states, forced outage rates, seasonal derations, and maintenance requirements. Specialized data may be input for conventional hydro units.

- Fuel Data - cost of the various fuels used by generating units.

- Load Data - demand and energy forecasts and chronological load shapes.

- Transaction Data - type, capacity, energy, availability, timing, and costs.

- Utility System Operating Data - operating reserve requirements, reliability target levels, and available tie support.

MODELING TECHNIQUE

At the heart of PROMOD III is a modeling technique which allows the explicit consideration of randomly occurring forced outages, forced derations, and postponable maintenance outages of every generating unit and generation resource alternative. PROMOD III's probabilistic technique, in effect, dispatches every possible configuration of the generation system to obtain the best forecast of expected fuel consumption, unit generation, and system reliability, and ultimately leading to the best estimate of future operating

costs. PROMOD III accounts not only for the effect of a unit's outages and derations on its own operation, but also for the effect of a unit's outage on the operation of all other units in the utility system.

A simple example provides an introduction to the PROMOD III probabilistic technique:

In this example, there is a single hour's load to be satisfied by two generating units. The value of the load is 150 MW. The generating unit, to be considered first on the basis of cost, has a capacity of 80 MW and an 80 percent probability of being available, while the second unit has a capacity of 100 MW and an availability of 90 percent.

In Figure 1, the loading of the first unit is depicted. The unit may be either available for service (probability 0.8) or unavailable (probability 0.2). In the event the unit is available, it will satisfy 80 MWH of load and leave 70 MWH remaining. In the event the unit is unavailable, it will supply nothing and 150 MWH will remain. The expected generation of Unit 1 is, therefore, 64 MWH, and the expected remaining load is 86 MWH.

In Figure 2, the loading of the second generating unit is illustrated. Because of the two possible outcomes from the loading of the first unit, there are now four possibilities for the loading of the second unit. The calculations show that the expected generation of Unit 2 is 68.4 MWH, and the expected remaining load is 17.6 MWH. If more units existed, the number of outcomes would continue to expand exponentially.

In PROMOD III, a number of separate calculations and probability branches shown in Figures 1 and 2 are replaced by a technique which, for this example, would require only one calculation per unit loaded. Although it is a more complex calculation, it requires the retention of only one outcome after each unit is loaded rather than an exponential proliferation of outcomes. This technique is illustrated diagrammatically in Figure 3. Each unit, together with its probability

of being available, is combined with the remaining load from the previous unit so that a new remaining load is produced representing all of the outcomes possible with the units dispatched to that point, weighted according to the appropriate probabilities. Thus, the remaining load in Figure 3 after Unit 2 is loaded is an accumulation of the same MW values and probability values that are used to describe the various remaining load outcomes in Figure 2 after Unit 2 is loaded.

The above example demonstrates PROMOD III's treatment of full-forced outages. Generating units can be further represented by a multistate failure model to give consideration to partial loss of unit capability.

The PROMOD III algorithms include much more than a multistate version of the probabilistic calculation discussed above. The basic program contains dispatch logic capable of simulating the effect of unit commitment and economic dispatch. The economic dispatch process is achieved by the division of thermal generation units (coal, oil, gas, nuclear) into discrete capacity segment much in the same way that a real-time control system dispatches units on load control in discrete steps. Heat rates and availability data for each segment, coupled with unit forced outage rates and fuel cost data, provide the program with input which must be considered in accurately predicting economic dispatch. CP&L models its generating units with five capacity and availability states.

CP&L employs a slightly different approach in the modeling of nuclear generation within PROMOD III. CP&L targets projected nuclear generation at a level which takes into account maintenance outage requirements and the available capacity factor expected between maintenance outages.

In addition to determining the generation anticipated from the Company's thermal power sources, PROMOD III uses heat rate data, along with the type of heat content of the fuel, to arrive at the amount of fuel consumed.

PROMOD III simulates the production of energy to meet projected customer loads. Historical CP&L load data provides the basis for determining the load pattern for a typical week during each month under consideration. The typical week load pattern is used to derive load duration curves for weekdays, weeknights, and weekends, three periods during which similar operating conditions exist. These load duration curves are used in the program's probabilistic simulation to accurately reflect CP&L's generation scheduling and unit commitment process.

