Carolina Power & Light Company

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April 30, 1992

The Honorable Charles W. Ballentine
Executive Director
South Carolina Public Service Commission
111 Doctors Circle
Columbia, South Carolina 29203

Re: Carolina Power & Light Company's 1992 Intergrated Resource Plan

Dear Mr. Ballentine:

Pursuant to Commision Order Nos. 91-885 and 91-1002 issued in Docket No. 87-223-E Carolina Power & Light Company hereby submits for filing the original and 25 copies of its 1992 Integrated Resource Plan.

Very truly yours,

Len S. Anthony
Associate General Counsel

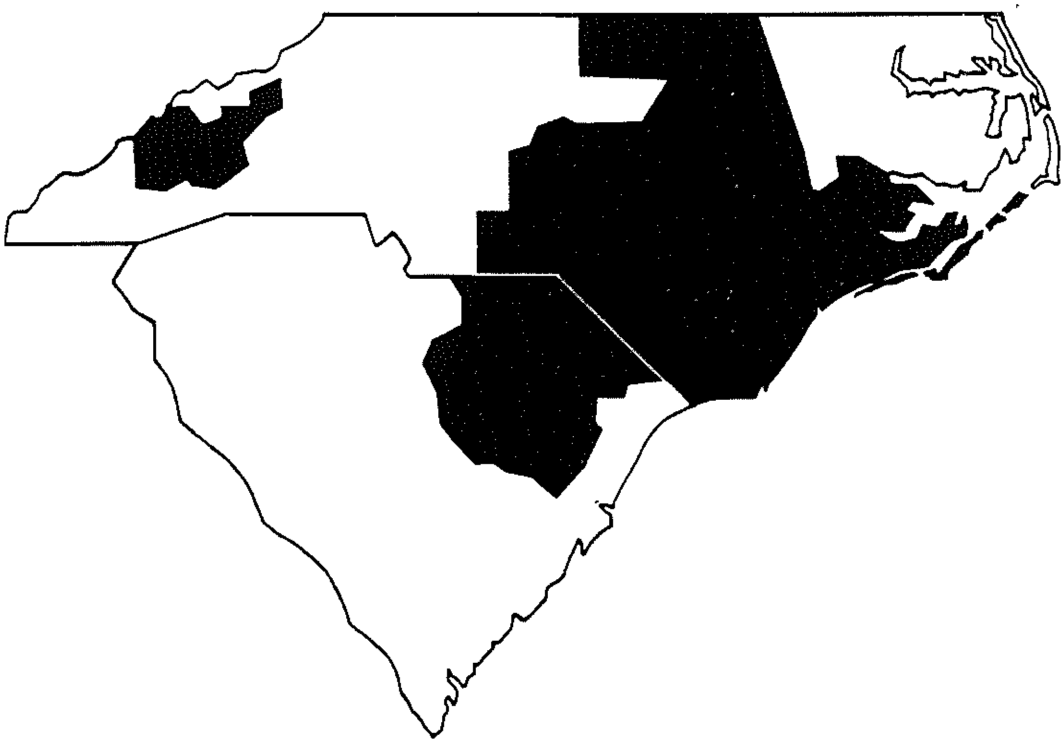
LSA:sww

CP&L

Carolina Power & Light Company

Integrated Resource Plan

Volume I, Volume II, Volume III



South Carolina Public Service Commission

Docket No. 92-902-E

April 30, 1992

CAROLINA POWER & LIGHT COMPANY

INTEGRATED RESOURCE PLAN

TABLE OF CONTENTS

Table of Contents

Volume I

Integrated Resource Plan Report

Chapter 1
Executive Summary

Introduction

It is CP&L's goal to provide its customers an adequate and reliable supply of electric power and to do so at the lowest reasonable cost. Until the 1970s, this meant building new, more efficient power plants. The rapid growth of the region during this period created a steady demand for more and more power. Because of economies of scale, each new more efficient plant brought the price of electricity down. Power supply planning was straightforward and the risks were minimal. Significant changes have occurred in the electric utility industry since the 1970s and today's energy choices are more complex. Management of energy growth has become an alternative to new construction. One way of managing growth is through demand-side management programs; an area in which CP&L has been an industry leader. CP&L recognized very early the need to encourage the efficient use of electric energy. CP&L customer services programs since 1971 have emphasized the need for efficient energy management. In 1981, CP&L implemented an integrated resource planning process in which both demand-side and supply-side resources are utilized to produce a reliable and cost effective resource plan.

This report presents the results of CP&L's Integrated Resource Planning Process and its current Integrated Resource Plan (IRP). The periodic documentation of CP&L's IRP efforts, in accordance with Commission rules, serves as a effective tool for continuing dialogue and for communicating our plan and the actions that will be taken to implement the plan. It is important to note that the IRP is a process and not an end result. It describes our ongoing evaluation of demand and supply-side options. It shows where we are today and where we plan to be in the coming years. We will continue to increase our knowledge of demand-side management programs and supply-side resources and improve our methods for evaluating them. With continued experience and changing future events, we will adjust our plans accordingly.

Objectives of the Integrated Resource Plan

The overall objective of the IRP process is the development of a flexible resource plan which will provide an adequate and reliable supply of electric power to our customers at the lowest reasonable cost.

CP&L's IRP achieves this objective by incorporating a cost-effective mix of demand-side and supply-side resources, which will increase the utilization of existing facilities and will minimize the price of electricity.

In formulating its demand-side portfolio, the Company examines the costs, benefits and market potential of those programs currently implemented and those new programs which appear to hold promise. CP&L's demand-side management process is a continuous cycle of planning, implementation, and monitoring. A key element in this process is the comprehensive evaluation of all DSM programs. In evaluating programs, multiple criteria relating to economic, operational, financial, technical, regulatory, and marketing are considered. The selection of cost-effective programs for inclusion in the Integrated Resource Plan is insured by comparing program costs to CP&L's "avoided costs." These avoided costs represent the supply-side capacity and energy costs that can be avoided by implementing DSM program options. These avoided costs are updated annually and are also the basis for determining payments to cogenerators and small power producers. This use of common avoided costs insures that supply-side resources and demand-side management programs can compete head-to-head so as to produce a least cost integrated resource plan.

Once cost-effective demand-side resources are identified and included in the forecasts and plan, the types and amounts of supply-side resources available to the Company within the planning horizon are then determined. Candidate resource plans are then developed using combinations of the most economical supply options. The candidate plans are developed in accordance with certain planning principles which serve as a framework within which alternative plans can be developed and evaluated. These planning principles are:

1. Maintain flexibility to adjust to changing conditions;
2. Develop capacity requirements to meet a specified reliability criterion;
3. Emphasize resource diversity as an appropriate response to future uncertainty;
4. Avoid excessive reliance on oil and natural gas fueled resources.

The candidate plans are then evaluated taking into consideration relevant criteria which include critical uncertainties such as load growth, fuel prices, regulatory requirements, etc. As plans extend into the future, the possibilities for unforeseen variations in each component of the plan increase. Further, in an uncertain environment, what appears to be the best option today may well become uneconomic tomorrow. Therefore, excessive reliance on any single resource is avoided. Instead, a balanced plan is developed in which each resource plays a different but complementary role. This strategy produces a diversified plan that minimizes cost over the long term while maintaining the flexibility necessary to respond to changing conditions. This balanced planning, like a well-managed portfolio, is expected to lead to consistent savings for our customers while minimizing the risks inherent in planning for an uncertain future.

Overview of the Plan

CP&L continues to experience growth in peak demand for electricity even with its aggressive DSM efforts. Although the current forecast projects slower load growth, 1.7% as compared with 1.9% last year, additional resources are needed to meet this forecasted peak load growth. As a consequence of this slower growth projection, CP&L's proposed generation additions schedule has been revised to reflect no generation additions until 1996. All generation additions scheduled for 1996 through 2006 are for relatively low cost combustion turbines needed for peaking capacity. Table 1-1 below summarizes CP&L's current Integrated Resource Plan and shows the forecasted system energy and peak load, the specific demand-side and supply-side resources planned, the projected year the resources will be needed, and the resulting annual capacity margins. These plans, of course, are subject to continuing change and, as appropriate, DSM programs will be enhanced or expanded to substitute for combustion turbines to the extent determined to be feasible in future plans.

Table 1-1

RESOURCE PLAN SUMMARY

	Annual Energy (GWH)	Peak Load (MW)	Demand-Side Management (MW)	Supply-Side Resouces (MW)	Capacity Margin (%)
1992	45,676	8,631	1430	49 NUG	17.9
1993	47,601	8,969	1527	400 DUKE	17.8
1994	49,058	9,226	1617	23 PA/SCPSA	15.6
1995	49,995	9,364	1698	150 PA CT	15.5
1996	50,774	9,516	1754	225 DARLINGTON CT	15.8
1997	51,518	9,646	1807	250 CT*	16.5
1998	52,352	9,796	1858	250 CT*, -50 PA/SCPSA	16.7
1999	53,197	9,949	1905	400 CT*, -400 DUKE, -50 PA/SCPSA	15.0
2000	53,974	10,095	1950	250 CT*	15.6
2001	54,698	10,227	1993	250 CT*	16.2
2002	55,404	10,356	2036	250 CT*	16.9
2003	56,091	10,483	2080	250 CT*	17.5
2004	56,813	10,615	2124		16.5
2005	57,618	10,753	2175	250 CT*	17.0
2006	58,408	10,896	2218	250 CT*	17.5

*The Company has not committed to a particular design, unit size, or location for the capacity.

Negative numbers indicate the expiration of purchase contracts.

NUG - Non Utility Generation
CT - Combustion Turbine
PA - Power Agency
PA/SCPSA - Power Agency/South Carolina Public Service Authority

Demand-side management will play an increasingly larger role in our future integrated resource plans. Expressed as a percentage of peak load, the plan projects a cumulative demand-side management load reduction capability in 1995 of over 15% as compared with just under 14% in last year's plan. The Company's plan calls for the addition of approximately 900 megawatts of DSM load reduction capability over the 15 year planning horizon. The 900 megawatts is in addition to 1318 megawatts of capability at year-end 1991. Our mix of DSM programs includes programs which enable us to influence the timing and magnitude of electric demands on our generating facilities. This "management" of load can: produce improvements in load factor, increase utilization of existing capacity, reduce the need for additional peaking capacity, reduce the level and frequency of future rate increases, increase customer satisfaction, and encourage economic growth. Table 1-2 lists the programs currently implemented and potential programs under study.

Table 1-2

Current Programs	Potential Programs
Residential Sector	**Residential**
Common Sense Home (Thermal Efficiency -New Homes)	High Efficiency Water Heater
Residential Energy - Conservation Discount	Appliance Turn-In
Residential High Efficiency Heat Pump	Residential Cool Thermal Storage
EZ - $64	
Residential Time-Of-Use	
Homeowner's Energy Loan Program	
Commercial Sector	**Commercial**
Commercial Thermal Energy Storage	Cool Schools 2000
Commercial Energy Efficient Design	Thermal Energy Storage - Schools
Commercial Energy Analysis (Audit)	Commercial Heat Pump
Commercial Time-Of-Use	Commercial Load Control
Safeshine	Heat Pump Water Heaters
	Energy-Efficient Lighting
Industrial Sector	**Industrial**
Industrial Audit/Energy Efficient Plants	Small Load Curtailment
Industrial Time-Of-Use	
Large Load Curtailment	
Cogeneration and Hydroelectric	
Electrotechnologies	
Cogeneration - Economy C	
Target Business Recruitment	
Dispatched Power	
System	
Remote-Controlled Voltage Reduction	

Purchased power continues to play a major role in our integrated resource plan. In 1993, total purchases from non-utility generators and from other utilities will be approximately 1300 megawatts, which represents about 12% of our supply-side capability. This compares to less than 5% only five years ago. Reliable and cost-effective purchases help minimize capital expenditures and reduce financial risks to the Company and its customers.

Studies continue to show that the system has adequate base load capacity but that additional peaking capacity will be needed to meet load growth, even after taking into account peak load reductions due to DSM programs. The most economical and reliable supply resource available to meet this need is combustion turbines. Combustion turbines also have short lead times; that is, they do not take long to construct. The short lead time increases flexibility by allowing more time to determine and verify the need for additional capacity before committing the Company and its customers to significant expenditures. When the need is clear and commitment is necessary, the low capital costs for combustion turbines minimize the size and need for rate increases.

While the plan shows a significant amount of combustion turbines being added in the future, all but the 225 MW Darlington addition are undesignated. These resources are not necessarily combustion turbines. The Company continues to research economical and efficient demand-side and supply-side options. DSM program enhancements and new DSM programs potentially can satisfy the need for a significant portion of this combustion turbine capacity. In addition, CP&L constantly receives new proposals for non-utility generation. All proposals are thoroughly evaluated to determine if the customer and the Company can benefit from the purchase of power. When it comes time to make commitments on how to satisfy the demands of its customers, CP&L will choose the most economical resource that will allow the Company to maintain reliability and the flexibility to respond to changing conditions.

Taken as a whole, the Company's Integrated Resource Plan offers a number of potential opportunities to the mutual benefit of the Company, its customers, and stockholders. Some of the opportunities are:

- additional customer options
- lower costs
- stability of rates
- lower generating capacity requirements
- better understanding of our market and customers
- improved efficiencies of energy utilization

Overview of Environmental Impacts

The attractive climate and natural beauty of the CP&L service area makes it a popular choice for residents and tourists alike. Maintaining the quality of the environment of the Carolinas is an important part of the way CP&L does business. The Company complies with a large number of federal, state, and local environmental regulations in the daily operation of its powerplants. CP&L takes its environmental responsibility seriously and takes into account the impact its facilities will have on the environment during all stages of planning and operation.

The Company's sulfur dioxide emissions are among the lowest of all utilities east of the Mississippi. CP&L has long supported efforts to ensure that the country's air is clean, and the Company has burned low sulfur coal for many years. The Company's current IRP reflects this concern. The plan, as already discussed, relies on demand-side management programs, purchases, and combustion turbines which are efficient and have low emissions. The Company's plan does not call for a major base-load facility within the fifteen year planning horizon.

Generally, demand-side management options e.g., energy efficiency improvements and load shifting have favorable environmental effects. The focus of these programs is on using energy more efficiently, thereby achieving more energy services for the same environmental effects of operation. In addition, successful demand-side management programs can defer the need for additional new supply. The success of DSM programs in shifting load to off-peak times may also produce environmental benefits by flattening the daily demand peak and thus allowing the operation of more efficient and cleaner energy sources.

Environmental characteristics of demand-side management options have not been as extensively scrutinized as supply-side options. Questions have surfaced regarding in-door air pollution, disposal of less efficient appliances, CFC emissions, and the release of mercury and PCBs. For example, energy efficient appliances and lighting have favorable efficiency characteristics; however, potential negative environmental impacts through improper disposal of the less efficient appliances and lights being replaced must be considered. CP&L will be investigating the impact and cost-effectiveness of an appliance turn-in program for the disposal of appliances replaced by higher efficiency appliances. The Company is also taking into consideration in the development of energy-efficient lighting programs, the proper disposal of florescent lights to mitigate the release of mercury and PCB.

With regard to environmental impacts of supply-side resources, compliance with environmental regulations increases the cost of new generation facilities. The costs associated with complying with existing regulations are incorporated into the planning process in several ways. Where quantifiable, the costs are included as part of the cost of the resource option. Otherwise, the impacts are considered in a qualitative manner. The methods used to include the costs of environmental compliance in the integrated resource plan are discussed in Volume II, Appendix F.

The costs of complying with regulations that have not been promulgated or have yet to take effect are also considered in the planning process. An example of this situation are the costs associated with complying with the Clean Air Act Amendments of 1990. The first of two phases becomes effective in 1995. The second phase, which contains more stringent provisions, will become effective in the year 2000. The Company is in the process of examining and evaluating numerous compliance alternatives. For planning purposes, a strategy to develop a plan of compliance with the legislation has been developed and preliminary compliance costs have been included in the analyses. This strategy is a rough "first-cut" estimate that complies with the legislation and allows cost estimates of compliance to be introduced into the IRP process.

Summary Risk Assessment of the Plan

The best overall integrated resource plan takes into consideration the most critical uncertainties which confront the Company, such as load growth, fuel prices and nuclear availability. In CP&L's IRP process, the uncertainties of the assumptions are taken into consideration using a technique known as decision analysis where both the value of an assumption that should be used in the analysis and its probability of occurrence are determined. The combination of all the possible outcomes and all the uncertainties produces a decision tree which contains many different scenarios. The results from all of the scenarios are combined to form an expected value result for each alternative plan which is then used in the evaluation process. Thus, while the final plan may not result in the lowest cost or the most reliable service under all circumstances, it should result in the best overall plan when all the different planning criteria are accounted for and the appropriate risks are considered and factored into the decision.

The specific options chosen in the resource plan are consistent with the IRP objective and reduce risks by:

- Incorporating a cost-effective mix of DSM programs balanced across program types and customer classes. This ensures that a shortfall in one type of program will not unduly jeopardize the entire strategy and that all retail customers have an opportunity to participate in DSM programs. In addition, the pace of DSM programs can be adjusted up or down as needed to respond to changing conditions.

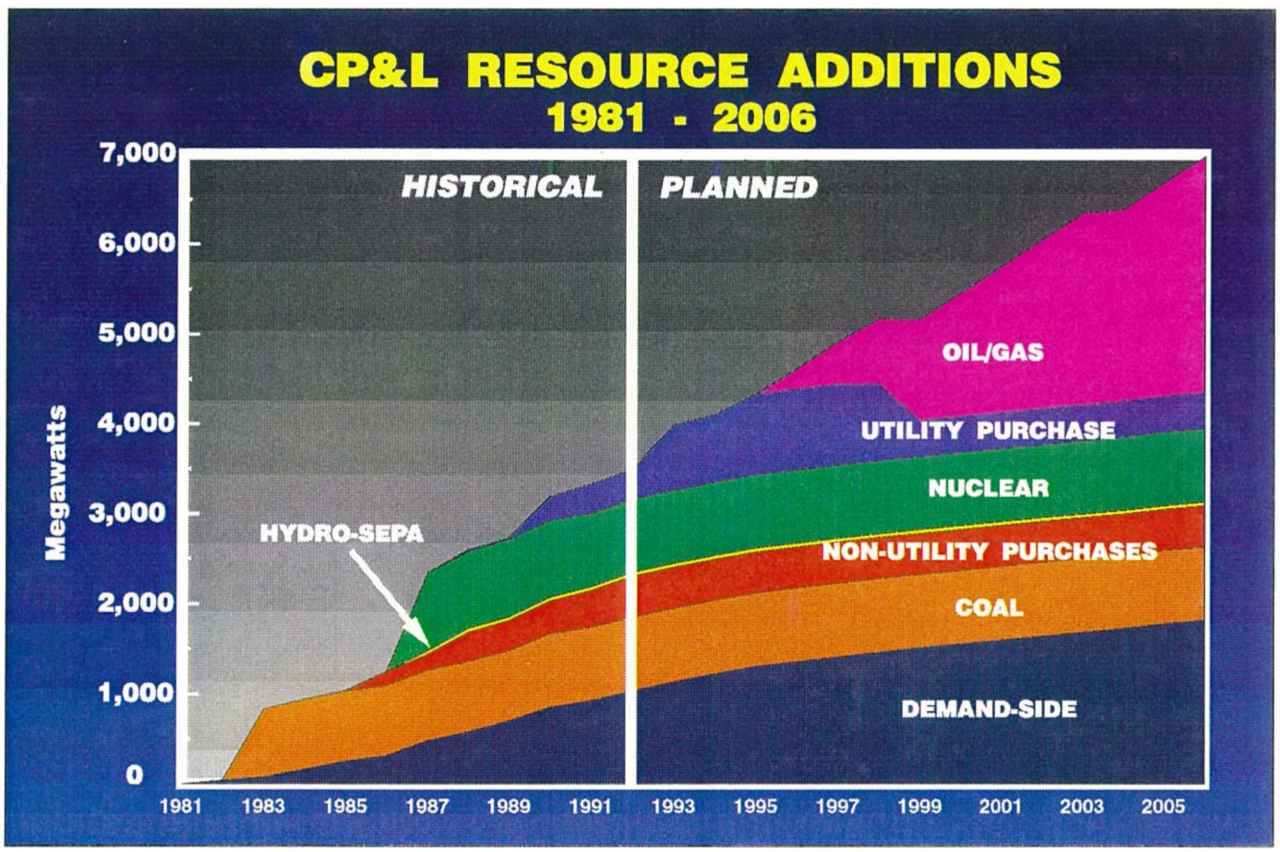
- Utilization of low-cost, short lead time peaking additions--All generation additions scheduled for 1996 through 2006 are for relative low cost, short lead-time combustion turbines. The additions are shown in 250 megawatt blocks with unit size between 75 to 125 megawatts. Smaller size generators can be added in increments which more closely track load growth. The short lead time for construction increases flexibility to respond to changing conditions and the relatively low capital cost reduces financial risks to the Company and its customers.

- Purchases from non-utility generators and other utilities--Through cost-effective and reliable purchases, the Company and its customers are not exposed to the financial risks that construction of the capacity would impose.

Conclusion

History has shown us that the only thing certain about the future is that it is uncertain. Uncertainty currently surrounds environmental legislation, fuel supply, economic growth, and industry regulation, to name only a few of the current issues. Clearly, plans must be developed that recognize the uncertainty of future events. Plans must be flexible and must not depend on a specific outcome of future events if they are to be successful. To that end, CP&L has emphasized diversity in its Integrated Resource Plan. This emphasis is illustrated in the Figure 1-1.

Figure 1-1

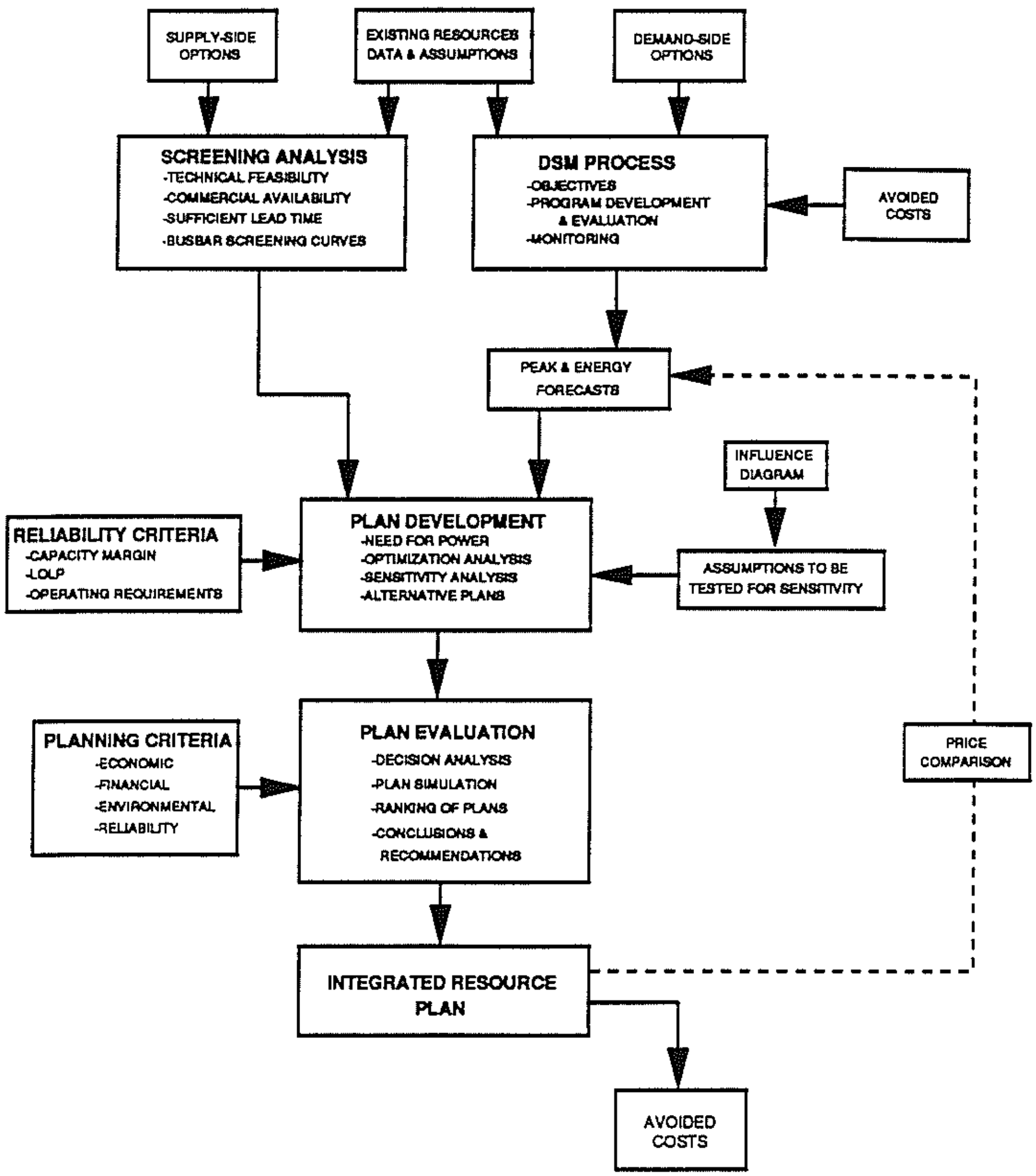


Carolina Power & Light Company's challenge is to meet customer needs for electric power with an energy supply that is reliable and economic. The Company's plans are continuously reviewed and appropriate changes are made to account for changing conditions, circumstances, and availability of alternative resources. By incorporating a balance of demand reduction and new supply options that provide maximum flexibility to adapt to uncertain and ever-changing conditions, CP&L's Integrated Resource Plan ensures that the challenge will be met.

This chapter discusses Carolina Power & Light's Integrated Resource Planning Process. In 1981, CP&L implemented an integrated resource planning process in which both demand-side and supply-side resources are utilized to produce a reliable and cost-effective resource plan. This process has evolved over the years and will continue to improve over time as planning methods and tools improve. The process used in the development of the Integrated Resource Plan (IRP) is depicted in the flowchart shown in Figure 2-1.

Figure 2-1

INTEGRATED RESOURCE PLANNING PROCESS



Existing Resources

The Integrated Resource Planning process begins with the review of the status of existing and committed demand-side and supply-side resources. This section provides a description of CP&L's existing and committed resources.

Demand-Side Resources

History

Through December, 1991, CP&L has achieved 1318 MW of peak load reduction as a result of Demand Side Management (DSM) programs. Residential demand-side management programs accounted for 310 MW of peak load reduction through December, 1991. The Commercial sector demand-side management programs contributed 135 MW toward the cumulative MW achievement and the Industrial demand-side management programs accounted for 873 MW of peak load reduction through December, 1991. Figure 2-2 shows the year-by-year cumulative peak load reduction achieved as a result of demand-side management programs. Table 2-1 displays the percent of cumulative megawatt of demand-side management peak load reduction capability as compared to the summer system peak. As this table shows, CP&L's demand-side management efforts have grown significantly each year, and have grown at a faster rate than the Company's summer system peak has grown.

Figure 2-2
Demand-Side Management Programs

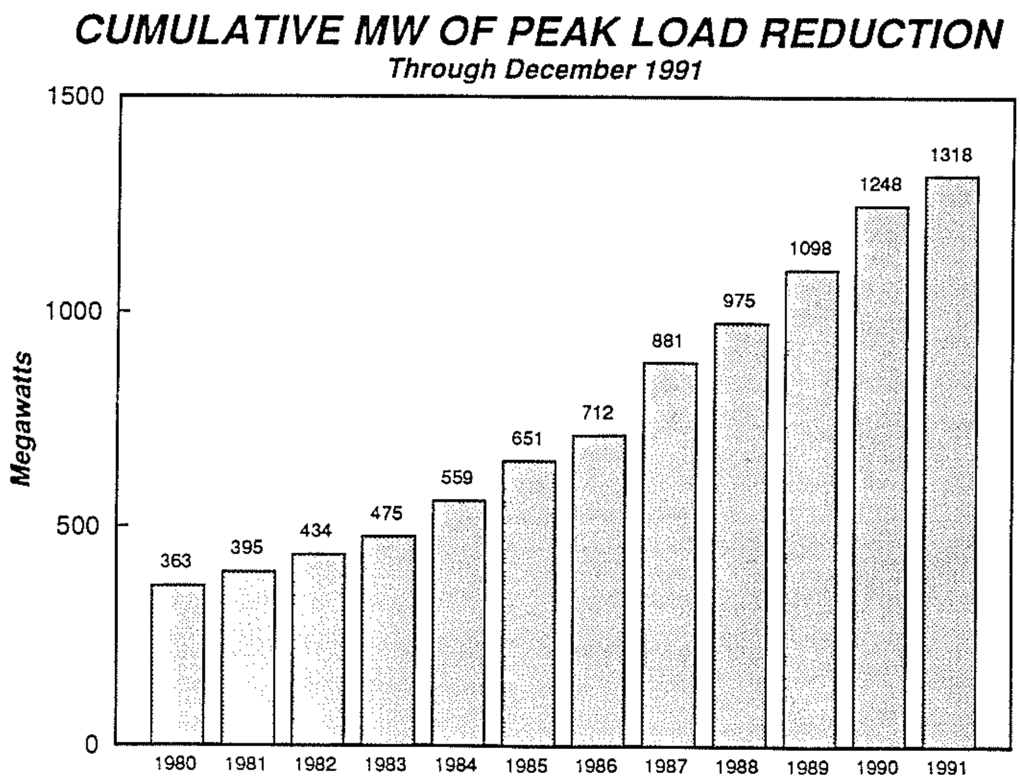


Table 2-1

Year	Peak Load Reduction Capability (MW)	Summer System Peak (MW)	Peak Load Reduction Capability As A Percent Of Summer System Peak
1980	363	6139	5.91
1981	395	6253	6.32
1982	434	6089	7.13
1983	475	6926	6.86
1984	559	6869	8.14
1985	651	6876	9.47
1986	712	7485	9.51
1987	881	7987	11.03
1988	975	8523	11.44
1989	1098	8327	13.19
1990	1248	8681	14.38
1991	1318	8960	14.71

CP&L's DSM programs have evolved over two decades. In those two decades the Company has been promoting successful energy management options for its customers. In the early to mid-1970's, CP&L focused primarily on conservation with emphasis on a general reduction in energy usage, increased insulation, and overall improved thermal efficiency. The Company initiated efforts to analyze residential customers' homes (Wrap-Up program) and commercial and industrial customers' premises to recommend energy conserving measures and practices. In 1976, the Company formally encouraged energy-efficient construction standards for houses, apartments, and mobile homes with the start of its Common Sense program. During the mid-to-late 70s, CP&L's programs expanded to focus not only on conservation but also load management. This effort continued previous conservation programs and added load shifting programs supported by new rate design such as Time-of-Use rates. In the early-to-mid-80s, in addition to the previous conservation and load management programs, CP&L added peak clipping programs supported by curtailable and other rate structures. Residential Water Heater Control was introduced in Raleigh in 1980 and was followed by Air Conditioner Control a year later. Both appliance control options are now available to approximately 75% of CP&L's service territory. To encourage further residential conservation, low-interest loans were made available to finance conservation measures such as insulation and storm doors. In addition, audit and thermal storage programs were further emphasized.

Evolution/Enhancements

As previously stated, many of CP&L's programs were implemented in the 1970s and 1980s. However, CP&L's demand-side management programs are not static - they are periodically evaluated and reviewed for possible enhancements. Modifications and enhancements to programs are designed for various purposes including the encouragement of customer participation, the promotion of further conservation efforts, and better utilization of existing capacity. Enhancements and modifications to our existing programs have been numerous. Program enhancements have occurred across all major retail customer classes.

In the Residential class, High-Efficiency Heat Pump, Homeowner's Energy Loan, EZ-$64, Common Sense Home, and Time-Of-Use are examples of programs that CP&L has modified and enhanced since their implementation. The Residential High-Efficiency Heat Pump Program dealer incentives and customer financing criteria for high-efficiency installations were recently modified. Both modifications were designed to better educate residential customers about heat pump operations and to further promote conservation through the use of high-efficiency heat pumps. This program was also modified to increase the allowable loan amount for heat pumps from $5000 to $6000. The Homeowner's Energy Loan Program (HELP) was intensified by increasing the amount of approved credit up to $1500 for cost-effective conservation measures. As previously stated, the EZ-$64 program began in 1980 as water heating control. Modified a year later, the customer was offered the option of air conditioning and water heating combined control as well as stand-alone water heating control. Stand-alone air conditioning control was added to the EZ-$64 program in 1990. To encourage greater energy efficiency, the Common Sense Home Program was modified, increasing the applicable thermal integrity requirements and adding the efficiency standards for heating and air conditioning equipment. The Residential Time-Of-Use Program has been enhanced several times since its implementation. Examples of such enhancements include the introduction of an all-energy time-of-use rate as an alternative to the demand and energy residential time-of-use rate, and the addition of off-peak holidays.

The Commercial sector has seen enhancements to the Commercial Energy Analysis (Audit) Program, the Commercial Time-Of-Use, and the Thermal Energy Storage Programs. The Commercial Energy Analysis (Audit) Program was originally targeted at large commercial customers and was expanded to also include smaller commercial customers, providing on-site energy evaluations. CP&L introduced the Small General Service Time-Of-Use rate in 1981. In addition to the enhancement to include holidays as off-peak days, the Time-Of-Use Program was enhanced to encourage the shifting of air conditioning load in conjunction with cool storage to off-peak periods through the introduction of the Small General Service Thermal Energy Storage Program.

Industrial Audit/Energy Efficient Plants, Large Load Curtailment, and Dispatched Power are examples of Industrial demand-side management programs that were enhanced since their implementation. Industrial energy audits have been available systemwide since 1983. To further conservation and load management efforts this program was expanded to include energy efficient plants, in which CP&L engineers make recommendations during the facility design phase. The Large

Load Curtailment Program designed as a peak clipping program was introduced in 1982 utilizing capacity curtailments when CP&L did not have adequate capacity and reserves available to meet anticipated customer requirements. This program was enhanced in 1987 to include economy curtailments when capacity is available but generation costs are relatively high. First offered as an experimental program in North Carolina, the Dispatched Power Program was enhanced, made a permanent program in North Carolina, and recently offered to customers in South Carolina. The program was enhanced to offer two categories of dispatched periods when system load and generation costs are low.

Enhancements and modifications to CP&L's existing demand-side management programs are an important component to achieving CP&L's objectives of increasing the utilization and efficiency of existing capacity, reducing the need for additional peaking capacity, providing downward pressure on the level and frequency of future rate increases, ensuring customer satisfaction, and supporting continued sound economic growth within CP&L's service area.

Balanced Portfolio

CP&L's DSM programs are balanced across the three major retail customer classes, offering a menu of programs to residential, commercial, and industrial customers. Additionally, the DSM programs are balanced across the major load shape objectives. CP&L pursues strategic conservation (e.g. residential thermal efficiency), load shifting (e.g. Time-of-Use), peak clipping (e.g. curtailable), valley filling (e.g. commercial thermal energy storage), and strategic load growth (e.g. target business recruitment). There is no contradiction in offering demand-side management options within our portfolio that are aimed at conservation and load management (strategic conservation, load shifting, and peak clipping) while others are designed for strategic sales (valley filling and strategic load growth). Table 2-2 through Table 2-4 illustrate the balance of CP&L's DSM programs across customer classes and load shape objectives. Following these tables are descriptions of CP&L's existing demand-side resources.

Table 2-2
Residential Demand-Side Management Programs

Programs	Strategic Conservation	Load Shifting	Peak Clipping	Valley Filling	Strategic Load Growth
Common Sense Home	X				
Homeowner's Energy Loan Program	X				
Residential High Efficiency Heat Pump	X			X	X
EZ - $64			X		
Residential Time-Of-Use		X			
Residential Energy Conservation Discount	X				

Table 2-3
Commercial Demand-Side Management Programs

Programs	Strategic Conservation	Load Shifting	Peak Clipping	Valley Filling	Strategic Load Growth
Commercial Thermal Energy Storage		X		X	
Commercial Energy Efficient Design	X	X			
Commercial Energy Analysis (Audit)	X	X		X	
Commercial Time-Of-Use		X		X	
Safeshine				X	

Table 2-4
Industrial Demand-Side Management Programs

Programs	Strategic Conservation	Load Shifting	Peak Clipping	Valley Filling	Strategic Load Growth
Industrial Audit/Energy Efficient Plants	X	X	X	X	
Industrial Time-Of-Use		X		X	
Large Load Curtailment			X		
Cogeneration & Hydroelectric	X				
Electrotechnologies	X			X	X
Cogeneration - Economy C				X	
Target Business Recruitment				X	X
Dispatched Power				X	

Common Sense Home Program
(Thermal Efficiency - New Homes)

The Company's Common Sense Home Program encourages the construction of energy-efficient residences. Structures which meet the program's requirements for thermal integrity and equipment efficiency earn the Common Sense Home designation and qualify for CP&L's 5% Residential Energy Conservation Discount.

Current Common Sense Home requirements are: (1) minimum insulation levels of R-30 in ceilings, R-16 in walls, R-19 in floors, and R-7 in slabs; (2) window area limited to 15% of heated floor area; (3) insulated windows and doors; (4) an electric hot water heater with a minimum tank size of 40 gallons and minimum insulation value of R-12; and (5) an electric heat pump with a minimum 10 SEER for split systems or 9.5 SEER for package systems.

Homeowner's Energy Loan Program

CP&L developed the Homeowner's Energy Loan Program in 1981 to promote conservation of energy and demand reduction by providing convenient and inexpensive financing of conservation measures for residential homeowners.

In 1990, the Homeowner's Energy Loan Program was enhanced to promote further conservation by residential customers. The Company recognized the need to add additional conservation measures to allow residential customers to have more control over their power usage.

Under the expanded program, CP&L will loan a homeowner with approved credit up to $1500 for the installation of cost-effective conservation measures for homes with electric heat or whole-house air conditioning at 6% simple interest. The homeowner will have up to five years to repay the loan conveniently via the monthly power bill.

The approved measures are: ceiling insulation, wall insulation, floor insulation, duct insulation/modification, storm or double glass windows, storm or insulated doors, programmable heat pump thermostats, and energy-efficient water heaters.

Residential Energy Conservation Discount

Energy efficiency for new and existing residential structures is encouraged through several programs, such as the Common Sense Home Program, the Common Sense Plus Home Pilot Program, the Homeowner's Energy Loan Program, and the Residential High Efficiency Heat Pump Program. The options available through these programs enable customers to meet minimum thermal integrity and equipment efficiency requirements which qualify them to receive the 5% Residential Energy Conservation Discount. Under this program, the customers' monthly kW and kWh charges are discounted by 5%. The discount is an additional incentive to encourage energy efficiency.

Residential High-Efficiency Heat Pump Program

In 1990, the High Seasonal Energy Efficiency Ratio (SEER) Program was incorporated into the Residential High-Efficiency Heat Pump Program. CP&L's High-Efficiency Heat Pump Program includes low-interest customer financing for high-efficiency heat pumps, a Quality Heat Pump Dealer List, dealer incentives for high-efficiency installations and mass-media advertising to educate residential customers regarding high-efficiency heat pumps. The heat pump financing is tied to the SEER rating of the equipment purchased by the residential customer.

The Company recently increased the maximum allowable loan amount for the installation of heat pumps from $5,000 to $6,000. CP&L has also made over 3600 heat pump loans through December, 1991, of which approximately 80% had a SEER of 11 or greater, qualifying them for 6% financing.

EZ-$64 Program

The EZ-$64 program uses either radio or distribution line carrier (DLC) to interrupt residential customers' central air conditioners for up to four hours per day (maximum of 60 hours during cooling season) and/or electric water heaters for up to four hours per day throughout the year. Participants receive a credit of $2 per month for water heater control and an additional $10 per month ($13 for multiple units) from June through September for air conditioner control with the water heater option. A stand alone air conditioner option is also available offering the customer a discount of $8 per month ($11 for multiple units).

Residential Time-Of-Use

The Company offers two residential time-of-use rates which use financial incentives through rate design to encourage customers to shift load and usage to off-peak periods. Participating customers may choose an all-energy time-of-use rate or a time-of-use rate that contains both demand and energy components.

Commercial Thermal Energy Storage (TES) Program

The TES program emphasis is placed on customer education and working closely with HVAC design professionals and other business associates to make them aware of the various CP&L off-peak rates that are available for Thermal Storage applications. The program encourages the customer or his design professional or business associate to perform a payback calculation for the additional first cost expenses associated with a TES installation. These expenses will be offset through savings on the power bill via the appropriate time-of-use or thermal storage rate.

Commercial Energy Efficient Design

Building owners and agents are contacted early in the planning process to discuss the services and programs that are available from CP&L to assist in reducing peak demand and improving overall energy efficiency. Recommendations and proposals are made by Marketing Representatives and/or Power Engineers to customers and design professionals with respect to increased energy efficiency and load management. Specific measures recommended include: thermal integrity improvements, the use of energy-efficient lights, high-efficiency heating/air-conditioning equipment, and proper control devices.

Commercial Energy Analysis (Audit)

The Commercial Energy Analysis Program was implemented in 1985 for large commercial customers (200 kw and above). This emphasis was increased in 1987 to include smaller commercial customers with the implementation of a Simplified Energy Analysis (walk-through audit). Recommendations and proposals are made to the customer by marketing representatives and/or power engineers with respect to increased energy efficiency and load management in end uses such as HVAC, energy-efficient lighting, thermal envelope, and other end uses including operations.

Commercial Time-Of-Use Program (TOU)

The Time-of-Use Program provides an incentive for customers to shift load to off-peak hours through time-of-use rates which send price signals for customers to reduce on-peak load. Customers have found various ways to reduce on-peak load and shift usage to off-peak. Some of these include the use of timers, energy management systems, cool storage systems, alteration of work schedules, and other measures that are customized for a specific customer's operation.

Safeshine

Safeshine is a program that promotes Company-owned outdoor lighting for all retail customers. This off-peak, valley filling load improves the utilization of facilities and will help delay the need for future rate increases.

Industrial Audit/Energy Efficient Plants Program

CP&L Energy Engineers and Power Engineers have been conducting detailed energy studies and "walk-thru" audits system-wide since 1983. Applications addressed include energy-efficient lighting, motors and motor drives, HVAC design and optimization, and energy management systems. Actual on-site measurement supports engineering analysis and conclusions.

The same engineers work during the facility design phase as part of the Industrial Energy Efficient Plants component of this program. Objectives from both components include reducing peak load, load shifting, and strategic conservation. The Power Quality component was a 1990 program enhancement. Power Quality is an area of major importance to all our customers, especially our industrial customers. The goal of this program is to provide technical expertise to enable the Power Engineers to better serve our customers.

Industrial Time-Of-Use

Optional time-of-use rates are available to all industrial customers. Demand and energy charges are lower during specified off-peak hours. When feasible, time-of-use rates are used as tools by CP&L's Energy Engineers and Power Engineers in conjunction with the Industrial Audit/Energy Efficient Plants Program to reduce peak load and improve load factor and increase the economic efficiency of our customers.

Large Load Curtailment

Customers are provided an economic incentive to participate in this program, by receiving a monthly discount for each kilowatt subject to curtailment. For capacity type curtailments, customers are expected to reduce load or pay back to the Company a significant portion of discounts previously received. If the curtailment is economic in nature, customers decide whether to curtail or continue to operate at their contract demand level and pay a cents-per-kWh premium. This program is popular with customers who have the ability to increase and decrease significant loads in a short period of time.

Cogeneration & Hydroelectric

Company representatives work with industrial customers to identify feasible cogeneration potential. Cogeneration can be economically attractive to customers who have process steam requirements. In addition the Company also works with developers for projects to be installed and used as supply-side resources. CP&L technically assists entrepreneurs in reactivating abandoned hydroelectric generating sites in the Company's service territory.

Electrotechnologies

"Electrotechnology" describes an electric-based technology used by industrial customers to manufacture or transform a product. Information about electrotechnologies is conveyed by the Power Engineer during normal customer contact and by CP&L Engineers as part of the Industrial Audit Program. CP&L has participated with the North Carolina Alternative Energy Corporation in the establishment of the Industrial Electrotechnologies Laboratory (IEL) at North Carolina State University. The IEL will offer industry the chance to assess electrotechnologies in real processes.

Cogeneration - Economy C

There are significant savings to the Company in cycling generating unit costs and in avoided cost payments in split-the-savings arrangements with certain cogeneration projects. This type of arrangement is conducted on a real time cost basis.

The transaction is optional for both parties and is initiated by CP&L's Skaale Energy Control Center. The transaction, which can occur at any time, occurs primarily during the off-peak hours as defined in the avoided cost rate schedule of the purchase power agreements. The term of the economy transaction is recorded and the time of curtailment logged on an hourly basis. CP&L makes the request based on the expected time the curtailment period would last. However, CP&L reserves the right to request the cogenerator to return to normal power levels at any time. If the cogenerator does not return to normal power levels upon request or at the end of the curtailment periods, then the split-the-savings transaction ends and normal billing takes place, both for the purchase power agreement and for retail/standby requirements.

Target Business Recruitment

The Target Business Recruitment Program entails the recruitment of select, new industries with load characteristics compatible with CP&L's system characteristics and needs. Specific initiatives encompass (1) the identification of targeted industrial sectors and firms with typical load profiles compatible with CP&L's system characteristics and needs; (2) national advertising in select trade journals promoting the location advantages of regions within CP&L's service area; (3) development and implementation of direct mail campaigns directed toward targeted firms; (4) implementation of telemarketing efforts directed toward targeted firms to determine their interest in consideration of regions within CP&L's service area for a facility location; (5) targeting qualified firms in cooperation with state and local economic development allies; and (6) providing assistance to targeted firms considering a location within CP&L's service area.

Dispatched Power

The purpose of the Dispatched Power program is to encourage large customers to increase load when CP&L's loads and costs are low. The Company constantly monitors system generation cost and when such cost falls below a predetermined level, a signal is sent to participants informing them that they may increase their load above normal levels for six hours. Normal demand charges are waived for the incremental demands. This is Class 1 Dispatched Power.

Class 2 Dispatched Power is offered when the Company forecasts its available capacity will significantly exceed the expected load. Customers can increase their demands above normal levels during Class 2 periods, which normally last 24 hours. Normal demand charges do not apply during these periods, but instead, a small charge applies to incremental kilowatt-hours which are not off-peak.

Remote-Controlled Voltage Reduction

The Remote-Controlled Voltage Reduction System, which has a Peak Clipping load shape objective, will allow Carolina Power & Light Company to take full economic advantage of megawatts available through a voltage reduction. It is anticipated that a 2.5% voltage reduction will be used as a load management tool by the Energy Control Center without limitation as to frequency of use. The system will also be capable of a 5% voltage reduction as an emergency measure to reduce demand during critical peak periods.

The design and installation of a Remote-Controlled Voltage Reduction System started in 1991 and initially involves 62 substations. Present plans are to install regulator voltage control units and receivers in substations during 1991 and 1992 such that exiting communication facilities (DLC & VHF) are utilized. To obtain complete system coverage, additional communications will be required in 1993 and 1994. Preliminary locations for additional VHF Transmitter sites to provide complete system coverage have been identified.

Supply-Side Resources

Supply-side resources utilized by CP&L represent a diverse mix of generation technologies, fuel types, and ownership. CP&L's total generating resources currently consist of coal, oil, and nuclear generation, hydro facilities, purchases from other utilities, and purchases from non-utility generators such as cogenerators. The diversity of these resources demonstrates CP&L's commitment to minimizing risk and providing economical electricity to our customers. A brief description of CP&L's existing generating resources is given below.

Table 2-5 summarizes the total generating capacity of the CP&L system at the time of the 1991 peak. The capacity mix is also shown graphically in Figure 2-3. Figure 2-4 is a map of North Carolina and South Carolina, and shows the location of each of CP&L's facilities.

Nuclear Generating System

The CP&L system has four nuclear generating units located at three plants. The total nuclear maximum dependable capacity (MDC) is 3064 MW.

The Brunswick plant, located near Southport, North Carolina, consists of two boiling water reactors (BWR) of 767 MW and 754 MW each, for a total of 1521 MW. The Brunswick plant is jointly owned by CP&L and the North Carolina Eastern Municipal Power Agency (NCEMPA).

The Harris plant, located near Raleigh, North Carolina, consists of one pressurized water reactor (PWR) of 860 MW. The Harris plant is also jointly owned by CP&L and NCEMPA.

The Robinson plant, located near Hartsville, South Carolina, consists of one pressurized water reactor (PWR) of 683 MW.

Coal-Fired Generating System

The CP&L system has 19 coal-fired generating units located at eight plants. The total coal-fired maximum dependable capacity is 5285 MW.

The Asheville Plant is located near Skyland, North Carolina in the Company's western service territory. The plant consists of two units, 198 MW and 194 MW each.

The Cape Fear Plant is located near Moncure, North Carolina. The plant consists of a 143 MW unit and a 173 MW unit.

The Lee Plant is located near Goldsboro, North Carolina, and consists of three coal-fired units. The units are 79 MW, 76 MW, and 252 MW in size.

Table 2-5
CP&L Existing Resources
Capacity Mix
Year-End 1991

Type	Capacity Mix (%)	Number of Plants	Number of Units	Generating Capacity (MW)
Nuclear	29	3	4	3064
Coal	51	8	19	5285
Combustion Turbine	10	9	33	1046
Hydro	2	4	15	218
Purchases	8	36	—	848
Total				10461

Figure 2-3

CP&L CAPACITY MIX

SUMMER 1991

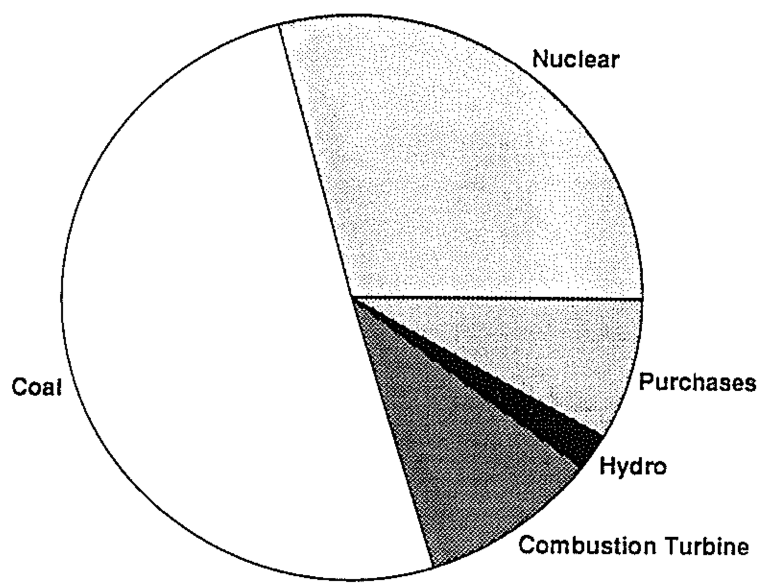
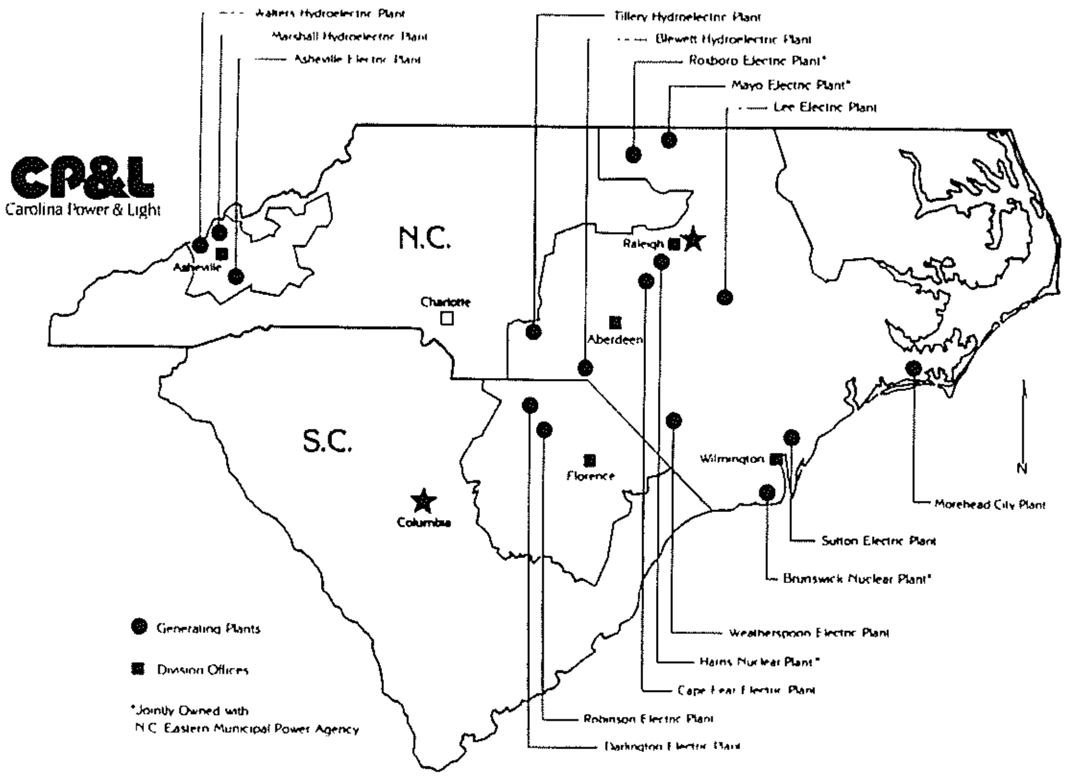


Figure 2-4



The Mayo Plant consists of one 745 MW unit and is located in Person County, North Carolina. The Mayo 1 unit is jointly owned with NCEMPA.

The Robinson Plant, located near Hartsville, South Carolina, has one 174 MW coal fired unit.

The Roxboro Plant consists of four units and is located near Roxboro, North Carolina. The units are 385 MW, 670 MW, 707 MW, and 700 MW in size. Roxboro Unit 4 is jointly owned with NCEMPA.

The Sutton Plant, located near Wilmington, North Carolina, consists of three coal fired units. The units are 97 MW, 106 MW, and 410 MW in size.

The Weatherspoon Plant consists of three units. Two of the units are 49 MW and the third unit is 78 MW in size. The plant is located near Lumberton, North Carolina.

Hydroelectric System

The CP&L system has four hydroelectric generating plants with a total generating capacity of 218 MW.

Both the largest and the smallest hydro facilities on the system are located in the Company's western service territory. The Walters Plant, located near Waterville, North Carolina has a capacity of 105 MW and has some storage capability. The Marshall Plant, also located in the Western Division, is a run-of-river facility with no storage and has a capacity of 5 MW. The Blewett and Tillery Plants are located in the eastern service territory. The Blewett Plant, located near Lilesville, North Carolina, has a capacity of 22 MW and the Tillery Plant, located near Mt. Gilead, North Carolina, is 86 MW in size.

Combustion Turbines

Combustion turbines play a vital role in the CP&L generating system. They provide a reliable source of electricity to service the peak needs of the CP&L customer demand. There are 33 combustion turbines (CTs) located at nine sites throughout the CP&L service territory. The total generating capacity of the CTs is 1,018 MW.

The largest CT plant is the Darlington Plant, located near Hartsville, South Carolina. The plant consists of 11 combustion turbines of 52 MW each, for a total of 572 MW. With the exception of the Morehead plant, which consists of one 15 MW turbine, all of the other CTs are located at other CP&L plant sites. The Blewett hydro plant contains 52 MW of combustion turbines. The Cape Fear plant has 56 MW of CTs; the Lee plant has 91 MW; both the Robinson and the Roxboro plants have 15 MW turbines; the Sutton plant has 64 MW of CTs; and the Weatherspoon plant has 138 MW of CTs.

When economical, the waste heat from two of the Cape Fear combustion turbines is used to generate steam. This steam is then used to generate an additional 28 MW from existing steam turbines located at the Cape Fear plant.

Purchased Power

There are two basic categories of purchased power options. Those are utility purchases where power is purchased from another electric utility and non-utility purchases where power is obtained from cogenerators, small power producers, and Independent Power Producers (IPPs). Both of these categories play a significant role in CP&L's Resource Plan.

Non-Utility Generation
CP&L has been very successful integrating non-utility power sources into its system and into both the demand-side and supply-side planning of the Company.

On the demand-side there is displacement cogeneration that is associated with manufacturing processes that either use process steam or generate waste heat. Industries such as pulp and paper, textiles, and chemical are typical examples. Displacement cogeneration is used by the industries themselves and is not sold to CP&L. This type of cogeneration is included in the resource plan as a demand-side resource because the effect of displacement cogeneration is to reduce the load on CP&L's system. CP&L has helped identify new displacement cogeneration potential by making proposals in conjunction with energy audits as part of the Company's intensified Conservation and Load Management Program that was initiated in 1981. CP&L continues to aid its industrial customers in identifying and enhancing their cogeneration potential.

On the supply-side, capacity has been obtained from various industries and entrepreneurs electing to sell the electric power to CP&L. This has been done through the standard avoided costs rates filed and approved by the North Carolina Utilities Commission and the South Carolina Public Service Commission and also through rates that are negotiated with the developer and the contracts then filed for review and approval by the Commissions. Various cogeneration and small power production project proposals are periodically presented to CP&L for consideration. They typically range in size from one or two megawatts to over one hundred megawatts. These proposals are reviewed by CP&L and consideration is given to such factors as price for energy and capacity, dispatchability, and the point in time when the project would come on line. A list of current and planned non-utility purchases is given in Table 2-6.

Utility Purchases
From time to time, opportunities to make long-term purchases of firm capacity from other utilities become available to CP&L. Long-term purchases can in general be classified as either unit power or system power. Unit power is purchased from a specific power plant. System power is purchased from the selling utility's overall system mix. These proposals are routinely screened to determine their economic and technical feasibility. The effect of proposed purchases on the transmission system is an extremely important factor which must be considered in evaluating the cost and feasibility of a purchase from another utility. Those purchases which merit further consideration are evaluated along with other resources in developing the resource plan.

The North Carolina Eastern Municipal Power Agency (NCEMPA) has arranged to purchase power from the South Carolina Public Service Authority (SCPSA). NCEMPA has notified CP&L of its plans to purchase the following amounts of SCPSA capacity: 77 MW from 1992 to 1993, 100 MW from 1994 to 1997, and 50 MW during 1998. NCEMPA has also notified CP&L of its plans to install approximately 150 MW of combustion turbine peaking capacity in 1995. This power will be available to supply the combined CP&L/NCEMPA load and is, therefore, included in CP&L's Integrated Resource Plan.

Table 2-6
Non-Utility Purchases
(as of December 31, 1991)

Name/Location	On-Line Output kW	Technology	On-Line Date
Rocky River/Chatham County	180	Hydroelectric	06/82
American Hydro/Montgomery Co.	990	Hydroelectric	06/83
Darrell Smith/Princeton, NC	80	Methane Digester	07/83
Catalyst Energy/Montgomery Co.	815	Hydroelectric	09/83
Deep River Hydro/Coleridge, NC	500	Hydroelectric	09/83
Upchurch Mill Dam/Raeford, NC	800	Hydroelectric	10/83
Bruce Cox/Randolph Co.	400	Hydroelectric	01/84
Natural Power/Raleigh, NC	170	Landfill Methane	06/84
New Hanover County/Wilmington, NC	7,500	Waste Incineration	08/84
Cook Industries/High Falls, NC	600	Hydroelectric	09/84
Texasgulf/Aurora, NC	42,000	Process Heat Recovery	12/84
Carbonton Assoc./Carbonton, NC	1,100	Hydroelectric	01/85
Solar Research Corp./Raleigh, NC	670	Hydroelectric	02/85
L & S Hydro Power/Franklinville, NC	550	Hydroelectric	08/86
K & K Hydro/Richmond County	300	Hydroelectric	04/85
Lockville/Moncure, NC	1,500	Hydroelectric	01/86
Christiansted/Mitchell County	80	Hydroelectric	09/85
Bill Wrenn Hydro/Chatham County	15	Hydroelectric	01/86
Cogentrix/Elizabethtown, NC	35,000	Coal Fired	01/86
Cogentrix/Lumberton, NC	35,000	Coal Fired	04/86
Cogentrix/Kenansville, NC	35,000	Coal Fired	04/86
P. K. Ventures/Bynum, NC	500	Hydroelectric	03/86
Lake Industries/Richmond County	325	Hydroelectric	12/86
Stone Container/Florence, SC	68,000	Coal Fired	03/87
M.S.D./Buncombe County, NC	700	Hydroelectric	12/86
Madison Hydro Partners/Jupiter, NC	1,200	Hydroelectric	03/85
Cogentrix/Roxboro, NC	53,900	Coal Fired	08/87
Cogentrix/Southport, NC	106,700	Coal Fired	09/87
House-Autrey/Spring Hope, NC	150	Hydroelectric	12/86
Foster Wheeler/Charleston, SC	8,700	Refuse	11/89
Craven Co. Wood/New Bern, NC	45,000	Wood Waste	10/90
Lake Junaluska/Lake Junaluska, NC	225	Hydroelectric	07/91
Biomass Energy/Asheboro, NC	4,400	Wood Gasification	12/88
Bullock Ind./Cedar Falls, NC	250	Hydroelectric	01/90

Name/Location	Planned Output kW	Technology	Projected On-Line Date
M.S.D./Buncombe County, NC	1,800	Hydroelectric	1992
ADM Company/Southport, NC	5,000	Oil/Gas Fired	1992
Bruce Cox/Worthville, NC	300	Hydroelectric	1992

CP&L has agreements with two utilities for the purchase of power. An agreement with American Electric Power (AEP) provides for the purchase of 250 MW of unit power from AEP's coal-fired Rockport 2 generating unit. This purchase continues through the year 2009. In 1991, CP&L settled a dispute with Duke Power Company regarding certain provisions of service Schedule J, which is a part of the CP&L-Duke Interchange Agreement. As a result of this settlement, the Company's 400 MW purchase agreement with Duke Power Company, previously scheduled for 1992-1997 is now scheduled to begin July 1, 1993 and to end June 30, 1999.

CP&L intends to continue to evaluate purchase power options as they become available. As load continues to grow nationally and with few utilities constructing new generating capacity, the opportunities to make long-term purchases from other utilities are expected to diminish rapidly.

In addition to long-term purchases, CP&L has established operating agreements with neighboring utilities including the VACAR member companies, TVA, and Appalachian Power Company for emergency assistance, economy interchange, and short-term capacity and energy exchanges. These types of short-term and non-firm power exchanges are extremely valuable for reducing power costs and maintaining reliable service. However, these purchases cannot replace the need for firm capacity in the resource plan.

Southeastern Power Administration

In addition to the above power purchases, CP&L has two contracts with the Department of Energy acting through the Southeastern Power Administration (SEPA). Under these contracts, CP&L delivers power from federal hydroelectric projects to preference customers of the government located in CP&L's control area. Preference customers include municipalities, electric membership cooperatives, and other public bodies. These customers receive allocations of capacity and energy from the projects as determined by the government. CP&L receives 14 MW from the Cumberland hydro projects at its western interconnections and delivers 12.3 MW to preference customers in the western service area. CP&L receives 95 MW of power at its eastern interconnections from the Kerr hydro project and delivers 76.4 MW to preference customers in CP&L's eastern area. The difference between power delivered to the interconnections and that which is delivered to the preference customers is provided to CP&L as compensation for transmission losses, backstand, and administrative services.

Plant Modifications and Retirements

For many years CP&L has utilized its maintenance programs to keep its units in the most up-to-date and the best operating condition that is economically reasonable. These maintenance programs deal both with replacement of worn parts to restore equipment to its original condition and with replacements intended to upgrade the equipment to a more reliable and more efficient condition. Because of this type of program, CP&L has no plans for major comprehensive life extension projects.

Key elements of our ongoing maintenance/testing programs are:

- Periodic inspection, overhaul, repair, and/or refurbishment of turbines and generators. Overhaul frequencies range from 5-7 years dependent on factors such as operating experience, equipment performance, industry experience, vendor recommendations, etc.

- Annual boiler inspection and periodic overhauls/repairs/refurbishment based on operating experience, vendor recommendations, industry experience, etc.

- Annual and 10-year inspections of nuclear facilities as part of an ongoing in-service inspection program.

- Periodic inspection, testing, and maintenance of other major equipment based on established periodic testing, preventive maintenance, and predictive maintenance programs.

One-year and five-year maintenance schedules are developed annually for our generating units. These schedules are periodically reviewed and adjusted as appropriate based on system conditions/needs, unit operating performance, etc.

The process of continually maintaining generating units, in conjunction with new test data and changing regulatory requirements, occasionally results in some uprating or derating of facilities. Units are periodically reviewed to determine if their capability ratings need to be revised; however, the overall impact on the resource plan of these changes is expected to be minimal.

The maintenance programs utilized by CP&L have allowed the Company to operate its units longer than their 30-40 years expected life. CP&L believes that continued maintenance will allow its plants to operate indefinitely. Thus, CP&L currently has no plans to retire any generating units.

Resource Options

The second step in the Integrated Resource Planning Process is the identification of future potential demand-side and supply-side resource options. CP&L has investigated and continues to research a wide variety of resource options. The Company has identified the most cost-effective resources that can be added to the existing system. The following section describes the portfolio of resource options, both demand-side and supply-side, considered by the Company in the development of the Integrated Resource Plan.

Demand-Side Options

Potential Options

CP&L is developing and studying an array of potential demand-side management (DSM) programs and pilots. Table 2-7 provides a list of DSM programs under development along with the associated load shape objectives. Refer to Appendix E for descriptions of these potential DSM options.

Research Activities

In addition to demand-side management programs being developed, enhanced, and offered to our customers, CP&L is also undertaking research that will improve our knowledge of demand-side management as well as assist in the development of demand-side management programs. The research activities currently taking place are listed below:

- Evaluating The Impact Of CFC Regulation
- Commercial Scale Thermal Energy Storage Test
- Heat Pump Monitoring For Demand-Side Management

Refer to Appendix E for descriptions of these research activities.

DSM Planning Enhancements

CP&L is also addressing improvements and enhancements in the planning process. Activities in this area include (1) Marketing End-User Database, (2) Residential Market Segmentation, (3) DSM Technology Research, and (4) Integrating DSM into T&D Planning. Descriptions of these activities are located in Appendix E.

Table 2- 7

Residential		
	High Efficiency Water Heater	Strategic Conservation Peak Clipping
	Appliance Turn-In	Strategic Conservation
	Residential Cool Thermal Storage	Load Shifting Valley Filling
Commercial		
	Cool Schools - 2000	Strategic Conservation Valley Filling Strategic Load Growth
	Thermal Energy Storage - Schools	Load Shifting Valley Filling
	Commercial Heat Pump	Strategic Conservation Valley Filling Strategic Load Growth
	Commercial Load Control	Peak Clipping
	Heat Pump Water Heaters	Strategic Conservation Valley Filling Strategic Load Growth
	Energy-Efficient Lighting	Strategic Conservation
Industrial		
	Small Load Curtailment	Peak Clipping

Supply-Side Options

Portfolio of Options

In developing the supply-side portfolio of options, planners continually review generating technologies and keep abreast of technological advancements by reading industry literature and attending conferences. For this cycle of the planning process, a wide range of alternatives, including conventional generation technologies, alternative technologies, and cogeneration were identified to be a part of the supply-side portfolio.

Conventional technologies include coal-fired, oil/gas-fired, nuclear, and storage technologies. Although some advanced technologies such as batteries and compressed air energy storage (CAES) are included, this group is composed primarily of technologies which have been proven through years of commercial operation.

Another category of generic supply-side options includes plants that generate electricity using renewable resources or waste materials. For the most part, these alternative technologies have not been employed on as large a scale as the conventional technologies to date.

The other supply-side technology included in the portfolio is cogeneration. Though it is difficult to project when and how much cogeneration will be available, this technology is playing an increasingly important role in CP&L's future and must be given consideration within the integrated resource planning framework.

The options that make up the supply-side portfolio are listed in Table 2-8. These technologies are described in more detail in Appendix E.

Table 2-8
Supply Options Selected for Screening

ALTERNATIVE GENERATION TECHNOLOGIES

Technology: Geothermal

Flash Steam Cycle
Dry Steam

Technology: Ocean Energy

Tidal Energy
Ocean Thermal Energy Storage
Wavepower
Ocean Current Turbines
Salinity Gradient Devices
Ocean Wind Turbines

Technology: Photovoltaic

Flat Plate
Concentrator

Technology: Solar Thermal

Solar Parabolic -
Through/Gas Hybrid

Technology: Wind

250 kW Turbine
2.5 MW Turbine

Technology: Municipal Waste

Mass Burn
Refuse Derived Fuel (RDF)

Technology: Biomass

Peat
Waste Wood

CONVENTIONAL GENERATION TECHNOLOGIES

Technology: Coal

Scrubbed Pulverized Coal
Pressurized Fluidized Bed
Coal Gasification -
Combined Cycle

Technology: Nuclear

Adv. Light Water Reactor -
Passive Safety

Technology: Combustion Turbine

Simple Cycle
Combined Cycle
Simple Cycle with Air Cooling

Technology: Storage

Pumped Hydro
Compressed Air Energy Storage
Battery

Technology: Fuel Cell

Phosphoric Acid

Technology: Purchased Power

Cogeneration A - Peak
Cogeneration B - Base Load

Environmental Impacts of Options

The environmental impacts of both demand-side and supply-side options are taken into consideration in the evaluation of resources available for the Company. The impacts are considered on both a quantitative and qualitative basis. This section discusses the impacts and standards associated with resource options. Appendix F provides a discussion of the methodology used to include the costs of environmental compliance in the Integrated Resource Planning process.

Demand-Side Options

The screening, evaluation, and selection of demand-side management options in the least cost integrated resource planning process is comprised of numerous factors one of which is environmental issues. Environmental issues cover more than the customarily thought of reduction or increase of emissions from coal-fired power plants. With regard to demand-side management options, questions surrounding indoor air pollution, disposal of less efficient appliances, CFC emissions, and the release of mercury and PCBs surface. In other words, just like supply-side resoources, demand-side management options have the potential of both positive and negative environmental impacts.

Demand-side management options designed to promote conservation through upgraded insulation and other thermal efficiency measures reduce the consumption of electricity and therefore reduce emissions. These conservation measures may also influence indoor air quality.

Energy-efficient appliances and lighting produce the same results for the consumer as less efficient products, but use less electricity and cause less emissions. The proper disposal of less efficient appliances and lighting must be considered in order to mitigate potential negative environmental impacts, e.g., the escape of CFCs into the atmosphere from compressors and insulation found in refrigerators. CP&L will be investigating the impact and cost-effectiveness of an appliance turn-in program for the disposal of appliances replaced by higher efficiency appliances. The Company is also taking into consideration the proper disposal of lights to mitigate the release of mercury and PCBs, in the development of energy-efficient lighting programs.

Supply-Side Options

Complying with environmental regulations increases the cost of new generation facilities. The costs associated with complying with existing regulations are incorporated into the planning process in several ways. Where quantifiable, the costs are included as part of the cost of the resource option. Otherwise, the impacts are considered in a qualitative manner.

Environmental Standards for Conventional Generation Technologies

The construction of new power plants requires that a whole host of environmental regulations and standards be met. There are also many regulations which require compliance when constructing any facility, be it a power plant or an apartment building. The purpose of this section is to identify some of the general environmental standards that apply to conventional generation technologies such as coal-fired, combined cycle, and combustion turbine units. The general standards that apply are divided into the categories of air, water, and waste. By no means is this section an exhaustive list of environmental standards and regulations, as that goes beyond the scope of this text.

Air Standards

Air permitting of coal-fired boiler, combined cycle, and simple cycle combustion turbine new generation requires both New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) review for primary pollutant standards and screening/review for toxic air pollutants (TAPs).

Coal-Fired Boilers

The NSPS standards for particulate matter (PM), opacity, SO_2, and NO_x emissions for boilers burning coal can be found in Table 2-9.

Table 2-9

Emission Standards for NSPS Coal-Fired Steam Generators (lb/MBtu)

PM	0.05
Opacity	20%[a]
SO_2	1.20[b]
NO_x	0.70

[a] Except for one six-minute period per hour of not more than 27% opacity.
[b] And is 10% of the potential SO_2 emission rate (90% reduction), and that contain SO_2 in excess of the emission limit determined by the formula found in 60.42b(a) of 40CFR60 (see formula below) if both coal and oil are burned simultaneously.

$E_s = (K_a H_a + K_b H_b) / (H_a + H_b)$, where
E_s is the sulfur dioxide emission limit, in lb/million Btu heat,
K_a is 1.2 lb/million Btu,
K_b is 0.8 lb/million Btu,
H_a is the heat input from the combustion of coal, in million Btu,
H_b is the heat input from the combustion of oil, in million Btu.

Although no federal hazardous air pollutant (HAP) regulations currently exist, both North Carolina and South Carolina have promulgated toxic air pollutant (TAP) standards. North Carolina requires review and compliance with 105 TAPs. South Carolina requires no review provided only clean unadulterated fuels are burned.

Combined Cycle and Simple Cycle Combustion Turbines

The NSPS standards established for SO_2 and NO_x emissions from combined cycle and simple cycle stationary gas turbines are determined by calculations that take into account the nitrogen and sulfur components of the fuel (percent by weight), the heat rate of the unit, and ambient conditions. The empirical calculations and constant definitions can be found in Subpart GG of the NSPS regulations.

Water Standards

The only environmental standards related to water that apply to electrical generation exclusively are the federal Effluent Guidelines and the New Source Performance Standards (NSPS) applied to the National Pollutant Discharge Elimination System (NPDES) permit for the discharge of wastewaters to waters of the U.S. These apply only to steam electric power generation, and therefore, do not apply to any generating facility that generates electricity without steam (e.g., combustion turbines or hydroelectric).

Waste Standards

The NSPS apply to several different categories of waste streams. These streams and the required limits are listed in Table 2-10. In addition to the limits in Table 2-10 (which are based on best available technology), new steam electric generating facilities are, like any other wastewater discharges, subject to NPDES limits based on the effect of the discharge on the quality of the receiving water.

General Standards

Electric generating facilities must also comply with the same requirements with which all new facilities of any type must comply. Table 2-11 lists the general types of requirements that must be met.

Table 2-10
NSPS Waste Stream Limits

Waste Stream	Pollutant	Limit	
Any	PCBs	0	
	pH	6-9	
Cooling tower blowdown	126 priority pollutants	0	
	Chromium (total)	0.2 mg/l	
	Zinc	1.0 mg/l	
	Free Available Chlorine (discharge cannot exceed 2 hours/day)	0.5 mg/l maximum 0.2 mg/l average	
Fly ash transport water sources	Any	0 (dry fly ash handling must be used)	
Low volume waste	Total Suspended Solids	100 mg/l max for one day 30 mg/l avg for 30 days	
	Oil and Grease	20 mg/l max for one day 15 mg/l avg for 30 days	
Bottom Ash Transport Water	Total Suspended Solids	100 mg/l max for one day 30 mg/l avg for 30 days	
	Oil and Grease	20 mg/l max for one day 15 mg/l avg for 30 days	
Once-through cooling water	Total Residue Chlorine	0.2 mg/l maximum	
Chemical metal cleaning		1 day max (μg/l)	30-day avg (mg/l)
	Total Suspended Solids	100	30
	Oil & Grease	20	15
	Copper	1.0	1.0
	Iron	1.0	1.0

Table 2-11
General Requirements for All New Facilities of Any Type

Water-related Permits/Approvals
NPDES Permits
Clean Water Act Section 401 Certifications
Clean Water Act Section 404 Permit
Rivers and Harbors Act Section 10 Permits
Authorization to Construct
Sedimentation and Erosion Control Plan (N.C.)
Stormwater and Sediment Control Plan (S.C.)
Stormwater Discharge Permit
Facility Stormwater Permit
Stormwater Runoff Determination
Public Water Supply Standards
Ground Water Quality Standards

Waste-related Permits/Approvals
Solid Waste Management Permit
Waste Not Discharged to Surface Waters Permit
Hazardous Waste Treatment, Storage, and Disposal Permit

Miscellaneous Standards
Underground Storage Tank Standards
Well Construction Standards
Coastal Area Management Act Permit (N.C.)
Emergency Planning and Community Right-to-Know
Hazardous Waste
Noise Abatement
Cultural/historic Resources

Environmental Impacts of Alternative Generation Technologies

CP&L takes into consideration the environmental impacts of alternative generating technologies; however, in some cases, the environmental impacts and costs of a technology are hard to quantify. In these cases, qualitative consideration of the impacts is given. Below is a summary of the environmental impacts taken into consideration when evaluating alternative technologies.

Wind
In its 1987 study, the North Carolina Alternative Energy Corporation found that the development of the wind energy resource may by inhibited by institutional and environmental factors such as visual and acoustic impacts. Television interference has been a problem at windpower installations near residential areas. As for visual impacts, a National Economics Research Associates (NERA) study states that "lovers of unspoiled scenery regard [wind farms] with the same animosity they have for transmission lines."

Municipal Waste
While municipal waste plants generate very little sulfur dioxide emissions compared to coal burning plants, the high content of plastics and metals found in municipal waste results in the potential for generation of hydrochloric acid and unacceptable high levels of heavy metals such as cadmium and lead in the fly and bottom ash. Reports from a sample of incinerators found that bottom ash exceeded Federal environmental standards for lead and cadmium about one-third of the time and fly ash exceeded the limits more than 95% of the time.

Peat
There are several environmental challenges associated with peat harvesting. Air quality is affected by dust from the peat collection process and from storage piles. Surface and ground water quality and streamflow characteristics can also be impacted by peat harvesting according to EPRI.

Wood
While most wood plants use waste wood residues for the fuel source, another source of fuel is forest harvesting and regeneration. This is a complex process requiring coordination between harvesting and reforestation programs and requires consideration of a number of environmental impacts on wildlife and soil stability.

Solar
The biggest environmental concern associated with solar technologies is the amount of land required for a multi-megawatt scale application. The Battelle Institute estimates that nine acres of land are required per megawatt. The Office of Technology Assessment foresees a range of four to 37 acres per megawatt, depending on the type and efficiency of the technology.

DSM Process

This section describes the DSM process used to develop the recommended DSM options. The process consists of objectives, program development and evaluation, and monitoring.

Objectives

The development of demand-side options is a dynamic process that begins with analysis of the corporate situation, continues with formulation of overall demand-side management objectives and leads to development of a strategy to meet these objectives. Since the corporate situation changes over time, the objectives and strategy are periodically reviewed. The analysis of the corporate situation considers such factors as current achievement of existing demand-side programs, customer needs and expectations, and the Company's financial situation, growth trends and capacity and energy costs.

The plan to reach these objectives can be characterized in terms of size, mix, pace, and cost. It is composed of a mix of load shape objectives and programs in the residential, commercial and industrial sectors. The diversity in the demand-side management portfolio reduces the effects of uncertainty. The load shape mix consists of strategic conservation, load shifting, peak clipping, valley filling, and strategic load growth. The pace can be adjusted up or down depending on progress to date, customer acceptance, anticipated program enhancements, and expected business conditions. The cost at which the objectives can be achieved is monitored and compared with costs of supply-side options.

Program Development and Evaluation

Individual programs that comprise the DSM portfolio are managed through a process that allows for systematic development and evaluation. As programs progress through development and evaluation, they become increasingly specific in their definition - target market, qualifications, marketing approach, program cost, and expected results. Questions covering areas such as the economic costs and benefits of the program, customer acceptance, and the market potential are investigated.

Economic Costs And Benefits

With regards to the economic evaluation of costs and benefits of demand-side management options, Carolina Power & Light Company seeks to develop and promote cost-effective demand-side management programs which tend to improve system load factor, increase the utilization and efficiency of existing capacity, minimize the need for future generating capacity, provide downward pressure on the level and frequency of future rate increases, ensure customer satisfaction, and support continued sound economic growth within its service area.

These objectives when viewed individually can be thought of as evaluating demand-side management options from different perspectives. Each of these perspectives is represented by its own economic test. The four economic tests are known by the following names 1) the Utility Cost Test, 2) the Ratepayer Impact Measure (RIM) Test, 3) the Participant Test, and 4) the Total Resource Cost (TRC) Test.

These four economic tests are measures of cost-effectiveness, weighing the benefits against the costs of a demand-side management option. However, since each test represents a different perspective, the assignment of benefits and costs vary for each test. The costs and benefits components measured for input to these tests include supply costs, utility program costs, participant costs, changes in revenues to the utility or changes in bills to the participant, incentives paid to participants and participation charges paid to the utility.

Supply costs are comprised of capacity and energy costs. Capacity costs are measured on a marginal basis and can include generation, fixed O&M, transmission, and distribution costs depending on the program. Energy costs are also measured on a marginal basis and include fuel, variable O&M, and line losses. These avoided costs are the basis for determining payments to cogenerators and small power producers. This use of common avoided costs insures that supply-side and demand-side management options can compete head-to-head so as to produce a least cost integrated resource plan. For a further discussion on the development and use of avoided costs methodology refer to Appendix C.

Utility program costs consist of any expense required to implement the program. This varies by program but typically includes up-front equipment, installation and customer contact costs, periodic O&M expenses, advertising and promotional materials such as brochures, bill stuffers, media costs, posters and displays, and any additional administrative costs that would not have occurred without the program. CP&L has a cost tracking system in place which accurately captures the specific costs associated with each demand-side management program. This system enhances our ability to manage and account for our costs more effectively, provides an improved audit trail, and serves as valuable input to evaluate the economic feasibility of DSM programs.

Any out-of pocket expenses incurred by a customer as a result of participating in a demand-side management option, such as equipment costs, and operation and maintenance costs, are considered participant costs.

The remaining costs, which include changes in revenues to the utility or bills to the participant, as well as incentives paid to the participant and participation charges, are based on Carolina Power & Light Company's rate schedules and riders. Changes in revenues or bills are those increases or decreases associated with responses to demand-side management options. For example, the utility would experience a revenue loss and the participant, a bill reduction as the result of a strategic conservation program. Conversely, valley filling and strategic load growth demand-side management options would result in a revenue gain for the utility and a bill increase for the participant. Customers will participate in those programs for which value received is greater than the increased cost. Incentives are dollar amounts given to a customer for his participation in a demand-side management option. Incentives are sometimes used as a vehicle for encouraging program participation. Participation charges, on the other hand, are dollar amounts paid by the participant to the utility as a requirement of program participation. Such charges help offset program costs.

The output of these four economic cost-effectiveness tests is a Net Present Value (NPV) and is used as a directional indicator of the long-term economic feasibility of a program. NPV is an important criteria for selecting demand-side management options to be included in the least cost integrated resource plan. However, other factors such as market potential, technical feasibility, impact on Company operations and reliability, environmental issues and regulatory concerns must also be considered. Also, the Company's business environment, costs and load shape objectives may change over time. Utilities must also take into consideration factors not explicitly accounted for in cost-effectiveness evaluation of demand-side management options, such as budget constraints, the urgency of load reduction, customer satisfaction, and regulatory mandates. Thus, a program might have a negative NPV but still be carried forward and a final decision made on the basis of all criteria.

A detailed discussion of the four economic cost-effectiveness tests mentioned above is contained in Appendix D. Appendix D also contains the results of the economic tests used in the study of the cost-effectiveness of CP&L's demand-side management options.

Customer Acceptance

Customer acceptance is an important component in the development and review of demand-side management options. Communications with our customers provide a vehicle for customer acceptance which is a vital factor in the success of our demand-side management efforts. CP&L utilizes varying communication forums to interact with customers. Our advertising and promotional materials such as brochures, bill stuffers, posters and displays educate the customers with regards to the benefits of the programs and encourage participation. CP&L also provides ongoing opportunities for exchange with customers from all classes and continues to actively seek input from a variety of perspectives about program options, enhancements or changes.

Customer Focus Groups are held to gather information and understanding of CP&L's residential DSM programs and associated advertising. These focus groups representing a broad cross-section of residential customers, provide valuable insight into customer needs which are factored into our DSM strategy and programs.

CP&L has also held periodic meetings with groups of large commercial and industrial customers to obtain customer feedback and input. Such meetings provide an update on the status of current issues and operating conditions which affect the Company and to get input on customer needs.

Market Potential

Forecasting the performance of DSM programs is conceptually similar to forecasting the performance of products found in many other industries. Success is driven by such factors as market size, product design and promotion, industry structure and competition and the level of economic growth and other relevant macro-economic variables.

These factors are processed in a varying conceptual framework to forecast the expected participation over time. Forecasting frameworks vary from simple routine judgements and opinions to sophisticated econometric models. The appropriate framework depends upon the nature of the product and the industry, data availability, and forecast horizon.

For CP&L's DSM programs, the forecasting method requires a long-run focus represented by a relatively smooth path of energy sales over time. It must also be consistent with the characteristics of durable goods and have the flexibility to accommodate programs with several years of experience as well as brand new programs with no historical data.

The methodology uses diffusion curves to model how new products or technologies are disseminated into the market place. It's part of a more general classification of methodologies which has been referred to as "technological" forecasting. This technique is consistent with the requirements above, is well established in marketing and economic theory, and has been applied to many industries, including utilities.

Under this methodology the penetration or diffusion of a new product over time is expected to follow some specified functional form. This form is often an S-curve or "learning curve," but can also be other functions such as exponential, logarithmic or double exponential to name a few.

The S-curve depicts product sales to be moderate at introduction, accelerate as awareness grows and the technology becomes more accepted in the industry, slow down again as more of the core customers have already been sold, and finally reach a point of saturation or long-run stability.

In practice each DSM program is forecasted by (1) identifying the target market, its size and growth, (2) specifying a model or functional form for the diffusion curve and (3) estimating the shape of the curve using limited historical data on product sales, a variety of marketing research techniques, or other available information such as the penetration of similar products.

Monitoring

CP&L feels it is critical to be able to measure, verify and document the achievement of demand-side management programs. At CP&L the megawatt achievement is monitored through an extensive tracking system once a program is implemented. Many of the residential programs are tracked with an on line computer system tied to each field office. In this system customer contact personnel automatically record details on demand-side management program participation for each customer. This information becomes part of a customer data base which also includes billing information as well as other service details.

An important point is that the customer accounting system provides a record of demand-side management program achievements tied to specific customer accounts. It also ensures that demand-side management program results are net of any program dropouts.

Commercial and industrial programs are typically monitored by on-site inspections by field engineers. Detailed implementation reports are submitted for each customer action, reviewed by staff energy engineers, and also recorded by customer account. For some industrial programs the load reductions are also verified by actual hourly metered data.

In order to centralize information about the progress of DSM programs, CP&L has undertaken a project to develop a database system called the Marketing Database System. The Marketing Database System is a continuously evolving system which provides an efficient structure for collecting, storing, and processing relevant data needed for planning, evaluating, and tracking DSM programs. The on-going project to develop the system has been defined in stages to ensure the feasibility, completeness, and efficiency of the system's functionality. Stages that have already been completed include: (1) defining DSM/Marketing needs and functions; (2) developing a working data model; (3) determining data entities, attributes, inputs, and outputs; (4) designing, developing, and testing the database structure; (5) developing data entry, reporting, and maintenance functions; and (6) populating and testing the system. The Marketing Database System is now operational and produces a monthly report on the year-to-date progress of the DSM programs. Currently under development are functions that will provide the capabilities to enter and retrieve DSM program data at the field offices. The system will also include a user-friendly, menu-driven interface to guarantee the useability of the system as well as security measures to protect the integrity of the data. The Marketing Database System will be expanded in later stages to provide additional functionality to be defined as the system grows.

Another important component in the monitoring of DSM programs is the tracking of utility program costs. Historically, DSM costs have been tracked on a sector basis (Residential, Commercial, Industrial). CP&L's ability to continue to manage and account for costs in this manner has grown increasingly difficult. In June, 1990 a project team was formed to develop a cost tracking system to account for each DSM program's expenses. Major cost components for each program were reviewed carefully and a methodology was developed to capture each of the identified costs. Procedures for administering the system were written and distributed in April, 1991 when the system was formally implemented. The system provides an organized approach to collecting costs from a wide range of sources and accounting for associated program expenses such as financial incentives (where applicable), market research, labor, advertising, travel, equipment, computer expenses, etc. It also provides CP&L with enhanced data for evaluating existing and potential DSM programs and making decisions on program cost effectiveness. Cost data is collected on a quarterly basis and distributed in a report which includes capital, labor, and operating & maintenance expenses incurred for each DSM program.

Supply-Side Screening Analysis

The screening analysis of the supply-side options identifies the generation technologies available to CP&L and determines which technologies merit further consideration in developing the Company's resource plan. The inputs to the screening analysis are (1) a list of supply options available to the Company, and (2) the associated data and assumptions for each of the supply options. The technologies identified are then subjected to a three-level screening process.

The first level screening is based on the availability of the various resources supplying the different technologies. Each technology is evaluated based on the question, "Is the required resource available in the CP&L service area?" Any technology requiring a resource not available in the CP&L service area is eliminated from further consideration.

The second level screening is designed to evaluate whether the technology will be available in the relevant time frame defined by CP&L's resource needs. The technologies that remain after the first level screening are evaluated against the question, "Does the estimated commercial date plus licensing and construction lead time occur before the year 2002?" Only those technologies meeting this requirement are retained for further analysis.

The purpose of the third level screen is to identify which of the technologies that have survived the non-financial screens are competitive with other technologies on a $/kW-Yr. basis in 1995. This comparison is accomplished using screening, or busbar, curves.

In the screening curve analysis the technologies are divided into two broad categories based on expected capacity factor in order to simplify the analysis. Those technologies with expected capacity factors of less than 20% form one group and those with expected capacity factors of greater than 20% form the second group. Those technologies in each capacity factor grouping found to be competitive on a busbar cost basis are retained for further analysis. Appendix E presents a detailed description of the results of the screening analysis.

Plan Development

In the Plan Development step of the process, a number of expansion plans are developed using the resources that pass through the screening analysis. Additional inputs to this step on the supply side are existing resources and planned resources that are not yet in service. On the demand side, existing and planned reductions in load and energy are included by being a part of the peak load and energy forecasts which are inputs to this step. Using these inputs, as well as other data and assumptions (such as the operating characteristics of the generating units and fuel price projections), optimal plans based on minimizing the present value of revenue requirements are developed. Different candidate resource plans are developed using different combinations of resource options that are passed on from the screening analysis.

Alternative resource plans are developed in accordance with certain planning principles which serve as a framework for the evaluation of the plans. These planning principles are:

1) Maintain flexibility to adjust to changing conditions;

2) Develop capacity requirements to meet a specified reliability criteria;

3) Emphasize resource diversity as an appropriate response to future uncertainty;

4) Avoid excess reliance on oil and natural gas fueled resources.

Reliability Criteria

A critical factor in developing the Integrated Resource Plan is determination of the reliability criteria. A plan developed without adequate consideration of reliability could seriously impair the safety and economic well-being of not only CP&L but also the region.

To ensure reliable service, utilities need a margin of generating capacity available to the system above the capacity used to serve expected load. Like all other major equipment and machinery, electric generating equipment requires periodic maintenance and is subject to unanticipated service interruptions and equipment failures. At any time during the year, some plants will be out of service and unavailable for these reasons. Adequate reserve capacity must be available to provide for this unavailable capacity and for higher than expected peak demand due to weather extremes. In addition, some reserve must be available as operating reserve to respond to the fluctuations in customer demand and to sudden outages of other generating units. This operating reserve represents the amount of capacity that must be immediately available to maintain the balance between supply and demand on a minute-to-minute basis.

The installed generating reserve needed to maintain a reliable supply of electricity is determined by the unique characteristics of each utility. Each system's load shape, unit sizes, capacity mix, fuel supply, maintenance scheduling, unit availability, and strength of its interconnections all play a part in determining the amount of reserve capacity needed. Because all utilities have different characteristics, there is no one standard reserve level which is appropriate for all systems.

It is important to realize that reserves do not remain at a constant level because of load growth and new capacity being brought in-service. Reserves will be higher immediately following the addition of new generating units and lower just before the installation of a new generating unit.

CP&L currently uses a minimum capacity margin of 16.7% to schedule generation additions. Capacity margin, which is defined as the ratio of installed capacity minus peak load divided by installed capacity, is now used as the industry standard measure of reliability, replacing the older reserve margin concept. The 16.7% capacity margin corresponds to a reserve margin of 20% of power resources over peak load.

The CP&L standard has been molded by analysis of system operating history and management judgement. Loss of load probability (LOLP) is also used by CP&L planners as a check to ensure the expansion plan will be able to provide a reliable supply of electricity for our customers.

The modeling system used to develop the resource plans is the Wien Automatic System Planning Package (WASP). WASP was developed jointly by the Tennessee Valley Authority and the Oak Ridge National Laboratory. It uses probabilistic simulation to estimate production costs according to the specified economic commitment schedule. The dynamic programming method of optimization is applied to find the most economical capacity expansion schedule, based on cumulative discounted revenue requirements. WASP also assesses the system reliability of candidate expansion plans by computing LOLP values.

All the candidate resource plans are compared using the cumulative present value of revenue requirements. Plans that are clearly uneconomical are dropped, resulting in some resource options being eliminated from consideration in the next step of the process.

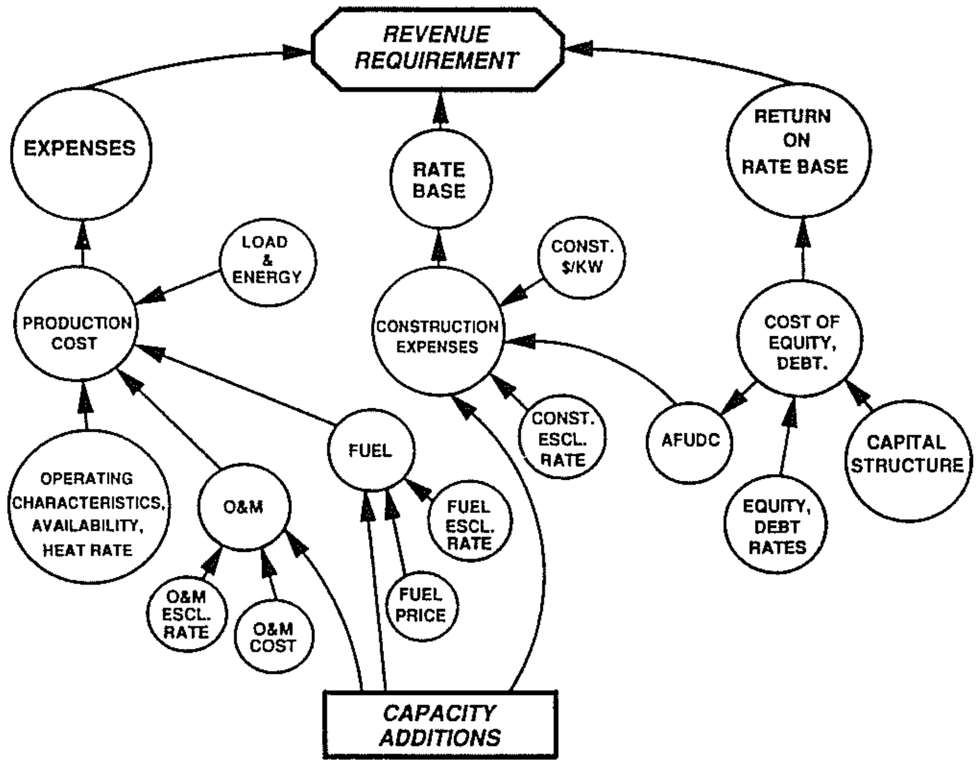
Sensitivity Analysis

In the sensitivity analysis, some of the major assumptions of the analysis are tested for their effect on the optimal resource plan; that is, the plan that has the lowest present value of revenue requirements of all the candidate plans developed. This is done to determine if the optimal plan is sensitive to any of the planning assumptions that are made.

To determine which assumptions should be tested in the sensitivity analysis, an influence diagram is created. An example of an influence diagram is shown in Figure 2-5. The purpose of an influence diagram is to pinpoint the variables and uncertainties which influence a decision. Using this process, a number of variables are chosen to test the sensitivity of the optimal resource plan to changes in the assumptions. Those variables that have the greatest impact on the optimal plan; that is, change the type and/or timing of the resources picked by WASP, are chosen as the major uncertainties for the next step in the process.

Figure 2-5

INFLUENCE DIAGRAM FOR REVENUE REQUIREMENTS



Plan Evaluation

The next major step in the process is Plan Evaluation. As mentioned previously, resource plans are developed in accordance with certain planning principles. It is in this step of the planning process that those principles, reflected in a set of resource planning criteria, are used to evaluate the candidate resource plans developed in the previous step. The criteria are divided into four major groups: economic, financial, environmental, and reliability. Within each group are attributes which are used to measure the "goodness" of the candidate plans relative to each other.

Decision analysis plays a major role in the evaluation and selection of the resource plan. Using decision analysis, the uncertainty of major assumptions is taken into account as a method of evaluating whether a candidate resource plan is a "robust" plan. A robust plan is a plan which provides the flexibility to change course should the future not materialize as currently foreseen and which produces acceptable results for a broad range of events. The uncertainties examined are selected from the influence diagram and verified as likely to affect the decision by the sensitivity analysis performed in the Plan Development step.

While the influence diagram and sensitivity analysis indicate which assumptions should be used as uncertainties, they provide neither the values of the uncertainties nor the probability of a given assumption occurring. Both the value of an assumption that should be used in the analysis, and its probability of occurrence are determined through an interview process. The results of the interviews are combined to create a decision tree. Each endpoint of the tree relates to a scenario. Thus, the total number of scenarios to be analyzed in evaluating a plan is the product of the number of possible outcomes of each uncertainty.

The Utility Planning Model (UPM) is used to simulate all of the scenarios established by the decision tree. The UPM was developed by Arthur Andersen and Company for the Electric Power Research Institute (EPRI). The UPM fully integrates all planning activities including load modification, expansion planning, production costing, fuel supply, plant accounting, financial analysis, and rates and revenue analysis. The UPM is a comprehensive model, yet it provides quick turnaround which makes it an excellent tool for scenario and sensitivity analyses. It is used in the resource planning process to measure the attributes used to evaluate the candidate resource plans in the economic, financial, strategic, and reliability areas.

Because four different planning criteria are used to evaluate each plan, a method of incorporating the trade-offs of one criterion against the others has to be pursued. The type of analysis used is known as utility function analysis. In this analysis the different planning criteria are assigned weights, with the sum of the weights equaling one. In this fashion, the relative importance of each planning criterion in the decision process is identified. Since each planning criterion is described by a group of attributes, these attributes are also assigned weights to identify their relative importance within the group with respect to the other attributes in the group. The weights are determined based on interviews with experts in the fields related to each planning criteria. The weights of the attributes within a group also sum to a value of 1.0 after accounting for the interaction of attributes.

Because the attributes have different units of measure, they have to be unitized before they can be compared to other attributes. To do this, the possible outcomes for each attribute are converted to values between zero and one, going from the worst possible outcome to the best possible outcome that can be achieved by any plan. Thus, the results used in a utility function analysis are non-dimensional and the different attributes can be combined and evaluated simultaneously.

The plans are then ranked based on the value of an expected utility function developed for each plan. The plans with higher expected utilities are considered more desirable, taking into consideration all the uncertainties and all the criteria and attributes, and given the probabilities of the outcomes of the uncertainties analyzed. While the plan with the best expected utility function may not be the best plan for each possible future and for each of the planning criteria, it is the most robust plan.

To further test the plans for robustness, the weights assigned to the planning criteria are varied. In this fashion, the importance of any given criteria relative to the others can be tested to see if assuming more importance in any area would change the decision.

The best plan is examined for any fatal flaws which may go unnoticed by examining only the attributes chosen to represent the planning criteria. For example, high rate increases in any year or severely low capacity margins would bring into question the desirability of the chosen plan. The plan is also checked against the planning principles. If no fatal flaws exist and if the plan is consistent with the planning principles, the plan is recommended to management.

Upon acceptance of the integrated resource plan by management, a forecast of the price of electricity that results from the plan is compared to the prices assumed in the econometric energy forecast. If the prices are significantly different, the process of developing an integrated resource plan is repeated. If there is no significant difference in the assumed and resultant price forecasts, the process is complete.

The final step in CP&L's Integrated Resource Planning Process is the determination of the avoided costs that result from the new integrated resource plan. These new avoided costs are used in planning analyses and evaluations during the next planning cycle.

Chapter 3
Forecasting Summary

Overview

CP&L's forecasting process has evolved over time. Currently econometric and end-use energy forecasts and an internally consistent system peak load forecast are produced. A load factor approach is used for the Load Forecast, using the energy forecast as direct input in producing the forecast of annual system peak load. This Load Forecast method assures that there is a direct coupling between the two forecasts, sharing assumptions and data.

A summary of the December 1991 econometric energy and peak load forecasts are provided later in this chapter. Details of these forecast processes, data, and assumptions are provided in Volume IV.

The Econometric and Load Forecast processes have been based on sophisticated statistical methods since the mid-70s. During this time enhancements have been made to the methodology as data became more available and accessible from computerized sources and software capable of processing the data into useful and meaningful forms became increasingly available. Enhancements have also been undertaken over time to meet the changing data needs of internal and external customers. The increasing sophistication of planning challenges are requiring data at increasing levels of detail. In response to these changing planning needs, CP&L's forecast processes have been expanded to include energy forecasts at the end-use level and hourly load forecasts, or load shapes.

During 1991, energy forecasts were produced for commercial and residential end-uses in parallel with the econometric forecast. EPRI's COMMEND and REEPS software was used for these end-use energy forecasts, respectively. These models combine engineering detail with economic relationships to produce appliance level forecasts within specific customer groups. Both REEPS and COMMEND forecast energy consumption using the choices by consumers of specific equipment, energy efficiency, and utilization of that equipment. Industrial end-use forecasting is in development at this time.

A brief summary of the REEPS and COMMEND forecasts are provided later in this chapter. Details of the REEPS and COMMEND forecasts are provided as Appendix A, Part 1, of Volume II.

End-use forecasting requires a major commitment of time, data, and resources. End-use models require collection and analysis of an enormous quantity of data, much of which is not available on a utility service area basis. EPRI's commercial and residential end-use models are provided with default data reflecting either national or broad regional characteristics. However, these data must be carefully analyzed and often modified to reflect service area specific characteristics.

End-use models should not be seen as a replacement for econometric methods. The use of two approaches is not superfluous duplication because each forecasting method has unique strengths which largely determine the usefulness of the results. Econometric approaches have the strength of using observable market-determined trends spanning many years, but do not immediately capture structural shifts in market behavior. End-use approaches, on the other hand, have the strength of modeling explicit technology, efficiency, and appliance choices; but base such choices on data from a single base year.

The end-use and econometric results are compared to assess forecast consistency and reliability. This procedure acts as a verification for the results of each model. In this way, the strengths of each model are maximized. This comparison of model results showed the econometric and end-use models to be very similar and consistent. Comparisons of the econometric and end-use results for the residential and commercial classes are contained in the end-use section of this chapter. Detail is provided in Appendix A, Part 1, of Volume II.

The load shape process has been structured to combine the individual strengths of the end-use and econometric forecasts with the load forecast. An enhanced process has been recently completed for 8760-hour system load shape modelling. This system load shape effort reflects the combined product of a model of normally expected weather and the detailed hourly response of system load to temperature. The hourly load shape and the forecasts of energy and load are used to develop annual forecasts of system hourly load. The changing patterns identified by the energy and peak load forecasts and other sources will then be reflected in the hourly load shapes for each year.

Examples of the system load shape forecast results are provided later in this chapter. Details of the process, data, and assumptions are provided in Appendix A, Part 2, of Volume II.

Because the integrated resource plans may contain minor timing and magnitude differences from year to year, expected future prices may also vary from plan to plan. CP&L has in the past, and continues, to verify that prices used in the forecasting models are consistent with those implied by the final integrated resource plan. This comparison showed negligible difference between the prices used in the 1991 forecasts and those implied by the final integrated resource plan.

The remainder of this chapter contains summaries of the various individual forecasts discussed earlier. Details of the end-use energy forecast and load shape forecast are provided in Appendix A of Volume II. Details of the econometric energy and system peak load forecasts are provided in Volume IV, as noted earlier.

Econometric Energy Forecast

The Econometric Energy forecast, usually referenced as the System Energy forecast, is a key input to the system resource planning process and provides the energy basis for the System Peak Load Forecast. The December 1991 System Energy forecast continues to include retail energy sales, demand-side management effects, wholesale energy usage, and the total North Carolina Eastern Municipal Power Agency (NCEMPA) energy requirements. Revenue class energies are forecast using comprehensive econometric service area based models. In addition, residential and commercial end-use models were run in parallel to the econometric models. The end-use results were highly consistent with the projections of the econometric models. The forecast approved in December 1991 projects an annual compound growth rate of 1.8% from 1991 through 2006, an increase of 13,200 GWh.

Projected total system energy from the December 1991 Forecast is shown in Table 3-1. Detailed data for the various customer classes are provided in Volume IV.

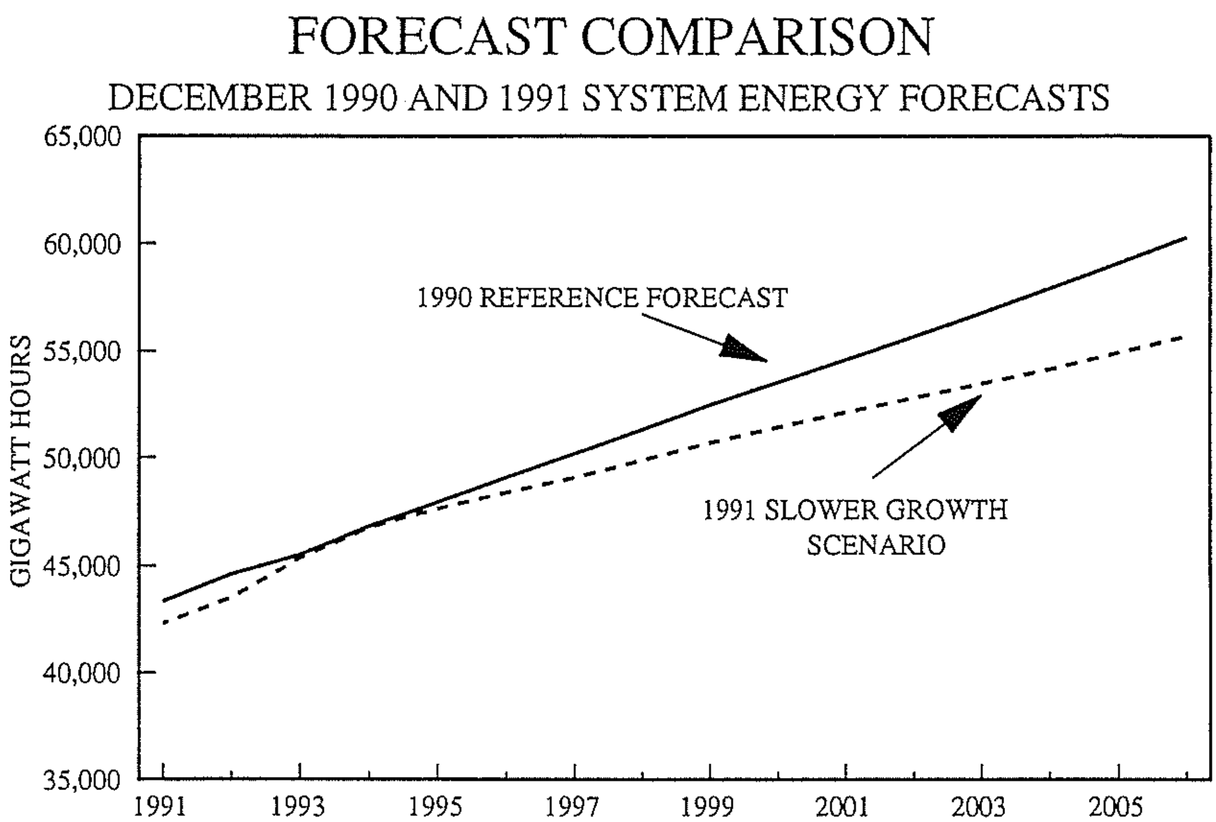
TABLE 3-1

DECEMBER 1991 SYSTEM ENERGY FORECAST
SLOWER GROWTH SCENARIO
REDUCED BY CONSERVATION AND LOAD MANAGEMENT

YEAR	ENERGY (MWH)
1992	43,501,663
1993	45,334,661
1994	46,721,926
1995	47,614,969
1996	48,356,311
1997	49,065,203
1998	49,859,564
1999	50,663,982
2000	51,403,552
2001	52,093,733
2002	52,765,786
2003	53,420,504
2004	54,107,276
2005	54,874,743
2006	55,626,234

Substantial differences exist between this forecast and the December 1990 projections, primarily due to a changed view of CP&L's future. Each year, three separate forecasts are prepared: a Reference or Base forecast, a Higher Growth scenario, and a Slower Growth scenario. Each scenario is based on different economic and demographic assumptions. For example, such things as employment, income, industrial production, and population are varied to produce the different scenarios. In 1990, the Reference forecast best reflected CP&L's future. For the first time, in 1991 the Slower Growth forecast now best typifies CP&L's long-run future. These forecasts are shown in Figure 3-1.

FIGURE 3-1



Future electricity growth is highly uncertain. There is an increasing prospect of slower growth due to changing relationships and power availability in our Wholesale markets. For example, the City of Camden has given notice that it will no longer receive service from CP&L effective May 1, 1995. In addition, other prospects involving increasing appliance efficiency, stricter building codes, conservation awareness, industrial cogeneration, and the possible expansion of natural gas in our Eastern Piedmont and Tidewater regions tend toward slower electricity growth. For all these reasons, the Slower Growth forecast best typifies CP&L's future. This scenario can be interpreted as a collective proxy for the prospect of reduced growth in future electricity needs served by CP&L.

Review And Analysis Of Historic Energy Usage

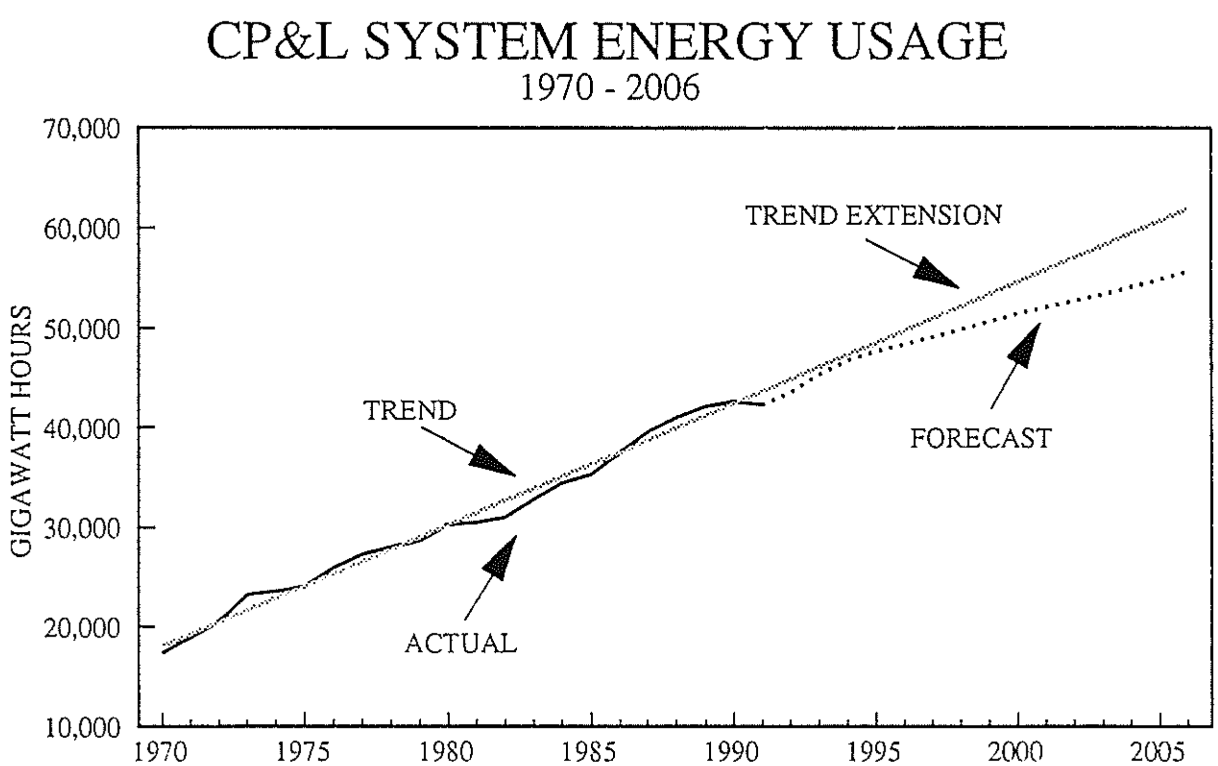
Figure 3-2, below, combines the Company's actual energy experience with the current projections of electricity use in the future. The figure starts in the early 1970s because that was the time when usage patterns for all forms of energy appreciably changed as a result of the first worldwide oil price shocks.

The comparison of actual electricity usage with forecast usage illustrates how the future is expected to unfold relative to the past. To help with this comparison, a trendline has been added. This trendline can be thought of as a trend of electricity usage around the frequent ups and downs seen in the actual usage from 1972 through 1990. This trendline was then extended into the future for comparison with the energy forecast. It is important to recognize that the trendline is not used for forecasting purposes; it is used only to provide some basis of comparison.

The figure illustrates several important points. Actual electricity usage has at times been both above and below the long-term trend. Even though energy consumption has this up and down pattern, it has repeatedly cycled around a long-term trend.

CP&L's current energy projection is shown in Figure 3-2 as the dotted line. Electricity usage in the future is seen to remain below the trendline extension suggesting that the growth in future energy usage will be less than that of the past. The main reasons for generally slower energy growth in the future are the Company's continuing commitment to conservation and load management, a general slowing of population growth, changing relationships and power availability in CP&L's wholesale market, and the increasing emphasis on general energy efficiency.

FIGURE 3-2



Conclusion

The annual percentage growth in system usage is forecast to average 1.8% over the next 15 years. With the exception of the first five years where annual growth is higher as the economy recovers from the 1990-1991 recession, growth in annual gigawatt-hour energy is a fairly constant 700 GWh per year. During the first five years of the forecast, growth in annual energy is projected to average 1200 GWh or 2.7%. In comparison, average annual energy growth on the system from 1970 to 1990 was 1250 GWh, or 4.5%, per year. While this suggests considerably slower growth in energy usage, electricity usage still increases and consequently places continuing requirements on both demand-side programs and supply-side resources.

Residential End-Use Forecast

In parallel to the econometric forecast, the Company has developed an end-use forecast of residential energy using the EPRI developed REEPS (Residential End-Use Energy Planning System) model. REEPS is an integrated end-use/econometric forecasting model which combines engineering detail with economic relationships at the appliance level. The focus of the REEPS model is to disaggregate energy usage patterns into highly detailed end-uses.

REEPS and other end-use models require vast amounts of market information and behavioral assumptions. REEPS models consumer appliance purchase decisions, efficiency choices, and utilization patterns for ten end-uses using multinomial and nested logit systems. These decisions are modeled with information on household and dwelling characteristics, demographic characteristics, fuel prices, fuel availability, weather patterns, and appliance attributes. The models also provide detail by appliance for each of four structure types (single family detached, small multi-family attached, large multi-family attached, and mobile homes).

Nine explicit end-uses are forecast: HVAC (heating, ventilation, and air conditioning), water heating, dishwashing, clothes washing, clothes drying, cooking, first refrigerators, second refrigerators, and freezers. The tenth end-use, "other", represents all remaining appliances and lighting collectively.

Data Sources

A considerable amount of end-use data are not available on a utility service-area basis. Utility-specific data was used where available; otherwise state, regional, and national data were employed. The REEPS program comes with a complete set of default data based on national surveys for a 1987 base year. A list of data sources is shown in Table 3-2.

Forecasts of electricity prices are identical with those used in the econometric forecast. Forecasts of natural gas prices are based on information from the North Carolina Utilities Commission Annual Report and DRI. Fuel oil/other price forecasts are from DRI. Firewood prices are expected to rise at 1% above the rate of inflation, the same rate as in the REEPS default data.

Forecasts of household income and total structures are identical with those used in the econometric forecast. Forecasts of more detailed demographic variables are based on North Carolina state data. Normal heating and cooling degree days are used for the forecast. Finally, forecasts of efficiency standards are based on existing and likely future efficiency standards consistent with the National Appliance Energy Conservation Act of 1987 and the 1990 amendments.

Adjustments To The REEPS Forecast

The REEPS forecast has been adjusted for CP&L DSM programs and is consistent with those adjustments used in the econometric forecast. Total (aggregated) end-use energy has been reduced to reflect projected voltage reduction capability.

REEPS Forecast

A detailed forecast of energy consumption for ten end-uses was completed for CP&L's residential class using three scenarios. Each scenario was based on various demographic inputs (from the Exogenous Variable Module) consistent with those used in the corresponding econometric scenario. A summary of the Slower Growth scenario results for each end-use and for the residential class in total is given in Table 3-3.

For the years 1990 through 2006, residential class energy consumption is expected to increase by 2.2% per year (on a weather normalized basis). The most rapidly growing end-use category is dishwashing (4.1% per year) due to the high penetration of dishwashers in CP&L's service territory. Rapid growth is also anticipated for the "other" end-use as increased electrification continues to occur within the home. Very slow growth is forecast for refrigeration (first and second refrigerators combined) and freezing. This occurs despite a sharp increase in the saturation of second refrigerators because of large increases in the average efficiency of these appliances. Moderate growth is anticipated for the other end-uses.

Comparison With The Econometric Forecast

Figure 3-3 shows a comparison of the Slower Growth econometric scenario and the end-use residential energy forecast scenarios. Both methodologies show relatively higher annual growth through the year 2000 and then relatively slower growth from 2000 to 2006. Comparing the Slower Growth scenarios, the econometric model predicts slightly more rapid annual growth in the first decade (2.9%) than the end-use (2.4%), then slower growth from 2000 to 2006 (1.5% versus 1.8% respectively). The two forecasts begin to converge after 1998. As shown, the end-use forecasts bracket the econometric slower growth scenario.

TABLE 3-2

MAJOR INPUTS TO THE REEPS MODEL

DATA	SOURCES
I. Fuel Price Forecasts	
A. Electricity	CP&L Forecast
B. Natural Gas	NCUC Report and DRI
C. Oil/Other	DOE/EIA Report and DRI
D. Wood	CP&L Forecast
II. Other Exogenous Variable Forecasts	
A. Income	CP&L Service Area Economic Forecast and the State Data Center
B. Number of Members per Household	CP&L Forecast using the State Statistical Register historic values
C. Forecast of Structures (4 types)	CP&L Service Area Economic Forecast, DRI and CP&L Appliance Information Survey
D. Efficiency Standards	National Appliance Energy Conservation Act of 1987 with 1990 Amendments and growth in these standards consistent with the verbiage in the standards
E. Weather Data	National Oceanic and Atmospheric Administration data weighted by CP&L area weather stations. Normal weather assumed constant through forecast.
F. Natural Gas Availability	CP&L 1990 Appliance Information Survey with penetration assumed constant through forecast
G. Rural/Non-Rural Homes	CP&L Forecast using the State Statistical Register historic values
H. Discount Rates	REEPS national sample data
III. Appliance Data	
A. Saturations	CP&L 1990 Apliance Information Survey, REEPS sample data
B. Penetrations	CP&L 1990 Apliance Information Survey, REEPS sample data
C. Efficiencies	REEPS sample data (updated from 1987 to 1990 base)
D. Unit Energy Consumptions	Load Research section, AEIC Load Research Committee, DSM section, REEPS sample data
E. Other Appliance Data	REEPS national sample data

TABLE 3 - 3

CAROLINA POWER & LIGHT COMPANY
1991 RESIDENTIAL END-USE ENERGY FORECAST
SLOWER GROWTH SCENARIO
REDUCED FOR CONSERVATION & LOAD MANAGEMENT
(GWH)

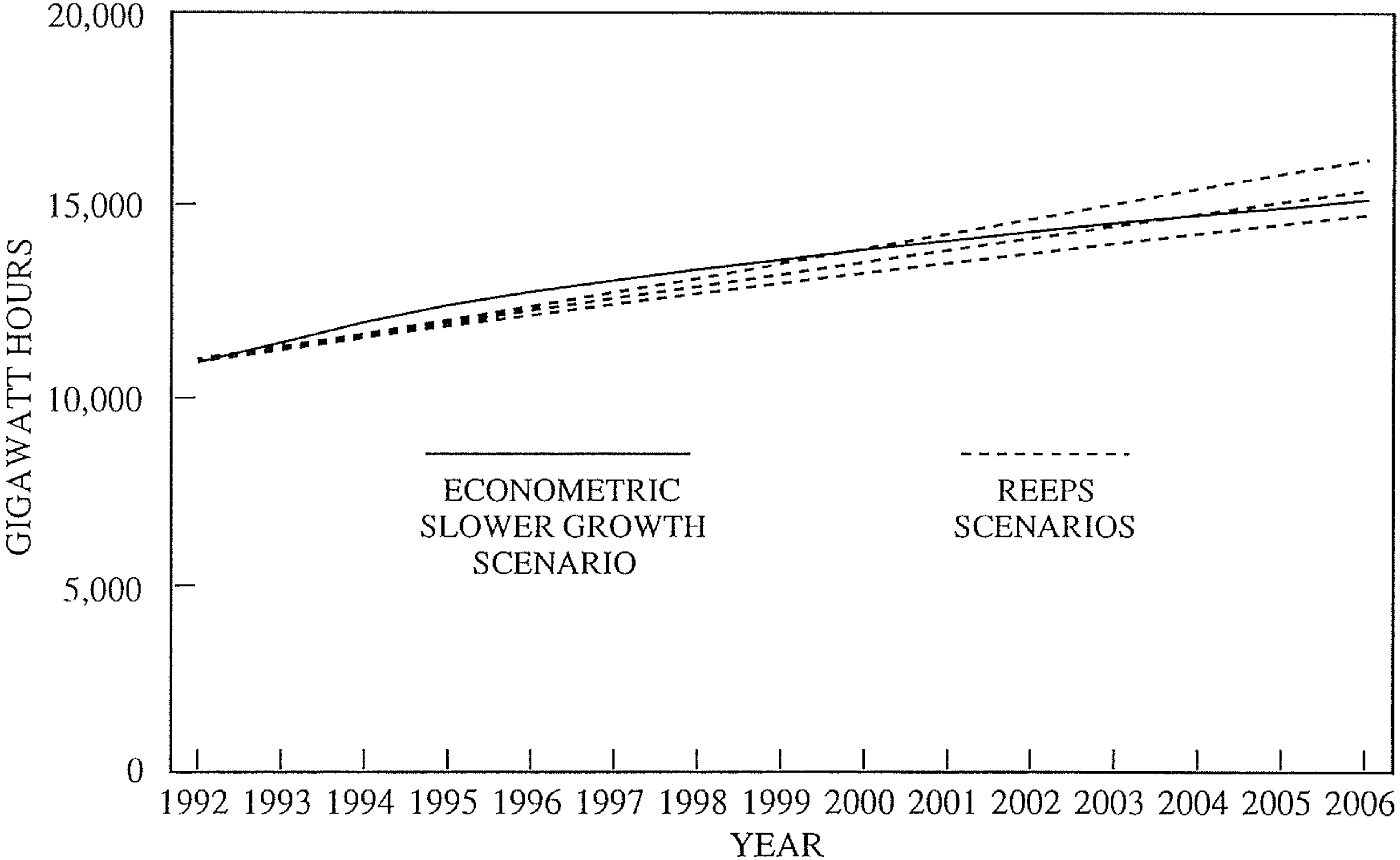
	HVAC (ADJUSTED) (GWH)	WATER HEATING (GWH)	DISH WASHERS (GWH)	CLOTHES WASHING (GWH)	CLOTHES DRYING (GWH)	REFRIGER-ATION (GWH)	FREEZING (GWH)	COOKING (GWH)	OTHER (GWH)	TOTAL (ADJUSTED) (GWH)
1991	3,571.6	2,385.9	108.4	67.5	550.1	897.9	345.0	429.3	2,175.0	10,529.5
1992	3,667.5	2,451.0	114.4	69.2	567.7	916.7	347.0	436.1	2,227.5	10,793.7
1993	3,789.7	2,522.3	120.7	71.1	586.9	920.3	347.6	443.3	2,298.2	11,094.7
1994	3,907.7	2,596.8	127.3	73.1	607.1	924.4	348.2	451.3	2,379.1	11,407.8
1995	4,006.3	2,666.5	133.7	75.0	626.1	927.2	348.3	458.9	2,462.8	11,696.1
1996	4,094.5	2,733.0	139.9	76.8	644.6	929.4	348.3	466.4	2,552.2	11,975.9
1997	4,177.9	2,796.6	146.0	78.5	662.5	931.4	348.3	473.7	2,649.8	12,255.1
1998	4,257.2	2,857.9	152.0	80.3	679.9	933.6	348.3	480.6	2,755.7	12,535.5
1999	4,334.0	2,917.9	158.0	81.9	697.0	936.0	348.5	487.5	2,869.8	12,820.2
2000	4,396.0	2,976.9	164.0	83.6	714.1	938.9	348.9	494.6	2,991.1	13,097.3
2001	4,443.2	3,032.1	169.7	85.3	730.5	941.8	349.4	501.5	3,112.6	13,354.8
2002	4,492.4	3,086.7	175.4	86.9	746.7	945.2	350.2	508.3	3,233.3	13,613.4
2003	4,543.0	3,141.1	181.1	88.5	762.7	949.3	351.4	514.9	3,353.1	13,873.0
2004	4,596.4	3,193.1	186.5	90.0	778.1	954.4	353.2	520.9	3,470.4	14,130.4
2005	4,641.4	3,241.5	191.8	91.4	792.7	960.6	355.4	526.5	3,584.4	14,372.6
2006	4,681.5	3,288.8	197.0	92.7	807.2	968.3	358.1	532.0	3,698.1	14,610.1
Average Annual Growth	1.8%	2.1%	4.1%	2.1%	2.6%	0.6%	0.3%	1.4%	3.5%	2.2%

NOTE: HVAC is adjusted for effects of the Residential High Efficiency Heat Pump Program, TOTAL is reduced for Voltage Reduction

FIGURE 3-3

COMPARISON OF RESIDENTIAL ENERGY FORECASTS

1991 REEPS AND ECONOMETRIC MODELS



Commercial End-Use Forecast

Carolina Power & Light Company uses the EPRI-developed COMMEND model for its commercial sector end-use forecast. COMMEND is a computer model that develops, organizes, and forecasts commercial energy use at the end-use level. COMMEND reflects the impacts of changes in energy prices, technology efficiencies, and economic growth on the forecast.

The COMMEND model segments the commercial market by building type and end-use. CP&L's end-use forecast includes 11 building types, (office, retail, warehouse, grocery, restaurant, lodging, nursing home, hospital, elementary and secondary school, higher education, and church) and eight end-uses (space heating, cooling, ventilation, water heating, cooking, refrigeration, lighting, and miscellaneous).

Data Sources

A considerable amount of end-use data is not available on a utility service area basis. Utility-specific data was used where available; otherwise state, regional, and national data were used. A list of data sources is shown in Table 3-4.

COMMEND Forecast

The COMMEND model provides a detailed description of current and future energy use patterns in the commercial sector. For each building type and end-use the model estimates fuel shares, energy use index (EUI) values, utilization, energy intensities, and energy sales.

A detailed forecast of energy consumption for the 11 building types and eight end-uses was completed for CP&L's commercial class using three scenarios. Each scenario was based on various inputs consistent with those used in the corresponding econometric scenario. All the following results are for the Slower Growth scenario.

A summary of the total forecast for electricity by building type is presented in Table 3-5. As shown office buildings and retail stores represent the largest total energy consuming commercial building categories in the Company's service area. Table 3-6 shows total electric sales by end-use. As shown in Table 3-7, lighting is the largest total energy consuming end-use in our commercial sector. A detailed forecast of commercial end-uses is provided in Appendix A of Volume II.

For the years 1991 through 2000 energy is expected to grow from 5838 to 6746 GWH, an average compound annual growth rate of 1.6% for the period. For the years 1991 through 2006 energy is expected to grow from 5838 to 7137 GWH, an average compound annual growth rate of 1.3% for the period.

Comparison With The Econometric Forecast

A comparison of the results of the 1991 commercial econometric forecast and the 1991 COMMEND forecast was made to verify the consistency and reliability of both models. The Econometric model includes SIC codes that are not included in the COMMEND model. Therefore, the projections of the econometric forecast have been reduced by the amount of the energy associated with the SIC codes that are out-of-scope in the COMMEND model to make a valid comparison of the forecasts. Figure 3-4 shows a comparison of the 1991 econometric and COMMEND forecasts.

TABLE 3-4

MAJOR INPUTS TO THE COMMEND MODEL

DATA	SOURCES
I. Fuel Price Module	
A. Historical Fuel Prices	
1. Electric	CP&L
2. Gas	NCUC Report
3. Oil	DOE Annual Energy Review
B. Forecast	
1. Electric	CP&L Forecast
2. Gas	DRI
3. Oil	DRI
II. Floor Stock Module	
A. Employment	
1. Historical	NC Employment & Wages Report
2. Forecast	CP&L Forecast
B. 1985 Floor Space	CP&L Commercial Sector Database prepared by Synergic Resources Corporation
C. Survival Functions	COMMEND National Sample Data
III. Market Profiles Module	
A. Fuel Shares	CP&L Commercial Sector Database prepared by Synergic Resources Corporation and EPA SERC regional data
B. EUI Values	CP&L Commercial Sector Database prepared by Synergic Resources Corporation
IV. Technology Data Module	
A. Heat Pump Data	
1. Market Share	CP&L Commercial Sector Database prepared by Synergic Resources Corporation
2. EUI Values	COMMEND National Sample Data
B. Equipment Cost	COMMEND National Sample Data
C. Technology Elasticities	COMMEND National Sample Data
D. Efficiency Trends	COMMEND National Sample Data
E. Cost Trends	COMMEND National Sample Data
F. Thermal Interactions	COMMEND National Sample Data
V. Economic Data Module	
A. Discount Rates	COMMEND National Sample Data
B. Price Weights	COMMEND National Sample Data
C. Choice Elasticities	COMMEND National Sample Data
D. Utilization Elasticities	COMMEND National Sample Data
E. Fuel Share Inertia Parameters	COMMEND National Sample Data
F. EUI Inertia Parameters	COMMEND National Sample Data
G. Retrofit Penetrations	COMMEND National Sample Data
H. Miscellaneous Electric Equipment Growth	COMMEND National Sample Data

TABLE 3-5

CAROLINA POWER & LIGHT COMPANY
1991 COMMERCIAL END-USE ENERGY FORECAST
SLOWER GROWTH SCENARIO
REDUCED FOR CONSERVATION & LOAD MANAGEMENT
(GWH)
BY BUILDING TYPE

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
OFFICE	1,410	1,427	1,461	1,494	1,524	1,549	1,566	1,579	1,595	1,613	1,627	1,642	1,657	1,672	1,687	1,697
RETAIL	1,051	1,058	1,092	1,131	1,156	1,167	1,172	1,186	1,202	1,218	1,233	1,242	1,250	1,258	1,270	1,283
WAREHOUSE	347	349	358	369	375	377	377	380	382	386	388	390	391	392	394	397
GROCERY	818	821	847	877	896	904	908	919	932	945	957	964	971	979	988	999
RESTAURANT	570	572	590	611	625	632	636	646	656	667	677	684	691	699	707	716
LODGING	285	291	302	311	317	323	327	330	334	340	344	347	351	355	359	363
NURSING HOMES	86	88	92	95	97	99	101	102	104	106	108	110	112	113	114	116
HOSPITALS	367	377	393	408	418	429	437	445	454	465	474	483	492	499	505	511
ELEM. & SEC. SCHOOL	381	383	388	394	400	405	408	410	412	415	417	420	424	427	431	434
HIGHER EDUCATION	347	352	363	373	379	384	388	390	393	397	400	403	406	409	413	416
CHURCHES	178	181	188	194	198	201	204	206	208	212	214	216	218	221	223	226
TOTAL (1)	5,838	5,895	6,067	6,244	6,373	6,457	6,510	6,577	6,658	6,746	6,822	6,884	6,947	7,006	7,073	7,137

TABLE 3-6

CAROLINA POWER & LIGHT COMPANY
1991 COMMERCIAL END-USE ENERGY FORECAST
SLOWER GROWTH SCENARIO
REDUCED FOR CONSERVATION & LOAD MANAGEMENT
(GWH)
BY END-USE

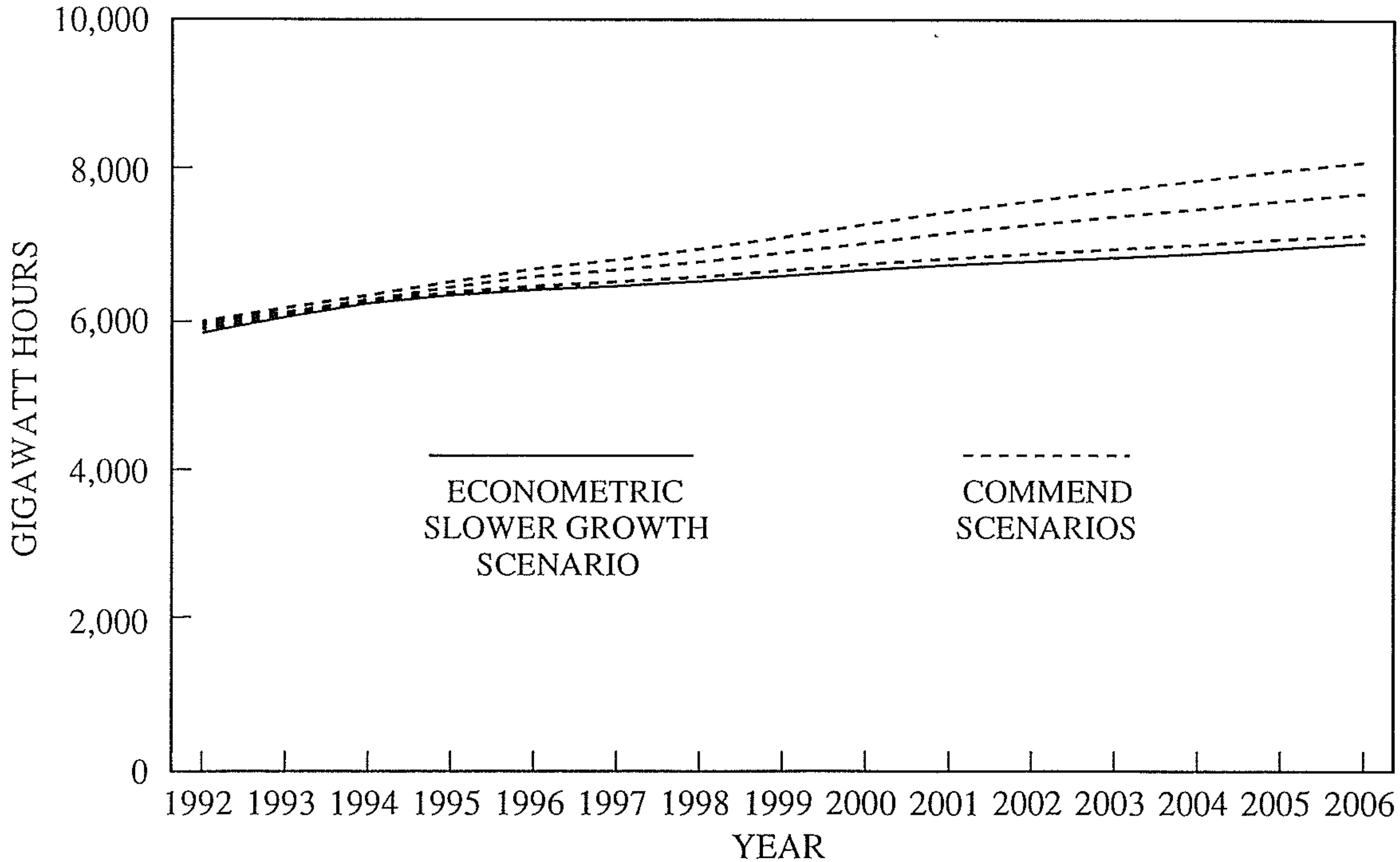
	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
SPACE HEATING	497	500	513	528	539	546	552	559	568	578	588	596	607	618	631	644
COOLING	775	783	805	826	842	852	858	864	872	881	887	891	896	900	906	912
VENTILATION	697	703	722	741	755	764	770	776	785	794	802	808	814	821	829	837
WATER HEATING	230	232	238	246	253	257	261	266	272	278	284	290	297	303	308	314
COOKING	136	136	140	145	148	150	152	155	159	163	167	170	173	177	181	185
REFRIGERATION	590	592	610	631	644	650	653	661	670	679	687	692	697	703	710	718
LIGHTING	2,364	2,385	2,449	2,512	2,556	2,582	2,594	2,609	2,628	2,650	2,667	2,678	2,688	2,693	2,703	2,714
MISCELLANEOUS	551	569	598	627	650	668	684	701	719	738	757	774	793	808	824	833
TOTAL (1)	5,838	5,895	6,067	6,244	6,373	6,457	6,510	6,577	6,658	6,746	6,822	6,884	6,947	7,006	7,073	7,137

(1) Total is reduced for Voltage Reduction.

FIGURE 3-4

COMPARISON OF COMMERCIAL ENERGY FORECASTS

1991 COMMEND AND ECONOMETRIC MODELS



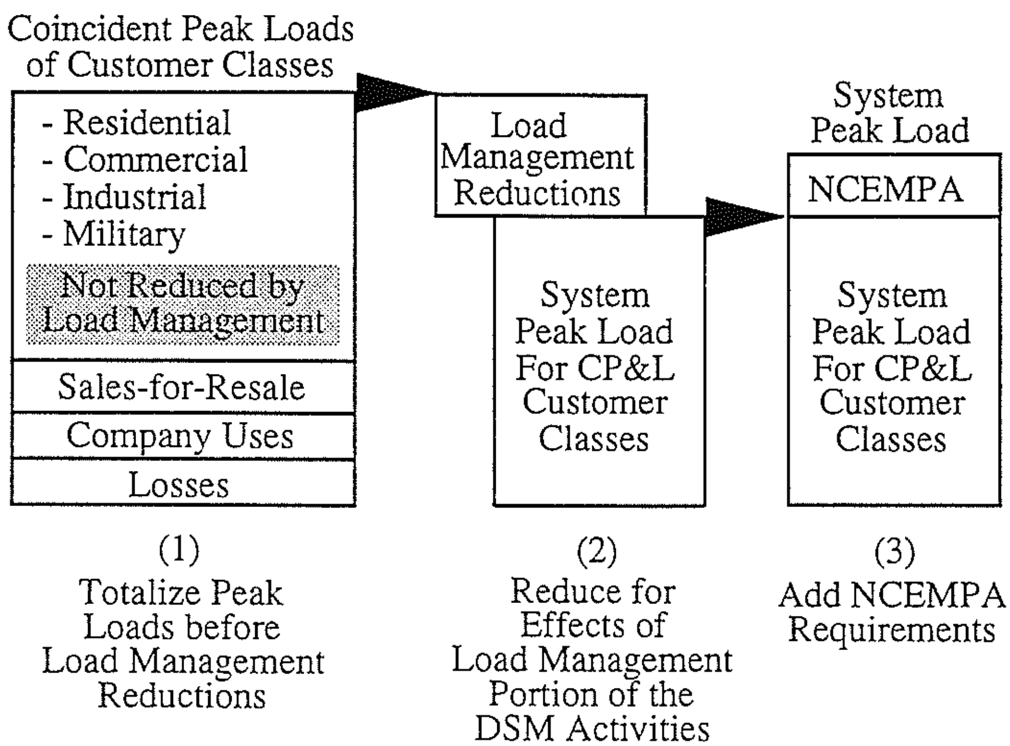
System Peak Load Forecast

The System Peak Load forecast is developed annually using the System Energy forecast and load management program reductions as primary inputs. In turn, the peak load forecast reduced for DSM becomes the basis for determining the need for new supply-side resources in the Company's Integrated Resource Plan.

System Peak Load Forecast Process

Development of the System Peak Load forecast can be viewed as the three step process shown below in Figure 3-5. Loads for CP&L wholesale and retail customer classes are calculated before reduction for DSM effects. A major input at this stage of the load forecast process is the System Energy forecast. The total of these loads is adjusted for losses between generation and the customer level. Load reductions associated with the load management portion of the Company's Demand-Side Management (DSM) Program are subtracted from this total of Class Loads, Company Uses, and Losses. North Carolina Eastern Municipal Power Agency (NCEMPA) load is added in the last step to determine System Peak Load.

FIGURE 3-5



Demand-Side Management Impact

Conservation is implicitly reflected in the load forecast as a result of the methods and models used for the System Energy forecasts. Because conservation is reflected in the forecast process, load management alone is subtracted from the gross load forecast. This approach prevents a double counting of conservation effects.

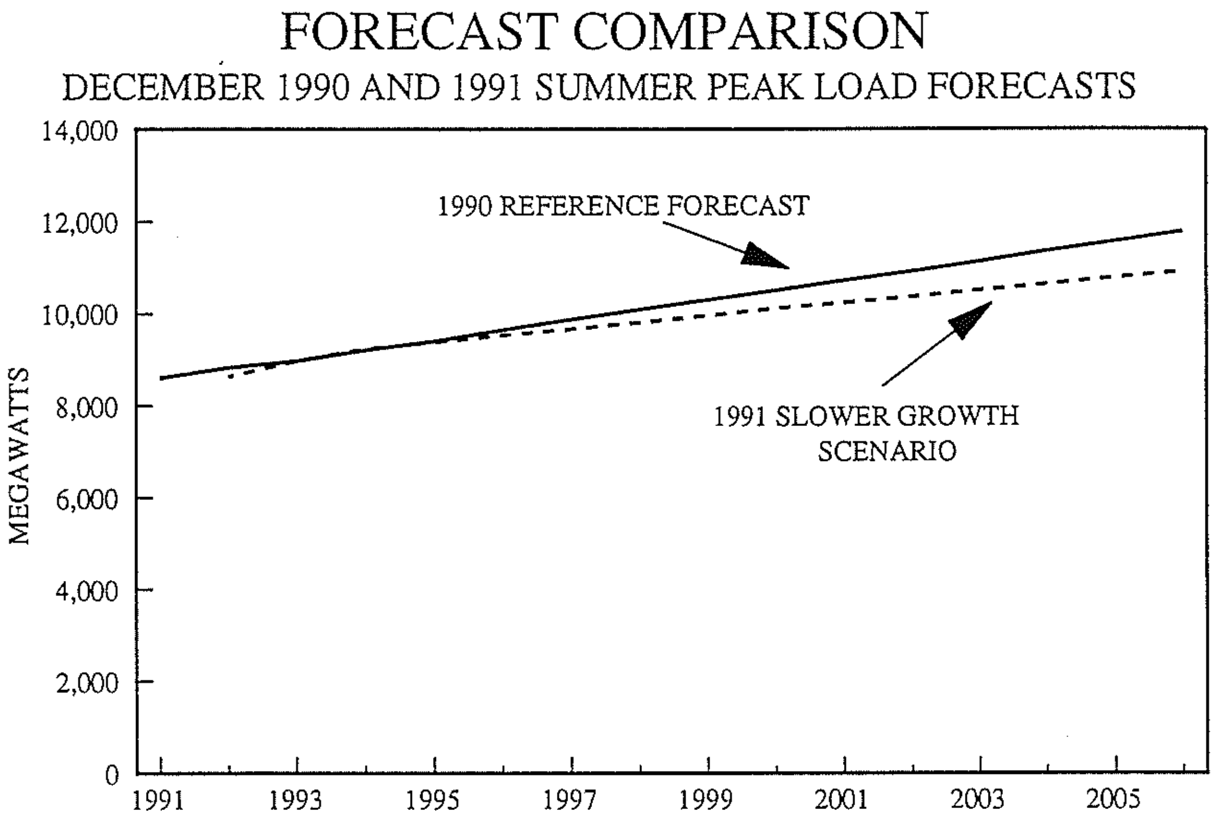
Load management has provided significant reductions to system peak load and is expected to continue to do so in the future. Between 1992 and the end of the forecast period in 2006, load management reductions are expected to increase approximately 500 MW. This represents a reduction of 17% of the forecast load growth during this time period.

Load management totals used in the load forecast do not include the projected purchases from sell-excess cogenerators and small power producers. These are included in supply-side tabulations as Company Power Resources. Since load management programs are intended to reduce system seasonal peaks, the associated energy reduction is proportionately much smaller. Load management affects the growth rates of both system energy and system peak load; however, the energy reduction is a much smaller percentage than the peak load reduction. This tends to make the growth rate for demand lower than the growth rate for energy. Thus, reductions due to load management efforts tend to result in increases in forecast system load factor.

December 1991 Peak Load Forecast Perspective

Paralleling the System Energy forecast, the System Peak Load forecast is below the previous forecast of December 1990. A comparison of the forecasts is shown below in Figure 3-6.

FIGURE 3-6



Since the System Energy forecast is the primary input to the System Peak Load forecast, those factors which influence a change in forecast energy use also influence similar changes in projected peak load. Additionally, the System Peak Load forecast is influenced to a greater extent by load management, as described earlier in this section. A discussion of those assumptions which influence both the energy sales and peak load forecasts in similar fashion is contained in the Econometric Energy Forecast section of this chapter.

Conclusion

The Company's cumulative load management capability is expected to increase 500 MW to approximately 1000 MW between 1992 and 2006. The resulting net System Peak Load (after reduction for DSM activities) from 1992 through 2006 is expected to grow at a rate of 1.7% over the same period. Even at this reduced growth rate, the Company is projected to experience average annual peak load growth of over 160 MW per year or over 2200 MW total growth between 1992 and 2006.

System annual peak load, system annual energy input, and system annual load factor from the forecast approved in December 1991 are provided in Table 3-7. Detailed data for the various customer classes are provided in Volume IV.

TABLE 3-7

DECEMBER 1991 SUMMER PEAK LOAD FORECAST
SLOWER GROWTH SCENARIO

YEAR	SYSTEM SUMMER PEAK LOAD (MW)	* SYSTEM WINTER PEAK LOAD (MW)	** ANNUAL SYSTEM ENERGY INPUT (MWH)	*** ANNUAL LOAD FACTOR
1992	8,631	8,484	45,675,990	60.4%
1993	8,969	8,817	47,600,880	60.6%
1994	9,226	9,069	49,057,620	60.7%
1995	9,364	9,205	49,995,340	60.9%
1996	9,516	9,354	50,773,820	60.9%
1997	9,646	9,482	51,518,170	61.0%
1998	9,796	9,629	52,352,270	61.0%
1999	9,949	9,780	53,196,950	61.0%
2000	10,095	9,923	53,973,570	61.0%
2001	10,227	10,053	54,698,220	61.1%
2002	10,356	10,180	55,403,910	61.1%
2003	10,483	10,305	56,091,380	61.1%
2004	10,615	10,435	56,812,540	61.1%
2005	10,753	10,570	57,618,460	61.2%
2006	10,896	10,711	58,407,580	61.2%

* Peak typically occurs during the period December (prior year) through February.

** System Energy Input is the sum of Energy Sales (reduced for Load Management), Losses and Company Uses.

*** Based on System summer peak load.

Load Shape Forecast

Overview

The quantity, detail, and type of load data used in planning has evolved in response to increasingly sophisticated planning requirements. At the same time there is increasing availability of load data in computer readable form and increasing availability of software capable of processing these data. The continuing evolution of planning requirements and models requires load data by hour. The ultimate level of detail is hourly load shape forecasts for the individual customer classes and for the total system. For such detailed load data to be meaningful, they must be based on normally expected temperatures, and reflect those changes in end uses and consumption determinants which affect system load patterns.

While the load data necessary to create hourly load shape forecasts have been available in a computerized format for many years, widespread availability of official National Oceanic and Atmospheric Administration (NOAA) weather data in this form are more recent. Computer software sufficient to create weather-normal hourly forecasts for the CP&L system was obtained in late 1990.

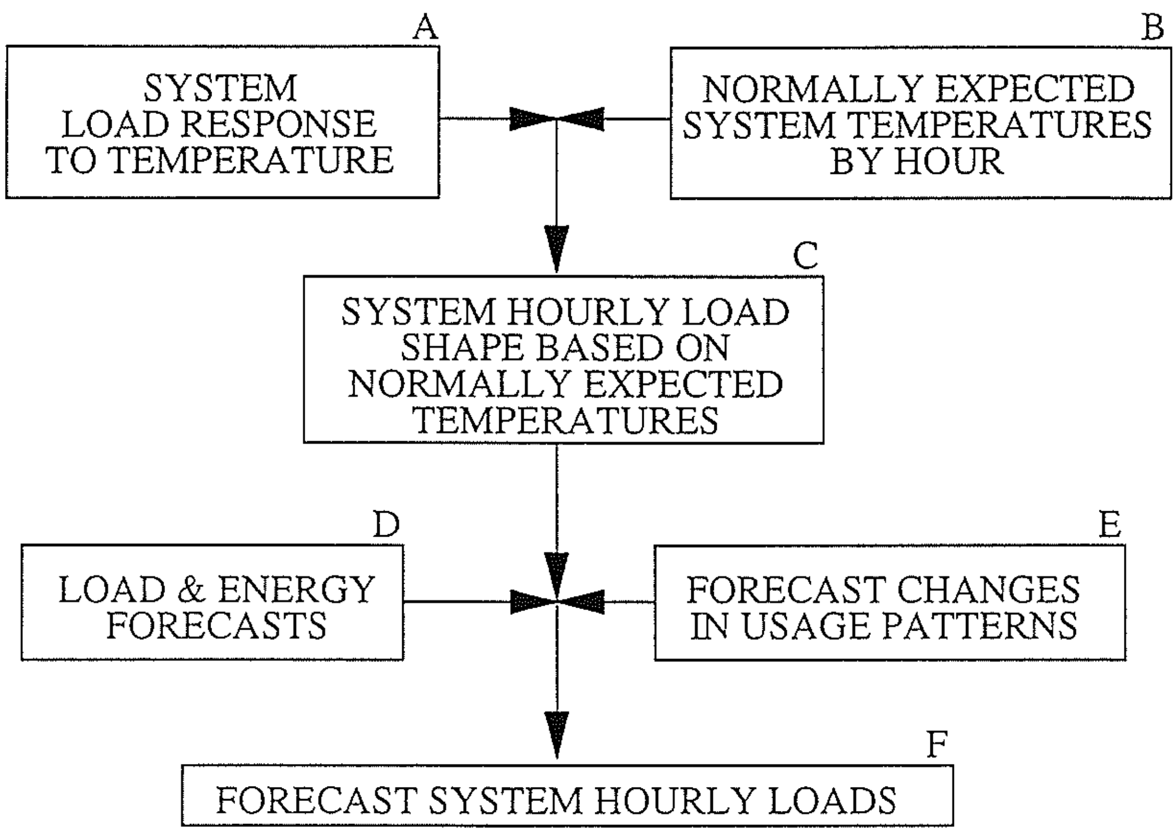
While load shape forecasts are usually developed in a "typical week" format which does not produce complete 8760 load detail, CP&L has chosen to develop true hourly load forecasts. The final goal of the load shape process will be to develop consistent 8760-hour load forecasts for the system and revenue class levels. Load shape changes identified in the end-use forecasts through various engineering and economic studies will be reflected in the class and system level 8760-hour load forecasts. This final goal will be attained over a period of time as the results of end-use forecasts and other research efforts are integrated into the hourly load forecast.

Process Structure

The structure for creating load shape forecasts is best viewed as a process consisting of several inter-related models. All interim and final results for EPRI's REEPS and COMMEND programs, described earlier in this chapter, are produced within a single model. By contrast, the load shape process is composed of several discrete steps, as shown in Figure 3-7. Each step is a separate model producing an input to the next step. These models are in some cases personal computer programs such as Battelle's SHAPES-PC or EPRI's Hourly Electric Load Model (HELM). Other models are mathematical or statistical functions developed using mainframe applications. As with the end-use models, a substantial amount of data must be processed to develop the inputs required by the various steps (or models) of the load shape forecast process.

FIGURE 3-7

CP&L HOURLY SYSTEM LOAD SHAPE PROCESS



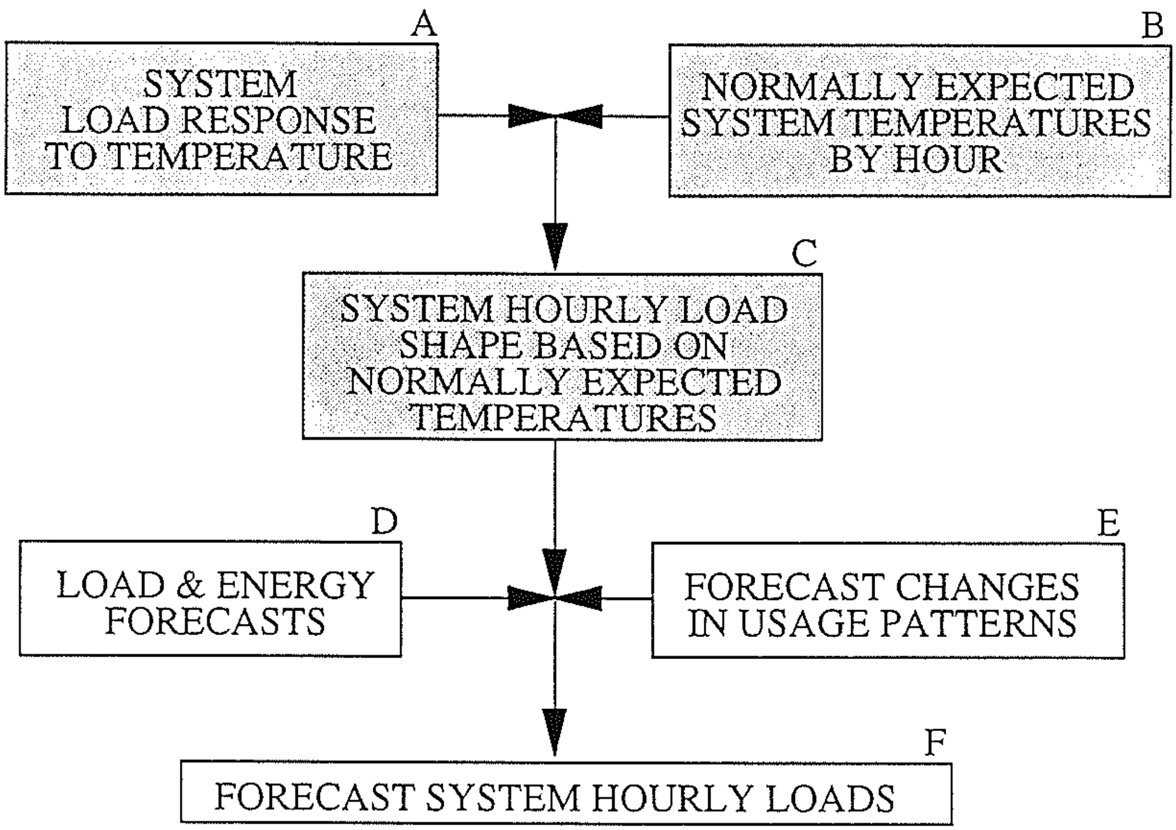
Process Description

During 1991 the initial development of the load shape project was completed by producing an 8760 hour system reference load shape (BLOCK C). As shown in Figure 3-8, producing this load shape required the output from two major steps :

(BLOCK A) - creation of the hourly response of system load to temperature
(BLOCK B) creation of normally expected hourly system temperatures

FIGURE 3-8

CP&L HOURLY SYSTEM LOAD SHAPE PROCESS



Battelle's SHAPES-PC was acquired in late 1990 for use in the enhanced load shape project. The Temperature Associated Use Pattern Analysis (TAUPA) model of this program was used to develop equations defining the response of system load to temperature for each hour of the year (BLOCK A). Three years of system load and temperature data were used to create a mathematical representation of the load which would be expected for each hour of the year over a range of temperatures. The expected response of load to temperature for selected periods are shown in graphical form at the end of this section.

A statistically-based mainframe computer model was developed and written to produce normally expected system temperatures (BLOCK B). An 8760 hour model of normally expected temperatures was created using 40 years of historic temperature data and other CP&L-specific variables. Monthly plots of the normally expected temperature developed in this step are provided for selected periods at the end of this section.

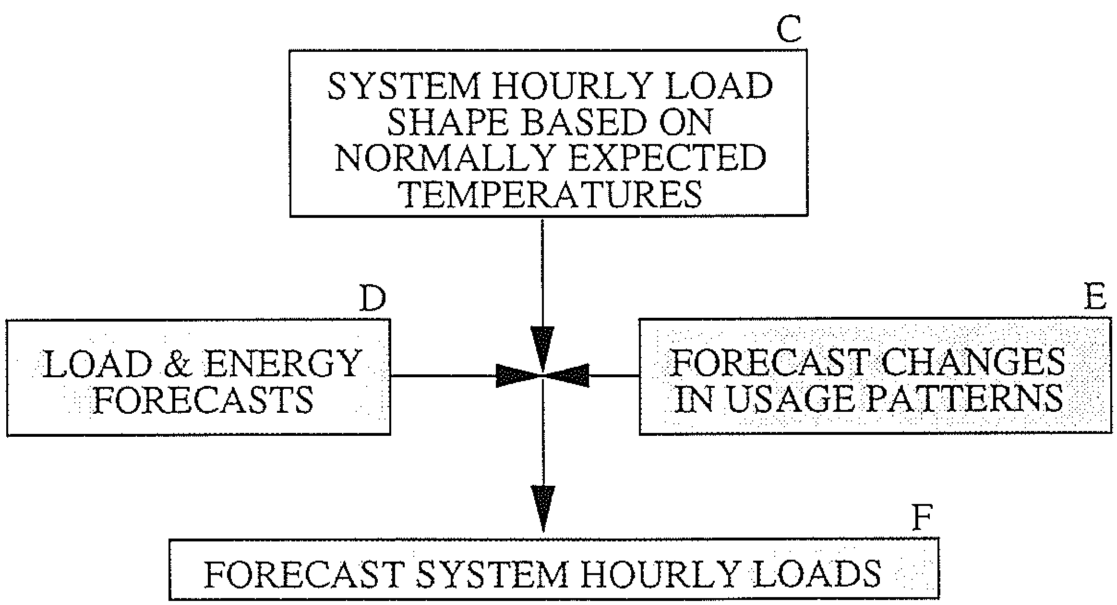
Another model within the SHAPES-PC program was used to produce expected loads for each hour of the year using the expected normal temperatures and the model defining the response of load to temperature for each hour from the first two steps (BLOCK C). A representation of the resulting system hourly load shape developed in this step is provided for selected periods at the end of the LOAD SHAPE FORECAST section. In total, several million separate data points were processed to produce the 8760-hour reference system load shape. Technical details of the Load Shape Forecast Process and results are provided in Appendix A, Part 2, of Volume II.

In the near term, further development of the load shape process will center around using this historical total system load shape to project future system hourly loads. As shown in Figure 3-9, the system energy and load forecasts (BLOCK D) will be used to modify the hourly system reference load shape (BLOCK C) to a shape of future projected load levels (BLOCK F) which also reflects projected changes in system load patterns (BLOCK E).

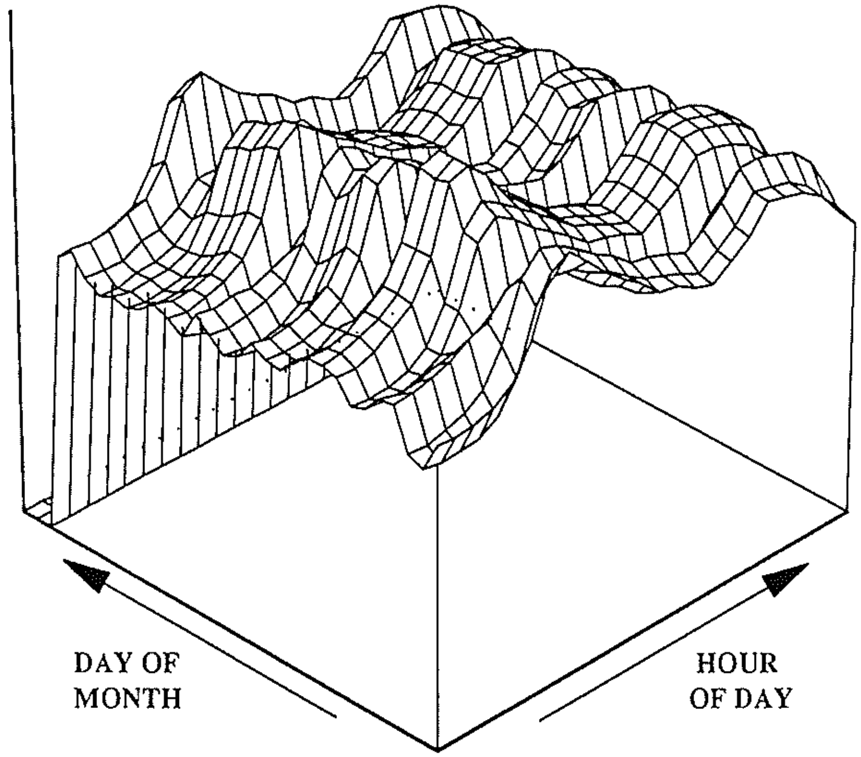
This same set of models and processes which have been developed for the system load shape forecast will be used to develop 8760 hour load forecasts for each customer class. Those class load forecasts will reflect on a customer class basis those specific and unique factors which affect future patterns of demand.

FIGURE 3-9

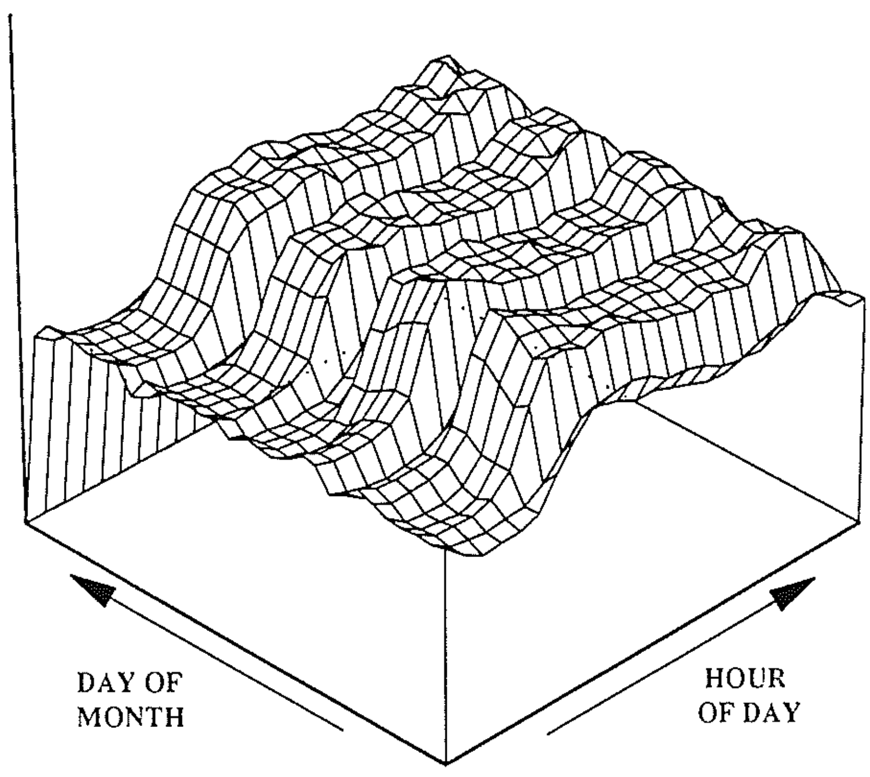
CP&L HOURLY SYSTEM LOAD SHAPE PROCESS



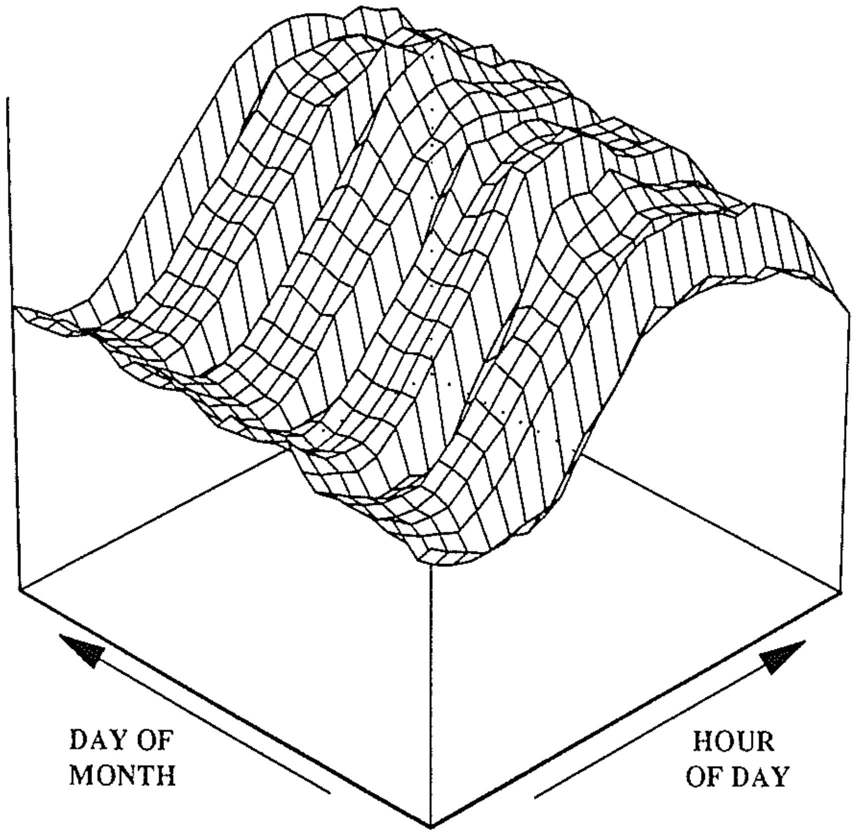
FEBRUARY HOURLY LOAD MODEL



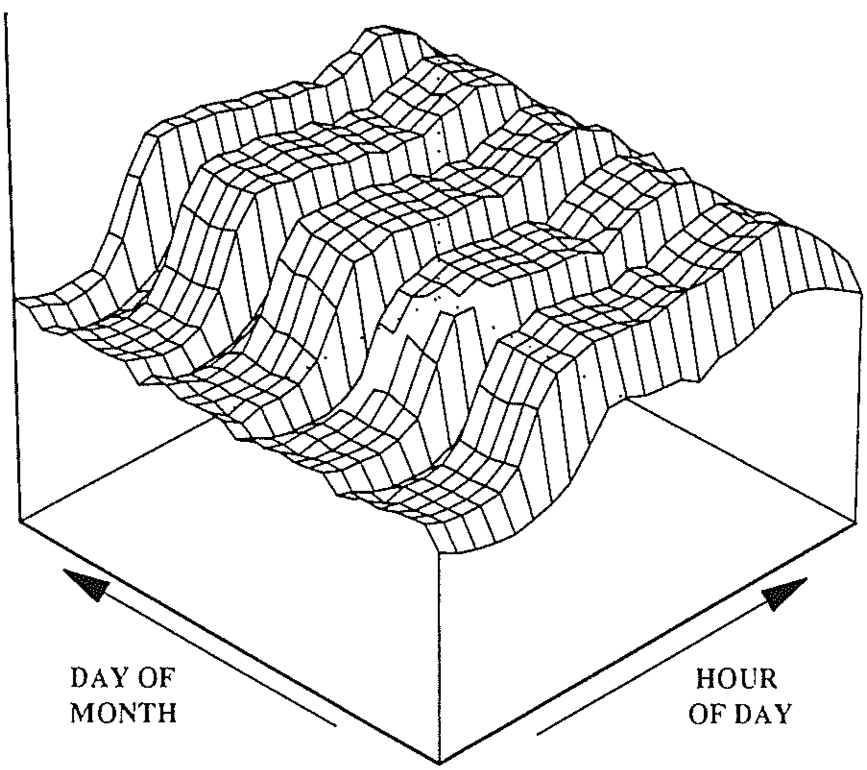
APRIL HOURLY LOAD MODEL



JULY HOURLY LOAD MODEL



OCTOBER HOURLY LOAD MODEL



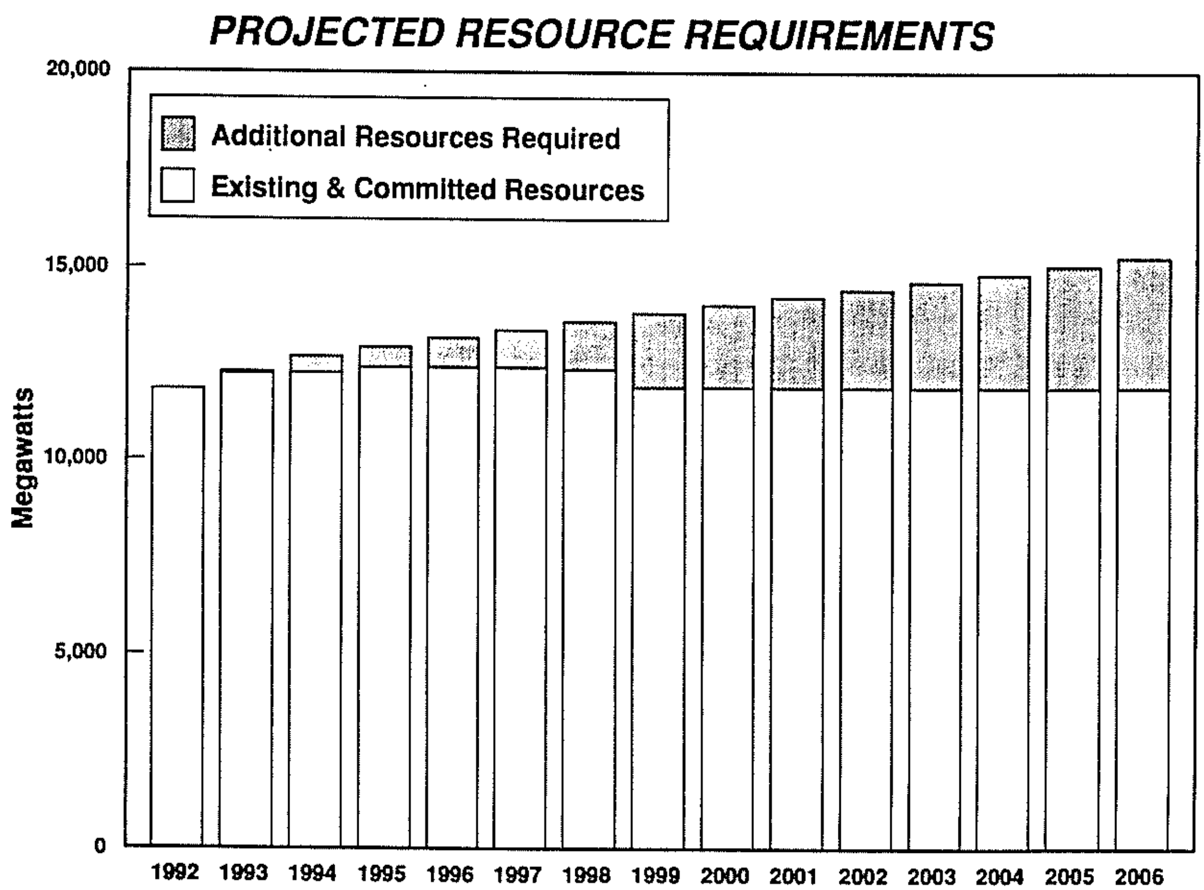
Chapter 4
Integrated Resource Plan

This chapter will discuss CP&L's Integrated Resource Plan. The demand-side and the supply-side resources included in the plan will be outlined.

Projected Resource Requirements

As discussed in Chapter 3, the growth of the CP&L service territory will require additional resources to meet customer demands. These resources are expected to be minimal in the short-term, but substantial in the long-term. This can be seen in Figure 4-1. The shaded area of the bars represents additional resources needed to meet the peak demands and reserve requirements of CP&L's customers.

Figure 4-1



Elements of the Resource Plan

CP&L's strategy of maintaining a diversified mix of resources is apparent in the Integrated Resource Plan. The plan builds on a well-balanced mix of existing demand-side and supply-side resources that includes conservation and load management programs, coal, nuclear, oil/gas, and hydroelectric generation facilities, and purchases from non-utility generators and other utilities. The plan includes an aggressive demand-side management program in addition to new supply resources. Planned additions are shown below in Table 4-1. A table of annual load, resources, and reserves can be found in Table 4-2. The rest of this section describes the demand-side and supply-side resource included in the Integrated Resource Plan.

Table 4-1
Planned Additions

	Total Demand-Side Management (MW)	Supply-Side Resources (MW)
1992	112	49 NUG
1993	97	400 DUKE
1994	90	23 PA/SCPSA
1995	81	150 PA CT
1996	56	225 DARLINGTON CT
1997	53	250 CT*
1998	51	250 CT*, -50 PA/SCPSA
1999	47	400 CT*, -50 PA/SCPSA, -400 DUKE
2000	45	250 CT*
2001	43	250 CT*
2002	43	250 CT*
2003	44	250 CT*
2004	44	
2005	51	250 CT*
2006	43	250 CT*

NUG - Non-Utility Generation
CT - Combustion Turbine
SCPSA - South Carolina Public Service Authority
DUKE - Duke Power Company
Negative numbers indicate the expiration of purchase contracts

*The Company has not committed to a particular design, unit size, or location for the capacity.

Table 4-2

CAROLINA POWER & LIGHT CO.
DECEMBER 1991 RESOURCE PLAN
PROJECTED SUMMER RESOURCES, LOAD, AND RESERVES

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
GENERATION ADDITIONS															
DARLINGTON CT ADDITION					225										
UNDESIGNATED C.T.						250	250	400	250	250	250	250		250	250
UNDESIGNATED COAL															
INSTALLED GENERATION															
OIL/GAS	1046	1046	1046	1046	1046	1271	1521	1771	2171	2421	2671	2921	3171	3171	3421
HYDRO	218	218	218	218	218	218	218	218	218	218	218	218	218	218	218
COAL	5285	5285	5285	5285	5285	5285	5285	5285	5285	5285	5285	5285	5285	5285	5285
NUCLEAR	3064	3064	3064	3064	3064	3064	3064	3064	3064	3064	3064	3064	3064	3064	3064
PURCHASES & OTHER RESOURCES															
SEPA	109	109	109	109	109	109	109	109	109	109	109	109	109	109	109
NON-UTILITY GENERATORS	461	461	461	461	461	461	461	461	461	461	461	461	461	461	461
AEP PURCHASE	250	250	250	250	250	250	250	250	250	250	250	250	250	250	250
NCEMPA/SCPSA PURCHASE	77	77	100	100	100	100	50								
NCEMPA PEAKING PROJECT				150	150	150	150	150	150	150	150	150	150	150	150
DUKE PURCHASE		400	400	400	400	400	400								
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL SUPPLY RESOURCES	10510	10910	10933	11083	11308	11558	11758	11708	11958	12208	12458	12708	12708	12958	13208
TOTAL INTERNAL DEMAND (1)	8901	9287	9587	9762	9929	10075	10240	10405	10565	10709	10850	10990	11133	11291	11444
INTERRUPTIBLE LOAD (2)	270	318	361	398	413	429	444	456	470	482	494	507	518	538	548
NET PEAK LOAD (3)	8631	8969	9226	9364	9516	9646	9796	9949	10095	10227	10356	10483	10615	10753	10896
RESERVES (4)	1879	1941	1707	1719	1792	1912	1962	1759	1863	1981	2102	2225	2093	2205	2312
CAPACITY MARGIN (5)	17.9%	17.8%	15.6%	15.5%	15.8%	16.5%	16.7%	15.0%	15.6%	16.2%	16.9%	17.5%	16.5%	17.0%	17.5%
RESERVE MARGIN (6)	21.8%	21.6%	18.5%	18.4%	18.8%	19.8%	20.0%	17.7%	18.5%	19.4%	20.3%	21.2%	19.7%	20.5%	21.2%
ANNUAL ENERGY (GWH)	45,676	47,601	49,058	49,995	50,774	51,518	52,352	53,197	53,974	54,698	55,404	56,091	56,813	57,618	58,408

NOTES: (1) NOT REDUCED FOR THE IMPACT OF DSM INTERRUPTIBLE LOAD PROGRAMS.
(2) INCLUDES WATER HEATER AND AIR CONDITIONER CONTROL, VOLTAGE REDUCTION, AND LARGE LOAD CURTAILMENT.
(3) INCLUDES THE IMPACT OF ALL DSM PROGRAMS.
(4) TOTAL SUPPLY RESOURCES - NET PEAK LOAD.
(5) RESERVES / TOTAL SUPPLY RESOURCES * 100.
(6) RESERVES / NET PEAK LOAD * 100.

Demand-Side Resources

Table 4-3 shows CP&L's long-range plan for demand-side management options. Diversity is one of the key elements of the plan. CP&L defines diversity of demand-side management options from two perspectives: (1) the point of view of the customer, and (2) the perspective of the Company.

CP&L's plan offers a menu of options to all major retail customer classes. Residential customers, for example, may choose from among programs designed toward thermal efficiency to appliance control to rates based on a customer's time of use. Commercial and industrial customers may participate in CP&L's energy audit program which encompasses recommendations on a wide variety of end-uses. Our industrial customers may also tailor their participation based on their specific needs. Some industrial customers may choose to participate in a curtailment program, while others may elect to participate in a dispatched power program, and yet others may opt to participate in both. Table 4-3 illustrates the diversity of choices CP&L gives customers.

Diversity is also important from the perspective of the utility. As shown in Chapter 2, Table 2-2 through Table 2-4, CP&L's demand-side management options cover the five load shape objectives of strategic conservation, load shifting, peak clipping, valley filling and strategic load growth. This diversity allows CP&L to meet kilowatt and kilowatt-hour system needs.

As Table 4-3 shows, CP&L's demand-side management efforts will grow from an estimated summer system peak load reduction capability of 1430 MW in 1992 to 2218 MW in 2006. These forecasted accomplishments will come from an array of demand-side management options designed for strategic conservation, load shifting, and peak clipping.

Table 4-3
Demand-Side Management Programs
Peak Load Reduction in Megawatts

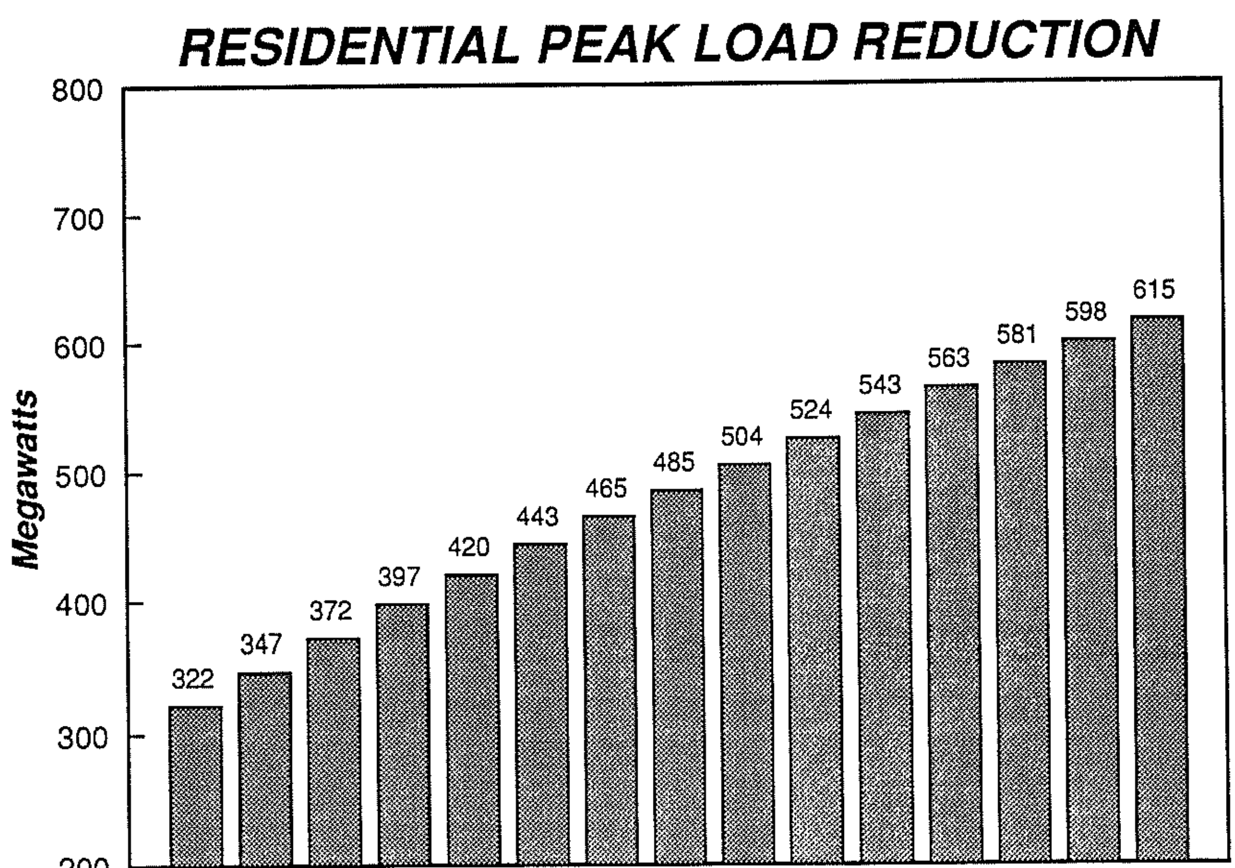
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Residential															
Common Sense Home	121	129	137	145	153	161	169	176	184	191	198	206	213	220	228
Homeowner's Energy Loan Program/Residential Energy Conservation Discount	33	35	36	36	37	38	38	38	39	39	39	40	40	40	40
Air Conditioner Control (EZ-$64)	114	125	136	147	156	166	175	182	190	197	204	212	218	223	228
Water Heater Control (EZ-$64)	27	29	31	33	35	38	40	42	44	46	48	49	51	53	55
High Efficiency Heat Pump	9	10	11	12	13	14	15	17	18	19	20	22	23	24	25
Time-Of-Use Rates	19	20	22	24	25	27	28	30	31	32	34	35	36	37	39
Residential Total	**322**	**347**	**372**	**397**	**420**	**443**	**465**	**485**	**504**	**524**	**543**	**563**	**581**	**598**	**615**
Commercial															
Audit	51	60	69	77	85	91	96	101	106	110	114	117	121	124	128
Energy Efficient Design	91	96	101	106	111	115	119	122	126	129	133	137	140	144	148
Thermal Storage	3	3	3	3	4	4	4	5	5	5	6	6	6	7	7
Commercial Total	**145**	**159**	**173**	**186**	**199**	**209**	**219**	**228**	**236**	**244**	**252**	**260**	**267**	**275**	**282**

Table 4-3 (continued)
Demand-Side Management Programs
Peak Load Reduction In Megawatts

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
Industrial															
Audit/Energy Efficient Plants	217	234	249	260	270	279	286	293	299	305	310	315	321	327	333
Large Load Curtailment	67	67	67	67	67	67	67	67	67	67	67	67	67	76	76
Time-Of-Use	142	144	147	150	152	155	158	161	164	166	169	171	174	177	180
Cogeneration Displacement	279	282	286	290	295	300	305	310	314	319	324	329	335	341	346
Qualifying Facilities	196	196	196	196	196	196	196	196	196	196	196	196	196	196	196
Industrial Total	**900**	**924**	**945**	**963**	**980**	**997**	**1012**	**1027**	**1041**	**1053**	**1066**	**1079**	**1093**	**1116**	**1132**
Voltage Reduction	62	97	127	151	155	158	162	165	169	172	175	179	182	186	189
GRAND TOTAL	**1430**	**1527**	**1617**	**1698**	**1754**	**1807**	**1858**	**1905**	**1950**	**1993**	**2036**	**2080**	**2124**	**2175**	**2218**

Of the 2218 MW of summer system peak load reduction in 2006, 615 MW is attributable to residential demand-side management options. Figure 4-2 displays CP&L's 15-year plan for residential demand-side management peak load reduction. As Table 4-3 shows, nearly half of the estimated residential class peak load reduction will be achieved through the EZ-$64 (air conditioner and water heater control) program. Thermal efficiency for new and existing homes, as promoted through Common Sense Home, Homeowner's Energy Loan Program, and Residential Energy Conservation Discount, will comprise more than 40% of the demand-side management residential peak load reduction efforts. With air conditioning being the primary driver of the residential summer peak and water heating being another important end-use, CP&L has targeted the peak load reduction efforts towards these end-uses. This is evidenced by the number of demand-side management options as well as the amount of peak load reduction megawatts associated with those options. In addition to the EZ-$64 and Thermal Efficiency programs addressing air conditioning/HVAC and water heating, the High Efficiency Heat Pump and Time-Of-Use programs promote peak load reduction efforts for these two major end-uses. Targeting air conditioning/HVAC and water heating will aid CP&L's objective of improving load factor, as well as reducing the need for peaking capacity.

Figure 4-2



The residential strategy consists of a diversity of programs which utilize a wide variety of the available DSM technologies. Table 4-4 displays a high-level summary of the DSM technologies and the associated DSM programs.

Table 4-4
Residential DSM Programs

	Common Sense Home	Homeowner's Energy Loan Program	EZ-$64	High Efficiency Heat Pump	Time-Of-Use	Residential Energy Conservation Discount
DIRECT CONTROL						
Air Conditioner			x			
Water Heater			x			
BUILDING SHELL						
Insulation						
Ceiling	x	x				x
Wall	x	x				x
Floor	x	x				x
Storm Windows	x	x				x
Storm Doors	x	x				x
Window Treatments	x	x				x
CUSTOMER USAGE						
Water Heater Timers					x	
Interlock Devices					x	
Price Induced Behavior					x	
EFFICIENT END-USES						
HVAC Systems	x	x		x		x
Water Heaters	x	x				x

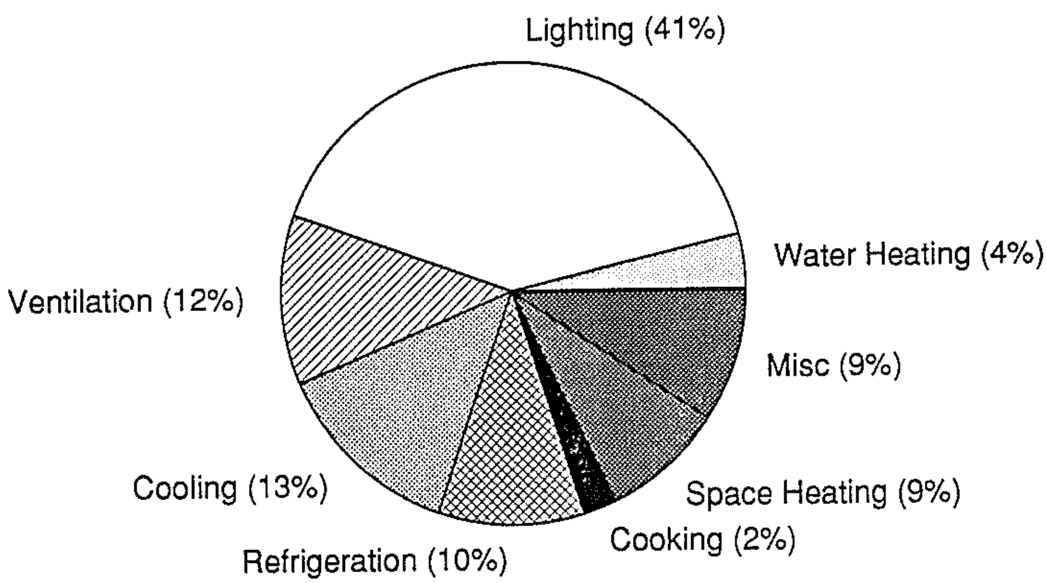
The commercial demand-side management strategy has reduced summer system peak by 133 MW as of summer 1991. This is expected to grow to 282 MW by 2006. CP&L's commercial demand-side management efforts include Energy Analysis (Audit), Energy Efficient Design, and Thermal Energy Storage.

Important loads for the commercial sector, in terms of their contribution to total energy use, include lighting, space cooling, ventilation and refrigeration. As shown in Figure 4-3 below these comprise over 74% of the total annual commercial energy usage. They are also major contributors to the commercial coincident summer peak.

Figure 4-3

1991 COMMERCIAL ENERGY SALES

BY END-USE



Correspondingly, our commercial strategy has targeted lighting and HVAC with refrigeration and water heating as secondary targets, through CP&L's Commercial Energy Analysis (Audit) and Commercial Energy Efficient Design programs.

The commercial strategy utilizes a wide variety of technologies for each of the targeted end-uses. These include technologies in the areas of lighting, building shell, efficient HVAC systems, refrigeration, water heating and energy management systems. The promotional tools are summarized into three programs, Audit, Energy Efficient Design (EED) and Thermal Energy Storage (TES). The technologies that correspond to each program are shown below in Table 4-5. The Audit program involves DSM projects for existing buildings while EED targets new construction.

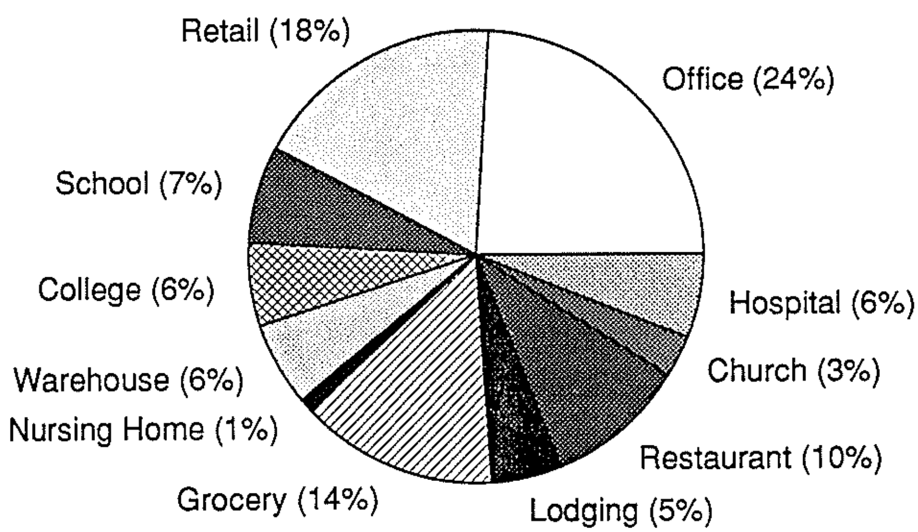
Table 4-5
Commercial DSM Programs

	Audit	Energy Efficient Design	Thermal Energy Storage
LIGHTING			
Lamps	x	x	
Ballasts	x	x	
Fixtures	x	x	
Controls	x	x	
System Design	x	x	
Daylighting	x	x	
BUILDING STRUCTURE			
Walls	x	x	
Windows	x	x	
Doors	x	x	
Roof	x	x	
Floor Surfaces	x	x	
HVAC			
Equipment Type	x	x	x
System Design	x	x	x
Compressors	x	x	x
Fans	x	x	x
Controls	x	x	x
OTHER			
Adjustable Speed Drives	x	x	
Motors	x	x	
Efficient Water Heating	x	x	
Refrigeration	x	x	
Pumps	x	x	
Energy Management Systems	x	x	

Another useful way to segment the commercial market is by customer type. Displayed in Figure 4-4 is a breakdown of the most common building types and their share of annual energy usage.