Power interchanges may also be addressed within a PROMOD III simulation. Transactions involving a fixed amount of energy increase or decrease the system load during the period for which they are applicable. Thus, hydro and thermal generating units will be called upon to produce more or less energy to meet the demand, depending upon the amount or nature of the transaction. CP&L models nonfirm (economy) purchases in PROMOD III as a power source which can be used after CP&L's fossil steam units have been loaded but before CP&L's internal combustion turbine units are utilized. The amount of IC generation displaced is controlled by the specific characteristics of the economy power source, such as maximum capability and availability, and is based upon analyses of historical economy interchange activity and future market conditions.

Emergency transactions occur in PROMOD III only when the utility system has exhausted all of its other resources and is faced with unserved energy. In the area of emergency transactions, CP&L's approach is to model the use of its ties with other utilities as a source of power with a capability consistent with maintaining targeted system reliability. This power source is not utilized until all other units have been loaded to their maximum dependable capacities.

ADDITIONAL INFORMATION

In 1977, CP&L acquired a license for the use of PROMOD III from Energy Management Associates, Inc., the creator of the program. Within that license, CP&L acknowledges and agrees that the use of the program is furnished on a confidential basis and that CP&L will treat the program and other supporting material as the proprietary information of Energy Management Associates. The information which has been provided herein is an attempt to supply as much detail as possible regarding the program employed by CP&L, without compromising CP&L's confidentiality commitment to Energy Management Associates, Inc.