Figure 4-4

1991 COMMERCIAL ENERGY SALES
BY CUSTOMER TYPE



While virtually every customer group has participated in DSM programs, CP&L's strategy targets promotional efforts to specific segments. Priorities are determined by both the size of the segment as well as the opportunity for DSM within the segment. CP&L's primary customer-type targets have been office buildings, retail, education, restaurants, and groceries which comprise 79% of commercial energy sales.

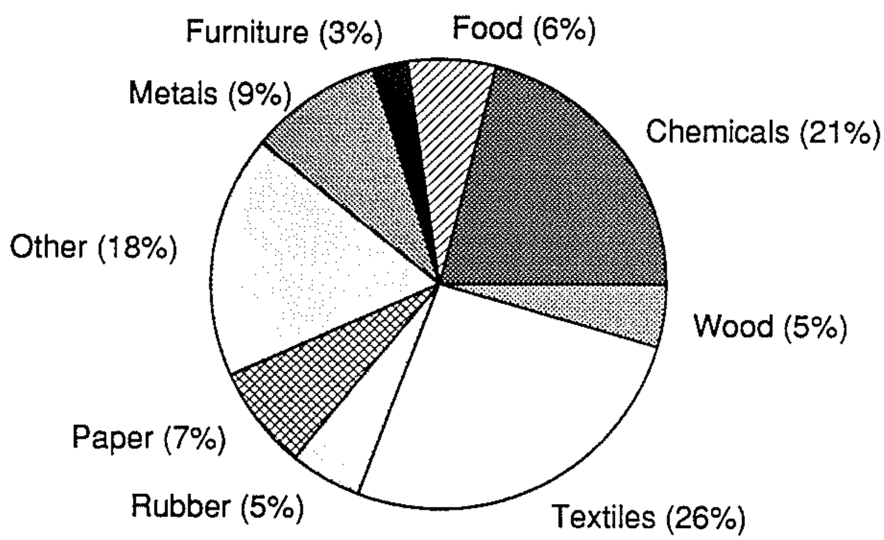
The industrial demand-side management strategy had received a system peak reduction capability of 866 MW as of the summer 1991. This is expected to grow to 1132 MW by 2006. CP&L's industrial 15-year demand-side management peak load reduction effort includes Audit/Energy Efficient Plants, Large Load Curtailment, Time-Of-Use, Cogeneration Displacement, and Qualifying Facilities.

The industrial market is typically segmented by Standard Industrial Classification (SIC) codes. Figure 4-5 displays a breakdown of the industrial contribution to summer peak by SIC code.

Figure 4-5

INDUSTRIAL SUMMER PEAK DEMAND

BY CUSTOMER TYPE



While virtually every industry classification has participated in demand-side management programs, CP&L's strategy promotes conservation and load management in specific segments. Priorities are determined by both the size of the segment as well as the opportunity for demand-side management participation within the segment. CP&L's industrial demand-side management effort has closely targeted the breakdown of SIC codes as shown in Figure 4-5 according to contribution to summer peak. Such targeting of the industrial class of customers aids in the Company's objectives of improving load factor, realizing better utilization of existing capacity, reducing the need for future generating capacity and placing downward pressure on the level and frequency of future rate increases.

The industrial strategy utilizes a wide variety of technologies for each of the targeted end-uses. These include technologies in the areas of lighting, efficient motors, efficient HVAC systems, process efficiency improvements, and cogeneration systems. The promotional tools are summarized into four programs, Audit/Energy Efficient Design (EED), TOU/TES, Curtailment, and cogeneration. The technologies that correspond to each program are shown in Table 4-6 below.

Table 4-6
Industrial DSM Programs

	Audit/EED	Time-Of- Use/Thermal Energy Storage	Cogeneration	Curtailment
LIGHTING				
Lamps	x	x		x
Ballasts	x	x		x
Fixtures	x	x		x
Controls	x	x		x
System Design	x	x		x
Daylighting	x	x		x
PROCESS EFFICIENCY				
Hot Water	x	x		x
Hot Air	x	x		x
Chilled Water	x	x		x
Chilled Air	x	x		x
Steam	x	x		x
Electrical	x	x		x
HVAC				
Equipment Type	x	x		x
System Design	x	x		x
Compressors	x	x		x
Fans	x	x		x
Controls	x	x		x
MOTORS				
Standard	x	x		x
Energy Efficient	x	x		x
Oversize	x	x		x
Belt Drives	x	x		x
Variable	x	x		x
DC	x	x		x
COGENERATION				
Topping		x	x	x
Bottoming		x	x	x
Waste Heat		x	x	x

Supply-Side Resources

Table 4-1 on the second page of this chapter shows purchases and combustion turbines as the only supply resource additions in the IRP. Analysis has shown that baseload capacity is not needed until beyond the 15-year planning horizon.

The purchases shown in the plan are both non-utility generator and utility purchases. The utility purchases (from Duke Power and South Carolina Public Service Authority by NCEMPA) are both purchases which last only a short number of years.

Combustion turbines are in the Integrated Resource Plan for several reasons. Studies continue to show that the most economical supply resource for the CP&L system is peaking capacity. This is because part of CP&L's supply strategy is to increase the utilization of its existing, dependable coal-fired capacity. By taking advantage of those valuable resources, the Company will not have to add any new baseload capacity until after 2006. Combustion turbines also have short lead times; that is, they do not take long to construct. By utilizing resources with short lead times, the Company can wait until the last possible moment to make a decision to build capacity; thus, gaining the flexibility needed to respond to changing conditions. In addition, combustion turbines have low capital costs which help to minimize the need for rate increases. While the operating costs of combustion turbines are higher than other types of supply resources, the analysis described in Appendix G shows that combustion turbines retain a cost advantage even if fuel prices increase significantly.

The 15-year Integrated Resource Plan was developed based on the integrated resource planning analysis discussed in Appendix F. The peak load and energy forecast presented in Chapter 3 was used to develop the resource plan shown in Table 4-2. The uncertainty analysis performed in the integrated resource planning analysis showed that the highest ranking plan (Plan B) continued to be the highest ranking plan even with a low energy and load forecast. The Integrated Resource Plan shown in Table 4-2 is not identical to Plan B. Plan B was adjusted to account for the lower growth in the most recent load and energy forecast.

Table 4-7 provides a projection of the fuel use by type of generation for both the existing and future resources in Table 4-2. Table 4-8 provides the capacity factors for the existing and planned resources shown in Table 4-2.

Transmission and Distribution Facilities

CP&L's transmission and distribution (T&D) facilities are an important consideration in the Company's plans for providing adequate and reliable service in a cost-effective manner. These systems must be continually evaluated and improved to provide for the adequate and reliable transfer of power from the various generation resources to the customers throughout CP&L's service area.

Table 4-7
Projected Fuel Use by Type of Generation

	1992	1993	1994	1995	1996
Existing Generation					
Coal (tons)	8,661,673	8,693,716	9,826,680	9,931,527	9,794,294
Nuclear (MBtu)	206,675,840	228,760,160	210,140,600	216,850,420	229,635,610
Combustion Turbine					
Oil (gallons)	405,494	686,800	352,704	857,056	358,483
Natural Gas (MCF)	62,125	93,861	98,104	180,750	72,029
Propane (gallons)	1,009,325	1,451,492	1,132,369	2,229,379	1,913,903
Future Generation					
Combustion Turbine					
Oil (gallons)	0	0	0	0	82,062
Natural Gas (MCF)	0	0	0	0	70,011

	1997	1998	1999	2000	2001
Existing Generation					
Coal (tons)	11,436,301	11,359,287	11,219,761	12,210,405	12,159,575
Nuclear (MBtu)	190,103,290	198,898,160	211,796,310	189,481,090	196,676,810
Combustion Turbine					
Oil (gallons)	2,289,685	2,502,815	7,015,472	6,877,800	8,761,306
Natural Gas (MCF)	453,162	387,296	1,095,940	1,424,864	1,893,415
Propane (gallons)	8,836,197	23,409,620	49,246,920	93,195,200	99,438,350
Future Generation					
Combustion Turbine					
Oil (gallons)	1,195,314	3,765,730	11,250,868	19,710,700	28,297,934
Natural Gas (MCF)	585,481	881,533	986,581	1,558,692	1,977,256

	2002	2003	2004	2005	2006
Existing Generation					
Coal (tons)	11,787,890	12,971,420	12,769,086	12,594,500	13,512,150
Nuclear (MBtu)	217,083,720	186,953,240	198,876,400	213,856,550	187,765,540
Combustion Turbine					
Oil (gallons)	5,759,910	7,199,932	7,586,650	7,160,966	9,407,388
Natural Gas (MCF)	1,627,105	2,099,967	2,608,236	2,577,783	3,413,590
Propane (gallons)	82,292,900	126,362,200	127,276,900	108,533,000	179,638,400
Future Generation					
Combustion Turbine					
Oil (gallons)	23,137,570	33,505,448	40,562,280	39,032,434	61,474,612
Natural Gas (MCF)	1,509,739	2,279,331	2,309,360	2,339,100	3,422,427

Table 4-8
Projected Capacity Factor by Type of Generation

	1992	1993	1994	1995	1996
Existing Resources					
Coal	45%	46%	52%	52%	51%
Nuclear	70%	78%	72%	74%	78%
Combustion Turbine	0%	0%	0%	0%	0%
Future Resources					
Combustion Turbine	-	-	-	-	1%

	1997	1998	1999	2000	2001
Existing Resources					
Coal	60%	60%	59%	64%	64%
Nuclear	65%	68%	72%	64%	67%
Combustion Turbine	1%	2%	4%	7%	8%
Future Resources					
Combustion Turbine	2%	2%	3%	3%	4%

	2002	2003	2004	2005	2006
Existing Resources					
Coal	62%	68%	67%	66%	71%
Nuclear	74%	64%	68%	73%	64%
Combustion Turbine	6%	10%	10%	9%	14%
Future Resources					
Combustion Turbine	3%	3%	4%	3%	5%

Cost effectiveness is one of the primary considerations in planning, constructing, and operating T&D facilities. This is accomplished through the development of alternatives in planning studies, the use of energy efficient and cost effective designs, construction of T&D facilities in an economical fashion compatible with environmental considerations, and by operating those facilities efficiently and reliably. T&D facility improvements are made based on long-term economics taking into account costs associated with engineering and design, construction, and the economic value of losses.

While the primary focus in the Company's efforts to improve its T&D facilities is centered around maintaining firm, reliable service to its customers, CP&L does this in the most overall economical manner. The effect of system losses is factored into every economic evaluation. Reducing losses can contribute to the deferral of additional supply-side resources. There are a number of practices at CP&L which focus on minimizing overall T&D-related expenses and line losses associated with operating those facilities. When performing T&D line upgrades or constructing new lines, CP&L selects optimum conductor sizes based on costs related to materials, construction and line losses. Transmission line losses are a consideration in optimizing the economic dispatch of energy from the generator to the customer. Information relating to transmission system line losses is provided to system dispatchers in selecting the most economic means of providing system energy.

The Company utilizes low loss distribution transformers as the standard for all new transformer purchases. Developments in recent years have provided further transformer loss reductions with no significant increase in transformer costs. CP&L has a program in place to compare the cost of repairing and operating an existing transformer with the cost of purchasing and operating a new low loss transformer.

The CP&L transmission system consists primarily of high capacity, low-loss 500 kV and 230 kV facilities. CP&L distribution loads are served primarily from low-loss 23 kV and 12 kV circuits. CP&L was one of the first electric utilities to use low cost high voltage designs, which reduce losses and reconductoring costs. Use of these high efficiency designs minimizes system losses and reduces the need for new supply-side resources.

In 1970, CP&L joined with neighboring utilities to form the Virginia-Carolinas (VACAR) reliability group. VACAR is a subregion of the Southeastern Electric Reliability Council (SERC), one of nine reliability regions of the North American Electric Reliability Council (NERC). Reliability groups promote the security and adequacy of bulk power supply in the electric utility systems of North America through the coordination of planning and operation of the generation and bulk power transmission facilities of the member systems. In addition, CP&L has established operating agreements with VACAR members, TVA, and Appalachian Power Company for emergency assistance, economy interchange, and other types of capacity and energy exchanges. The Company's transmission system has thirty-three transmission interconnections with seven neighboring power systems. These interconnections permit power exchanges with other utilities and provide both economic and reliability benefits to CP&L's customers.

CP&L cooperates with its neighboring utilities to perform regional transmission planning studies. Semi-annual studies focus on short-term system operating conditions for upcoming seasonal peak load periods. Additional long-range reliability studies concentrate on determining system capabilities five to ten years into the future. Both the operating studies and the reliability studies determine limitations for the transfer of power between various systems. These studies are performed jointly with utilities in the Southeastern Electric Reliability Council, the Mid-Atlantic Area Council, and the East Central Area Reliability Coordination Agreement.

Cooperation with neighboring utilities for the planning, construction, and operation of interconnected transmission systems provides many advantages over isolated operation. These advantages include emergency assistance, economy sales and purchases, and shared operating reserves which lead to more reliable and economical operation for CP&L and all parties involved. In addition, CP&L's interconnections with other utilities reduce the need for supply-side resources CP&L would otherwise have to provide to ensure an adequate and reliable supply of electric power.

Transmission Additions/Improvements

The transmission network is an important element in utility planning. The impact of loads and resources must be carefully evaluated to determine their impact on transmission system adequacy, reliability, and cost. As new forecasts and resource plans are developed, they are incorporated into the transmission planning process. The transmission planning process at CP&L involves detailed analysis of the transmission system to determine if adequate levels of service can be maintained under various operating conditions. These analyses typically involve loadflow, stability, transient voltage, and system reactive studies. Once a problem has been identified, several alternative solutions which alleviate the problem are developed. An economic evaluation of the proposed alternatives is performed. This evaluation includes the cost of construction, the cost of losses, and other financial considerations. The best overall alternative, from a combined technical and economic appraisal, is recommended as the appropriate course of action to eliminate the original problem. The recommended solution then becomes a part of the transmission expansion plan.

Using this process, the CP&L system has grown to over 6,000 miles of 69, 115, 138, 161, 230, and 500 kV transmission lines in its North and South Carolina service areas. The primary purpose of this transmission system is to provide the bulk power electrical path from generating units to customer loads at the substations located throughout the CP&L service area.

CP&L has experienced steady load growth in recent years and is in need of additional transmission facilities and power resources to assure a reliable supply of electric power. This need is particularly acute in CP&L's western service area around Asheville, North Carolina where load growth is reaching the limits of existing transmission facilities during peak load emergency conditions.

An agreement between CP&L and AEP provides for the strengthening of transmission interconnections between their respective systems. This strengthening involves upgrading of existing 138 kV facilities to 230 kV in CP&L's western service area and construction of 500 kV facilities in CP&L's eastern service area. The strengthened transmission facilities will provide timely reliability improvements in CP&L's western service area and allow the continuance of reliable and economical service to CP&L's customers in the Asheville area. The transmission interconnections with AEP also increase CP&L's options for meeting the future energy needs of our customers and enhance our ability to negotiate economic purchases and sales of electricity within a broader market, resulting in potential cost savings for our customers. These projects and others are included in the long-range transmission plan which is shown in Table 4-9.

Table 4-9
CP&L Transmission Line Additions (Continued)

	Location				
YEAR	FROM	TO	CAPACITY MVA	VOLTAGE KV	COMMENTS
1992	Cane River	(APCO) Nagel Interconnection	617	230	Conversion
	Cane River	Craggy West	534	230	Conversion
	Cary Regency Park-Durham	Cary Triangle Forest	408	230	Tap*
	Castle Hayne-Jacksonville	Topsail	408	230	Tap*
	Brunswick Plant-Castle Hayne 230 kV West	Wilmington Corning	408	230	Tap*
	Brunswick Plant	Delco	534	230	Uprate
	Cane River	Burnsville	83	115	Conversion from 138 kV
1993	Roxboro Plant	Falls	534	230	Relocate & Extend
	Milburnie	Falls	534	230	Relocate & Extend
	Harris Plant-Erwin	Duncan	408	230	Tap*
	Raleigh Leesville 230 kV Sub	Raleigh Leesville #2	408	230	Tap*

Table 4-9
CP&L Transmission Line Additions (Continued)

YEAR	Location FROM	TO	CAPACITY MVA	VOLTAGE KV	COMMENTS
1994	None				
1995	New Bern - Womack	Dover	408	230	Tap*
	Aurora Switching Sta.	New Bern	617	230	New
	Durham	Falls	1234	230	New
	Fayetteville	Fayetteville East	1234	230	Reconductor
	Harris Plant	Fayetteville	1234	230	Relocate & Extend
	Fayetteville East	Smith Lake	1234	230	New
	Wilmington East 230 kV Sub	Wilmington East #2	408	230	Tap*
	Durham - Falls	Raleigh Mt. Vernon	408	230	Tap*
	Method	Milburnie	534	230	Uprate
	Roxboro Plant	Falls	534	230	Uprate
	Falls	Milburnie	534	230	Uprate
	Milburnie	Person	534	230	Uprate

Table 4-9
CP&L Transmission Line Additions (Continued)

YEAR	Location FROM	TO	CAPACITY MVA	VOLTAGE KV	COMMENTS
1996	Lenoir	Wake	4025	500	New
	Greenville	Lenoir	617	230	New
	Harris Plant-Wake	Holly Springs	408	230	Tap*
	Florence-Kingstree	Florence Cashua	408	230	Tap*
	Harris Plant-Asheboro	Siler City Hwy 64E	408	230	Tap*
	Darlington Co. Plant-Sumter	Sumter Guignard Dr.	408	230	Tap*
	Darlington Co. Plant	Sumter	534	230	Relocate
	Robinson Plant	Sumter	534	230	Relocate to Darlington County Plant
	Cary Piney Plains 230 kV Sub	Cary Piney Plains #2	408	230	Tap*
1997	Person	Axton (APCO) Interconnection	4025	500	New
	Wilmington Winter Park 230 kV Sub	Wilmington Winter Park #2	408	230	Tap*
	Brunswick Plant	Castle Hayne East	534	230	Relocate
	Milburnie	Wake	1068	230	Uprate

Table 4-9
CP&L Transmission Line Additions (Continued)

YEAR	Location FROM	TO	CAPACITY MVA	VOLTAGE KV	COMMENTS
1998	Asheville Plant	Enka East	534	230	Conversion
	Asheville Plant	Enka West	534	230	Conversion
	Enka	West Asheville	534	230	Conversion
	Craggy	West Asheville	534	230	Conversion
	Havelock	Cherry Point	408	230	Conversion
	Method-Milburnie	Raleigh Centennial Campus	408	230	Tap*
	Bonnie Doone 230 kV	Bonnie Doone #2	408	230	Tap*
	Florence DuPont	Hemingway (SCPSA)	308	115	Rebuild for 230 kV, Operate 115 kV
	Havelock	Carteret Craven EMC Havelock 115 kV POD	308	115	Rebuild for 230 kV, Operate 115 kV
	Method	Milburnie	308	115	Rebuild for 230 kV, Operate 115 kV

Table 4-9
CP&L Transmission Line Additions (Continued)

YEAR	Location FROM	TO	CAPACITY MVA	VOLTAGE KV	COMMENTS
1999	Sutton Plant	Delco	1068	230	Reconductor
	Morehead Wildwood 230 kV Sub	Morehead Wildwood	408	230	Tap*
	Farmville 230 kV	Farmville	408	230	Tap*
	Lee 230 kV Sub	Mt. Olive	308	115	Rebuild for 230 kV, Operate 115 kV
2000	Jonesboro 230 kV Sub	Sanford Switching Station	617	230	New
	Sutton Plant	Castle Hayne North	617	230	Conversion
	Robinson Plant-Rockingham	Cheraw Cash	408	230	Tap*
	Milburnie-Falls	Raleigh Homestead	408	230	Tap*
	Person-Rocky Mt.	Nashville Matthews	408	230	Tap*
	Roxboro Plant-Durham	Roxboro West	408	230	Tap*
	Enka-West Asheville	Skyland Industrial Park	408	230	Tap*
	Erwin-Milburnie	Garner I-40E	408	230	Tap*
	Roxboro-Method	Raleigh Honeycutt	408	230	Tap*
	Rockingham-West End	Whispering Pines	408	230	Tap*
	Clinton	Vander	308	115	Rebuild for 230 kV, Operate 115 kV

Table 4-9
CP&L Transmission Line Additions (Continued)

YEAR	Location FROM	TO	CAPACITY MVA	VOLTAGE KV	COMMENTS
2001	Havelock	New Bern	617	230	Conversion
	Havelock-Jacksonville	Jacksonville Hwy 17N	408	230	Tap*
	Weatherspoon Plant-Laurinburg	Lumberton West	408	230	Tap*
2002	Rocky Mount	Wilson	617	230	Conversion
	Milburnie-Falls	Raleigh Bayleaf	408	230	Tap*
	Cape Fear-West End	Olivia	408	230	Tap*
2003	Cary Regency Pk.-Method	Cary Penny Rd.	408	230	Tap*
2004	Raleigh Six Forks 230 kV Sub.	Raleigh Six Forks #2	408	230	Tap*
	Clinton-Erwin	Dunn East	408	230	Tap*
2005	Method	Milburnie South	617	230	Conversion
	Cary Regency Pk.-Durham	Cary Green Level	408	230	Tap*
	Robinson Plant-SCPSA Darlington	Hartsville Hwy 15 By-Pass	408	230	Tap*
	Brunswick Plant-Castle Hayne 230 kV East	Wilmington Hillside	408	230	Tap*
	Raleigh Oakdale 230 kV Sub.	Raleigh Oakdale #2	408	230	Tap*
2006	Roxboro Plant-Method	Raleigh Rowland Rd.	408	230	Tap*

*Tap - Connection made at intermediate points on circuit.

Comparing the Plan to CP&L's IRP Objectives and Planning Principles

As discussed in Chapter 1, the overall objective of the Integrated Resource Planning process is to develop a flexible resource plan that will provide an adequate and reliable supply of electric power to our customers at the lowest reasonable cost. To accomplish this objective, plans are developed in accordance with certain planning principles, as discussed in Chapter 2. This section compares the Integrated Resource Plan to the overall objective and to CP&L's planning principles.

Overall Objective

CP&L's IRP achieves the overall objective by incorporating a cost-effective mix of demand-side and supply-side resources which will improve the utilization of existing resources and will minimize the price of electricity. This is achieved by demand-side programs which reduce the growth in peak demand, the purchase of power from other utilities and non-utility sources when it is less expensive than building our own plants, and the addition of low-cost, short lead-time peaking capacity. In addition, demand-side programs which shift energy use to off-peak times will improve the utilization of our existing capacity, thereby improving productivity and operating efficiency, and lowering the cost per unit of output.

Flexibility

The first planning principle is to maintain flexibility to adjust to changing conditions. The Integrated Resource Plan exemplifies how CP&L adheres to this planning principle. The planning analysis discussed in Appendix F was performed before the load and energy forecast (discussed in Chapter 3) was complete. Once it was determined that the slow growth forecast was the best proxy for the electricity needs to be served by CP&L, the Integrated Resource Plan was modified to conform to the new load forecast.

Since the Integrated Resource Plan contained short lead-time combustion turbines, the plan could be changed without penalty. Had an annual review not been performed, the Darlington Addition, which was scheduled to be in-service in 1994, would have started construction. By delaying the in-service date of the Darlington Addition to 1996, the Company can continue to investigate other methods of serving customers' needs, such as through new demand-side management programs.

This points to a primary advantage of having combustion turbines in a resource plan. Their short lead-time allows the decision to begin construction to be made at the latest possible moment. To enhance flexibility, CP&L plans to maintain the option to bring the Darlington Addition on-line in 1995, should load growth be higher than expected.

Flexibility is also an important concept in the DSM process. The pace of DSM can be adjusted up or down depending on progress to date, customer acceptance, anticipated program enhancements, and expected business conditions.

Reliability

The Integrated Resource Plan was developed using a 16.7% capacity margin reliability criteria to ensure that the reliability of the generation system met the reliability requirements. Although capacity margins are slightly below 16.7% in some years, loss of load probability (LOLP) analyses confirmed that the IRP provides adequate reliability in all years of the 15-year planning horizon.

Diversity

Since 1981, when CP&L first implemented an integrated resource planning process, one of the focuses has been on resource diversity. Figure 4-6 shows the resource additions made and planned by CP&L since in 1981. The figure shows that CP&L has added (or is planning to add) seven different types of resources. In the early- and mid-1980s the Company added baseload nuclear and coal-fired capacity. In the late-1980s and early-1990s, baseload and intermediate purchases were made from utility and non-utility generators. In the late- and mid-1990s, the plan calls for the addition of peaking capacity in the form of combustion turbines.

Throughout the time period, a mix of demand-side resources contribute a significant portion of the additions. CP&L defines demand-side management diversity from two perspectives, from the point of view of the customer as well as from the perspective of the Company. CP&L offers a menu of demand-side management options to all major retail customers. Additionally, CP&L's demand-side management efforts include the five major load shape objectives, strategic conservation, load shifting, peak clipping, valley filling, and strategic load growth. The figure clearly demonstrates that the plan implements the planning principle to emphasize resource diversity as an appropriate response to future uncertainty.

Reliance on Oil and Gas

The fourth planning principle used by CP&L to evaluate resource plans is to avoid excess reliance on oil and natural gas fueled resources. This principle is a reminder of the supply disruption in the 1970s and is focused on the continued uncertainty in oil and gas availability and price. While the majority of the additions in the preferred resource plan are combustion turbines, the amount of energy produced by these oil and natural gas fueled resources is projected to remain small. Figure 4-7 is a pie chart depicting the sources of energy for the CP&L system in the year 2006. The figure shows that only a small portion of the energy of the system (less than 4%) will be generated from oil- and natural gas-fired resources. Thus, this principle is also adhered to by the Integrated Resource Plan.

Figure 4-6

CP&L RESOURCE ADDITIONS

1981 - 2006

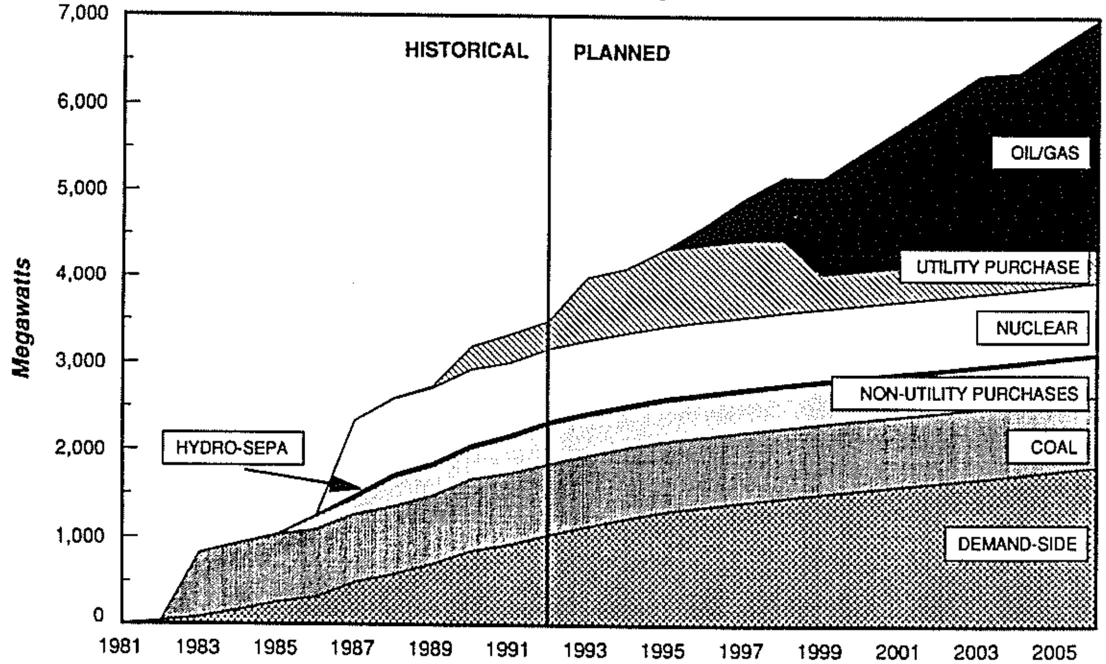
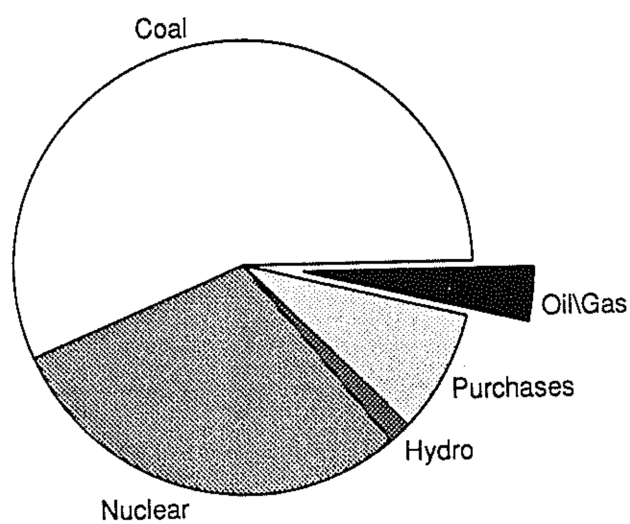


Figure 4-7

CP&L ENERGY MIX

2006



Plan Revisions

The IRP discussed in this chapter is CP&L's Integrated Resource Plan at this point in time. Future plans may or may not be the same as the current plan. CP&L continually reviews the resource plan through the use of regular planning cycles. It is through this regular review that the plan adapts to changing conditions.

The integrated resource planning process discussed in Chapter 2 will continue to evolve and improve as it has over the past 10 years. CP&L monitors planning activities, methodologies, and models in search of better ways to plan for the reliable and economic supply of electricity in the service territory.

While the plan shows a significant amount of combustion turbines being added in the future, all but the 225 MW Darlington addition are undesignated. Studies have shown that the resources that are needed by the system are peaking resources. These resources are not necessarily combustion turbines. The Company continues to research economical and efficient demand-side and supply-side options. As technologies improve, they may become part of future resource plans. CP&L constantly receives new proposals for non-utility generation. All proposals are thoroughly evaluated to determine if the customer and the shareholder can benefit from the purchase of the power. When it comes time to make commitments on how to satisfy the demands of its customers, CP&L will choose the most economical resource that will allow the Company to maintain its reliability yet continue to be flexible enough to respond to changing conditions.

Table of Contents

Volume II

Appendices

Table of Contents

Volume II (Continued)

Appendix A
End-Use And Load Shape Forecasts

Part 1 - End-Use Forecasts

Introduction

Historically, Carolina Power and Light Company has used econometric modeling to forecast electric energy sales. In response to the changing character and determinants of energy usage patterns, CP&L has augmented its forecasting methods with end-use models.

This year marks the first time that two independent methods were used to develop residential and commercial energy projections. Econometric and highly detailed end-use methods were used for these two revenue classes. The EPRI-developed REEPS and COMMEND models were used for the residential and commercial class end-use forecasts, respectively.

The use of two approaches should not be viewed as superfluous duplication. Each forecasting method has unique strengths which largely determine the usefulness of the results. Econometric approaches have the strength of using observable market-determined trends spanning many years, but do not immediately capture structural shifts in market behavior. End-use approaches, on the other hand, have the strength of modeling explicit technology and appliance choices, but do not base such choices on data from a single year.

End-use models require the collection and analysis of an enormous amount of data. Both REEPS and COMMEND come with national and regional default data. However, these data must be analyzed and changed where appropriate to service area specific values.

Both REEPS and COMMEND model energy consumption based on the stock of equipment, and the efficiency and utilization of that equipment. These models combine engineering detail with economic relationships to produce appliance specific forecasts.

The focus of end-use models is on the disaggregate final uses of energy such as heating, air conditioning, water heating, lighting, etc. This approach provides a framework for analyzing highly detailed energy usage patterns and the likely change in these patterns from such things as fuel prices, appliance costs, efficiency trends, and technology choices.

The detailed end-use and aggregate econometric forecast results are compared to assess model validity and reliability. This procedure acts as a verification for the results of each model. In this way, the strengths of each model are maximized. This comparison of model results showed that the end-use and econometric forecasts were very similar and consistent.

Residential End-Use Model - REEPS

Model Overview

Carolina Power & Light Company develops its end-use forecast of residential energy sales using the EPRI-developed Residential End-Use Energy Planning System (REEPS) model. REEPS is an integrated end-use/econometric forecasting model. REEPS is both a forecasting tool for estimating future energy use in the residential sector and a planning tool for gauging the effects of various influences on the forecast, such as appliance efficiency standards. The focus of the REEPS model is to disaggregate energy usage patterns into highly detailed end-uses.

REEPS and other end-use models require vast amounts of market information and behavioral assumptions. REEPS models consumer appliance purchase decisions, efficiency choices, and utilization patterns for ten end-uses using multinomial and nested logit systems. These decisions are modeled with information on household and dwelling characteristics, demographic characteristics, fuel prices, fuel availability, weather patterns, and appliance attributes. The models provide detail by appliance for each of four structure types (single family detached, small multi-family attached, large multi-family attached, and mobile homes).

Nine explicit end-uses are forecast: HVAC (heating, ventilation, and air conditioning), water heating, dishwashing, clothes washing, clothes drying, cooking, first refrigerators, second refrigerators, and freezers. The tenth end-use, "other", represents all other appliances and lighting collectively.

REEPS is programmed as a series of modules, each containing specific types of input data and parameters. A description of each module follows:

Fuel Price Module
The Fuel Price Module is used to provide fuel prices for the base year (1990) and each forecast year. Fuel price forecasts are input for electricity (summer, winter, and annual average), natural gas, fuel oil/other, and wood in real (deflated) or nominal terms (with a deflator). The program converts all prices to common units of $/million Btu.

Exogenous Variable Module
The Exogenous Variable Module is a database for base year and forecast values of selected variables. These include forecasts of single family housing stock, income, household size, weather, appliance efficiency standards, fuel availability, and other exogenous variables used for appliance choice, efficiency level, or usage.

Households Module
The Households Module is used to provide forecasts of housing stock for small multi-family, large multi-family, and mobile homes. For each structure type, there is a distribution for ages of the structure (vintage blocks) and decay rate.

Demographic Segments Module

The Demographic Segments Module is a framework for segmenting the residential sector into demographic segments. By segmenting, a more accurate representation of the market is possible. Currently, the REEPS forecast is segmented by structure type. Data provided include base year and forecast distributions across segments and base year values for each segment category.

HVAC Module

The HVAC Module calculates base year and forecast energy consumption for 18 different combinations of primary heating, cooling, and ventilation equipment by structure type. It also calculates the energy requirements of three different secondary heat options and one secondary cooling option. In addition to energy requirements, the HVAC Module forecasts appliance saturation, penetration, and efficiency as well as thermal shell efficiency for each type of structure. Data requirements includes base year saturation and penetration rates for each combination of primary and secondary heating, cooling, and ventilation equipment by structure. Also required are average and marginal appliance size and efficiency values, base year unit energy consumptions (UECs), capital costs, thermal shell efficiency, and availability information for each appliance by structure type.

Appliance List Module

The Appliance List Module defines the end-uses that are active in a model run. For each end-use active on the appliance list, there must be an appliance module prepared and updated. The appliance list also tells the directory location and filename for each of the active appliance modules.

Appliance Modules

An Appliance Module is created for each end-use, providing a general framework for modeling appliance purchases, usage, and efficiency choices. Ultimately, the quantity of a particular appliance, the usage pattern for that appliance, and the efficiency of that appliance will determine the energy consumed by that appliance. Aggregating the energy of all appliances within an end-use yields the total energy consumed by that end-use. In addition to forecasting energy requirements, the appliance modules forecast saturation, penetration, efficiency, and usage of each appliance by structure type. Data required for each appliance includes base year saturation and penetration rates, average and marginal efficiencies and size, UECs, capital costs, and availability by structure type.

Major Inputs And Assumptions

The inputs and assumptions required to run the REEPS model are many and to provide all of the inputs and assumptions in this report would make it voluminous. Therefore, listed below are the major inputs and assumptions in CP&L's 1991 REEPS forecast.

A considerable amount of end-use data are not available on a utility service-area basis. Utility-specific data was used where available; otherwise state, regional, and national data were employed. The REEPS program comes with a complete set of default data based on national surveys for a 1987 base year. A list of data sources is shown in Table A1-1. Assumptions made in the residential end-use forecast are consistent with those used in the econometric forecast.

Forecasts of electricity prices are identical with those used in the econometric forecast. Forecasts of natural gas prices are based on information from the North Carolina Utilities Commission Annual Report and DRI. Fuel oil/other price forecasts are from DRI. Firewood prices are expected to rise at 1% above the rate of inflation, the same rate as in the REEPS default data. Average compound annual growth rates of real fuel prices (1990 dollars) for the period 1991 through 2006 are projected as follows: electric -0.5%, gas 2.5%, oil/other 2.6% and firewood 1%.

Demographic characteristics assumptions made in the residential end-use model are similar to those assumptions made in the econometric model. The breakdown of residential structure types in the base year in CP&L's service area is as follows: single family detached 69%, small multi-family attached 7%, large multi-family attached 10%, and mobile homes 14%. Base year median household income in the company's service area is estimated to be approximately 34,000 dollars.

Forecasts of household income and total structures are identical with those used in the econometric forecast. Real median household income is projected to increase at an average compound growth rate of 1.9% from 1991 to 2006. Average compound annual growth rates in residential structure types are projected for the 1991 through 2006 period as follows: single family detached 1.1%, small multifamily attached 2.3%, large multi-family attached 1.7%, and mobile home 1.5%. Forecasts of more detailed demographic variables are based on North Carolina state data.

Normal heating and cooling degree days are used for the forecast. Finally, forecasts of efficiency standards are based on existing and likely future efficiency standards consistent with the National Appliance Energy Conservation Act of 1987 and the 1990 amendments. Further growth in minimum efficiency is assumed throughout the forecast consistent with the language in the standards.

Adjustments To The REEPS Forecast

The REEPS forecast reflects CP&L DSM programs and is consistent with the econometric forecast. For HVAC end-use energy, the results of the High Efficiency Heat Pump program have been incorporated. Total (aggregated) end-use energy has been reduced to reflect projected voltage reduction capability.

REEPS Results

A detailed forecast of energy consumption for ten end-uses was completed for CP&L's residential class using three scenarios. Each scenario was based on various demographic inputs (from the Exogenous Variable Module) consistent with those used in the corresponding econometric scenario. A summary of the Slower Growth scenario results for each end-use and for the residential class in total is given in Table A1-2.

For the years 1990 through 2006, residential class energy consumption is expected to increase by 2.2% per year (on a weather normalized basis). The most rapidly growing end-use category is dishwashing (4.1% per year) due to the high penetration of dishwashers in CP&L's service territory. Rapid growth is also anticipated for the "other" end-use as increased electrification continues to occur within the home. Very slow growth is forecast for refrigeration (first and second refrigerators combined) and freezing. This occurs despite a sharp increase in the saturation of second refrigerators because of large increases in the average efficiency of these appliances. Moderate growth is anticipated for the other end-uses.

Comparison With The Econometric Forecast

Figure A1-1 shows a comparison between the Slower Growth econometric scenario and the end-use residential energy forecast scenarios. Both methodologies show relatively higher annual growth through the year 2000 and then relatively slower growth from 2000 to 2006. Comparing the Slower Growth scenarios, the Econometric model predicts slightly more rapid annual growth in the first decade (2.9%) than the End-Use (2.4%), then slower growth from 2000 to 2006 (1.5% versus 1.8% respectively). The two forecasts begin to converge after 1998. As shown, the end-use forecasts bracket the econometric forecast Slower Growth scenario.

Conclusion

In 1991 Carolina Power & Light Company developed a forecast of residential energy sales using the EPRI-developed REEPS model. REEPS is a modular framework for developing, organizing, and performing forecasts of residential energy sales at the end-use level. It is also a tool for gauging the effects of various influences on the forecast such as appliance efficiency standards. REEPS models consumers' appliance selections, efficiency choices, and utilization patterns for ten end-uses. It segments each of these end-uses by four structure types.

The REEPS model requires vast amounts of data, of which a considerable portion is not available on a service area basis. Service area specific data were utilized where available. All data inputs and assumptions for REEPS are consistent with the Company's econometric models, including electricity prices, other fuel prices, income, and residential customers.

The results of the REEPS forecast are consistent with the econometric model. Both models predict relatively higher annual growth rates for the first half of the forecast horizon, followed by slower growth rates in the second half. Overall annual growth rates were approximately the same (2.2 - 2.4% in the Slower Growth scenarios). The REEPS model predicts rapid energy growth for dishwashers and "other" end-uses and slow energy growth for refrigeration and freezing.

While the results of both the REEPS end-use and the econometric forecasts are consistent, the use of the two approaches should not be considered superfluous duplication. The combination of strengths of each methodology helps to verify the usefulness and reliability of the results. The econometric forecast focuses on long-term market-determined trends but fails to capture immediate structural shifts in market behavior. The REEPS forecast captures these shifts immediately, but bases such behavior on data only from the most recent past. The fact that both models present similar results is a strong indication of forecast reliability.

TABLE A1-1

MAJOR INPUTS TO THE REEPS MODEL

DATA	SOURCES
I. Fuel Price Forecasts	
A. Electricity	CP&L Forecast
B. Natural Gas	NCUC Report and DRI
C. Oil/Other	DOE/EIA Report and DRI
D. Wood	CP&L Forecast
II. Other Exogenous Variable Forecasts	
A. Income	CP&L Service Area Economic Forecast and the State Data Center
B. Number of Members per Household	CP&L Forecast using the State Statistical Register historic values
C. Forecast of Structures (4 types)	CP&L Service Area Economic Forecast, DRI and CP&L Appliance Information Survey
D. Efficiency Standards	National Appliance Energy Conservation Act of 1987 with 1990 Amendments, Growth in efficiency is consistent with these standards
E. Weather Data	National Oceanic and Atmospheric Administration data weighted by CP&L area weather stations. Normal weather assumed constant through forecast.
F. Natural Gas Availability	CP&L 1990 Appliance Information Survey with penetration assumed constant through forecast
G. Rural/Non-Rural Homes	CP&L Forecast using the State Statistical Register historic values
H. Discount Rates	REEPS national sample data
III. Appliance Data	
A. Saturations	CP&L 1990 Appliance Information Survey, REEPS sample data
B. Penetrations	CP&L 1990 Appliance Information Survey, REEPS sample data
C. Efficiencies	REEPS sample data (updated from 1987 to 1990 base)
D. Unit Energy Consumptions	CP&L Load Research & DSM data, AEIC Load Research data, REEPS sample data
E. Other Appliance Data	REEPS national sample data

FIGURE A1-1

COMPARISON OF RESIDENTIAL ENERGY FORECASTS

1991 REEPS AND ECONOMETRIC MODELS

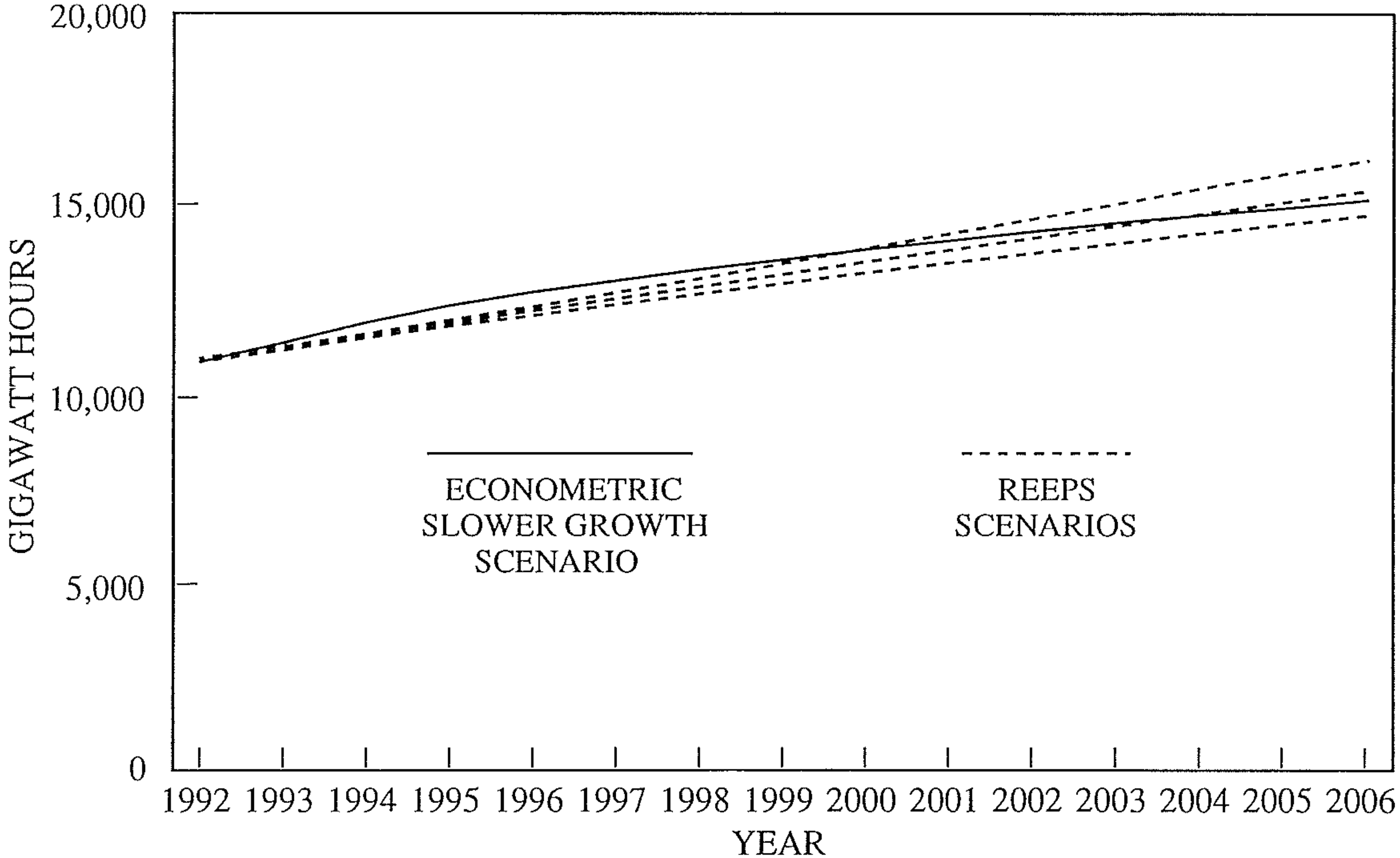


TABLE A1 - 2

CAROLINA POWER & LIGHT COMPANY
1991 RESIDENTIAL END-USE ENERGY FORECAST
SLOWER GROWTH SCENARIO
REDUCED FOR CONSERVATION & LOAD MANAGEMENT
(GWH)

	HVAC (ADJUSTED) (GWH)	WATER HEATING (GWH)	DISH WASHERS (GWH)	CLOTHES WASHING (GWH)	CLOTHES DRYING (GWH)	REFRIGER-ATION (GWH)	FREEZING (GWH)	COOKING (GWH)	OTHER (GWH)	TOTAL (ADJUSTED) (GWH)
1991	3,571.6	2,385.9	108.4	67.5	550.1	897.9	345.0	429.3	2,175.0	10,529.5
1992	3,667.5	2,451.0	114.4	69.2	567.7	916.7	347.0	436.1	2,227.5	10,793.7
1993	3,789.7	2,522.3	120.7	71.1	586.9	920.3	347.6	443.3	2,298.2	11,094.7
1994	3,907.7	2,596.8	127.3	73.1	607.1	924.4	348.2	451.3	2,379.1	11,407.8
1995	4,006.3	2,666.5	133.7	75.0	626.1	927.2	348.3	458.9	2,462.8	11,696.1
1996	4,094.5	2,733.0	139.9	76.8	644.6	929.4	348.3	466.4	2,552.2	11,975.9
1997	4,177.9	2,796.6	146.0	78.5	662.5	931.4	348.3	473.7	2,649.8	12,255.1
1998	4,257.2	2,857.9	152.0	80.3	679.9	933.6	348.3	480.6	2,755.7	12,535.5
1999	4,334.0	2,917.9	158.0	81.9	697.0	936.0	348.5	487.5	2,869.8	12,820.2
2000	4,396.0	2,976.9	164.0	83.6	714.1	938.9	348.9	494.6	2,991.1	13,097.3
2001	4,443.2	3,032.1	169.7	85.3	730.5	941.8	349.4	501.5	3,112.6	13,354.8
2002	4,492.4	3,086.7	175.4	86.9	746.7	945.2	350.2	508.3	3,233.3	13,613.4
2003	4,543.0	3,141.1	181.1	88.5	762.7	949.3	351.4	514.9	3,353.1	13,873.0
2004	4,596.4	3,193.1	186.5	90.0	778.1	954.4	353.2	520.9	3,470.4	14,130.4
2005	4,641.4	3,241.5	191.8	91.4	792.7	960.6	355.4	526.5	3,584.4	14,372.6
2006	4,681.5	3,288.8	197.0	92.7	807.2	968.3	358.1	532.0	3,698.1	14,610.1
Average Annual Growth	1.8%	2.1%	4.1%	2.1%	2.6%	0.6%	0.3%	1.4%	3.5%	2.2%

NOTE: HVAC is adjusted for effects of the Residential High Efficiency Heat Pump Program, TOTAL is reduced for Voltage Reduction

Commercial End-Use Model - COMMEND

Model Overview

Carolina Power & Light Company uses the EPRI-developed COMMEND model for its commercial sector end-use forecast. COMMEND is a computer modeling tool that develops, organizes, and forecasts commercial energy use patterns at the end-use level. COMMEND can be used to analyze the impacts of changes in energy prices, technology efficiencies, and economic growth on the forecast.

The COMMEND model segments the commercial market by building type and end-use. COMMEND is designed in a modular structure with each module containing a specific class of data and parameter inputs. These modules are briefly explained below:

Fuel Price Module
The Fuel Price Module is used to enter fuel price history and forecast values for up to three competing fuel types. A deflator series used to convert nominal prices to real values is also entered. The program converts all prices to common units in $/million Btu.

Floor Stock Module
The Floor Stock Module defines building types in the commercial sector. The model estimates floor space by building type for both a historical and a forecast period. Survival functions are entered for each building type in order for the model to calculate net floor space in any historical or forecast year.

Market Profiles Module
Energy use profiles are entered for each building type into the Market Profiles Module. The key parameters are fuel shares and energy use indices (EUI) values. Fuel share and EUI values are entered for each building type by end-use and the corresponding energy intensity and sales values are interactively updated.

Technology Data Module
In the Technology Data Module information concerning end-use efficiencies and costs are entered. The major inputs are listed below:

> **Heat Pump Data.** When dealing with heating, ventilation, and air conditioning (HVAC) energy use, the presence of heat pumps, which provide both heating and cooling must be considered. The electric heating EUI value in each building type is a weighted average of heat pump and electric resistance heating technologies. The purpose of the heat pump data is to allow the average EUI value to be unbundled into heating and cooling technology components.
>
> **Capital Costs.** Average equipment costs in new construction for all end uses are required.

Tradeoff Data. Tradeoff elasticities between equipment costs and energy in new construction are required. The concept behind these parameters is the existence of a technology curve representing the range of available technologies. The marginal EUI and capital cost values represent weighted averages across options on this curve.

Efficiency and Cost Trends and Shifts. These are parameters that describe trends and shifts in the efficiency tradeoff curves, and trends and shifts in equipment costs.

Thermal Interactions. Two sets of interactions with HVAC energy use are modeled directly through interaction elasticities. The first set describe the impacts of changes in internal heat gains from lighting and miscellaneous equipment on HVAC energy use. The second set of parameters describe the impacts of changes in the building thermal shell on HVAC energy use.

Economic Data Module. The Economic Data Module is used to enter information about decision makers and decision rules. Given this information, parameters for choice functions are calibrated and reduced form elasticities are simulated by the model. A brief description of the types of economic data requirements follows.

Decision Maker Data. Two types of decision maker data are required. The first is a set of distributions for discount rates. Separate distributions can be entered for each building type. The second type of decision maker data is a set of weights for price expectations. The price weights allow the introduction of distributed lags of past prices.

Choice Elasticities. These parameters indicate the sensitivity of equipment decisions to life-cycle cost. These parameters are used to simulate efficiency elasticities and fuel share changes.

Utilization Elasticities. These parameters indicate the sensitivity of equipment usage to energy prices. These parameters are used directly in the forecast to simulate changes in usage levels over time.

Replacement Factors. Two sets of replacement parameters are entered. These parameters are fuel share and EUI inertia factors. These variables serve as an adjustment between fuel share and efficiency changes in new buildings and the degree to which these changes are adopted in older buildings.

Thermal Integrity Trends. These parameters describe the change in overall thermal integrity in new buildings during the forecast period.

Retrofit Penetration Changes. These parameters control changes in the penetration of end uses in existing structures.

Miscellaneous Electric EUI Growth. These parameters allow miscellaneous electric EUI values to grow independently for each building type.

Forecast Calculation

Once the above data has been entered into COMMEND and a forecast period and the building types to include in the forecast are selected, a forecast is then performed. Energy use in any forecast year is determined by building vintages of floor stock, end-use fuel share, EUI, and utilization.

The COMMEND results provide a detailed description of current and future energy use patterns in the commercial sector. For each building type and end-use the model estimates fuel shares, EUIs, utilization, energy intensities, and energy sales.

Major Inputs And Assumptions

The inputs and assumptions required to run the COMMEND model are many and to provide all of the inputs and assumptions in this report would make it voluminous. Therefore, listed below are the major inputs and assumptions in CP&L's 1991 COMMEND forecast.

A considerable amount of end-use data is not available by utility service area. Utility-specific data was used where available, otherwise state, regional, and national data were used. A list of data sources is shown in Table A1-3.

Fuel Prices
Historical electric prices were collected from CP&L data, historical gas prices were obtained from North Carolina Utilities Commission reports, and historical oil prices were obtained form the DOE Annual Energy Review. The forecast of electric, gas, and oil prices are identical to fuel price projections from the 1991 Econometric forecast.

Average compound annual growth rates of real fuel prices (1987 dollars) for the period 1991 through 2006 are projected as follows: electric -0.01%, gas 2.5%, and oil 2.2%.

Floor Stock
CP&L's end-use forecast includes 11 building types: office, retail, warehouse, grocery, restaurant, lodging, nursing home, hospital, elementary and secondary schools, higher education, and church. Commercial employment by SIC code was used as the basis for both historical and forecast floor space. Commercial employment projections used in the COMMEND forecast are consistent with commercial employment projections in the Econometric forecast.

Employment by 2-digit SIC code was mapped into building types using the COMMEND mapping scheme. Table A1-4 shows the building types in the Company's forecast and the corresponding SIC codes that they encompass.

CP&L's historical and forecast commercial employment data is by 1-digit SIC code. Therefore, the ratios of employment by 2-digit SIC codes to corresponding 1-digit SIC codes were calculated based on the North Carolina Employment and Wages Reports. These ratios were averaged for the 1975 through 1990 period and then applied to the Company's 1-digit SIC code data in order to calculate historical and to forecast service area commercial employment by 2-digit SIC code.

Floor space per employee by building type was calculated on the basis a 1985 Synergic Resources Corporation (SRC) study of CP&L's commercial sector (see Table A1-5). Historical and projected employment by building type, and floor space per employee by building type were used to construct commercial floor space by building type in CP&L's service area.

Figure A1-2 shows a breakdown of floor space by building type. In 1991 there was approximately 348 million square feet of commercial floor space in the Company's service area. As shown, office buildings occupy the most floor space in CP&L's commercial sector. As shown in Figure A1-3 commercial floor space is projected to grow from approximately 348 million square feet in 1991 to over 400 million square feet in 2006. This is net floor space after accounting for the building survival functions in COMMEND.

Market Profiles
Base year fuel share and EUI values are based on the SRC study mentioned above, and data developed by the Environmental Protection Agency (EPA) for the Southeastern Electric Reliability Council (SERC) region from the 1986 DOE Nonresidential Building Energy Consumption Survey.

1990 actual energy sales and estimated floor space by building type were used to calculate actual energy intensities by building type for 1990. Base year fuel share and EUI values were calibrated to produce the corresponding 1990 energy intensity values. Tables A1-6 and A1-7 contain summaries of the base year EUI and fuel share values respectively.

Figure A1-4 shows a breakdown of 1990 energy intensity by building type. As shown, grocery stores and restaurants are the most energy intensive building types in CP&L's commercial sector.

Technology Data
All input data required for this module were taken from the COMMEND default data except heat pump shares which was taken from the SRC study.

Economic Data
All input data required for this module were taken from the COMMEND default data except retrofit penetration values.

COMMEND Results

A detailed forecast of energy consumption for 11 building types and eight end-uses was completed for CP&L's commercial class using three scenarios. Each scenario was based on various inputs consistent with those used in the corresponding econometric scenario. All the following results are for the Slower Growth scenario.

A summary of the total electric forecast by building type is presented in Table A1-8. As shown, office buildings and retail stores are the largest energy consuming building types in the Company's service area. Table A1-9 shows total electric sales by end-use. As shown in Table A1-9, lighting is the largest energy consuming end-use in our commercial sector. Selected output of the Slower Growth scenario is attached as Exhibit B.

For the years 1991 through 2000 energy is expected to grow from 5838 to 6746 GWH, a compound growth rate of 1.6% for the period. For the years 1991 through 2006 energy is expected to grow from 5838 to 7137 GWH, a compound growth rate of 1.3% for the period.

Figure A1-5 shows a comparison of electric energy sales by building type for the years 1991 and 2000. Office buildings, retail stores, and grocery stores comprise approximately 56 percent of the commercial sector electric energy sales in both years.

Figure A1-6 shows electric energy sales by end-use for the years 1991 and 2000. As shown, lighting is the largest energy consuming end-use in CP&L's commercial sector, comprising approximately 40 percent of electric energy sales.

A comparison between the results of the 1991 commercial econometric forecast and the 1991 COMMEND forecast was made as a check of reliability for both models. The Econometric model includes SIC codes that are not included in the COMMEND model. Therefore, the results of the econometric forecast has been reduced by the amount of the energy associated with the SIC codes that are out-of-scope in the COMMEND model to make a valid comparison of the forecasts.

Figure A1-7 shows a comparison of the 1991 econometric and COMMEND forecasts. The results from both models are consistent throughout the forecast period.

Conclusions

In 1991, the COMMEND model was used to develop the commercial sector end-use energy projections. The use of end-use and econometric forecasting approaches should not be viewed as duplication but rather as a way of using the unique strengths of both methods to determine the reliability of the results from each model.

The econometric model has the strength of capturing long-term market determined trends over many years but does not immediately capture structural shifts in market behavior. The COMMEND model, on the other hand has the strength of capturing continuing shifts in market behavior but bases such market behavior on data from only the most recent past.

The focus of the COMMEND model is on the disaggregate final uses of energy. This approach provides a highly detailed framework for analyzing energy usage patterns and their affect on future energy consumption.

TABLE A1-3

MAJOR INPUTS TO THE COMMEND MODEL

DATA	SOURCES
I. Fuel Price Module	
A. Historical Fuel Prices	
1. Electric	CP&L
2. Gas	NCUC Report
3. Oil	DOE Annual Energy Review
B. Forecast	
1. Electric	CP&L Forecast
2. Gas	DRI
3. Oil	DRI
II. Floor Stock Module	
A. Employment	
1. Historical	NC Employment & Wages Report
2. Forecast	CP&L Forecast
B. 1985 Floor Space	CP&L Commercial Sector Database prepared by Synergic Resources Corporation
C. Survival Functions	COMMEND National Sample Data
III. Market Profiles Module	
A. Fuel Shares	CP&L Commercial Sector Database prepared by Synergic Resources Corporation and EPA SERC regional data
B. EUI Values	CP&L Commercial Sector Database prepared by Synergic Resources Corporation
IV. Technology Data Module	
A. Heat Pump Data	
1. Market Share	CP&L Commercial Sector Database prepared by Synergic Resources Corporation
2. EUI Values	COMMEND National Sample Data
B. Equipment Cost	COMMEND National Sample Data
C. Technology Elasticities	COMMEND National Sample Data
D. Efficiency Trends	COMMEND National Sample Data
E. Cost Trends	COMMEND National Sample Data
F. Thermal Interactions	COMMEND National Sample Data
V. Economic Data Module	
A. Discount Rates	COMMEND National Sample Data
B. Price Weights	COMMEND National Sample Data
C. Choice Elasticities	COMMEND National Sample Data
D. Utilization Elasticities	COMMEND National Sample Data
E. Fuel Share Inertia Parameters	COMMEND National Sample Data
F. EUI Inertia Parameters	COMMEND National Sample Data
G. Retrofit Penetrations	COMMEND National Sample Data
H. Miscellaneous Electric Equipment Growth	COMMEND National Sample Data

TABLE A1-4

COMMEND BUILDING TYPES AND CORRESPONDING SIC CODES

BUILDING TYPES	SIC CODES
OFFICE	60, 61, 62, 63, 64, 65, 67, 73, 81, 87, 89, FEDERAL, LOCAL, AND PARTIAL STATE GOVERNMENT, AND PARTIAL 80
RETAIL	52, 53, 55, 56, 57, AND 59
WAREHOUSE	42, 50, AND 51
GROCERY	54
RESTAURANT	58
LODGING	70
NURSING HOME	PARTIAL 80
HOSPITAL	PARTIAL 80
ELEM. & SEC. SCHOOL	82 AND PARTIAL STATE GOVERNMENT
HIGHER EDUCATION	82 AND PARTIAL STATE GOVERNMENT
CHURCH	PARTIAL 86

TABLE A1-5

FLOOR SPACE PER EMPLOYEE BY BUILDING TYPE

BUILDING TYPE	SQUARE FEET PER EMPLOYEE
OFFICE	231
RETAIL	306
WAREHOUSE	623
GROCERY	473
RESTAURANT	212
LODGING	1,083
NURSING HOME	284
HOSPITAL	464
ELEM. & SEC. SCHOOL	1,325
HIGHER EDUCATION	842
CHURCH	3,809

FIGURE A1-2
1991 COMMERCIAL FLOOR SPACE

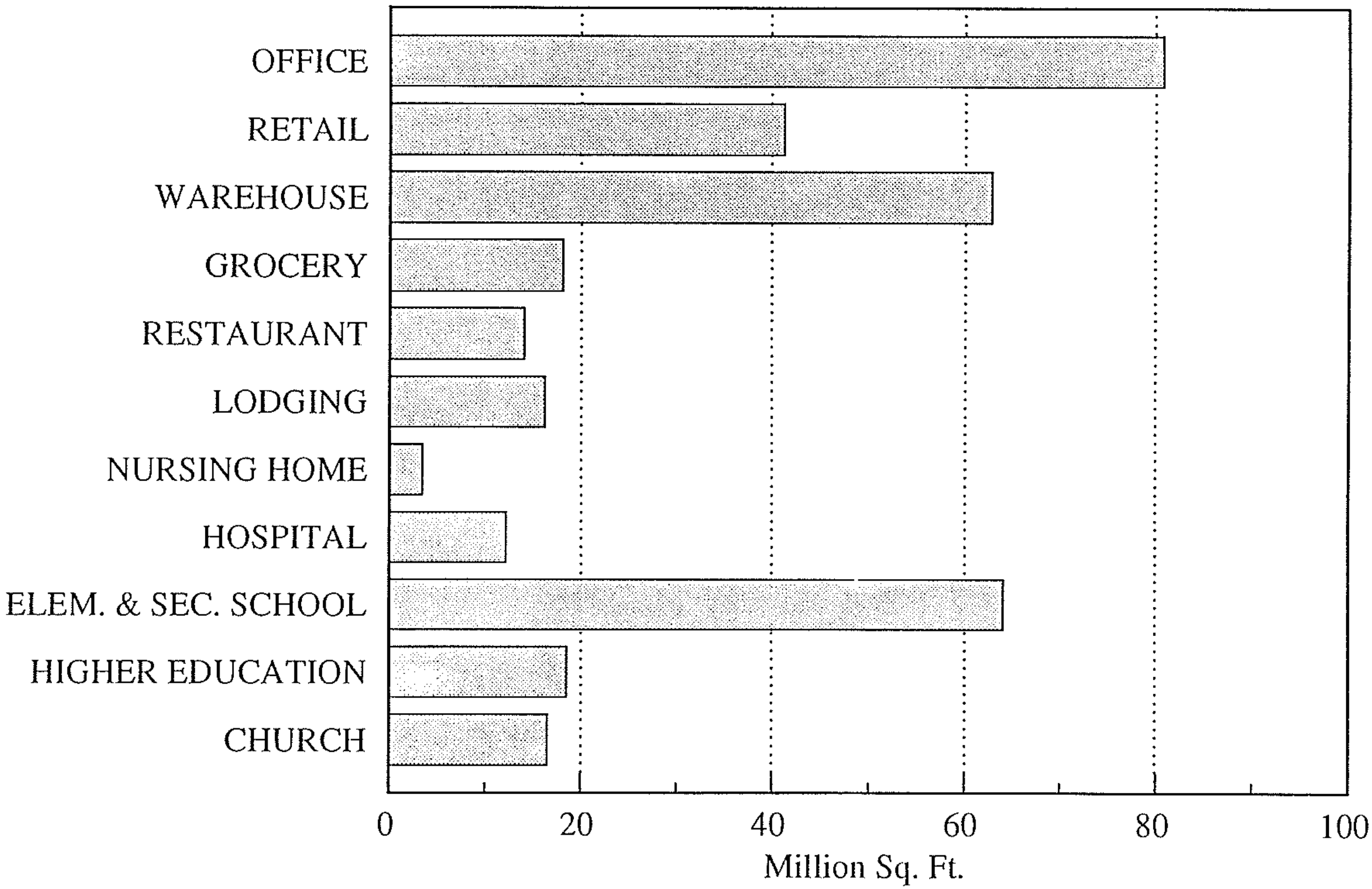


FIGURE A1-3

COMMERCIAL FLOOR SPACE PROJECTION

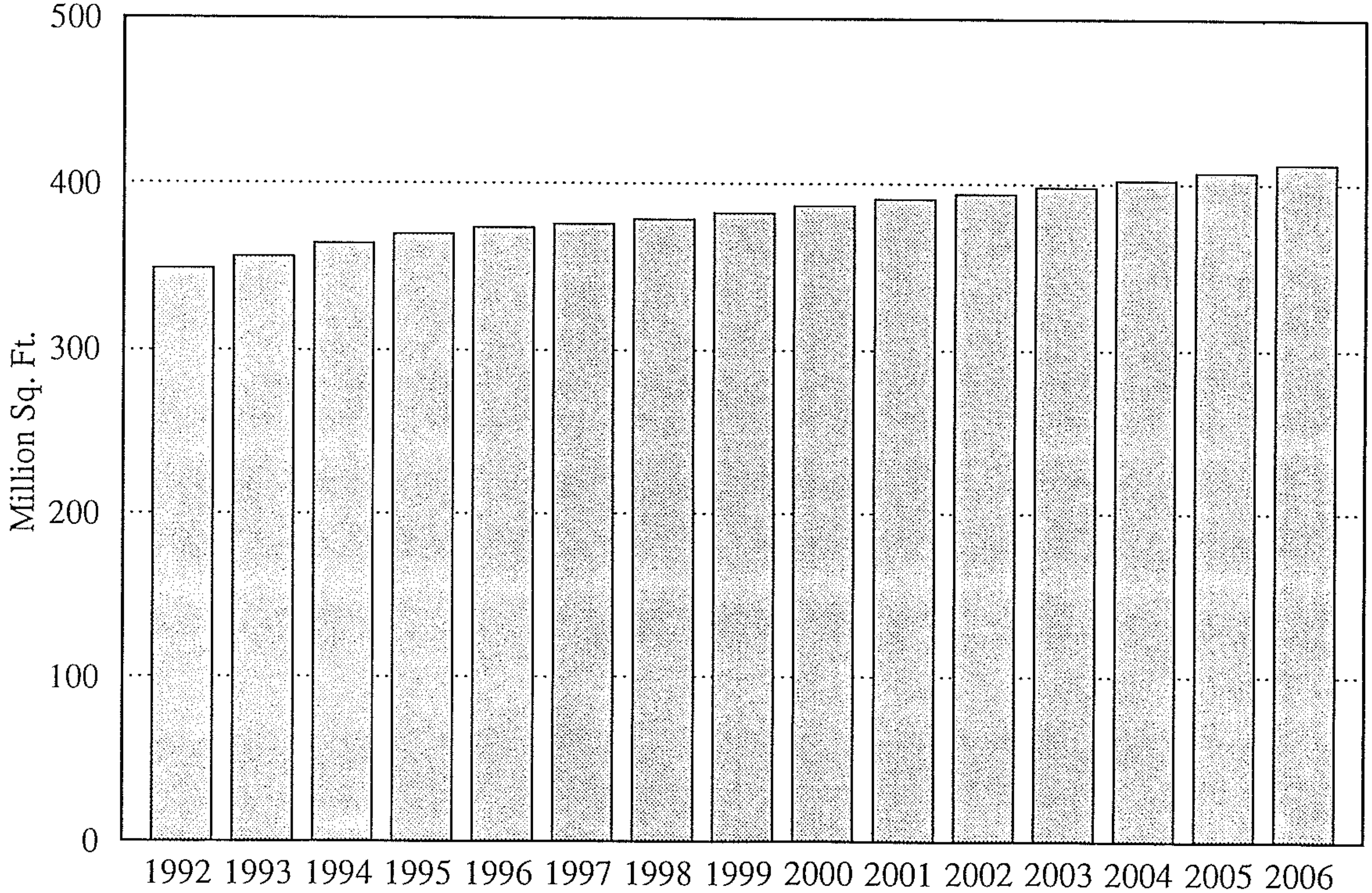


TABLE A1-6

COMMEND 1990 BASE YEAR
ENERGY UTILIZATION INDEX (EUI) VALUES

	OFFICE	RETAIL	WAREHOUSE	GROCERY	RESTAURANT	LODGING	NURSING HOME	HOSPITAL	ELEM/SEC SCHOOL	HIGHER EDUCATION	CHURCH
SPACE HEATING											
ELECT (KWH/SQ. FT.)	1.1	4.4	2.1	5.2	3.0	2.2	5.1	5.1	2.4	3.6	2.4
GAS (KBTU/SQ. FT.)	65.8	43.8	31.3	214.1	61.0	108.1	198.6	198.6	37.3	35.4	37.3
OIL (KBTU/SQ. FT.)	37.2	41.1	89.2	47.8	5.8	43.9	53.2	53.2	78.5	79.7	78.5
COOLING											
ELECT (KWH/SQ. FT.)	3.7	4.7	0.6	1.7	3.9	4.2	3.5	3.5	2.6	2.8	2.6
GAS (KBTU/SQ. FT.)	64.1	67.2	11.7	147.2	41.1	9.6	65.7	65.7	8.4	12.7	8.4
VENTILATION											
ELECT (KWH/SQ. FT.)	2.6	3.3	1.1	1.6	2.8	2.4	3.6	12.3	2.3	2.9	2.3
WATER HEATING											
ELECT (KWH/SQ. FT.)	0.3	1.2	0.5	0.8	10.7	3.9	1.5	3.8	0.8	1.6	0.8
GAS (KBTU/SQ. FT.)	9.8	18.6	8.6	57.8	35.9	24.8	40.7	40.7	18.1	14.1	18.1
OIL (KBTU/SQ. FT.)	17.7	99.4	108.4	37.6	30.6	29.0	39.8	39.8	32.0	29.4	32.0
COOKING											
ELECT (KWH/SQ. FT.)	0.6	1.4	0.0	0.7	16.1	0.7	0.8	1.5	0.2	0.8	0.2
GAS (KBTU/SQ. FT.)	0.6	2.2	0.1	107.0	43.4	15.2	4.2	4.2	4.5	5.1	4.5
REFRIGERATION											
ELECT (KWH/SQ. FT.)	0.3	1.6	0.0	23.5	6.0	1.7	1.0	1.2	0.2	0.5	0.7
LIGHTING											
ELECT (KWH/SQ. FT.)	8.6	10.0	3.3	11.3	9.1	8.3	11.5	12.9	2.6	7.3	5.4
MISCELLANEOUS											
ELECT (KWH/SQ. FT.)	1.8	3.4	0.2	2.7	2.8	0.2	3.2	5.9	0.1	3.5	0.8

TABLE A1-7

COMMEND 1990 FUEL SHARES BASE YEAR

	OFFICE	RETAIL	WAREHOUSE	GROCERY	RESTAURANT	LODGING	NURSING HOME	HOSPITAL	ELEM/SEC SCHOOL	HIGHER EDUCATION	CHURCH
SPACE HEATING											
ELECT (%)	53.0	58.0	28.9	74.0	48.0	80.0	50.0	50.0	55.0	63.0	55.0
GAS (%)	45.0	32.0	24.4	13.0	52.0	15.0	30.0	30.0	10.0	15.0	10.0
OIL (%)	2.0	10.0	8.5	13.0	0.0	5.0	20.0	20.0	35.0	22.0	35.0
TOTAL	100.0	100.0	61.8	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
COOLING											
ELECT (%)	94.0	94.0	28.9	96.6	96.0	86.7	77.9	77.9	30.0	84.7	55.0
GAS (%)	1.4	3.6	3.6	3.4	4.0	9.3	2.1	2.1	6.4	6.4	6.4
TOTAL	95.4	97.6	32.5	100.0	100.0	96.0	80.0	80.0	36.4	91.1	61.4
VENTILATION											
ELECT (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	30.0	100.0	55.0
WATER HEATING											
ELECT (%)	49.0	57.0	23.4	63.0	68.0	15.0	40.0	40.0	59.0	10.0	59.0
GAS (%)	22.0	8.0	12.3	8.0	28.0	68.0	40.0	40.0	13.0	41.0	13.0
OIL (%)	1.0	3.0	0.6	0.0	2.0	5.0	3.0	3.0	23.0	12.0	23.0
TOTAL	72.0	68.0	36.3	71.0	98.0	88.0	83.0	83.0	95.0	63.0	95.0
COOKING											
ELECT (%)	16.9	12.1	0.3	18.3	45.6	15.5	46.7	46.7	11.1	11.1	11.1
GAS (%)	28.3	11.0	0.0	2.2	52.8	27.8	34.7	34.7	30.0	30.5	30.0
TOTAL	45.2	23.1	0.3	20.5	98.4	43.3	81.4	81.4	41.1	41.6	41.1
REFRIGERATION											
ELECT (%)	72.4	60.0	0.0	100.0	100.0	33.3	33.3	33.3	33.3	33.3	33.3
LIGHTING											
ELECT (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
MISCELLANEOUS											
ELECT (%)	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

FIGURE A1-4

COMMEND 1990 BASE YEAR ENERGY INTENSITY

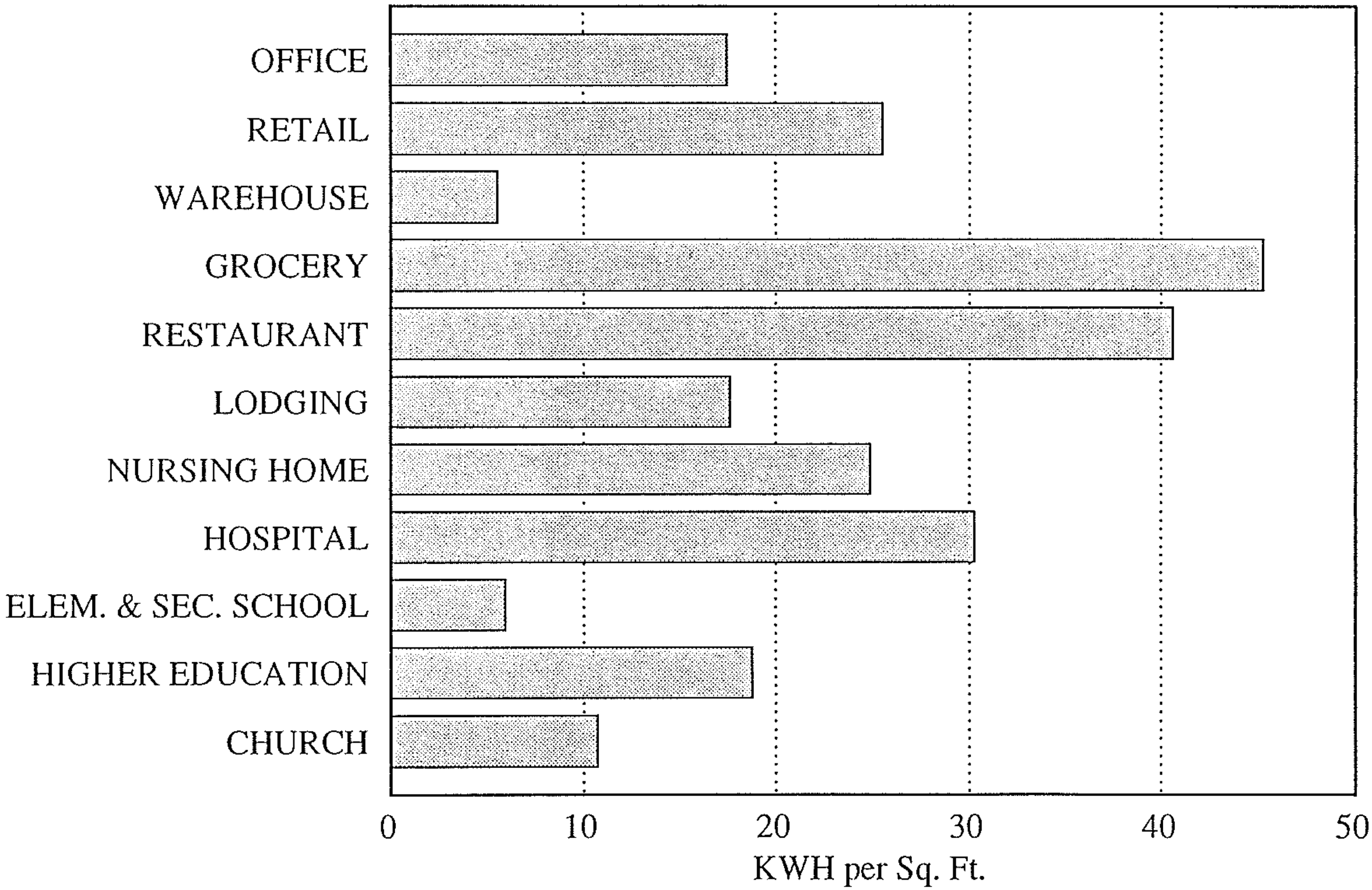


TABLE A1-8

CAROLINA POWER & LIGHT COMPANY
1991 COMMERCIAL END-USE ENERGY FORECAST
SLOWER GROWTH SCENARIO
REDUCED FOR CONSERVATION & LOAD MANAGEMENT
(GWH)
BY BUILDING TYPE

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
OFFICE	1,410	1,427	1,461	1,494	1,524	1,549	1,566	1,579	1,595	1,613	1,627	1,642	1,657	1,672	1,687	1,697
RETAIL	1,051	1,058	1,092	1,131	1,156	1,167	1,172	1,186	1,202	1,218	1,233	1,242	1,250	1,258	1,270	1,283
WAREHOUSE	347	349	358	369	375	377	377	380	382	386	388	390	391	392	394	397
GROCERY	818	821	847	877	896	904	908	919	932	945	957	964	971	979	988	999
RESTAURANT	570	572	590	611	625	632	636	646	656	667	677	684	691	699	707	716
LODGING	285	291	302	311	317	323	327	330	334	340	344	347	351	355	359	363
NURSING HOMES	86	88	92	95	97	99	101	102	104	106	108	110	112	113	114	116
HOSPITALS	367	377	393	408	418	429	437	445	454	465	474	483	492	499	505	511
ELEM. & SEC. SCHOOL	381	383	388	394	400	405	408	410	412	415	417	420	424	427	431	434
HIGHER EDUCATION	347	352	363	373	379	384	388	390	393	397	400	403	406	409	413	416
CHURCHES	178	181	188	194	198	201	204	206	208	212	214	216	218	221	223	226
TOTAL (1)	5,838	5,895	6,067	6,244	6,373	6,457	6,510	6,577	6,658	6,746	6,822	6,884	6,947	7,006	7,073	7,137

TABLE A1-9

CAROLINA POWER & LIGHT COMPANY
1991 COMMERCIAL END-USE ENERGY FORECAST
SLOWER GROWTH SCENARIO
REDUCED FOR CONSERVATION & LOAD MANAGEMENT
(GWH)
BY END-USE

	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
SPACE HEATING	497	500	513	528	539	546	552	559	568	578	588	596	607	618	631	644
COOLING	775	783	805	826	842	852	858	864	872	881	887	891	896	900	906	912
VENTILATION	697	703	722	741	755	764	770	776	785	794	802	808	814	821	829	837
WATER HEATING	230	232	238	246	253	257	261	266	272	278	284	290	297	303	308	314
COOKING	136	136	140	145	148	150	152	155	159	163	167	170	173	177	181	185
REFRIGERATION	590	592	610	631	644	650	653	661	670	679	687	692	697	703	710	718
LIGHTING	2,364	2,385	2,449	2,512	2,556	2,582	2,594	2,609	2,628	2,650	2,667	2,678	2,688	2,693	2,703	2,714
MISCELLANEOUS	551	569	598	627	650	668	684	701	719	738	757	774	793	808	824	833
TOTAL (1)	5,838	5,895	6,067	6,244	6,373	6,457	6,510	6,577	6,658	6,746	6,822	6,884	6,947	7,006	7,073	7,137

(1) Total is reduced for Voltage Reduction.

FIGURE A1-5

ENERGY SALES BY BUILDING TYPE

1991 COMMEND FORECAST

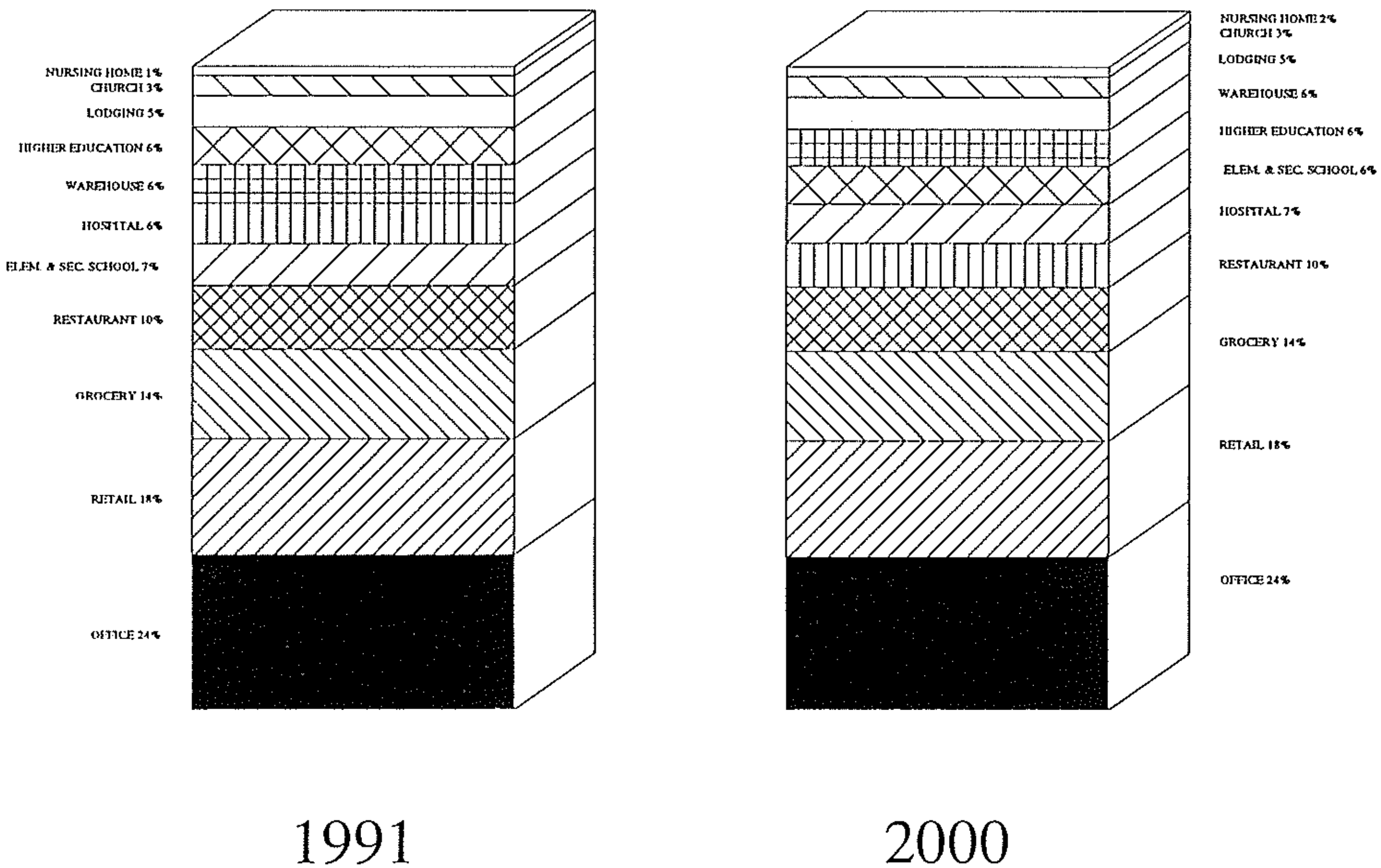


FIGURE A1-6

ENERGY SALES BY END-USE

1991 COMMEND FORECAST

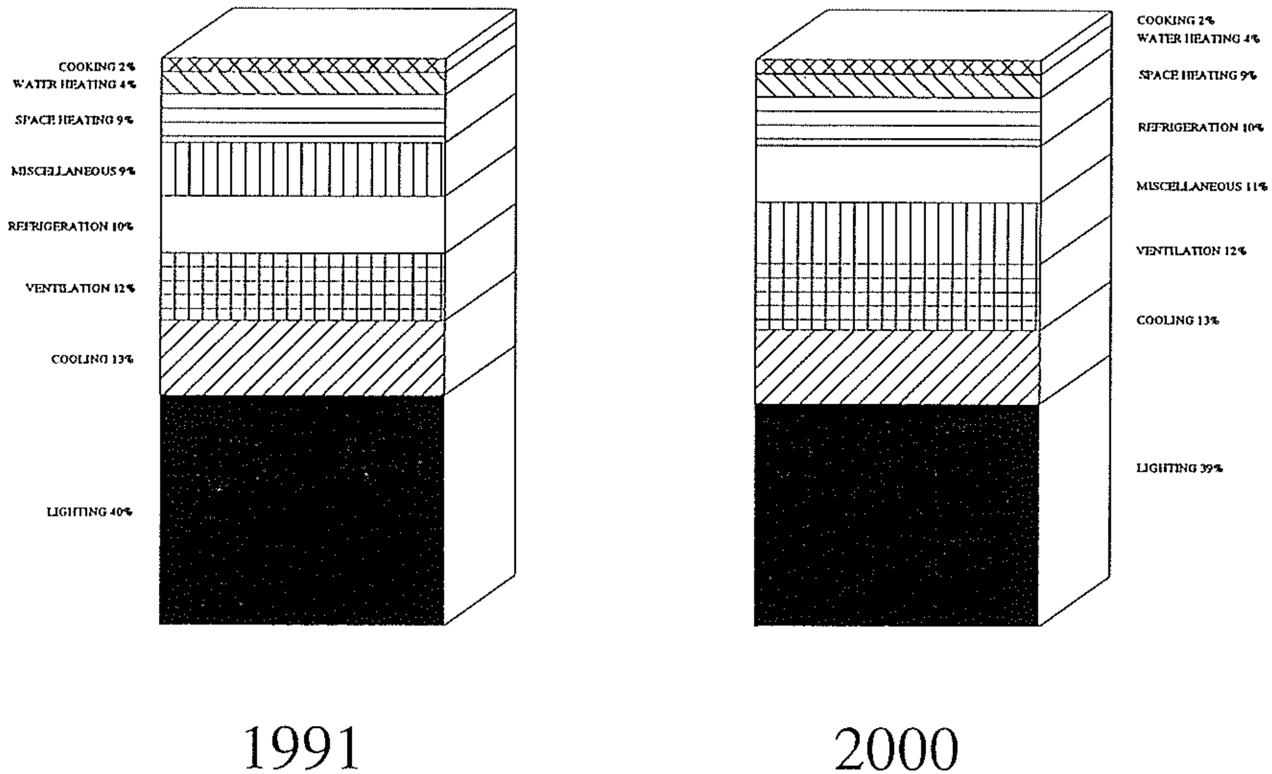
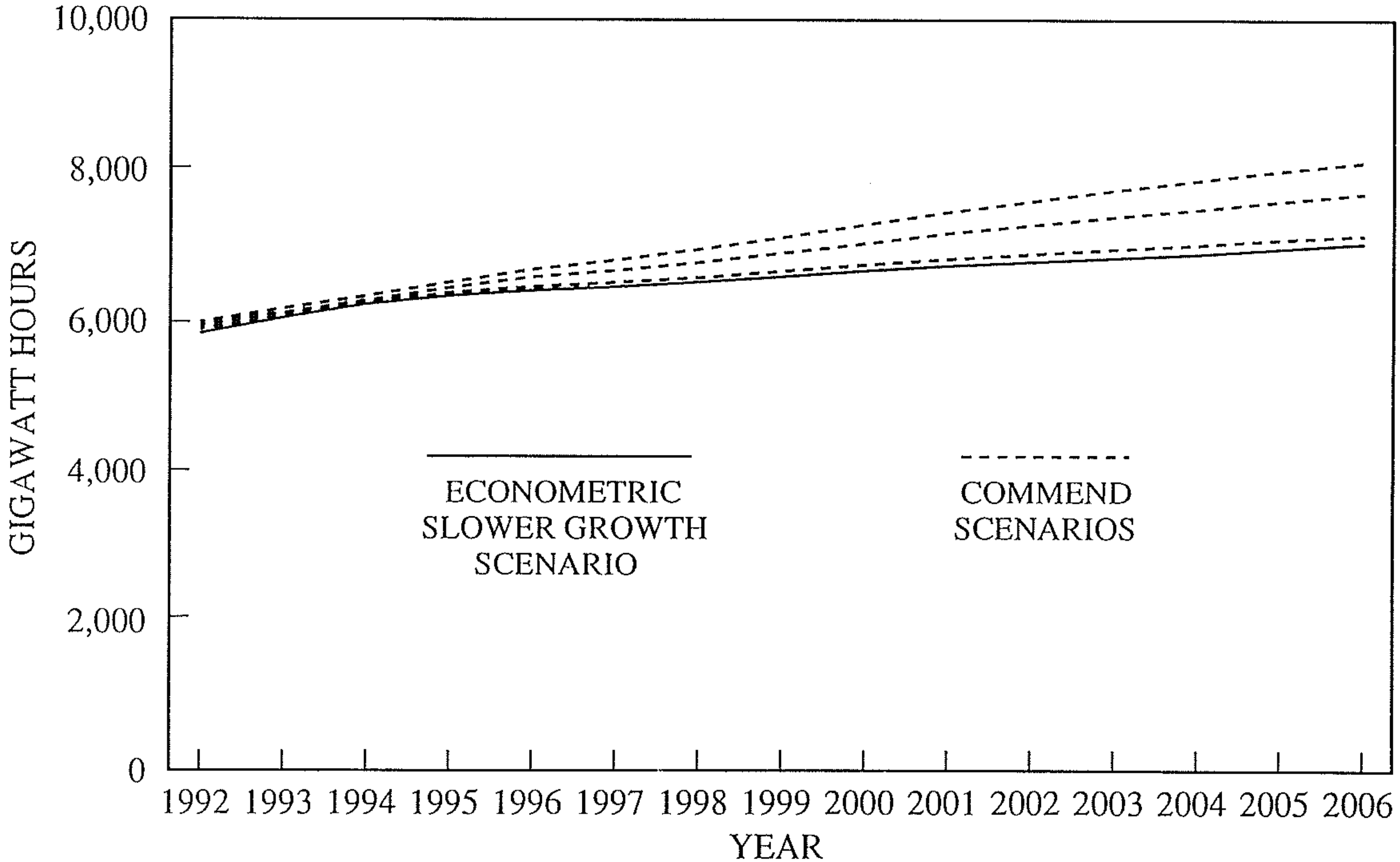


FIGURE A1-7

COMPARISON OF COMMERCIAL ENERGY FORECASTS

1991 COMMEND AND ECONOMETRIC MODELS



Part 2 - System Hourly Load Shape Forecast

Overview

Over time, the quantity and form of system load data provided for planning has evolved in response to the increasing sophistication and detail of planning models, requiring more detailed input data. At the same time there has been increasing availability of source data in computer readable form and increasing availability of software capable of processing the source data into useful and meaningful information. This evolution of planning models now requires more sophisticated hourly system load data. For such detailed load data to be meaningful, it must be based on a model of normally expected temperatures, and reflect those changes in end use and consumption determinants which affect system load patterns.

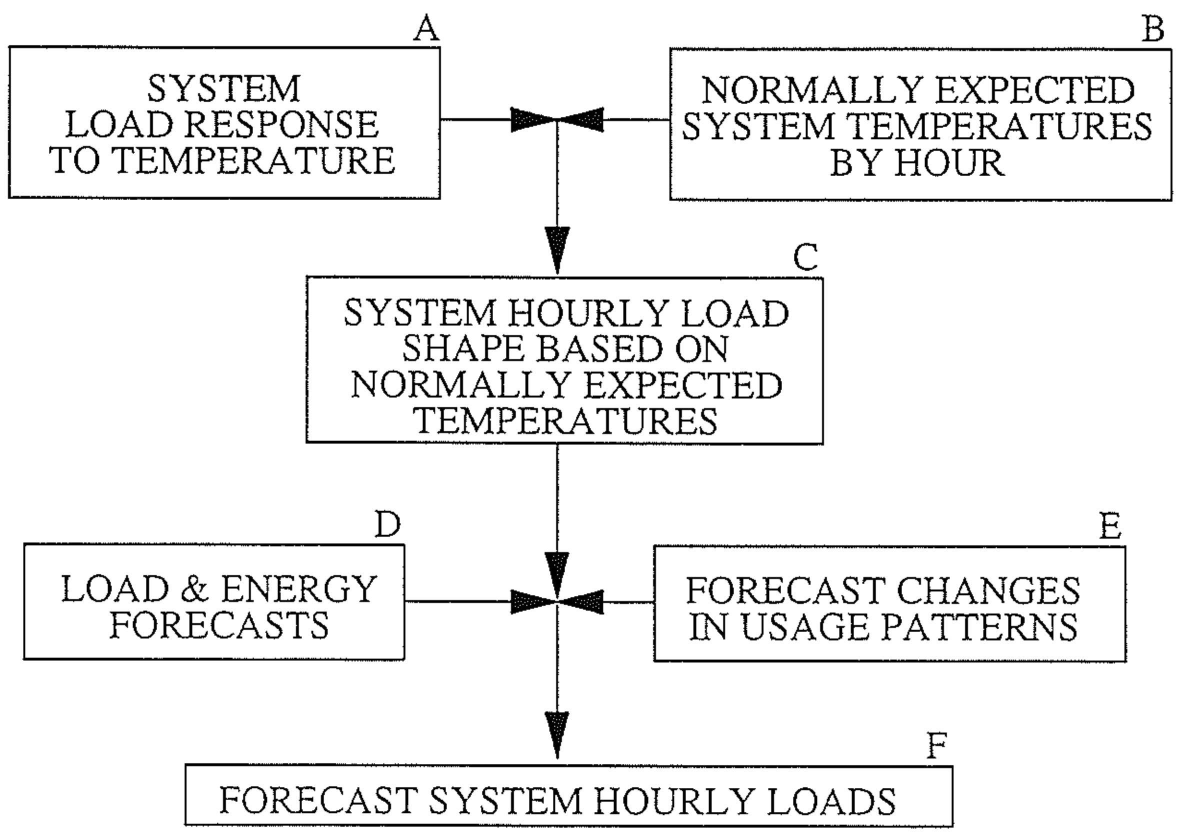
While the hourly load data necessary to create hourly load shape forecasts has been available in computerized format for many years, widespread availability of National Oceanic and Atmospheric Administration (NOAA) weather data in this form is more recent. Computer software sufficient to create such forecasts was obtained in late 1990.

Process Overview

The hourly load forecast process shown in Figure A2-1 begins with two independent steps: estimation of the relationship of system load level to system temperature (Block A), and creation of an hourly model of system temperatures reflecting the frequency and severity of temperatures which could be expected over a period of many years (Block B). Combining the load-temperature relationship with the hourly temperature model produces a normal weather system hourly load shape (Block C). The energy and load forecasts (Block D) are used to forecast the basic load shape at future load levels. Through the forecast period, certain changes are expected in the system load shape as a result of such factors as appliance efficiency changes, response to TOU rates, and block changes to load (such as a large customer adding or dropping large load increments). Such pattern changes are identified in end-use modeling and the various engineering and economic studies, and reflected implicitly in the hourly load forecast (Block E). A forecast of system hourly loads appropriately reflecting forecast pattern changes is the final result (Block F). A detailed explanation of the methodology involved in each of these steps follows in the next section of this report. Exhibit A2-A is also included at the end of the report providing specific results.

FIGURE A2-1

CP&L HOURLY SYSTEM LOAD SHAPE PROCESS



Detailed Process Methodology

Load-Temperature Relationship

System load response to temperature (Block A) is estimated as a function of hour, day of the week, and month. Battelle's SHAPES-PC program is used to process three years of hourly load and temperature data to create this relationship in a mathematical form using regression techniques.

Load Data

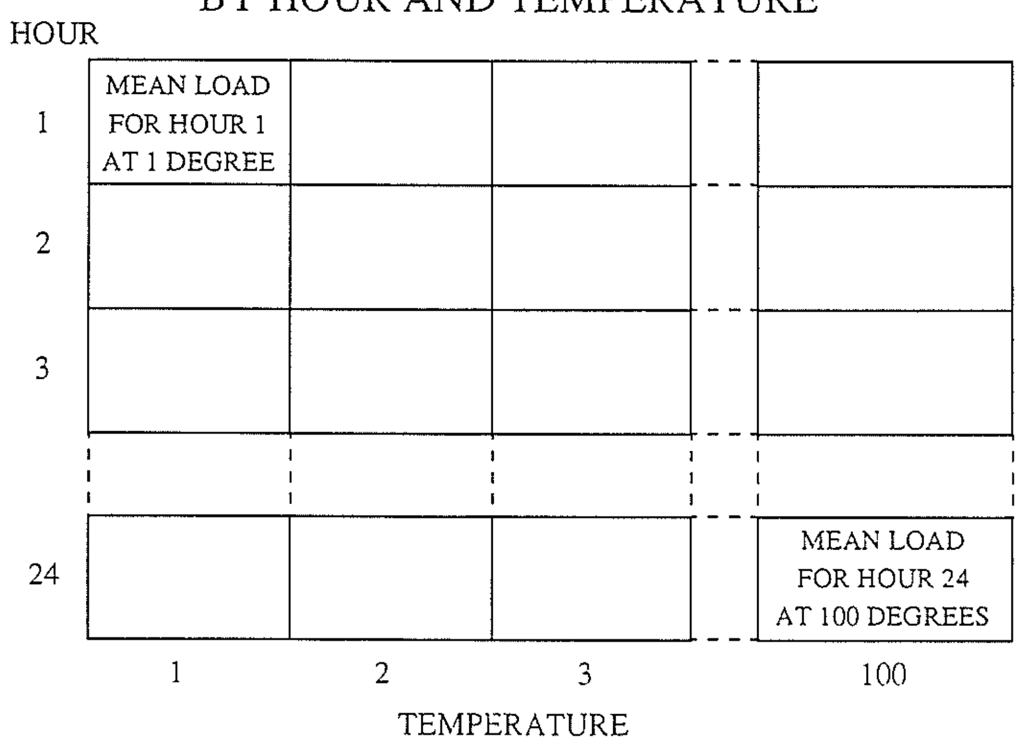
Three years of system load data (1987-1989) are processed to determine the chronological hourly load-temperature relationships for each daytype, by month. Actual load data obviously contains significant growth across the three-year period. An adjustment is made to the data by escalating the 1987 and 1988 load data to a 1989 basis using the growth in weather normal energy. Daytypes are defined for each month as weekday, Saturday, and Sunday for a total of 36 separate daytypes.

Matrix Building

SHAPES-PC processes the load and matching temperature data and forms a matrix of loads for the hour of day, by daytype. Should multiple loads occur for a given hour and temperature, the mean of the observations is placed into the matrix as shown in Figure A2-2.

FIGURE A2-2

MATRIX OF LOADS
BY HOUR AND TEMPERATURE



Curve Fitting

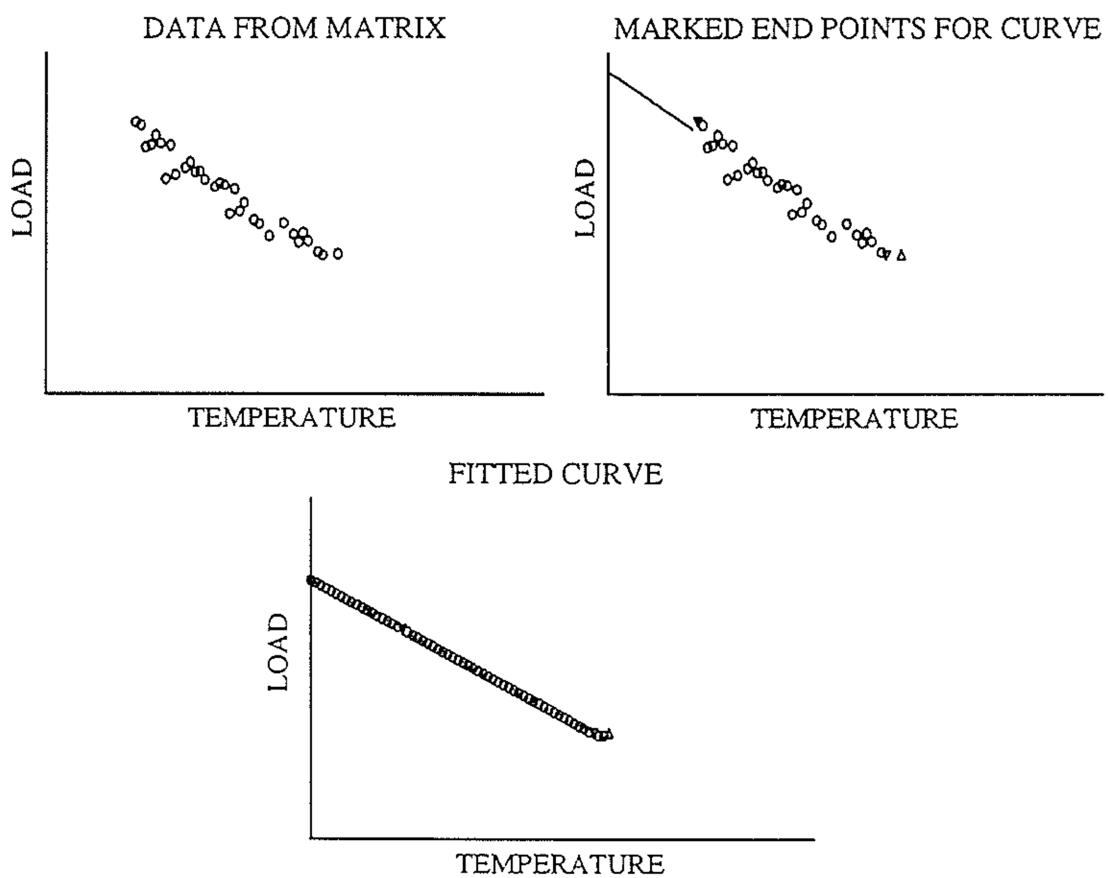
SHAPES-PC then processes the load and temperature matrix data one hour at a time, using regression techniques to specify the load-temperature relationship in a mathematical form. Figure A2-3 provides a sequence of plots which illustrate the process. The sequence begins with a plot of the raw data for a January weekday, taken from the hourly load-temperature matrix.

SHAPES-PC provides the user with the capability of interactively setting the end points for straight line segments to approximate the load-temperature relationship for each hour. The second plot in the sequence shows as triangles the straight line segment end points which have been set. Regression techniques are used to estimate the a straight line relationship for the points between the triangles.

The final plot is the fitted load-temperature curve by hour. The load-temperature relationship is represented as straight line segments generated by the regression functions.

FIGURE A2-3

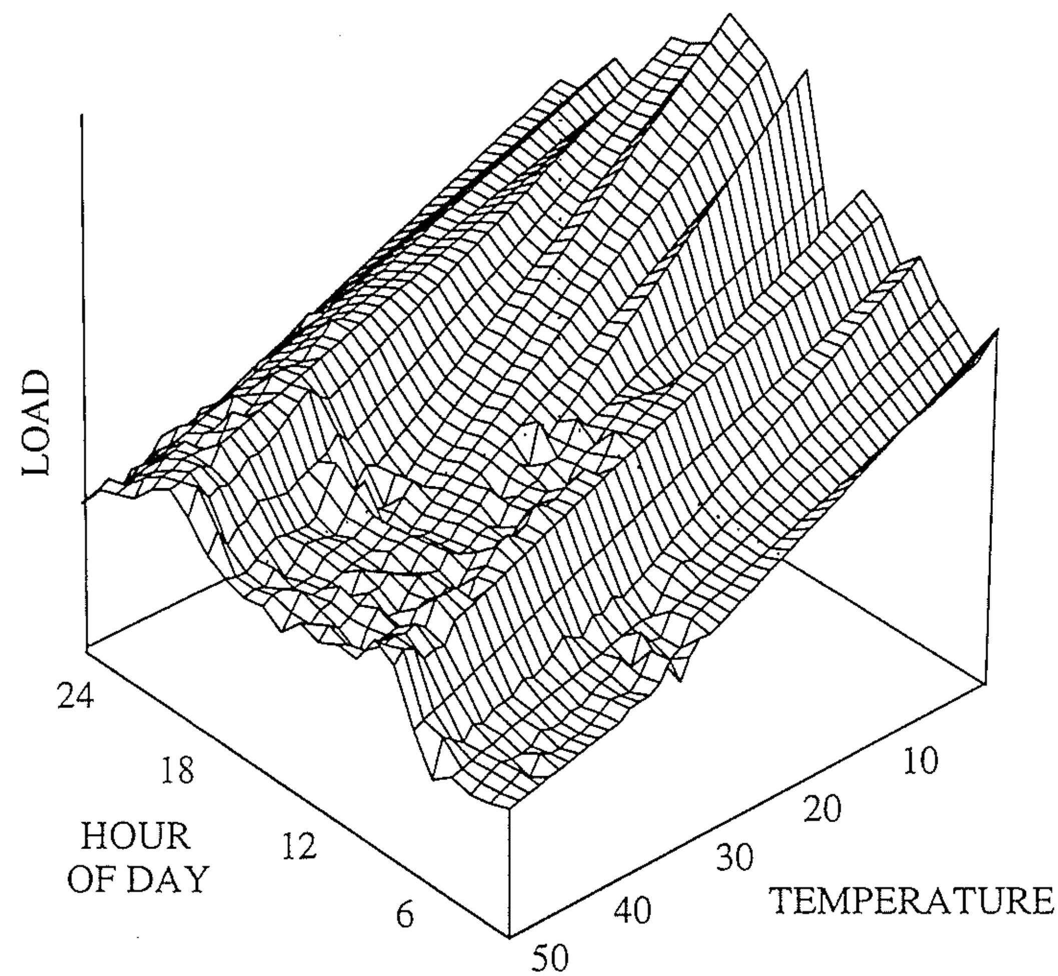
FITTING LOAD-TEMPERATURE RELATIONSHIP



When the process is completed, the entire load-temperature matrix has been filled with representative load values. The load-temperature relationship for each hour of the daytype is now defined. The same is repeated for each daytype, for each month. Figure A2-4 presents a three dimensional plot of this completed data matrix for a weekday daytype in January. For each hour and possible temperature, the expected load can be determined.

FIGURE A2-4

LOAD-TEMPERATURE RELATIONSHIP

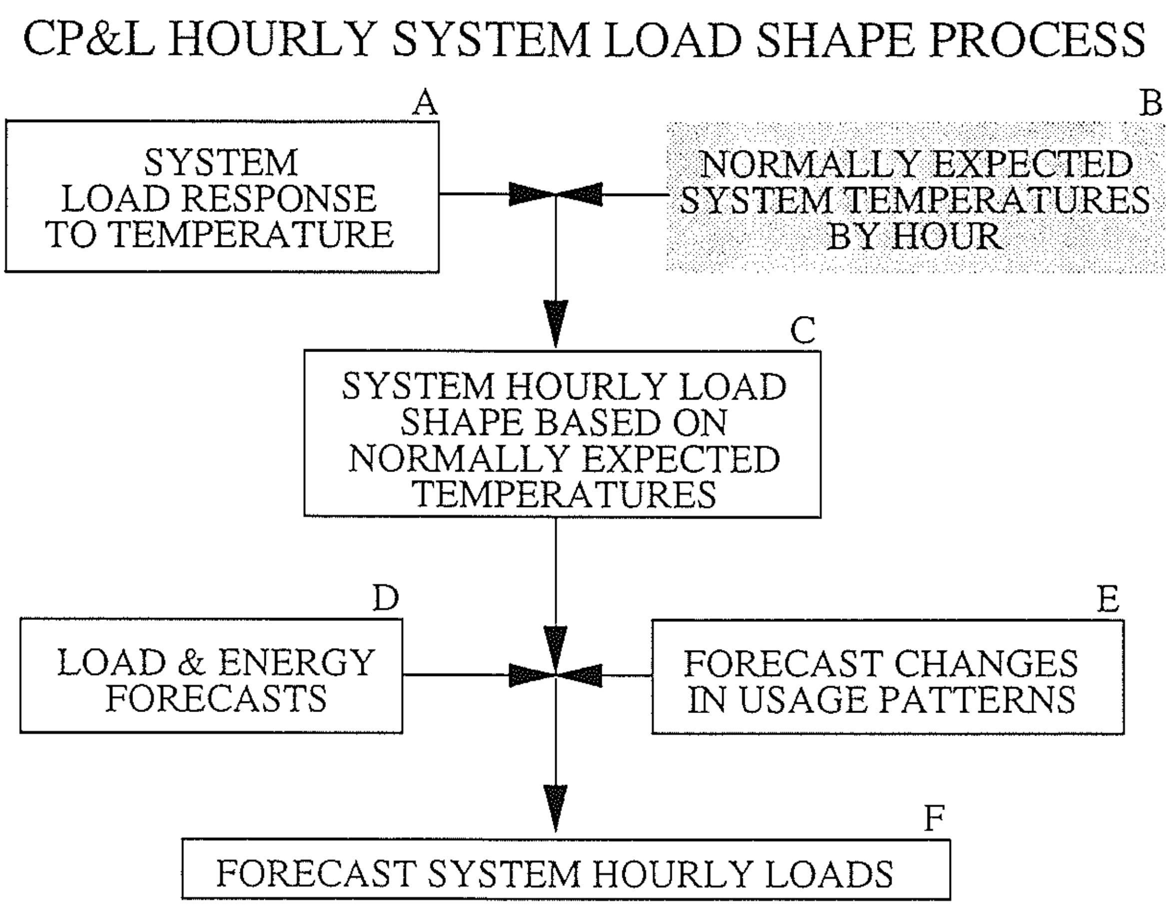


Hourly Model of Normally Expected System Temperatures

The range of temperatures which have occurred historically for a specific hour of the year is very wide. This wide range of possible temperatures demands that considerable care be taken in creating forecasts which reflect the concept of normally expected temperatures. Averaging techniques tend to "flatten" the model, showing no extremes. This is generally acceptable for energy models which are based on a degree day basis, and are concerned basically with monthly energy consumption totals. Load models, however, have to be concerned with the extreme temperatures which might be expected during a year, and the load which will result from the response of load to an extreme temperature for a single hour.

Recognizing that temperature is a random variable, statistical techniques can be used to create a model which reflects the expected occurrence of all temperature levels, including extreme temperatures. The CP&L temperature model, Block B highlighted on Figure A2-5, was based on 30 years of temperature data.

FIGURE A2-5



Four NOAA weather stations are used to reflect CP&L system temperatures (Asheville, Raleigh-Durham, Wilmington, and Columbia, S.C.). The temperatures from these four stations are weighted into a system temperature variable

Summer and winter weights are derived from the proportion of load on transmission to distribution substations in the various areas. These current weights are:

	Summer	Winter
Asheville	0.059	0.077
Raleigh-Durham	0.307	0.444
Wilmington	0.353	0.252
Columbia, S.C.	0.281	0.227

Weighted temperatures are formed into a normally expected model using a "ranked-average methodology." The methodology follows the sequence:

(1) **Establish Rank of Each Chronological Hour of the Year**
Temperatures are averaged for each chronological hour of the year. This establishes which hour would typically be expected to have the lowest average temperature (the lowest rank), the second lowest, and so on to the hour expected to have the highest average temperature (the highest rank). Many models might stop at this point and use the average hourly temperature. For many applications this would be perfectly acceptable, but not for load shape modeling. The "flattening" effects described earlier require additional steps in the process.

(2) **Establish an Average of Temperatures With Same Annual Rank (Average of Rank)**
Hourly temperatures are sorted into rank order by year. Temperatures of like rank are then averaged for the number of years included in the data. This provides the average of each temperature rank, from the lowest to the highest. The result is, then, an average of the lowest temperature to occur in each year (lowest rank), an average of the highest temperature in each year (average of the highest rank), and an average of all ranks in between.

(3) **Match Average of Rank With Chronological Hour Having That Rank**
An estimate of the relative rank (1 to 8760) of expected temperature for each chronological hour is calculated in Step (1). Step (2) provides the average temperature for each rank (1 to 8760).

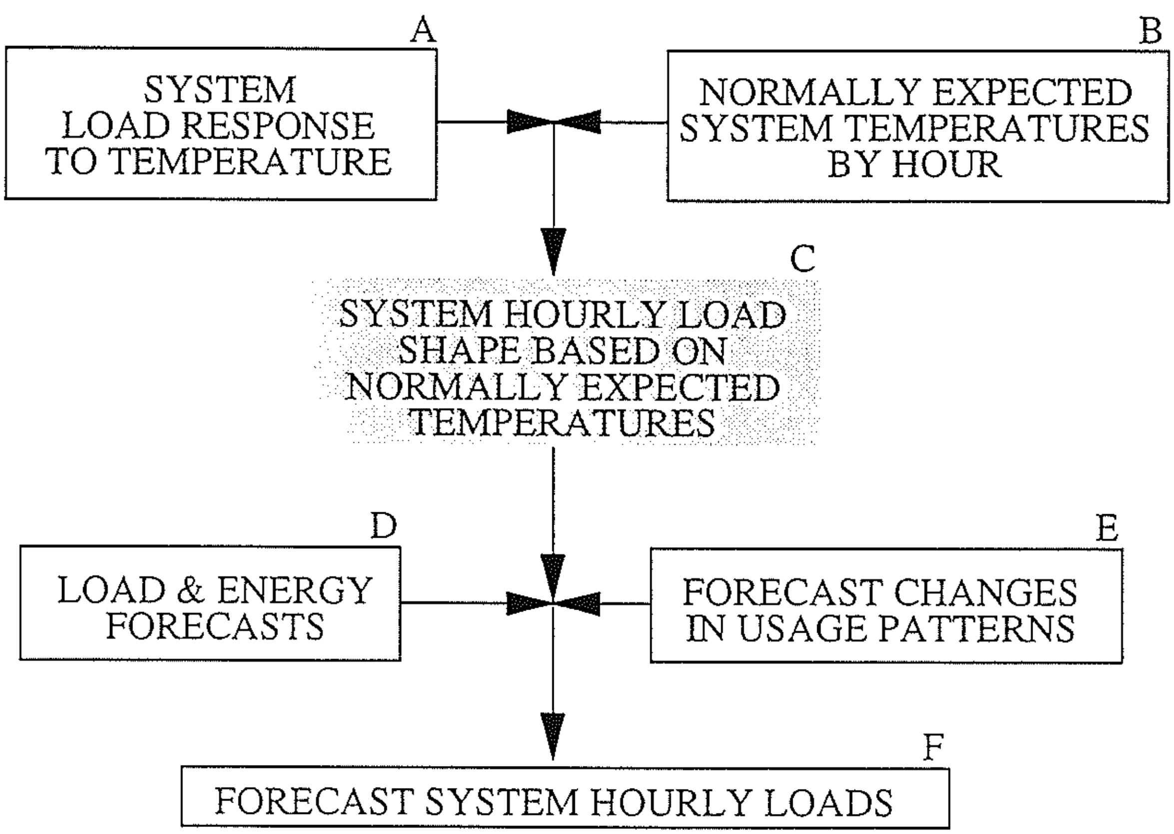
The final step is to match the temperature (average of a rank) to the hour in which it is expected to occur (the rank of the hour).

System Hourly Load Shape Based on Normally Expected Temperatures

At this point in the process, the temperature which could normally be expected for each hour of the year has been established (Block B). The response of load to temperature has been established by month for each hour of a day of the week (Block A). For each chronological hour of the year, the expected temperature is known and the month and day of week can be calculated from calendar functions. The resulting load for each hour's expected temperature can be calculated, creating an 8760-hour typical or expected load shape, Block C as highlighted in Figure A2-6.

FIGURE A2-6

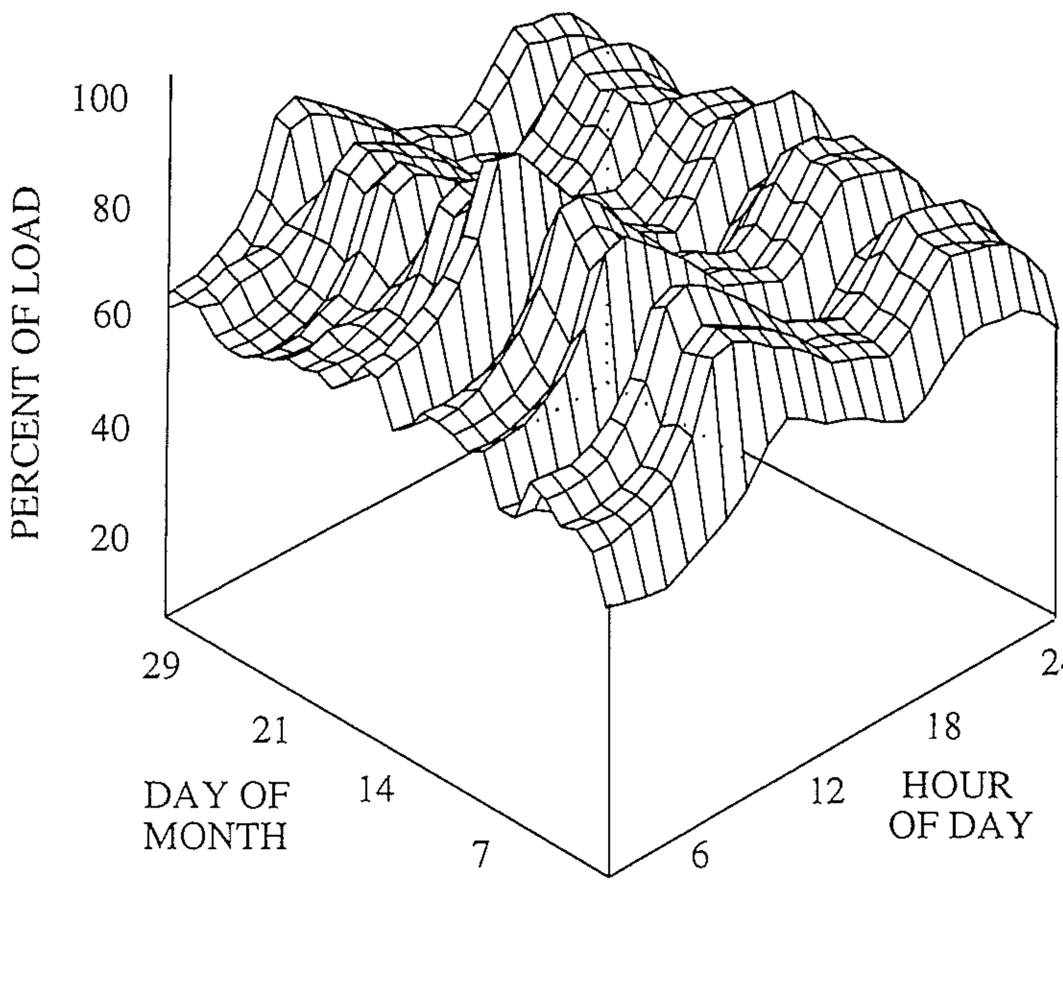
CP&L HOURLY SYSTEM LOAD SHAPE PROCESS



For convenience, the typical load shape values are transferred into "per-unit" values by dividing each value by the maximum value for the year. Thus, the annual peak load hour will have a value of 1.0 and all other hours will have a value less than 1.0. The results of this model are provided in Exhibit A2-A. Figure A2-7 provides a three dimensional plot of the system hourly load model for the month of January.

FIGURE A2-7

JANUARY HOURLY LOAD MODEL

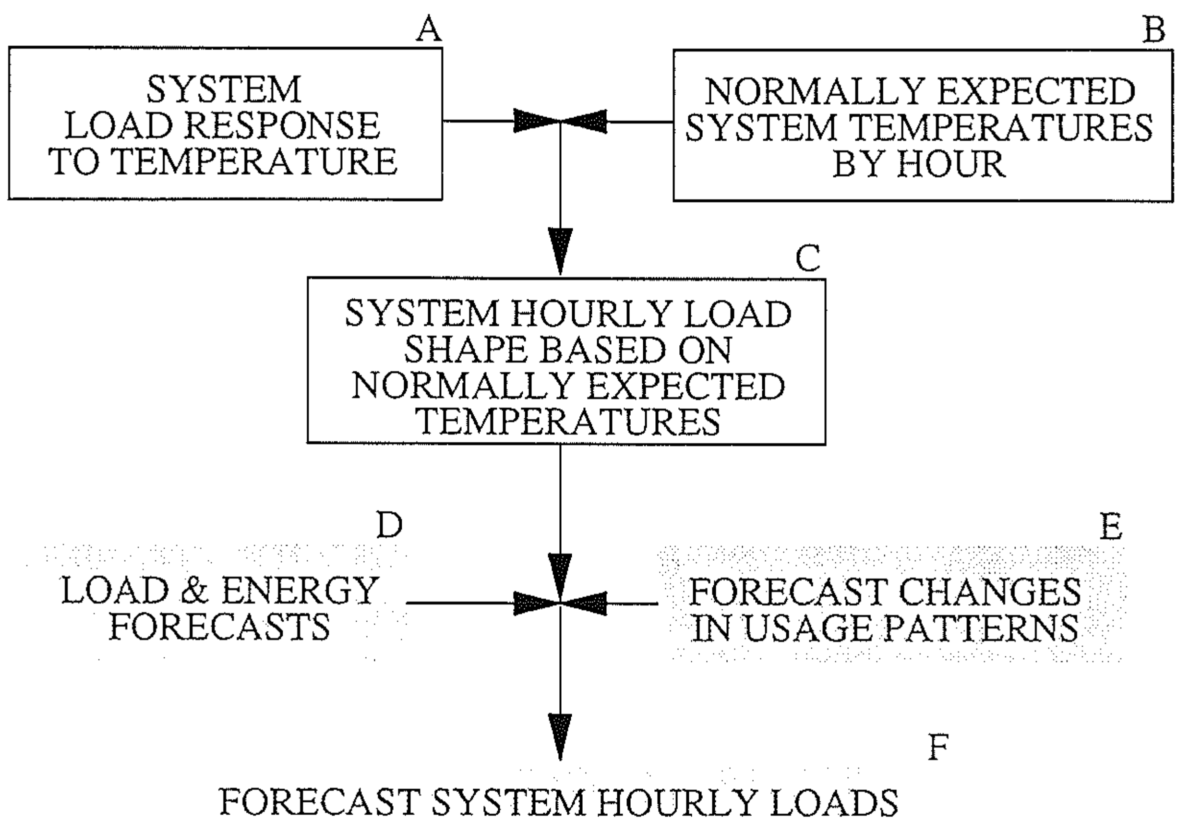


Forecast Hourly System Loads

Individual hourly values of the system load shape are expressed as a percentage (or per-unit) of the annual system peak load. As such, it provides a pattern of usage and does not provide by itself an hourly load forecast. Hourly load values (Block F) are produced as a product of the hourly system load shape and the system peak load forecast, Block D as highlighted in Figure A2-8. Producing hourly load forecasts also requires the detailed changes in load pattern from end-use studies, economic studies, and engineering studies to be reflected in forecast hourly loads (Block E). Part of these changes will have been reflected in the energy and load forecasts and must be translated into hourly effects. Other changes will not effect peak load or energy consumption, being only a shift of consumption from one period to another. SHAPES-PC and EPRI's Hourly Electric Load Model (HELM) offer the capability to effect such modifications to system load shape. Both software programs are available for this purpose and a selection is expected to be made during 1992.

FIGURE A2-8

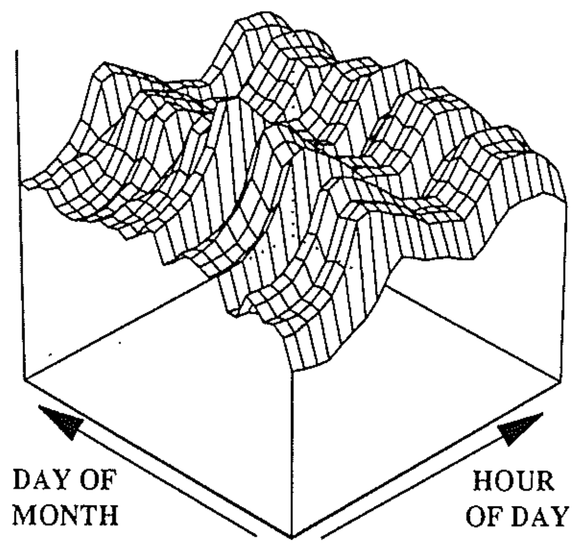
CP&L HOURLY SYSTEM LOAD SHAPE PROCESS



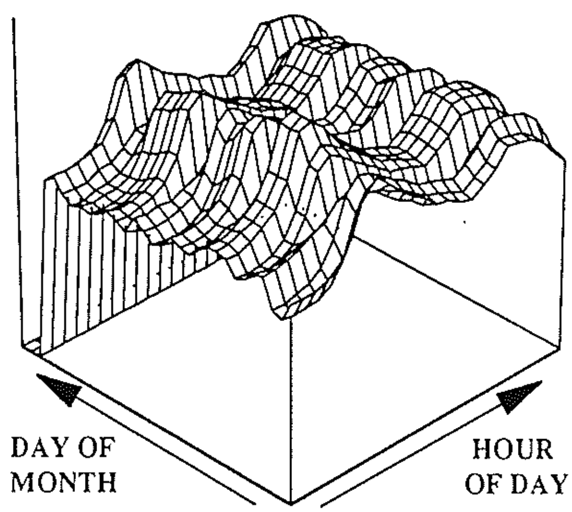
Completion of this step requires the future shifts in end uses be formed into hourly pattern changes. These changes will then be used to modify base year shape throughout the forecast period. Residential and commercial end-use energy forecasts have recently been completed and have yet to be translated into hourly patterns, and the shifts in hourly patterns determined. Industrial end-use models are expected to be initiated in 1992, with an industrial end-use forecast possibly being produced during 1993. Other pattern changes on a more global basis than end use, such as TOU rate effects, will be approached on a case-by-case basis as the load shape project proceeds.

Appendix Exhibit A2-A

JANUARY HOURLY LOAD MODEL

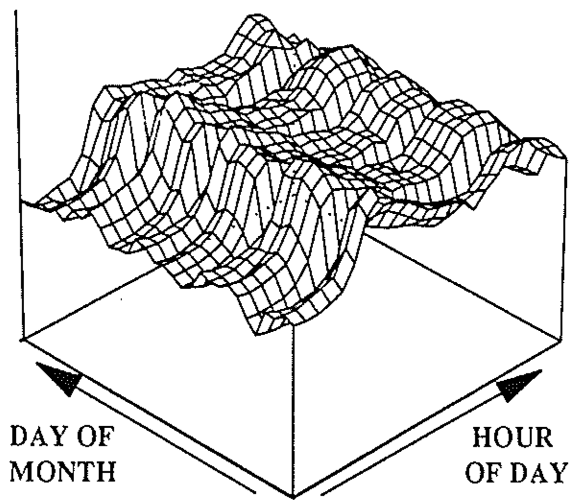


FEBRUARY HOURLY LOAD MODEL

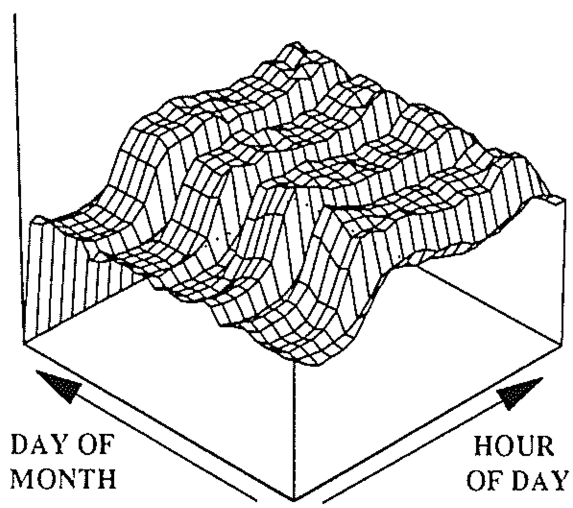


Appendix Exhibit A2-A

MARCH HOURLY LOAD MODEL

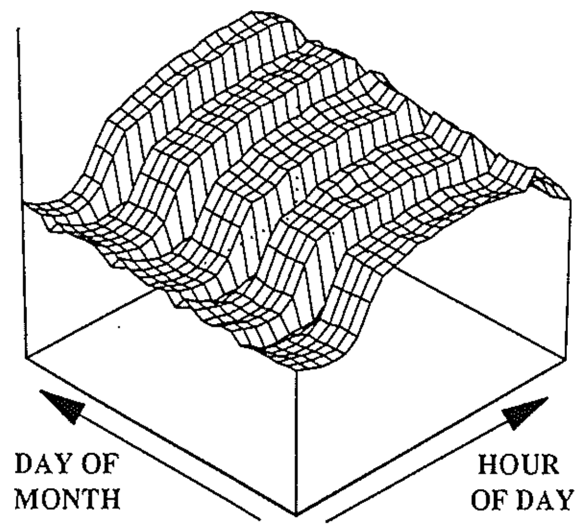


APRIL HOURLY LOAD MODEL

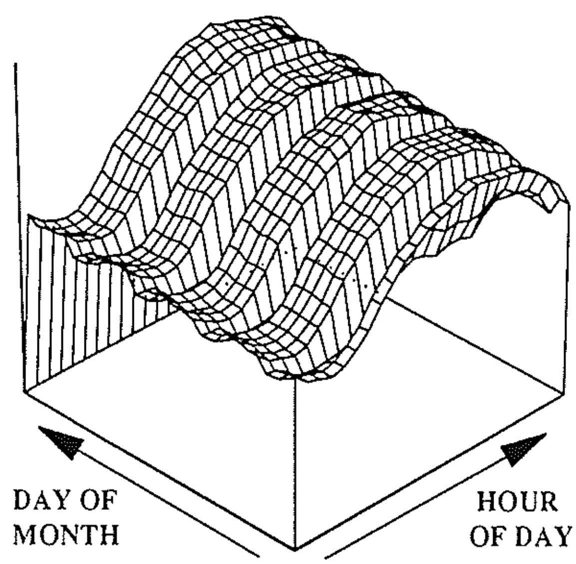


Appendix Exhibit A2-A

MAY HOURLY LOAD MODEL

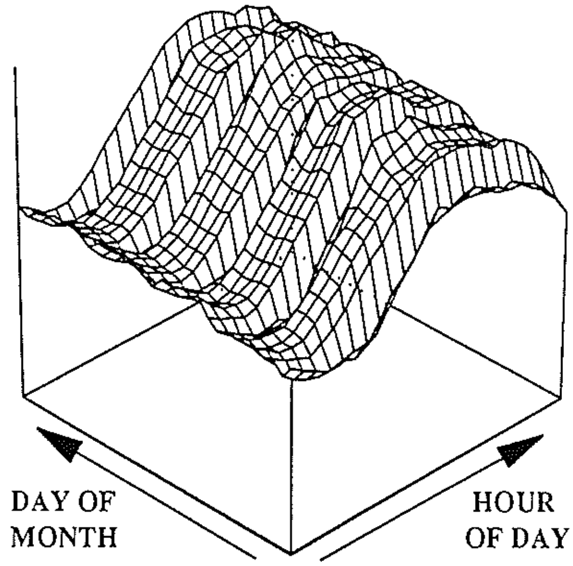


JUNE HOURLY LOAD MODEL

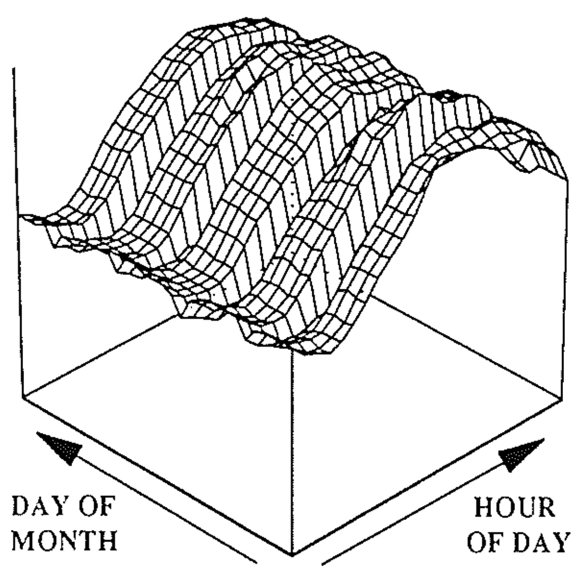


Appendix Exhibit A2-A

JULY HOURLY LOAD MODEL

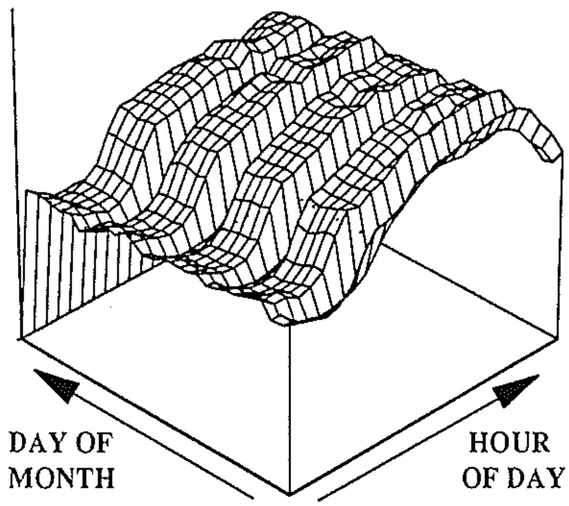


AUGUST HOURLY LOAD MODEL

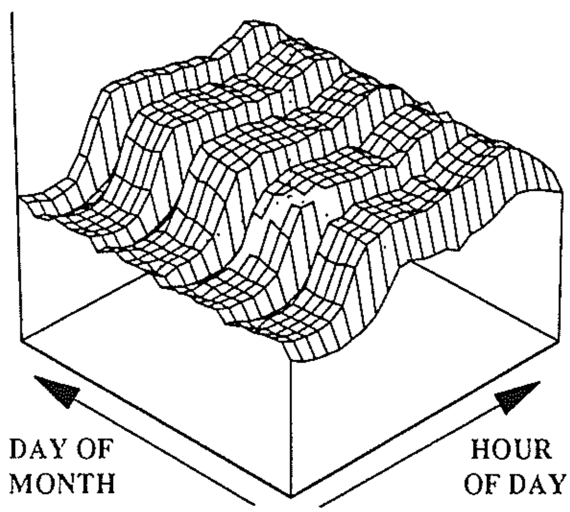


Appendix Exhibit A2-A

SEPTEMBER HOURLY LOAD MODEL

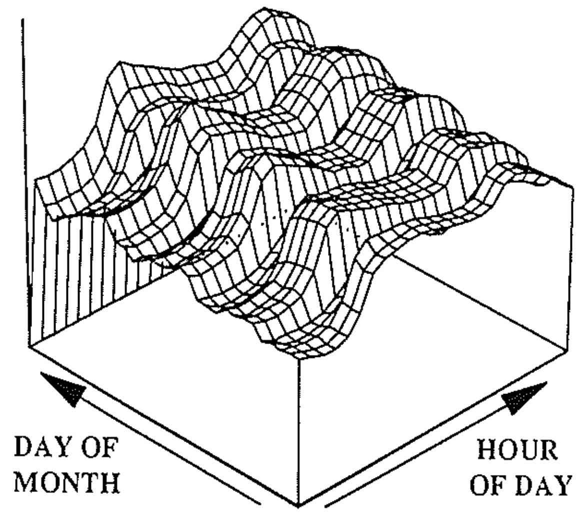


OCTOBER HOURLY LOAD MODEL

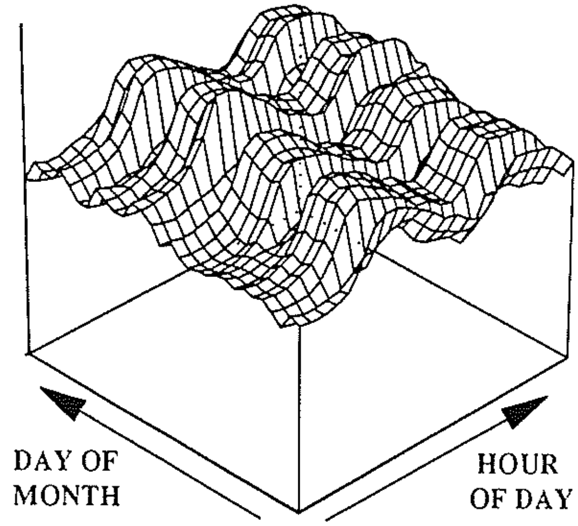


Appendix Exhibit A2-A

NOVEMBER HOURLY LOAD MODEL



DECEMBER HOURLY LOAD MODEL



Appendix B
Generating System Descriptive Data

The basic information required for the planning study include load and energy forecasts, fuel price forecasts, cost and operating assumptions for existing and future power resources, and economic assumptions. This appendix gives a complete description of the database inputs and assumptions used in the Integrated Resource Plan analyses described in Appendix F.

Peak Load And Energy Forecast

The load and energy forecast data used in the planning models are based on the annual CP&L system energy and peak load forecasts. Included in the system peak load and energy forecasts are the total NCEMPA demand and losses incurred in transferring the power to the individual NCEMPA members. Adjustments are also made to reflect the effects of the Company's DSM Load Management program. Following is an explanation of how the official load data was adapted for the Least Cost Integrated Resource Planning (LCIRP) study.

Adaptation for Study

Table B-1 shows the 1990 peak load, energy, load factor, and growth rates for the forecasts. The load forecast represents the most likely projection of summer peak load levels based on historical trends and expected future events. However, this represents just one of many possible outcomes. The possibility that the actual load may be higher or lower than projected was accounted for by developing high, mid, and low projections and their associated probabilities.

In order to minimize end effects, the study period was extended from 2010 to 2020 by holding the load and energy constant at the 2010 values.

Fuel Price Forecasts

Fuel price forecasts are required for each generating unit, both existing and future, throughout the study period. The forecasts are grouped according to type of fuel: nuclear, coal, and combustion turbine.

Nuclear

The Company's Nuclear Fuel Section provided the nuclear fuel price projections. The data were extrapolated after 2010 using the average escalation rate for all four nuclear units over the last five years of the forecast (2006-2010). See Table B-2 for the nuclear fuel price forecast, including yearly escalation rates, for each unit.

Coal

The coal price forecast for 1991-2010 was supplied by the Fossil Fuel Department. The average annual escalation rate for each coal category for the last five years of the forecast was used to extrapolate the data through 2020. The extended forecast is given in Table B-3. In addition to the forecasts for existing units, a projection for "New Units" is included for use with the generic coal alternatives. The coal price forecast includes anticipated impacts of the Clean Air Act Amendments. The price forecasts also reflect some units switching to lower sulfur coal in the year 2000 as a compliance action.

Combustion Turbine

Combustion turbines on the CP&L system utilize three types of fuel: oil, natural gas, and propane. Price forecasts for these fuels were provided by the Fossil Fuel Department. The base forecasts provided for 1991-2010 were extrapolated through 2020. The extrapolation was based on the average escalation rate from the last five years of the forecasts. Price forecasts for the three CT fuels are provided in Table B-4.

Existing Resources

The existing system includes power resources already in operation as well as committed capacity within the study period. In addition to fuel prices, the data required for modeling existing resources includes capacity ratings, heat rates, availability, and O&M costs. The assumptions defining the existing system for the base year of 1991 are summarized in Table B-5. While the operating characteristics are assumed to remain the same throughout the study period, all costs - fuel, O&M, and purchased power - are subject to escalation rates. Costs for non-utility purchases, emergency purchases, and utility purchases are shown in Tables B-6, B-7, and B-8, respectively.

Economic Assumptions

Assumptions about financial parameters, O&M escalation rate, and construction cost escalation rate are required to evaluate resource plans over time. The financial assumptions used in evaluating AFUDC, taxes and the present value of future expenditures are summarized in Table B-9.

The O&M cost escalation rate assumed for all technologies is 5.0%. This escalation rate was determined based on a forecast of CP&L's O&M expenditures and a comparison of the O&M escalation rates currently in use by neighboring electric utilities.

The construction cost escalation rate used for all future generating units is 5.0%. This is also an internally-generated value.

Table B-1
1990 Peak Load and Energy Forecast Summary

YEAR	SYSTEM PEAK LOAD MW	SYSTEM PEAK LOAD % INCR	SYSTEM ENERGY INPUT GWH	SYSTEM ENERGY INPUT % INCR	ANNUAL LOAD FACTOR
1991	8,600		45,713		0.607
1992	8,827	2.6	47,100	3.0	0.609
1993	8,978	1.7	48,102	2.1	0.612
1994	9,202	2.5	49,470	2.8	0.614
1995	9,400	2.2	50,637	2.4	0.615
1996	9,638	2.5	51,851	2.4	0.614
1997	9,855	2.3	53,033	2.3	0.614
1998	10,073	2.2	54,204	2.2	0.614
1999	10,286	2.1	55,385	2.2	0.615
2000	10,493	2.0	56,530	2.1	0.615
2001	10,698	2.0	57,633	2.0	0.615
2002	10,901	1.9	58,751	1.9	0.615
2003	11,113	1.9	59,910	2.0	0.615
2004	11,330	2.0	61,109	2.0	0.616
2005	11,549	1.9	62,344	2.0	0.616
2006	11,779	2.0	63,604	2.0	0.616
2007	12,011	2.0	64,886	2.0	0.617
2008	12,242	1.9	66,150	1.9	0.617
2009	12,479	1.9	67,459	2.0	0.617
2010	12,723	2.0	68,852	2.1	0.618

Table B-2
Nuclear Fuel Prices

	BRUNSWICK 1		BRUNSWICK 2		HARRIS 1		ROBINSON 2	
YEAR	¢/MBTU	ESC-%	¢/MBTU	ESC-%	¢/MBTU	ESC-%	¢/MBTU	ESC-%
1991	50.40		47.74		44.28		45.72	
1992	50.86	0.9	50.51	5.8	44.96	1.5	45.42	(0.7)
1993	51.36	1.0	51.46	1.9	45.13	0.4	46.83	3.1
1994	52.19	1.6	52.27	1.6	46.68	3.4	47.30	1.0
1995	53.79	3.1	54.52	4.3	48.03	2.9	48.80	3.2
1996	54.66	1.6	56.58	3.8	52.05	8.4	50.05	2.6
1997	57.26	4.8	57.57	1.8	55.53	6.7	52.35	4.6
1998	59.53	4.0	61.20	6.3	57.27	3.1	54.64	4.4
1999	60.84	2.2	63.35	3.5	59.60	4.1	56.14	2.7
2000	63.54	4.4	64.55	1.9	62.69	5.2	58.41	4.0
2001	66.49	4.6	67.32	4.3	64.53	2.9	62.31	6.7
2002	68.10	2.4	71.17	5.7	67.82	5.1	64.60	3.7
2003	72.94	7.1	72.95	2.5	72.59	7.0	67.79	4.9
2004	77.44	6.2	78.82	8.0	75.31	3.8	72.63	7.1
2005	79.72	2.9	83.47	5.9	80.39	6.7	75.60	4.1
2006	86.65	8.7	85.66	2.6	86.10	7.1	80.47	6.4
2007	92.04	6.2	93.67	9.3	89.48	3.9	86.32	7.3
2008	94.72	2.9	100.08	6.8	96.33	7.7	89.86	4.1
2009	102.85	8.6	102.88	2.8	102.36	6.3	95.69	6.5
2010	108.56	5.5	111.05	7.9	105.89	3.4	102.56	7.2
2011	115.50	6.4	117.61	5.9	111.90	5.7	109.02	6.3
2012	122.88	6.4	124.56	5.9	118.26	5.7	115.88	6.3
2013	130.74	6.4	131.92	5.9	124.97	5.7	123.18	6.3
2014	139.10	6.4	139.71	5.9	132.07	5.7	130.94	6.3
2015	147.99	6.4	147.97	5.9	139.57	5.7	139.18	6.3
2016	157.45	6.4	156.71	5.9	147.50	5.7	147.94	6.3
2017	167.52	6.4	165.98	5.9	155.88	5.7	157.26	6.3
2018	178.23	6.4	175.78	5.9	164.73	5.7	167.16	6.3
2019	189.62	6.4	186.17	5.9	174.08	5.7	177.68	6.3
2020	201.74	6.4	197.17	5.9	183.97	5.7	188.87	6.3

NOTE: Nuclear fuel prices extrapolated for 2011 through 2020 using average escalation rate for nuclear fuel from 2006 to 2010.

Table B-3
Coal Prices and Escalation Rates

YEAR	ASHEVILLE COST ¢/MBTU	ASHEVILLE ESC-%	ROXBORO 1-3 COST ¢/MBTU	ROXBORO 1-3 ESC-%	ROX 4, MAYO COST ¢/MBTU	ROX 4, MAYO ESC-%	SUTTON COST ¢/MBTU	SUTTON ESC-%	CF 5&6, ROB 1 COST ¢/MBTU	CF 5&6, ROB 1 ESC-%	OTHER COST ¢/MBTU	OTHER ESC-%	NEW COST ¢/MBTU	NEW ESC-%
1991	147.3		191.9		201.6		206.2		227.5		227.5			
1992	160.7	9.1	204.8	6.7	200.2	(0.7)	218.4	5.9	239.9	5.5	239.9	5.5		
1993	168.0	4.5	211.7	3.4	207.8	3.8	230.6	5.6	251.4	4.8	251.4	4.8		
1994	171.4	2.0	221.6	4.7	217.4	4.6	244.8	6.2	263.8	4.9	263.8	4.9		
1995	187.7	9.5	231.5	4.5	227.0	4.4	256.0	4.6	276.3	4.7	276.3	4.7		
1996	200.8	7.0	243.0	5.0	251.0	10.6	268.8	5.0	290.1	5.0	290.1	5.0		
1997	255.8	27.4	257.5	6.0	267.1	6.4	290.7	8.1	305.0	5.1	305.0	5.1		
1998	269.9	5.5	272.1	5.7	286.1	7.1	306.5	5.4	321.8	5.5	321.8	5.5		
1999	287.0	6.3	288.6	6.1	306.1	7.0	322.4	5.2	338.7	5.3	338.7	5.3	283.5	
2000	328.2	14.4	307.1	6.4	307.1	0.3	363.3	12.7	378.6	11.8	357.6	5.6	315.5	11.3
2001	344.2	4.9	322.1	4.9	322.1	4.9	381.0	4.9	397.1	4.9	374.6	4.8	333.3	5.6
2002	362.2	5.2	340.1	5.6	340.1	5.6	400.9	5.2	417.9	5.2	397.6	6.1	351.0	5.3
2003	380.2	5.0	359.1	5.6	359.1	5.6	420.8	5.0	438.6	5.0	410.6	3.3	371.0	5.7
2004	400.2	5.3	375.1	4.5	375.1	4.5	443.0	5.3	461.7	5.3	427.6	4.1	390.0	5.1
2005	420.2	5.0	395.1	5.3	395.1	5.3	465.1	5.0	484.8	5.0	447.6	4.7	412.0	5.6
2006	442.2	5.2	418.1	5.8	418.1	5.8	489.5	5.2	510.2	5.2	468.6	4.7	435.0	5.6
2007	465.2	5.2	439.1	5.0	439.1	5.0	514.9	5.2	536.7	5.2	492.6	5.1	459.0	5.5
2008	489.2	5.2	464.1	5.7	464.1	5.7	541.5	5.2	564.4	5.2	516.6	4.9	484.0	5.4
2009	515.2	5.3	490.1	5.6	490.1	5.6	570.3	5.3	594.4	5.3	541.6	4.8	511.0	5.6
2010	542.2	5.2	516.1	5.3	516.1	5.3	600.2	5.2	625.5	5.2	568.6	5.0	539.0	5.5
2011	571.2	5.3	545.1	5.6	545.1	5.6	632.3	5.3	659.0	5.4	596.6	4.9	568.5	5.5
2012	601.2	5.3	574.8	5.4	574.8	5.4	665.5	5.3	693.6	5.3	626.1	4.9	599.8	5.5
2013	632.8	5.3	606.1	5.4	606.1	5.4	700.5	5.3	730.0	5.3	657.1	4.9	632.7	5.5
2014	666.0	5.3	639.1	5.4	639.1	5.4	737.3	5.3	768.4	5.3	689.6	4.9	667.5	5.5
2015	701.0	5.3	674.0	5.4	674.0	5.4	776.0	5.3	808.7	5.3	723.8	4.9	704.2	5.5
2016	737.8	5.3	710.7	5.4	710.7	5.4	816.8	5.3	851.2	5.3	759.6	4.9	743.0	5.5
2017	776.6	5.3	749.4	5.4	749.4	5.4	859.7	5.3	895.9	5.3	797.2	4.9	783.8	5.5
2018	817.4	5.3	790.2	5.4	790.2	5.4	904.8	5.3	943.0	5.3	836.6	4.9	826.9	5.5
2019	860.3	5.3	833.3	5.4	833.3	5.4	952.4	5.3	992.5	5.3	878.0	4.9	872.4	5.5
2020	905.5	5.3	878.7	5.4	878.7	5.4	1002.4	5.3	1044.6	5.3	921.4	4.9	920.4	5.5

NOTE: (1) Coal prices extrapolated from 2012 through 2020 using the average escalation rate for each coal from 2007 to 2011.
(2) These costs include an estimate of the impact that the Clean Air Act Amendments will have on the price of coal and reflect lower sulfur coal being burned for compliance purposes.

Table B-4
Combustion Turbine Fuel Prices

	SYSTEM OIL		SYSTEM NATURAL GAS		SYSTEM PROPANE	
YEAR	PRICE ¢/MBTU	ESC-%	PRICE ¢/MBTU	ESC-%	PRICE ¢/MBTU	ESC-%
1991	481		337		496	
1992	505	5.0	314	(6.8)	467	(5.8)
1993	545	7.9	318	1.3	444	(4.9)
1994	600	10.1	321	0.9	417	(6.1)
1995	645	7.5	357	11.2	447	7.2
1996	679	5.3	399	11.8	480	7.4
1997	747	10.0	416	4.3	523	9.0
1998	818	9.5	511	22.8	572	9.4
1999	903	10.4	606	18.6	631	10.3
2000	993	10.0	673	11.1	695	10.1
2001	1096	10.4	748	11.1	766	10.2
2002	1214	10.8	829	10.8	842	9.9
2003	1336	10.0	916	10.5	920	9.3
2004	1457	9.1	1003	9.5	998	8.5
2005	1581	8.5	1142	13.9	1075	7.7
2006	1711	8.2	1193	4.5	1157	7.6
2007	1854	8.4	1294	8.5	1246	7.7
2008	1999	7.8	1402	8.3	1336	7.2
2009	2149	7.5	1458	4.0	1427	6.8
2010	2302	7.1	1631	11.9	1520	6.5
2011	2482	7.8	1752	7.4	1629	7.2
2012	2675	7.8	1882	7.4	1746	7.2
2013	2884	7.8	2022	7.4	1871	7.2
2014	3109	7.8	2172	7.4	2005	7.2
2015	3352	7.8	2334	7.4	2149	7.2
2016	3614	7.8	2507	7.4	2304	7.2
2017	3896	7.8	2693	7.4	2469	7.2
2018	4200	7.8	2893	7.4	2646	7.2
2019	4527	7.8	3108	7.4	2836	7.2
2020	4881	7.8	3339	7.4	3039	7.2

NOTE: Fuel price extrapolated from 2011 through 2020 using average escalation rate for fuel 2006 to 2010.

Table B-5
Existing Resources
Unit Descriptions

UNIT NAME	MIN LOAD (MW)	MAX LOAD (MW)	HEAT RATE @ MIN LOAD (BTU/KWH)	AVG. INCR. HEAT RATE (BTU/KWH)	MAINT. OUTAGE (DAYS/YEAR)	EQUIV. F.O.R. (%)	FIRST YEAR O&M COSTS FIXED ($/kW-Mon)	VARIABLE ($/MWh)	YEAR INST.
NUCLEAR									
Brunswick 1	250	790	11538	9606	87	14.0	8.38	1.00	1977
Brunswick 2	250	790	12130	9811	87	19.0	8.38	1.00	1975
Harris 1	290	860	13243	9089	50	11.0	7.98	1.00	1987
Robinson 2	250	665	13105	9881	40	24.0	10.03	1.00	1971
COAL									
Asheville 1	33	198	13767	8428	32	3.11	1.82	0.00	1964
Asheville 2	26	194	14780	8941	32	3.08	1.53	0.00	1971
Cape Fear 5	41	143	11061	8571	28	3.80	1.71	0.00	1956
Cape Fear 6	45	173	11313	8876	32	5.49	1.30	0.00	1958
Lee 1	35	79	11224	9963	30	2.76	1.59	0.00	1951
Lee 2	35	76	11296	10854	26	5.08	2.34	0.00	1952
Lee 3	70	252	10231	8907	26	2.15	1.25	0.00	1962
Mayo 1	210	745	11612	8740	22	8.07	0.83	0.00	1983
Robinson 1	35	174	11497	8860	25	4.72	2.62	0.00	1960
Roxboro 1	100	385	11324	8872	31	6.83	1.85	0.00	1966
Roxboro 2	200	670	10827	8665	30	10.87	1.07	0.00	1968
Roxboro 3	180	707	11294	8887	26	6.20	1.06	0.00	1973
Roxboro 4	180	700	11801	8910	25	4.18	0.92	0.00	1980
Sutton 1	35	97	12603	10864	24	5.93	1.51	0.00	1954
Sutton 2	23	106	12422	10036	28	2.70	1.44	0.00	1955
Sutton 3	50	410	12753	8988	26	7.86	1.28	0.00	1972
Weatherspoon 1	20	49	12778	11356	17	2.73	2.25	0.00	1949
Weatherspoon 2	20	49	13045	11252	16	1.05	1.98	0.00	1950
Weatherspoon 3	34	78	10592	9496	15	2.80	2.13	0.00	1952
COMBUSTION TURBINES									
Blewett 1-4	26	52	20823	11082	6	3.03	0.22	0.00	1971
Cape Fear CC	42	84	14112	7360	6	3.03	0.22	0.00	1969
Darlington 1-11 *	26	52	17478	9191	6	3.03	0.22	0.00	1974
Lee 1-4	46	91	20434	10342	6	3.03	0.22	0.00	1968,71
Other **	22	45	20280	9704	6	3.03	0.22	0.00	1968
Sutton 1-3	32	64	20896	9908	6	3.03	0.22	0.00	1968,69
Weatherspoon 1-4	69	138	18018	10041	6	3.03	0.22	0.00	1970,71
COGENERATION									
Entrepreneur	265	265	10000	10000	0	13.0	See Table B-6		1986-91
Cogenerators	84	84	10000	10000	0	37.0	See Table B-6		1986-91
Small Power	62	62	10000	10000	0	26.0	See Table B-6		1986-91
PURCHASES									
AEP	250	250	10000	10000	33	17.41	See Table B-8		1990
Duke	400	400	10000	10000	0	0	See Table B-8		1992
SCPSA/NCEMPA	77	77	10000	10000	0	0	See Table B-8		1991

* Each Darlington unit is modeled individually.

** "Other" includes Morehead, Robinson, and Roxboro combustion turbines.

Table B-5
Existing Resources
Unit Descriptions

HYDRO UNITS

UNIT NAME	MAX LOAD (MW)	TOTAL ENERGY (GWh/Yr)	MAINT. OUTAGE (DAYS/YEAR)	EQUIV. F.O.R. (%)	FIRST YEAR O&M COSTS FIXED ($/kW-Mon)	VARIABLE ($/MWh)
Hydro	218	761	0	0	0.62	0
SEPA	109	182	0	0	0.62	0

Table B-6
Contracted Non-Utility Purchases

YEAR	¢/KWH*	ESC-%
1991	5.78	
1992	5.90	2.1
1993	6.04	2.4
1994	6.18	2.2
1995	6.32	2.3
1996	6.51	3.0
1997	6.60	1.4
1998	6.66	0.8
1999	6.74	1.2
2000	6.71	(0.4)
2001	6.95	3.5
2002	7.35	5.8
2003	7.75	5.5
2004	8.06	3.9
2005	8.40	4.3
2006	8.75	4.1
2007	9.15	4.6
2008	8.39	(8.4)
2009	8.94	6.6
2010	9.15	2.3
2011	9.35	2.3
2012	9.57	2.3
2013	9.78	2.3
2014	10.00	2.3
2015	10.23	2.3
2016	10.46	2.3
2017	10.70	2.3
2018	10.94	2.3
2019	11.19	2.3
2020	11.44	2.3

* Prices extrapolated from 2010 to 2020 using average escalation rate for 2005 to 2009.

Table B-7
Emergency Purchases

YEAR	$/MWH*	ESC-%
1991	96.2	
1992	101.0	5.0
1993	109.0	7.9
1994	120.0	10.1
1995	129.0	7.5
1996	135.8	5.3
1997	149.4	10.0
1998	163.6	9.5
1999	180.6	10.4
2000	198.6	10.0
2001	219.2	10.4
2002	242.8	10.8
2003	267.2	10.0
2004	291.4	9.1
2005	316.2	8.5
2006	342.2	8.2
2007	370.8	8.4
2008	399.8	7.8
2009	429.8	7.5
2010	460.4	7.1
2011	496.3	7.8
2012	535.1	7.8
2013	576.8	7.8
2014	621.9	7.8
2015	670.4	7.8
2016	722.7	7.8
2017	779.1	7.8
2018	839.9	7.8
2019	905.5	7.8
2020	976.2	7.8

* Escalation rate for 2011-2020 is the same as the CT fuel escalation rate.

Table B-8
Contracted Utility Purchases

YEAR	AMERICAN ELECTRIC POWER					DUKE POWER					SCPSA/NCEMPA *		
	CAPACITY MW	CAPACITY $/KW-MO	ESC-%	ENERGY $/MWh	ESC-%	CAPACITY MW	CAPACITY $/KW-MO	ESC-%	ENERGY $/MWh	ESC-%	CAPACITY MW	ENERGY $/MWh	ESC-%
1991	250	13.19		12.23							77	22.99	
1992	250	13.28	0.7	12.97	6.1	400	10.93		19.50		77	23.63	2.8
1993	250	13.36	0.5	13.74	5.9	400	10.99	0.6	21.00	7.7	77	24.82	5.1
1994	250	13.45	0.7	13.82	0.6	400	11.06	0.6	22.50	7.1	100	25.41	2.4
1995	250	13.56	0.8	14.11	2.1	400	11.12	0.6	24.00	6.7	100	25.98	2.2
1996	250	13.69	1.0	14.81	5.0	400	11.19	0.6	24.50	2.1	100	26.17	0.8
1997	250	13.85	1.1	15.56	5.0	400	11.27	0.7	26.50	8.2	100	26.65	1.8
1998	250	14.01	1.2	16.33	5.0						50	27.49	3.2
1999	250	14.18	1.2	17.15	5.0								
2000	250	14.35	1.2	18.00	5.0								
2001	250	14.55	1.4	18.90	5.0								
2002	250	14.74	1.3	19.85	5.0								
2003	250	14.94	1.3	20.84	5.0								
2004	250	15.15	1.4	21.88	5.0								
2005	250	15.38	1.5	22.98	5.0								
2006	250	15.63	1.7	24.12	5.0								
2007	250	15.87	1.5	25.34	5.0								
2008	250	16.13	1.7	26.60	5.0								
2009	250	16.42	1.8	27.93	5.0								

* Capacity charges are paid by NCEMPA.

Appendix C
Incremental Cost Methodology

Introduction

This appendix addresses incremental cost and its application in various planning and analysis processes taking place at Carolina Power & Light Co.. The discussion begins with background information followed by an overview of embedded and incremental costing concepts and methods, followed by conclusions.

Background

Prior to the passage of the Public Utilities Regulatory Policies Act of 1978 (PURPA) electric utilities directed most of their cost-of-service efforts towards producing embedded cost studies. With the passage of PURPA, the electric utility industry began to more closely study incremental costs, and to develop more consistent ways to identify, produce, and report the incremental cost to provide service. The law also requires public utilities to accept and purchase, as delivered, energy produced by qualifying facilities (QFs). QFs are defined as those facilities able to use the same steam to generate electricity and to be used in some other process, as in cogeneration, or those facilities able to generate electricity using renewable resources. While the law clearly indicates the incremental nature of the rates to be paid to QFs by utilities, the actual rates are to be determined by individual state authority under Federal Energy Regulatory Commission, FERC, rules implementing PURPA. State regulatory bodies necessarily became more involved with incremental cost analysis and thus required additional reporting of incremental cost studies by the utilities under their jurisdiction.

Electric utility incremental cost analysis is a concept that has existed for a long time. The passage of PURPA ushered its more general use into the 1980's as a tool needed not only to provide the basis for the purchase of QF power but also as a tool for the screening, selecting and analyzing of new supply- and demand-side options for maintaining the balance between customer demand and utility supply.

Discussion

Embedded Cost

Embedded cost of service reflects actual historic, booked expenditures and investments that the utility has made in order to provide service. The costs are grouped according to function; i.e., generation, transmission, distribution, and general; are classified according to causality such as demand, energy, or customer; and allocated to various customer classes. This process provides the basis for the rates included in the utility's retail and wholesale tariffs. The embedded costs are a result of those monies which have been spent, booked, and are subject to depreciation and other accounting treatment. Embedded cost figures also provide the basis for tracking rates of return, financial reporting, and control (e.g., analysis of budget vs. actual). These costs are sunk, and while they indicate what costs have been incurred to provide service, they provide neither consistently reliable nor economically correct information as to the cost to supply existing customers' incremental needs, nor do they provide reliable information in regard to the most economic methods of providing various incremental services.

Incremental Cost: General

At electric utilities, the terms "Marginal," and "Incremental" when used to describe costs, are often used interchangeably. While this is not technically correct, in most cases, confusion does not result. In strictest terms, marginal cost is more theoretical than practical and is defined as the change in total cost which occurs in response to an infinitesimally small change in production; or, the first derivative of the production cost function with respect to output. The term incremental cost, more practically refers to the additional cost incurred as a result of producing and delivering one additional increment of output. Rather than this increment being infinitesimally small, the units of output for an electric utility are usually expressed in larger sizes such as kilowatts, kilowatt-hours or even megawatts, or megawatt-hours. Because of the FERC rule implementing PURPA, incremental costs are often calculated and reported in blocks of 100 megawatts. Incremental cost can be defined and calculated at any convenient level in the utility's supply/delivery system, e.g., at the customer's meter, at the output of the utility's generator, or at any convenient level in the delivery system in between the two. A brief overview of incremental costing methodology follows.

Perhaps the most widely accepted method for the calculation of incremental cost involves the concept of dividing total incremental production cost into three basic cost causing components: demand, energy, and customer. Each major segment of the utility's system; i.e., generation, transmission, and distribution, is then analyzed to identify and collect the incremental costs applicable to each segment. Unlike an embedded study which strives to classify and allocate a known amount of expenses and investment to various customer groups, an incremental study begins at zero and strives to collect incremental costs applicable at various levels throughout the power system. These costs can then be combined by voltage level or customer class as needed.

The components which may be included in the calculation of incremental cost depend upon how the result will be used. For instance, the costs may be used in a short-run or a long-run analysis, they may be used in a study requiring special treatment, or they may be required as a result of a regulatory order requiring certain treatment of the input parameters. The components typically included in a long-run analysis are the fixed or capital costs associated with the physical facilities required to serve load at some location, and the variable costs associated with producing and delivering the power such as fuel and other variable operation and maintenance, O&M, expenses. Short-run incremental costs include only the components which are variable in the short run.

Periodically, the Company performs an incremental cost study. Incremental cost information, updated annually, is typically required for various demand-side management program analyses, rate designs, and other evaluations of capital expenditures. The incremental cost study is an input for the Company's avoided cost rates which are filed in compliance with regulatory orders and avoided cost hearings held approximately every two years by the regulatory bodies in North and South Carolina. It is in these proceedings that the state regulatory bodies establish the rates and Terms and Conditions under which the public utilities in the two states deal with QFs.

Incremental Demand Related Cost

The most debated aspect of incremental costing has been the method for determining the incremental demand related costs of generation. The method often used, and approved by many regulatory authorities including the NCUC, is based upon work done by National Economic Research Associates, Inc. (NERA). The so called NERA method or "peaker" method assumes the least capital intensive option, usually the combustion turbine, to be the incremental source of capacity. Other features of the NERA method include analyzing annual changes in transmission and distribution plant investments as they relate to changes in system load over a series of years, thus producing the incremental demand related costs for these system segments.

Incremental Energy Related Cost

Energy related costs are derived by obtaining incremental fuel cost during on- and off-peak periods through the use of a production cost model. These fuel costs are grossed up to account for variable O&M expenses and working capital expenses, and then adjusted for system losses occurring at various voltage levels in the system to produce the incremental cost to deliver energy to a given level in the system.

Incremental Customer Related Cost

Customer related costs are obtained by identifying those costs which occur because of the existence of the customer. These include such items as accounts maintenance, meter expense and meter reading expense, customer service expenses, and the cost of the minimum system required to serve some minimum customer load. These expenses are analyzed in light of changes in customer growth to produce the marginal customer costs.

Avoided Cost

The term avoided cost as commonly used, especially since the passage of PURPA, generally means the production cost saved or avoided as a result of the supply of electricity from a source outside of a host utility's system. Specifically, it is the cost that the utility would have incurred if not for the power supplied by the QF. As defined in this manner, and as articulated in PURPA and FERC rules, the avoided costs are clearly incremental in nature and very closely follow the definition of incremental cost.

As mentioned above, the terms avoided or incremental cost can also apply to DSM options. In this case, avoided cost is that cost avoided as a result of conservation or some other load reducing or load avoiding technique being used; e.g., customer added insulation or utility controlled water heating. Since the term avoided cost is applied in a variety of ways, usually when the term is used, some qualification is required. For instance, some DSM options or off-system sources do not necessarily allow the utility to avoid the cost of supplying reserve capacity, or may not be equivalent in all respects to an actual generation source. Similarly, the off-system source or DSM option may not allow for the avoidance of facilities because of the point of application or interconnection of the option or the source. Full avoided cost reflects the cost of completely avoiding the generation or facilities. Since different DSM applications impact the utility's system in different ways and at different levels, the analyst must properly adjust the full avoided cost to accurately reflect the cost impact of the application being analyzed. This is accomplished by examining the physical point of impact as well as the time of day, the month, and season of the year that the impact occurs.

The calculation of avoided costs usually requires that a long-run approach be taken. The planning horizons for electric utilities are necessarily long because of the length of time required to site and construct utility generation, transmission, and distribution plant. Expected system growth, along with the relatively long life of these facilities, as well as the options and programs, which would cause their avoidance, usually require that a long-run approach be taken.

Conclusions

A theoretically correct and consistent method of economic comparison and analysis must be used in order to perform meaningful utility planning, to make prudent decisions about how to best serve present and future requirements and to identify opportunities for improving the characteristics of the demands placed upon the company's resources. Proper economic analysis is also needed to develop effective, economic approaches not only to manage the demands for service from the system, but also to provide the customers with choices and options so that they can manage their own energy requirements.

When a new service requirement appears on the Company's system, there are choices to be made in regard to the utility's response. One can choose to meet the new requirements by adding one of several types of supply options to the system. To the extent a utility can influence the nature of existing and new load requirements, the utility may be able shape system load so that it may be served with some existing but not fully utilized resource. The utility may also be able to encourage an alternative to adding the new requirement at all.

Any one of these options have costs and benefits, but none will have any affect on costs already incurred. Making the right choice requires an analysis based upon incremental precepts which are used consistently to evaluate various options. Successful least cost integrated resource planning requires that all options are judged consistently. The use of incremental costs for such analyses assures that the evaluations are consistent and economically sound.

CP&L

Appendix D
Economic Cost-Effectiveness Of Demand-Side Options

Economic Cost-Effectiveness

CP&L evaluates the economic cost-effectiveness of demand-side management options from four different perspectives; 1) the utility point of view - the Utility Cost Test, 2) the ratepayers' perspective - the Ratepayer Impact Measure (RIM) Test, 3) the potential participant in a demand-side management option - the Participant Test and 4) the utility and its ratepayer as a whole - the Total Resource Cost (TRC) Test.

The net present value (NPV) results of these four economic tests are measures of cost-effectiveness, weighing the benefits against the costs of a demand-side management option. However, since each test represents a different perspective, the assignment of benefits and costs vary for each test. The costs and benefits components measured for input to these tests include supply costs, utility program costs, participant costs, changes in revenues to the utility or changes in bills to the participant, incentives paid to participants and participation charges paid to the utility. The definitions of costs and benefits also vary by load shape objective. For example, demand-side management options designed to achieve strategic conservation, load shifting, or peak clipping avoid supply costs. Therefore for these load shape objectives, supply costs are considered a benefit because these costs are avoided. However, supply costs become a component of the total costs when evaluating valley filling or strategic load growth demand-side management options since they increase the need for the supply of energy. The following tables summarize the classification of costs and benefits among each economic test and load shape objective.

Table D-1
Strategic Conservation, Load Shifting, Peak Clipping
Load Shape Objectives

	Benefits	Costs
Utility Cost	Avoided Supply Costs Participation Charges	Incentives Utility Program Costs
Ratepayer Impact Measure	Avoided Supply Costs Participation Charges	Incentives Utility Program Costs Revenue Loss
Participant	Incentives Bill Reductions	Participant Costs Participation Charges
Total Resource Cost	Avoided Supply Costs	Utility Program Costs Participant Costs

Table D-2
Valley Filling, Strategic Load Growth
Load Shape Objectives

	Benefits	Costs
Utility Cost	Participation Charges	Incentives Utility Program Costs Increased Supply Cost
Ratepayer Impact Measure	Participation Charges Revenue Gain	Incentives Utility Program Costs Increased Supply Cost
Participant	Incentives	Participant Costs Participation Charges Bill Increases
Total Resource Cost		Participant Costs Utility Program Costs Increased Supply Cost

The above tables highlight the relationships between the tests as well as the appropriateness of applying a specified test to the various load shape objectives.

The Utility Cost Test differs from the Ratepayer Impact Measure Test only in that changes in revenue (losses or gains) are not reflected as a component of total utility costs. Any changes in revenues are viewed as transfer payments between different groups of ratepayers. From a strictly utility total costs view point, it is irrelevant to which group of customers revenue changes are shifted. The Utility Cost Test measures the cost-effectiveness of a demand-side management option from the perspective of the total costs to the utility. If the NPV of a demand-side management option is positive, the economic indication is a reduction in the utility's costs as the result of such an option. A reduction in the utility's costs implies a reduction in the amount of energy bills over all customers. However, if there is no reduction in rates, then only customers participating in the demand-side management option will see a reduction in their bills. For valley filling or strategic load growth demand-side management options the only measurable benefit from the utility perspective as shown in the above table would be participation charges, because these load shape objectives do not avoid any supply costs. This factor renders the Utility Cost Test inappropriate for demand-side management options whose load shape objective is either valley filling or strategic load growth.

The Ratepayer Impact Measure (RIM) Test assesses the cost-effectiveness of a demand-side management option from the point of view of the ratepayer. This test measures what happens to customers rates as the result of a demand-side management option. Demand-side management options cause changes in revenues paid to the utility. Strategic conservation, load shifting, and peak clipping demand-side management options result in revenue losses to the utility, while revenue gains to the utility are the results of valley filling or strategic load growth demand-side management options. As shown in the above tables, the RIM test and the Participant test consider changes in revenues or bills in the determination of cost-effectiveness. However, unlike the Participant test, RIM is evaluating a demand-side management option from the point of view of the ratepayer (the participant as well as the non-participant). The above tables also show that while RIM considers changes in revenue, the perspectives taken by the Utility Cost test and the Total Resource Cost test do not consider changes in revenue as anything other than transfer payments. RIM is the only one of the four economic cost-effectiveness tests that is meaningful to study for all demand-side management load shape objective options.

The Participant Test measures the cost-effectiveness of a demand-side management option from the point of view of a customer evaluating whether to participate in the DSM option. Based on quantifiable direct measures, a customer would consider bill reductions or bill increases in his evaluation. A customer would also weigh any out-of-pocket costs that would be caused by his participation in a DSM option. Incentives paid to participants as well as charges associated with participating would also be considered in the customer's mind. As with the other cost-effectiveness tests, this test measures only quantifiable direct benefits and costs. The degree to which customers evaluate participation based on qualitative or indirect factors such as inconvenience or conversely increased production of goods and services will influence the meaningfulness of the results of the Participant Test.

The Total Resource Cost (TRC) Test represents the viewpoint of the utility and its ratepayers as a whole in evaluating the cost-effectiveness of a demand-side management option. Benefits and costs of the TRC are avoided or increased supply costs, participant costs, and utility program costs. Changes in revenues to the utility or bills to customers as well as incentives paid to participants and participation charges are not factors in the TRC test. These components are considered transfer payments because the TRC test is from the perspective of the utility and ratepayers as a whole; i.e., it doesn't matter whether the utility absorbs revenue losses or ratepayers see an increase in their rates, or for that matter whether one group of ratepayers subsidize another group of ratepayers. In the TRC test, the utility and all ratepayers are viewed as a single entity. The above tables highlight the relationship between the TRC test and the RIM and Participant tests. The TRC test can be thought of as the sum of the Ratepayer Impact Measure test and the Participant test. Incentives and revenue losses are considered costs to the ratepayer, while incentives and bill reductions are benefits to the participant and thus "cancel" each other out of the equation (transfer payment). Likewise participation charges and revenue gains are considered benefits to the ratepayer and costs to the participant; and, therefore, also "cancel" out of the equation and are not a component of the TRC test. The TRC test can be used to evaluate strategic conservation, load shifting, and peak clipping demand-side management options. However, the TRC test will result in meaningless measures of cost-effectiveness when evaluating valley filling or strategic load growth demand-side management options because as Table D-2 shows there are no benefits to balance against increased supply costs, participant costs, and utility program costs. Thus, valley filling and strategic load growth demand-side management options would never "pass" the Total Resource Cost Test.

Table D-3 through D-22 on the following pages present the Net Present Value results of CP&L's economic evaluation of demand-side management options. As discussed, not all tests are appropriate for all demand-side management load shape objective options. The definitions of benefits and costs vary between the four economic cost-effectiveness tests. Therefore, the benefits are shown in **bold** type for each test. Due to round-off effects, the benefits minus costs row may not equal the compilation of the individual rows. The notation "N/A" in Tables D-3 through D-22 means that the data are not available.

Common Sense Home Program

Thermal Efficiency: New Homes

Description:

The Common Sense Home Program encourages the construction of energy-efficient residences. Structures which meet the program's requirements for thermal integrity and equipment efficiency earn the Common Sense Home designation and qualify for CP&L's 5% Residential Energy Conservation Discount.

Load Shape Objective: Strategic Conservation

Table D-3
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**1746**	**1746**	-	**1746**
Energy	**1505**	**1505**	-	**1505**
Participation Charges	0	0	0	-
Incentives	708	708	**708**	-
Changes In Revenue	-	2736	**2736**	-
Utility Program Costs	17	17	-	17
Participant Costs	-	-	825	825
Benefits Minus Costs	2526	(210)	2619	2409

Thermal Efficiency-Existing Homes

Description:

Thermal efficiency is promoted for existing residential structures through the Homeowner's Energy Loan Program (HELP) used for insulation and high-efficiency heat pumps, energy audits, and customer education. In addition, an upgraded structure that meets CP&L's efficiency standards will also quality for the 5% Residential Energy Conservation Discount which provides a reduction in energy usage costs.

Load Shape Objective: Strategic Conservation

Table D-4
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**1746**	**1746**	-	**1746**
Energy	**1607**	**1607**	-	**1607**
Participation Charges	0	0	0	-
Incentives	0	0	0	-
Changes In Revenue	-	2920	**2920**	-
Utility Program Costs	411	411		411
Participant Costs	-	-	1640	1640
Benefits Minus Costs	2942	22	1280	1302

Residential High-Efficiency Heat Pump Program

Description:

The objective of this program is to encourage the use of high-efficiency equipment to reduce system peak and reduce the need for future generation capacity. This also helps to assure a balanced and optimized future system design. In 1990, the High SEER Program was incorporated into the Residential High-Efficiency Heat Pump Program. CP&L's High-Efficiency Heat Pump Program includes customer financing for high-efficiency heat pumps, a Quality Heat Pump Dealer List, dealer incentives for high-efficiency installations and mass-media advertising to educate residential customers regarding high-efficiency heat pumps. The heat pump financing is tied to the SEER rating of the equipment purchased by the residential customer. This program has multiple load shape objectives. During summer months, the program achieves strategic conservation and during winter months, valley filling and strategic load growth. The net effect of this program is increased supply costs and revenue gains.

Load Shape Objective: Strategic Conservation, Valley Filling, Strategic Load Growth

Table D-5
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	-	557	-	-
Energy	-	937	-	-
Participation Charges	-	0	-	-
Incentives	-	0	-	-
Changes In Revenue	-	**1709**	-	-
Utility Program Costs	-	147	-	-
Participant Costs	-	-	-	-
Benefits Minus Costs	-	68	-	-

EZ-$64 Program

Description:

The EZ-$64 program uses either radio or distribution line carrier (DLC) to interrupt residential customers' central air conditioners for up to four hours per day (maximum of 60 hours during cooling season) and/or electric water heaters for up to four hours per day throughout the year. Participants receive a credit of $2 per month for water heater control and an additional $10 per month ($13 for multiple units) from June through September for air conditioner control with the water heater option. A stand-alone air conditioner option is also available offering the customer a discount of $8 per month ($11 for multiple units). Economic cost-effectiveness tests for stand-alone air conditioner, stand-alone water heater, and air conditioner and water heater combined are contained in Tables D-6A, D-6B, and D-6C.

Load Shape Objective: Peak Clipping

EZ-$64 Program
(Stand-Alone A/C)

Table D-6A
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**638**	**638**	-	**638**
Energy	0	0	-	0
Participation Charges	0	0	0	-
Incentives	154	154	**154**	-
Changes In Revenue	-	0	0	-
Utility Program Costs	261	261	-	261
Participant Costs	-	-	0	0
Benefits Minus Costs	223	223	154	377

EZ-$64 Program
(Stand-Alone Water Heater)

Table D-6B
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**638**	**638**	-	**638**
Energy	0	0	-	0
Participation Charges	0	0	0	-
Incentives	312	312	**312**	-
Changes In Revenue	-	0	0	-
Utility Program Costs	714	714	-	714
Participant Costs	-	-	0	0
Benefits Minus Costs	(388)	(388)	312	(76)

EZ-$64 Program
(Air Conditioner and Water Heater Combined)

Table D-6C
Economic Cost-Effectiveness Tests (Present Value $/Kw)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**638**	**638**	-	**638**
Energy	0	0	-	0
Participation Charges	0	0	0	-
Incentives	225	225	**225**	-
Changes In Revenue	-	0	0	-
Utility Program Costs	215	215	-	215
Participant Costs	-	-	0	0
Benefits Minus Costs	198	198	225	423

Residential Time-Of-Use

Description:

The Company offers two residential time-of-use rates (demand & energy) which use financial incentives through rate design to encourage customers to shift load and usage to off-peak periods.

Load Shape Objective: Load Shifting

Table D-7
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**1745**	**1745**	-	**1745**
Energy	**402**	**402**	-	**402**
Participation Charges	0	0	0	-
Incentives	0	0	0	-
Changes In Revenue	-	2820	**2820**	-
Utility Program Costs	289	289	-	289
Participant Costs	-	-	137	137
Benefits Minus Costs	1858	(962)	2683	1721

Commercial Thermal Energy Storage

Description:

The objective of this program is to promote the installation of Thermal Energy Storage (TES) with emphasis on the utilization of off-peak air conditioning in conjunction with cool storage to shift peak summer load. The TES program emphasis is placed on customer education and working closely with HVAC design professionals and other business associates to make them aware of the various CP&L off-peak rates that are available for Thermal Storage applications. The program encourages the customer or his design professional or business associate to perform a payback calculation for the additional first cost expenses associated with a TES installation which will be off set through savings on the power bill via the appropriate time-of-use or thermal storage rate. The results of the economic cost-effectiveness tests are sensitive to case-specific assumptions.

Load Shape Objective: Load Shifting, Valley Filling

Table D-9
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**1526**	**1526**	-	**1526**
Energy	**71**	**71**	-	**71**
Participation Charges	0	0	0	-
Incentives	0	0	0	-
Changes In Revenue	-	728	**728**	-
Utility Program Costs	86	86	-	86
Participant Costs	-	-	224	224
Benefits Minus Costs	1511	783	504	1287

Commercial Energy Efficient Design

Description:

The objective of this program is to assist commercial customers with the design of energy-efficient new and renovated facilities. Building owners and agents are contacted early in the planning process to discuss the services and programs that are available from CP&L to assist in reducing peak demand and improving overall energy efficiency. Recommendations and proposals are made by Marketing Representatives and/or Power Engineers to customers and design professionals with respect to increased energy efficiency and load management. Specific measures recommended include: thermal integrity improvements, the use of energy-efficient lights, high-efficiency heating/air-conditioning equipment, and proper control devices.

Load Shape Objective: Load Shifting, Strategic Conservation

Table D-10
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**1746**	**1746**	-	**1746**
Energy	**1469**	**1469**	-	**1469**
Participation Charges	0	0	0	-
Incentives	0	0	0	-
Changes In Revenue	-	2261	**2261**	-
Utility Program Costs	6	6	-	6
Participant Costs	-	-	16	16
Benefits Minus Costs	3209	948	2245	3193

Commercial Energy Analysis (Audit)

Description:

To provide commercial customers with detailed on-site energy recommendations and proposals to increase energy efficiency and load management in end uses and site operations. Recommendations and proposals are made to the customer by marketing representatives and/or power engineers with respect to increased energy efficiency and load management in end uses such as HVAC, energy-efficient lighting, thermal envelope, and other end uses including operations.

Load Shape Objective: Load Shifting, Strategic Conservation, Valley Filling

Table D-11
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**1746**	**1746**	-	**1746**
Energy	**2540**	**2540**	-	**2540**
Participation Charges	0	0	0	-
Incentives	0	0	0	-
Changes In Revenue	-	3573	**3573**	-
Utility Program Costs	6	6	-	6
Participant Costs	-	-	19	19
Benefits Minus Costs	4280	707	3554	4261

Safeshine

Description:

Company-owned dusk-to-dawn off-street security lighting are leased for the home, farm, business and industry and improve the Company's load factor. The Safeshine program provides the customer with several outdoor energy-efficient leased lighting options. This off-peak, valley filling load improves the utilization of facilities and will help delay the need for future rate increases.

Load Shape Objective: Valley Filling

Table D-12
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	-	0	-	-
Energy	-	449	-	-
Participation Charges	-	0	-	-
Incentives	-	0	-	-
Changes In Revenue	-	2143	-	-
Utility Program Costs	-	1004	-	-
Participant Costs	-	-	-	-
Benefits Minus Costs	-	690	-	-

Industrial Audit/Energy Efficient Plants Program

Description:

The purpose is to influence the specification and installation of state-of-the-art energy-efficient technologies to improve the Company's load shape and maximize the efficiency of the customer's facility and/or process. Detailed energy studies and "walk-thru" audits include energy-efficient lighting, motors and motor drives, HVAC design and optimization, and energy management systems. Actual on-site measurement supports engineering analysis and conclusions. The same engineers work during the facility design phase as part of the Industrial Energy Efficient Plants component of this program. Objectives from both components include reducing peak load, load shifting, and strategic conservation.

Load Shape Objective: Peak Clipping, Strategic Conservation, Load Shifting, Valley Filling

Table D-13
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**1746**	**1746**	-	**1746**
Energy	**2257**	**2257**	-	**2257**
Participation Charges	0	0	0	-
Incentives	0	0	0	-
Changes In Revenue	-	3484	**3484**	-
Utility Program Costs	57	57	-	57
Participant Costs	N/A	N/A	243	243
Benefits Minus Costs	3946	462	3241	3703

Industrial Time-Of-Use

Description:

The Company provides price signals which encourage customers to shift load and energy use to off-peak periods.

Optional time-of-use rates are available to all industrial customers. Demand and energy charges are lower during specified off-peak hours.

Load Shape Objective: Load Shifting, Valley Filling

Table D-14
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**1746**	**1746**	-	**1746**
Energy	**603**	**603**	-	**603**
Participation Charges	0	0	0	-
Incentives	0	0	0	-
Changes In Revenue	-	2176	**2176**	-
Utility Program Costs	10	10	-	10
Participant Costs	-	-	N/A	N/A
Benefits Minus Costs	2339	163	N/A	2339

Large Load Curtailment

Description:

This program is designed to reduce peak load at times when available generating capacity is low relative to system load or when capacity is available but at a relatively high generation cost. Customers are provided an economic incentive to participate in the program. The customer receives a discount monthly for each kW subject to curtailment. For capacity type curtailments, customers are expected to reduce load or "pay" back to the Company a significant portion of discounts previously received. If the curtailment is economic in nature, customers decide whether to curtail or continue to operate at their contract demand level and pay a cents-per-kWh premium. This program is popular with customers who have the ability to increase and decrease significant loads in a short period of time.

Load Shape Objective: Peak Clipping

Table D-15
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**638**	**638**	-	**638**
Energy	**57**	**57**	-	**57**
Participation Charges	0	0	0	-
Incentives	803	803	**803**	-
Changes In Revenue	-	18	**18**	-
Utility Program Costs	132	132	-	132
Participant Costs	-	-	0	0
Benefits Minus Costs	(240)	(258)	821	563

Cogeneration & Hydroelectric

Description:

The program's goal is to offset a portion of CP&L's need for generation where cost effective. Company representatives work with industrial customers to identify feasible cogeneration potential. Cogeneration can be economically attractive to customers who have process steam requirements. In addition the Company also works with developers for projects to be installed and used as supply-side resources. CP&L technically assists entrepreneurs in reactivating abandoned hydroelectric generating sites in the Company's service territory.

Load Shape Objective: Strategic Conservation

Table D-16
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**977**	**977**	-	**977**
Energy	**3891**	**3891**	-	**3891**
Participation Charges	**17**	**17**	17	-
Incentives	0	0	0	-
Changes In Revenue	-	5524	**5524**	-
Utility Program Costs	1	1	-	1
Participant Costs	-	-	N/A	N/A
Benefits Minus Costs	4884	(640)	N/A	N/A

Electrotechnologies

Description:

The objective of this program is to inform the customer of electricity based options for industrial processes which have the potential to improve energy efficiency and product quality and increase productivity. "Electrotechnology" describes an electric-based technology used by industrial customers to manufacture or transform a product. Information about electrotechnologies is conveyed by the Power Engineer during normal customer contact and by CP&L Engineers as part of the Industrial Audit Program. CP&L has participated in the establishment of the Industrial Electrotechnologies Laboratory (IEL) at North Carolina State University. The IEL will offer industry the chance to assess electrotechnologies in real processes.

Load Shape Objective: Valley Filling, Strategic Load Growth

Table D-17
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	-	1527	-	-
Energy	-	7690	-	-
Participation Charges	-	0	-	-
Incentives	-	0	-	-
Changes In Revenue	-	**9056**	-	-
Utility Program Costs	-	40	-	-
Participant Costs	-	-	-	-
Benefits Minus Costs	-	(201)	-	-

Cogeneration - Economy C

Description:

The objective is to reduce costs for CP&L, its customers, and the cogenerator. There are significant savings to the Company in cycling costs and in avoided cost payments in split-the-savings arrangements with certain cogeneration projects. This type of arrangement is conducted on a real time cost basis.