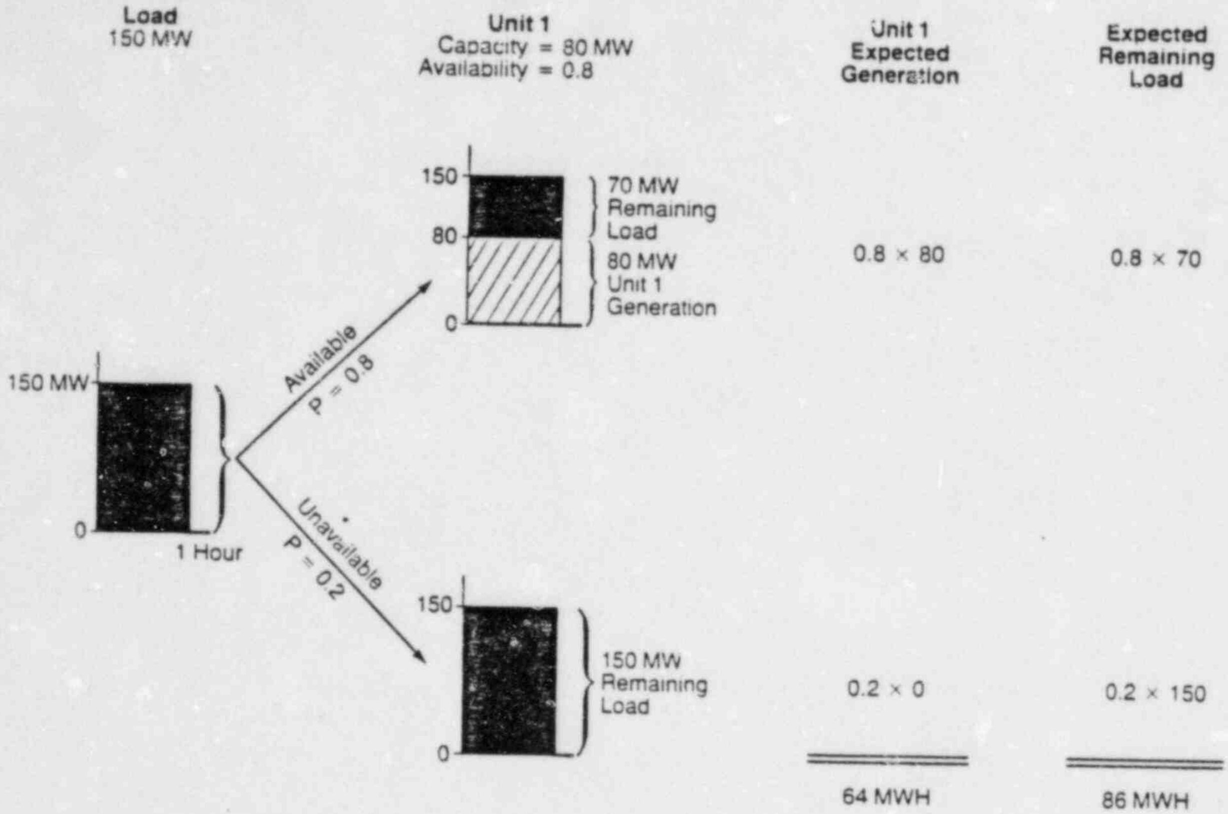

Figure 1: Probabilistic View of Loading One Unit

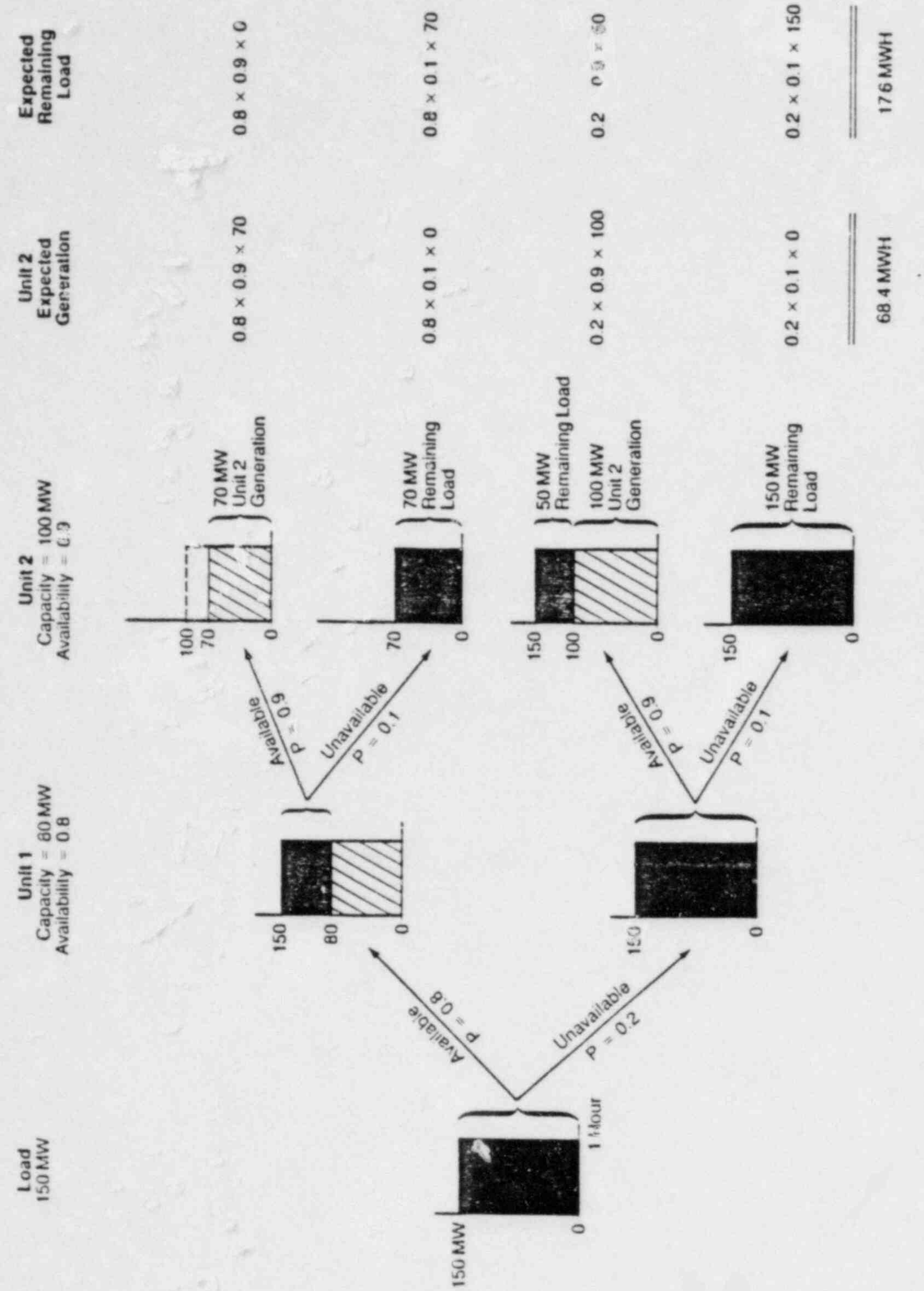

Figure 2: Probabilistic View of Loading Two Units

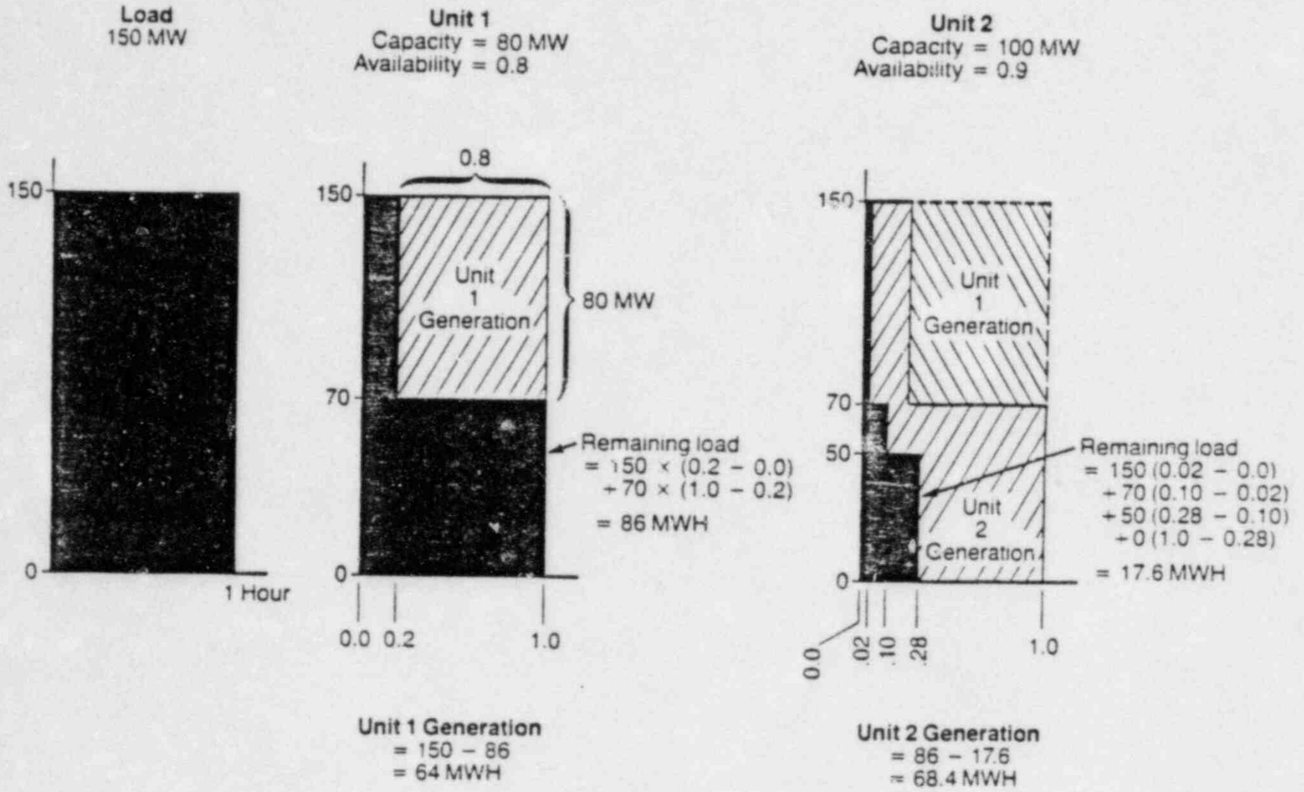

Figure 3: PROMOD III's Method of Probabilistic Simulation

CAROLINA POWER & LIGHT COMPANY
ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

ROBINSON 2 ESTIMATED FUEL AND SPENT FUEL DISPOSAL COSTS

The following table provides the Company's annual estimates of Robinson 2 fuel and spent fuel disposal costs, as used in the study for the Replacement Case:

Years	Robinson 2 Total* Fuel Cost ($/MWH)	Robinson 2 Spent Fuel Disposal Cost ($/MWH)
1984	4.7	1.1
1985	5.0	1.2
1986	6.5	1.3
1987	7.1	1.4
1988	7.5	1.5
1989	8.3	1.6
1990	9.2	1.7
1991	10.0	1.8
1992	11.0	1.9
1993	12.7	2.0
1994	13.7	2.1
1995	14.4	2.2
1996	15.6	2.3
1997	16.9	2.5
1998	17.7	2.7

*Includes spent fuel disposal costs.

CAROLINA POWER & LIGHT COMPANY

ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

1983 LONG-TERM O&M COST PROJECTIONS FOR ROBINSON 2

In early 1983, CP&L developed long-term O&M cost projections for its generating plants. These long-term projections were based on the Company's 1983 O&M Budget and the schedule of outages and maintenance activities which had been identified at that time. The following are the Company's 1983 long-term O&M cost projections for Robinson 2, which were used in the study:

Year	Robinson 2 O&M Cost Projections (000s $)
1984	37,769
1985	32,944
1986	28,724
1987	38,519
1988	41,978
1989	41,306
1990	37,141
1991	49,155
1992	52,706
1993	49,651
1994	54,290
1995	64,910
1996	69,589
1997	60,426
1998	77,198

CAROLINA POWER & LIGHT COMPANY

ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

PURCHASED POWER COST ASSUMPTIONS

The following assumptions for the cost of purchased power were used for the Robinson 2 Steam Generator Replacement Study.