Load Shape Objective: Valley Filling

Table D-18
Economic Cost-Effectiveness Tests (Total Program $/Year)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	-	0	-	-
Energy	-	4,825,208	-	-
Participation Charges	-	0	-	-
Incentives	-	9,477,768	-	-
Avoided Contractual Cogeneration Costs	-	**15,576,317**	-	-
Utility Program Costs	-	243	-	-
Participant Costs	-	-	-	-
Benefits Minus Costs	-	1,273,098	-	-

Target Business Recruitment

Description:

The Target Business Recruitment Program entails the recruitment of select, new industries with load characteristics compatible with CP&L's system characteristics and needs. Specific initiatives encompass (1) the identification of targeted industrial sectors and firms with typical load profiles compatible with CP&L's system characteristics and needs; (2) national advertising in select trade journals promoting the location advantages of regions within CP&L's service area; (3) development and implementation of direct mail campaigns directed toward targeted firms; (4) implementation of telemarketing efforts directed toward targeted firms to determine their interest in consideration of regions within CP&L's service area for a facility location; (5) targeting qualified firms in cooperation with state and local economic development allies; and (6) providing assistance to targeted firms considering a location within CP&L's service area.

Load Shape Objective: Valley Filling, Strategic Load Growth

Table D-20
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	-	977	-	-
Energy	-	3903	-	-
Participation Charges	-	0	-	-
Incentives	-	0	-	-
Changes In Revenue	-	**5957**	-	-
Utility Program Costs	-	0	-	-
Participant Costs	-	0	-	-
Benefits Minus Costs	-	1077	-	-

Dispatched Power

Description:

The purpose of the Dispatched Power Program is to encourage large customers to increase load when CP&L loads and costs are low. The Company constantly monitors system generation cost and when such cost falls below a predetermined level, a signal is sent to participants informing them that they may increase their load above normal levels for six hours. Normal demand charges are waived for the incremental demands. This is Class 1 Dispatched Power. Class 2 Dispatched Power is offered when the Company forecasts its available capacity will significantly exceed the expected load. Customers can increase their demands above normal levels during Class 2 periods, which normally last 24 hours. Normal demand charges do not apply during these periods, but instead, a small charge applies to incremental kilowatt-hours which are not off-peak. This program enhances the efficiencies of both the Company and it's customers.

Load Shape Objective: Valley Filling

Table D-21
Economic Cost-Effectiveness Tests (Total Program $/Year)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	-	0	-	-
Energy	-	311,228	-	-
Participation Charges	-	13,440	-	-
Incentives	-	0	-	-
Changes In Revenue	-	539,094	-	-
Utility Program Costs	-	106,802	-	-
Participant Costs	-	-	-	-
Benefits Minus Costs	-	134,504	-	-

Remote-Controlled Voltage Reduction

Description:

The Remote-Controlled Voltage Reduction System will allow Carolina Power & Light Company to take full economic advantage of megawatts available through a voltage reduction. It is anticipated that 2.5% voltage reduction will be used as a load management tool by the Energy Control Center without limitation as to frequency of use. The system will also be capable of a 5% voltage reduction as an emergency measure to reduce demand during critical peak periods. The design and installation of a Remote-Controlled Voltage Reduction System started in 1991 and initially involves 62 substations. Present plans are to install regulator voltage control units and receivers in substations during 1991 and 1992 such that exiting communication facilities (DLC & VHF) are utilized. To obtain complete system coverage, additional communications will be required in 1993 and 1994. Preliminary locations for additional VHF Transmitter sites to provide complete system coverage have been identified.

Load Shape Objective: Peak Clipping

Table D-22
Economic Cost-Effectiveness Tests (Present Value $/kW)

Benefits & Costs	Utility Cost Test	Ratepayer Impact Measure Test	Participant Test	Total Resource Cost Test
Supply Costs				
Capacity	**638**	**638**	-	**638**
Energy	**107**	**107**	-	**107**
Participation Charges	0	0	0	-
Incentives	0	0	0	-
Changes In Revenue	-	150	**150**	-
Utility Program Costs	16	16	-	16
Participant Costs	0	-	0	-
Benefits Minus Costs	729	579	150	729

Appendix E
Future Potential Demand-Side Management and Supply-Side Resource Options

This appendix provides descriptions of future potential demand-side management (DSM) and supply-side resource options. The first section describes potential DSM options which are being examined by CP&L. In addition to the descriptions, the overall objective and the load shape objectives of the options are provided. In the second section, on-going research activities are described. The third section of this appendix describes alternative and conventional supply-side resource options and discusses the supply-side screening process.

Potential Demand-Side Management Options

CP&L is developing and studying an array of potential DSM options as shown in Table E-1. The options are divided into three categories: residential, commercial, and industrial. This section describes each option and provides the overall and load shape objectives of each option and the status of the option's development.

Table E-1
Potential DSM Options

Residential

High Efficiency Water Heater
Appliance Turn-In
Residential Cool Thermal Storage

Commercial

Cool Schools 2000
Thermal Energy Storage - Schools
Commercial Heat Pump
Commercial Load Control
Heat Pump Water Heaters
Energy-Efficient Lighting

Industrial

Small Load Curtailment

High Efficiency Water Heater Program

This program, which is under investigation, has the objectives of encouraging energy efficiency, improving the utilization of existing facilities, and, in conjunction with EZ-$64, controlling peak demand. Customers will be encouraged to install high-efficiency electric water heaters and EZ-$64 load control equipment. The load shape objectives of this program are Strategic Conservation and Peak Clipping.

Appliance Turn-In

An appliance turn-in program for refrigerators, freezers, and water heaters will be investigated. Such a program would encourage the replacement of older less efficient appliances with newer energy-efficient models, resulting in energy conservation and a reduction in peak demand. An appliance turn-in program can also recover CFCs for recycling, provide proper disposal of hazardous materials, and collection of metal components for recycling.

The appliance turn-in program has an overall objective of reducing peak demand and has a load shape objective of Strategic Conservation. The preliminary feasibility investigation of this program is underway.

Residential Cool Thermal Storage

The objective of this program is to shift demand and energy to off-peak periods; hence, the load shape objectives are Load Shifting and Valley Filling.

One of the major HVAC manufacturers is developing a residential and light commercial cool thermal storage module to be used in conjunction with split-system air conditioners. This system will give the customer the ability to shift a portion of his on-peak demand and kWhs to the off-peak periods. The system utilizes an ice storage module which is completely frozen during the off-peak periods for use to cool the refrigerant during on-peak periods.

CP&L is monitoring the development and field testing of this cool (thermal energy) storage system. The product is being field tested in 1992 with commercial implementation planned in 1993.

Cool Schools 2000

The objective of this program is to encourage energy efficiency and conservation in the renovation of existing schools and the construction of new schools. The load shape objectives are Strategic Conservation, Valley Filling, and Strategic Load Growth.

The Cool Schools 2000 Program will emphasize improvements in the thermal integrity of the school building such as improved insulation, energy-efficient lights, and recommended ways to control the school's demand requirements. Heat pumps will be included as part of a total efficiency package to achieve energy efficiency when schools are adding air conditioning. The program is primarily being designed for existing schools which are not currently air conditioned, but that will be air conditioned in the next few years. By adding energy-efficient heat pumps instead of simply adding air conditioners, the school's total energy costs are reduced. The program is intended to reduce peak load, enhance CP&L's load shape, and improve the utilization of facilities, thereby deferring the need for future rate increases.

The program is under development and is planned for implementation during 1992.

Thermal Energy Storage - Schools

With the increased emphasis to air condition new and existing education facilities, the TES - Schools pilot program is being investigated as a means to provide the cooling, while limiting the summer demand impact to CP&L and the school system. The pilot program will address the technology transfer from the Faison Iceberg Project to a new school application. This project would serve as a demonstration facility, as well as a prototype school, that could revolutionize the present systems being used to condition educational buildings.

The load shape objectives of this program are Load Shifting and Valley Filling by shifting demand and energy to off-peak periods.

Commercial Heat Pump Program

By encouraging the installation of energy-efficient heat pumps in the new and replacement market, this program's load shape objectives are Strategic Conservation, Valley Filling, and Strategic Load Growth.

The Commercial Heat Pump Program is under development to increase energy efficiency by providing technical support and education in the selection of state-of-the-art equipment options. Through the existing Energy-Efficient Design Program and the Commercial Audit Program, we are currently working with customers and design professionals to ensure energy-efficient structures. The Commercial Heat Pump Program is under development to complement our existing efforts by encouraging the installation of energy-efficient heat pumps in target markets. Through these efforts, CP&L expects to help its customers achieve higher efficiency levels in the use of electricity. The program is intended to reduce peak load, enhance CP&L's load shape, and improve the utilization of facilities, thereby deferring the need for future rate increases.

The program is currently under development.

Commercial Load Control

The objective of this Peak Clipping load shape objective program is to investigate the potential for developing and implementing a program to interrupt service to air-conditioning (cooling) systems and/or electric water heaters in the commercial sector.

A pilot program is planned for implementation to test the feasibility of certain types of commercial load control in a limited geographical area using CP&L offices. The primary end use under consideration for control at present is air conditioning. Heat pumps with associated strip heat and water heating may also be evaluated in the program. The program may be expanded beyond CP&L offices in late 1992 to include a sampling of customers in the commercial sector in order to determine customer acceptance. Incentives to encourage program participation will also be evaluated.

Heat Pump Water Heaters

A pilot heat pump water heater program is being investigated to test the feasibility and customer acceptance of heat pump water heaters. Heat pump water heaters have been proven to work economically and efficiently in facilities where equipment creates lots of unwanted heat (i.e., restaurants, kitchens, cafeterias, laundries). The unwanted heat is simply captured and transferred to make hot water. As the heat is removed, the heat pump provides air conditioning as a by-product. Heat pump water heaters are expected to provide hot water at less cost and at a reduced kW demand over a conventional electric heater.

The load shape objectives of this program are Strategic Conservation, Valley Filling, and Strategic Load Growth. The overall objective of the program is to increase energy efficiency.

The investigation of feasibility of this program is planned for 1992.

Energy Efficient Lighting
(Center Plaza Building Lighting Test)

This program will test the T-8 fluorescent lamp and electronic ballast technology combination and evaluate the performance from an illumination, maintenance, and power quality perspective. The load shape objective of this program is Strategic Conservation.

As part of the renovation of floors 3 and 19 of the Center Plaza Building, CP&L plans to install state-of-the-art fluorescent light fixtures with one of the most energy-efficient lamp and ballast systems available on the market today. Results of the test which began in November 1991, will be used to evaluate the potential of this energy-efficient lighting technology in commercial and industrial buildings.

Small Load Curtailable Experiment

The program is being developed to achieve the same peak load reduction objectives of the Large Load Curtailment Program. The experiment will measure customer response, peak load reduction, and cost savings for smaller curtailable loads characteristic of smaller commercial and industrial customers. An alternative incentive will also be evaluated.

Customers will be provided an economic incentive to reduce load during periods when available capacity is low relative to load. Administration of the program will closely parallel that of the Large Load Curtailment Program. The Company will experiment with a different inventive (discount) structure which may more appropriately address actual loads curtailed. More incentive will be provided for available curtailable load when the Company is most likely to need it, such as the summer and winter peak seasons.

The program is in the development stage and is expected to be available for use prior to the 1992 summer season.

Demand-Side Management Research Activities

CP&L is also involved in research that will enhance the Company's knowledge of DSM as well as assist in the development of DSM options. This section describes the research activities.

Evaluating The Impact Of CFC Regulation

The objective of this project is to assess the impact of chlorofluorocarbon (CFC) regulation on utility loads through changes in refrigeration and air conditioning practice. In addition, CP&L wants to be in a position to assist customers in the transition to new refrigerants and practices.

A substantial portion of CP&L's load is air conditioning and refrigeration. Current and proposed regulation of CFCs will require dramatic changes in all aspects of the selection and operation of refrigeration equipment. It is quite likely that new or retrofitted equipment will be less efficient and, consequently, will impose a larger load on utilities. This project provides a framework for keeping abreast of current and proposed regulation so that we can plan for the impact on system load.

CP&L has begun collecting a library of literature on the subject and has sent representatives to several seminars. One alternate refrigerant has been tested, and the results are being documented. Further tests and studies will be conducted as the need and opportunities are identified.

Commercial Scale Thermal Energy Storage Test

A research project has been undertaken to evaluate the operational characteristics of ice storage for commercial air conditioning. Project experience has been used in efforts to encourage the use of thermal energy storage for peak load reduction.

A 7.5 ton ice storage system was installed to provide air conditioning at CP&L's Method Research Building. The system has been monitored extensively to evaluate performance and load characteristics. Valuable insights about system sizing and discharge strategy have been gained through direct experience in operating this system.

In addition, a bench-top thermal energy storage system has been used to evaluate various ice building techniques. This facility can compare the performance of the generic techniques available in commercial equipment. Ice building and discharge characteristics are documented for comparison with some of the more common strategies for TES utilization.

Results from this project will help influence development of relevant DSM programs. Experience with the potential and limitations of this technology have already proven valuable in adjusting the peak period for the TES rate. In addition, this experience can be used to help our customers avoid some of the pitfalls associated with TES technology.

The building ice storage system was installed in 1987 and is now the permanent air conditioning system for the building. We will continue to monitor the system and work to improve its operation.

The bench-top system was completed in 1990. We have completed the comparison of several ice building techniques and documented the results.

Heat Pump Monitoring For Demand Side Management

Peak demand can be reduced and customer satisfaction enhanced by improving the performance of installed heat pumps. CP&L is developing a portable heat pump monitoring system coupled with an expert system to measure efficiency and to perform system diagnostics on heat pumps and air conditioners in order to maximize system efficiency.

The heat pump monitoring system is a tool developed for diagnostic and efficiency testing of residential and light commercial heating and air conditioning equipment. It consists of a microcomputer coupled to a data collection system which monitors and records equipment operating data. It is designed to be portable and easily installed by field service technicians. The heat pump monitor software is designed to aid technicians in diagnosing system problems. It displays results immediately and can also record data for later review. A key feature is the capability to display instantaneous efficiency which provides feedback for technicians working to fine tune a system.

Apart from its diagnostic capabilities, the heat pump monitor also provides a relatively simple way to establish a performance database of existing heat pump, air conditioning, and refrigeration installations. It also provides a method for evaluating new heat pump related technologies such as alternate refrigerants, ground coupling, and multiple or variable speed compressors. It may also provide a tool for evaluating the performance of heat pumps installed under the heat pump incentive programs and helping contractors improve the quality of their installations.

CP&L has assembled the third generation heat pump monitor that puts all instrumentation and the diagnostic computer in a field portable form, constructed a test bed heat pump for comparing heat pump alternatives and developing the expert system, and performed field testing to improve instrument reliability, simply installation, and reduce setup time. CP&L has also contracted with a heat pump expert to develop the knowledge base for the expert system. Software that will be used by equipment technicians and provide sufficient detail for diagnostics is being developed. In 1992 CP&L will begin testing a sample of heat pumps in order to determine the performance level of the selected systems.

Agricultural Thermal Storage

The objective of agricultural thermal storage research is to demonstrate the feasibility of performing produce cooling via off-peak ice production and storage in a manner which:

- Provides large capacity produce cooling coincident with utility summer peaks
- Provides high humidity cooling air to prevent moisture removal from fresh produce during post harvest cooling
- Confirms that a thermal storage cooling system can be economically cost competitive with direct acting cooling systems
- Improves load factor for post harvest cooling
- Provides high peak demand cooling while minimizing the cost of T&D upgrade

Southern Produce, a CP&L customer, needed approximately 300 tons of directing acting refrigeration to cool fresh green peppers for six weeks in the summer. The project became a joint venture to share the risk of using an annual ice storage tank to spread the electrical load associated with the produce cooling from six weeks duration over a period of one year. The partners included N.C. Department of Commerce, Energy Division, N.C. A.E.C., CP&L, EPRI and Southern Produce, Inc. The project converted a 300 ton (400 kW) load with a load factor less than 0.1 to a 10 ton (30 kW) load with a load factor of 0.95. By spreading the ice building phase of the project into a year round task waste heat recovery and utilization also became feasible. A sweet potato curing system was developed using the rejected waste heat from the ice machine as the curing heat and humidity source. In addition, the waste heat from the ice machine has been used as a heat source on the grading and packing line through the winter months.

The thermal storage system was installed in 1988-89. Produce was cooled in the summer of 1989, 90, and 91, sweet potatoes were cured in the fall of 1989, 90 and 91. Sweet potatoes were cooled in the spring of 1990, and 91. Additional ice machines have been added to the system to utilize the shoulder capacity of the thermal storage system to provide cooling for the sweet potatoes in spring and early summer. This produce cooling was not part of the original project specification. System modification are currently being investigated to expand the application to cool fresh corn using slush ice. Future activity will include the licensing of system suppliers and investigation of additional applications of the technology.

As an offshoot of Agricultural Thermal Storage, CP&L has initiated an R&D project to determine the technical and economic feasibility of an ice thermal storage system which can be charged during off peak periods and used during the summer on peak periods to cool the inlet air for combustion turbines.

Demand-Side Management Planning Enhancements

CP&L is improving and enhancing its DSM planning process. This section describes the enhancements.

Marketing End User Database

The Marketing End User Database will provide Carolina Power & Light Company with an efficient structure for collecting, storing, and processing relevant data needed for planning, evaluating, marketing, and tracking DSM programs. A database will be provided to enhance the availability of customer data and the efficiency of collecting and accessing the data.

The database system has been defined, designed, and developed, and implemented. Electronic data transfers occur monthly from CP&L's Customer Accounting Information System. This, along with the manual entry functions, allows the database system to produce the monthly marketing report which tracks progress for DSM programs. Present plans include expanding the database's functionality to automate inputs and outputs from field locations, and to provide additional reporting functions.

Residential Market Segmentation

The objective of this research is to enhance the market penetration and cost-effectiveness of residential DSM programs by more effectively targeting program promotions. This will be done by developing a residential market segmentation system based upon available demographic data.

In 1991, CP&L implemented a geo-demographic segmentation system which links demographic and lifestyle characteristics with customers in geographic segments or our service territory. This year the system is being tested for program design, advertising design, forecasting, and direct mail applications.

DSM Technology Research

The objective of this research is to provide technical details of the characteristics and performance of DSM technologies to support the screening of DSM options.

Work on this project has assessed the installed costs and operating costs to the customer for various DSM options, as well as typical reductions in the utilities peak load and annual energy. This information will be used for screening potential programs, especially for performing the participant and total resource cost economic tests.

CP&L has completed an analysis with the Alternative Energy Corporation which studied the price, applicable market, installation cost, life, efficiency, and demand and energy savings for the following technologies:

Residential
Foundation insulation-interior
Foundation insulation-exterior
Floor insulation
Attic insulation
Electric thermal storage
Ground-coupled heat pump
Variable speed heat pump
Water-source heat pump
High-efficiency central ac
Heat pump water heater
Desuperheater
Compact fluorescent lights 5w to 36w

Commercial/Industrial
Water loop heat pump
Packaged terminal high efficiency heat Pump
High efficiency air-source heat pump
Thermal energy storage - large
Thermal energy storage - small
Adjustable speed drives - ventilation
Adjustable speed drives - pumps
Energy-efficient motors 5hp to 100hp
Daylighting - new
Daylighting - retrofit
Metal halide lamps
High pressure sodium lamps
Ellipsoidal lamps
Heat pump water heater
Refrigeration, high efficiency Compressor

Integrating DSM Into T&D Planning

The objective of this project is to target DSM programs to specific geographic areas to reduce peak load which drives the need for transmission and/or distribution system expansion or upgrades.

The expansion and/or modification of transmission and distribution facilities to accommodate load growth can require significant investments. In some cases, the capital cost of new distribution facilities can exceed the marginal cost of generation on a $/kW basis. There may be opportunities to target DSM programs to reduce peak load on specific transmission and distribution facilities to delay or avoid costly new facilities or upgrades. In recognition of this potential, CP&L is investigating opportunities to enhance the integration of DSM planning and T&D planning.

Work is underway to develop a pilot program for identifying potential distribution upgrades which may be deferred through targeted DSM programs.

Supply-Side Resource Options

The objective of the supply-side screening analysis was to identify the generation technologies available to CP&L and to determine which of those merited further consideration in developing the Company's resource plan. The generation technologies considered in this analysis were identified through a survey of industry literature, technical journals, and U. S. Government and Company reports. This survey also provided a basic understanding of the current status and future potential of each technology.

Due to the large number of supply-side options, it was necessary to split the options into two groups. The most convenient solution was to divide the resources into conventional and alternative technologies. The technologies identified for consideration in this analysis are given in Table E-2. The major documents used in identifying and understanding the technologies were the December 1989 EPRI Technical Assessment Guide (TAG), the Office of Technology Assessment's July 1985 publication, New Electric Power Technologies, a November 1983 Battelle report entitled, Alternative Generating Technologies, and a NERA paper by Bruce Netshert entitled "The Implications of New Generation Technology for Electric Utilities".

Screening Methodology

The technologies identified were subjected to a three level screening process which eliminated those technologies that are not 1) significantly available in the CP&L service area; 2) available by the year 2002; or 3) economically competitive with other technologies in 1995. This economic screening was accomplished using screening, or busbar, curves which plotted each technology's total levelized annual cost in $/kW-Yr. as a function of capacity factor.

In the screening, or busbar, curve analysis the technologies were divided into two broad categories based on expected capacity factor in order to simplify the analysis and to separate peaking resources from baseload resources. Those technologies with expected capacity factors of less than 20% formed one group (the peaking resources) and those with expected capacity factors of greater than 20% formed the second group (the baseload resources). Only those technologies in each capacity factor grouping that were found to be competitive on a busbar cost basis were retained for further analysis.

Table E-2
Supply Options Selected For Screening

ALTERNATIVE GENERATION TECHNOLOGIES

Technology: Geothermal

Flash Steam Cycle
Dry Steam

Technology: Ocean Energy

Tidal Energy
Ocean Thermal Energy Storage
Wavepower
Ocean Current Turbines
Salinity Gradient Devices
Ocean Wind Turbines

Technology: Photovoltaic

Flat Plate
Concentrator

Technology: Solar Thermal

Solar Parabolic -
Through/Gas Hybrid

Technology: Wind

250 kW Turbine
2.5 MW Turbine

Technology: Municipal Waste

Mass Burn
Refuse Derived Fuel (RDF)

Technology: Biomass

Peat
Waste Wood

CONVENTIONAL GENERATION TECHNOLOGIES

Technology: Coal

Scrubbed Pulverized Coal
Pressurized Fluidized Bed
Coal Gasification -
Combined Cycle

Technology: Nuclear

Adv. Light Water Reactor -
Passive Safety

Technology: Combustion Turbine

Simple Cycle
Combined Cycle
Simple Cycle with Air Cooling

Technology: Storage

Pumped Hydro
Compressed Air Energy Storage
Battery

Technology: Fuel Cell

Phosphoric Acid

Technology: Purchased Power

Cogeneration A - Peak
Cogeneration B - Base Load

First And Second Level Screening Process

Geothermal

Geothermal energy is derived from magma deep beneath the earth's surface. These geothermal resources fall into four broad categories: petrothermal, geopressured, hydrothermal, and normal gradient heat. Hydrothermal resources, which can be either dry steam (vapor dominated) or wet steam (liquid dominated), are considered to be the only resources with potential for electric power generation in the near future. Dry steam, which is the easiest thermal resource to tap, accounts for only about 8% of the hydrothermal potential in the United States. Thus, development centers on technologies that will tap the wet steam resources.

There are two energy conversion cycles under consideration for these wet steam resources: the flashed-steam cycle and the binary cycle. The flashed-steam cycle reduces the pressure of the wet steam, thus causing some of this resource to vaporize (flash) to dry steam. The dry steam is then used to turn a steam turbine. The binary cycle, on the other hand, uses a heat exchanger to transfer heat from the wet steam to a working fluid which is then vaporized and sent to a steam turbine.

There are a number of reasons for interest in this technology. First, geothermal energy is a renewable resource in the long term. Second, air emissions are less than those of conventional power plants. Finally, the plants are operationally suitable for base load generation.

While this resource has potential for further development in the United States, reports prepared by EPRI, Battelle, and the Office of Technology Assessment indicate that suitable geothermal resources are limited to the western states. Further, a CP&L commissioned study by E. D'Appolonia Consulting Engineers in 1973 concluded that geothermal resources are not likely to exist in the CP&L service area.

Ocean Energy

The November 1986 EPRI Report, Ocean Energy Technologies: The State of the Art describes six technologies deriving power from the ocean. Three of these technologies are described by EPRI as being more highly developed than the others. These technologies are Tidal Energy, Ocean Thermal Energy Conversion (OTEC), and Wavepower. Ocean Current Turbines, Salinity Gradient Devices, and Ocean Wind Turbines are described as being somewhat less developed.

Tidal Energy is the most mature of the ocean technologies with a 240 MW unit operating in France and an 18 MW unit operating in Nova Scotia. The most promising U. S. sites are in northern Maine and Alaska. According to EPRI's 1986 analysis, North Carolina does not have the large tidal variations required to support this technology.

Ocean Thermal Energy Conversion (OTEC) has been demonstrated in Hawaii and the Japanese Islands. This technology takes advantage of the thermodynamic principle that power can be generated from heat sources that have different temperatures. While there are several U. S. sites that EPRI feels offer potential for OTEC development, the most promising sites are in the tropical regions. The only areas around the continental U. S. with a thermal temperature gradient large enough to support OTEC are in the Gulf of Mexico, in the Gulf Stream off of Florida's coast, and Puerto Rico. The thermal gradient off the coast of North Carolina is considered insufficient for OTEC development.

Wavepower is the wave technology that has had the best potential in North Carolina. For this reason, it has been monitored by Carolina Power & Light Company. Several years ago, EPRI felt that the North Carolina coast might offer some electrical power potential. However, due to the nature of the waves, their relative strength, and wave energy density figures developed by MIT, EPRI feels that this commercial power potential is no longer available in this area.

Ocean current turbines, which are designed to utilize the swiftly flowing currents in some parts of the world, are a recent development. According to EPRI's 1986 study, the only current around the U. S. considered to have potential for this technology is the Florida Current that flows northerly along the east coast of Florida. The strait between Miami and Bimini being the most conducive to development. The ocean off the coast of North Carolina is not considered to have currents strong enough to warrant consideration.

Salinity gradient devices use the energy difference between fresh water and salt water to generate electricity. This concept has not been subjected to engineering evaluations and no prototypes have been built.

Ocean wind turbines have been studied both in the U. S. and in Britain. As with salinity gradient devices, no prototypes of this technology have been built either.

Photovoltaic

In the past few years, there have been great strides in the development of this technology. Several photovoltaic (PV) technologies are technically feasible and currently operable but pose some concern at present for utility scale applications. EPRI and the Office of Technology Assessment are the most optimistic, predicting that PV could develop to the point where utility installations are feasible in some cases in the 1990s. One of the most promising is the development of revolutionary solar panels by Southern California Edison and Texas Instruments. This installation will be tested in 1992 and will be monitored by CP&L.

The flat plate technology in most applications utilizes thin film crystalline silicon or amorphous silicon cells. Multiple junction cells have been investigated to demonstrate higher efficiency resulting from capture of a wide portion of the solar radiation spectrum. The flat plate configuration is static in that is does not track the sun.

The concentrator technology uses optical concentrators to focus the direct normal radiation onto cells much smaller in area than the entire module. Due to the diffusion of the solar rays in North

Carolina, Sandia National Laboratories does not recommend this particular technology for North Carolina. For this reason, concentrator technology was eliminated from the screening process.

The North Carolina Alternative Energy Corporation (NCAEC) has operated a 4 kW flat plate, residential type, flat plate system near New Hill, NC since March 1985. The NCAEC's annual reports indicate that the facility has operated "reliably and trouble free." The system has had a 20% capacity factor, which is consistent with what the NCAEC had expected based on the PV cells' efficiency and the solar insulation characteristics of the area. This installation shows that this technology is currently available and can be placed in CP&L's service area.

One of the advantages of the photovoltaic technologies is their high reliability. EPRI foresees availability rates above 90%. This level of performance was realized in the NCAEC system. Another advantage is the modular nature of the systems. Thus, blocks of capacity can be added as needed because there are few economies of scale to be gained from large initial installations.

In addition to the currently high initial cost, there are several other disadvantages associated with PV technology. While PV generation can contribute significantly to meeting peak load conditions in the southwestern U. S., the NCAEC found that PVs will provide little generation in North Carolina under seasonal peak load conditions in either the summer or winter. In both summer and winter, the PV system's maximum output occurs at noon. The PV's output is only about 30% of its maximum at the time of CP&L's usual 5 p.m. summer peak. In the winter the PV system usually is not yet operating when the CP&L system reaches its peak at 7 a.m. on a typical day. These findings were consistent with the analysis of Dr. Saifur Rahman of Virginia Tech in a 1985 study of the potential impact of PVs on the CP&L system. This experience indicates that PVs will have to be justified on the basis of energy savings alone given their minimal output at the time of CP&L's peaks.

Another concern about photovoltaics is the amount of land required for multimegawatt scale application. Battelle estimates that nine acres of land per MW will be required. The Office of Technology Assessment foresees a range of 4 to 37 acres/MW depending on the efficiency of the PV cells used. Thus, a 100 MW installation could require from 400 to 3700 acres.

Solar Thermal

As with the photovoltaic technologies, the Office of Technology Assessment (OTA) states that development to date of solar thermal technologies has been highly dependent on tax credits that have expired. The most promising solar thermal technology is the Trough/Gas Hybrid system that utilizes either parabolic dishes or solar troughs to heat an oil that is pumped to a heat exchanger to produce steam.

NERC states that photovoltaic systems have outperformed solar thermal technologies to date. They see PV as dominating the solar market for utilities in the 1990s. NERC also states that because of the economies of scale associated with solar thermal technologies, cost competitiveness for non-utility applications is even further in the future. Regardless, like PV, solar thermal is currently available and can be placed in CP&L's service area.

Wind

A 1987 NCAEC study, North Carolina Wind Energy Evaluation concluded that windpower is not currently economically feasible although technologically it "has achieved the level of maturity required for utility application." The NCAEC found that there were "limitations in possible annual energy production and subsequent energy value which will deter the application of wind turbines in the utility market."

One of the NCAEC's purposes in this study was to identify sites in North Carolina that have sufficient wind resources to support windpower development. Several areas in the Appalachian Mountains of North Carolina were found to have some wind resources. The wind resource in the State's coastal areas has little potential for development.

Another wind resource study performed by Pacific Northwest Laboratory showed that while there is some wind resources available in North Carolina, it is a small amount and is probably not available for commercial operations.

Even if there existed sufficient wind resources in western North Carolina, the NCAEC stated that "significant institutional and environmental factors, such as visual and acoustic impacts, may inhibit wind energy development in North Carolina" and thus inherently limit capacity that may ultimately be supplied by wind. Television interference has been a problem at windpower installations near residential areas. This phenomenon was recorded in NASA tests in Boone, North Carolina. As for the visual impacts, NERA states that "lovers of unspoiled scenery regard [wind farms] with the same animosity they have for transmission lines."

Municipal Waste

A North Carolina Alternative Energy Corporation publication states that "for each person in North Carolina, more than half a ton of refuse is generated per year by residential and commercial sources," not including industrial waste and sewage sludge. Further, the publication states that "close to 80% of the active sanitary landfills in North Carolina are approaching maximum capacity." Given that approximately 85% of municipal solid waste is combustible, incineration of substantial amounts of this refuse is a viable option for future solid waste disposal. The waste heat from the incineration process can be recovered and used as process heat or in the generation of electricity.

One of the advantages of combining incineration and electricity generation is that it allows an independent power producer or a municipality to turn the source of a major problem (solid waste) into a resource (electricity) that benefits the entire community. Another advantage of this solution is that land requirements are significantly less than for a sanitary landfill. Tipping fees and revenues from electricity sales (and possibly steam sales) help to offset the costs of operating such a facility for a municipality.

There are two basic technologies used to convert waste to energy: mass burning and conversion of waste to refuse-derived fuel (RDF). In mass burning, municipal solid waste is burned in the same state as it is received, except that bulky, noncombustible items are first separated. The combustor directly recovers the energy from the incineration in the form of steam which can be used for process heat or to drive a steam turbine. Since such a facility is currently operating in New Hanover County, North Carolina, the mass burning technology passed both the first and second screen.

In the RDF process, bulky, noncombustible items are likewise removed at the outset. The remaining solid waste is then processed through a mechanical shredder to remove any smaller noncombustibles. The refuse-derived fuel that results from this process is in the form of pellets, powder, or wet pulp, which is then used in a fluidized bed combustion chamber. Heat from the combustion process is transferred to water tubes that line the chamber, which in turn produce steam for a turbine generator. Industry literature indicates that the RDF technology is probably best only for very large-scale municipal waste facilities. The CP&L service area, however, has no cities that could support such a large-scale facility. Because of this concern and since the RDF process is similar to the mass burn municipal waste technology, RDF was eliminated from further consideration.

Despite the many advantages of converting waste to energy, there are concerns about the environmental effects of burning garbage. While these plants generate very little sulfur dioxide emissions compared to coal burning plants, the fact that garbage has a higher content of plastics and metals than other organic fuels results in the potential for generation of hydrochloric acid and of fly and bottom ash with unacceptably high levels of heavy metals such as cadmium and lead. Industry literature indicates that a properly designed emissions control system with scrubbers, filters, and electrostatic precipitators will keep these potential pollutants well below required levels. Reports from a sample of incinerators found that bottom ash exceeded Federal environmental standards for lead and cadmium about one third of the time and fly ash exceeded the limits more than 95% of the time. The debate resulting from such diverse claims about the ability of such plants to control emissions has resulted in the delay or cancellation of several large waste to energy projects in the northeastern U. S.

Peat

A U. S. Department of Energy study estimates that North Carolina has 2.7 billion tons of peat spread across 1.2 million acres in its coastal counties. While efforts to develop peat-fired generation in North Carolina have not yet produced such a plant, the technology is well developed in the Soviet Union, Ireland, and parts of Europe. According to EPRI, the Soviet Union possesses about 61% of the world's peat resources and has built 76 peat-fired power plants with a total capacity of 5000 MW. Ireland's 450 MW of peat-fired capacity supplies about 17% of its electric power.

A 1983 EPRI study focused on the peat resource in North Carolina owned by First Colony Farms and investigated methods of harvesting, storage, and combustion. EPRI found that North Carolina's peat has a very low sulfur content, on the order of .2%. Despite this low sulfur content the study did not conclude that a North Carolina peat plant could be built without scrubbers.

In the area of peat harvesting, EPRI stated that only dry harvesting methods have been used to date in commercial fuel peat production. Dry harvesting requires drainage of bogs and natural evaporation to achieve acceptable moisture levels. This type of process requires considerable land resources. For example, EPRI estimates that 50,000 acres would be required to support a 300 MW plant over a 30-year life. Wet harvesting techniques, which offer the possibility of reduced land requirements, have yet to be implemented because of cost and reliability concerns.

EPRI's report states that pulverized firing of milled peat is the most common combustion method for large boilers. Peat-fired boilers are larger than coal or oil-fired boilers of the same rating because more time is required for a complete burn and because more surface space is required in the boiler to minimize slagging and fouling. Because of the larger boiler and because of special considerations in peat handling and drying, a peat plant has a higher capital cost than a comparably sized coal plant though the designs are basically similar. For power generation the fluidized bed combustion (FBC) of peat will be a technically feasible alternative to conventional peat combustion whenever the utility scale FBC demonstrations at Colorado Ute, Northern States Power, and TVA are successful. Therefore, it was determined that peat-fired generation would be technically available by 2002 in the CP&L service area.

There are several environmental challenges associated with peat harvesting. Air quality is affected by dust from the peat collection process and from storage piles. Surface and ground water quality, and streamflow characteristics can also be impacted by peat harvesting according to EPRI.

Wood

There are two sources of wood fuel for wood-fired power plants. Most wood plants to date use waste wood residues from forest product processing plants and residues such as sawdust, bark, and wood chips from logging operations. Another source of wood fuel is forest harvesting and regeneration. This, however, is a complex process requiring coordination between harvesting and reforestation programs and requires consideration of a number of environmental impacts on wildlife and soil stability.

Given that a 50 MW plant typically uses 400,000 tons of wood per year, plant siting requires that a considerable source of wood fuel be located in the area. Battelle studies indicate that the South Central and Southeastern states generate some of the largest quantities of unused wood residues in the nation. Battelle also states, however, that "wood availability must be determined on a local basis because transportation costs become a large factor if shipment of more than 50 miles is required."

Development to date has mostly been limited to cogeneration plans owned by, and located at, forest product plants. There are several of these units operating within CP&L's service area. Therefore, it is obvious that this technology passes the first and second screens.

Coal

Coal is the most prevalent fossil fuel found in the United States, so understandably it is responsible for more production of electricity in this country than any other fuel source. The concerns with coal are largely with its environmental affects. For this reason, new technologies are being studied that will lessen these environmental problems.

Three different coal burning technologies that have been used in commercial operation are the conventional pulverized coal (PC), pressurized fluidized bed (PFB), and coal gasification combined cycle (CGCC). The conventional pulverized coal units are by far the most widely used of these three options. These units are used throughout the country, so knowledge in building and operating are readily available. The environmental effects of a conventional coal unit can be lessened by using low-sulfur coal or installing flue gas desulfurization (FGD) systems.

The pressurized fluidized bed technology is similar to the conventional PC except for the boiler island and the absence of the FGD system. In this type of unit crushed coal is burned with limestone while being suspended by blown air. The calcium in the limestone captures most of the sulfur that is released from the coal during combustion. The steam which is produced in tubes passing through the bed is used to drive a conventional steam turbine generator.

The coal gasification combined cycle resource is becoming more popular in the commercial sector. The major component of this technology is a coal gasifier. Pulverized coal in a concentrated water slurry is pumped into an entrained flow gasifier where a partial oxidation process produces an intermediate Btu gas. After the gas passes through the cooling section, the sulfur and nitrogen compounds are removed, and clean gas is fired in a combustion turbine. In addition to the environment benefit, modular construction is possible with this type of plant.

All three of these technologies can be available by 2002 and can be sited in CP&L's service territory.

Nuclear

The nuclear industry is currently in the mode of research and development. Of the developing nuclear technologies, the advanced light water reactors-passive safety (ALWR) appears to be the most promising.

ALWR designs have either pressurized or boiling water reactors (PWR and BWR, respectively). Both versions are expected to have similar economic and technical performance characteristics, and will compete with each other for initial market penetration.

The ALWR has been designed to meet three fundamental acceptance criteria: First, it should meet or exceed current licensing requirements for a generating unit in all respects, including safety, reliability, maintainability, and compatibility with the environment. Second, it must be economically competitive with fossil-fuel-fired electricity generation. Finally, the ALWR must provide predictable construction costs and schedule, assured licensability, predictable O&M costs, and very low risk of severe accident.

To achieve these criteria, U.S. utility sponsors have established several design principles. These include primary emphasis on safety to ensure that the risk of a core-damaging accident is extremely low, use of passive safety systems such as natural circulation cooling, design margins to allow inherent ability to ride through transients without challenging safety systems, and human factors.

There is some question as to whether the passive safety advanced nuclear reactor will be available by the year 2002. However, the EPRI Technical Assessment Guide states that in its opinion, this technology would be available in 2002. With this concern identified, the technology was passed on to the third level screen.

Combustion Turbines

Combustion turbines are generally classified into two categories: simple cycle and combined cycle. Both consist of an air compressor, a combustor, and an expansion turbine. The combined cycle unit also contains a heat recovery system. This heat recovery system may be added to an existing simple cycle turbine to create a combined cycle unit.

The only major emission concern from combustion turbines is nitrous oxides. These emissions are normally controlled by injecting water or steam into the combustor.

The power output of a combustion turbine is very sensitive to ambient temperature. With this in mind, the technology of cooling the inlet air entering the combustion turbine is being developed. If the inlet air going into the turbine is passed over ice, the air is cooled and approximately 20% more power can be produced by the turbine. The massive block of ice can be formed using off peak power and a vapor compressor machine. This is similar to the process used by an ice machine in a refrigerator.

Lincoln Electric System in Nebraska recently completed the only facility of this type in the United States. Carolina Power & Light Company, realizing the potential of such a project, is closely monitoring the developments of this new technology. However, given its uncertainty and lack of data, it was decided not to include this developing technology in our third screening level. However, the simple and combined cycle technologies were passed to the third level screen.

Storage

There are three types of storage facilities for producing peaking power: pumped hydro, compressed air energy storage, and battery energy storage. A limiting factor for pumped hydro and compressed air is the special geographical formations needed to site a facility. With pumped hydro, water is pumped from a lower reservoir to an upper reservoir using off-peak energy. Electricity is produced when the water returns downhill through a turbine to the lower reservoir. Sites might be available in the CP&L service area, so pumped hydro was sent to the third level of screening.

Instead of water, compressed air energy storage (CAES) uses air as the storage medium. Air is pumped into an underground cavern using off-peak power. At peak times, the air is released, heated, and passed through a turbine to produce power. Alabama Electric Cooperative has built the first unit of this type in the United States. Carolina Power and Light Company is closely monitoring this facility for information concerning this technology. A preliminary study has been completed identifying six possible sites in CP&L's service territory that may have the geographical formations needed for this technology. Although further study on these six sites is necessary before any conclusions can be reached, CAES was passed onto the third level of screening since sufficient resources may exist.

Battery energy storage works in much the same way as rechargeable batteries in that they can be charged by electricity. They have some special advantages that would be extremely important in certain situations. These include the ability to reach full load almost instantaneously and the benefit of being able to be used in densely populated urban areas. Since they have these capabilities, batteries can be considered in transmission planning as well as in generation planning. This storage technology was also passed to the third screen.

Fuel Cell

Fuel cells electrochemically convert the chemical energy in a fuel gas to direct current (dc) electricity. Conceptually, they are similar to a battery with a continuous addition of chemical energy. Since fuel cells convert the chemical energy of the fuel directly to electricity, without an intermediate thermal energy stage, energy conversion efficiencies near 80% are feasible in ideal systems. However, practical systems are limited to efficiencies of 40-60% due to parasitic losses, which include the electrical resistance of the components.

Fuel cells can be assembled building block style to make power plants of varying sizes and capabilities tailored to the utility's load growth needs and the constraints of the site. Practical output voltages are obtained by connecting many cells in a series to constitute a fuel cell stack. The maximum size of a stack is dictated by engineering considerations, manufacturing technology, and cost tradeoffs.

Since fuel cell could be sited in CP&L's service area and will be available by 2002, it was sent to the third level of screening.

Cogeneration

Non-utility generation has become a viable supply-side option. It is CP&L's view that each of these options must be thoroughly examined in order to assure the use of the least cost plan. With this in mind, two generic cogeneration units were examined. Cogeneration A is a natural gas combined cycle unit, and Cogeneration B is a coal-fired plant. Both options were passed on to the third level screen.

Summary Of The First And Second Level Screening Process

As discussed in the description of each alternative option, the geothermal technologies, ocean energy resources, RDF technology, photovoltaic concentrator technology, and wind energy technologies are not significantly available in the CP&L service area. Therefore, these technologies did not pass the first level screen and were eliminated from further analysis. The flat plate photovoltaic, solar thermal, municipal waste, and biomass supply-side options were passed on to the second level screen. These technologies were determined to be available by the year 2002, thus passing the second level screen and progressing on to the third level screen.

When the conventional technologies were evaluated with the first level screen, it was evident that all of the technologies are available in the CP&L service area; therefore, they were all passed to the second level screen.

Except for Simple Cycle with Air Cooling, the second level screen found no conventional resource that would not be available by 2002. As mentioned in the descriptions, even though it was passed to the third level, nuclear's ability to be commercial by 2002 was of some concern.

Third Level Screening Process

The third level, or economic, screening process uses EPRI's COMPETE computer program to help determine the results. COMPETE is used to compare long-term economics of new power generating plants. The purpose of this process is to screen generation options, eliminating those that are economically unattractive for the resource plan. The data for this model is shown in Tables E-3 and E-4. The base year for this analysis is 1995.

Figure E-1 presents the screening curves derived in the third level screening process for the conventional technologies under consideration. For technologies with expected capacity factors of less than 20%, only the battery and fuel cell technologies are clearly not competitive with the others on a $/kW-Yr. basis. Thus, of the technologies in this group, all but the battery and fuel cell were retained for additional consideration. Figure E-1 also shows that, except for pressurized fluidized bed, all of the conventional technologies with expected capacity factors of greater than 20% have competitive busbar costs.

Although the nuclear option appears to be cost competitive, there are several important points to consider. In addition to the concern if the technology would be available by 2002 as mentioned earlier, there are also concerns about the ability to license a nuclear facility in a timely fashion. Also, public sentiment toward nuclear power is less than favorable. Given these conditions and uncertainties, beginning the construction of a nuclear plant seems infeasible at this point in time. Thus, the nuclear power option was eliminated and not reviewed any further.

Table E-3
Data For Screening Analysis

	CONSTRUCTION COST ($/KW)	FIXED O&M ($/KW)	VARIABLE O&M ($/MWh)	FUEL CHARGE RATE (%)	FULL LOAD HEAT RATE	FIXED CHARGE RATE (%)
Scrubbed Pulverized Coal	1251	36.4	2.9	1.93	9647	14.8
Fluidized Bed	1617	53.9	4.4	1.93	9765	14.8
Coal Gasification Combined Cycle	1496	64.5	0.4	1.93	8950	14.3
Nuclear - ALWR - Passive Safety	1773	100.3	1.6	0.44	10220	14.6
Simple Cycle	414	9.4	0.1	4.81	11780	15.1
Combined Cycle	812	35.9	0.5	4.81	7820	15.1
Pumped Hydro	1137	15.0	0.0	2.23	13399	14.6
Compressed Air Energy Storage	823	7.9	0.0	3.14	11332	15.1
Battery	1905	7.7	0.0	2.23	12863	14.6
Fuel Cell - Phosphoric Acid	1149	22.4	0.2	4.81	8300	14.6
Cogeneration A	See Note 2	87.32	1.7	2.10	8350	N/A
Cogeneration B	See Note 2	4.75	4.8	21.20[4]	N/A	N/A
Photovoltaic	2871	12.8	0.0	0.00	N/A	15.1
Solar Thermal	3392	48.1	0.9	0.00	N/A	15.1
Municipal Waste	5173	197.5	7.6	-2.70	16544	15.1
Peat Wood	1625	48.7	1.5	1.00	10870	14.8
Wood	2233	100.7	0.0	1.32	16250	15.1

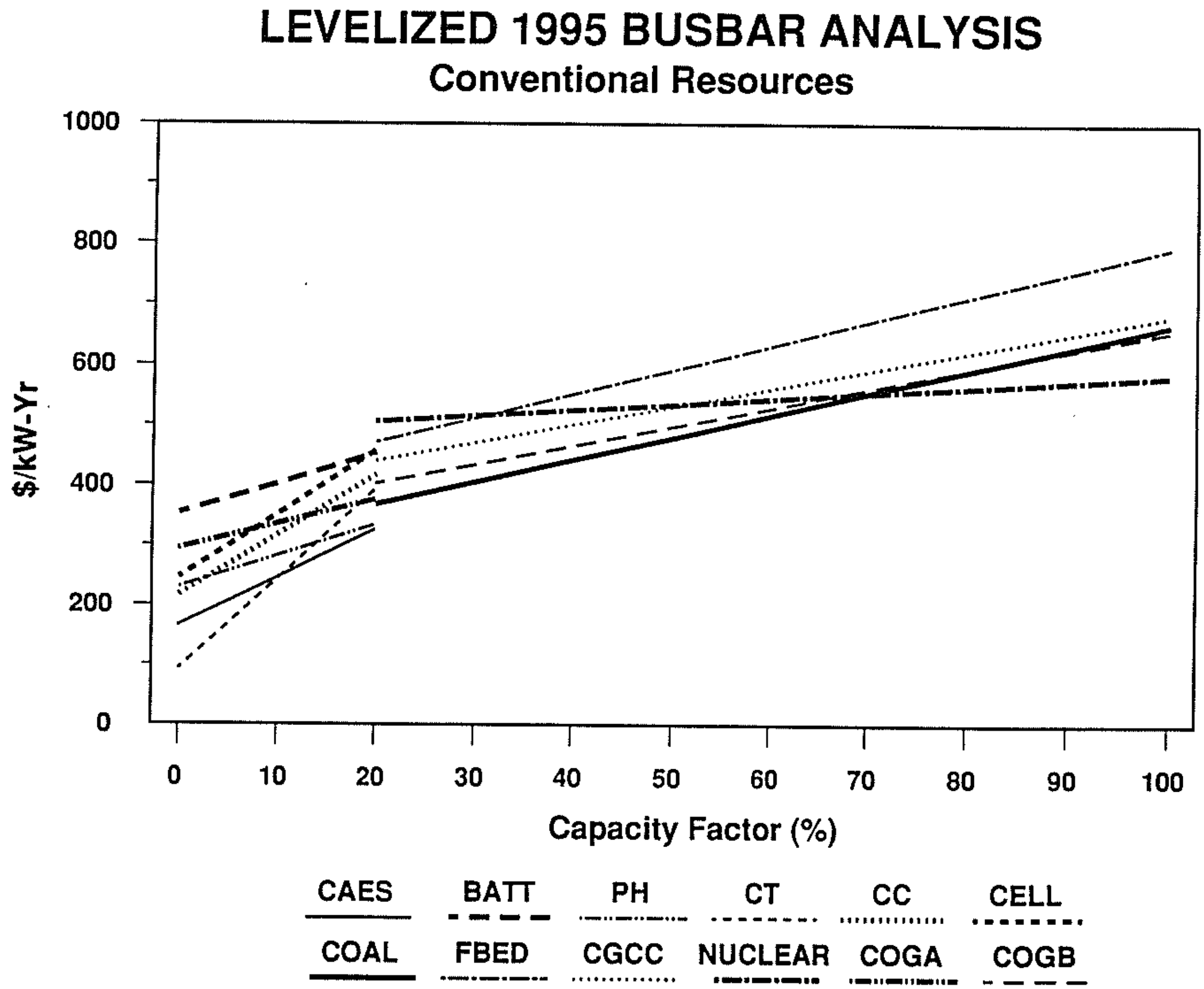
NOTE:
(1) All figures are in 1991$ except for Cogeneration B which is given in 1996$.
(2) The Capacity Cost for Cogeneration A was $12.50/kW for years 1-15 and $2.50/kW for years 16-25.
(3) The Capacity Cost for Cogeneration B was $25.00/kW for years 1-15 and $6.75/kW for years 16-25.
(4) The Fuel Rate for Cogeneration B is in $/MWh.

Table E-4
Fuel Data For Screening Analysis

	Coal #1		Coal #2		Coal #3		Oil		Nuclear		CAES		Peat	
	$/MBTU	ESC-%	$/MBTU	ESC-%	$/MBTU	ESC-%	$/MBTU	ESC-%	$/MBTU	ESC-%	$/MBTU	ESC-%	$/MBTU	ESC-%
1991	1.93		1.93		2.23		4.81		0.44		3.14		1.00	
1992	2.03	5.0%	2.03	5.0%	2.34	5.0%	5.05	5.0%	0.45	1.5%	3.30	5.0%	1.04	4.4%
1993	2.13	5.0%	2.13	5.0%	2.46	5.0%	5.45	7.9%	0.47	4.0%	3.52	6.7%	1.09	4.4%
1994	2.23	5.0%	2.23	5.0%	2.58	5.0%	6.00	10.1%	0.48	3.4%	3.80	8.0%	1.14	4.4%
1995	2.35	5.0%	2.35	5.0%	2.71	5.0%	6.45	7.5%	0.50	2.9%	4.05	6.5%	1.19	4.4%
1996	2.46	5.0%	2.46	5.0%	2.85	5.0%	6.79	5.3%	0.54	8.4%	4.26	5.2%	1.24	4.4%
1997	2.59	5.0%	2.59	5.0%	2.99	5.0%	7.47	10.0%	0.58	6.7%	4.60	8.0%	1.29	4.4%
1998	2.72	5.0%	2.72	5.0%	3.14	5.0%	8.18	9.5%	0.59	3.1%	4.95	7.7%	1.35	4.4%
1999	2.85	5.0%	2.85	5.0%	3.29	5.0%	9.03	10.4%	0.62	4.1%	5.36	8.3%	1.41	4.4%
2000	3.17	11.0%	3.08	8.0%	3.56	8.0%	9.97	10.4%	0.65	5.2%	5.93	10.6%	1.50	6.0%
2001	3.34	5.5%	3.25	5.4%	3.75	5.4%	11.01	10.4%	0.67	2.9%	6.44	8.6%	1.59	6.0%
2002	3.52	5.5%	3.42	5.4%	3.95	5.4%	12.20	10.8%	0.70	5.1%	7.01	8.9%	1.68	6.0%
2003	3.72	5.5%	3.61	5.4%	4.17	5.4%	13.42	10.0%	0.75	7.0%	7.60	8.4%	1.78	6.0%
2004	3.92	5.5%	3.80	5.4%	4.39	5.4%	14.64	9.1%	0.78	3.8%	8.20	7.9%	1.89	6.0%
2005	4.14	5.5%	4.01	5.4%	4.63	5.4%	15.88	8.5%	0.83	6.7%	8.82	7.5%	2.00	6.0%
2006	4.36	5.5%	4.22	5.4%	4.88	5.4%	17.18	8.2%	0.89	7.1%	9.46	7.3%	2.12	6.0%
2007	4.60	5.5%	4.45	5.4%	5.14	5.4%	18.63	8.4%	0.93	3.9%	10.17	7.5%	2.25	6.0%
2008	4.86	5.5%	4.69	5.4%	5.42	5.4%	20.08	7.8%	1.00	7.7%	10.89	7.1%	2.38	5.8%
2009	5.12	5.5%	4.94	5.4%	5.71	5.4%	21.59	7.5%	1.06	6.3%	11.65	6.9%	2.52	5.8%
2010	5.41	5.5%	5.21	5.4%	6.02	5.4%	23.12	7.1%	1.10	3.4%	12.41	6.6%	2.66	5.8%
2011	5.70	5.5%	5.49	5.4%	6.35	5.4%	24.92	7.8%	1.16	5.7%	13.30	7.1%	2.82	5.8%
2012	6.02	5.5%	5.79	5.4%	6.69	5.4%	26.87	7.8%	1.23	5.7%	14.24	7.1%	2.98	5.8%
2013	6.35	5.5%	6.10	5.4%	7.05	5.4%	28.96	7.8%	1.30	5.7%	15.25	7.1%	3.15	5.8%
2014	6.70	5.5%	6.43	5.4%	7.43	5.4%	31.22	7.8%	1.37	5.7%	16.33	7.1%	3.34	5.8%
2015	7.07	5.5%	6.78	5.4%	7.83	5.4%	33.65	7.8%	1.45	5.7%	17.51	7.2%	3.53	5.8%
2016	7.45	5.5%	7.14	5.4%	8.25	5.4%	36.28	7.8%	1.53	5.7%	18.77	7.2%	3.74	5.8%

NOTES:
(1) These figures include the coal price and the estimated cost for compliance with the Clean Air Act of 1990.
(2) Coal #1 is used for Scrubbed Pulverized Coal and Pressurized Fluidized Bed.
(3) Coal #2 is used for Coal Gasification Combined Cycle.
(4) Coal #3 is used for Pumped Hydro and Battery Storage.
(5) Those fuels that are not listed are escalated at 5%.

Figure E-1


LEVELIZED 1995 BUSBAR ANALYSIS
Conventional Resources
1000
800
600
400
200
0
$/kW-Yr
0
10
20
30
40
50
60
70
80
90
100
Capacity Factor (%)
CAES
BATT
PH
CT
CC
CELL
COAL
FBED
CGCC
NUCLEAR
COGA
COGB

As with the conventional technologies, the alternative technologies were divided into two broad groups depending on whether their expected capacity factor was greater than or less than 20%. To provide a reference point, technologies with expected capacity factors of less than 20% were compared to a conventional combustion turbine. Technologies with expected capacity factors of greater than 20% were compared to a conventional subcritical pulverized coal unit. Figure E-2 presents the screening curves developed for alternative resources.

The figure shows that the peat-fired power plant is the only alternative technology that is competitive on a $/kW-Year basis with the conventional technologies. For the other options, high capital costs render the technologies economically uncompetitive.

Summary Of Screening Results

Tables E-5 and E-6 show a summary of the results from the screening analysis. As you can see from the tables, ten technologies passed all three screens.

Examination of Figures E-1 and E-2 shows that peat, coal gasification combined cycle, and pulverized coal technologies have very similar busbar cost characteristics. For this reason, it was decided to use the subcritical pulverized coal technology as a proxy for peat and coal gasification combined cycle in the analysis that followed the screening process. If this proxy is chosen as part of the resource plan, then additional study will be required to determine which of the technologies is actually the most feasible alternative. Cogeneration B was not placed in this group since it is a purchase. A purchase has different financial implications and must be modeled differently; therefore, it could not be grouped with the others.

Table E-7 shows the technologies that were passed from the screening analysis to the next step for further consideration in the resource planning process.

Figure E-2

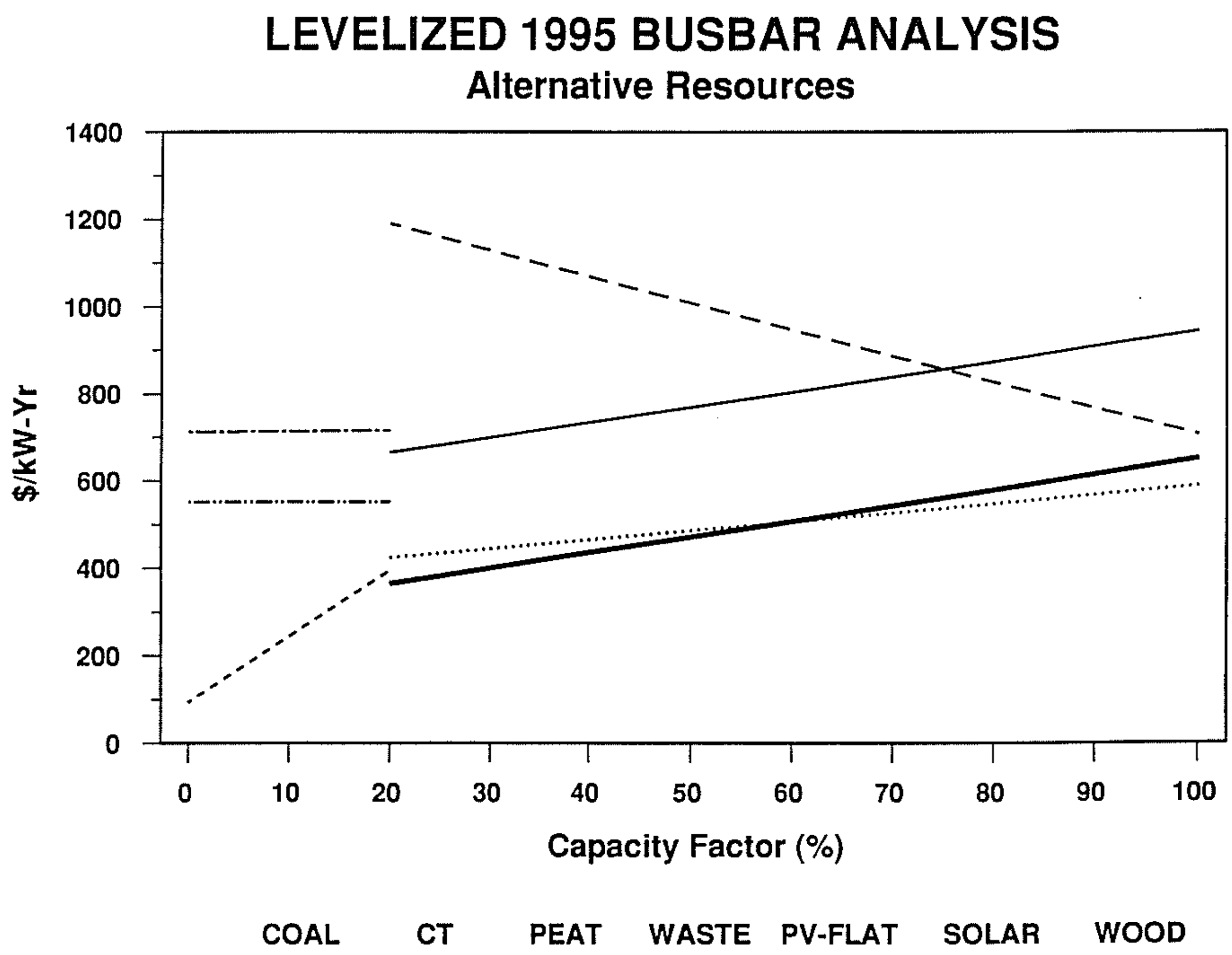

LEVELIZED 1995 BUSBAR ANALYSIS
Alternative Resources
1400
1200
1000
800
600
400
200
0
$/kW-Yr
0
10
20
30
40
50
60
70
80
90
100
Capacity Factor (%)
COAL
CT
PEAT
WASTE
PV-FLAT
SOLAR
WOOD

Table E-5
Summary of Conventional Technology Screening Process

	1st Screen: Significantly Avail. in CP&L Service Area?	2nd Screen: Commercial Avail. + Lead Time 2002?	3rd Screen: Cost Competitive in 1995?
Technology: Coal			
Scrubbed Pulverized Coal	Yes	Yes	Yes
Pressurized Fluidized Bed	Yes	Yes	No
Coal Gasification Combined Cycle	Yes	Yes	Yes
Technology: Nuclear			
Advanced Light Water Reactor - Passive Safety	Yes	Yes	Yes
Technology: Combustion Turbine			
Simple Cycle	Yes	Yes	Yes
Combined Cycle	Yes	Yes	Yes
Simple Cycle with Air Cooling	Yes	No	-
Technology: Storage			
Pumped Hydro	Yes	Yes	Yes
Compressed Air Energy Storage	Yes	Yes	Yes
Battery	Yes	Yes	No
Technology: Fuel Cell			
Phosphoric Acid	Yes	Yes	No
Technology: Purchased Power			
Cogeneration A - Peak	Yes	Yes	Yes
Cogeneration B - Base Load	Yes	Yes	Yes

Table E-6
Summary of Alterntaive Technology Screening Process

	1st Screen: Significantly Avail. in CP&L Service Area?	2nd Screen: Commercial Avail. + Lead Time 2002?	3rd Screen: Cost Competitive w/Conv. Techs. in 1995?
Technology: Geothermal			
Flash Steam Cycle	No	-	-
Binary Cycle	No	-	-
Technology: Ocean Energy			
Tidal Energy	No	-	-
Ocean Thermal Energy Conversion	No	-	-
Wavepower	No	-	-
Ocean Current Turbines	No	-	-
Salinity Gradient Devices	No	-	-
Ocean Wind Turbines	No	-	-
Technology: Photovoltaic			
Flat Plate	Yes	Yes	No
Concentrator	No	-	-
Technology: Solar Thermal			
Solar Parabolic Trough/Gas Hybrid	Yes	Yes	No
Technology: Wind			
250 kW Turbine	No	-	-
2.5 MW Turbine	No	-	-
Technology: Municipal Waste			
Mass Burn	Yes	Yes	No
Refuse Derived Fuel (RDF)	No	-	-
Technology: Biomass			
Peat	Yes	Yes	Yes
Waste Wood	Yes	Yes	No

Table E-7
Technologies Selected for Further Analysis

COAL

- Scrubbed Pulverized Coal

PURCHASED POWER

- Cogeneration A
- Cogeneration B

COMBUSTION TURBINE

- Simple Cycle
- Combined Cycle

STORAGE

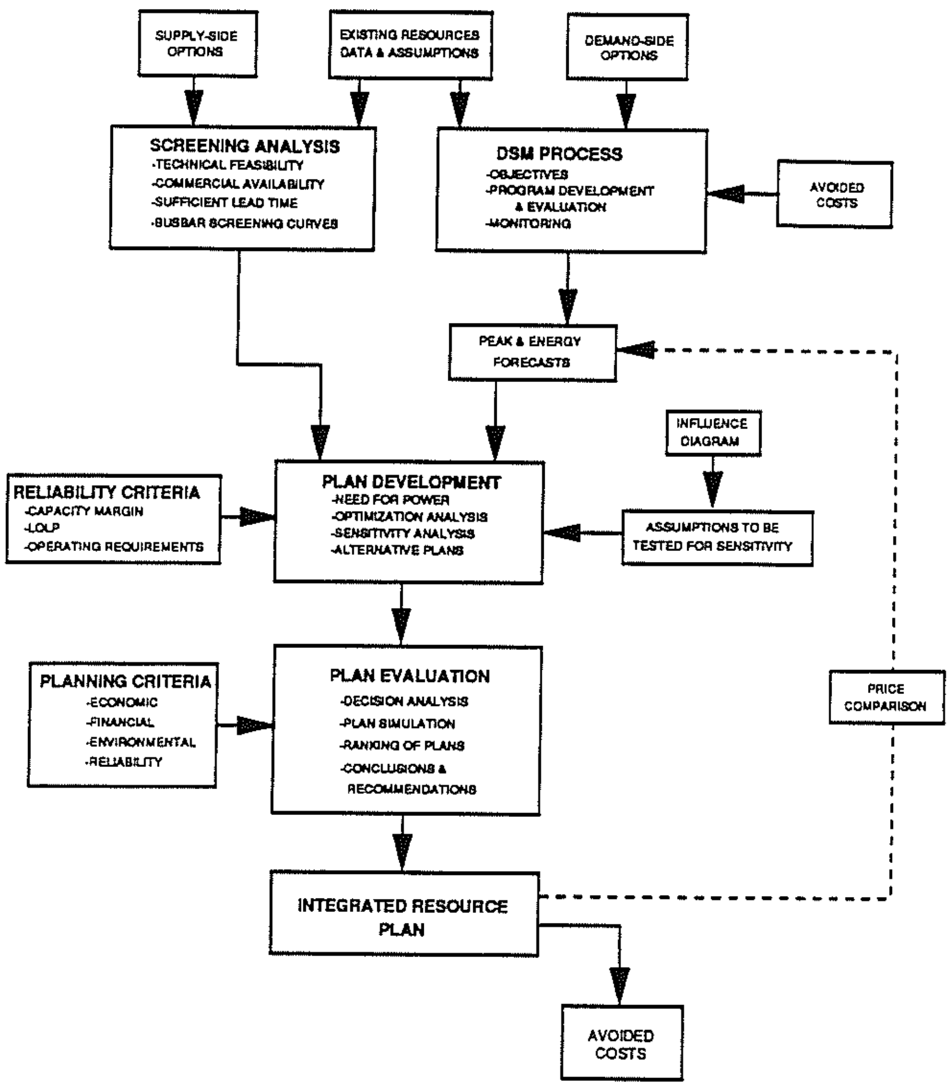
- Compressed Air Energy Storage
- Pumped Hydro

Appendix F
Results of the Integration Process

The assessment of resource options is a multi-step process which is described in Chapter 2 and is shown in Figure F-1. Briefly, demand-side and supply-side options available to the Company are identified and subjected to screening analyses and economic evaluations. Next, alternative resource plans are developed in response to the defined need for power and the uncertainties of the planning environment. Finally, these alternative plans are evaluated against a set of planning criteria using a decision analysis process. This appendix discusses the integration analysis performed to support the Integrated Resource Plan presented in Chapter 4. Also contained in this appendix is a special section discussing the methodology used to include the costs of environmental compliance in the Integrated Resource Planning Process.

Figure F-1

INTEGRATED RESOURCE PLANNING PROCESS



Supply-Side Screening

In the supply-side screening analysis, technologies that are not significantly available in the CP&L service area, or would not be available by the year 2002, or are not economically competitive are eliminated from further consideration. Appendix E contains the details of the supply-side screening process. The supply-side technologies that pass the screening tests are passed on to the Plan Development phase.

Demand-Side Management Process

Appendix D contains a description and the results of the economic evaluation of demand-side programs. Demand-side programs are incorporated into the peak load and energy forecasts which are used as input in the Plan Development phase of the integration process.

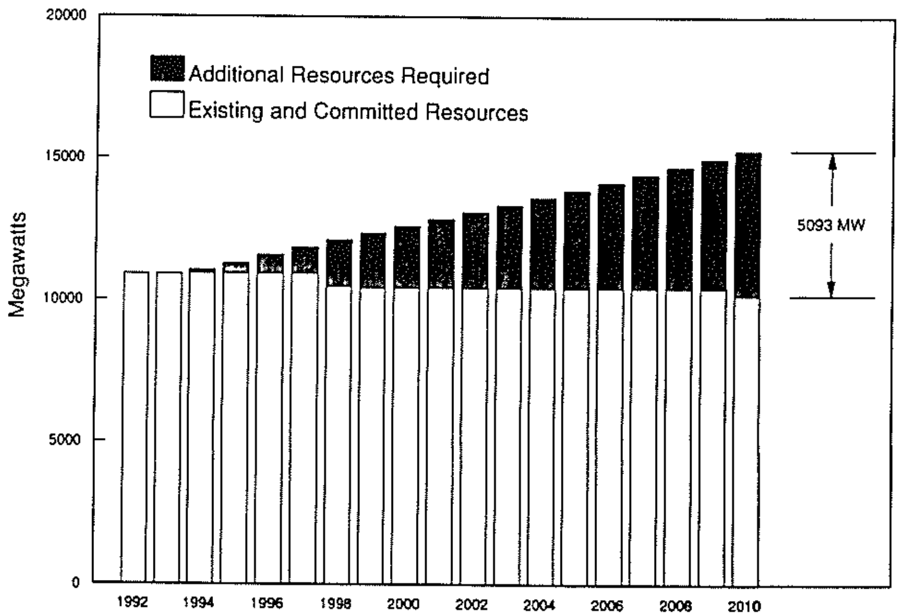
Plan Development

The development of alternative resource plans involves several steps. First, the need for power is defined. Second, the optimal resource plan given the base case assumptions is developed. Then, a series of sensitivity analyses are performed. The results from the sensitivity analysis are used to identify the uncertainties that, depending on their outcomes, could potentially change the resource mix. Also, possible alternative resource plans that may perform well under uncertainty are developed.

Need for Power

The projected load growth of the CP&L system dictates that additional resources are needed in the 1990s; either supply-side or demand-side. Figure F-2 shows the additional resources required between 1992 and 2010 to maintain a 16.7% capacity margin. This margin has been found to be necessary for maintaining reliable electric service. The figure, which is based on the 1990 system peak load forecast, shows the need for an additional 5093 MW by 2010.

Figure F-2
RESOURCES REQUIRED TO MAINTAIN 16.7% CAPACITY MARGIN



Optimization Analysis

The optimization analysis was the next step in the process to identify feasible resource options. The purpose of the optimization analysis was to identify the optimal resource plan given the base case assumptions, which are presented in Appendix B. The optimization analysis does not account for the uncertainties surrounding the variables influencing the decision. The "optimal" plan is the plan that results in the lowest present value of revenue requirements over the study period 1991-2020. The optimization analysis was performed using the WASP planning model. This model is described in Chapter 2.

The first optimal plan was developed by allowing WASP to choose from coal, combined cycle, and combustion turbines. On the basis of minimizing the present value of revenue requirements while maintaining a minimum 16.7% capacity margin, the model chose only simple cycle combustion turbines through 2003 and coal units after that. Next, pumped hydro and compressed air energy storage (CAES) were made available to the optimization model (in separate model runs) along with coal, combined cycle, and combustion turbines. One plan was developed utilizing just the pumped hydro storage technology and one was developed using just the compressed air storage technology. Both plans resulted in savings when compared to the base optimization plan which had no storage technology. Of the two plans with storage technologies, the plan with the CAES technology offered more savings.

Sensitivity Analysis

The sensitivity analysis was the final part of the process to identify feasible resource options and alternative plans. The purpose of the sensitivity analysis was to identify the uncertainties that, depending on their outcomes, could potentially change the resource mix. Supply options that were determined to perform well under various outcomes for these uncertainties were retained for use in developing alternative resource plans.

The first step in the sensitivity analysis incorporated the use of an influence diagram to pinpoint the uncertainties that could influence the resource plan decision. The influence diagram for revenue requirements is shown in Figure F-3. From the influence diagram, the uncertainties shown in Table F-1 were chosen for the sensitivity analysis.

Figure F-3

INFLUENCE DIAGRAM FOR REVENUE REQUIREMENTS

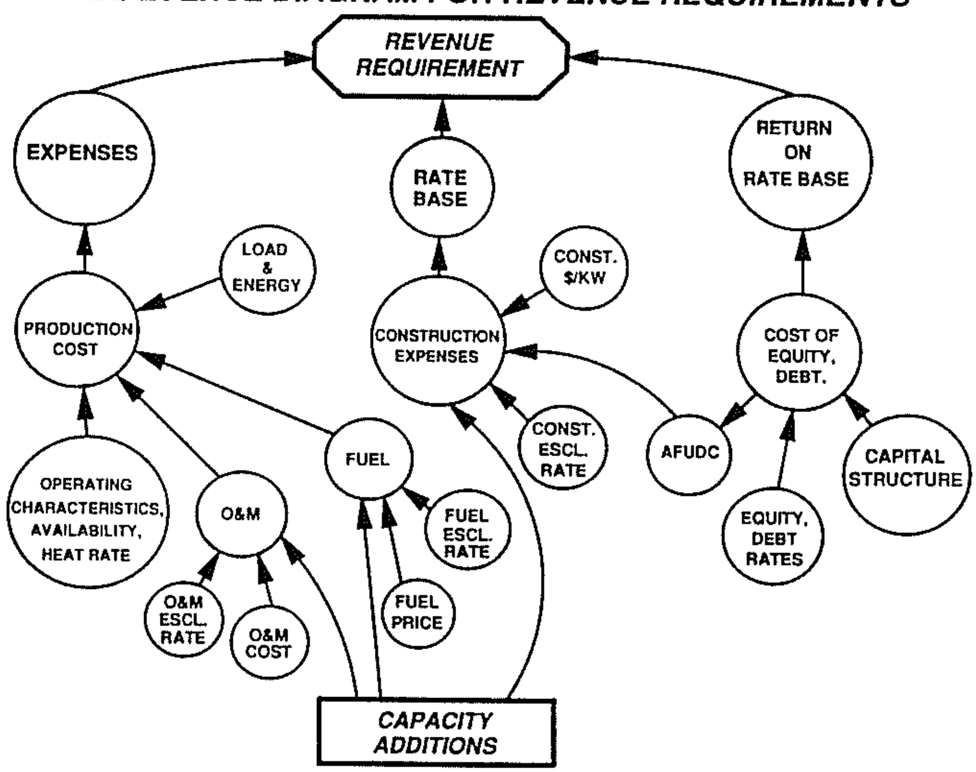


Table F-1
Sensitivities Analyzed

Uncertainty	Scenario Analyzed
Oil Prices (Price Shock)	2 x Base Case
Combustion Turbine Capital Cost	1.1 x Base Case
Coal Unit Capital Costs	0.9 x Capital Cost
Coal Unit O&M Costs	0.75 x O&M Cost
System Nuclear Capacity Factor	60% (Base = 68%)
Electricity Demand	Growth = 3%
SO2 Allowance Costs	1.5 x Base Case

Each of the uncertainties in Table F-1 were analyzed to identify which could affect the resource plan decision. The uncertainties were evaluated by determining the optimal plan under extreme outcomes for the different uncertainties. For, example, the resource plan's sensitivity to oil price uncertainty was evaluated by developing an optimal plan for a scenario in which oil prices were double those of the base case assumptions.

It was determined that the resource plan was insensitive to four of the seven uncertainties analyzed. The outcomes for the combustion turbine capital cost, coal unit capital cost, the coal unit O&M cost, and the SO_2 allowance cost did not significantly alter the resource plan. Thus, these uncertainties were eliminated from further analysis. The resource plan was, however, found to be sensitive to the other three uncertainties analyzed. These uncertainties were oil price, electricity demand, and system nuclear capacity factor. The outcomes analyzed for these uncertainties significantly altered the optimal plan from that when using the base case assumptions by advancing the in-service date of the first coal unit. These uncertainties were thus retained for further evaluation in the decision tree analysis.

Alternative Resource Plans

Seven alternative resource plans were developed to be evaluated in the Plan Evaluation phase of the integration process. These plans are shown in Table F-2. This section describes the alternative plans and how they were developed.

Plan A

Plan A is the reference plan. This plan was the same as the Company's December 1990 Resource Plan. It consisted of 2475 MW of combustion turbines being installed through the year 2001. In 2002, the first 500 MW coal unit is installed. Subsequent to that, 750 MW of CTs and 1500 MW of additional coal units are installed by the year 2010.

Plan B

Plan B is the base case optimization plan discussed above. The plan contains 2975 MW of CTs prior to the first coal unit being installed in the year 2004. Three other 500 MW coal units are installed before the year 2010.

Plan C

Plan C was developed based on the results of the sensitivity analysis on double oil prices. When the base case optimal plan was re-optimized given higher oil prices, the first coal unit was scheduled to be in-service in the year 2000 rather than 2004. Additional coal plants were also selected by the model in later years, rather than combustion turbines.

Plan D

Plan D is similar to the reference plan (Plan A) with the exception being that the first coal unit was moved to be in service in the year 2000 rather than 2004. This plan resulted from the sensitivity analysis performed with lower system nuclear capacity factor.

Plan E

Plan E was designed to examined the impact of lower oil prices. Recent trends in oil and natural gas prices indicate that CT fuels may not escalate as fast as anticipated. Under this scenario, a resource plan with additional CTs would be able to take advantage of the lower capacity cost of CTs without being subjected to high fuel expenses.

Plan F

Plan F was developed to include a storage technology in the resource plan evaluation. As described above, compressed air energy storage resulted in a lower present value of revenue requirements than when using pumped hydro; thus, a plan with CAES as the storage technology was developed. Plan F includes a 250 MW CAES plant in the year 2001.

Plan G

To reflect the financial implications of purchases, a plan was developed in which cogeneration was purchased rather than CP&L building its own facilities. Plan G contains one 350 MW gas-fired combined cycle cogeneration facility added in 1996, one 165 MW coal-fired cogeneration facility in 1997 and one 165 MW coal-fired cogeneration facility in 1998.

Table F-2

Alternative Resource Plans

	Plan A	Plan B	Plan C	Plan D	Plan E	Plan F	Plan G
1994	225 Darl'ton	225 Darl'ton	225 Darl'ton	225 Darl'ton	225 Darl'ton	225 Darl'ton	225 Darl'ton
1995	250 CT	250 CT	250 CT	250 CT	250 CT	250 CT	250 CT
1996	250 CT	250 CT	250 CT	250 CT	250 CT	250 CT	350 Cogen A
1997	250 CT	250 CT	250 CT	250 CT	250 CT	250 CT	165 Cogen B
1998	750 CT	750 CT	750 CT	750 CT	750 CT	750 CT	165 Cogen B 570 CT
1999	250 CT	250 CT	250 CT	250 CT	250 CT	250 CT	250 CT
2000	250 CT	250 CT	500 Coal	500 Coal	250 CT	250 CT	250 CT
2001	250 CT	250 CT			250 CT	250 CAES	250 CT
2002	500 Coal	250 CT	500 Coal	250 CT	250 CT	500 Coal	250 CT
2003		250 CT		250 CT	250 CT		250 CT
2004	250 CT	500 Coal	500 Coal	250 CT	250 CT	250 CT	250 CT
2005	250 CT			250 CT	250 CT	250 CT	250 CT
2006	500 Coal	500 Coal	500 Coal	500 Coal	250 CT	500 Coal	500 Coal
2007					250 CT		
2008	500 Coal	500 Coal	500 Coal	500 Coal	500 Coal	500 Coal	500 Coal
2009	250 CT			250 CT	250 CT	250 CT	250 CT
2010	500 Coal	500 Coal 250 CT	500 Coal 250 CT	500 Coal	500 Coal	500 Coal	500 Coal

Plan Evaluation

Decision Analysis

Decision analysis plays a major role in the evaluation and selection of the resource plan. Using decision analysis, the uncertainty of major assumptions is taken into account as a method of evaluating whether a candidate resource plan is a "robust" plan. A robust plan generally provides the flexibility to change course should the future not materialize as currently projected, thereby minimizing the adverse impacts of unforeseen changes, and produces acceptable results for a broad range of events.

As discussed in the Plan Development Section, the influence diagram and sensitivity analysis indicate which assumptions should be used as uncertainties; however, they provide neither the values of the uncertainties nor the probabilities of the assumptions occurring. Both the value of an uncertainty used in the analysis, and the probability of its occurrence are determined through an interview process. In the interview process, qualified experts are questioned regarding their insights of the future and the chances of specific futures occurring. Using the results of the interview process, a probability distribution is developed for each major uncertainty which expresses the probability associated with the occurrence of a range of possible futures.

The probability distributions depicting probable outcomes for the CT fuel price, energy growth, and nuclear capacity factor uncertainties are shown in Figure F-4. These distributions quantify the experts' opinions as to the range of possible outcomes for these uncertainties. The probability distributions were used to develop branch representations for high, mid, and low outcomes of these uncertainties. The branch representations of the uncertainties are shown in Figure F-5. The branches were then combined to form the decision tree shown in Figure F-6.

Each endpoint on the far right side of the decision tree represents a possible combination of outcomes for the three uncertainties and defines a scenario. For instance, the endpoint at the top right side of the tree represents a scenario where CT fuel prices are high (greater than 8.4% annual growth rate), energy growth is high (greater than 2.6% annual growth rate), and nuclear capacity factor is high (greater than 67%). The probability of a particular scenario occurring is the product of the probabilities of the individual outcomes comprising the scenarios. For this scenario, the probability is calculated as follows: 0.30 (probability that CT fuel prices will be high) X 0.15 (probability that energy growth will be high) X 0.30 (probability that nuclear capacity factor will be high) = 0.0135 (1.35%). The remaining endpoints are interpreted in a similar manner depending on the combination of outcomes for the different uncertainties.

Figure F-4
PROBABILITY DISTRIBUTIONS FOR KEY UNCERTAINTIES

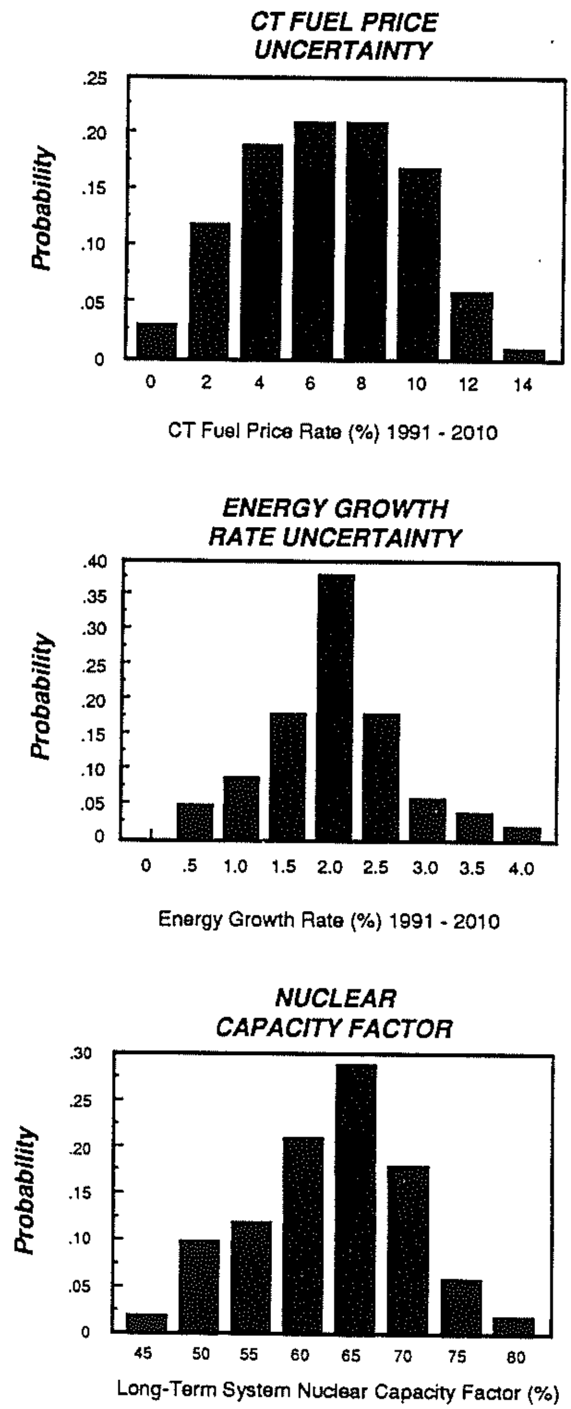


Figure F-5

KEY UNCERTAINTIES

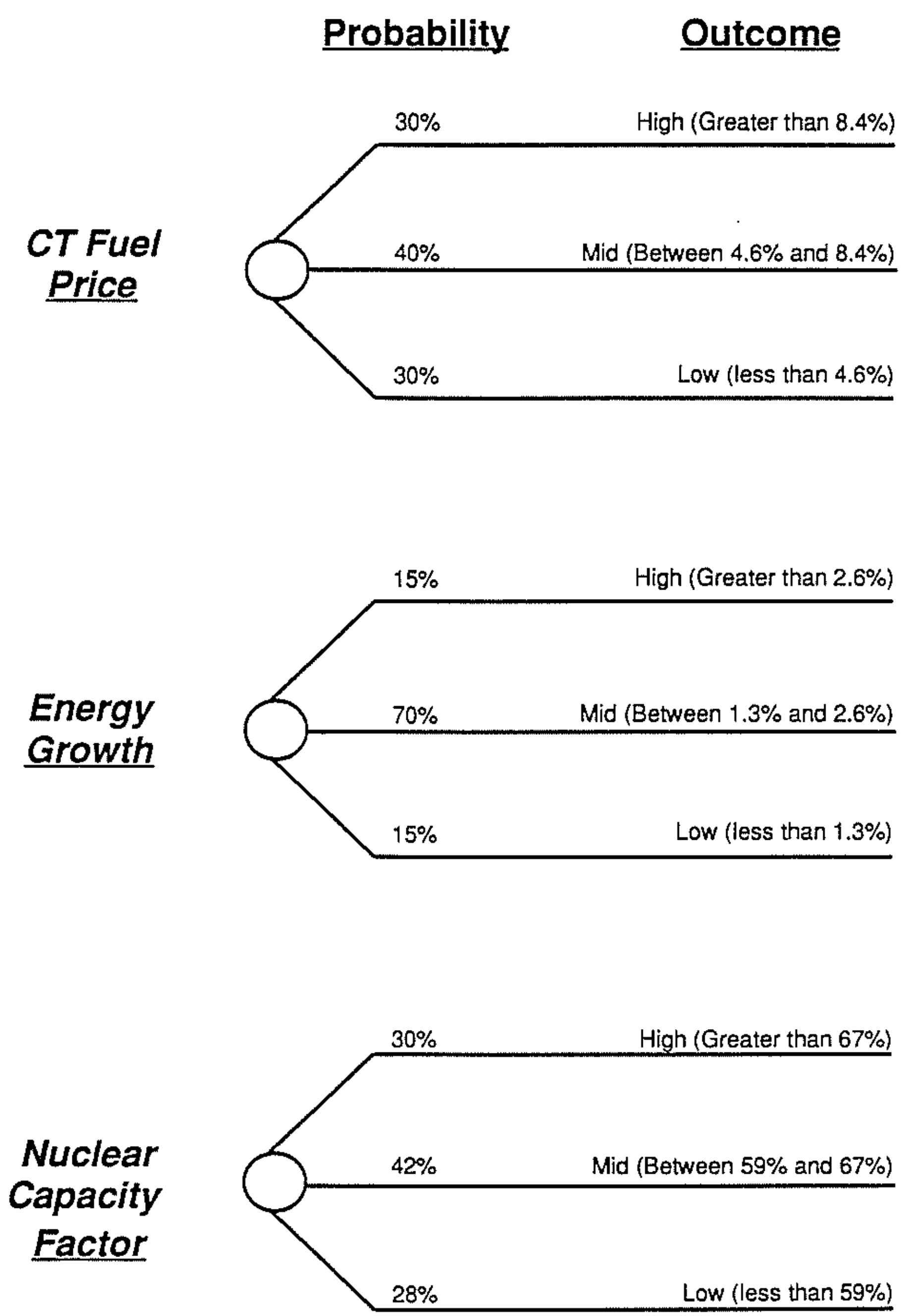
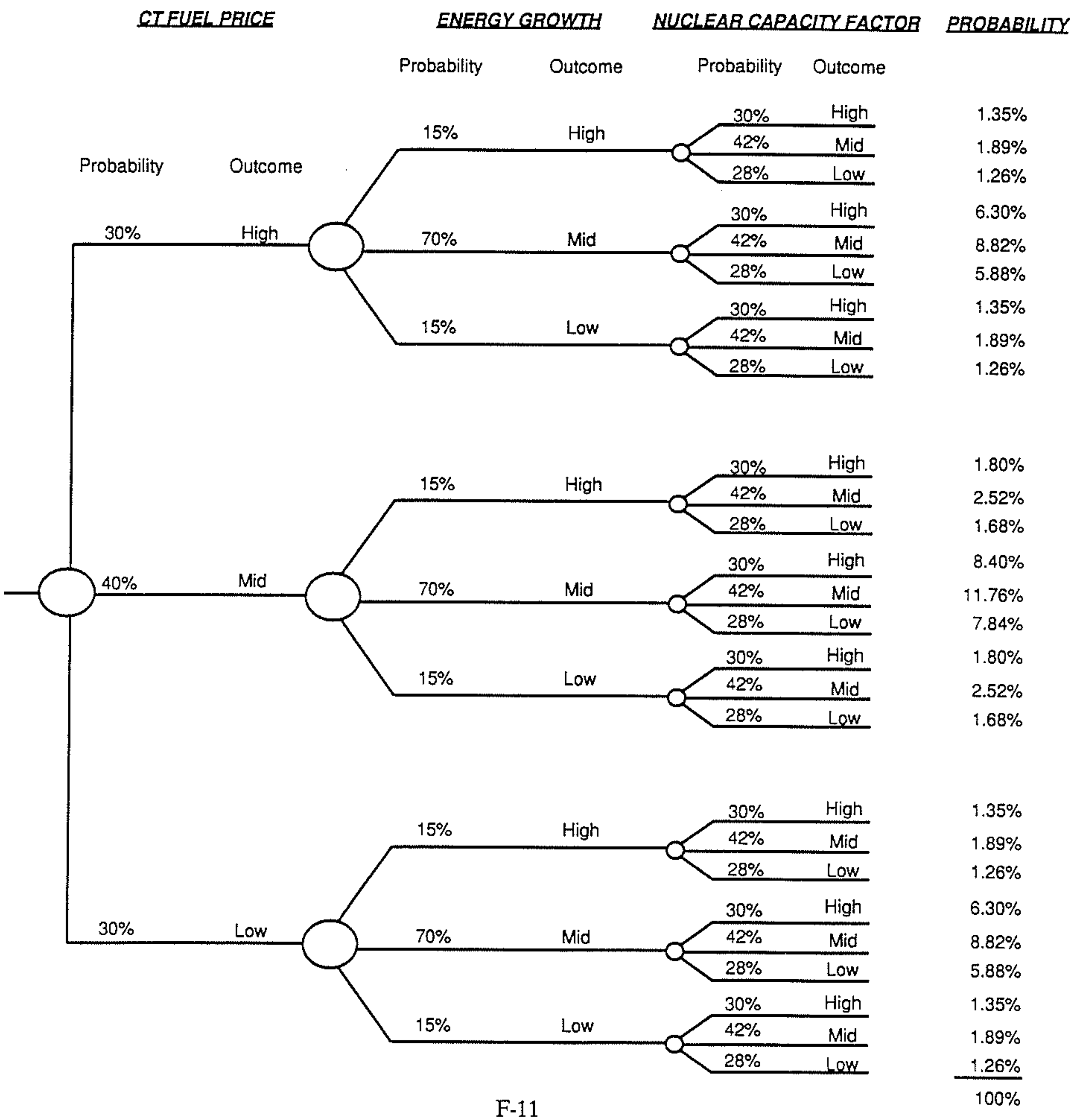


Figure F-6

DECISION TREE



Plan Simulation

The Utility Planning Model (UPM) was used to simulate all of the plans for each of the decision tree scenarios. For purposes of this analysis, zero load growth was assumed for the years of the study period that extended beyond the planning horizon. The planning horizon ended in the year 2010 while the model simulation continues through 2020. Thus, the years 2011 through 2020 were assumed to have zero load growth. This is done to minimize end effects related to generation additions at the end of the planning horizon.

Performance Measures

The alternate resource plans were evaluated against each other in accordance with certain planning principles as described in Chapter 2. Those principles, reflected in a set of resource planning criteria, are used to evaluate the candidate resource plans developed in the Plan Development step. The four criteria used in the evaluation are Economic, Financial, Environmental, and Reliability. Each criteria is described by one or more attributes which are used to measure the "goodness" of the candidate plans relative to each other. A brief description of the attributes is given below.

Economic Criterion

The attributes in the Economic group are present Value of Long-Term Revenue Requirements Savings and Present Value of Short-Term Revenue Requirement Savings. These were calculated as the savings in total revenue requirements over the period achieved by an alternative resource plan when compared with the current resource plan (Plan A). The long-term savings were calculated over the 1991-2020 time period and the short-term savings were calculated over the 1991-2000 time period. Because revenue requirements are used to determine the price of electricity, this attribute gauges the impact of the alternate resource plans on the customer.

Environmental Criterion

The environmental attribute was calculated as the cumulative SO_2 emissions of the alternate plans from 1991-2005. SO_2 emissions were chosen to represent the environmental impact of alternative resource plans because they are the most significant emission to be controlled under the Clean Air Act Amendment of 1990.

Financial Criterion

The financial attribute was calculated based on the annual Funds from Operations Interest Coverage Ratio determined by the Utility Planning Model (UPM) for the years 1991-2010. The coverage ratios from UPM, however, were not directly used. The actual ratios were converted to values on a linear scale. This was necessary because, unlike the other attributes, the value to the Company of a higher coverage ratio does not increase linearly with an increase in Funds from Operations Interest Coverage Ratio. The attribute was calculated as the average of the transformed annual coverage ratios from 1991 through 2010. Funds from Operations Interest Coverage Ratio is a new indicator used by the bond rating agencies to determine the financial health of the Company.

Reliability Criterion

The reliability attribute is represented by two attributes: Low Reserve Margin and High Reserve Margin. The Low Reserve Margin attribute was calculated by accumulating the difference between the actual percent reserve levels and the minimum target of 20% in years that the percent reserves were less than 20% during the 1991-2005 time period. The High Reserve Margin was calculated by accumulating the difference between the actual percent reserve levels and the maximum target of 25% in years that percent reserves exceeded 25% during the 1991-2005 time period.

Utility Functions

Since four different planning criteria are used to evaluate each plan, a method of incorporating the trade-offs of one criterion against the others is needed. The type of analysis used is known as utility function analysis. In this analysis, the different planning criteria are assigned weights, with the sum of the weights equaling one. In this fashion, the relative importance of each planning criterion in the decision process is identified. Since each planning criterion is described by one or more attributes, these attributes are also assigned weights to identify their relative importance to other attributes within a criterion. The weights of the attributes within a criterion also sum to a value of one. The weights for the criteria and attributes were determined from a survey of Company experts in the fields relating to the planning criteria and are shown in Table F-3.

Table F-3
Criteria Used To Rank Alternative Plans

Attribute	Weight
Economic	**45%**
Long-Term Present Value of Revenue Requirements	60%
Short-Term Present Value of Revenue Requirements	40%
Financial	**15%**
Funds From Operations Interest Coverage	
Environmental	**20%**
Cumulative SO_2 Emissions	
Reliability[1]	**20%**
Low Reserves	100%
High Reserves	0%

(1) Analysis demonstrated that the alternative plans achieved the same measure of performance based on the high reserves attribute. The low reserves attribute was thus assigned full weighting for the reliability criteria since the plans were indifferent regarding the high reserves performance measure.