General

Power purchases based on these assumptions were used as necessary to maintain a 20% annual planning reserve margin. All other purchases were economy or emergency purchases.

Period 1984-1988

For this period it was assumed that sufficient capacity to replace Robinson 2 would be available from Southern, TVA, and/or SCE&G systems. Based on a 1982 survey of all three companies, the following estimated purchased power costs were used.

Demand Charge: Based on an average cost of existing mature coal-fired units, as follows:

	1984	1985	1986	1987	1988
$/KW/MO.	*	8.00	8.50	9.00	10.00

Energy: Based on mid-priced coal-fired fuel cost + O&M cost + 10% of that sum, as follows:

	1984	1985	1986	1987	1988
Mills/KWH:	*	39.81	47.61	51.73	52.11

*No firm purchases required in 1984.

Period 1989-1998

In this period, no determination can be made as to the availability of capacity from neighboring utilities. A reasonable assumption might be that some capacity could be purchased in this time period; but in lieu of the lower rates being offered in the mid 1980's, it should be assumed that capacity would have to be purchased at prices based on new coal-fired units with scrubbers installed in this time period. Purchased power costs were assumed as follows (note that 1989 demand charge is based on a transition value between the 1988 and 1990 demand charges):

	Year	$/KW/MO.
Demand Charge:		
	1989	20**
	1990	30
	1991	33
	1992	36
	1993	39
	1994	42
	1995	46
	1996	50
	1997	55
	1998	60
Energy Charge: Mills/KWH	Undesignated Unit Fuel Cost + O&M + 10% (for each year in this period)	

The price for economy purchases continued to be based on a split between the Company's coal and oil generating costs.

**Transition Value

CAROLINA POWER & LIGHT COMPANY

ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

PROJECTED SYSTEM RESOURCES, LOADS AND RESERVES FOR THE REPLACEMENT CASE

Year	Previous Year's Installed Capacity (MW)	Other Resources (MW)	New Capacity (MW)	Total Resources (MW)	Peak Load (MW)	Reserves (MW)	Percent Reserves*
1984	8725	75		8800	7043	1757	24.9
1985	8725	75		8800	7346	1454	19.8
1986	8725	75	900	9700	7557	2143	28.4
1987	9625	75		9700	7674	2026	26.4
1988	9625	75		9700	7852	1848	23.5
1989	9625	75		9700	8043	1657	20.6
1990	9625	75	900	10600	8224	2376	28.9
1991	10525	75		10600	8461	2139	25.3
1992	10525	75	720	11320	8605	2715	31.6
1993	11245	75		11320	8854	2466	27.9
1994	11245	75		11320	9094	2226	24.5
1995	11245	75		11320	9386	1934	20.6
1996	11245	75	690	12010	9696	2314	23.9
1997	11935	75		12010	9998	2012	20.1
1998	11935	75	690	12700	10300	2400	23.3

*CP&L's planning criteria is to maintain a minimum 20% reserve margin.

CAROLINA POWER & LIGHT COMPANY

ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

PROJECTED SYSTEM RESOURCES, LOADS AND RESERVES FOR THE RETIREMENT CASE

Year	Previous Year's Installed Capacity (MW)	Other Resources (MW)	New Capacity (MW)	Total Resources (MW)	Peak Load (MW)	Reserves (MW)	Percent Reserves*
1984	8725	75		8800	7043	1757	24.9
1985	8060	740		8800	7346	1454	19.8
1986	8060	93	900	9053	7557	1496	19.8
1987	8960	234		9194	7674	1520	19.8
1988	8960	447		9407	7852	1555	19.8
1989	8960	677		9637	8043	1594	19.8
1990	8960	75	900	9935	8224	1711	20.8
1991	9860	75	720	10655	8461	2194	25.9
1992	10580	75		10655	8605	2050	23.8
1993	10580	75		10655	8854	1801	20.3
1994	10580	75	690	11345	9094	2251	24.8
1995	11270	75		11345	9386	1959	20.9
1996	11270	75	690	12035	9696	2339	24.1
1997	11960	75		12035	9998	2037	20.4
1998	11960	75	690	12725	10300	2425	23.5

*CP&L's planning criteria is to maintain a minimum 20% reserve margin.