Because the attributes have different units of measure, they must be unitized before they can be compared to other attributes. This is accomplished by identifying the range for each attribute, from the worst possible outcome to the best possible outcome, among all the alternative plans. This range is used as a basis to scale the possible outcomes for each attribute to values between zero and one. Thus, the results used in a utility function analysis are non-dimensional and the different attributes can be combined and evaluated simultaneously.

Plan Simulation Results

The attribute results were taken from UPM and entered into a spreadsheet model to evaluate the decision tree and determine the expected utility for each plan. The plans were ranked based on the value of the expected utility function developed for each plan. The plans with higher expected utilities are considered more desirable, taking into consideration all the uncertainties and all the criteria and attributes, and given the probabilities of the outcomes of the uncertainties analyzed. While the plan with the highest expected utility function may not be the best plan for all possible futures and for all the planning criteria, it is the most robust plan.

Table F-4 presents the ranking of the alternative resource plans resulting from the simulation of all the decision tree scenarios. Plan B, which is the base case optimization plan and which reflects installation of the first coal unit in 2004, is the highest overall ranking plan. It is noted from this table that while Plan B does not rank as the highest plan for any particular attribute, it does rank as the second highest plan for three of the five attributes.

Plan E, which includes 4225 MW of CT capacity and reflects the first coal unit in 2008, ranks as the second highest plan overall and the most favorable plan for the Short-Term Present Value of Revenue Requirements (PVRR) and Funds From Operations Interest Coverage attributes. However, Plan E ranks sixth out of the seven alternative plans on the basis of Long-Term PVRR due to its heavy reliance on CT capacity and resulting sensitivity to the CT fuel price uncertainty.

Plan G contains 680 MW of cogeneration in the early years of the study in lieu of CT capacity. It should be noted that new independent power producers and cogenerators are responsible for environmental emissions from their facilities. For this reason, emissions resulting from cogeneration in this plan are not reflected in the analysis as emissions by CP&L, and Plan G is ultimately the most favorable plan based on the environmental attribute. Plan G is the least favorable choice overall, however, and ranks last for both the long-term and short-term revenue requirements attributes.

It is also noted from the table that Plan F, which contains 250 MW of compressed air energy storage capacity in 2001, is the most favorable plan from the Long-Term PVRR perspective. The implication here is that the energy storage technologies produce significant cost savings, and investigations should continue to ascertain the availability of these options to CP&L for possible inclusion in the resource plan after the turn of the century.

Table F-4

Ranking Of Alternative Plans

	Plan A	Plan B	Plan C	Plan D	Plan E	Plan F	Plan G
Overall Ranking	3	1	6	5	2	4	7
ATTRIBUTE			RANKING BY ATTRIBUTE				
LT PVRR	3	2	5	4	6	1	7
ST PVRR	2	2	6	5	1	4	7
Financial	4	2	7	5	1	5	3
Environmental	4	5	2	3	7	6	1
Reliability	4	4	1	1	4	4	3

Sensitivity Analysis

To further test Plan B for robustness, two additional sensitivity analyses were performed related to the probabilities of the uncertainties and the weights assigned to the planning criteria.

In the first sensitivity, the probabilities assigned to the outcomes of the key uncertainties are evaluated. This is accomplished by varying the probability assigned to an outcome of a particular uncertainty, while maintaining the original relationship among the probabilities of the other outcomes. For example, assume the original probabilities assigned to the high, mid, and low outcomes of an uncertainty are 25%, 50%, and 25%, respectively. If the probability of the high outcome is being evaluated at 40%, the original 2 to 1 ratio between the mid and low outcomes is maintained. The assigned probabilities for the mid and low outcomes thus become 40% and 20%, respectively. The probabilities assigned to the outcomes of all other uncertainties are maintained at their original value. The expected utilities for all the alternatives are then computed and compared. This iterative process is repeated to determine the range of probabilities for each uncertainty outcome for which the highest ranking plan remains the highest ranking plan.

The results are presented in Table F-5 as a range of probabilities for the high, mid, and low outcomes for each of the three uncertainties. For example, the low outcome of the energy growth uncertainty has an original probability of 15%. The sensitivity analysis determined that Plan B remains the most robust plan as long as the probability of low energy growth is less than 97%.

The second analysis evaluated the sensitivity of the decision to the weights of the various planning criteria used in the process using the same methodology as described above. Table F-6 contains the results of this assessment and is interpreted in a similar manner to Table F-5.

The results of these tests confirmed that Plan B was the most robust plan over wide ranges of both uncertainty probabilities and planning criteria weightings.

Table F-5

Sensitivity To Uncertainty Probabilities

Uncertainty	Original Probability	Range for Which Plan B is the Most Robust Plan
High CT Fuel Price	30%	28% - 56%
Mid. CT Fuel Price	40%	0% - 54%
Low CT Fuel Price	30%	0% - 33%
High Energy Growth	15%	11% - 88%
Mid. Energy Growth	70%	1% - 78%
Low Energy Growth	15%	0% - 97%
High Nuclear Capacity Factor	30%	0% - 46%
Mid. Nuclear Capacity Factor	42%	0% - 100%
Low Nuclear Capacity Factor	28%	11% - 100%

Table F-6

Sensitivity To Planning Criteria Weightings

Planning Criteria	Original Weighting	Range for Which Plan B is the Most Robust Plan
Economic	45%	42% - 92%
Financial	15%	1% - 16%
Environmental	20%	0% - 40%
Reliability	20%	0% - 29%

Methodology for Including Costs of Environmental Compliance in the LCIRP

As stated before, CP&L considers the impact its facilities will have on the environment during all stages of planning and operation. Part of the consideration process is the cost of environmental protection required by generation facilities. This section describes the process by which environmental costs are included in the planning process.

Costs Associated with Existing Regulations

The majority of the environmental compliance costs in the resource plan are associated with the existing facilities. Because safeguarding the environment is part of the normal business routine, these costs are embedded in the normal O&M and capital addition forecasts developed by the Company and included in the planning models.

The conventional generating technologies considered by CP&L in its screening analysis of supply-side options are generic in nature. Because they are not site-specific, it is impossible to consider local environmental impacts. However, in general and by design, they all comply with existing national air quality standards and regulations. For example, the generic pulverized coal unit is designed with a flue gas desulfurization system, and the costs of this system are included in the cost estimates of the option. According to the EPRI Technical Assessment Guide (which serves as the basis of the generic unit cost estimates) environmental control equipment accounts for approximately 15 percent of the total cost of a pulverized coal unit.

Costs Associated with Future Regulations

Estimates of the costs for complying with regulations that have not been promulgated or have yet to take effect are also included in the planning data and in the planning process. An example of this situation are the costs associated with complying with the Clean Air Act Amendments of 1990 ("Amendments"). The major impact on CP&L of the Amendments is in the area of acid deposition. The first of two phases becomes effective in 1995. The second phase, which contains more stringent provisions, will become effective in the year 2000. The Company is in compliance with the first phase and, with regard to the second phase, the eight year lead-time gives the Company adequate time to plan for the changes it must make in order to comply with the legislation and regulations.

The complexity of the Amendments makes planning more difficult and more time-consuming. There are many options available to electric utilities to reduce their emissions of sulfur dioxide (SO_2) and nitrogen oxides (NO_x). CP&L is in the process of examining and evaluating numerous compliance alternatives. For planning purposes, a strategy to comply with the legislation has been developed and the costs of this strategy have been included in the analyses performed as part of this IRP. The strategy involves scrubbing three of the existing units, switching several plants to burn compliance coal, and the additional of low NO_x burners on all existing coal-fired units. This strategy is a rough "first cut" estimate that complies with the legislation and allows cost estimates of compliance to be introduced into the IRP process.

The costs of compliance with the Amendments is included in the cost of all options involved in the resource plan; both demand-side and supply-side. On the demand-side, the costs are included in the avoided energy costs. On the supply-side, the costs are included in the screening of resource options, in the determination of the dispatch order, in optimization analyses, and in the evaluation of alternative resource plans.

The majority of the costs associated with compliance with the Amendments are associated with actions taken to reduce the SO_2 emissions of existing units. The Amendments call for utilities to receive "allowances" for a certain level of emissions, based on the operation of fossil-fueled units during the 1985-1987 time period. An allowance is equal to one ton of SO_2 emissions. Emissions may not exceed the number of allowances held by the utility. Because the allowable emissions are based on the historical operation of existing units, new generating facilities do not receive SO_2 emission allowances.

A key feature of the Amendments is that the SO_2 allowances are a tradable commodity. Utilities will be able to comply by either restricting their emissions to less than the number of allowances they hold or they may buy allowances from others. It is foreseen that there will be an open market for allowances, with buyers and sellers bidding on the allowances. Because of the open market for allowances, economic theory suggests that the allowances will be priced approximately the same as what it would cost to comply by building scrubbers or burning cleaner fuels. Thus, the cost of allowances can be used to represent the cost of the sulfur dioxide emissions of new power plants.

Cost of Allowances

At this early stage of compliance, the cost of SO_2 allowances is highly uncertain. Cost estimates abound and range from $300 per allowance to $2000 per allowance. Predicting the cost of allowances is beyond the scope of the work done in the LCIRP analysis; therefore, an allowance price projection published in a paper by the NERA (Energy Outlook, "The Impacts of the 1990 Clean Air Act on Utility Planning") was used. In this paper, NERA discussed a study they performed on 17 midwest utilities. From this study, NERA projected that the price of allowances (in 1989 dollars) would be $420 per allowance in 1995, $600 in 2000, and $810 in 2010. Assuming a 5% inflation rate allowance prices would be $563 in 1995, $1026 in 2000, and $2257 in 2010, in nominal dollars.

Emission Costs in Avoided Energy Costs

Avoided energy costs are used in the economic screening of demand-side management programs. Compliance with the Amendments increases the avoided energy costs through an increase in the fuel costs. The coal CP&L burns is known as "low sulfur" and "compliance" coal. These coals are low in sulfur content, with the low sulfur coal containing approximately 1.2% sulfur by weight and the compliance coal containing 0.7% sulfur by weight. It is anticipated that these high quality coals will increase in price due to higher demand by other utilities in their efforts to comply with the regulations. Also, modifications to the units required by the regulations will likely cause the unit to be slightly less efficient; thus, burning more fuel. The end result is higher total fuel costs.

Emissions Cost in Dispatch Order

When determining the dispatch order for a generating system, the incremental costs of generating one megawatt hour of electricity are examined. Traditionally, the incremental costs are composed of the fuel and variable O&M costs of the units. However, given the annual cap on utility SO_2 emissions under the Amendments, the cost of emitting SO_2 should also be included in the determination of the dispatch order. A reasonable estimate of this cost is the cost of an allowance. The easiest way to incorporate the cost of an allowance (which is usually stated in terms of dollars per ton of SO_2) into the dispatch cost is to convert $/ton to $/MBtu and add it to the fuel cost (which is usually stated in $/MBtu). This technique is sometimes referred to as shadow-pricing. The conversion can be done by multiplying the price of allowances (in $/ton) by the sulfur content of the fuel (in percent) times 1000 (for conversion of units) and dividing by the heat content of the fuel (in Btu/lb). Adjustments to this cost must be made if the generating unit employs some form of SO_2 reduction system. Thus, the allowance cost in $/MBtu is equal to:

$$\frac{\text{Allowance Cost (\$/ton)} * \text{Sulfur Content} * (1 - SO_2 \text{ reduction efficiency}) * 1000}{\text{Heat Content of Fuel (Btu/lb)}}$$

In developing the dispatch order, the heat rate impact related to the addition of NO_x controls and scrubbers were also taken into consideration. Also, if a unit has a scrubber system, the cost of limestone and/or other consumables is also included in the dispatch cost.

Emission Cost in Screening Analyses and Optimization Analyses

The "fuel adder" approach used to determine the dispatch order can also be used to assess an SO_2 emission penalty to the cost of new supply resource options. Under the Amendments, new units do not receive any allowances. Thus, their emissions must be offset by other units on the system, which adds to the cost of the new supply option. The cost of the offsetting reduction can be approximated using the cost of allowances. Using the same methodology as used in determining the dispatch order, fuel adders were determined for all supply-side technologies that have SO_2 emissions (such as coal units, combustion turbines, and combined cycle units) as well as for technologies that require the generating system to produce more electricity (such as the pumped hydro, compressed air energy storage, and battery technologies).

Cost of Compliance in Plan Evaluation

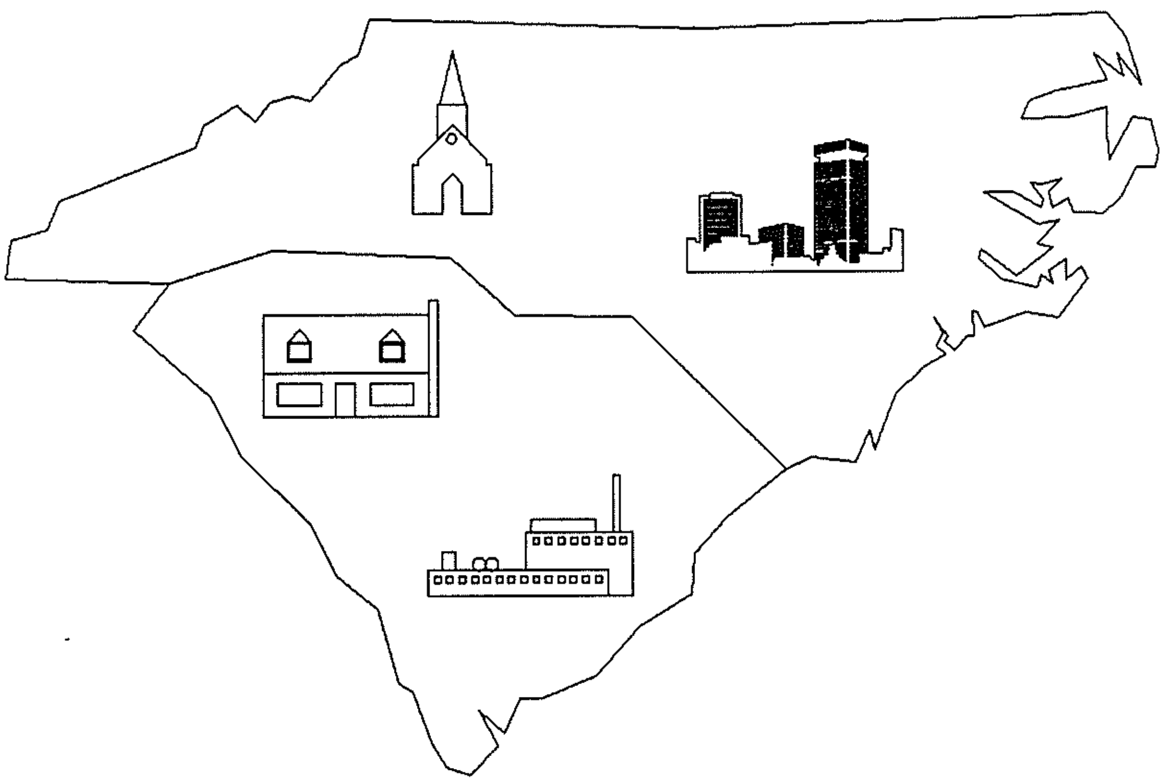
In the Plan Evaluation step of CP&L's Integrated Resource Planning Process, the cost of compliance with the Amendments was included by simulating actions the Company may take to comply with the regulations. The cost of compliance includes higher fuel costs as discussed above, increased capital costs associated with the installation of flue gas desulfurization equipment on several units, and NO_x controls on all coal units.

Table of Contents

Volume III

ENERGY FORECAST

CAROLINA POWER & LIGHT COMPANY



1991

TABLE OF CONTENTS

Adopted by the Senior Management Committee

Date: December 10, 1991

CAROLINA POWER & LIGHT COMPANY

ENERGY FORECAST

INTRODUCTION

The methodology in this report of forecast energy usage requires the use of econometrics, which involves the application of statistical techniques to economics in the study of problems, analysis of data, and application of theories. This econometric forecast is based on equations which explain future usage in the different customer classes which CP&L serves (e.g., residential, industrial, commercial, etc.). These equations are derived by relating historical usage of electricity to economic and demographic (population characteristics) variables, and estimating the effect of each of the chosen variables on historical energy usage by the statistical technique known as regression analysis. These equations (known as behavioral equations) are derived for the most disaggregated groupings (sectors or sub-sectors) for which data is available, which further adds reliability to the entire forecasting procedure.

When coefficients of the above described independent variables are estimated, summary statistical tests are performed on each. The inferences of these tests give an indication of how good the choice of variables has been to explain observed usage. The most common statistics which are used are the R-bar squared, the t-statistic, the Durbin-Watson statistic, the standard error and, in certain applications, the F-statistic.

The R-bar squared is a measure of how well the chosen variables and their estimated coefficients explain the usage for all of the historical period. Obviously, 1.000, or 100%, indicates that all of the usage has been explained for each observation. This test is especially indicative when there are "rich" or widely fluctuating data such as weather. A low R-bar square might indicate that the chosen variables have not adequately captured the variation of usage, or that some other specification should be investigated. The R-bar square measures the explanatory power of all the independent variables together.

To test whether each chosen variable individually contributes significantly to the explanation of usage, t-statistics are calculated and tested. Generally, if the absolute value of a t-statistic is 2.0 or greater, it is concluded that that particular variable is significant in explaining the variation in usage. If the absolute value of a t-statistic is below the critical value, then it is concluded that the contribution to the explanation of movement in the usage by that chosen variable is not significantly different from zero.

Variables whose t-statistics have statistically low values are generally dropped from the equation, and the equation is re-estimated with the remaining explanatory variables. In the theoretical case, if one begins with the true specification of a model and removes any explanatory variables from that specification, then the coefficients of the remaining explanatory variables will be biased if the removed variables are correlated with the included independent variables. However, in practical applications, one generally does not know the true specification of the model, but uses judgment as to what explanatory variables may cause changes in the dependent variable. With large sample sizes, evaluating the t-statistic of each variable will test whether the assumption that a particular explanatory variable contributes significantly to the dependent variable with precision and reliability was correct. Thus, with a sufficiently large sample, a low t-statistic can be interpreted as meaning that a particular variable does not have a systematic effect on the dependent variable; and thus, its removal will not reduce the explanatory power of the model. However, with small sample sizes comes a lack of precision. Removing variables from a regression strictly as a result of a low t-statistic lends itself to uncertainty as to whether that variable truly has no effect on the dependent variable, or whether the low t-statistic is a result of imprecision based on a small sample and that the variable does in fact contribute to the variation of the dependent variable. In other words, with small sample sizes, one cannot be sure whether or not a variable with a low t-statistic is a component of the true specification. In such cases, removal of those variables may lead to serious bias if they were part of the true specification and were correlated with the independent variable.

The Durbin-Watson statistic is a measure of autocorrelation or serial correlation (correlation refers to interdependence between variables). Many economic indicators do not change instantaneously due to a given stimulus, but change more slowly over time. This carry-over into later periods can create residual autocorrelation. Employment, for example, frequently changes more slowly than output in both contractive and expansive phases of the economy. This lag can cause inefficiency in the estimated coefficients of the variables. A Durbin-Watson statistic of 2.0 indicates that there is negligible first-order autocorrelation in the regression.

A Durbin-Watson statistic less than or more than the critical value for the given regression indicates that a correction for serial correlation should be made to minimize the inefficiency of the estimated coefficients. The type of correction necessary to eliminate or to minimize autocorrelation can be determined by an Autoregressive Integrated Moving-Average analysis.

The standard error of regression indicates a range or band from the regression line into which a given percentage of the actual regressed values fall. A specification which very accurately captures the movement of the dependent variable will have a small standard error of regression and the error terms will be small relative to the magnitude of the dependent variable.

The F-statistic is a measure of the significance of all of the variables acting in concert. In this report, the F-statistic indicates that the final behavioral equation does contain explanatory information. If the F-stat is above the critical value, the inference is that at least one of the coefficients in the behavioral equation is statistically significantly different from zero.

R-bar square, t-stat, Durbin-Watson statistic, and standard error were calculated for each regression used in deriving the forecast equations used by CP&L. An appropriate change was made in specification or a correction was made in the treatment of the data when the value of a calculated statistic was not acceptable. Thus, the appropriateness of chosen variables in explaining historical usage is statistically tested.

In performing econometric forecasts, it is sometimes helpful to use dichotomous or dummy variables. There are two types of dummy variables which have been used extensively in deriving the forecast equations. The first type is seasonal dummies.

Seasonal dummy variables are used to capture the variation in usage corresponding to the calendar month. The methodology is similar to a seasonal adjustment. Longer daylight hours, holiday usage, resort seasons, and many other non-stochastic (systematic) influences cause a variation in usage which follows a definite cycle. A seasonal dummy is specified to be 1 during a single month and 0 for the other eleven months. The estimated coefficient for the dummy gives the relative usage for that month attributed solely to a repetitive monthly variation. This coefficient could be thought of as a form of a seasonal adjustment factor.

The second type of dummy is specified to capture the discontinuity of the equation due to a known change in usage. This known change could be the addition of a steam turbine for self-generation, a large chemical plant, a glass furnace, or any other specific change in observed usage. The use of dummies to capture discontinuities allows a greater data base to be used, and consequently the statistical advantage of being able to use a larger number of observations for modeling purposes.

Some economic forecast data used to develop the Energy Forecast was obtained from Data Resources, Inc. (DRI). The Macro Economic Model of DRI forecasts economic variables for the United States (quarterly values throughout the forecast period). These particular projections do not forecast business cycles in the economy. The forecast values from the DRI Macro Economic Model become the input for the DRI Regional Information Service (RIS) models. One of the regions forecasted is the South Atlantic Region Model which includes the states of North and South Carolina.

In the RIS Model, independent forecasts for major economic and demographic indicators are also made by state. The forecasts by states are reconciled to the region and the regions are reconciled to the Macro Model; thus, there is consistency and linkage in the state forecast with the national forecast.

CP&L has developed and maintains an economic model of the CP&L service area. The North Carolina RIS Model forecasts become input for the North Carolina portion of the CP&L Service Area Economic Model, and the South Carolina RIS Model forecasts become input for the South Carolina portion of the CP&L Service Area Economic Model. The forecast values for economic variables in the CP&L Energy Model come from the CP&L Service Area Economic Model.

While all economic variables play important roles in developing the forecast, future electricity prices are especially important. The electricity prices used in the forecast reflect the expected costs of CP&L's integrated resource plan. In addition, forecast prices also reflect general estimates of environmental compliance with the Clean Air Act amendments signed into law during 1990.

Because integrated resource plans may contain minor timing or magnitude changes from year to year, expected future prices also vary from plan to plan. A comparison is made between the electricity prices produced by the resource integration process with those incorporated in the forecast. This price comparison showed negligible differences.

A summary of the econometric Energy Forecast is shown in Table I and Table II on the following pages. Table I shows the energy projections for each customer class and total system including conservation activity but before reduction for the Company's load management activities. Table II, on the other hand, shows the energy projections for each customer class and total system after reduction for conservation activity and load management activity. When these two tables are considered together, they illustrate the effect of the Company's demand-side activities and non-price induced load management on future energy usage.

The forecast completed during 1991 incorporated for the first time the assumption of considerably slower growth. The city of Camden has given notice that it will no longer receive service from CP&L effective May 1, 1995. The prospect of further load and customer losses due to changing relationships and power availability in our wholesale markets is increasing. In addition, the prospect of other issues involving increasing appliance efficiency standards, stricter building codes, industrial cogeneration, and the possible expansion of natural gas into the Piedmont and Tidewater regions of the service area all tend toward slower electricity growth. Table I and Table II reflect the increasing prospects for slower growth in future electricity needs served by CP&L.

The exact timing and magnitude of load and customer attrition are highly uncertain. After careful review and consideration, the slower growth scenario stemming from our assessments of uncertainty (see Appendix A) was judged to be a suitable collective proxy for reduced growth in future electricity needs served by CP&L. As a matter of interpretation, both the higher and slower growth scenarios form an approximate upper and lower bound on future electricity needs to be served by CP&L. Given the continuing prospects in our retail and wholesale markets, we believe that the slower growth scenario best typifies CP&L's electricity future.

This report summarizes the forecast of energy use using econometric methods. CP&L has also undertaken over the past several years the development of residential and commercial sector forecasts using end-use methods. Considerable effort has been expended to make the inputs to both the econometric and end-use models consistent. The forecasts using end-use methods are very close to the econometric projections. The high degree of similarity between these different projections serves as a verification and credibility check. A report of end-use results can be found in the report <u>End-Use Energy Forecast</u>.

CAROLINA POWER & LIGHT CO.
ENERGY FORECAST
NOT REDUCED BY CONSERVATION AND LOAD MANAGEMENT
(IN MWH)
SLOWER GROWTH SCENARIO

	RESIDENTIAL	% CH	COMMERCIAL	% CH	INDUSTRIAL	% CH	PUB ST. & H. LIGHT	% CH	MILITARY	% CH	SALES FOR RESALE	% CH	NCEMPA	% CH	TOTAL	% ANN. GR.
1986	9,028,062	9.5	6,364,888	6.9	11,053,697	3.1	92,866	−2.0	961,006	5.8	5,320,207	7.7	4,655,707	4.9	37,476,433	6.17
1987	9,614,322	6.5	6,731,821	5.8	11,477,238	3.8	88,835	−4.3	995,020	3.5	5,749,167	8.1	4,933,251	6.0	39,589,654	5.64
1988	9,854,258	2.5	7,059,737	4.9	11,925,679	3.9	90,803	2.2	1,019,641	2.5	5,938,009	3.3	5,090,429	3.2	40,978,556	3.51
1989	9,942,971	0.9	7,378,331	4.5	12,344,506	3.5	93,660	3.1	1,060,617	4.0	6,016,311	1.3	5,318,182	4.5	42,154,578	2.87
1990	10,013,870	0.7	7,669,623	3.9	12,335,935	−0.1	95,640	2.1	1,067,179	0.6	6,211,715	3.2	5,268,712	−0.9	42,662,674	1.21
1991	10,270,072	2.6	7,411,169	−3.4	11,930,774	−3.3	95,500	−0.1	1,058,731	−0.8	6,063,351	−2.4	5,465,311	3.7	42,294,908	−0.86
1992	10,790,284	5.1	7,541,566	1.8	12,528,300	5.0	96,296	0.8	1,054,321	−0.4	6,151,281	1.5	5,429,553	−0.7	43,591,600	3.07
1993	11,291,733	4.6	7,813,197	3.6	13,083,194	4.4	96,777	0.5	1,059,592	0.5	6,465,966	5.1	5,622,707	3.6	45,433,165	4.22
1994	11,803,623	4.5	8,045,729	3.0	13,264,577	1.4	97,261	0.5	1,064,890	0.5	6,769,991	4.7	5,785,513	2.9	46,831,583	3.08
1995	12,232,536	3.6	8,192,021	1.8	13,347,009	0.6	97,747	0.5	1,070,215	0.5	6,896,754	1.9	5,899,728	2	47,736,009	1.93
1996	12,586,750	2.9	8,283,512	1.1	13,443,917	0.7	98,236	0.5	1,075,566	0.5	7,012,601	1.7	6,004,593	1.8	48,505,175	1.61
1997	12,897,301	2.5	8,351,819	0.8	13,560,071	0.9	98,727	0.5	1,080,944	0.5	7,141,530	1.8	6,110,861	1.8	49,241,252	1.52
1998	13,182,872	2.2	8,432,597	1.0	13,741,466	1.3	99,221	0.5	1,086,348	0.5	7,296,801	2.2	6,223,059	1.8	50,062,365	1.67
1999	13,451,944	2.0	8,524,067	1.1	13,909,496	1.2	99,717	0.5	1,091,780	0.5	7,478,701	2.5	6,338,850	1.9	50,894,555	1.66
2000	13,717,234	2.0	8,626,767	1.2	14,033,047	0.9	100,215	0.5	1,097,239	0.5	7,646,904	2.2	6,439,808	1.6	51,661,215	1.51
10 yr. Cmpd. 90–2000	3.2		1.2		1.3		0.5		0.3		2.1		2.0		1.9	
2001	13,952,265	1.7	8,709,184	1.0	14,147,201	0.8	100,717	0.5	1,102,725	0.5	7,824,943	2.3	6,540,537	1.6	52,377,572	1.39
2002	14,184,089	1.7	8,770,748	0.7	14,251,322	0.7	101,220	0.5	1,108,239	0.5	8,021,051	2.5	6,641,498	1.5	53,078,166	1.34
2003	14,408,415	1.6	8,837,520	0.8	14,336,424	0.6	101,726	0.5	1,113,780	0.5	8,221,178	2.5	6,742,416	1.5	53,761,460	1.29
2004	14,612,524	1.4	8,909,655	0.8	14,465,755	0.9	102,235	0.5	1,119,349	0.5	8,420,668	2.4	6,849,138	1.6	54,479,323	1.34
2005	14,806,015	1.3	8,994,744	1.0	14,658,269	1.3	102,746	0.5	1,124,946	0.5	8,630,873	2.5	6,961,318	1.6	55,278,910	1.47
2006	15,015,181	1.4	9,090,043	1.1	14,817,172	1.1	103,260	0.5	1,130,570	0.5	8,836,027	2.4	7,070,025	1.6	56,062,278	1.42
2007	15,225,589	1.4	9,201,493	1.2	14,978,850	1.1	103,776	0.5	1,136,223	0.5	9,048,116	2.4	7,189,974	1.7	56,884,023	1.47
2008	15,454,115	1.5	9,308,323	1.2	15,131,223	1.0	104,295	0.5	1,141,904	0.5	9,252,404	2.3	7,304,615	1.6	57,696,879	1.43
2009	15,697,877	1.6	9,412,182	1.1	15,287,456	1.0	104,816	0.5	1,147,614	0.5	9,451,444	2.2	7,418,842	1.6	58,520,231	1.43
2010	15,964,217	1.7	9,526,801	1.2	15,469,164	1.2	105,341	0.5	1,153,352	0.5	9,651,146	2.1	7,530,474	1.5	59,400,494	1.50
20 yr. Cmpd. 90–2010	2.4		1.1		1.1		0.5		0.4		2.2		1.8		1.7	

Table I

CAROLINA POWER & LIGHT CO.
ENERGY FORECAST
REDUCED BY CONSERVATION AND LOAD MANAGEMENT
(IN MWH)
SLOWER GROWTH SCENARIO

	RESIDENTIAL	% CH	COMMERCIAL	% CH	INDUSTRIAL	% CH	PUB ST. & H. LIGHT	% CH	MILITARY	% CH	SALES FOR RESALE	% CH	NCEMPA	% CH	TOTAL	% ANN. GR.
1986	9,028,062	9.5	6,364,888	6.9	11,053,697	3.1	92,866	−2.0	961,006	5.8	5,320,207	7.7	4,655,707	4.9	37,476,433	6.17
1987	9,614,322	6.5	6,731,821	5.8	11,477,238	3.8	88,835	−4.3	995,020	3.5	5,749,167	8.1	4,933,251	6.0	39,589,654	5.64
1988	9,854,258	2.5	7,059,737	4.9	11,925,679	3.9	90,803	2.2	1,019,641	2.5	5,938,009	3.3	5,090,429	3.2	40,978,556	3.51
1989	9,942,971	0.9	7,378,331	4.5	12,344,506	3.5	93,660	3.1	1,060,617	4.0	6,016,311	1.3	5,318,182	4.5	42,154,578	2.87
1990	10,013,870	0.7	7,669,623	3.9	12,335,935	−0.1	95,640	2.1	1,067,179	0.6	6,211,715	3.2	5,268,712	−0.9	42,662,674	1.21
1991	10,282,550	2.7	7,410,470	−3.4	11,906,891	−3.5	95,500	−0.1	1,058,731	−0.8	6,063,351	−2.4	5,465,311	3.7	42,282,803	−0.89
1992	10,832,200	5.3	7,536,644	1.7	12,401,369	4.2	96,296	0.8	1,054,321	−0.4	6,151,281	1.5	5,429,553	−0.7	43,501,663	2.88
1993	11,345,861	4.7	7,805,383	3.6	12,938,376	4.3	96,777	0.5	1,059,592	0.5	6,465,966	5.1	5,622,707	3.6	45,334,661	4.21
1994	11,871,022	4.6	8,035,255	2.9	13,097,994	1.2	97,261	0.5	1,064,890	0.5	6,769,991	4.7	5,785,513	2.9	46,721,926	3.06
1995	12,314,361	3.7	8,179,257	1.8	13,156,908	0.4	97,747	0.5	1,070,215	0.5	6,896,754	1.9	5,899,728	2	47,614,969	1.91
1996	12,668,118	2.9	8,270,082	1.1	13,227,114	0.5	98,236	0.5	1,075,566	0.5	7,012,601	1.7	6,004,593	1.8	48,356,311	1.56
1997	12,978,268	2.4	8,337,808	0.8	13,317,067	0.7	98,727	0.5	1,080,944	0.5	7,141,530	1.8	6,110,861	1.8	49,065,203	1.47
1998	13,263,430	2.2	8,417,990	1.0	13,472,713	1.2	99,221	0.5	1,086,348	0.5	7,296,801	2.2	6,223,059	1.8	49,859,564	1.62
1999	13,532,088	2.0	8,508,859	1.1	13,613,987	1.0	99,717	0.5	1,091,780	0.5	7,478,701	2.5	6,338,850	1.9	50,663,982	1.61
2000	13,796,964	2.0	8,610,956	1.2	13,711,465	0.7	100,215	0.5	1,097,239	0.5	7,646,904	2.2	6,439,808	1.6	51,403,552	1.46
10 yr. Cmpd. 90–2000	3.3		1.2		1.1		0.5		0.3		2.1		2.0		1.9	
2001	14,031,574	1.7	8,692,760	0.9	13,800,477	0.6	100,717	0.5	1,102,725	0.5	7,824,943	2.3	6,540,537	1.6	52,093,733	1.34
2002	14,262,970	1.6	8,753,703	0.7	13,877,105	0.6	101,220	0.5	1,108,239	0.5	8,021,051	2.5	6,641,498	1.5	52,765,786	1.29
2003	14,486,851	1.6	8,819,827	0.8	13,934,726	0.4	101,726	0.5	1,113,780	0.5	8,221,178	2.5	6,742,416	1.5	53,420,504	1.24
2004	14,690,500	1.4	8,891,294	0.8	14,034,092	0.7	102,235	0.5	1,119,349	0.5	8,420,668	2.4	6,849,138	1.6	54,107,276	1.29
2005	14,883,522	1.3	8,975,700	0.9	14,195,639	1.2	102,746	0.5	1,124,946	0.5	8,630,873	2.5	6,961,318	1.6	54,874,743	1.42
2006	15,092,140	1.4	9,070,201	1.1	14,324,012	0.9	103,260	0.5	1,130,570	0.5	8,836,027	2.4	7,070,025	1.6	55,626,234	1.37
2007	15,301,986	1.4	9,180,834	1.2	14,455,455	0.9	103,776	0.5	1,136,223	0.5	9,048,116	2.4	7,189,974	1.7	56,416,366	1.42
2008	15,529,940	1.5	9,286,832	1.2	14,580,037	0.9	104,295	0.5	1,141,904	0.5	9,252,404	2.3	7,304,615	1.6	57,200,026	1.39
2009	15,773,111	1.6	9,389,832	1.1	14,704,503	0.9	104,816	0.5	1,147,614	0.5	9,451,444	2.2	7,418,842	1.6	57,990,163	1.38
2010	16,038,841	1.7	9,503,562	1.2	14,852,314	1.0	105,341	0.5	1,153,352	0.5	9,651,146	2.1	7,530,474	1.5	58,835,029	1.46
20 yr. Cmpd. 90–2010	2.4		1.1		0.9		0.5		0.4		2.2		1.8		1.6	

1991 – Same as Reference Case

Table II

SECTION I

Econometric Energy Forecast

In the Econometric Energy Forecast, we have regressed historical Total Residential Customers, All-Electric Use Per Customer, Water Heating Use Per Customer, Minimum Service Use Per Customer, Commercial Usage by SIC Code, Industrial Usage by SIC Code, Sales for Resale Usage, Other Sales to Public Authorities Usage, and Public Street and Highway Lighting Usage on independent variables which explain the variation of each dependent variable. In each case, the final specification reasonably explained the variation in the dependent variable and passed statistical tests of reliable coefficients. The coefficients were estimated using ordinary least squares, maximum likelihood, or transfer function techniques. In each case, the analysis was disaggregated to the extent of the availability of the data, and the interval was selected with the highest frequency of the available data in order to exploit the richness of the data. In most cases, monthly data was used over at least an 18-year interval for approximately 200 observations, or quarterly data for at least 18 years for at least 72 observations. In each grouping, the independent variables used along with the estimated coefficients and the applicable test statistics are shown for the final model. A plot shows visually the goodness-of-fit of the estimation with the actual data.

A forecast equation is formed from the coefficients of the independent variables in each model. Forecasted values of the economic independent variables from the CP&L Service Area Economic Model are used in these equations to produce a monthly or quarterly forecast. These forecast values are then summed to an annual frequency for the forecast summary.

I.1 RESIDENTIAL ECONOMETRIC FORECAST

1) Residential Customers

Historically, the total number of residential customers in the CP&L service area has correlated with the North and South Carolina stock of housing units and mobile homes. The level of long-run housing activity is a function of population growth, mortgage rates, depreciation of existing stock, and occupancy rate.

The total number of CP&L residential customers was regressed on the North and South Carolina stock of houses and mobile homes. The regression results and the applicable statistics are shown in Figure 1.

A plot of the actual and model values for total residential customers is shown in Figure 2. The fit, which is statistically summarized by the R-bar squared, shows a very high degree of correlation.

ORDINARY LEAST SQUARES

MONTHLY(1972:1 TO 1991:3) 231 OBSERVATIONS
DEPENDENT VARIABLE: XCURSA

	COEFFICIENT	STD. ERROR	T–STAT	INDEPENDENT VARIABLE
	3083.9	978.3	3.152	CONSTANT
1)	0.905686	0.02212	40.94	XCURSA\1
2)	113.982	41.51	2.746	KH&MH@NC&SC
3)	–97.6418	40.9	–2.388	KH&MH@NC&SC\1
4)	18256	1458	12.53	DUMXCUR@838

R–BAR SQUARED: 0.9998
F–STATISTIC(4,226): 247916.82
DURBIN–WATSON STATISTIC: 2.2300
DURBIN H–STATISTIC (LDV= 1): –1.8560
SUM OF SQUARED RESIDUALS: 4.775E+08
STANDARD ERROR OF THE REGRESSION: 1454 NORMALIZED: 0.002223

WHERE:

XCURSA	TOTAL RESIDENTIAL CUSTOMERS – SEASONALLY ADJUSTED
KH&MH@NC&SC	CAPITAL STOCK OF HOUSING AND MOBIL HOMES FOR NORTH AND SOUTH CAROLINA
DUMXCUR@838	RESIDENTIAL CUSTOMER DUMMY FOR 83:8

Figure 1

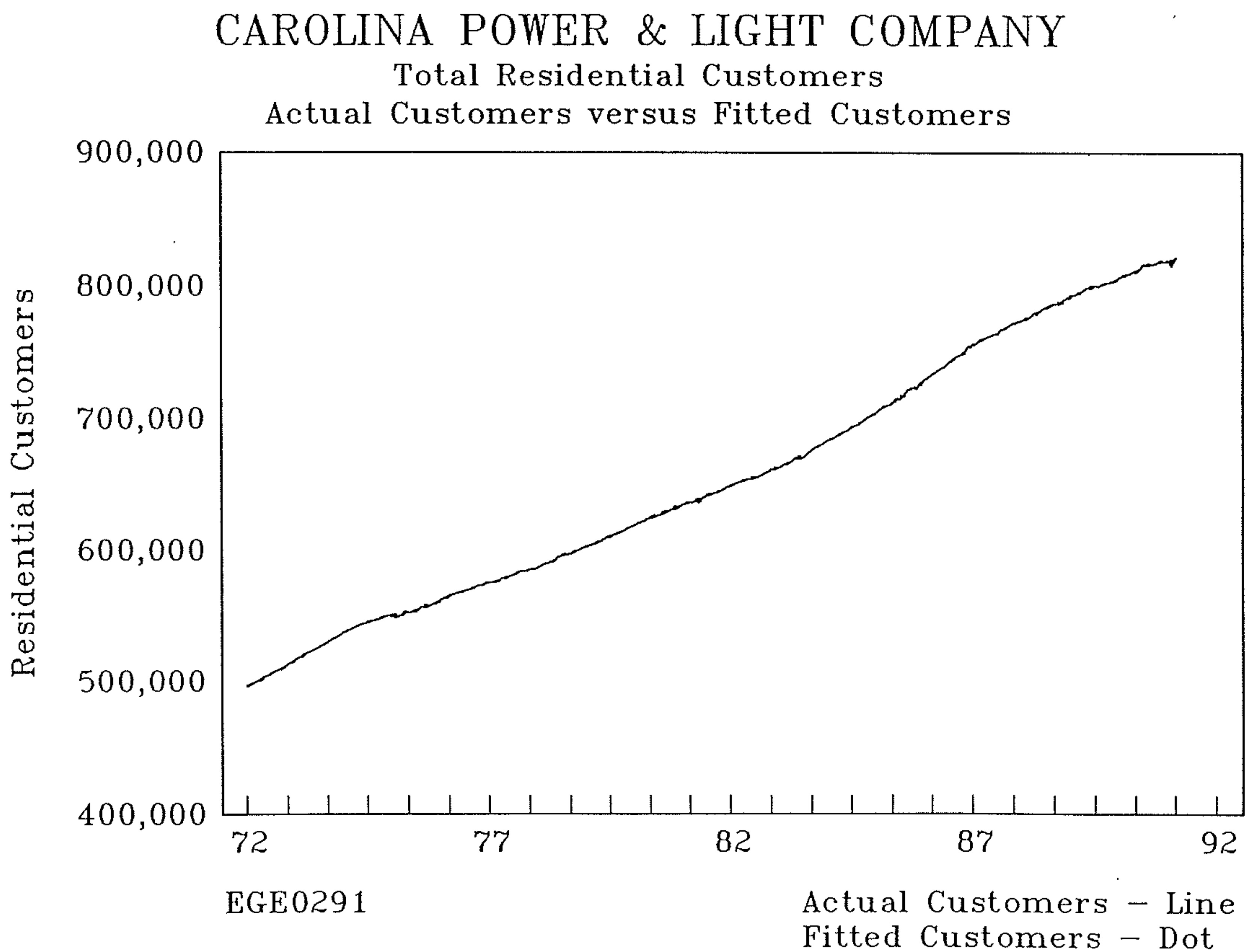

CAROLINA POWER & LIGHT COMPANY
Total Residential Customers
Actual Customers versus Fitted Customers
Residential Customers
900,000
800,000
700,000
600,000
500,000
400,000
72
77
82
87
92
EGE0291
Actual Customers – Line
Fitted Customers – Dot

Figure 2

For forecasting purposes, it is desirable to disaggregate total residential customers into those with electric space heat, electric water heating only, and minimum service. Prior to the oil embargo of 1973 and the subsequent rise in the price of fuel oil, there were approximately 6,000 to 7,000 water heating customers added per year who heated primarily with fuel oil. The saturation of electric heat was constantly increasing while the minimum service customers were declining. After 1974, the number of electric water heating customers added annually dropped appreciably. Due to conversions in existing houses, the number of net all-electric customers was approximately equal to the number of net new customers.

The percentage of the net total customers who were all-electric is shown in the following table:

TABLE III

	Percent Net Total New Customers Who Were All-Electric
1970	64%
1971	69%
1972	76%
1973	82%
1974	109%
1975	99%
1976	91%
1977	131%
1978	98%
1979	104%
1980	108%
1981	118%
1982	114%
1983	94%
1984	104%
1985	103%
1986	98%
1987	96%
1988	98%
1989	99%
1990	98%

Space heating and water heating fuel choices by residential customers have been modeled in the econometric forecast using a multinomial logit approach. Using life-cycle costing theory as a general guide, some residential customers will switch among the main available fuels of electricity, gas, and fuel oil based on the perceived relative cost of each fuel. Even though space heating and water heating appliances have lengthy life cycles, continuing new construction and retrofits affect the total number of customers in each subclass. The multinomial logit approach allows these fuel type choices to be modeled using income and relative prices. The results of the logit approach are percentage shares by each subclass. Each subclass share is multiplied by the total number of customers to obtain the number of customers making up each subclass for the service area.

The forecast proportions of all-electric, electric water heating, and minimum service residential customers have been cross-checked with the proportions projected from CP&L's residential end-use model.

Table IV shows the forecast for the average number of residential customers by class and subclass.

RESIDENTIAL CUSTOMERS BY CLASS & TOTAL (1986–2010)

	ALL ELECTRIC CUSTOMERS	WATER HEATER CUSTOMERS	MINIMUM USE CUSTOMERS	TOTAL CUSTOMERS
1986	310,737	339,883	90,360	740,980
1987	333,541	339,003	91,884	764,428
1988	351,224	337,677	93,427	782,328
1989	367,032	336,743	94,886	798,661
1990	380,742	335,569	97,033	813,344
1991	381,814	343,601	99,369	824,785
1992	387,131	352,075	97,442	836,648
1993	413,575	341,188	94,699	849,462
1994	443,447	329,022	91,069	863,537
1995	467,974	319,841	89,110	876,925
1996	486,835	314,974	88,261	890,070
1997	504,877	310,725	87,029	902,632
1998	523,141	305,632	85,909	914,682
1999	541,272	300,185	85,047	926,504
2000	560,129	294,666	83,996	938,790
2001	577,185	289,969	83,687	950,841
2002	594,518	284,828	83,501	962,847
2003	611,841	279,553	83,250	974,644
2004	627,839	274,734	83,014	985,587
2005	643,232	269,763	82,735	995,730
2006	660,083	263,733	82,035	1,005,851
2007	676,912	257,155	81,000	1,015,067
2008	693,652	250,933	80,030	1,024,616
2009	709,620	245,376	79,156	1,034,152
2010	725,140	240,081	78,411	1,043,632

1991 – Same as Reference Case

Table IV

2) **Residential All-Electric Use Per Customer**

Table V shows a summary of the forecast for the all-electric customers. The use per customer forecast equation came from a regression analysis where historical monthly usage was regressed on income, price, a structural shift price term, twelve seasonal dummies, winter weather, and summer weather.

Real Disposable Income per Capita. Personal and Disposable Income per Capita expressed in real and nominal dollars were among the wealth terms specified for all-electric use per customer. Since the use per customer has generally decreased since the mid-1970's while income has increased, the sign on the coefficient for wealth is negative. This required the income term to be omitted in the final estimation.

Weighted Heating Degree Days. The weather in the heating season is very significant with respect to usage as might be expected. In order to align the actual weather experienced during the period of the billed usage, it is necessary to weight the heating degree days by the actual meter reading cycles.

Approximately one-twentieth or five percent of CP&L's residential meters are read each meter reading cycle. The first cycle is read five work days before the first of the month and indicates the usage of the past month. The second cycle is read the following work day and so on until the twentieth cycle is read. The total of these usage readings is recorded as the monthly total. As an example, the total March 1988 residential billing was based on actual usage from January 27 to March 23. Because there is no weather tabulation which covers this period, it is necessary to construct one.

ALL ELECTRIC CUSTOMERS

	MHW/CUSTOMER	CUSTOMERS	TOTAL MWH
1986	15.432	310,737	4,795,429
1987	15.908	333,541	5,305,924
1988	15.840	351,224	5,563,393
1989	15.386	367,032	5,647,227
1990	14.858	380,742	5,657,102
1991	14.917	381,814	5,695,661
1992	16.406	387,131	6,366,950
1993	16.786	413,575	6,969,727
1994	17.051	443,447	7,593,273
1995	17.242	467,974	8,114,578
1996	17.372	486,835	8,518,753
1997	17.448	504,877	8,885,490
1998	17.486	523,141	9,239,240
1999	17.492	541,272	9,577,835
2000	17.474	560,129	9,911,311
2001	17.439	577,185	10,204,777
2002	17.389	594,518	10,494,275
2003	17.334	611,841	10,783,245
2004	17.279	627,839	11,053,895
2005	17.228	643,232	11,317,245
2006	17.187	660,083	11,603,582
2007	17.164	676,912	11,904,375
2008	17.165	693,652	12,214,679
2009	17.195	709,620	12,534,012
2010	17.259	725,140	12,876,703

1991 – Same as Reference Case

Table V

The first cycle of the March billing is read on February 25. The weather on that day then affects 5% of our customers. The second cycle is read on the next work day, and consequently the weather on this day affects the customers in the first and second cycles, or 10% of the total. Each day is calculated this way, and the results are used to weight the weather for the corresponding usage as it is billed.

Four weather stations are used to weight the billing cycle usage. New Hanover Airport, Asheville Airport, and the Raleigh-Durham Airport are used as representative of the North Carolina weather. These are the only Class A reporting stations in the CP&L service area. Professional employees record the weather conditions at these stations hourly, and a summary is published monthly by the National Oceanic & Atmospheric Administration.

Columbia Airport is used as representative of the South Carolina service area for several reasons. While Columbia is not in our service area, it has been determined by the National Weather Bureau that Columbia temperatures are representative of a geographic band extending from Columbia through Florence. Furthermore, we have done a study which verifies that the daily mean temperature from which heating and cooling degree days are calculated is not statistically different for the Florence and Columbia weather stations. By using Columbia weather as a proxy for Florence weather, more historical data is available as well.

Daily degree days for these four Class A stations are calculated and weighted for the effect of the billing cycle. Monthly degree days weighted by the residential sales in the CP&L Eastern Division, Central Region, Western Division, and Southern Division are then calculated for the final system weighted heating degree days.

The model indicates that approximately 8,000 kwh per customer per year are associated with heating degree days.

Weighted Cooling Degree Days. The system weighted cooling degree days are calculated exactly the same way as the system weighted heating degree days. In both cases, 65 degrees is used as the base. The model indicates that approximately 2,700 kwh per customer per year are associated with cooling degree days.

Average Real Price of Electricity. The nominal average price for the all-electric customers is deflated by the Consumer Price Index. The price term used is for the preceding month which generally corresponds to the period of usage. This "price response" term also captures the effect of those measures which customers take to conserve electricity. These measures include, for example, adding insulation, using wood stoves or fireplaces, installing storm windows, etc.

Marginal real price has also been researched for use in the residential models because of economic theory. The use of marginal real price produces negligible differences in the historical results and is difficult to forecast due to the unknown structure of future rate schedules. For these reasons, average real price has been used in the forecast models.

Seasonal Dummies. The use of twelve monthly constants in the regression is a combination of the regression constant and the seasonal factors. This form of seasonal adjustment is used because, in some cases, it produces an estimation of the base load for comparison purposes.

Conservation. Conservation activity models the effect of the second OPEC oil embargo of 1979 and the resultant shift in consumer behavior. This effect is in addition to the traditional consumer price response captured by the average real price of electricity.

There is more apparent effect of conservation in the all-electric customer class than in the water heating and minimum-use class. Because the all-electric usage is higher, there is more opportunity to conserve.

The model of all-electric usage is shown in Figure 3. An ARIMA analysis indicated that this regression required a first-order autoregressive correction and a seasonal first-order autoregressive correction. The ARIMA analysis is shown in Figure 4 and a plot of the actual values versus the fitted values of usage per customer is shown in Figure 5.

ORDINARY LEAST SQUARES

MONTHLY(1975:1 TO 1991:3) 195 OBSERVATIONS
DEPENDENT VARIABLE: M@CR2

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.0024442	9.628E-05	25.39	WHDD65R@CPL
2)	0.00179579	0.0002106	8.527	WCDD65R@CPL
3)	1.94016	0.1303	14.89	SEASONM01
4)	1.73321	0.128	13.54	SEASONM02
5)	1.48991	0.1216	12.25	SEASONM03
6)	1.42665	0.1153	12.37	SEASONM04
7)	1.51077	0.1146	13.18	SEASONM05
8)	1.18996	0.1365	8.718	SEASONM06
9)	1.21758	0.1485	8.198	SEASONM07
10)	1.24732	0.1601	7.793	SEASONM08
11)	1.23409	0.1505	8.202	SEASONM09
12)	1.18417	0.1379	8.589	SEASONM10
13)	1.61681	0.128	12.64	SEASONM11
14)	1.724	0.1241	13.89	SEASONM12
15)	-0.100417	0.02104	-4.773	SDUM*ARPER2\1
16)	-0.176012	0.01866	-9.432	WDUM*ARPER2\1
17)	-0.11659	0.006769	-17.22	OPECII*ARPER2\1

R-BAR SQUARED: 0.9671 (RELATIVE TO Y=0, RBSQ: 0.9964)
F-STATISTIC(17,178): 3168.2395
DURBIN-WATSON STATISTIC: 0.9023
DURBIN H-STATISTIC (LDV=1): 7.6645
SUM OF SQUARED RESIDUALS: 1.496
STANDARD ERROR OF THE REGRESSION: 0.09168 NORMALIZED: 0.06365

Figure 3

WHERE:

M@CR2	USAGE PER CUSTOMER – ALL ELECTRIC – (MEGAWATT HOURS)
WHDD65R@CPL	HEATING DEGREE DAYS – 65 BASE – WEIGHTED FOR BILLING CYCLES AND RESIDENTIAL SALES IN CP&L DIVISIONS
WCDD65R@CPL	COOLING DEGREE DAYS – 65 BASE – WEIGHTED FOR BILLING CYCLES AND RESIDENTIAL SALES IN CP&L DIVISIONS
ARPER2	AVERAGE REAL PRICE OF ELECTRICITY ALL ELECTRIC
SEASONM01	SEASONAL DUMMY FOR JANUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1= THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1= THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1= THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1= THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1= THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1= THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1= THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1= THEREIN, 0 ELSEWHERE)
WDUM	WINTER DUMMY (1=NOVEMBER – JUNE, 0 ELSEWHERE)
SDUM	SUMMER DUMMY (1= JULY – OCTOBER, 0 ELSEWHERE)
OPECII	CONSERVATION RESPONSE TO 1979 OIL PRICE SHOCK

Figure 3 (cont'd.)

COMBINED ARIMA/REGRESSION ANALYSIS

CONVERGENCE TOLERANCE....0.01

	DEGREE OF AUTOREGRESSIVE PROCESS	DEGREE OF MOVING AVERAGE PROCESS
NON-SEASONAL	1	0
SEASONAL	1	0

PERIOD OF SEASONALITY....12

CONVERGED AFTER 2 ITERATIONS

ORDINARY LEAST SQUARES

MONTHLY(1976:2 TO 1991:3) 182 OBSERVATIONS
DEPENDENT VARIABLE: WM@CR2

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.00244636	7.501E-05	32.62	WHDD65R@CPL
2)	0.00176543	0.000162	10.9	WCDD65R@CPL
3)	1.77937	0.1027	17.32	SEASONM01
4)	1.5877	0.1005	15.81	SEASONM02
5)	1.35596	0.09553	14.19	SEASONM03
6)	1.29717	0.09157	14.17	SEASONM04
7)	1.40203	0.0916	15.31	SEASONM05
8)	1.15973	0.1181	9.822	SEASONM06
9)	1.19605	0.1261	9.483	SEASONM07
10)	1.22407	0.1354	9.043	SEASONM08
11)	1.20902	0.1281	9.438	SEASONM09
12)	1.1539	0.1203	9.592	SEASONM10
13)	1.47063	0.1023	14.38	SEASONM11
14)	1.56032	0.09769	15.97	SEASONM12
15)	−0.0947429	0.01838	−5.154	SDUM*ARPER2\1
16)	−0.155584	0.01489	−10.45	WDUM*ARPER2\1
17)	−0.107377	0.00598	−17.95	OPECII*ARPER2\1

R-BAR SQUARED: 0.9799 (RELATIVE TO Y=0, RBSQ: 0.9979)
F-STATISTIC(17,165): 5070.0938
DURBIN-WATSON STATISTIC: 2.0097
DURBIN H-STATISTIC (LDV= 1): −0.065698
SUM OF SQUARED RESIDUALS: 0.7834
STANDARD ERROR OF THE REGRESSION: 0.06890 NORMALIZED: 0.04850

Figure 4

STOCHASTIC ARIMA ANALYSIS

MONTHLY(1975:1 TO 1991:3) 195 OBSERVATIONS
VARIABLE NAME: OLDERROR
DEGREE OF DIFFERENCING = 0
DEGREE OF SEASONAL DIFFERENCING = 0
PERIOD OF SEASONALITY = 12

MAXIMUM LIKELIHOOD COEFFICIENT ESTIMATES:

COEFFICIENT	STD. ERROR*	T-STAT	PARAMETER
0.5015	0.06282	7.983	PHI 1
0.4294	0.06925	6.2	SEASONAL PHI 1

* MAXIMUM LIKELIHOOD ESTIMATE, WITHOUT DEGREES-OF-FREEDOM CORRECTION

LOG-LIKELIHOOD = 132.38352645
STANDARD ERROR OF INNOVATION = 0.06578
STANDARD ERROR WITH DEGREES-OF-FREEDOM CORRECTION = 0.06612

ANALYSIS OF THE RESIDUALS
MEAN = -0.002, STANDARD DEVIATION = 0.066

AUTOCORRELATION STATISTICS:
APPROXIMATE STANDARD ERROR = 0.074
Q-STATISTIC, CHI-SQUARED (22 D.F.) = 45.560
LJUNG-BOX Q-STATISTIC = 50.1920

LAG	AUTO- CORR.	T-STAT	AUTO- COVAR.	-1 - - - - - - - - - 0 + + + + + + + + + 1
1	-0.027	-0.361	0.000	(**)
2	-0.023	-0.305	0.000	(*)
3	-0.005	-0.071	0.000	(*)
4	0.107	1.442	0.000	(***)
5	0.08	1.075	0.000	(***)
6	0.162	2.183	0.001	(****
7	-0.058	-0.779	0.000	(**)
8	0.091	1.234	0.000	(***)
9	-0.075	-1.015	0.000	(***)
10	-0.041	-0.56	0.000	(**)
11	0.086	1.164	0.000	(***)
12	-0.002	-0.032	0.000	(*)
13	0.151	2.032	0.001	(****
14	-0.14	-1.883	-0.001	****)
15	-0.043	-0.573	0.000	(**)

LAG	PARTIAL ACOR.	T-STAT	-1 - - - - - - - - - 0 + + + + + + + + + 1
1	-0.027	-0.361	(**)
2	-0.023	-0.315	(*)
3	-0.006	-0.088	(*)
4	0.106	1.432	(***)
5	0.086	1.164	(***)
6	0.175	2.363	(***)*
7	-0.041	-0.551	(**)
8	0.09	1.221	(***)
9	-0.095	-1.277	(***)
10	-0.09	-1.21	(***)
11	0.06	0.807	(**)
12	-0.045	-0.61	(**)
13	0.192	2.586	(***)*
14	-0.153	-2.06	****)
15	0.004	0.052	(*)

Figure 4 (cont'd.)

CAROLINA POWER & LIGHT COMPANY

Residential Usage per Customer - All-Electric
Actual Usage versus Fitted Usage

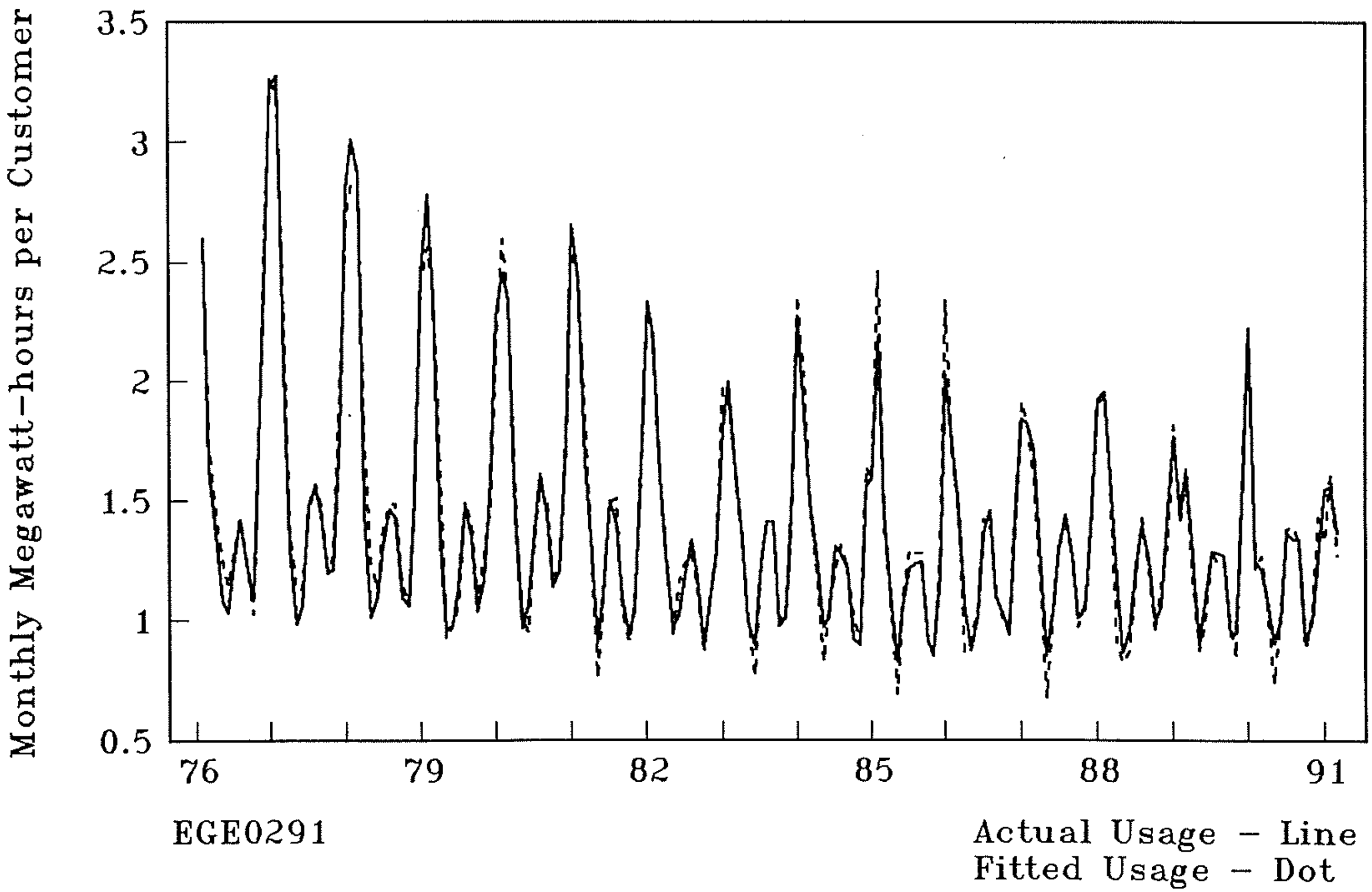


Figure 5

To forecast with this model, it is necessary to have a monthly series of forecasted values of each of the independent variables in the regression equation. For the all-electric use per customer equation, the values came from the following sources:

Weighted Normal Heating Degree Days - Calculated by CP&L

Weighted Normal Cooling Degree Days - Calculated by CP&L

Conservation Effect - Represented by response to price

Average Real Price of Electricity for All-Electric Customers - Calculated by CP&L

Seasonal Dummies - 1 for the given month and 0 elsewhere

3) Residential Water Heating Customers Use Per Customer

Table VI shows a summary of the forecast for the water heating customers. The use per customer forecast equation came from a regression analysis where historical monthly usage for water heating customers was regressed on income, price, a conservation term, twelve seasonal dummies, winter weather, and summer weather.

Real disposable income per capita was significant and positive for water heating customers. Summer weather affected usage of these customers more than winter weather, while the converse was true for the all-electric customers.

Weighted Heating Degree Days. The same heating degree days were used for the water heating customers as were used for the all-electric customers. The results indicate that approximately 1,300 kwh per year per customer are associated with heating degree days.

Cold weather not only affects the water temperature entering electric water heaters, but it also affects the electric usage of oil-fired and gas-fired heating systems. For example, residential central warm air furnace systems require approximately 1 kwh to run the furnace fan for each gallon of fuel oil burned.

WATER HEATER CUSTOMERS

	MWH/CUSTOMER	CUSTOMERS	TOTAL MWH
1986	10.461	339,883	3,555,602
1987	10.628	339,003	3,602,931
1988	10.558	337,677	3,565,085
1989	10.510	336,743	3,539,334
1990	10.593	335,569	3,554,773
1991	10.267	343,601	3,527,732
1992	10.451	352,075	3,688,661
1993	10.536	341,188	3,609,193
1994	10.603	329,022	3,503,427
1995	10.664	319,841	3,430,227
1996	10.721	314,974	3,401,531
1997	10.756	310,725	3,371,083
1998	10.782	305,632	3,328,449
1999	10.816	300,185	3,284,586
2000	10.850	294,666	3,237,531
2001	10.882	289,969	3,199,173
2002	10.926	284,828	3,159,078
2003	10.972	279,553	3,118,569
2004	11.015	274,734	3,083,482
2005	11.057	269,763	3,046,120
2006	11.103	263,733	2,994,979
2007	11.149	257,155	2,937,517
2008	11.197	250,933	2,882,501
2009	11.246	245,376	2,834,636
2010	11.296	240,081	2,790,275

1991 – Same as Reference Case

Table VI

Weighted Cooling Degree Days. The same cooling degree days were used for water heating customers as were used for all-electric customers. The results indicate that for the average water heating customer, approximately 1,800 kwh per year are associated with cooling degree days.

Average Real Price of Electricity. The water heating customer's average real price of electricity for the preceding month was used in the regression. Two separate price concepts were used and they are exclusive of each other. The first price concept estimates price response during the winter months, while the second concept estimates the price response during the summer months.

The coefficients on these variables indicate that due to price response, water heating customers will reduce usage by approximately 120 kwh in the eight winter months for each one cent real price increase, and will reduce usage by approximately 100 kwh in the four summer months for the same price increase. The total indicates approximately a 200 kwh reduction in annual usage for each one cent real price increase.

Conservation. Conservation was statistically insignificant for the water heating customers. However, by dropping the explicit conservation term, the price response effect increased accordingly.

Seasonal Dummies. As with the all-electric customers, these dummies capture the seasonal variation which is cyclic but not related to weather.

Real Disposable Income per Capita. Real disposable income per capita averaged over the past twelve months is a measure of an individual's permanent disposable income. As this indicator increases, there is a general expectation of future increases in income, and additional electric consumption is a likely result.

With the water heating customers, expectation of future increases in income frequently result in the purchase of air conditioning units.

The model of water heating usage is shown in Figure 6 and the ARIMA analysis in Figure 7. A plot of the actual values versus the fitted values of use per customer is shown in Figure 8.

For the forecast, it is necessary to have a monthly series of forecasted values of each of the independent variables in the regression equation. For the water heating use per customer, the values came from the following sources:

Weighted Normal Heating Degree Days - Calculated by CP&L

Weighted Normal Cooling Degree Days - Calculated by CP&L

Average Real Price of Electricity for Water Heating Customers -
Calculated by CP&L

Seasonal Dummies - 1 for the given month and 0 elsewhere

Real Disposable Income per Capita - CP&L's Service Area Economic Model

Real disposable income per capita in the CP&L service area is forecast to increase at an average annual rate of 1.4% from 1991 to 2011.

ORDINARY LEAST SQUARES

MONTHLY(1972:1 TO 1991:3) 231 OBSERVATIONS
DEPENDENT VARIABLE: M@CR3

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.000390947	2.471E-05	15.82	WHDD65R@CPL
2)	0.00110824	5.324E-05	20.82	WCDD65R@CPL
3)	0.538182	0.02999	17.95	SEASONM01
4)	0.467191	0.02971	15.73	SEASONM02
5)	0.47226	0.02804	16.84	SEASONM03
6)	0.48928	0.02606	18.78	SEASONM04
7)	0.459498	0.02531	18.15	SEASONM05
8)	0.485869	0.02889	16.82	SEASONM06
9)	0.500129	0.03119	16.04	SEASONM07
10)	0.518552	0.03319	15.62	SEASONM08
11)	0.510422	0.03134	16.29	SEASONM09
12)	0.491165	0.02884	17.03	SEASONM10
13)	0.480574	0.02626	18.3	SEASONM11
14)	0.500231	0.02764	18.1	SEASONM12
15)	−0.0134122	0.003401	−3.943	WDUM*ARPER3\1
16)	−0.019982	0.004306	−4.641	SDUM*ARPER3\1
17)	0.0245088	0.002764	8.869	MOVAVG(12 TO 1,RYDN@CPL)

R−BAR SQUARED: 0.9559 (RELATIVE TO Y=0, RBSQ: 0.9991)
F−STATISTIC(17,214): 14950.949
DURBIN−WATSON STATISTIC: 1.4242
DURBIN H−STATISTIC (LDV= 1): 4.3755
SUM OF SQUARED RESIDUALS: 0.1426
STANDARD ERROR OF THE REGRESSION: 0.02581 NORMALIZED: 0.03045

Figure 6

WHERE:

M@CR3	USAGE PER CUSTOMER – WATER HEATER – (MEGAWATT HOURS)
WHDD65R@CPL	HEATING DEGREE DAYS – 65 – BASE – WEIGHTED FOR BILLING CYCLES AND RESIDENTIAL SALES IN CP&L DIVISIONS
WCDD65R@CPL	COOLING DEGREE DAYS – 65 BASE – WEIGHTED FOR BILLING CYCLES AND RESIDENTIAL SALES IN CP&L DIVISIONS
ARPER3	AVERAGE REAL PRICE OF ELECTRICITY – WATER HEATER
SEASONM01	SEASONAL DUMMY FOR JANUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1= THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1= THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1= THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1= THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1= THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1= THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1= THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1= THEREIN, 0 ELSEWHERE)
RYDN@CPL	REAL DISPOSABEL PERSONAL PER CAPITA INCOME
WDUM	WINTER DUMMY (1= NOVEMBER – JUNE, 0 ELSEWHERE)
SDUM	SUMMER DUMMY (1= JULY – OCTOBER, 0 ELSEWHERE)

Figure 6 (cont'd.)

COMBINED ARIMA/REGRESSION ANALYSIS

CONVERGENCE TOLERANCE....0.01

	DEGREE OF AUTOREGRESSIVE PROCESS	DEGREE OF MOVING AVERAGE PROCESS
NON-SEASONAL	0	1
SEASONAL	0	0

CONVERGED AFTER 1 ITERATIONS

ORDINARY LEAST SQUARES

MONTHLY(1972:1 TO 1991:3) 231 OBSERVATIONS
DEPENDENT VARIABLE: WM@CR3

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.000404084	2.312E-05	17.47	WHDD65R@CPL
2)	0.00113009	4.982E-05	22.68	WCDD65R@CPL
3)	0.532059	0.02807	18.96	SEASONM01
4)	0.461224	0.0278	16.59	SEASONM02
5)	0.468128	0.02624	17.84	SEASONM03
6)	0.487617	0.02439	19.99	SEASONM04
7)	0.459552	0.02369	19.4	SEASONM05
8)	0.484226	0.02704	17.91	SEASONM06
9)	0.495248	0.02919	16.97	SEASONM07
10)	0.512463	0.03106	16.5	SEASONM08
11)	0.505487	0.02933	17.23	SEASONM09
12)	0.48984	0.02699	18.15	SEASONM10
13)	0.480434	0.02458	19.55	SEASONM11
14)	0.497294	0.02587	19.22	SEASONM12
15)	-0.0142903	0.003183	-4.489	WDUM*ARPER3\1
16)	-0.0208425	0.00403	-5.172	SDUM*ARPER3\1
17)	0.0247753	0.002586	9.579	MOVAVG(12 TO 1,RYDN@CPL)

R-BAR SQUARED: 0.9614 (RELATIVE TO Y=0, RBSQ: 0.9992)
F-STATISTIC(17,214): 17071.012
DURBIN-WATSON STATISTIC: 2.0650
DURBIN H-STATISTIC (LDV= 1): -0.49411
SUM OF SQUARED RESIDUALS: 0.1249
STANDARD ERROR OF THE REGRESSION: 0.02416 NORMALIZED: 0.02850

Figure 7

STOCHASTIC ARIMA ANALYSIS

MONTHLY(1972:1 TO 1991:3) 231 OBSERVATIONS
VARIABLE NAME: OLDERROR
DEGREE OF DIFFERENCING = 0
DEGREE OF SEASONAL DIFFERENCING = 0
PERIOD OF SEASONALITY = 12

MAXIMUM LIKELIHOOD COEFFICIENT ESTIMATES:

COEFFICIENT	STD. ERROR*	T-STAT	PARAMETER
-0.41123	0.06003	-6.85	THETA 1

* MAXIMUM LIKELIHOOD ESTIMATE, WITHOUT DEGREES-OF-FREEDOM CORRECTION

LOG-LIKELIHOOD = 261.68822253
STANDARD ERROR OF INNOVATION = 0.02328
STANDARD ERROR WITH DEGREES-OF-FREEDOM CORRECTION = 0.02333

ANALYSIS OF THE RESIDUALS
MEAN = 0.000, STANDARD DEVIATION = 0.023

AUTOCORRELATION STATISTICS:
APPROXIMATE STANDARD ERROR = 0.066
Q-STATISTIC, CHI-SQUARED (23 D.F.) = 42.102
LJUNG-BOX Q-STATISTIC = 44.8156

LAG	AUTO-CORR.	T-STAT	AUTO-COVAR.	-1 - - - - - - - - - 0 + + + + + + + + + 1
1	-0.037	-0.557	-0.000	(**)
2	-0.099	-1.501	-0.000	(***)
3	-0.069	-1.042	-0.000	(**)
4	-0.108	-1.638	-0.000	(***)
5	0.099	1.503	0.000	(***)
6	0.131	1.987	0.000	(****
7	0.018	0.267	-0.000	(*)
8	-0.058	-0.888	-0.000	(**)
9	-0.073	-1.107	0.000	(**)
10	0.003	0.039	0.000	(*)
11	0.111	1.691	0.000	(***)
12	0.175	2.657	0.000	(****
13	0.039	0.593	0.000	(**)
14	0	-0.002	-0.000	(*)
15	-0.155	-2.349	-0.000	****)

LAG	PARTIAL ACOR.	T-STAT	-1 - - - - - - - - - 0 + + + + + + + + + 1
1	-0.037	-0.557	(**)
2	-0.1	-1.524	(***)
3	-0.077	-1.171	(***)
4	-0.126	-1.919	****)
5	0.074	1.129	(**)
6	0.114	1.726	(***)
7	0.034	0.511	(**)
8	-0.033	-0.504	(**)
9	-0.04	-0.602	(**)
10	0.009	0.142	(*)
11	0.084	1.279	(***)
12	0.162	2.464	(****
13	0.076	1.152	(***)
14	0.076	1.154	(***)
15	-0.097	-1.477	(***)

Figure 7 (cont'd.)

CAROLINA POWER & LIGHT COMPANY

Residential Usage per Customer - Water Heater
Actual Usage versus Fitted Usage

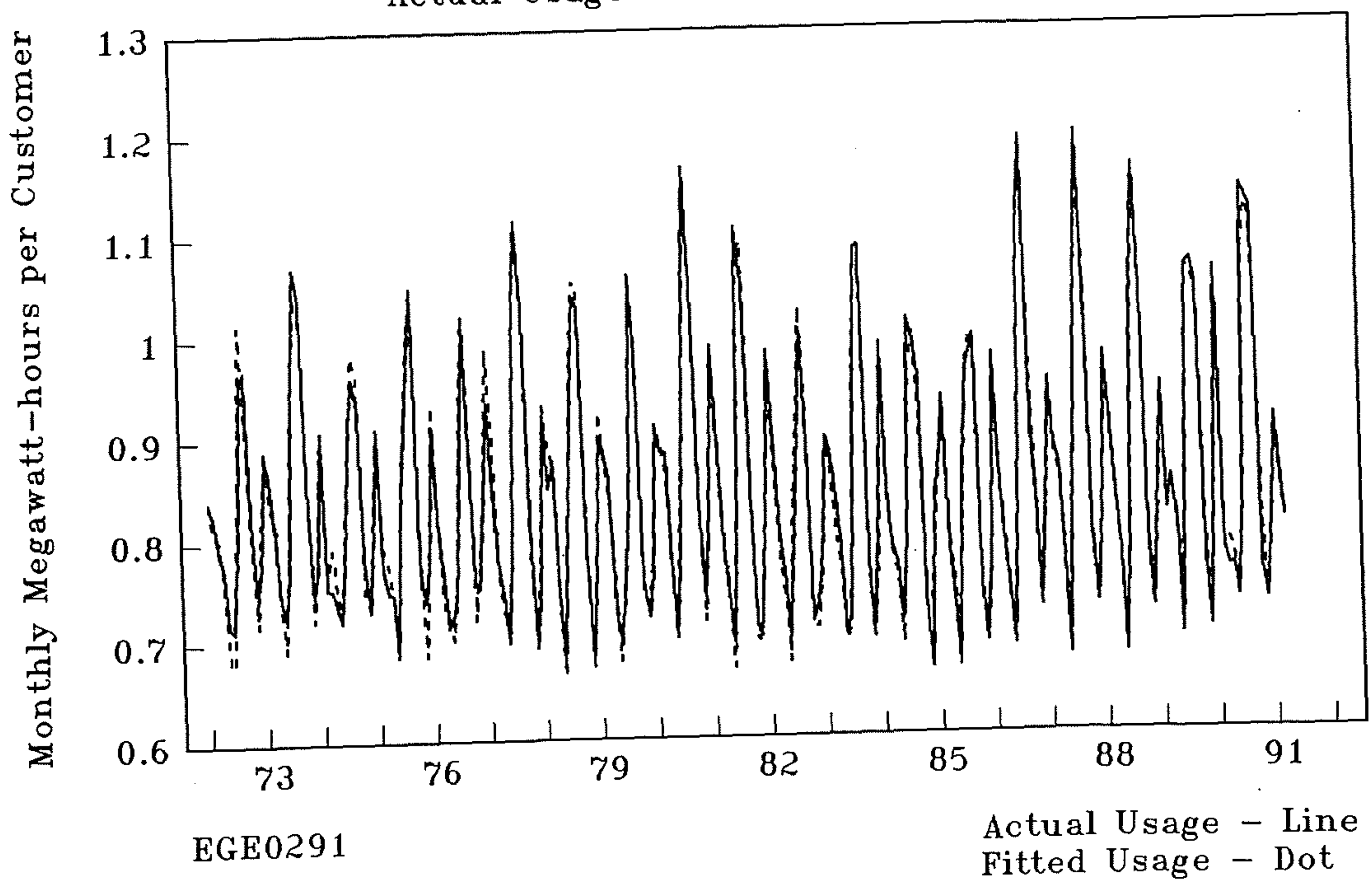


Figure 8

4) **Residential Minimum-Service Customers Use Per Customer**

Table VII shows the summary of the forecast for minimum-service customers. The use per customer forecast equation came from a regression analysis where historical monthly usage for minimum-service customers was regressed on income, winter weather, real price, summer weather, and twelve seasonal dummies.

The initial specification for the minimum-service use per customer was similar to the initial specification for the all-electric and water heating use per customer. The coefficients on the winter price term and the conservation term were not statistically significant in the first estimation. Real disposable income, however, was highly significant for the minimum-service class.

Seasonal Dummies. These dummies are used to seasonally adjust the cyclic variations in usage which are not associated with the weather.

Real Disposable Income per Capita. The use per customer for the minimum-service customers is highly correlated with real disposable income per capita in the CP&L service area. The coefficient on income is higher than the corresponding coefficient for the water heating customers when using the same values for income. As a result of historic income and air conditioning growth, the minimum-service use per customer is growing faster in percentage terms than other classes within the residential sector.

Average Real Price. The average real price response of the minimum-service customers was not statistically significant in the winter. There was a small response in the summer. Many of these customers use natural or bottle gas for space heating, water heating, and cooking. For these customers, air conditioning is a major electric end-use.

MINIMUM USE CUSTOMERS

	MWH/CUSTOMER	CUSTOMERS	TOTAL MWH
1986	6.841	90,360	618,159
1987	6.999	91,884	643,128
1988	7.045	93,427	658,197
1989	7.200	94,886	683,146
1990	7.458	97,033	723,715
1991	7.166	99,369	712,107
1992	7.250	97,442	708,191
1993	7.368	94,699	700,508
1994	7.479	91,069	683,951
1995	7.596	89,110	680,679
1996	7.713	88,261	685,688
1997	7.798	87,029	684,512
1998	7.875	85,909	683,346
1999	7.970	85,047	685,729
2000	8.067	83,996	686,184
2001	8.166	83,687	692,869
2002	8.285	83,501	702,263
2003	8.407	83,250	711,586
2004	8.525	83,014	721,074
2005	8.640	82,735	730,001
2006	8.759	82,035	734,935
2007	8.876	81,000	736,644
2008	8.994	80,030	738,414
2009	9.108	79,156	740,600
2010	9.220	78,411	743,814

1991 – Same as Reference Case

Table VII

<u>Weighted Cooling Degree Days</u>. The cooling degree days used in the regression were identical to those used in the all-electric and water heating regressions. It was found that cooling degree days alone did not adequately explain summer usage. It was necessary to add a time trend to capture the growth in the effect of cooling degree days as the saturation of air conditioning increased.

CP&L customer surveys show an increase in air conditioning saturation for minimum-service customers since 1970. When one of these customers who is averaging 400 kwh per month in the summer adds central air conditioning, usage could jump to 1400 kwh per month. As air conditioning saturation increases from year to year, a given number of cooling degree days will significantly increase the average use per customer.

To capture this increase in saturation of air conditioners in the minimum-service class, the weighted cooling degree days were multiplied by a linear time series. This addition to the specification gave an R-bar square of .9809.

The original regression analysis is shown in Figure 9. The ARIMA analysis is shown in Figure 10 and the plot of the minimum-service use per customer actual values versus fitted values is shown in Figure 11.

For the forecast, it is necessary to have a monthly series of forecasted values for each of the independent variables in the regression equation. For the minimum-service customers, the values came from the following sources:

Weighted Normal Heating Degree Days - Calculated by CP&L
Weighted Normal Cooling Degree Days - Calculated by CP&L
Real Disposable Income - CP&L Service Area Economic Model
Seasonal Dummies - 1 for the given month and 0 elsewhere
Average Real Price of Electricity for Minimum Service Customers - Calculated by CP&L

Real disposable income in the CP&L service area is forecast to increase at an average annual rate of 1.4% from 1991 to 2011.

ORDINARY LEAST SQUARES

MONTHLY(1972:1 TO 1991:3) 231 OBSERVATIONS
DEPENDENT VARIABLE: M@CR4

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.000198887	1.907E-05	10.43	WHDD65R@CPL
2)	2.1729E-06	8.688E-08	25.01	WCDD65R@CPL*TIME
3)	0.016469	0.02454	0.671	SEASONM01
4)	-0.0258311	0.02438	-1.06	SEASONM02
5)	-0.0275688	0.02283	-1.208	SEASONM03
6)	-0.01619	0.02075	-0.7803	SEASONM04
7)	-0.0349483	0.01922	-1.819	SEASONM05
8)	0.0799208	0.0366	2.184	SEASONM06
9)	0.0782308	0.0355	2.203	SEASONM07
10)	0.0921608	0.03582	2.573	SEASONM08
11)	0.0850734	0.03454	2.463	SEASONM09
12)	0.0855095	0.03501	2.442	SEASONM10
13)	-0.00985235	0.02004	-0.4917	SEASONM11
14)	0.00093693	0.02218	0.04225	SEASONM12
15)	0.0384618	0.002506	15.35	MOVAVG(12 TO 1,RYDN@CPL)
16)	-0.0156308	0.0045	-3.474	SDUM*ARPER4\1
17)	0.0571424	0.004112	13.9	WDUM*SHIFT801&
18)	0.0357527	0.005654	6.324	SDUM*SHIFT801&

R-BAR SQUARED: 0.9751 (RELATIVE TO Y=0, RBSQ: 0.9984)
F-STATISTIC(18,213): 8116.3537
DURBIN-WATSON STATISTIC: 1.1856
DURBIN H-STATISTIC (LDV= 1): 6.1892
SUM OF SQUARED RESIDUALS: 0.08870
STANDARD ERROR OF THE REGRESSION: 0.02041 NORMALIZED: 0.04105

Figure 9

WHERE:

M@CR4	USAGE PER CUSTOMER – MINIMUM SERVICE – (MEGAWATT HOURS)
WHDD65R@CPL	HEATING DEGREE DAYS – 65 – BASE – WEIGHTED FOR BILLING CYCLES AND RESIDENTIAL SALES IN CP&L DIVISIONS
WCDD65R@CPL	COOLING DEGREE DAYS – 65 BASE – WEIGHTED FOR BILLING CYCLES AND RESIDENTIAL SALES IN CP&L DIVISIONS
TIME	TIME TREND
SEASONM01	SEASONAL DUMMY FOR JANUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1= THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1= THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1= THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1= THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1= THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1= THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1= THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1= THEREIN, 0 ELSEWHERE)
WDUM	WINTER DUMMY (1= NOVEMBER – JUNE, 0 ELSEWHERE)
SDUM	SUMMER DUMMY (1= JULY – OCTOBER, 0 ELSEWHERE)
SHIFT801&	SHIFT VARIABLE FOR 80:1
RYDN@CPL	REAL DISPOSABLE PERSONAL PER CAPITA INCOME
ARPER4	AVERAGE REAL PRICE OF ELECTRICITY – MINIMUM USE

Figure 9 (cont'd.)

COMBINED ARIMA/REGRESSION ANALYSIS

CONVERGENCE TOLERANCE....0.01

	DEGREE OF AUTOREGRESSIVE	DEGREE OF MOVING AVERAGE
PROCESS	PROCESS	PROCESS
NON-SEASONAL	1	0
SEASONAL	1	0

PERIOD OF SEASONALITY....12

CONVERGED AFTER 1 ITERATIONS

ORDINARY LEAST SQUARES

MONTHLY(1973:2 TO 1991:3) 218 OBSERVATIONS
DEPENDENT VARIABLE: WM@CR4

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.000201978	1.718E-05	11.75	WHDD65R@CPL
2)	2.1500E-06	7.918E-08	27.15	WCDD65R@CPL*TIME
3)	0.00611039	0.02293	0.2664	SEASONM01
4)	-0.0383974	0.02258	-1.701	SEASONM02
5)	-0.038613	0.0211	-1.83	SEASONM03
6)	-0.0271769	0.01912	-1.421	SEASONM04
7)	-0.0464623	0.01769	-2.627	SEASONM05
8)	0.073047	0.03336	2.19	SEASONM06
9)	0.0759478	0.03251	2.336	SEASONM07
10)	0.0895596	0.03288	2.724	SEASONM08
11)	0.0795634	0.03176	2.505	SEASONM09
12)	0.0772415	0.03204	2.411	SEASONM10
13)	-0.0205235	0.01845	-1.113	SEASONM11
14)	-0.00833806	0.02045	-0.4077	SEASONM12
15)	0.0398406	0.002263	17.6	MOVAVG(12 TO 1,RYDN@CPL)
16)	-0.01623	0.004014	-4.043	SDUM*ARPER4\1
17)	0.0550608	0.003634	15.15	WDUM*SHIFT801&
18)	0.0369361	0.004973	7.427	SDUM*SHIFT801&

R-BAR SQUARED: 0.9809 (RELATIVE TO Y=0, RBSQ: 0.9988)
F-STATISTIC(18,200): 10351.901
DURBIN-WATSON STATISTIC: 1.9182
DURBIN H-STATISTIC (LDV= 1): 0.60360
SUM OF SQUARED RESIDUALS: 0.06328
STANDARD ERROR OF THE REGRESSION: 0.01779 NORMALIZED: 0.03528

Figure 10

STOCHASTIC ARIMA ANALYSIS

MONTHLY(1972:1 TO 1991:3) 231 OBSERVATIONS
VARIABLE NAME: OLDERROR
DEGREE OF DIFFERENCING = 0
DEGREE OF SEASONAL DIFFERENCING = 0
PERIOD OF SEASONALITY = 12

MAXIMUM LIKELIHOOD COEFFICIENT ESTIMATES:

COEFFICIENT	STD. ERROR*	T-STAT	PARAMETER
0.399	0.06044	6.602	PHI 1
0.27325	0.06716	4.069	SEASONAL PHI 1

* MAXIMUM LIKELIHOOD ESTIMATE, WITHOUT DEGREES-OF-FREEDOM CORRECTION

LOG-LIKELIHOOD = 291.44040472
STANDARD ERROR OF INNOVATION = 0.01727
STANDARD ERROR WITH DEGREES-OF-FREEDOM CORRECTION = 0.01735

ANALYSIS OF THE RESIDUALS
MEAN = 0.000, STANDARD DEVIATION = 0.017

AUTOCORRELATION STATISTICS:
APPROXIMATE STANDARD ERROR = 0.068
Q-STATISTIC, CHI-SQUARED (22 D.F.) = 47.262
LJUNG-BOX Q-STATISTIC = 50.7591

LAG	AUTO-CORR.	T-STAT	AUTO-COVAR.	-1 - - - - - - - - - 0 + + + + + + + + + 1
1	0.038	0.558	0.000	(**)
2	-0.131	-1.936	-0.000	****)
3	0.018	0.271	0.000	(*)
4	-0.036	-0.537	-0.000	(**)
5	0.094	1.392	0.000	(***)
6	0.217	3.203	0.000	(***)*
7	0.046	0.674	0.000	(**)
8	-0.042	-0.626	-0.000	(**)
9	-0.07	-1.034	-0.000	(**)
10	0.038	0.555	0.000	(**)
11	0.029	0.428	0.000	(**)
12	-0.016	-0.231	-0.000	(*)
13	0.068	1.002	0.000	(**)
14	0	0.003	0.000	(*)
15	-0.18	-2.661	-0.000	*(***)

LAG	PARTIAL ACOR.	T-STAT	-1 - - - - - - - - - 0 + + + + + + + + + 1
1	0.038	0.558	(**)
2	-0.133	-1.96	****)
3	0.03	0.436	(**)
4	-0.057	-0.842	(**)
5	0.107	1.587	(***)
6	0.2	2.958	(***)*
7	0.063	0.925	(**)
8	0.004	0.054	(*)
9	-0.065	-0.957	(**)
10	0.04	0.592	(**)
11	-0.029	-0.426	(**)
12	-0.06	-0.886	(**)
13	0.049	0.728	(**)
14	0.008	0.121	(*)
15	-0.152	-2.25	****)

Figure 10 (cont'd.)

CAROLINA POWER & LIGHT COMPANY
Residential Usage per Customer - Minimum Use
Actual Usage versus Fitted Usage

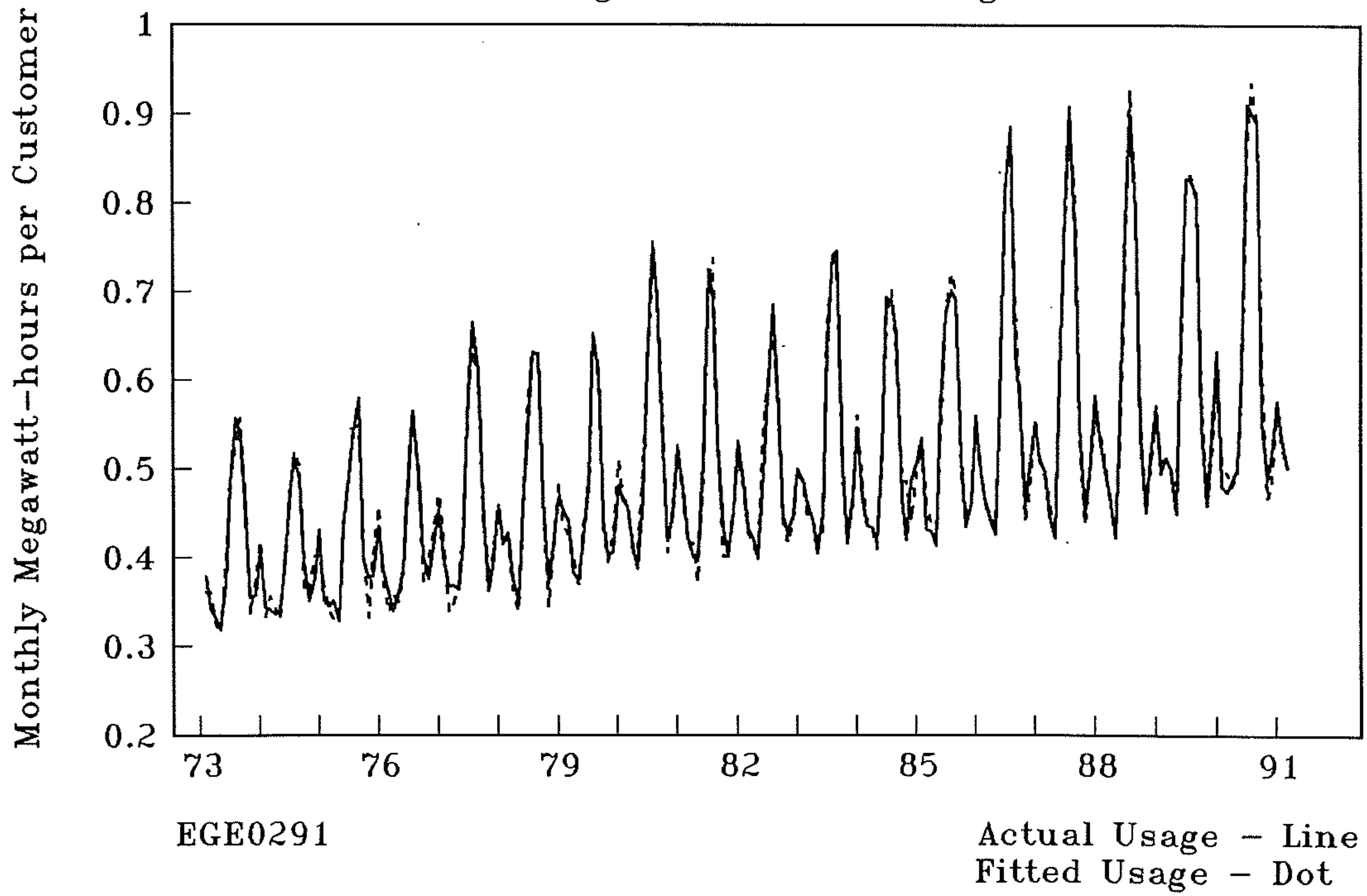


Figure 11

5) **Residential Total Forecast**

Table VIII summarizes the total residential forecast. The total usage for each class was calculated as the product of the average use per customer and the average number of customers. The residential customer total is the sum of the three classes.

In the forecast, the all-electric use per customer increases slightly, while the number of customers also increases. Average water heating customer usage increases slightly over the forecast period, but total electric water heating customers decline. Minimum-service use per customer increases while the number of minimum-service customers decreases slightly. The combined result is that the average use per customer for the entire residential sector increases slightly. Total residential energy increases primarily because of customer growth along with increasing penetration of all-electrics.