CAROLINA POWER & LIGHT COMPANY

ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

PROJECTED SYSTEM ENERGY INPUT REQUIREMENTS

The following table provides the Company's projected system energy input requirements which must be served by the Company's generating units or purchases from other utilities. These system energy input requirements are based on the Company's 1983 forecast of energy sales.

Year	Projected System Energy Input Requirements* (GWH)
1984	35985.0
1985	37303.0
1986	38475.0
1987	39460.0
1988	40705.0
1989	41978.0
1990	43232.0
1991	44654.0
1992	46064.0
1993	47427.0
1994	48789.0
1995	50290.0
1996	51868.0
1997	53493.0
1998	55171.0

*Based on 1983 Energy Forecast

CAROLINA POWER & LIGHT COMPANY

ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

PROJECTED OPERATING DATA[1] FOR ROBINSON 2 FOR THE REPLACEMENT CASE

Year	Operating[2] Capacity Factor (Percent)	Scheduled Outages	Annual[3] Capacity Factor (Percent)	Energy[4] Generation (GWH)
1984	85[5]	01/21 - 11/16	15	878.7
1985	85	10/19 - 12/31	69	4045.0
1986	85	01/01 - 01/31	80	4660.0
1987	85	01/31 - 05/15	62	3611.4
1988	85	07/16 - 10/28	63	3671.7
1989	85	-	88	5103.3
1990	85	01/01 - 04/01	65	3804.5
1991	85	06/03 - 09/01	66	3866.3
1992	85	11/02 - 12/31	73	4259.9
1993	85	01/01 - 01/31	80	4660.6
1994	85	04/04 - 07/07	66	3850.4
1995	85	09/04 - 12/03	66	3824.4
1996	85	-	88	5117.6
1997	85	02/03 - 05/04	65	3806.7
1998	85	07/06 - 10/04	66	3867.0

NOTES:

(1) The data provided are the Company's current projections at the time the study was performed; however, these projections are subject to change as system or controlling conditions change.

(2) Operating capacity factor reflects forced outages only, not scheduled outages.

(3) Based on a 665 MW maximum dependable capacity rating for Robinson 2 and projected annual energy generation.

(4) Annual energy generation is developed from seasonal Robinson 2 capacity ratings of 665 MW for summer and 700 MW for winter.

(5) In 1984, prior to the start of the steam generator replacement outage (January 21) Robinson 2 is projected to operate at only 70% operating capacity factor. Upon return to service following that outage, Robinson 2 is projected to operate at 85% operating capacity factor.

CAROLINA POWER & LIGHT COMPANY

ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY

ESTIMATED FUTURE CAPITAL INVESTMENTS FOR ROBINSON 2

The following table provides estimates of the future capital investments for additions and modifications at Robinson 2, as used in the study for the Replacement Case:

Year	Robinson 2 Estimated Net Construction Cost of Future Additions and Modifications ($000s)
1984	69,155
1985	26,021
1986	7,921
1987	2,174
1988	2,377
1989	2,584
1990	2,829
1991	3,075
1992	3,359
1993	3,656
1994	3,992
1995	4,354
1996	4,742
1997	5,168
1998	5,633

NOTE

For study purposes, it was assumed that $62,800,000 was spent for the Robinson 2 steam generator replacement project in years prior to 1984. The estimated total capital cost of the Robinson 2 steam generator replacement project, which was used in the study and reflected in the Company's 1983 Construction Budget, is $105,673,000.

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UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of	)	
	)	
CAROLINA POWER & LIGHT COMPANY	)	Docket No. 50-261-OLA
	)	
(H. B. Robinson Steam Electric Plant, Unit 2)	)	ASLBP No. 83-484-03LA
	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of "CAROLINA POWER & LIGHT COMPANY - ROBINSON UNIT 2 STEAM GENERATOR REPLACEMENT STUDY FOR OPERATING LICENSE AMENDMENT PROCEEDING - NRC DOCKET NO. 50-261 OLA - September 1983" were served this 12th day of October, 1983 by depositing in the United States mail, first class, postage prepaid to the parties on the attached SERVICE LIST.

Andrew McDaniel

Andrew McDaniel
Attorney for Carolina Power & Light Company

October 12, 1983

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of CAROLINA POWER & LIGHT COMPANY (H. B. Robinson Steam Electric Plant, Unit 2)	))))))	 Docket No. 50-261-OLA ASLBP No. 83-484-03LA

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