TOTAL RESIDENTIAL CUSTOMERS
(Excluding Residential Street Lighting)

	MWH/CUSTOMER	CUSTOMERS	TOTAL MWH
1986	12.104	740,980	8,969,190
1987	12.496	764,428	9,551,983
1988	12.510	782,328	9,786,675
1989	12.358	798,661	9,869,707
1990	12.216	813,344	9,935,590
1991	12.046	824,785	9,935,500
1992	12.812	836,648	10,718,800
1993	13.206	849,462	11,218,003
1994	13.581	863,537	11,727,561
1995	13.860	876,925	12,154,168
1996	14.051	890,070	12,506,078
1997	14.197	902,632	12,814,348
1998	14.319	914,682	13,097,662
1999	14.425	926,504	13,364,487
2000	14.516	938,790	13,627,502
2001	14.577	950,841	13,860,267
2002	14.634	962,847	14,089,823
2003	14.684	974,644	14,311,892
2004	14.726	985,587	14,513,790
2005	14.768	995,730	14,705,121
2006	14.825	1,005,851	14,912,134
2007	14.896	1,015,067	15,120,449
2008	14.978	1,024,616	15,346,874
2009	15.074	1,034,152	15,588,544
2010	15.190	1,043,632	15,852,806

1991 – Same as Reference Case

Table VIII

I.2 COMMERCIAL FORECAST

Table IX shows the summary of the forecast for the commercial sector. The commercial models were specified using monthly data and a logarithmic specification. In this form, the coefficients can be interpreted directly as elasticities.

To account for the diversity of commercial customers, seven 1-digit commercial SIC Codes were used for the commercial forecast. An annual econometric model for the class as a whole cannot adequately account for the wide variety in the saturation of heating and cooling equipment, resort installations, or deviations from normal weather. To capture the effects of these variables, the CP&L models were specified on a monthly basis.

Because electrical service to the commercial customers is currently supplied under a two-part rate, the marginal price of electricity does not capture the effect of the cost of service as well as the average cost. The demand component is fixed in a number of cases and, even where it can be controlled, the methods used to control the demand are generally one-time occurrences and remain constant for an extended period. As the demand charge goes up, it is quite possible that the energy charge could go down. The marginal cost does not reflect the trend, and consequently does not represent the true stimulus to the consumer. For these reasons, average real price is used in the forecasting models.

CAROLINA POWER AND LIGHT CO.
COMMERCIAL ENERGY REPORT
(in MWh)
(Reduced By Conservation and Load Management)

	AGRICULTURE	%CH YEAR AGO	CONSTRUCTION	%CH YEAR AGO	FINANCE INSURANCE AND REAL ESTATE	%CH YEAR AGO	GOVERNMENT	%CH YEAR AGO	UTILITIES COMMUNICATION AND TRANSPORTATION	%CH YEAR AGO	SERVICES	%CH YEAR AGO	WHOLESALE AND RETAIL TRADE	%CH YEAR AGO	TOTAL COMMERCIAL	%CH YEAR AGO
1986	351,067	4.0	41,086	10.6	553,014	13.5	580,435	0.5	624,490	7.1	1,934,994	7.6	2,279,802	6.9	6,364,888	6.9
1987	391,935	11.6	44,378	8.0	612,705	10.8	582,487	0.4	655,188	4.9	2,045,683	5.7	2,399,445	5.2	6,731,821	5.8
1988	413,261	5.4	47,025	6.0	666,679	8.8	584,952	0.4	704,392	7.5	2,138,922	4.6	2,504,507	4.4	7,059,738	4.9
1989	452,342	9.5	49,779	5.9	707,370	6.1	592,456	1.3	737,660	4.7	2,237,693	4.6	2,601,031	3.9	7,378,331	4.5
1990	501,691	10.9	51,891	4.2	728,004	2.9	603,272	1.8	782,376	6.1	2,318,507	3.6	2,683,882	3.2	7,669,623	3.9
1991	486,953	−2.9	45,816	−11.7	688,826	−5.4	584,558	−3.1	768,076	−1.8	2,254,740	−2.8	2,581,501	−3.8	7,410,470	−3.4
1992	501,846	3.1	39,355	−14.1	707,640	2.7	590,308	1.0	754,099	−1.8	2,341,515	3.8	2,601,881	0.8	7,536,644	1.7
1993	522,534	4.1	42,776	8.7	751,417	6.2	590,943	0.1	781,934	3.7	2,406,636	2.8	2,709,143	4.1	7,805,383	3.6
1994	543,767	4.1	46,532	8.8	789,542	5.1	592,218	0.2	806,828	3.2	2,460,027	2.2	2,796,341	3.2	8,035,255	2.9
1995	563,676	3.7	47,742	2.6	815,041	3.2	593,913	0.3	806,155	−0.1	2,498,243	1.6	2,854,486	2.1	8,179,257	1.8
1996	584,269	3.7	47,138	−1.3	832,988	2.2	595,139	0.2	797,432	−1.1	2,531,869	1.3	2,881,248	0.9	8,270,082	1.1
1997	605,601	3.7	46,239	−1.9	849,546	2.0	595,822	0.1	790,139	−0.9	2,556,439	1.0	2,894,022	0.4	8,337,808	0.8
1998	627,437	3.6	45,934	−0.7	864,308	1.7	596,334	0.1	783,458	−0.8	2,573,861	0.7	2,926,659	1.1	8,417,990	1.0
1999	649,368	3.5	46,193	0.6	878,506	1.6	596,952	0.1	778,881	−0.6	2,597,166	0.9	2,961,794	1.2	8,508,859	1.1
2000	673,167	3.7	47,189	2.2	894,267	1.8	597,726	0.1	776,353	−0.3	2,626,387	1.1	2,995,867	1.2	8,610,956	1.2
2001	695,967	3.4	48,031	1.8	906,512	1.4	598,409	0.1	770,507	−0.8	2,646,291	0.8	3,027,043	1.0	8,692,760	0.9
2002	714,957	2.7	48,377	0.7	916,521	1.1	599,152	0.1	763,889	−0.9	2,663,372	0.6	3,047,436	0.7	8,753,703	0.7
2003	733,954	2.7	47,641	−1.5	928,033	1.3	600,297	0.2	758,935	−0.6	2,683,548	0.8	3,067,421	0.7	8,819,827	0.8
2004	754,065	2.7	46,579	−2.2	940,115	1.3	601,514	0.2	754,878	−0.5	2,703,422	0.7	3,090,722	0.8	8,891,294	0.8
2005	775,012	2.8	46,471	−0.2	954,371	1.5	602,784	0.2	752,915	−0.3	2,725,012	0.8	3,119,134	0.9	8,975,700	0.9
2006	795,527	2.6	46,519	0.1	970,631	1.7	604,013	0.2	752,218	−0.1	2,749,697	0.9	3,151,595	1.0	9,070,201	1.1
2007	816,905	2.7	46,831	0.7	991,043	2.1	605,411	0.2	753,120	0.1	2,779,695	1.1	3,187,828	1.1	9,180,834	1.2
2008	840,239	2.9	47,500	1.4	1,011,443	2.1	606,748	0.2	752,457	−0.1	2,809,166	1.1	3,219,279	1.0	9,286,832	1.2
2009	865,110	3.0	48,357	1.8	1,031,555	2.0	607,977	0.2	750,586	−0.2	2,837,213	1.0	3,249,034	0.9	9,389,832	1.1
2010	891,319	3.0	48,806	0.9	1,054,607	2.2	609,120	0.2	749,463	−0.1	2,867,419	1.1	3,282,828	1.0	9,503,562	1.2

1991 – Same as Reference Case

Table IX

TABLE X

Energy Per Employee
1973-1975 Average, CP&L Area
CP&L Load Research Data
(Reverified 1985)

Sector	Annual MWH Per Employee
Services	10.832
Finance, Insurance, Real Estate	8.780
Trade	7.764
Transportation, Communication, Public Utilities	5.313
Government	2.380
Construction	.549

The individual commercial SIC Code forecasting equations use a common set of variables.

Employment. Employment is closely correlated with both energy utilization and floor stock in the commercial sector. In order to capture the seasonal variation in energy, the employment variable was not seasonally adjusted.

Real Average Price. The average price for the commercial sector is deflated by the CPI. This price term reflects the mix and the varying cycles of commercial customers. Since response to price is not instantaneous in the commercial sector, we have used a twelve-month distributed lag.

Seasonal Factors. The twelve seasonal factors or seasonal dummies account for the conventional seasonal variations including the usage at the resort areas which we serve. As resort commercial establishments open and close with the seasons, the number of customers fluctuates appreciably. These seasonal factors account for this fluctuation.

Heating Degree Days. The heating degree days were weighted for the billing cycle just as they were in the residential model, but they were weighted by the four Class A weather stations and the commercial consumption in the four areas rather than residential consumption. Heating degree days are used in conjunction with installed heating equipment. As more heating equipment is connected, a given number of heating degree days will have more effect on total usage. The product of the kw of heating equipment and degree days models this effect.

Cooling Degree Days. The cooling degree days were weighted just as the heating degree days. Cooling degree days are also statistically significant.

The models were specified in the Log-Log Form. The regression models and the applicable statistics are shown along with an ARIMA analysis of the residuals.

Interesting insights to the commercial forecast can be obtained by assessing not only subgroup employment but also the energy intensity per employee in each subgroup. Table X shows that a change in the employment mix can influence future energy use just as readily as a change in total employment. While these energy intensities are not directly used in the forecast, they illustrate how changing employment mix can increase or decrease overall energy intensiveness.

For the forecast, it is necessary to have a monthly series of forecasted values for each of the variables in the regression model. For the commercial sector, the values come from the following sources:

Service area commercial employment comes from the CP&L Economic Model

Weighted Normal Heating Degree Days - Calculated by CP&L

Weighted Normal Cooling Degree Days - Calculated by CP&L

Real Average Price of Electricity - Calculated by CP&L

Seasonal Dummies - 1 for the given month and 0 elsewhere

In the forecast, total employment and employment distribution are the significant independent variables. Employment in 1) Agriculture; 2) Construction; 3) Finance, Real Estate, and Insurance; 4) Government; 5) Utilities, Communication, Transportation; 6) Services; and 7) Wholesale & Retail Trade are forecast for the CP&L service area in the CP&L Service Area Economic Model. The growth rates vary appreciably, and consequently affect the commercial energy usage in the forecast period. The rates of growth from 1991 to 2011 by sub-sector are shown below:

COMPOUNDED ANNUAL EMPLOYMENT GROWTH RATES

1991-2011

	Service Area
Construction	1.4
Utilities, Comm., Trans.	0.3
Trade	1.8
Services	2.1
Finance, Insurance, Real Estate	1.5
Government	1.1

1) **Agriculture** (SIC 01-09)

This category includes establishments primarily engaged in agricultural production, forestry, fishing, hunting, and related services. Consequently, farms, ranches, dairies, greenhouses, and timber tracts are modeled in this category.

Employment in the agricultural sector is forecast to increase from 18,636 in 1991 to 33,671 in 2010. The energy delivered to these facilities and establishments is forecast to increase at an average annual compounded rate of 3.5%.

The regression model is shown in Figure 12, and a plot of the actual versus fitted values during the historical period is shown in Figure 14.

The annual power usage by this sector is shown in Table IX.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

MONTHLY(1982:1 TO 1991:3) 111 OBSERVATIONS
DEPENDENT VARIABLE: LOG(MHCM@AG@CPL)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.08443	0.1596	6.797	LOG(EAGNS@CPL)
2)	0.0613346	0.05784	1.06	WDUM•LOG(WHDD65CM@CPL)
3)	0.201374	0.0965	2.087	SDUM•LOG(WCDD65CM@CPL)
4)				PDL(LNARPECM,1,12,FAR)
\0	−0.049399	0.08201		+ • . +
\1	−0.0452824	0.07517		+ • . +
\2	−0.0411658	0.06834		+ • . +
\3	−0.0370493	0.06151		+ • . +
\4	−0.0329327	0.05467		+ • . +
\5	−0.0288161	0.04784		+ • . +
\6	−0.0246995	0.041		+ • . +
\7	−0.0205829	0.03417		+ • . +
\8	−0.0164663	0.02734		+ • . +
\9	−0.0123498	0.0205		+ • . +
\10	−0.00823317	0.01367		+ •.+
\11	−0.00411658	0.006834		+ •.+
SUM	−0.321094	0.5331	−0.6024	
AVG	3.66667	0	NC	
5)	7.61425	1.345	5.66	SEASONM01
6)	7.63302	1.342	5.69	SEASONM02
7)	7.48305	1.351	5.54	SEASONM03
8)	7.28641	1.363	5.346	SEASONM04
9)	7.19394	1.358	5.299	SEASONM05
10)	6.4882	1.388	4.674	SEASONM06
11)	6.54034	1.413	4.628	SEASONM07
12)	7.03104	1.417	4.962	SEASONM08
13)	7.34583	1.401	5.244	SEASONM09
14)	7.2108	1.361	5.3	SEASONM10
15)	7.47216	1.337	5.59	SEASONM11
16)	7.5094	1.347	5.574	SEASONM12
17)	−2.77901	0.1036	−26.83	DUM845
	0.421263	0.09524	4.423	RHO

R-BAR SQUARED: 0.9569 (RELATIVE TO Y=0, RBSQ: 0.9999)
F-STATISTIC(18,93): 59892.760
DURBIN-WATSON STATISTIC: 2.0264
SUM OF SQUARED RESIDUALS: 1.005
STANDARD ERROR OF THE REGRESSION: 0.1039 NORMALIZED: 0.01016

Figure 12

WHERE:

MHCM@AG@CPL	COMMERCIAL USAGE – AGRICULTURE (GIGAWATT HOURS)
EAGNS@CPL	SERVICE AREA EMPLOYMENT – AGRICULTURE
WDUM	WINTER DUMMY (1–NOVEMBER – JUNE, 0 ELSEWHERE)
SDUM	SUMMER DUMMY (1=JULY – OCTOBER, 0 ELSEWHERE)
WHDD65CM@CPL	COMMERCIAL HEATING DEGREE DAYS – BASE 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
WCDD65CM@CPL	COMMERCIAL COOLING DEGREE DAYS – BASE – 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
LNARPECM	AVERAGE REAL PRICE OF ELECTRICITY – COMMERCIAL
SEASONM01	SEASONAL DUMMY FOR JANUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1= THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1= THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1= THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1= THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1= THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1= THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1= THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1= THEREIN, 0 ELSEWHERE)
DUM845	UNEXPLAINED DROP IN USAGE 84:5

Figure 12 (cont'd.)

STOCHASTIC ARIMA ANALYSIS

MONTHLY(1982:1 TO 1991:3) 111 OBSERVATIONS
VARIABLE NAME: RESIDUALS(@RR)
DEGREE OF DIFFERENCING = 0
DEGREE OF SEASONAL DIFFERENCING = 0
NUMBER OF PERIODS PER SEASON = 12
MEAN = 0.00025318106841*, STANDARD DEVIATION = 0.09513244050026*

AUTOCORRELATION STATISTICS:
APPROXIMATE STANDARD ERROR = 0.095
Q−STATISTIC, CHI−SQUARED (24 D.F.) = 16.345
LJUNG−BOX Q−STATISTIC = 19.0385

LAG	AUTO− CORR.	T−STAT	AUTO− COVAR.	−1 − − − − − − − − − 0 + + + + + + + + + 1
1	−0.015	−0.153	−0.000	(*)
2	0.032	0.336	0.000	(**)
3	−0.008	−0.085	−0.000	(*)
4	0.078	0.82	0.001	(***)
5	0.032	0.34	0.000	(**)
6	−0.02	−0.211	−0.000	(*)
7	0.035	0.367	0.000	(**)
8	−0.079	−0.83	−0.001	(***)
9	0.07	0.742	0.001	(**)
10	−0.051	−0.542	−0.000	(**)
11	−0.132	−1.386	−0.001	(****)
12	0.137	1.442	0.001	(****)
13	0.024	0.252	0.000	(*)
14	0.223	2.352	0.002	(*****
15	−0.082	−0.861	−0.001	(***)

LAG	PARTIAL ACOR.	T−STAT	−1 − − − − − − − − − 0 + + + + + + + + + 1
1	−0.015	−0.153	(*)
2	0.032	0.333	(**)
3	−0.007	−0.075	(*)
4	0.077	0.808	(***)
5	0.035	0.37	(**)
6	−0.024	−0.252	(*)
7	0.034	0.354	(**)
8	−0.083	−0.872	(***)
9	0.062	0.651	(**)
10	−0.044	−0.458	(**)
11	−0.144	−1.52	(****)
12	0.155	1.637	(****)
13	0.028	0.292	(**)
14	0.224	2.361	(*****
15	−0.052	−0.547	(**)

Figure 13

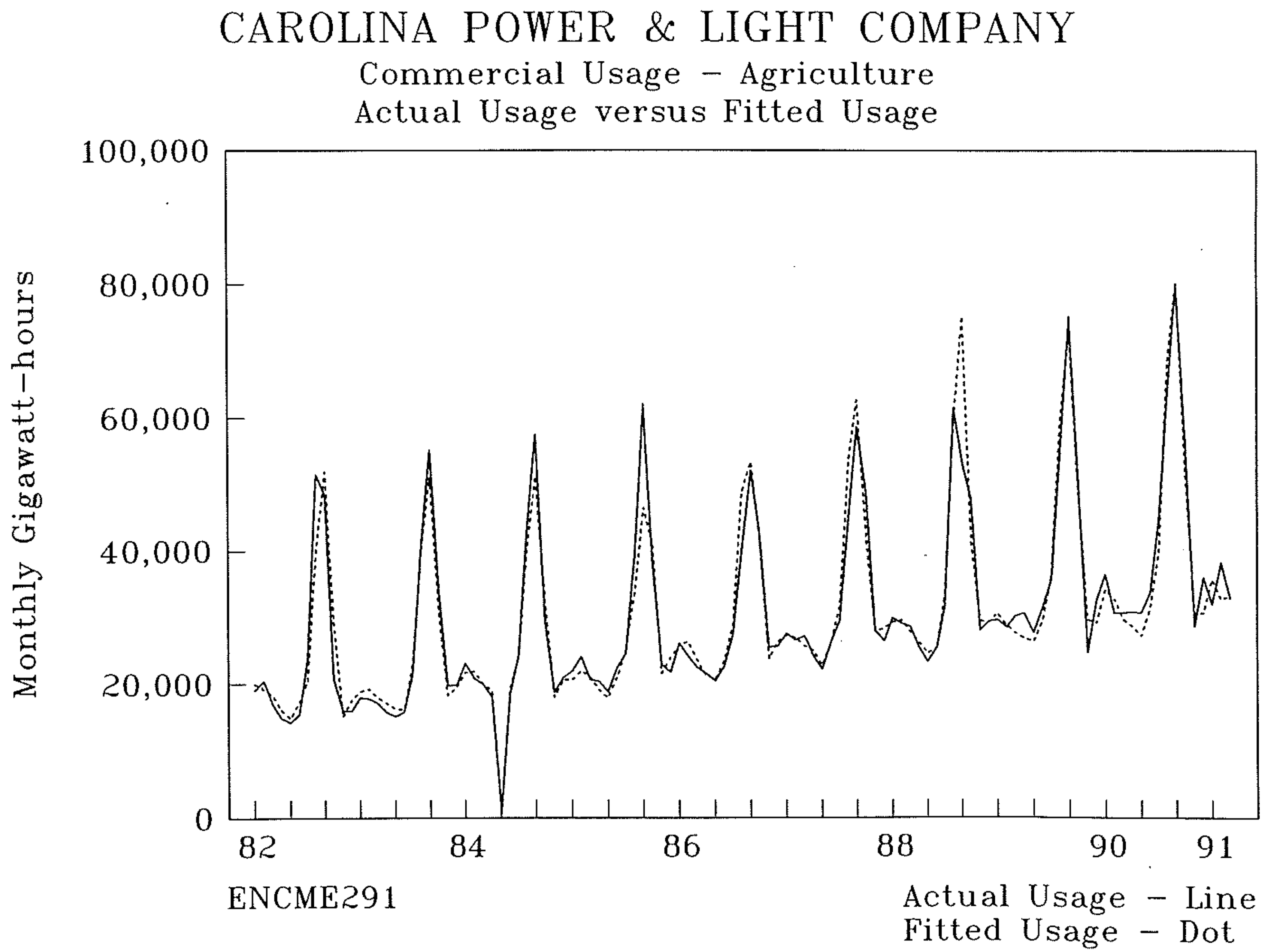

CAROLINA POWER & LIGHT COMPANY
Commercial Usage - Agriculture
Actual Usage versus Fitted Usage
100,000
80,000
60,000
40,000
20,000
0
Monthly Gigawatt-hours
82
84
86
88
90
91
ENCME291
Actual Usage - Line
Fitted Usage - Dot

Figure 14

2) **Construction** (SIC 15-17)

This category of commercial customers includes establishments engaged in new work, additions, alternations, reconstruction, and repairs. Construction activities are generally managed or administered from a relatively fixed place of business, but the actual construction work is performed at one or more different sites. Such sites are included in this classification as well as establishments engaged in the installation of prefabricated construction equipment and materials.

Employment in the construction sector is expected to increase from 64,484 in 1991 to 84,188 in 2010. The energy forecast for this subgroup ranks the lowest of all commercial activity because the energy intensity per employee is the lowest of any commercial activity. Energy growth is projected to increase at an average annual compounded rate of 1.3%.

The model is shown in Figure 15 and the plot of actual versus fitted values is shown in Figure 17.

The annual electrical energy use in the sector is shown in Table IX.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

MONTHLY(1980:1 TO 1991:3) 135 OBSERVATIONS
DEPENDENT VARIABLE: LOG(MHCM@C@CPL)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00971	0.1474	6.851	LOG(ECNS@CPL)
2)	0.147813	0.02603	5.678	WDUM*LOG(WHDD65CM@CPL)
3)	0.205831	0.04007	5.137	SDUM*LOG(WCDD65CM@CPL)
4)				PDL(LNARPECM,1,12,FAR)
\0	−0.0767472	0.05535		+ * + .
\1	−0.0703516	0.05074		+ * + .
\2	−0.063956	0.04613		+ * + .
\3	−0.0575604	0.04151		+ * + .
\4	−0.0511648	0.0369		+ * + .
\5	−0.0447692	0.03229		+ * + .
\6	−0.0383736	0.02768		+ * + .
\7	−0.031978	0.02306		+ * + .
\8	−0.0255824	0.01845		+ * + .
\9	−0.0191868	0.01384		+ * +.
\10	−0.0127912	0.009226		+ * +
\11	−0.0063956	0.004613		+*+.
SUM	−0.498857	0.3598	−1.387	
AVG	3.66667	0	NC	
5)	3.98664	0.8619	4.626	SEASONM01
6)	4.021	0.8605	4.673	SEASONM02
7)	3.94709	0.8619	4.58	SEASONM03
8)	3.84127	0.864	4.446	SEASONM04
9)	3.86552	0.862	4.484	SEASONM05
10)	3.64166	0.8767	4.154	SEASONM06
11)	3.66782	0.8829	4.154	SEASONM07
12)	3.68197	0.8836	4.167	SEASONM08
13)	3.68157	0.8796	4.185	SEASONM09
14)	3.67173	0.8706	4.217	SEASONM10
15)	3.81709	0.8604	4.437	SEASONM11
16)	3.84562	0.8627	4.457	SEASONM12
	0.809742	0.05612	14.43	RHO

R-BAR SQUARED: 0.9416 (RELATIVE TO Y=0, RBSQ: 0.9999)
F-STATISTIC(17,118): 155256.61
DURBIN-WATSON STATISTIC: 2.3678
SUM OF SQUARED RESIDUALS: 0.3934
STANDARD ERROR OF THE REGRESSION: 0.05774 NORMALIZED: 0.007155

Figure 15

WHERE:

MHCM@C@CPL	COMMERCIAL USAGE – CONSTRUCTION (GIGAWATT HOURS)
ECNS@CPL	SERVICE AREA EMPLOYMENT – CONSTRUCTION
WDUM	WINTER DUMMY (1–NOVEMBER – JUNE, 0 ELSEWHERE)
SDUM	SUMMER DUMMY (1=JULY – OCTOBER, 0 ELSEWHERE)
WHDD65CM@CPL	COMMERCIAL HEATING DEGREE DAYS – BASE 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
WCDD65CM@CPL	COMMERCIAL COOLING DEGREE DAYS – BASE – 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
LNARPECM	AVERAGE REAL PRICE OF ELECTRICITY – COMMERCIAL
SEASONM01	SEASONAL DUMMY FOR JANUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1= THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1= THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1= THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1= THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1= THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1= THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1= THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1= THEREIN, 0 ELSEWHERE)

Figure 15 (cont'd.)

STOCHASTIC ARIMA ANALYSIS

MONTHLY(1980:1 TO 1991:3) 135 OBSERVATIONS
VARIABLE NAME: RESIDUALS(@RR)
DEGREE OF DIFFERENCING = 0
DEGREE OF SEASONAL DIFFERENCING = 0
NUMBER OF PERIODS PER SEASON = 12
MEAN = 0.00160761842115*, STANDARD DEVIATION = 0.05396003114192*

AUTOCORRELATION STATISTICS:
APPROXIMATE STANDARD ERROR = 0.086
Q-STATISTIC, CHI-SQUARED (24 D.F.) = 31.649
LJUNG-BOX Q-STATISTIC = 35.5053

LAG	AUTO-CORR.	T-STAT	AUTO-COVAR.	-1 - - - - - - - - - 0 + + + + + + + + + 1
1	-0.205	-2.386	-0.001	*(***)
2	-0.023	-0.264	-0.000	(*)
3	0.048	0.557	0.000	(**)
4	0.087	1.015	0.000	(***)
5	0.041	0.472	0.000	(**)
6	0.135	1.569	0.000	(****
7	-0.032	-0.374	-0.000	(**)
8	-0.028	-0.32	-0.000	(**)
9	0.023	0.268	0.000	(*)
10	0.019	0.222	0.000	(*)
11	0.151	1.752	0.000	(****
12	0.055	0.643	0.000	(**)
13	0.031	0.364	0.000	(**)
14	0.177	2.06	0.000	(***)*
15	-0.126	-1.46	-0.000	(**)

LAG	PARTIAL ACOR.	T-STAT	-1 - - - - - - - - - 0 + + + + + + + + + 1
1	-0.205	-2.386	*(***)
2	-0.068	-0.788	(**)
3	0.03	0.354	(**)
4	0.108	1.252	(***)
5	0.091	1.059	(***)
6	0.18	2.096	(***)*
7	0.037	0.433	(**)
8	-0.036	-0.414	(**)
9	-0.029	-0.339	(**)
10	-0.028	-0.331	(**)
11	0.144	1.673	(****
12	0.128	1.493	(****
13	0.113	1.309	(***)
14	0.246	2.854	(***)**
15	-0.073	-0.847	(**)

Figure 16

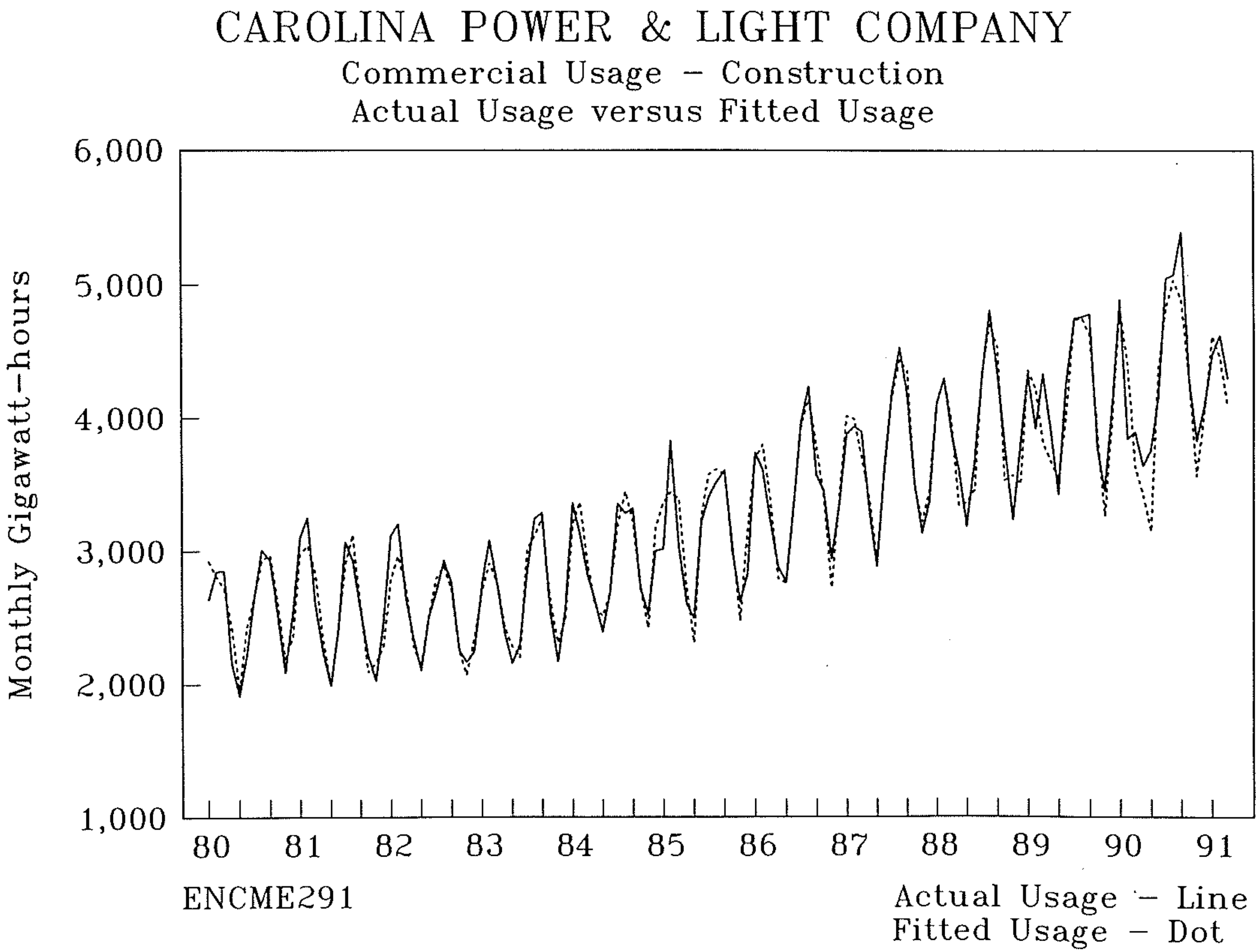

CAROLINA POWER & LIGHT COMPANY
Commercial Usage – Construction
Actual Usage versus Fitted Usage
Monthly Gigawatt-hours
6,000
5,000
4,000
3,000
2,000
1,000
80
81
82
83
84
85
86
87
88
89
90
91
ENCME291
Actual Usage – Line
Fitted Usage – Dot

Figure 17

3) **Finance, Insurance, and Real Estate** (SIC 60-67)

This division of the commercial sector includes establishments operating in the field of financial, insurance, and real estate services. Among the financial establishments are depository institutions, brokers and dealers in securities, and other credit institutions. The insurance classification includes the operations of brokers as well as agents. Real estate is primarily made up of sales agents as well as those engaged in buying, selling, managing, and appraising real estate for others.

Employment in the FIR sector is forecast to increase from 51,626 in 1991 to 68,512 in 2010. Electricity use is forecast to increase at a 3.0% average annual compounded rate.

The FIR model is shown in Figure 18 and a plot of the actual vs. fitted values during the historical period is shown in Figure 20.

The annual power usage by this sector is shown in Table IX.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

MONTHLY(1982:1 TO 1991:3) 111 OBSERVATIONS
DEPENDENT VARIABLE: LOG(MHCM@FIR@CPL)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.67437	0.1388	12.07	LOG(EFIRNS@CPL)
2)	0.105077	0.02948	3.564	WDUM*LOG(WHDD65CM@CPL)
3)	0.161985	0.04969	3.26	SDUM*LOG(WCDD65CM@CPL)
4)				PDL(LNARPECM,1,12,FAR)
\0	−0.109756	0.05122		+ * + .
\1	−0.10061	0.04695		+ * + .
\2	−0.0914635	0.04269		+ * + .
\3	−0.0823172	0.03842		+ * + .
\4	−0.0731708	0.03415		+ * + .
\5	−0.0640245	0.02988		+ * + .
\6	−0.0548781	0.02561		+ * + .
\7	−0.0457318	0.02134		+ * + .
\8	−0.0365854	0.01707		+ * + .
\9	−0.0274391	0.01281		+ * + .
\10	−0.0182927	0.008537		+ * + .
\11	−0.00914635	0.004269		+*+.
SUM	−0.713415	0.3329	−2.143	
AVG	3.66667	0	NC	
5)	5.00975	1.064	4.707	SEASONM01
6)	5.00358	1.064	4.703	SEASONM02
7)	4.92626	1.064	4.631	SEASONM03
8)	4.87767	1.063	4.588	SEASONM04
9)	4.89225	1.058	4.625	SEASONM05
10)	4.67089	1.063	4.395	SEASONM06
11)	4.67149	1.071	4.363	SEASONM07
12)	4.65105	1.072	4.338	SEASONM08
13)	4.67079	1.069	4.37	SEASONM09
14)	4.65223	1.058	4.396	SEASONM10
15)	4.87678	1.059	4.607	SEASONM11
16)	4.88428	1.064	4.59	SEASONM12
17)	−0.217149	0.06297	−3.449	DUM881
18)	−0.298401	0.07114	−4.194	DUM882
19)	−0.209685	0.06189	−3.388	DUM883
	0.541367	0.09127	5.932	RHO

R-BAR SQUARED: 0.9569 (RELATIVE TO Y=0, RBSQ: 1.0000)
F-STATISTIC(20,91): 205634.58
DURBIN-WATSON STATISTIC: 2.0347
SUM OF SQUARED RESIDUALS: 0.2817
STANDARD ERROR OF THE REGRESSION: 0.05564 NORMALIZED: 0.005197

Figure 18

WHERE:

MHCM@FIR@CPL	COMMERCIAL USAGE – FINANCE, INSURANCE AND REAL ESTATE (GIGAWATT HOURS)
EFIRNS@CPL	SERVICE AREA EMPLOYMENT – FINANCE, INSURANCE AND REAL ESTATE
WDUM	WINTER DUMMY (1–NOVEMBER – JUNE, 0 ELSEWHERE)
SDUM	SUMMER DUMMY (1=JULY – OCTOBER, 0 ELSEWHERE)
WHDD65CM@CPL	COMMERCIAL HEATING DEGREE DAYS – BASE 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
WCDD65CM@CPL	COMMERCIAL COOLING DEGREE DAYS – BASE – 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
LNARPECM	AVERAGE REAL PRICE OF ELECTRICITY – COMMERCIAL
SEASONM01	SEASONAL DUMMY FOR JANUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1= THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1= THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1= THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1= THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1= THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1= THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1= THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1= THEREIN, 0 ELSEWHERE)
DUM881	UNEXPLAINED INCREASE IN USAGE 88:1
DUM882	UNEXPLAINED INCREASE IN USAGE 88:2
DUM883	UNEXPLAINED INCREASE IN USAGE 88:3

Figure 18 (cont'd.)

STOCHASTIC ARIMA ANALYSIS

MONTHLY(1982:1 TO 1991:3) 111 OBSERVATIONS
VARIABLE NAME: RESIDUALS(@RR)
DEGREE OF DIFFERENCING = 0
DEGREE OF SEASONAL DIFFERENCING = 0
NUMBER OF PERIODS PER SEASON = 12
MEAN = −0.00010937372195*, STANDARD DEVIATION = 0.05037591279918*

AUTOCORRELATION STATISTICS:
APPROXIMATE STANDARD ERROR = 0.095
Q−STATISTIC, CHI−SQUARED (24 D.F.) = 27.826
LJUNG−BOX Q−STATISTIC = 32.7431

LAG	AUTO−CORR.	T−STAT	AUTO−COVAR.	−1 − − − − − − − − − − 0 + + + + + + + + + + 1
1	−0.019	−0.201	−0.000	(*)
2	−0.043	−0.453	−0.000	(**)
3	0.068	0.718	0.000	(**)
4	0.117	1.237	0.000	(***)
5	0.053	0.561	0.000	(**)
6	0.09	0.953	0.000	(***)
7	0.101	1.065	0.000	(***)
8	−0.092	−0.974	−0.000	(***)
9	0.126	1.329	0.000	(****)
10	−0.015	−0.157	−0.000	(*)
11	0.17	1.79	0.000	(****)
12	0.07	0.742	0.000	(**)
13	0.139	1.462	0.000	(****)
14	0.093	0.978	0.000	(***)
15	−0.158	−1.667	−0.000	(****)

LAG	PARTIAL ACOR.	T−STAT	−1 − − − − − − − − − − 0 + + + + + + + + + + 1
1	−0.019	−0.201	(*)
2	−0.043	−0.457	(**)
3	0.067	0.702	(**)
4	0.119	1.251	(***)
5	0.065	0.688	(**)
6	0.101	1.066	(***)
7	0.1	1.053	(***)
8	−0.102	−1.072	(***)
9	0.107	1.13	(***)
10	−0.06	−0.632	(**)
11	0.168	1.772	(****)
12	0.067	0.704	(**)
13	0.149	1.569	(****)
14	0.105	1.11	(***)
15	−0.198	−2.085	*****)

Figure 19

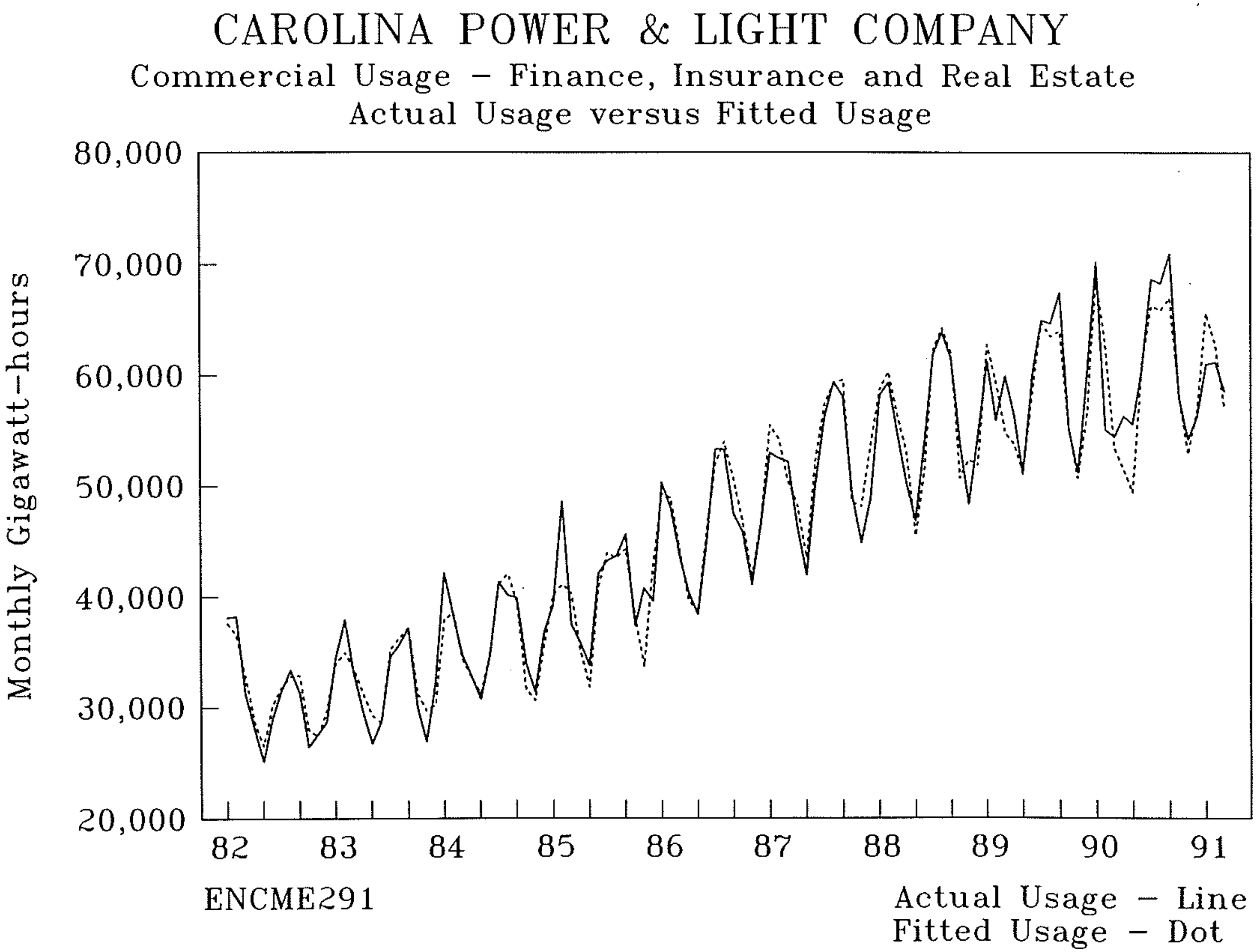

CAROLINA POWER & LIGHT COMPANY
Commercial Usage - Finance, Insurance and Real Estate
Actual Usage versus Fitted Usage
Monthly Gigawatt-hours
80,000
70,000
60,000
50,000
40,000
30,000
20,000
82
83
84
85
86
87
88
89
90
91
ENCME291
Actual Usage - Line
Fitted Usage - Dot

Figure 20

4) **Government** (SIC 91-97)

This classification includes the executive, legislative, judicial, administrative, and regulatory activities of federal, state, and local governments. Even though elementary, secondary, and college education are publicly funded, these establishments are a component of the services subgroup. Total government is the second largest employer in the service area. Electricity use by military organizations which are directly billed appear as MILITARY in Table I and Table II in the front of this report.

Government employment at the federal, state, and local levels within the service area is projected to increase from 261,784 in 1991 to 324,235 in 2010. Government activities collectively rank the next to lowest in energy intensiveness. Consequently, large changes in government employment do not change energy use nearly as much as other commercial sector employment changes. Electricity use by the government subgroup is projected to grow at an average annual compounded rate of 0.3%.

The model is shown in Figure 21 and a plot of the actual vs. fitted values is shown in Figure 23.

The annual power usage by this sector is shown in Table IX.

ORDINARY LEAST SQUARES

MONTHLY(1985:1 TO 1991:3) 75 OBSERVATIONS
DEPENDENT VARIABLE: LOG(MHCM@G@CPL)

	COEFFICIEN'	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.227329	0.08283	2.745	LOG(EGNS@CPL)
2)	0.0902937	0.02619	3.447	WDUM*LOG(WHDD65CM@CPL)
3)	0.180144	0.05235	3.441	SDUM*LOG(WCDD65CM@CPL)
4)	8.98785	0.4909	18.31	SEASONM01
5)	8.95936	0.4903	18.27	SEASONM02
6)	8.94087	0.4891	18.28	SEASONM03
7)	8.91948	0.4855	18.37	SEASONM04
8)	8.94506	0.4782	18.7	SEASONM05
9)	8.5974	0.5408	15.9	SEASONM06
10)	8.62131	0.5524	15.61	SEASONM07
11)	8.61681	0.5538	15.56	SEASONM08
12)	8.62662	0.5516	15.64	SEASONM09
13)	8.56843	0.5354	16	SEASONM10
14)	8.91807	0.4823	18.49	SEASONM11
15)	8.91527	0.4889	18.23	SEASONM12

R-BAR SQUARED: 0.8711 (RELATIVE TO Y=0, RBSQ: 1.0000)
F-STATISTIC(15,60): 388070.56
DURBIN-WATSON STATISTIC: 1.6181
SUM OF SQUARED RESIDUALS: 0.09003
STANDARD ERROR OF THE REGRESSION: 0.03874 NORMALIZED: 0.003590

Figure 21

WHERE:

MHCM@G@CPL	COMMERCIAL USAGE – GOVERNMENT (GIGAWATT HOURS)
EGNS@CPL	SERVICE AREA EMPLOYMENT – GOVERNMENT
WDUM	WINTER DUMMY (1–NOVEMBER – JUNE, 0 ELSEWHERE)
SDUM	SUMMER DUMMY (1=JULY – OCTOBER, 0 ELSEWHERE)
WHDD65CM@CPL	COMMERCIAL HEATING DEGREE DAYS – BASE 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
WCDD65CM@CPL	COMMERCIAL COOLING DEGREE DAYS – BASE – 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
SEASONM01	SEASONAL DUMMY FOR JANUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1= THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1= THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1= THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1= THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1= THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1= THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1= THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1= THEREIN, 0 ELSEWHERE)

Figure 21 (cont'd.)

STOCHASTIC ARIMA ANALYSIS

MONTHLY(1985:1 TO 1991:3) 75 OBSERVATIONS
VARIABLE NAME: RESIDUALS(@RR)
DEGREE OF DIFFERENCING = 0
DEGREE OF SEASONAL DIFFERENCING = 0
NUMBER OF PERIODS PER SEASON = 12
MEAN = −0.00000000013175*, STANDARD DEVIATION = 0.03464615714548*

AUTOCORRELATION STATISTICS:
APPROXIMATE STANDARD ERROR = 0.115
Q−STATISTIC, CHI−SQUARED (24 D.F.) = 20.999
LJUNG−BOX Q−STATISTIC = 27.6045

LAG	AUTO-CORR.	T-STAT	AUTO-COVAR.	−1 − − − − − − − − − − 0 + + + + + + + + + + 1
1	0.188	1.629	0.000	(*****)
2	0.027	0.231	0.000	(**)
3	−0.004	−0.039	−0.000	(*)
4	0.099	0.859	0.000	(***)
5	−0.078	−0.677	−0.000	(***)
6	0.063	0.55	0.000	(**)
7	−0.097	−0.844	−0.000	(***)
8	−0.028	−0.24	−0.000	(**)
9	0.1	0.864	0.000	(***)
10	−0.033	−0.29	−0.000	(**)
11	−0.037	−0.316	−0.000	(**)
12	0.096	0.834	0.000	(***)
13	0.036	0.308	0.000	(**)
14	−0.031	−0.273	−0.000	(**)
15	0.029	0.249	0.000	(**)

LAG	PARTIAL ACOR.	T-STAT	−1 − − − − − − − − − − 0 + + + + + + + + + + 1
1	0.188	1.629	(*****)
2	−0.009	−0.078	(*)
3	−0.008	−0.071	(*)
4	0.106	0.914	(***)
5	−0.122	−1.055	(***)
6	0.106	0.919	(***)
7	−0.136	−1.174	(****)
8	0.006	0.052	(*)
9	0.142	1.233	(****)
10	−0.137	−1.184	(****)
11	0.055	0.473	(**)
12	0.08	0.693	(***)
13	−0.033	−0.287	(**)
14	0.014	0.125	(*)
15	−0.009	−0.075	(*)

Figure 22

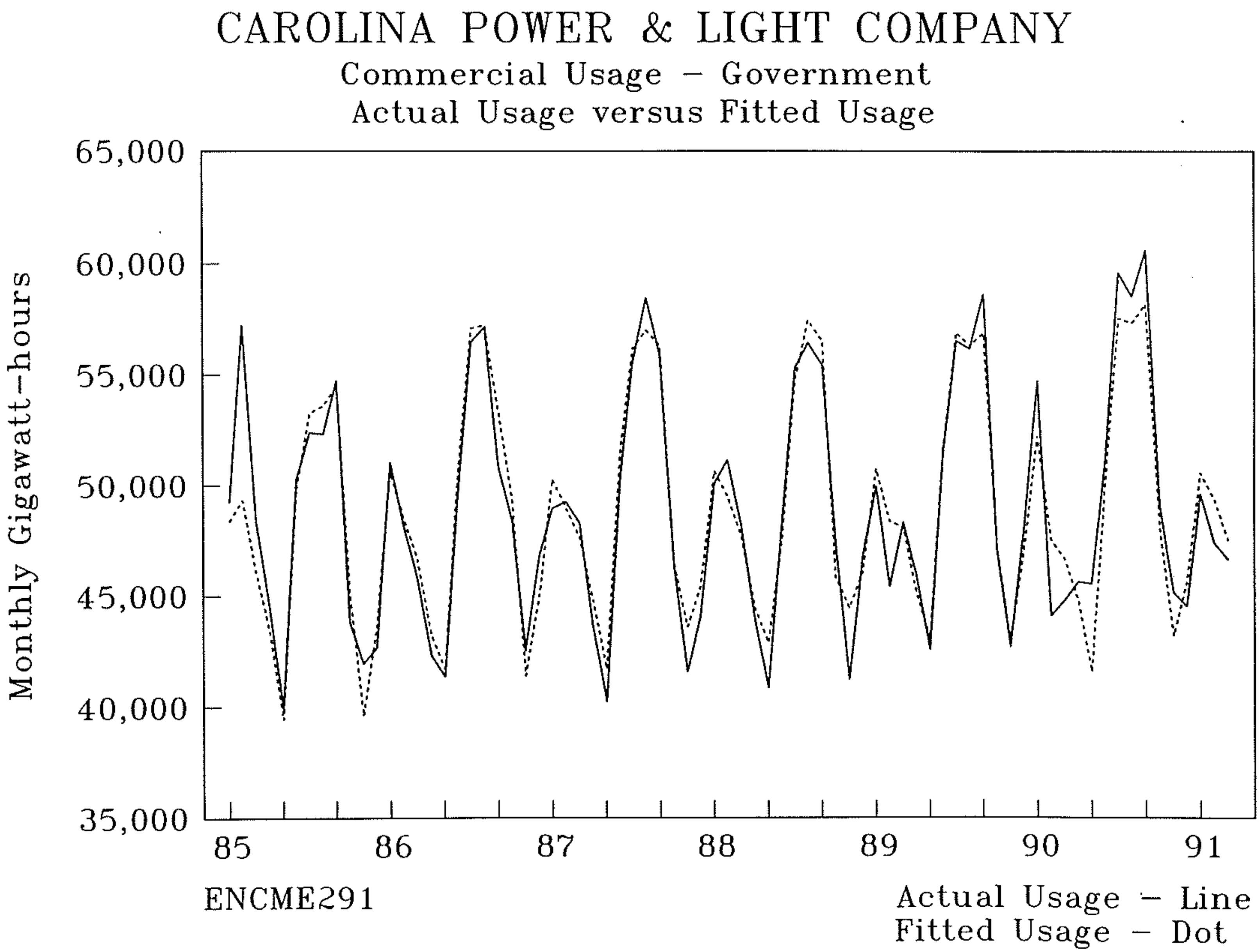

CAROLINA POWER & LIGHT COMPANY
Commercial Usage - Government
Actual Usage versus Fitted Usage
Monthly Gigawatt-hours
65,000
60,000
55,000
50,000
45,000
40,000
35,000
85
86
87
88
89
90
91
ENCME291
Actual Usage - Line
Fitted Usage - Dot

Figure 23

5) **Utilities, Communication, and Transportation** (SIC 40-49)

This subgroup includes establishments engaged in passenger and freight transportation, communications services, electricity--gas--water--sanitary services, and all establishments of the U.S. Postal Service. The construction or replacement activities for these types of enterprises are classified in the construction subgroup.

Employment in this subgroup is projected to increase from 54,538 in 1991 to 57,678 in 2010. Energy use is projected to grow at an average annual compounded rate of 0.6%.

The model is shown in Figure 24 and a plot of the actual versus fitted values is shown in Figure 26.

The energy forecast for this subgroup is shown in Table IX.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

MONTHLY(1982:1 TO 1991:3) 111 OBSERVATIONS
DEPENDENT VARIABLE: LOG(MHCM@R@CPL)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.43954	0.1464	9.836	LOG(ERNS@CPL)
2)	0.0643155	0.01855	3.468	WDUM*LOG(WHDD65CM@CPL)
3)	0.102937	0.03145	3.273	SDUM*LOG(WCDD65CM@CPL)
4)				PDL(LNARPECM,1,12,FAR)
\0	−0.0490945	0.04189		+ • +.
\1	−0.0450033	0.0384		+ • +.
\2	−0.0409121	0.03491		+ • +.
\3	−0.0368209	0.03142		+ • +.
\4	−0.0327297	0.02793		+ • +.
\5	−0.0286385	0.02444		+ • +.
\6	−0.0245473	0.02094		+ • +.
\7	−0.0204561	0.01745		+ • +.
\8	−0.0163648	0.01396		+ • +
\9	−0.0122736	0.01047		+ • +.
\10	−0.00818242	0.006982		+ • +
\11	−0.00409121	0.003491		+•+.
SUM	−0.319115	0.2723	−1.172	
AVG	3.66667	0	NC	
5)	5.50393	0.9754	5.643	SEASONM01
6)	5.46602	0.9744	5.61	SEASONM02
7)	5.44314	0.975	5.583	SEASONM03
8)	5.46867	0.9755	5.606	SEASONM04
9)	5.46491	0.975	5.605	SEASONM05
10)	5.31991	0.9879	5.385	SEASONM06
11)	5.29405	0.9927	5.333	SEASONM07
12)	5.26963	0.9938	5.302	SEASONM08
13)	5.30401	0.9919	5.347	SEASONM09
14)	5.30181	0.9873	5.37	SEASONM10
15)	5.43286	0.9778	5.556	SEASONM11
16)	5.43709	0.9776	5.562	SEASONM12
17)	0.120763	0.0389	3.104	DUM881
18)	0.163323	0.04518	3.615	DUM882
19)	0.12237	0.03918	3.123	DUM883
20)	0.303709	0.03638	8.348	DUM889
21)	−0.476432	0.03682	−12.94	DUM8810
	0.645511	0.08165	7.906	RHO

R-BAR SQUARED: 0.9581 (RELATIVE TO Y=0, RBSQ: 1.0000)
F-STATISTIC(22,89): 454966.61
DURBIN-WATSON STATISTIC: 2.3567
SUM OF SQUARED RESIDUALS: 0.1163
STANDARD ERROR OF THE REGRESSION: 0.03614 NORMALIZED: 0.003331

Figure 24

WHERE:

MHCM@R@CPL	COMMERCIAL USAGE – TRANSPORTATION, COMM. & UTILITIES (GIGAWATT HOURS)
ERNS@CPL	SERVICE AREA EMPLOYMENT – TRANSPORTATION, COMM. & UTILITIES
WDUM	WINTER DUMMY (1–NOVEMBER – JUNE, 0 ELSEWHERE)
SDUM	SUMMER DUMMY (1=JULY – OCTOBER, 0 ELSEWHERE)
WHDD65CM@CPL	COMMERCIAL HEATING DEGREE DAYS – BASE 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
WCDD65CM@CPL	COMMERCIAL COOLING DEGREE DAYS – BASE – 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
LNARPECM	AVERAGE REAL PRICE OF ELECTRICITY – COMMERCIAL
SEASONM01	SEASONAL DUMMY FOR JANUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1= THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1= THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1= THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1= THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1= THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1= THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1= THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1= THEREIN, 0 ELSEWHERE)
DUM881	UNEXPLAINED DECREASE IN USAGE 88:1
DUM882	UNEXPLAINED DECREASE IN USAGE 88:2
DUM883	UNEXPLAINED DECREASE IN USAGE 88:3
DUM889	INCREASE DUE TO ACCOUNTING ADJUSTMENTS IN USAGE 88:9
DUM8810	DECREASE DUE TO ACCOUNTING ADJUSTMENTS IN USAGE 88:10

Figure 24 (cont'd.)

STOCHASTIC ARIMA ANALYSIS

MONTHLY(1982:1 TO 1991:3) 111 OBSERVATIONS
VARIABLE NAME: RESIDUALS(@RR)
DEGREE OF DIFFERENCING = 0
DEGREE OF SEASONAL DIFFERENCING = 0
NUMBER OF PERIODS PER SEASON = 12
MEAN = 0.00024775245009*, STANDARD DEVIATION = 0.03236183856634*

AUTOCORRELATION STATISTICS:
APPROXIMATE STANDARD ERROR = 0.095
Q-STATISTIC, CHI-SQUARED (24 D.F.) = 39.922
LJUNG-BOX Q-STATISTIC = 46.0085

LAG	AUTO-CORR.	T-STAT	AUTO-COVAR.	-1 - - - - - - - - - 0 + + + + + + + + + 1
1	-0.181	-1.911	-0.000	*****)
2	0.01	0.107	0.000	(*)
3	0.208	2.192	0.000	(******
4	0.227	2.392	0.000	(****)*
5	0.103	1.089	0.000	(***)
6	-0.053	-0.563	-0.000	(**)
7	0.138	1.455	0.000	(****)
8	0.085	0.899	0.000	(***)
9	0.162	1.702	0.000	(****)
10	-0.034	-0.359	-0.000	(**)
11	0.104	1.091	0.000	(***)
12	-0.006	-0.067	-0.000	(*)
13	0.103	1.082	0.000	(***)
14	-0.034	-0.358	-0.000	(**)
15	-0.028	-0.291	-0.000	(**)

LAG	PARTIAL ACOR.	T-STAT	-1 - - - - - - - - - 0 + + + + + + + + + 1
1	-0.181	-1.911	*****)
2	-0.023	-0.247	(*)
3	0.213	2.242	(*****
4	0.328	3.461	(****)***
5	0.261	2.749	(****)*
6	-0.023	-0.243	(*)
7	-0.033	-0.347	(**)
8	-0.065	-0.69	(**)
9	0.135	1.425	(****)
10	0.04	0.424	(**)
11	0.082	0.864	(***)
12	-0.122	-1.29	(***)
13	-0.041	-0.431	(**)
14	-0.116	-1.225	(***)
15	-0.066	-0.699	(**)

Figure 25

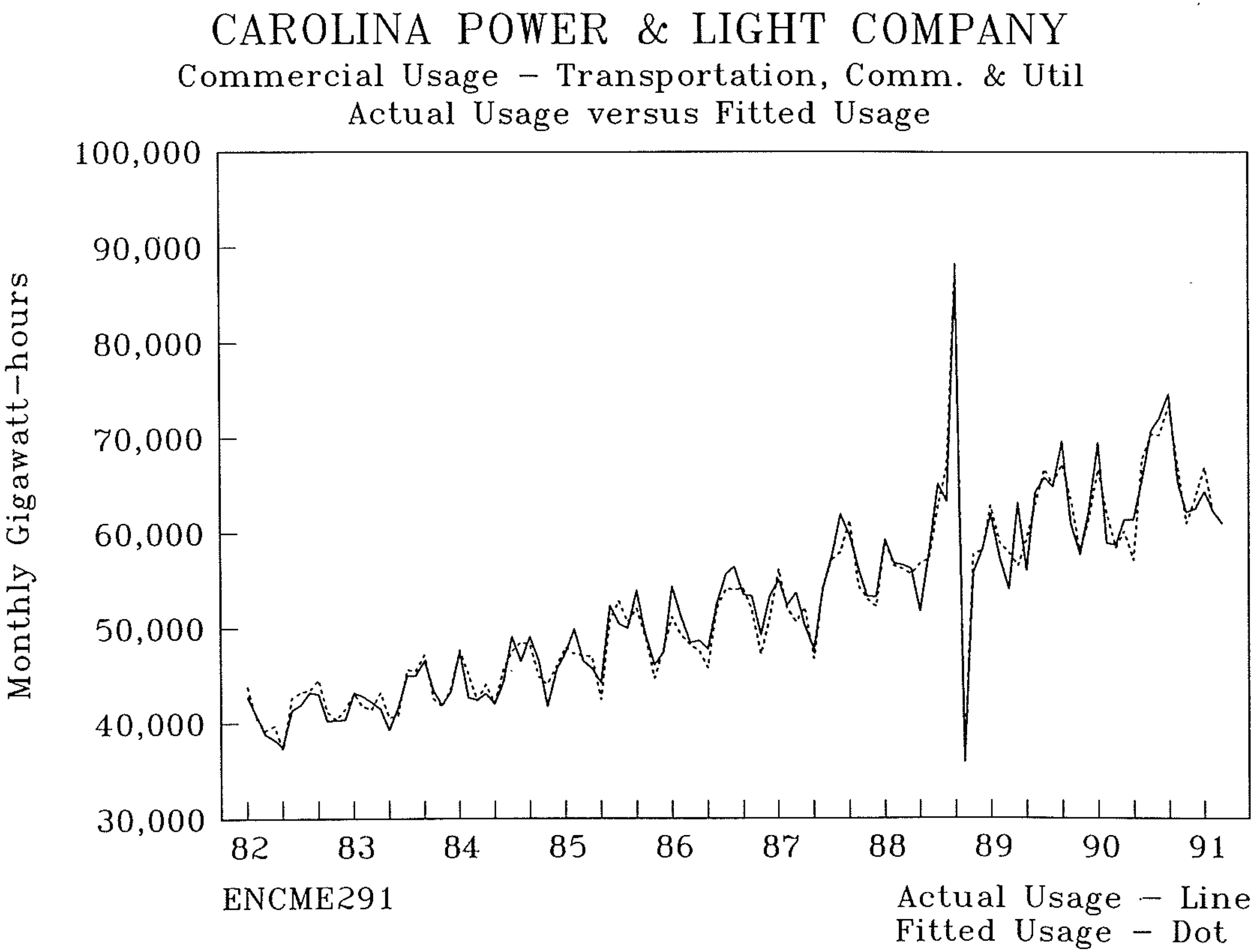

CAROLINA POWER & LIGHT COMPANY
Commercial Usage - Transportation, Comm. & Util
Actual Usage versus Fitted Usage
Monthly Gigawatt-hours
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
82
83
84
85
86
87
88
89
90
91
ENCME291
Actual Usage - Line
Fitted Usage - Dot

Figure 26

6) **Services** (SIC 70-89)

This sector of commercial activities includes establishments providing a diversity of services for individuals, businesses, and government. Included here are hotels, repair, amusement, health, legal, educational, and social services. This sector is the third largest employer of all commercial or manufacturing activities. As the national and state economies continue the trend towards a service-oriented base, this subgroup will provide the majority of new jobs. In addition, this sector ranks the highest in electricity intensity of all commercial subgroups.

Services employment is expected to increase from 225,256 in 1991 to 336,001 in 2010. This growth translates into growth in electricity use of 1.6% compounded annually over the forecast horizon.

The services model is shown in Figure 27 and a plot of the actual versus fitted values is shown in Figure 29.

The annual energy projection for this subgroup is shown in Table IX.

ORDINARY LEAST SQUARES

MONTHLY(1982:1 TO 1991:3) 111 OBSERVATIONS
DEPENDENT VARIABLE: LOG(MHCM@SV@CPL)

	CCOEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.632342	0.03926	16.11	LOG(ESVNS@CPL)
2)	0.159337	0.02698	5.907	WDUM*LOG(WHDD65CM@CPL)
3)	0.234008	0.04316	5.422	SDUM*LOG(WCDD65CM@CPL)
4)				PDL(LNARPECM,1,12,FAR)
\0	-0.0404411	0.02092		+ * + .
\1	-0.037071	0.01918		+ * + .
\2	-0.0337009	0.01743		+ * + .
\3	-0.0303308	0.01569		+ * + .
\4	-0.0269607	0.01395		+ * + .
\5	-0.0235906	0.0122		+ * + .
\6	-0.0202205	0.01046		+ * + .
\7	-0.0168504	0.008717		+ * + .
\8	-0.0134804	0.006973		+ * + .
\9	-0.0101103	0.00523		+ * + .
\10	-0.00674018	0.003487		+ * + .
\11	-0.00337009	0.001743		+*+.
SUM	-0.262867	0.136	-1.933	
AVG	3.66667	0	NC	
5)	8.26155	0.4874	16.95	SEASONM01
6)	8.29292	0.4866	17.04	SEASONM02
7)	8.23149	0.4839	17.01	SEASONM03
8)	8.17226	0.4786	17.08	SEASONM04
9)	8.20634	0.4671	17.57	SEASONM05
10)	7.89561	0.4663	16.93	SEASONM06
11)	7.83576	0.4785	16.38	SEASONM07
12)	7.8194	0.481	16.26	SEASONM08
13)	7.90097	0.4772	16.56	SEASONM09
14)	7.92773	0.4611	17.19	SEASONM10
15)	8.20177	0.4714	17.4	SEASONM11
16)	8.18523	0.4829	16.95	SEASONM12
17)	0.158718	0.05009	3.169	DUM905

R-BAR SQUARED: 0.9264 (RELATIVE TO Y=0, RBSQ: 1.0000)
F-STATISTIC(17,94): 450812.58
DURBIN-WATSON STATISTIC: 1.6110
SUM OF SQUARED RESIDUALS: 0.1955
STANDARD ERROR OF THE REGRESSION: 0.04561 NORMALIZED: 0.003806

Figure 27

WHERE:

MHCM@SV@CPL	COMMERCIAL USAGE – SERVICES (GIGAWATT HOURS)
ESVNS@CPL	SERVICE AREA EMPLOYMENT – SERVICES
WDUM	WINTER DUMMY (1–NOVEMBER – JUNE, 0 ELSEWHERE)
SDUM	SUMMER DUMMY (1=JULY – OCTOBER, 0 ELSEWHERE)
WHDD65CM@CPL	COMMERCIAL HEATING DEGREE DAYS – BASE 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
WCDD65CM@CPL	COMMERCIAL COOLING DEGREE DAYS – BASE – 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
LNARPECM	AVERAGE REAL PRICE OF ELECTRICITY – COMMERCIAL
SEASONM01	SEASONAL DUMMY FOR JANUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1= THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1= THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1= THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1= THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1= THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1= THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1= THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1= THEREIN, 0 ELSEWHERE)
DUM905	UNEXPLAINED DECREASE IN USAGE 90:5

Figure 27 (cont'd.)

STOCHASTIC ARIMA ANALYSIS

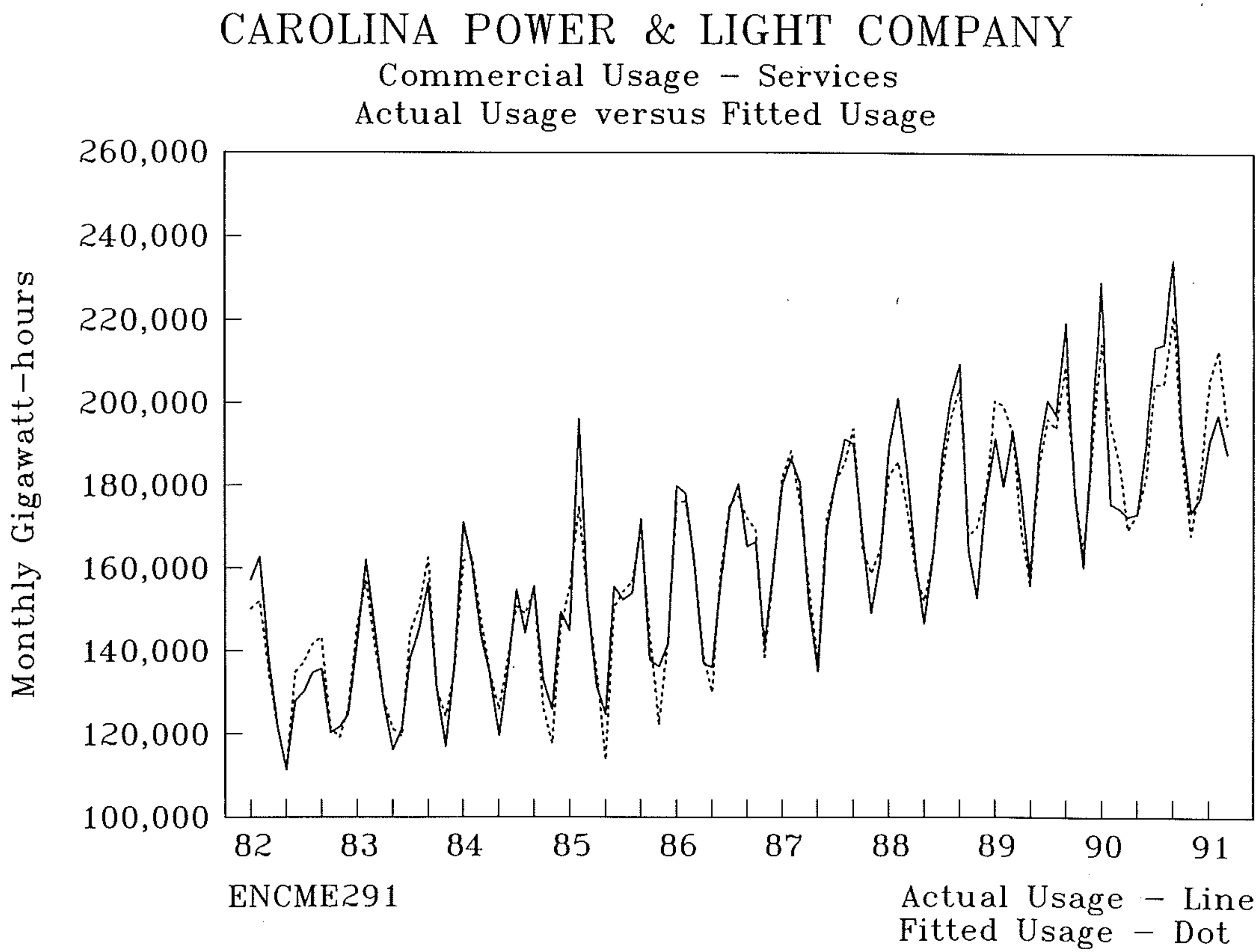
MONTHLY(1982:1 TO 1991:3) 111 OBSERVATIONS
VARIABLE NAME: RESIDUALS(@RR)
DEGREE OF DIFFERENCING = 0
DEGREE OF SEASONAL DIFFERENCING = 0
NUMBER OF PERIODS PER SEASON = 12
MEAN = −0.00000000001255*, STANDARD DEVIATION = 0.04196987140272*

AUTOCORRELATION STATISTICS:
APPROXIMATE STANDARD ERROR = 0.095
Q−STATISTIC, CHI−SQUARED (24 D.F.) = 33.865
LJUNG−BOX Q−STATISTIC = 38.4119

LAG	AUTO−CORR.	T−STAT	AUTO−COVAR.	−1 − − − − − − − − − − 0 + + + + + + + + + + 1
1	0.187	1.974	0.000	(*****
2	−0.023	−0.241	−0.000	(*)
3	0.116	1.224	0.000	(***)
4	−0.094	−0.987	−0.000	(***)
5	−0.237	−2.501	−0.000	*(****)
6	−0.041	−0.43	−0.000	(**)
7	−0.105	−1.107	−0.000	(***)
8	−0.15	−1.581	−0.000	(****)
9	0.009	0.093	0.000	(*)
10	−0.066	−0.693	−0.000	(**)
11	0.021	0.222	0.000	(*)
12	0.118	1.247	0.000	(***)
13	0.129	1.355	0.000	(****)
14	0.11	1.164	0.000	(***)
15	0.052	0.552	0.000	(**)

LAG	PARTIAL ACOR.	T−STAT	−1 − − − − − − − − − − 0 + + + + + + + + + + 1
1	0.187	1.974	(*****
2	−0.06	−0.633	(**)
3	0.137	1.446	(****)
4	−0.154	−1.625	(****)
5	−0.186	−1.963	*****)
6	0.017	0.176	(*)
7	−0.105	−1.109	(***)
8	−0.074	−0.783	(**)
9	0.001	0.011	(*)
10	−0.119	−1.258	(***)
11	0.073	0.769	(**)
12	0.031	0.331	(**)
13	0.09	0.945	(***)
14	0.065	0.687	(**)
15	−0.043	−0.453	(**)

Figure 28



CAROLINA POWER & LIGHT COMPANY
Commercial Usage - Services
Actual Usage versus Fitted Usage
Monthly Gigawatt-hours
260,000
240,000
220,000
200,000
180,000
160,000
140,000
120,000
100,000
82
83
84
85
86
87
88
89
90
91
ENCME291
Actual Usage - Line
Fitted Usage - Dot

Figure 29

7) **<u>Wholesale and Retail Trade</u>** **(SIC 50-59)**

This commercial subgroup is composed of two trade activities -- businesses selling merchandise to retailers and businesses selling merchandise for personal or household consumption. The exceptions to this general classification are lumber yards; paint, glass and wallpaper stores; stationery stores; and gasoline service stations which sell to both the general public for personal or household consumption and to businesses. These types of businesses are included here even if a higher proportion of their sales is made to businesses.

Employment in wholesale and retail trade is the largest employment sector in the service area. Trade employment is forecast to increase from 315,670 in 1991 to 440,472 in 2010. Electrical energy use is also expected to increase at an average annual compounded rate of 1.7%.

The trade model is shown in Figure 30 and a plot of actual versus fitted values is shown in Figure 32.

The energy projection for this subgroup is shown in Table IX.

ORDINARY LEAST SQUARES

MONTHLY(1982:1 TO 1991:3) 111 OBSERVATIONS
DEPENDENT VARIABLE: LOG(MHCM@T@CPL)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.855204	0.03476	24.61	LOG(ETNS@CPL)
2)	0.030208	0.0171	1.767	WDUM*LOG(WHDD65CM@CPL)
3)	0.145619	0.02808	5.185	SDUM*LOG(WCDD65CM@CPL)
4)				PDL(LNARPECM,1,12,FAR)
\0	−0.0361305	0.01364		+ * + .
\1	−0.0331196	0.0125		+ * + .
\2	−0.0301088	0.01137		+ * + .
\3	−0.0270979	0.01023		+ * + .
\4	−0.024087	0.009094		+ * + .
\5	−0.0210761	0.007957		+ * + .
\6	−0.0180653	0.00682		+ * + .
\7	−0.0150544	0.005684		+ * + .
\8	−0.0120435	0.004547		+ * + .
\9	−0.00903263	0.00341		+ * + .
\10	−0.00602175	0.002273		+ * + .
\11	−0.00301088	0.001137		+*+.
SUM	−0.234848	0.08867	−2.649	
AVG	3.66667	0	NC	
5)	7.5652	0.3729	20.29	SEASONM01
6)	7.51751	0.3722	20.2	SEASONM02
7)	7.48466	0.3707	20.19	SEASONM03
8)	7.48762	0.3678	20.36	SEASONM04
9)	7.50725	0.3609	20.8	SEASONM05
10)	7.03534	0.3555	19.79	SEASONM06
11)	7.04942	0.3622	19.46	SEASONM07
12)	7.03111	0.3638	19.33	SEASONM08
13)	7.04207	0.3616	19.47	SEASONM09
14)	7.0056	0.3532	19.83	SEASONM10
15)	7.47636	0.3644	20.51	SEASONM11
16)	7.48687	0.3709	20.19	SEASONM12
17)	0.140287	0.03198	4.387	DUM888

R−BAR SQUARED: 0.9703 (RELATIVE TO Y=0, RBSQ: 1.0000)
DURBIN−WATSON STATISTIC: 1.5808
SUM OF SQUARED RESIDUALS: 0.08258
STANDARD ERROR OF THE REGRESSION: 0.02964 NORMALIZED: 0.002442

Figure 30

WHERE:

MHCM@T@CPL	COMMERCIAL USAGE – TRADE (GIGAWATT HOURS)
ETNS@CPL	SERVICE AREA EMPLOYMENT – TRADE
WDUM	WINTER DUMMY (1–NOVEMBER – JUNE, 0 ELSEWHERE)
SDUM	SUMMER DUMMY (1=JULY – OCTOBER, 0 ELSEWHERE)
WHDD65CM@CPL	COMMERCIAL HEATING DEGREE DAYS – BASE 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
WCDD65CM@CPL	COMMERCIAL COOLING DEGREE DAYS – BASE – 65 – WEIGHTED FOR 4 STATIONS, BILL CYCLE & CM USAGE
LNARPECM	AVERAGE REAL PRICE OF ELECTRICITY – COMMERCIAL
SEASONM01	SEASONAL DUMMY FOR JANUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1= THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1= THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1= THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1= THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1= THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1= THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1= THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1= THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1= THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1= THEREIN, 0 ELSEWHERE)
DUM888	UNEXPLAINED INCREASE IN USAGE 90:5

Figure 30 (cont'd.)

STOCHASTIC ARIMA ANALYSIS

MONTHLY(1982:1 TO 1991:3) 111 OBSERVATIONS
VARIABLE NAME: RESIDUALS(@RR)
DEGREE OF DIFFERENCING = 0
DEGREE OF SEASONAL DIFFERENCING = 0
NUMBER OF PERIODS PER SEASON = 12
MEAN = 0.00000000000639*, STANDARD DEVIATION = 0.02727492267601*

AUTOCORRELATION STATISTICS:
APPROXIMATE STANDARD ERROR = 0.095
Q-STATISTIC, CHI-SQUARED (24 D.F.) = 46.462
LJUNG-BOX Q-STATISTIC = 54.4477

LAG	AUTO-CORR.	T-STAT	AUTO-COVAR.	-1 - - - - - - - - - - 0 + + + + + + + + + + 1
1	0.207	2.176	0.000	(*****
2	0.008	0.087	0.000	(*)
3	0.003	0.034	0.000	(*)
4	0.263	2.772	0.000	(****)*
5	-0.027	-0.287	-0.000	(**)
6	-0.113	-1.194	-0.000	(***)
7	-0.148	-1.559	-0.000	(****)
8	-0.079	-0.833	-0.000	(***)
9	0.062	0.658	0.000	(**)
10	-0.038	-0.397	-0.000	(**)
11	-0.045	-0.469	-0.000	(**)
12	-0.003	-0.03	-0.000	(*)
13	0.135	1.424	0.000	(****)
14	0.042	0.447	0.000	(**)
15	-0.159	-1.675	-0.000	(****)

LAG	PARTIAL ACOR.	T-STAT	-1 - - - - - - - - - - 0 + + + + + + + + + + 1
1	0.207	2.176	(*****
2	-0.036	-0.379	(**)
3	0.009	0.097	(*)
4	0.273	2.874	(****)*
5	-0.157	-1.653	(****)
6	-0.078	-0.818	(***)
7	-0.104	-1.099	(***)
8	-0.122	-1.29	(***)
9	0.171	1.799	(****)
10	-0.056	-0.587	(**)
11	0.026	0.276	(**)
12	0.048	0.501	(**)
13	0.024	0.248	(*)
14	0.02	0.215	(*)
15	-0.22	-2.313	*****)

Figure 31

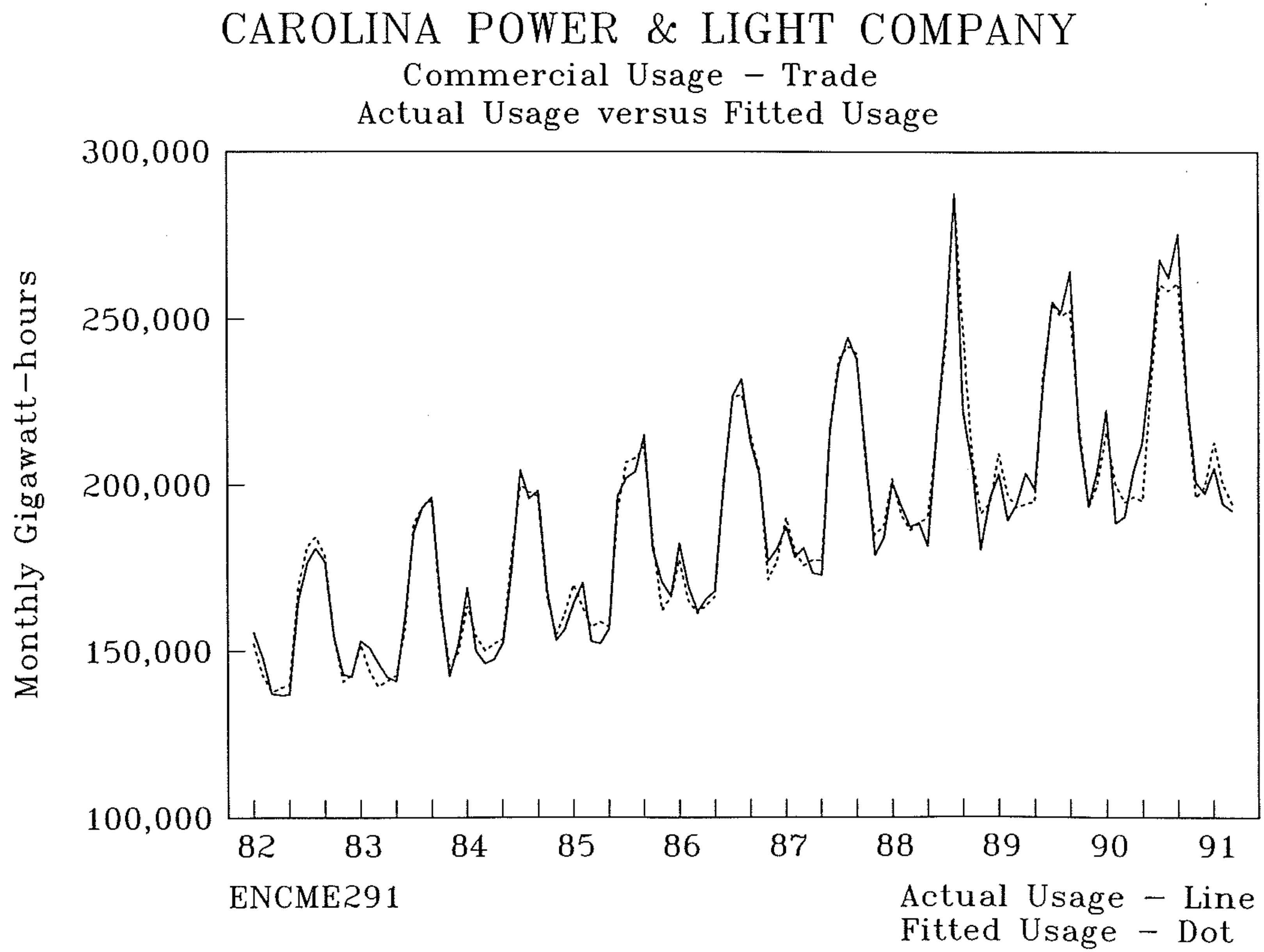

CAROLINA POWER & LIGHT COMPANY
Commercial Usage - Trade
Actual Usage versus Fitted Usage
Monthly Gigawatt-hours
300,000
250,000
200,000
150,000
100,000
82
83
84
85
86
87
88
89
90
91
ENCME291
Actual Usage - Line
Fitted Usage - Dot

Figure 32

I.3 INDUSTRIAL FORECAST

In analyzing the historical usage in the industrial sector, the industrial sector is divided into fourteen two-digit SIC Codes and the remaining industrial consumption is combined into one miscellaneous group. Each of these fifteen subgroups was estimated separately. From this perspective, these models represent a generalized end-use approach.

Table XI shows the industrial forecast by two-digit SIC and the total. An individual analysis of each two-digit group is also included separately in this report.

There are many indices which correlate closely with industrial electrical usage. Some of these indices, however, are as difficult to predict in the forecast period as electrical usage itself. For example, historical value-added in certain SIC Codes is closely correlated with electrical usage in these same SIC Codes. Predicting value-added in the future, however, requires many assumptions. The industrial models that have been used are based on variables which are relatively stable over the long run.

One of the primary forces which will determine electrical usage in the future is the population, especially the working age population. The population during the historical period has been accurately determined. As the present population matures, estimates of the work force and potential employment can be estimated. This potential manufacturing labor force then serves as one basis for forecasting electrical usage.

CAROLINA POWER & LIGHT CO.
INDUSTRIAL ENERGY REPORT
(in MWh)
(Reduced By Conservation and Load Management)

	SIC 20 FOOD	%CH YEAR AGO	SIC 22 TEXTILES	%CH YEAR AGO	SIC 23 APPAREL	%CH YEAR AGO	SIC 24 LUMBER WOOD	%CH YEAR AGO	SIC 25 FURNITURE	%CH YEAR AGO	SIC 26 PAPER	%CH YEAR AGO	SIC 27 PRINTING PUBLISHING	%CH YEAR AGO
1986	497,248	3.3	3,003,982	1.5	170,978	2.2	367,968	2.9	162,129	−1.4	1,000,302	5.2	40,765	6.2
1987	512,857	3.1	3,221,992	6.0	178,188	4.2	387,011	5.2	175,380	8.2	929,451	−7.1	41,057	0.7
1988	523,021	2.0	3,340,488	3.7	176,676	−0.8	382,795	−1.1	182,722	4.2	906,084	−2.5	41,265	0.5
1989	533,326	2.0	3,505,188	4.9	175,278	−0.8	374,723	−2.1	177,321	−3.0	906,625	0.1	42,033	1.9
1990	549,871	3.1	3,390,716	−3.3	180,038	2.7	389,710	4.0	173,648	−2.1	908,196	0.2	44,862	6.7
1991	548,126	−0.3	3,190,241	−5.9	163,474	−9.2	332,519	−14.7	163,341	−5.9	927,323	2.1	42,251	−5.8
1992	565,722	3.4	3,332,616	7.2	174,566	8.0	344,898	7.9	160,656	0.8	1,054,574	16.5	43,065	3.1
1993	578,567	2.3	3,482,599	4.5	178,867	2.5	385,605	11.8	165,295	2.9	1,089,129	3.3	44,588	3.5
1994	593,244	2.5	3,457,780	−0.7	177,295	−0.9	412,880	7.1	166,549	0.8	1,071,568	−1.6	45,740	2.6
1995	605,690	2.1	3,423,236	−1.0	174,816	−1.4	423,772	2.6	164,642	−1.1	1,054,058	−1.6	46,419	1.5
1996	616,345	1.8	3,395,672	−0.8	173,041	−1.0	429,401	1.3	161,777	−1.7	1,046,745	−0.7	46,984	1.2
1997	625,948	1.6	3,383,312	−0.4	171,893	−0.7	435,862	1.5	159,092	−1.7	1,042,742	−0.4	47,551	1.2
1998	635,812	1.6	3,396,654	0.4	171,599	−0.2	445,712	2.3	157,699	−0.9	1,045,305	0.2	48,245	1.5
1999	646,461	1.7	3,401,167	0.1	171,234	−0.2	457,290	2.6	156,821	−0.6	1,043,673	−0.2	49,022	1.6
2000	657,470	1.7	3,389,715	−0.3	170,469	−0.4	468,392	2.4	155,938	−0.6	1,036,498	−0.7	49,791	1.6
2001	668,213	1.6	3,374,923	−0.4	169,454	−0.6	475,915	1.6	154,671	−0.8	1,031,603	−0.5	50,654	1.7
2002	678,800	1.6	3,357,466	−0.5	168,771	−0.4	477,467	0.3	153,053	−1.0	1,026,860	−0.5	51,702	2.1
2003	689,466	1.6	3,333,230	−0.7	167,956	−0.5	476,392	−0.2	151,954	−0.7	1,018,184	−0.8	52,626	1.8
2004	700,345	1.6	3,324,749	−0.3	167,384	−0.3	480,382	0.8	150,940	−0.7	1,013,520	−0.5	53,513	1.7
2005	711,720	1.6	3,333,732	0.3	167,105	−0.2	489,449	1.9	150,899	0.0	1,013,966	0.0	54,496	1.8
2006	723,568	1.7	3,328,542	−0.2	166,437	−0.4	493,573	0.8	150,643	−0.2	1,009,081	−0.5	55,517	1.9
2007	735,602	1.7	3,326,391	−0.1	165,816	−0.4	499,597	1.2	150,166	−0.3	1,003,989	−0.5	56,535	1.8
2008	747,611	1.6	3,319,801	−0.2	165,081	−0.4	506,198	1.3	149,639	−0.4	1,000,853	−0.3	57,498	1.7
2009	759,514	1.6	3,317,082	−0.1	164,315	−0.5	514,511	1.6	149,311	−0.2	995,288	−0.6	58,414	1.6
2010	771,696	1.6	3,319,674	0.1	163,882	−0.3	520,382	1.1	149,130	−0.1	993,094	−0.2	59,346	1.6

1991 – Same as Reference Case

Table XI

CAROLINA POWER & LIGHT CO.
INDUSTRIAL ENERGY REPORT
(in MWh)
(Reduced By Conservation and Load Management)

	SIC 28 CHEMICALS	%CH YEAR AGO	SIC 281 BASIC CHEMICALS	%CH YEAR AGO	SIC 282 SYNTHETIC FIBERS	%CH YEAR AGO	SIC 287 AGRIC CHEMICALS	%CH YEAR AGO	SIC 28 ALL OTHER	%CH YEAR AGO	SIC 30 RUBBER PLASTICS	%CH YEAR AGO	SIC 32 STONE CLAY GLASS	%CH YEAR AGO
1986	2,893,111	4.8	427,957	4.2	1,521,667	5.6	661,801	−3.4	281,686	25.0	438,213	14.0	286,461	4.6
1987	2,980,352	3.0	429,456	0.4	1,608,440	5.7	679,182	2.6	263,274	−6.5	479,272	9.4	290,845	1.5
1988	3,088,435	3.6	410,818	−4.3	1,720,191	6.9	687,880	1.3	269,546	2.4	539,086	12.5	278,170	−4.4
1989	3,175,925	2.8	397,436	−3.3	1,791,748	4.2	703,710	2.3	283,031	5.0	553,653	2.7	278,356	0.1
1990	3,204,527	0.9	413,306	4.0	1,756,772	−2.0	737,422	4.8	298,623	2.7	563,432	1.8	266,760	−4.2
1991	3,197,935	−0.2	410,889	−0.6	1,749,260	−0.4	725,999	−1.5	311,787	4.4	546,578	−3.0	244,000	−8.5
1992	3,265,694	3.2	348,227	−15.1	1,815,728	4.9	736,019	2.3	365,720	19.3	572,493	6.9	253,730	4.0
1993	3,367,450	3.1	350,044	0.5	1,872,898	3.1	764,111	3.8	380,396	4.0	650,784	13.7	262,525	3.5
1994	3,421,189	1.6	350,194	0.0	1,904,994	1.7	779,986	2.1	386,015	1.5	723,877	11.2	265,834	1.3
1995	3,461,211	1.2	349,913	−0.1	1,927,646	1.2	790,649	1.4	393,003	1.8	768,058	6.1	266,974	0.4
1996	3,504,556	1.3	349,905	0.0	1,951,528	1.2	801,658	1.4	401,465	2.2	800,055	4.2	267,335	0.1
1997	3,555,785	1.5	350,248	0.1	1,981,360	1.5	813,971	1.5	410,206	2.2	828,933	3.6	267,496	0.1
1998	3,621,467	1.8	351,169	0.3	2,020,735	2.0	829,204	1.9	420,359	2.5	864,072	4.2	268,307	0.3
1999	3,675,470	1.5	351,900	0.2	2,053,701	1.6	841,829	1.5	428,040	1.8	902,684	4.5	268,973	0.2
2000	3,710,782	1.0	352,213	0.1	2,074,240	1.0	849,745	0.9	434,584	1.5	941,738	4.3	269,333	0.1
2001	3,747,514	1.0	352,673	0.1	2,094,202	1.0	857,058	0.9	443,581	2.1	979,425	4.0	269,513	0.1
2002	3,775,691	0.8	352,984	0.1	2,108,798	0.7	862,348	0.6	451,561	1.8	1,021,892	4.3	269,590	0.0
2003	3,801,697	0.7	353,266	0.1	2,121,614	0.6	867,058	0.5	459,759	1.8	1,061,829	3.9	269,041	−0.2
2004	3,837,337	0.9	353,782	0.1	2,140,107	0.9	873,993	0.8	469,456	2.1	1,104,224	4.0	269,261	0.1
2005	3,889,808	1.4	354,769	0.3	2,169,662	1.4	885,018	1.3	480,358	2.3	1,154,434	4.5	270,556	0.5
2006	3,929,234	1.0	355,452	0.2	2,192,128	1.0	893,676	1.0	487,978	1.6	1,210,896	4.9	271,288	0.3
2007	3,967,085	1.0	356,033	0.2	2,212,582	0.9	901,835	0.9	496,636	1.8	1,268,398	4.7	272,138	0.3
2008	4,000,824	0.9	356,492	0.1	2,230,216	0.8	909,181	0.8	504,936	1.7	1,326,555	4.6	273,224	0.4
2009	4,037,008	0.9	356,861	0.1	2,248,733	0.8	917,309	0.9	514,105	1.8	1,382,696	4.2	274,313	0.4
2010	4,087,561	1.3	357,242	0.1	2,275,922	1.2	929,321	1.3	525,076	2.1	1,438,664	4.0	274,967	0.2

1991 – Same as Reference Case

Table XI (cont'd.)

CAROLINA POWER & LIGHT CO.
INDUSTRIAL ENERGY REPORT
(in MWh)
(Reduced By Conservation and Load Management)

	SIC 33&34 PRIMARY FABRICATED METALS	%CH YEAR AGO	SIC 35 MACHINERY EXCEPT ELEC.	%CH YEAR AGO	SIC 36 ELEC. EQUIP.	%CH YEAR AGO	SIC 37 TRANSPORTATION EQUIPMENT	%CH YEAR AGO	ALL OTHER SALES	%CH YEAR AGO	TOTAL INDUSTRIAL	%CH YEAR AGO
1986	845,341	0.9	140,337	1.5	619,496	3.1	116,481	15.6	470,885	9.6	11,053,697	3.1
1987	877,049	3.8	146,883	4.7	610,128	−1.5	128,651	10.4	518,122	10.0	11,477,238	3.8
1988	943,488	7.6	164,297	11.9	630,055	3.3	150,572	17.0	578,523	10.5	11,925,679	3.9
1989	958,199	1.6	171,972	4.7	633,783	0.6	151,581	0.7	706,542	22.1	12,344,506	3.5
1990	947,143	−1.2	179,783	4.5	641,644	1.2	149,530	−1.4	744,479	5.4	12,335,935	−0.1
1991	922,642	−2.6	168,823	−6.1	607,348	−5.3	137,196	−8.2	715,094	−4.1	11,906,891	−3.5
1992	967,454	6.6	170,986	2.6	636,151	5.0	146,277	10.2	712,486	3.9	12,401,369	6.1
1993	1,003,204	3.7	179,308	4.9	655,013	3.0	166,428	13.8	729,015	2.3	12,938,376	4.3
1994	1,007,844	0.5	184,294	2.8	671,857	2.6	176,481	6.0	721,564	−1.0	13,097,994	1.2
1995	1,006,566	−0.1	187,832	1.9	684,447	1.9	178,273	1.0	710,915	−1.5	13,156,908	0.4
1996	1,009,765	0.3	190,859	1.6	694,382	1.5	181,202	1.6	708,997	−0.3	13,227,114	0.5
1997	1,010,897	0.1	193,333	1.3	702,316	1.1	185,789	2.5	706,119	−0.4	13,317,067	0.7
1998	1,014,182	0.3	195,882	1.3	709,786	1.1	192,169	3.4	705,822	0.0	13,472,713	1.2
1999	1,016,966	0.3	198,648	1.4	717,668	1.1	199,702	3.9	708,207	0.3	13,613,987	1.0
2000	1,017,910	0.1	201,118	1.2	725,626	1.1	207,081	3.7	709,605	0.2	13,711,465	0.7
2001	1,018,116	0.0	203,159	1.0	733,211	1.0	214,166	3.4	709,940	0.0	13,800,477	0.6
2002	1,017,563	−0.1	204,907	0.9	740,922	1.1	221,113	3.2	711,308	0.2	13,877,105	0.6
2003	1,016,185	−0.1	206,619	0.8	748,665	1.0	227,687	3.0	713,196	0.3	13,934,726	0.4
2004	1,016,301	0.0	208,345	0.8	756,402	1.0	234,776	3.1	716,612	0.5	14,034,092	0.7
2005	1,019,077	0.3	210,425	1.0	764,668	1.1	243,512	3.7	721,792	0.7	14,195,639	1.2
2006	1,021,076	0.2	212,561	1.0	773,567	1.2	252,705	3.8	725,326	0.5	14,324,012	0.9
2007	1,021,946	0.1	214,479	0.9	782,345	1.1	261,657	3.5	729,310	0.5	14,455,455	0.9
2008	1,022,695	0.1	216,176	0.8	790,590	1.1	270,013	3.2	733,278	0.5	14,580,037	0.9
2009	1,022,910	0.0	217,638	0.7	798,083	0.9	277,122	2.6	736,298	0.4	14,704,503	0.9
2010	1,023,149	0.0	219,425	0.8	805,266	0.9	285,145	2.9	740,933	0.6	14,852,314	1.0

1991 – Same as Reference Case

Table XI (cont'd.)

Historically, the investment in plant and equipment, along with the manufacturing labor force, has given an indication of the potential gross national product (GNP). Making policy assumptions about investment in plant and equipment in the future, economists have made estimates of the future GNP. While many scenarios are possible, future trends in potential GNP are relatively stable. There is general agreement among economists that real GNP will increase at an average rate of approximately 2.1% annually during the forecast period. The specific numbers in given years used in the CP&L forecast come from Data Resources, Inc. (DRI). These numbers, however, have been corroborated and are in general agreement with other forecasters.

The population of the future creates a demand for given products. A given population will require a given quantity of food stuffs, clothing, appliances, etc., subject to price and the general performance of the economy. This forecast assumes that the per capita quantities of these goods demanded will be similar to those demanded in the historical period given due adjustment to future income, price, and technology trends.

The share of national production in the CP&L service area has generally been increasing during the historical period. As new industry moves into the area and offers new job opportunities, migration patterns frequently change. There was a net out-migration from the CP&L service area during the 1960s, but this trend was reversed during the 1970s. It is assumed during the forecast period that this net in-migration will continue. As population growth declines in the future, the effects of any migration pattern will become more important.

Finally, the power consumption by industry in the CP&L service area is dependent on local production. A local production index has been derived where national production per employee in a given industry is assumed to be representative of the production rate in the service area. When this production rate is multiplied by the number of employees predicted for the industry in the CP&L service area, an index which represents the production in the service area is obtained. This index has generally correlated closely with power consumption during the historical period. The index for the forecast period is derived in the same manner. The forecast production rate per employee nationally is multiplied by the forecasted number of employees from the CP&L Service Area Economic Model.

As an example, the regression equation used to forecast power usage in SIC 20, Food Products, is obtained by the following steps:

1) The historical employment in the Food Products industry in the North Carolina service area has correlated with both the employment in the Food Products industry in North Carolina as tabulated by the Employment Security Commission and with the local production index in the CP&L service area. Employment in the North Carolina portion of the CP&L service area has generally varied as the employment in the industry in North Carolina. Employment in the South Carolina CP&L service area is correlated with state employment in SIC 20 in a similar way. Forecast values for employment in SIC 20 for each state come from the DRI Regional Information Service.

2) The production index for the CP&L service area is derived by taking the Federal Reserve Board Production Index per employee in the industry nationally and multiplying it by the number of Food Products employees in the CP&L service area.

3) Historically, the power delivered to the Food Products industry in the CP&L service area is regressed on the local production index and a price variable. The resultant regression equation was used to forecast electrical power for the Food Products industry in the service area during the forecast period.

The same procedure was used in each of the two-digit industrial classifications. Disaggregation was necessary to the three-digit classification in the chemical industry because of its inherent diversity.

There were known loads which were installed in several of the industrial classifications which had to be accounted for separately. For example, when a glass company installed an electric furnace where it had previously used gas, there was an abrupt increase in usage in this industrial classification which had to be accounted for prior to making a forecast. The same situation arose where a large synthetic fibers plant was connected to the system where there had previously been only one or two, or even no existing plants. Large drag lines in the phosphate industry had to be treated in a similar manner. In most cases where there were large discontinuities in power usage, we were able to verify through records these large loads as they were added to the system.

1) **<u>Food Products</u> (SIC 20)**

In the Service Area Economic Model, we are forecasting that employment in the Food Products industry will decrease from 25,048 employees in 1991 to 22,922 employees in the year 2010. Due to technological improvements in the industry, however, it is estimated that the local production index will increase at an average compounded growth rate of 2.2% per year.

The energy delivered to the Food Products industry is projected to increase at an average annual rate of 2.2%. There will tend to be more energy use due to increased equipment use per unit of labor.

The regression model is shown in Figure 33 and a plot of the actual versus the fitted values during the historical period is shown in Figure 34.

The table showing the annual power usage by this industrial classification is shown in Table XI.

ORDINARY LEAST SQUARES

QUARTERLY(1970:2 TO 1991:1) 84 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@20SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	0.841953	0.2948	2.856	CONSTANT
1)	0.828491	0.06051	13.69	LOG(GHID@20SA\1)
2)	0.168136	0.06277	2.679	LOG(X20@CPL)
3)	0.0223611	0.009888	2.261	SHIFT843861

R-BAR SQUARED: 0.9915
F-STATISTIC(3,80): 3214.6895
DURBIN-WATSON STATISTIC: 2.0019
SUM OF SQUARED RESIDUALS: 0.03878
STANDARD ERROR OF THE REGRESSION: 0.02202 NORMALIZED: 0.004822

WHERE:

GHID@20SA	GIGAWATT HOUR SALES – FOOD PRODUCTS – SEASONALLY ADJUSTED
X20@CPL	CP&L SERV. AREA PRODUCTION INDEX – FOOD PRODUCTS
SHIFT843861	SHIFT VARIABLE FOR STRUCTURAL CHANGE IN SIC 20

Figure 33

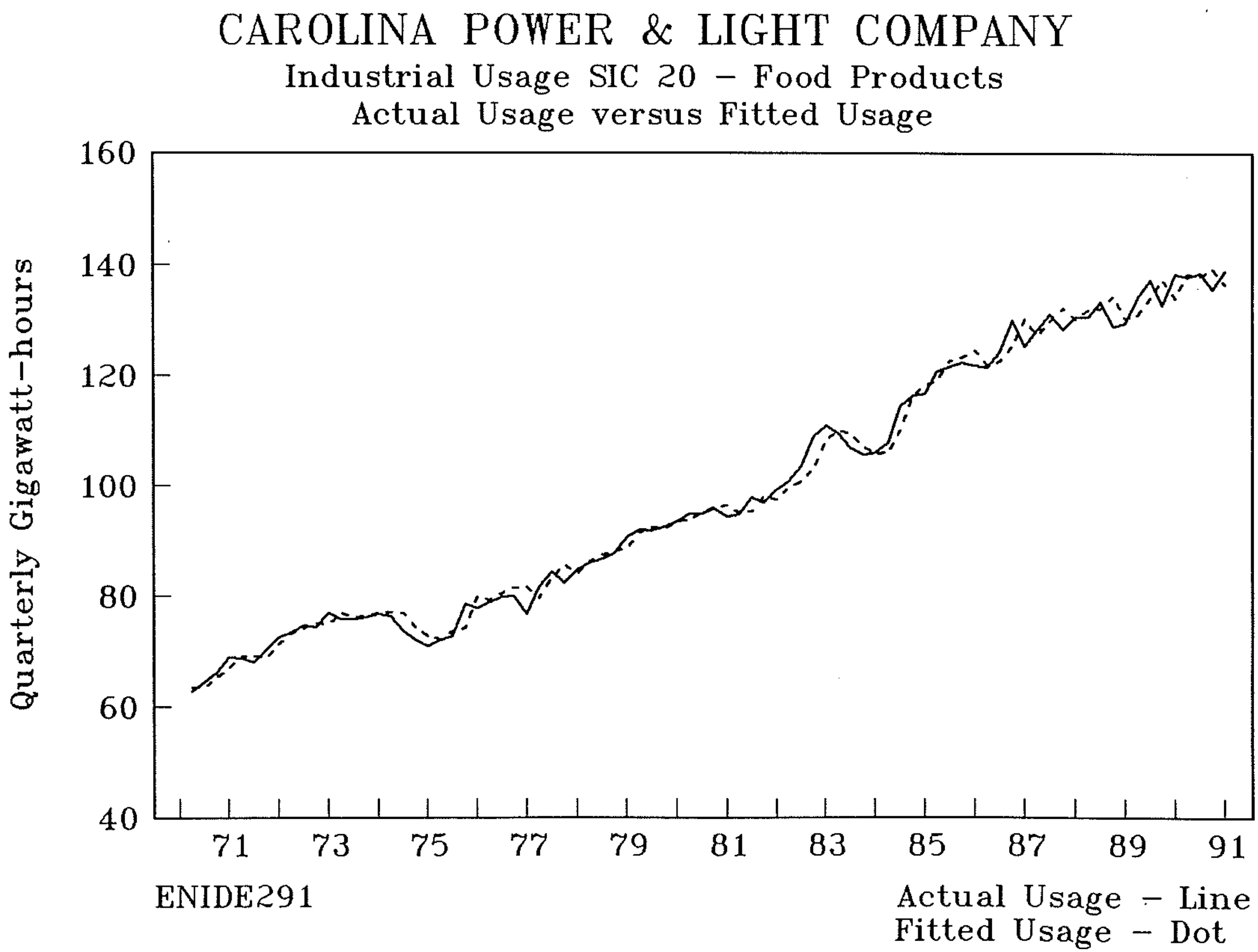
ORDINARY LEAST SQUARES

QUARTERLY(1970:2 TO 1991:1) 84 OBSERVATIONS
DEPENDENT VARIABLE: GHID@20SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.0001	0.002361	423.7	EXP(FIT(@RR))

R-BAR SQUARED: 0.9913 (RELATIVE TO Y=0, RBSQ: 0.9995)
F-STATISTIC(1,83): 179497.37
DURBIN-WATSON STATISTIC: 2.1272
SUM OF SQUARED RESIDUALS: 400.9
STANDARD ERROR OF THE REGRESSION: 2.198 NORMALIZED: 0.02222

Figure 33 (cont'd.)



CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 20 - Food Products
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
160
140
120
100
80
60
40
71
73
75
77
79
81
83
85
87
89
91
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 34

2) **Textile Products** (SIC 22)

For years, the Textile Products industry used appreciably more power in the CP&L system than any other group. However, in the last few years, the rate of increase has fallen off appreciably and, in some years, has actually been negative. In the North Carolina service area, the maximum number of 75,000 employees in this industry was reached in 1974 and, since that time, the employment in the industry has been dropping at an average annual rate of between 2 and 3 percent per year. In 1991, there were 73,400 employees in the North and South Carolina service area, and it is estimated that there will be 43,240 in the year 2010.

This industry also is expected to benefit from technological improvements. The local production index for the industry is expected to increase at a compounded growth rate of 0.7% per year in spite of the drop in employment.

The Textile Products industry has been both labor and energy intensive. Since 1974, however, there have been great efforts to more effectively use electrical power. Some large companies have initiated very productive conservation programs and this trend is expected to continue. The 0.7% increase in output over the forecast period is expected to result in electrical energy consumed by this group to increase at a compounded annual rate of 0.7% per year.

The regression model is shown in Figure 35, corrected for autocorrelation since an ARIMA analysis indicated first-order autoregressive error. A plot of the actual versus the fitted values during the historical period is shown in Figure 36.

The forecast values are shown in Table XI.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

QUARTERLY(1970:1 TO 1991:1) 85 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@22SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDEI VARIABLE
	6.97483	0.05658	123.3	CONSTANT
1)	0.732857	0.04359	16.81	LOG(X22@CPL)
2)				PDL(LNRELINPCOST@ID,2,8,BOTH)
\0	-0.0116263	0.002415		+ * + .
\1	-0.020346	0.004226		+ * + .
\2	-0.0261591	0.005434		+ * + .
\3	-0.0290657	0.006037		+ * + .
\4	-0.0290657	0.006037		+ * + .
\5	-0.0261591	0.005434		+ * + .
\6	-0.020346	0.004226		+ * + .
\7	-0.0116263	0.002415		+ * + .
SUM	-0.174394	0.03622	-4.814	
AVG	3.5	0	NC	
	0.548354	0.09256	5.924	RHO

R-BAR SQUARED: 0.9589
F-STATISTIC(3,81): 653.49765
DURBIN-WATSON STATISTIC: 1.9902
SUM OF SQUARED RESIDUALS: 0.03502
STANDARD ERROR OF THE REGRESSION: 0.02079 NORMALIZED: 0.003160

WHERE:

GHID@22SA	GIGAWATT HOUR SALES – TEXTILE PRODUCTS – SEASONALLY ADJUSTED
X22@CPL	CP&L SERV. AREA PRODUCTION INDEX – TEXTILE PRODUCTS
LNRELINPCOST@ID	RELATIVE COST OF ELEC. FOR INDUSTRIAL

Figure 35

ORDINARY LEAST SQUARES

QUARTERLY(1970:1 TO 1991:1) 85 OBSERVATIONS
DEPENDENT VARIABLE: GHID@22SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00037	0.002165	462.2	EXP(FIT(@RR))

R-BAR SQUARED: 0.9618 (RELATIVE TO Y=0, RBSQ: 0.9996)
F-STATISTIC(1,84): 213600.58
DURBIN-WATSON STATISTIC: 1.9675
SUM OF SQUARED RESIDUALS: 1.775E+04
STANDARD ERROR OF THE REGRESSION: 14.54 NORMALIZED: 0.02005

Figure 35 (cont'd.)

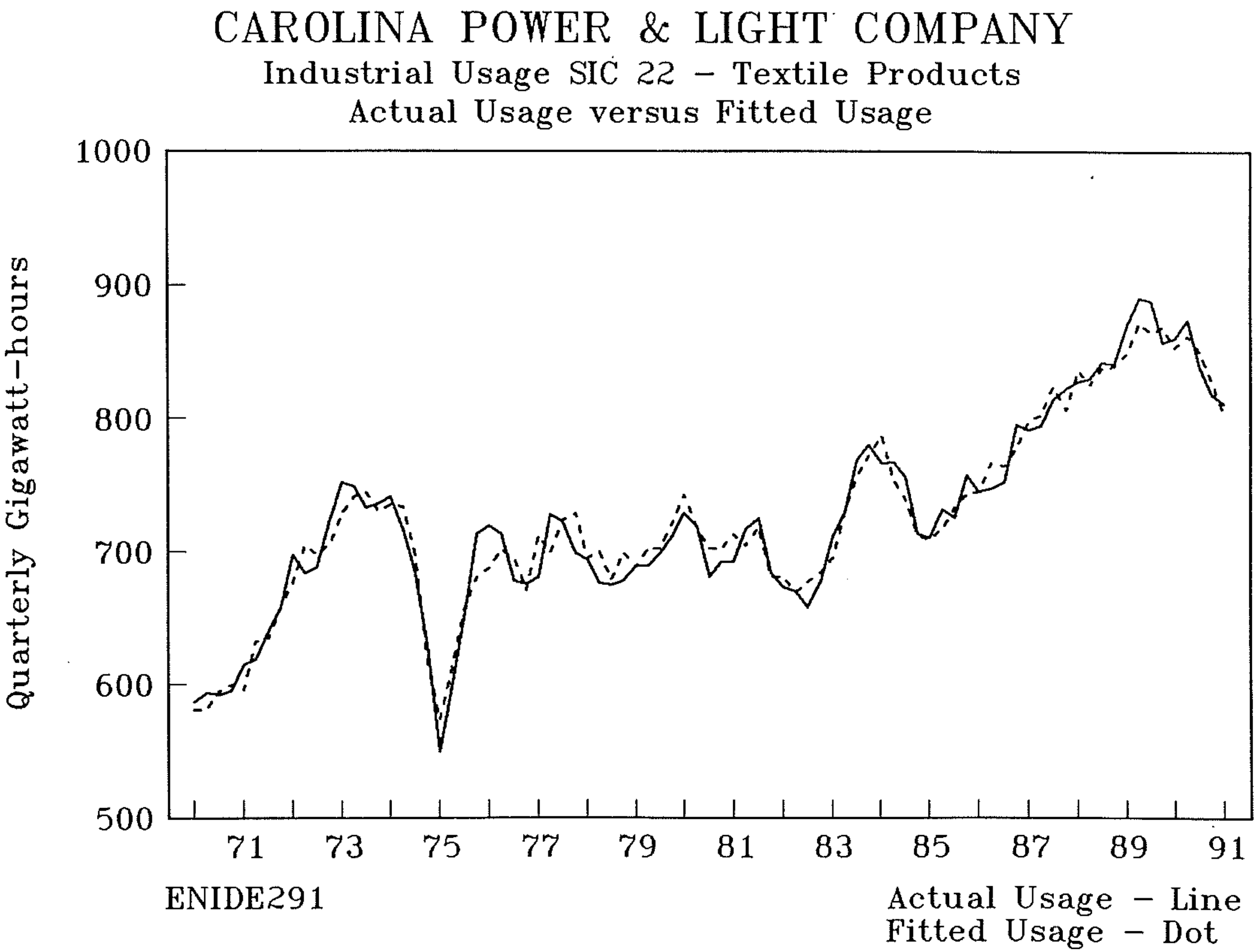

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 22 - Textile Products
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
1000
900
800
700
600
500
71
73
75
77
79
81
83
85
87
89
91
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 36

3) **Apparel Products** (SIC 23)

The Apparel Products industry in our service area is very labor intensive. In our service area, it is forecast that the employment will decrease from 46,968 in 1991 to 26,477 in the year 2010. We are forecasting production to increase slightly over this same period.

In this labor-intensive industry, the power consumption is not as directly related to units of output as in many other industries. Lighting, air conditioning, etc. consume much of the power used while the actual units of production contribute comparatively little consumption. This industry is also closely associated with both the textile products industry and with the synthetic fibers industry. We are forecasting that between 1991 to 2010 the electric consumption increase will be at a compounded annual growth rate of 0.4%.

The regression model is shown in Figure 37 along with the ARIMA analysis of first-order autocorrelation. A plot of the actual versus the fitted values during the historical period is shown in Figure 38.

A table showing the forecasted values for the Apparel Products industry is shown in Table XI.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

QUARTERLY(1970:1 TO 1991:1) 85 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@23SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	3.70788	0.01789	207.2	CONSTANT
1)	0.422474	0.03987	10.6	LOG(X23@CPL)
2)	0.0644863	0.02159	2.987	SHIFT854&
3)	−0.112369	0.02697	−4.167	DUM741
4)	0.0853604	0.02691	3.172	DUM764
	0.592226	0.09214	6.428	RHO

R-BAR SQUARED: 0.9482
F-STATISTIC(5,79): 308.57174
DURBIN-WATSON STATISTIC: 1.8982
SUM OF SQUARED RESIDUALS: 0.07660
STANDARD ERROR OF THE REGRESSION: 0.03114 NORMALIZED: 0.008645

WHERE:

GHID@23SA	GIGAWATT HOUR SALES – APPAREL PRODUCTS – SEASONALLY ADJUSTED
X23@CPL	CP&L SERV. AREA PRODUCTION INDEX – APPAREL PRODUCTS
SHIFT854&	SHIFT VARIABLE FOR STRUCTURAL CHANGE IN SIC 23
DUM741	UNEXPLAINED DROP IN USAGE 74:1
DUM764	DUMMY FOR INDUSTRIAL 76:4 CHANGE IN SIC 23

Figure 37

ORDINARY LEAST SQUARES

QUARTERLY(1970:1 TO 1991:1) 85 OBSERVATIONS
DEPENDENT VARIABLE: GHID@23SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.0005	0.003233	309.5	EXP(FIT(@RR))

R-BAR SQUARED: 0.9513 (RELATIVE TO Y=0, RBSQ: 0.9991)
F-STATISTIC(1,84): 95769.661
DURBIN-WATSON STATISTIC: 1.8967
SUM OF SQUARED RESIDUALS: 103.9
STANDARD ERROR OF THE REGRESSION: 1.112 NORMALIZED: 0.03005

Figure 37 (cont'd.)

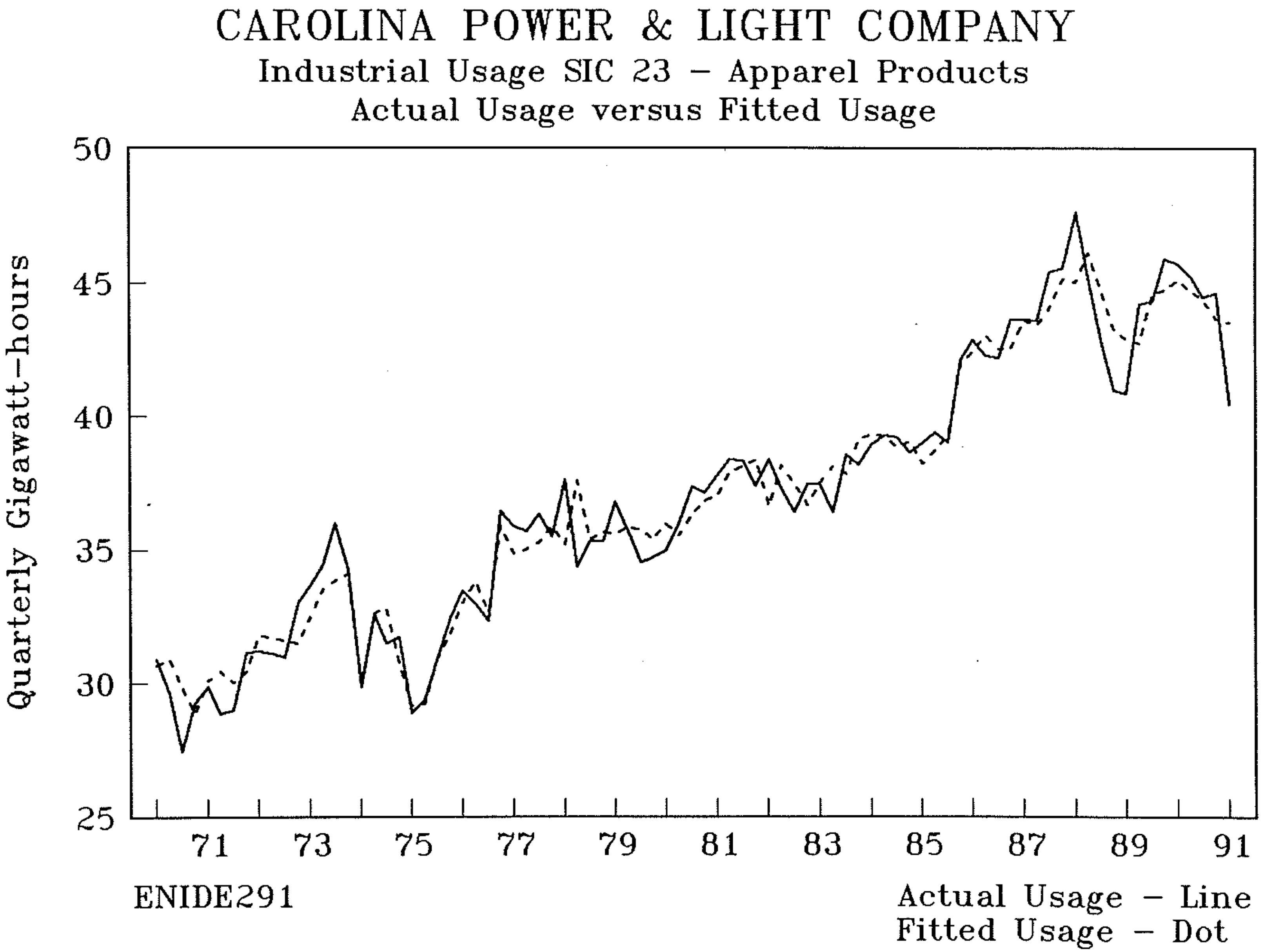

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 23 - Apparel Products
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
50
45
40
35
30
25
71
73
75
77
79
81
83
85
87
89
91
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 38

4) **Lumber and Wood** (SIC 24)

While the Lumber and Wood industry is closely associated with the building industry, it is somewhat stabilized by the paper industry. Some of the large paper companies that previously produced extensively in the northwestern part of the United States have experienced resource problems in the last few years, and a part of the growth in our service area is due to conditions in the Northwest. This migratory growth, however, is expected to level off in the mid-1990's. After that time, the growth will closely parallel the growth of the general economy.

In our service area, we are expecting employment in the Lumber and Wood industry to increase from 17,713 in 1991 to 19,252 in the year 2010. The output from the industry is expected to increase at a rate of 2.8% for the forecast period.

The average electric power consumption is expected to increase over the forecast period at a compounded annual growth rate of approximately 3.4%.

The Lumber and Wood industry regression model is shown in Figure 39 and a plot of the actual versus the fitted values during the historical period is shown in Figure 40.

A table showing the forecasted electrical consumption over the forecast period is shown in Table XI.

ORDINARY LEAST SQUARES

QUARTERLY(1972:1 TO 1991:1) 77 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@24SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	0.712752	0.1682	4.238	CONSTANT
1)	0.829987	0.0401	20.7	LOG(GHID@24SA\1)
2)	0.578772	0.09716	5.957	LOG(X24@CPL)
3)	−0.387309	0.1061	−3.651	LOG(X24@CPL\1)
4)	0.0653149	0.01842	3.546	SHIFT764&

R−BAR SQUARED: 0.9826
F−STATISTIC(4,72): 1074.7355
DURBIN−WATSON STATISTIC: 1.9617
SUM OF SQUARED RESIDUALS: 0.09256
STANDARD ERROR OF THE REGRESSION: 0.03585 NORMALIZED: 0.008400

WHERE:

GHID@24SA	GIGAWATT HOUR SALES – LUMBER & WOOD – EXCEPT GEORGIA PACIFIC SEASONALLY ADJUSTED
SHIFT764&	SHIFT VARIABLE FOR STRUCTURAL CHANGE IN SIC 24
X24@CPL	CP&L SERV. AREA PRODUCTION INDEX – LUMBER & WOOD

Figure 39

ORDINARY LEAST SQUARES

QUARTERLY(1972:1 TO 1991:1) 77 OBSERVATIONS
DEPENDENT VARIABLE: GHID@24SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00071	0.003919	255.3	EXP(FIT(@RR))

R-BAR SQUARED: 0.9802 (RELATIVE TO Y=0, RBSQ: 0.9988)
F-STATISTIC(1,76): 65200.313
DURBIN-WATSON STATISTIC: 2.0897
SUM OF SQUARED RESIDUALS: 520.4
STANDARD ERROR OF THE REGRESSION: 2.617 NORMALIZED: 0.03540

Figure 39 (cont'd.)

CAROLINA POWER & LIGHT COMPANY

Industrial Usage SIC 24 – Wood & lumber

Actual Usage versus Fitted Usage

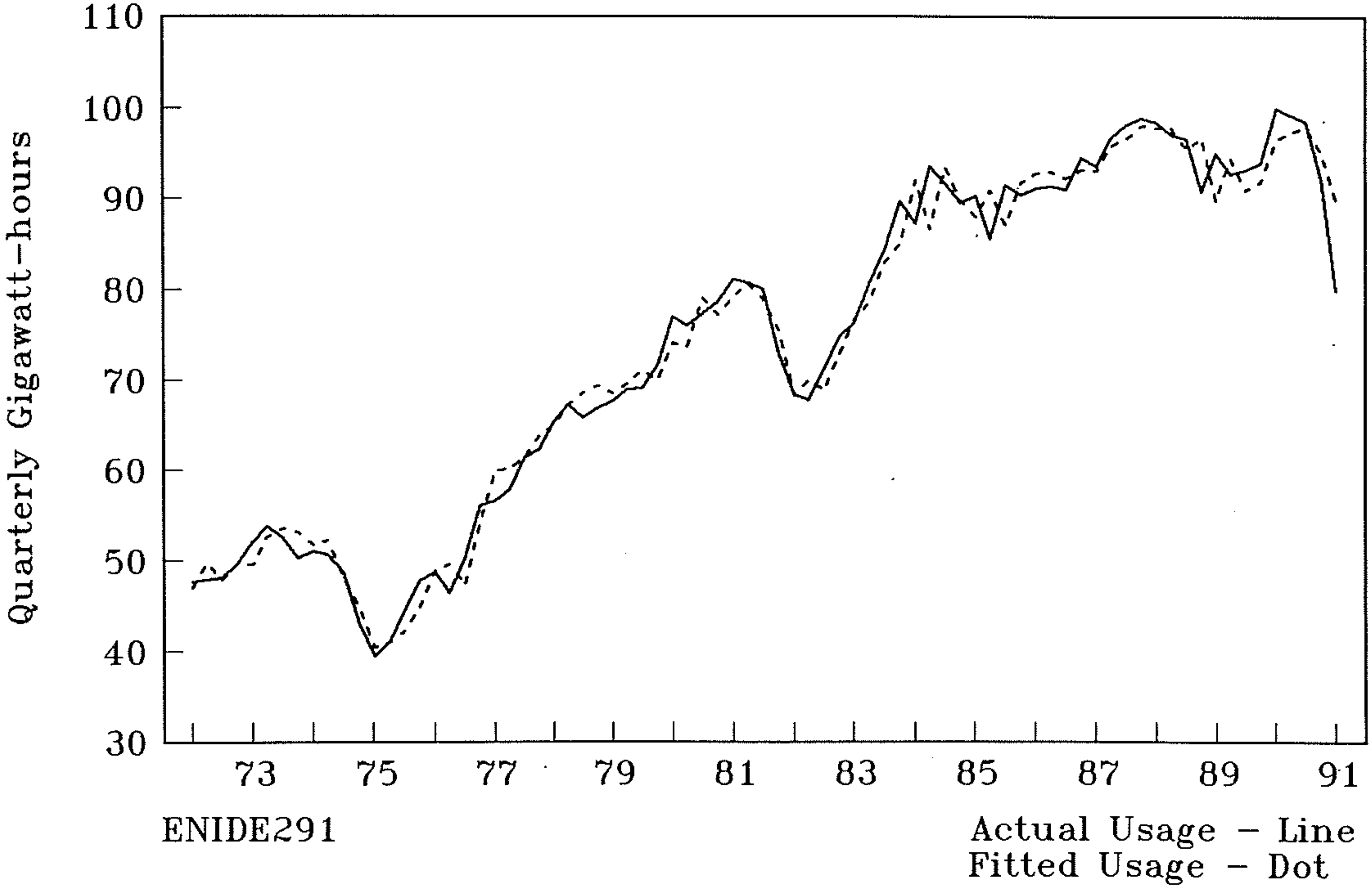


Figure 40

5) **Furniture Products** (SIC 25)

In our service area, we are forecasting a slight employment decline in the furniture industry from 15,185 in 1991 to 14,605 by the year 2010. During this period, we are forecasting a compounded annual growth rate of product output to average 0.3%.

This is an industry which has been labor intensive, and indications are that growth in this industry will continue. With a forecasted increase of 0.3% in output, we are forecasting an average power usage increase of 0.3% per year.

The regression model and its associated statistics are shown in Figure 41. A plot of the actual versus the fitted values is shown in Figure 42.

The forecast electrical usage is shown in Table XI.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

QUARTERLY(1972:1 TO 1991:1) 77 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@25SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	3.75615	0.01828	205.5	CONSTANT
1)	0.811771	0.05679	14.29	LOG(X25@CPL)
2)	−0.111524	0.02652	−4.205	DUM904911
	0.789703	0.07853	10.06	RHO

R-BAR SQUARED: 0.9765
F-STATISTIC(3,73): 1051.9931
DURBIN-WATSON STATISTIC: 2.3012
SUM OF SQUARED RESIDUALS: 0.05185
STANDARD ERROR OF THE REGRESSION: 0.02665 NORMALIZED: 0.007406

WHERE:

GHID@25SA	GIGAWATT HOUR SALES – FURNITURE PRODUCTS – SEASONALLY ADJUSTED
X25@CPL	CP&L SERV. AREA PRODUCTION INDEX – LUMBER & WOOD PRODUCTS
DUM904911	UNEXPLAINED DROP IN USAGE 90:4 – 91:1

Figure 41

ORDINARY LEAST SQUARES

QUARTERLY(1972:1 TO 1991:1) 77 OBSERVATIONS
DEPENDENT VARIABLE: GHID@25SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00246	0.003001	334.1	EXP(FIT(@RR))

R-BAR SQUARED: 0.9736 (RELATIVE TO Y=0, RBSQ: 0.9993)
F-STATISTIC(1,76): 111599.24
DURBIN-WATSON STATISTIC: 2.4607
SUM OF SQUARED RESIDUALS: 73.91
STANDARD ERROR OF THE REGRESSION: 0.9862 NORMALIZED: 0.02660

Figure 41 (cont'd.)

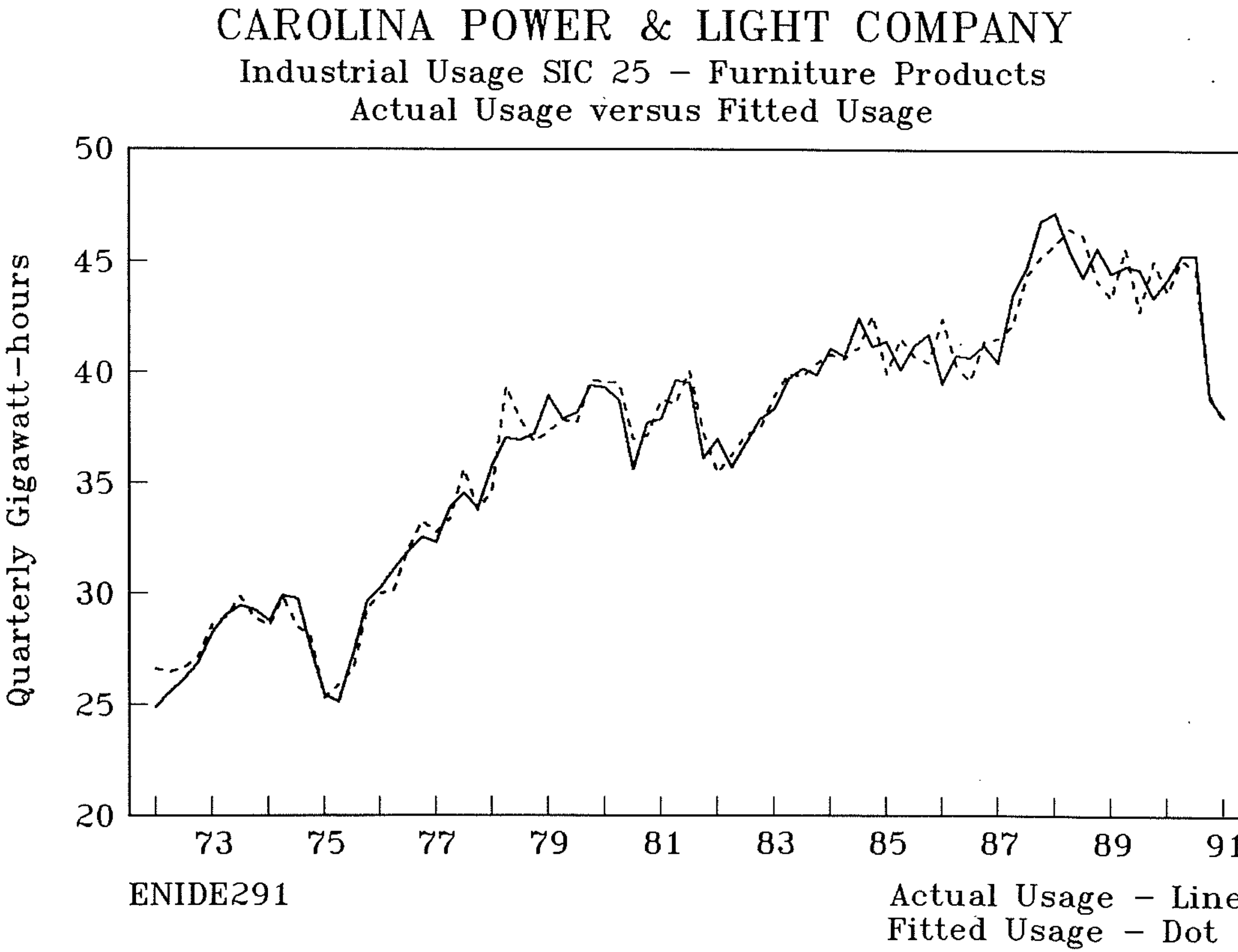

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 25 - Furniture Products
Actual Usage versus Fitted Usage
50
45
40
35
30
25
20
Quarterly Gigawatt-hours
73
75
77
79
81
83
85
87
89
91
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 42

6) **Paper Products** (SIC 26)

In the Paper Products industry, there are several waste products which have high heating value such as bark and black liquor. Because steam is needed in the drying process, most paper mills use topping turbines. Steam is generated at a higher pressure and temperature than needed for a drying process and is run through a backpressure turbine in order to generate electricity. The exhaust from the turbine is then used to dry the products. The steam that is generated in most cases is a function of the process steam needed rather than the electricity needed. The result is that as production is reduced, less steam is generated for drying, and consequently less power is generated on site. But, because the power requirement for the mills is relatively constant, this means that more purchased power is consumed. Conversely, as the production rate goes up, less power is purchased.

In the Paper Products industry, we are forecasting that employment in the service area will decline slightly from 11,320 in 1991 to 10,864 in the year 2010. We are forecasting that the output growth will average 2.2% per year.

We are forecasting that the electric power usage in the paper industry will grow in our service area at a compounded annual growth rate of 2.7%.

The regression model for the Paper Products industry is shown in Figure 43. A plot of the actual versus the fitted values is shown in Figure 44.

The forecast electrical usage is shown in Table XI.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

QUARTERLY(1980:1 TO 1991:1) 45 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@26AOSA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	5.31963	0.0251	211.9	CONSTANT
1)	1.13805	0.1226	9.284	LOG(X26@CPL)
2)	−0.128264	0.03212	−3.994	SHIFT881&
3)	−0.1715	0.03808	−4.504	DUM873
4)	−0.258832	0.0429	−6.034	DUM874
	0.554457	0.1439	3.853	RHO

R-BAR SQUARED: 0.8943
F-STATISTIC(5,39): 75.456182
DURBIN-WATSON STATISTIC: 2.0540
SUM OF SQUARED RESIDUALS: 0.04852
STANDARD ERROR OF THE REGRESSION: 0.03527 NORMALIZED: 0.006853

WHERE:

GHID@26AOSA	GIGAWATT HOUR SALES – PAPER PRODUCTS – EXCEPT CHAMPION PAPER SEASONALLY ADJUSTED
X26@CPL	CP&L SERV. AREA PRODUCTION INDEX – PAPER PRODUCTS
SHIFT873&	SHIFT VARIABLE FOR STRUCTURAL CHANGE IN SIC 26
DUM873	UNEXPLAINED DROP IN USAGE 87:3
DUM874	UNEXPLAINED DROP IN USAGE 87:4

Figure 43

ORDINARY LEAST SQUARES

QUARTERLY(1980:1 TO 1991:1) 45 OBSERVATIONS
DEPENDENT VARIABLE: GHID@26AOSA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00139	0.004875	205.4	EXP(FIT(@RR))

R-BAR SQUARED: 0.9008 (RELATIVE TO Y=0, RBSQ: 0.9990)
F-STATISTIC(1,44): 42196.114
DURBIN-WATSON STATISTIC: 2.1310
SUM OF SQUARED RESIDUALS: 1414
STANDARD ERROR OF THE REGRESSION: 5.669 NORMALIZED: 0.03281

Figure 43 (cont'd.)

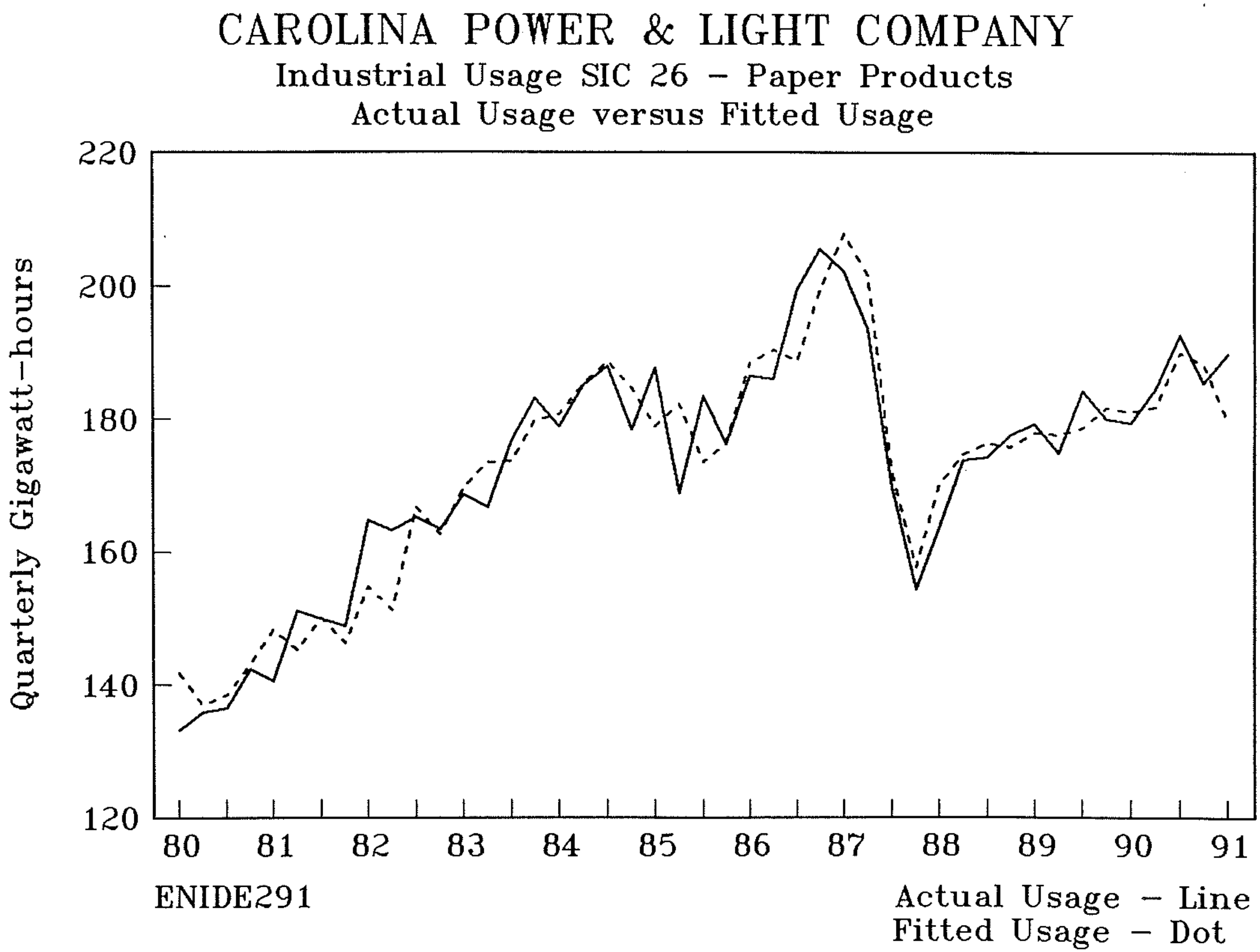

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 26 - Paper Products
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
220
200
180
160
140
120
80
81
82
83
84
85
86
87
88
89
90
91
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 44

7) **Printing and Publishing** (SIC 27)

The Printing and Publishing industry in the service area is predominately split between newspaper publishing and commercial printing. Employment in this industry is forecast to increase in the service area from 9,559 employees in 1991 to 11,672 in 2010. This represents an average annual growth rate of 1.1%. Over the same period, production from this industry is expected to increase at an average annual rate of 3.1% and electricity usage is expected to grow at a 2.2% average annual rate.

The model for this industry is shown in Figure 45. A plot of the actual versus fitted values is shown in Figure 46.

The forecast electrical usage is shown in Table XI.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

QUARTERLY(1979:1 TO 1991:1) 49 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@27SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	2.35391	0.02505	93.96	CONSTANT
1)	0.669959	0.06685	10.02	LOG(X27@CPL)
2)	-0.0650504	0.02782	-2.338	SHIFT883&
	0.765287	0.0975	7.849	RHO

R-BAR SQUARED: 0.9700
F-STATISTIC(3,45): 517.58115
DURBIN-WATSON STATISTIC: 1.6621
SUM OF SQUARED RESIDUALS: 0.03434
STANDARD ERROR OF THE REGRESSION: 0.02762 NORMALIZED: 0.01257

WHERE:

GHID@27SA	GIGAWATT HOUR SALES - PUBLISHING & PRINTING
X27@CPL	CP&L SERV. AREA PRODUCTION INDEX - PUBLISHING & PRINTING
SHIFT883&	SHIFT VARIABLE FOR STRUCTURAL CHANGE IN SIC 27

Figure 45

ORDINARY LEAST SQUARES

QUARTERLY(1979:1 TO 1991:1) 49 OBSERVATIONS
DEPENDENT VARIABLE: GHID@27SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00194	0.003676	272.5	EXP(FIT(@RR))

R-BAR SQUARED: 0.9724 (RELATIVE TO Y=0, RBSQ: 0.9994)
F-STATISTIC(1,48): 74278.651
DURBIN-WATSON STATISTIC: 1.6200
SUM OF SQUARED RESIDUALS: 2.695
STANDARD ERROR OF THE REGRESSION: 0.2369 NORMALIZED: 0.02598

Figure 45 (cont'd.)

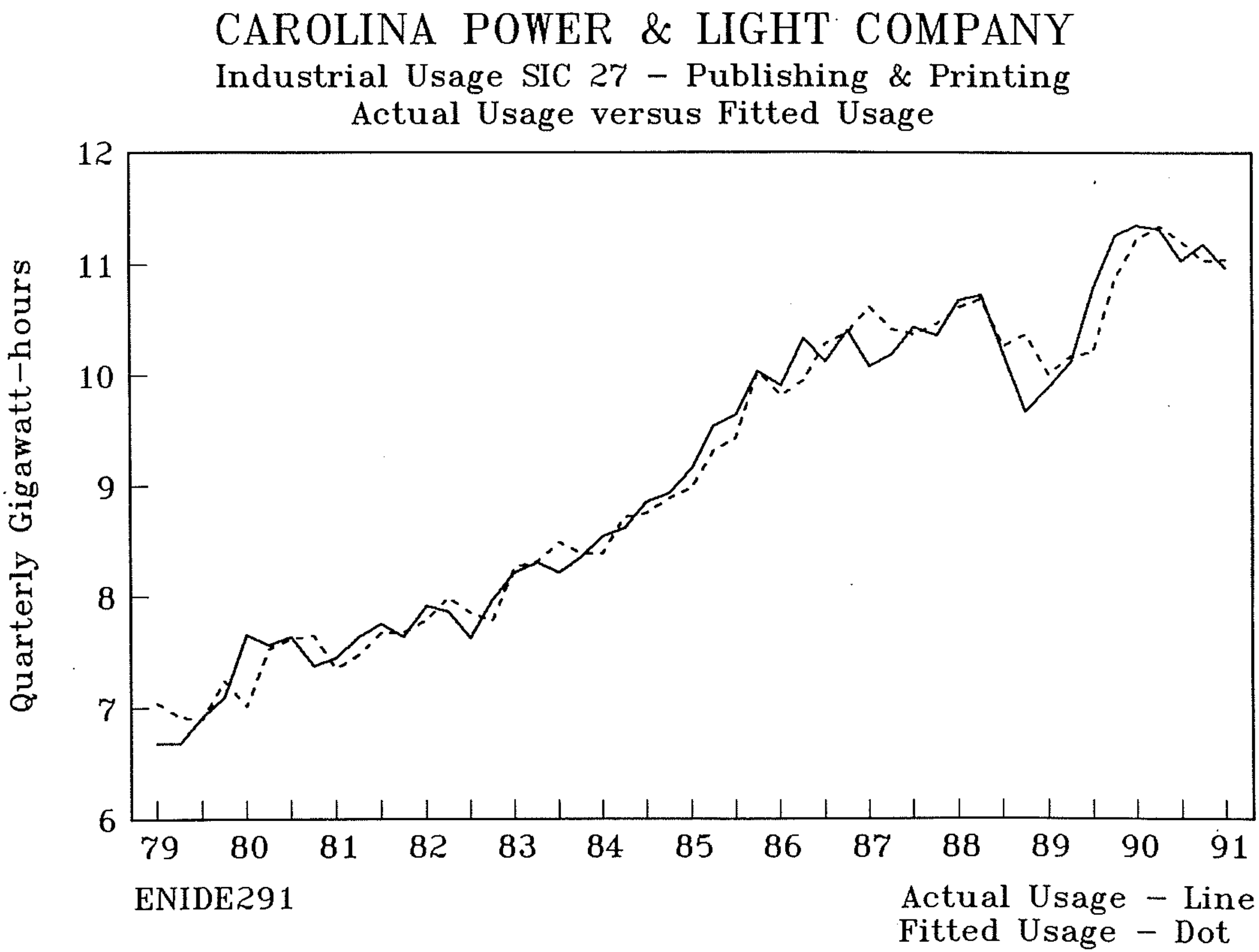

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 27 - Publishing & Printing
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
12
11
10
9
8
7
6
79
80
81
82
83
84
85
86
87
88
89
90
91
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 46

8) **Chemicals** (SIC 28)

We are forecasting that the employees in the service area will increase slightly during the forecast period going from 22,848 in 1991 to 23,370 in 2010. The output, however, is expected to increase at a compounded annual rate of 3.7% and the corresponding power consumption will increase at a compounded annual rate of 1.7%.

This forecast was made by utilizing the local production index and a nationally-based production index for the four subgroups. The basic concept of relating historical usage to local or national production was maintained.

The basic chemical industry is relatively small in our service area. Like all chemical industries, pollution control and abatement and environmental matters require considerable lead time. We are forecasting that the subgroup will increase its electrical consumption by 0.4% compounded annually.

The synthetic fibers industry is the largest classification of chemical manufacturers in the service area. The forecast shows increasing electricity consumption for this classification at an average annual rate of 1.9%.

Agricultural chemicals are also growing in our service area, and there are prospects for this segment to become larger. We are forecasting that this subgroup will have a rate of increase of 1.6% annually over the forecast period.

The other Chemical industries are combined into a single group. We are forecasting that the miscellaneous group will increase electricity consumption at an average annual rate of 2.7%.

The models and their applicable statistics and plots of the actual versus the fitted values are shown in Figures 47 through 54.

The forecast for the industry usage is shown in Table XI.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

QUARTERLY(1970:1 TO 1991:1) 85 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@281SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	4.34516	0.04228	102.8	CONSTANT
1)	0.416739	0.06145	6.782	LOG(X28@CPL)
2)	-0.312442	0.1071	-2.919	SHIFT761&*LOG(X28@CPL)
3)	0.282188	0.04477	6.304	SHIFT761&
4)	-0.201012	0.04374	-4.596	DUM752753
	0.461115	0.09963	4.628	RHO

R-BAR SQUARED: 0.9604
F-STATISTIC(5,79): 408.20772
DURBIN-WATSON STATISTIC: 2.1730
SUM OF SQUARED RESIDUALS: 0.2146
STANDARD ERROR OF THE REGRESSION: 0.05212 NORMALIZED: 0.01168

WHERE:

GHID@281SA	GIGAWATT HOUR SALES - INORGANIC CHEMICALS SEASONALLY ADJUSTED
SHIFT761&	SHIFT VARIABLE FOR ADDITION OF NEW PLANT
X28@CPL	CP&L SERV. AREA PRODUCTION INDEX - SYNTHETIC FIBERS
LNRELINPCOST@ID	RELATIVE COST OF ELEC. FOR INDUSTRIAL
DUM752753	UNEXPLAINED DROP IN USAGE 75:2 - 75:3

Figure 47

ORDINARY LEAST SQUARES

QUARTERLY(1970:1 TO 1991:1) 85 OBSERVATIONS
DEPENDENT VARIABLE: GHID@281SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.0023	0.005554	180.5	EXP(FIT(@RR))

R-BAR SQUARED: 0.9469 (RELATIVE TO Y=0, RBSQ: 0.9974)
F-STATISTIC(1,84): 32570.591
DURBIN-WATSON STATISTIC: 2.0962
SUM OF SQUARED RESIDUALS: 1842
STANDARD ERROR OF THE REGRESSION: 4.682 NORMALIZED: 0.05230

Figure 47 (cont'd.)

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 281 - Inorganic Chemicals
Actual Usage versus Fitted Usage

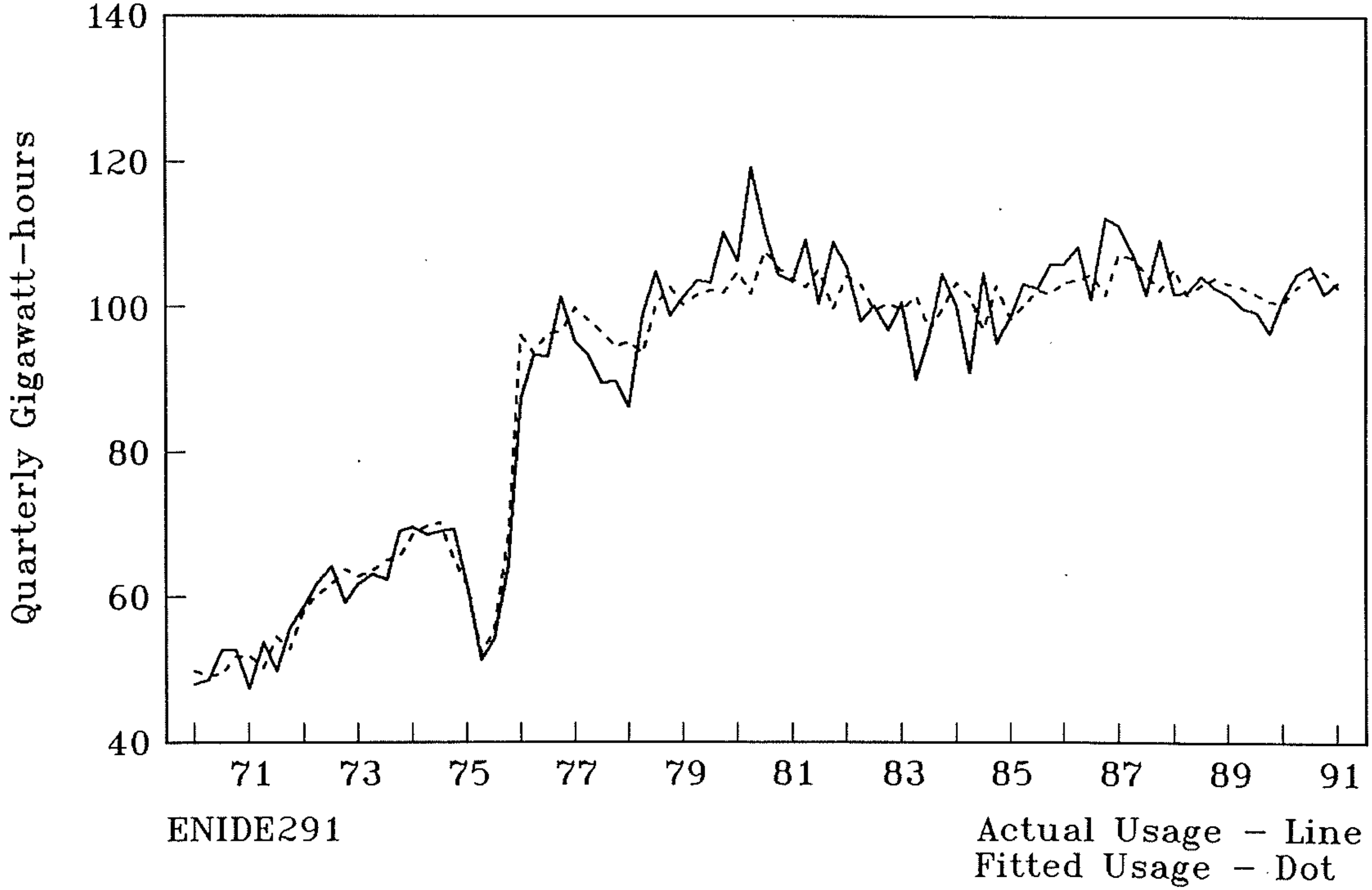


Figure 48

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

QUARTERLY(1974:1 TO 1991:1) 69 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@282SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	6.4984	0.1728	37.6	CONSTANT
1)	0.484072	0.07591	6.377	LOG(X28@CPL)
2)				PDL(LNRELINPCOST@ID,2,8,BOTH)
\0	−0.0200773	0.007955		+ * + .
\1	−0.0351353	0.01392		+ * + .
\2	−0.0451739	0.0179		+ * + .
\3	−0.0501933	0.01989		+ * + .
\4	−0.0501933	0.01989		+ * + .
\5	−0.0451739	0.0179		+ * + .
\6	−0.0351353	0.01392		+ * + .
\7	−0.0200773	0.007955		+ * + .
SUM	−0.30116	0.1193	−2.524	
AVG	3.5	0	NC	
	0.798302	0.07476	10.68	RHO

R-BAR SQUARED: 0.7576
F-STATISTIC(3,65): 71.823583
DURBIN-WATSON STATISTIC: 2.0405
SUM OF SQUARED RESIDUALS: 0.09189
STANDARD ERROR OF THE REGRESSION: 0.03760 NORMALIZED: 0.006260

WHERE:

GHID@282SA	GIGAWATT HOUR SALES – SYNTHETIC FIBERS – SIC 282 – SEASONALLY ADJUSTED
X28@CPL	CP&L SERV. AREA PRODUCTION INDEX – SYNTHETIC FIBERS
LNRELINPCOST@ID	RELATIVE COST OF ELEC. FOR INDUSTRIAL

Figure 49

ORDINARY LEAST SQUARES

QUARTERLY(1974:1 TO 1991:1) 69 OBSERVATIONS
DEPENDENT VARIABLE: GHID@282SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00085	0.004426	226.1	EXP(FIT(@RR))

R-BAR SQUARED: 0.7600 (RELATIVE TO Y=0, RBSQ: 0.9987)
F-STATISTIC(1,68): 51127.074
DURBIN-WATSON STATISTIC: 2.0329
SUM OF SQUARED RESIDUALS: 1.528E+04
STANDARD ERROR OF THE REGRESSION: 14.99 NORMALIZED: 0.03681

Figure 49 (cont'd.)

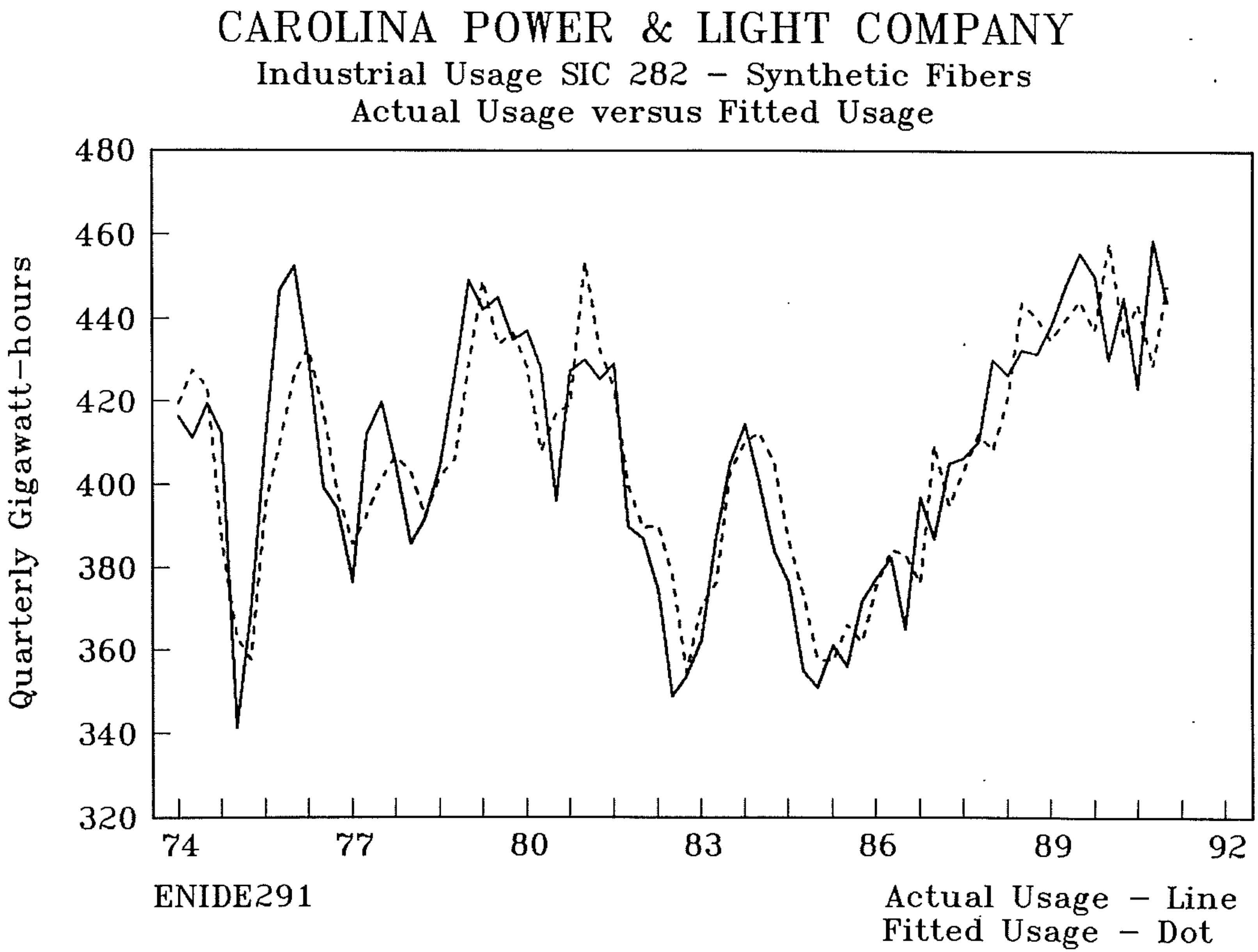

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 282 - Synthetic Fibers
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
480
460
440
420
400
380
360
340
320
74
77
80
83
86
89
92
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 50

ORDINARY LEAST SQUARES

QUARTERLY(1977:1 TO 1991:1) 57 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@287SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	5.26074	0.2376	22.14	CONSTANT
1)	0.427883	0.09875	4.333	LOG(X28@CPL)
2)				PDL(LNRELINPCOST@ID,2,8,BOTH)
\0	−0.0246393	0.01143		+ * + .
\1	−0.0431187	0.02001		+ * + .
\2	−0.0554384	0.02572		+ * + .
\3	−0.0615982	0.02858		+ * + .
\4	−0.0615982	0.02858		+ * + .
\5	−0.0554384	0.02572		+ * + .
\6	−0.0431187	0.02001		+ * + .
\7	−0.0246393	0.01143		+ * + .
SUM	−0.369589	0.1715	−2.155	
AVG	3.5	0	NC	
3)	0.458553	0.03882	11.81	SHIFT834&
4)	−0.193574	0.04715	−4.105	DUMID823824
5)	−0.277335	0.06288	−4.41	DUM834

R−BAR SQUARED: 0.9411
F−STATISTIC(5,51): 179.84282
DURBIN−WATSON STATISTIC: 1.3953
SUM OF SQUARED RESIDUALS: 0.1927
STANDARD ERROR OF THE REGRESSION: 0.06146 NORMALIZED: 0.01252

WHERE:

GHID@287SA	GIGAWATT HOUR SALES – AGRICULTURAL CHEMICALS – SIC 287 – SEASONALLY ADJUSTED
X28@CPL	CP&L SERV. AREA PRODUCTION INDEX – SYNTHETIC FIBERS
LNRELINPCOST@ID	RELATIVE COST OF ELEC. FOR INDUSTRIAL
SHIFT834&	SHIFT VARIABLE FOR STRUCTURAL CHANGE IN SIC 287
DUMID823824	UNEXPLAINED DROP IN USAGE FROM 82:3 TO 82:4
DUM834	UNEXPLAINED INCREASE IN USAGE 83:4

Figure 51

ORDINARY LEAST SQUARES

QUARTERLY(1977:1 TO 1991:1) 57 OBSERVATIONS
DEPENDENT VARIABLE: GHID@287SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00159	0.008365	119.7	EXP(FIT(@RR))

R-BAR SQUARED: 0.9308 (RELATIVE TO Y=0, RBSQ: 0.9961)
F-STATISTIC(1,56): 14338.276
DURBIN-WATSON STATISTIC: 1.4567
SUM OF SQUARED RESIDUALS: 4600
STANDARD ERROR OF THE REGRESSION: 9.063 NORMALIZED: 0.06478

Figure 51 (cont'd.)

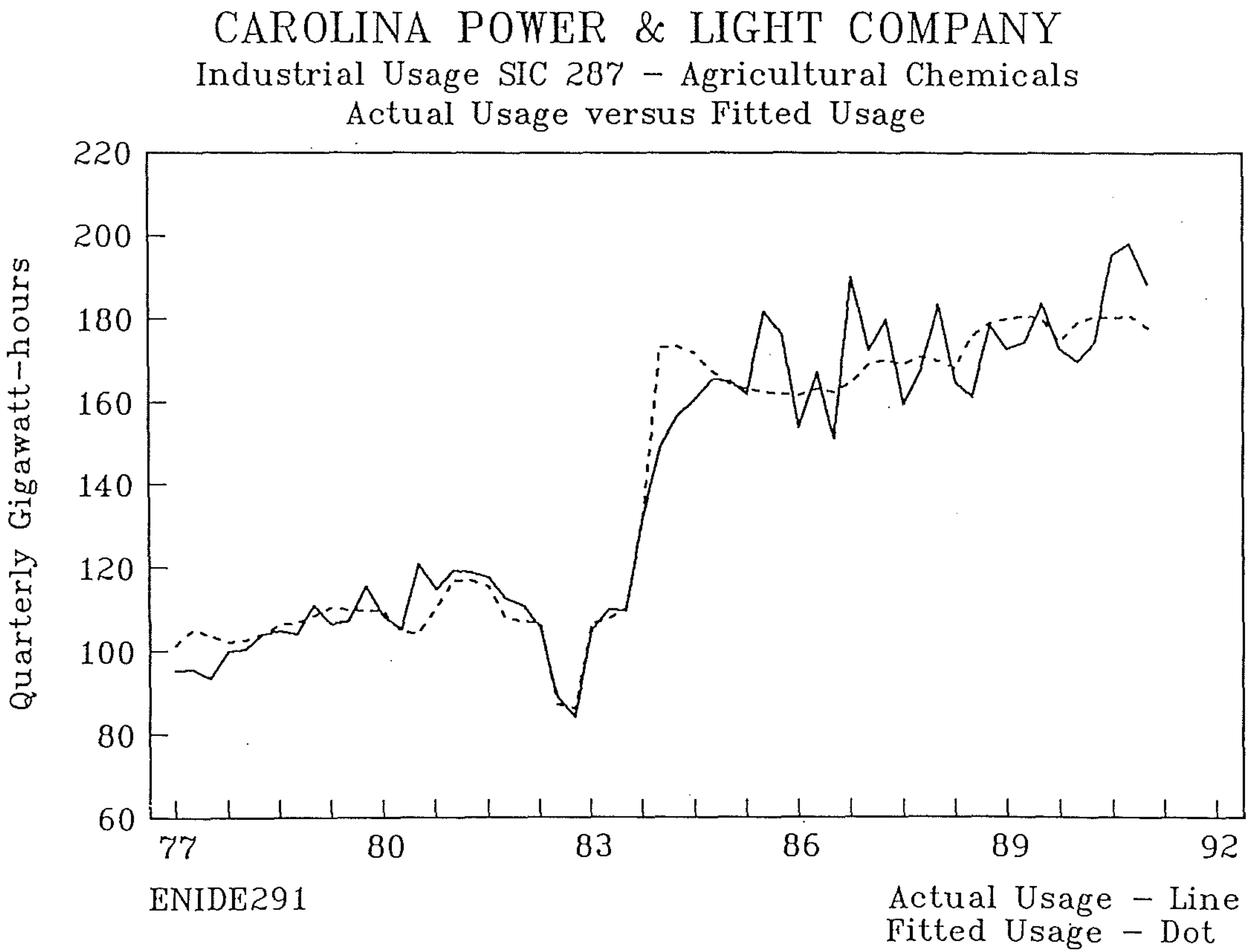

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 287 - Agricultural Chemicals
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
220
200
180
160
140
120
100
80
60
77
80
83
86
89
92
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 52

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

QUARTERLY(1982:1 TO 1991:1) 37 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@28OMSA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	3.89684	0.04777	81.57	CONSTANT
1)	0.688405	0.2498	2.756	LOG(.7*JQIND283+.3*JQIND284)
2)	0.311065	0.05568	5.587	SHIFT854&
3)	0.130632	0.04083	3.2	SHIFT842853
	0.753826	0.1216	6.201	RHO

R-BAR SQUARED: 0.9550
F-STATISTIC(4,32): 191.82013
DURBIN-WATSON STATISTIC: 1.6148
SUM OF SQUARED RESIDUALS: 0.05525
STANDARD ERROR OF THE REGRESSION: 0.04155 NORMALIZED: 0.01015

WHERE:

GHID@28OMSA	GIGAWATT HOUR SALES - OTHER CHEMICAL MFG. - SIC's 283,284,285, AND 289 - SEASONALLY ADJUSTED
JQIND283	INDUSTRIAL PRODUCTION INDEX - SIC 283
JQIND284	INDUSTRIAL PRODUCTION INDEX - SIC 284
SHIFT854	SHIFT VARIABLE FOR CHANGE IN SIC 28 - 85:4
SHIFT842853	SHIFT VARIABLE FOR CHANGE IN SIC 28 - 84:2 TO 85:3

Figure 53

ORDINARY LEAST SQUARES

QUARTERLY(1982:1 TO 1991:1) 37 OBSERVATIONS
DEPENDENT VARIABLE: GHID@28OMSA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00181	0.005802	172.7	EXP(FIT(@RR))

R-BAR SQUARED: 0.9625 (RELATIVE TO Y=0, RBSQ: 0.9988)
F-STATISTIC(1,36): 29811.478
DURBIN-WATSON STATISTIC: 1.7838
SUM OF SQUARED RESIDUALS: 172.4
STANDARD ERROR OF THE REGRESSION: 2.188 NORMALIZED: 0.03579

Figure 53 (cont'd.)

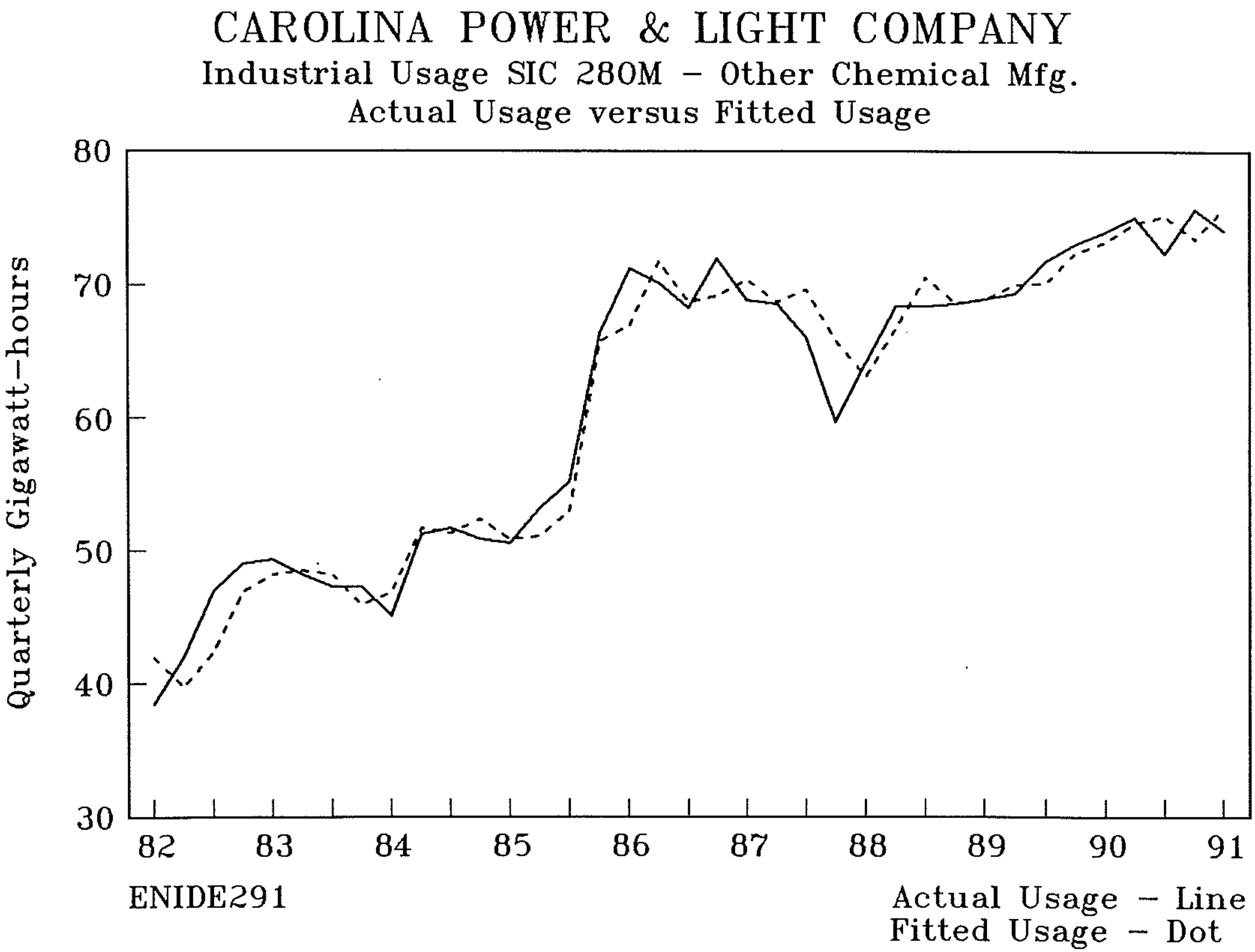

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 280M - Other Chemical Mfg.
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
80
70
60
50
40
30
82
83
84
85
86
87
88
89
90
91
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 54

9) **Rubber and Plastics** (SIC 30)

The Rubber and Plastics industry is among the fastest growing industries in the service area. We are forecasting that employment in the service area will grow 1.0% compounded annually from 1991 to the year 2010. The projected employment level will increase from 18,836 to 22,848 employees. The output from this industry is expected to increase at an annual rate of 3.8% and the power consumption is projected to increase at 6.4% per year.

The model for the Rubber and Plastics classification is shown in Figure 55 with the applicable statistics and the plot of the actual versus the fitted values is shown in Figure 56.

The forecast for the industry usage is shown in Table XI.

ORDINARY LEAST SQUARES

QUARTERLY(1972:1 TO 1991:1) 77 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@30SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	0.713166	0.2009	3.551	CONSTANT
1)	0.853835	0.04206	20.3	LOG(GHID@30SA\1)
2)	0.232697	0.0728	3.197	LOG(X30@CPL)

R-BAR SQUARED: 0.9942
F-STATISTIC(2,74): 6549.8695
DURBIN-WATSON STATISTIC: 2.1071
SUM OF SQUARED RESIDUALS: 0.09556
STANDARD ERROR OF THE REGRESSION: 0.03593 NORMALIZED: 0.008432

WHERE:

GHID@30SA	GIGAWATT HOUR SALES – RUBBER & PLASTICS
X30@CPL	CP&L SERV. AREA PRODUCTION INDEX – RUBBER & PLASTICS

Figure 55

ORDINARY LEAST SQUARES

QUARTERLY(1972:1 TO 1991:1) 77 OBSERVATIONS
DEPENDENT VARIABLE: GHID@30SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDEIVARIABLE
1)	0.999127	0.003562	280.5	EXP(FIT(@RR))

R-BAR SQUARED: 0.9943 (RELATIVE TO Y=0, RBSQ: 0.9990)
F-STATISTIC(1,76): 78682.892
DURBIN-WATSON STATISTIC: 1.7716
SUM OF SQUARED RESIDUALS: 555.7
STANDARD ERROR OF THE REGRESSION: 2.704 NORMALIZED: 0.03428

Figure 55 (cont'd.)

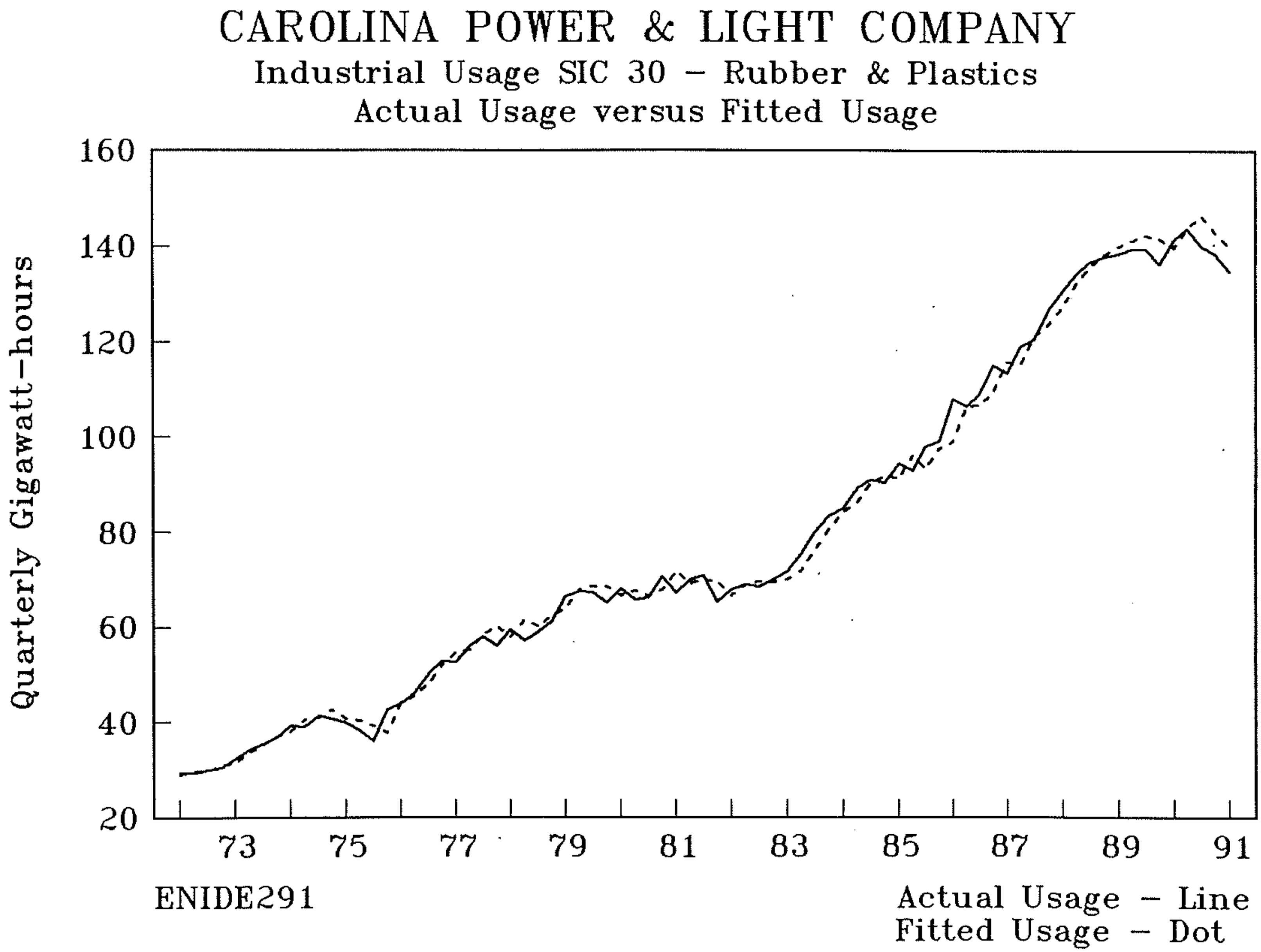

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 30 - Rubber & Plastics
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
160
140
120
100
80
60
40
20
73
75
77
79
81
83
85
87
89
91
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 56

10) **Stone, Clay, and Glass** (SIC 32)

In 1984, we lost two large loads in SIC 32. Ideal Cement in Wilmington was shut down with a loss of 12 MW, and Laurens-Pierce in Henderson reduced their load by 7 MW. Consequently, the usage for this classification dropped 12.4% in 1985. In 1987, Ideal Basic Industries planned to decommission one of its plants which resulted in usage for this classification falling 4.4% in 1988.

Employment for the remaining industry in the service area in Stone, Clay, and Glass is projected to decline slightly from 6,939 to 6,182 during the forecast period. Output, however, is forecast to increase at an average compounded annual growth rate of 1.5%, and power consumption is expected to increase at a compounded annual rate of 0.9%.

The model of the Stone, Clay, and Glass industry and its applicable statistics are shown in Figure 57 and the plot of the actual usage versus the fitted usage is shown in Figure 58.

The forecast for the industry usage is shown in Table XI.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

QUARTERLY(1974:1 TO 1991:1) 69 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@32AOSA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	4.03501	0.04617	87.39	CONSTANT
1)	0.34175	0.1131	3.022	LOG(X32@CPL)
	0.882424	0.06115	14.43	RHO

R-BAR SQUARED: 0.9259
F-STATISTIC(2,66): 425.66182
DURBIN-WATSON STATISTIC: 2.0662
SUM OF SQUARED RESIDUALS: 0.1040
STANDARD ERROR OF THE REGRESSION: 0.03970 NORMALIZED: 0.009990

WHERE:

GHID@32AOSA	GIGAWATT HOUR SALES - STONE, CLAY & GLASS EXCEPT LAUREN GLASS & IDEAL CEMENT
X32@CPL	CP&L SERV. AREA PRODUCTION INDEX - STONE, CLAY & GLASS PLANT

Figure 57

ORDINARY LEAST SQUARES

QUARTERLY(1974:1 TO 1991:1) 69 OBSERVATIONS
DEPENDENT VARIABLE: GHID@32AOSA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00192	0.004463	224.5	EXP(FIT(@RR))

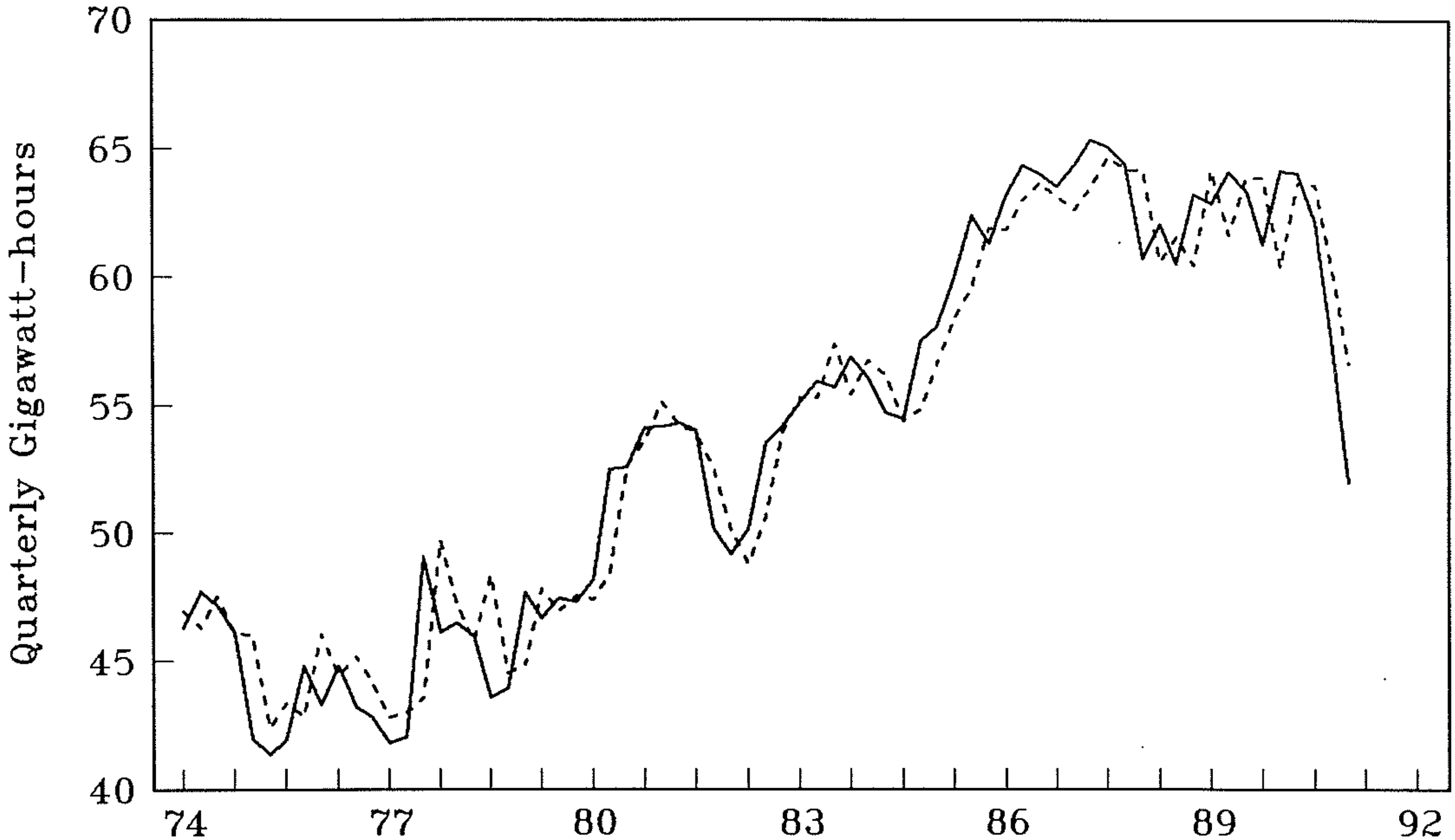
R-BAR SQUARED: 0.9325 (RELATIVE TO Y=0, RBSQ: 0.9987)
F-STATISTIC(1,68): 50397.502
DURBIN-WATSON STATISTIC: 2.0284
SUM OF SQUARED RESIDUALS: 274.0
STANDARD ERROR OF THE REGRESSION: 2.007 NORMALIZED: 0.03735

Figure 57 (cont'd.)

CAROLINA POWER & LIGHT COMPANY

Industrial Usage SIC 32 – Stone, Clay & Glass

Actual Usage versus Fitted Usage



ENIDE291

Actual Usage – Line
Fitted Usage – Dot

Figure 58

11) **Primary and Fabricated Steel** (SIC 33 & 34)

The Steel industries are very energy intensive. Because the Primary Steel industry is not yet mature in the service area, it is expected that the percentage growth rates which we have experienced historically will not continue. Recently, Fabricated Steel industries are beginning to appear as satellites to the Primary Steel industry. Between the two, the forecast is for continued moderate growth.

In the total service area, we are forecasting that employment will increase slightly from 18,437 to 19,080 employees from 1991 to 2010. Industry output is forecast to increase at 1.8% compounded annually, and the power consumption is projected to increase at an annual rate of 0.8%.

The model for these industries (excluding our one largest customer) and their associated statistics are shown in Figure 59. A plot of the actual versus the fitted values is shown in Figure 60. The usage for our largest customer is added to the forecast of the other companies in the industry.

The forecast of power usage is shown in Table XI.

ORDINARY LEAST SQUARES

QUARTERLY(1974:1 TO 1991:1) 69 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@33&34AOSA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	0.183916	0.06892	2.669	CONSTANT
1)	0.961211	0.01519	63.27	LOG(GHID@33&34AOSA\1)
2)	0.320029	0.05062	6.322	LOG(X33&34@CPL)
3)	-0.303801	0.05147	-5.903	LOG(X33&34@CPL\1)

R-BAR SQUARED: 0.9927
F-STATISTIC(3,65): 3087.7467
DURBIN-WATSON STATISTIC: 1.9549
SUM OF SQUARED RESIDUALS: 0.04962
STANDARD ERROR OF THE REGRESSION: 0.02763 NORMALIZED: 0.006324

WHERE:

GHID@33&34AOSA	GIGAWATT HOUR SALES - PRIMARY & FABRICATED METALS EXCEPT NUCOR - SEASONALLY ADJUSTED
X33&34@CPL	CP&L SERV. AREA PRODUCTION INDEX - PRIMARY & FABRICATED METALS

Figure 59

ORDINARY LEAST SQUARES

QUARTERLY(1974:1 TO 1991:1) 69 OBSERVATIONS
DEPENDENT VARIABLE: GHID@33&34AOSA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.999714	0.002771	360.8	EXP(FIT(@RR))

R-BAR SQUARED: 0.9927 (RELATIVE TO Y=0, RBSQ: 0.9995)
F-STATISTIC(1,68): 130195.05
DURBIN-WATSON STATISTIC: 1.9812
SUM OF SQUARED RESIDUALS: 265.4
STANDARD ERROR OF THE REGRESSION: 1.976 NORMALIZED: 0.02388

Figure 59 (cont'd.)

CAROLINA POWER & LIGHT COMPANY

Industrial Usage SIC 33 & 34 – Primary & Fabricated Metals
Actual Usage versus Fitted Usage

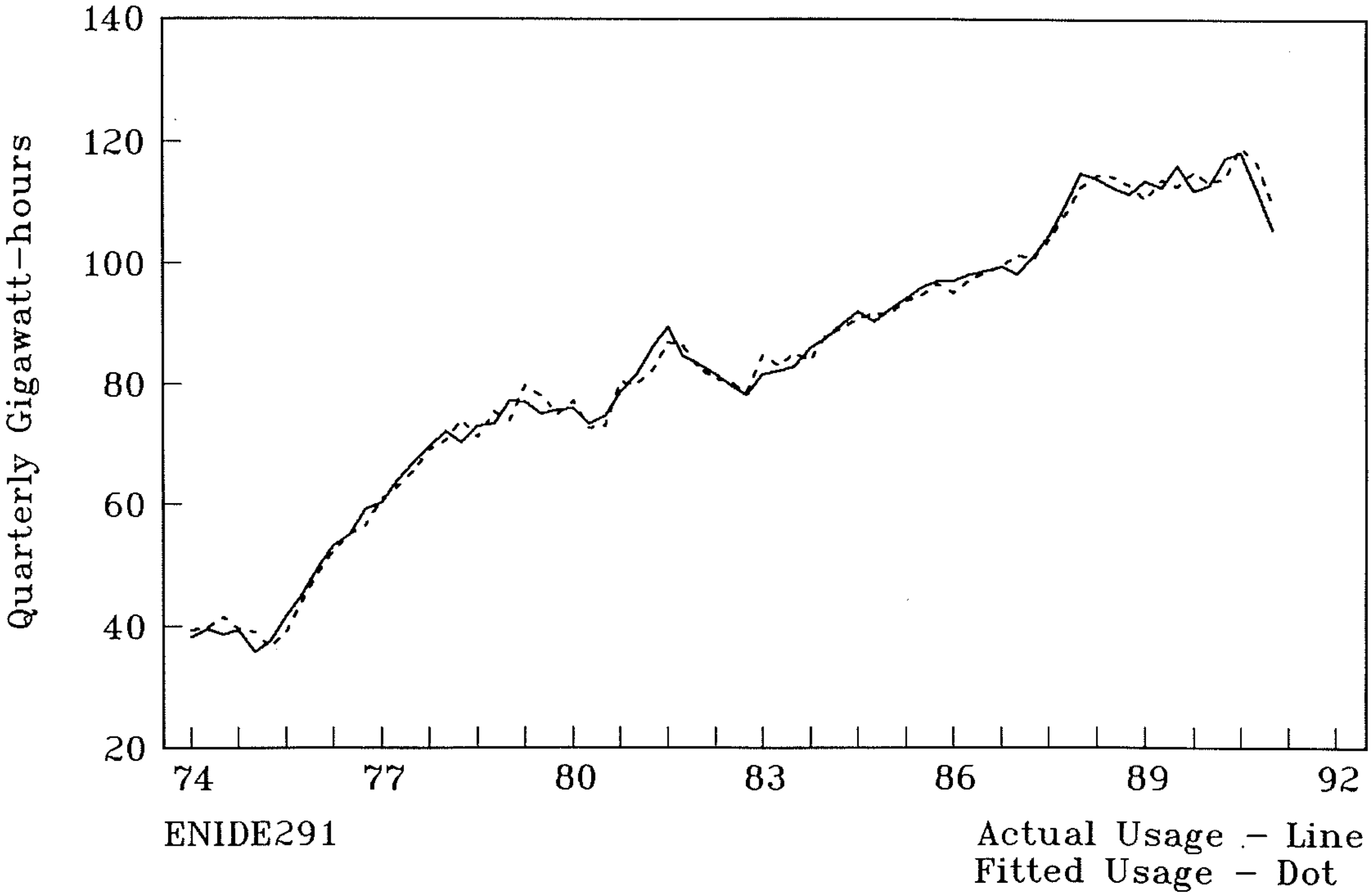


Figure 60

12) **Non-Electrical Machinery** (SIC 35)

The largest component of the Non-Electrical Machinery industry in the service area is concentrated in the general industrial equipment category which includes pumps, compressors, furnaces, and drives. Other manufacturers in the service area of this industry use electricity to produce metalworking machinery, construction machinery, and refrigeration equipment. While only a small proportion of electricity usage in this industry comes from electronic computing equipment, this SIC contains the computer hardware and office equipment industry (software production is reflected in the services industry).

Employment in the service area for this industry is expected to increase slightly from 21,172 in 1991 to 21,435 in 2010. Industry production over the same period is projected to increase at an average annual rate of 4.8%, while electrical consumption is expected to increase at a 1.6% average annual rate.

The model and applicable statistics for this industry are shown in Figure 61. A plot of the actual versus fitted values is shown in Figure 62.

The forecast of energy usage for this industry is shown in Table XI.

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

QUARTERLY(1979:1 TO 1991:1) 49 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@35SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	4.09366	0.1834	22.32	CONSTANT
1)	0.30872	0.02657	11.62	LOG(X35@CPL)
2)				PDL(LNRELINPCOST@ID,2,8,BOTH)
\0	−0.0189451	0.007966		+ * + .
\1	−0.0331539	0.01394		+ * + .
\2	−0.0426264	0.01792		+ * + .
\3	−0.0473627	0.01991		+ * + .
\4	−0.0473627	0.01991		+ * + .
\5	−0.0426264	0.01792		+ * + .
\6	−0.0331539	0.01394		+ * + .
\7	−0.0189451	0.007966		+ * + .
SUM	−0.284176	0.1195	−2.378	
AVG	3.5	0	NC	
3)	−0.0714375	0.01614	−4.426	SHIFT814832
4)	−0.0781178	0.01842	−4.24	DUM853
5)	−0.0572086	0.01781	−3.212	DUM862863
	0.663586	0.1134	5.853	RHO

R-BAR SQUARED: 0.9765
F-STATISTIC(6,42): 333.48869
DURBIN-WATSON STATISTIC: 1.9900
SUM OF SQUARED RESIDUALS: 0.02043
STANDARD ERROR OF THE REGRESSION: 0.02206 NORMALIZED: 0.006196

WHERE:

GHID@35SA	GIGAWATT HOUR SALES – MACHINERY – EXCEPT ELECTRICAL – SEASONALLY ADJUSTED
X35@CPL	CP&L SERV. AREA PRODUCTION INDEX – MACHINERY – EXCEPT ELECTRICAL
SHIFT814832	SHIFT VARIABLE FOR CHANGE IN SIC 35 – 81:4 TO 83:2
DUM853	UNEXPLAINED DROP IN USAGE 85:3
DUM862863	UNEXPLAINED DROP IN USAGE 86:2 TO 86:3

Figure 61

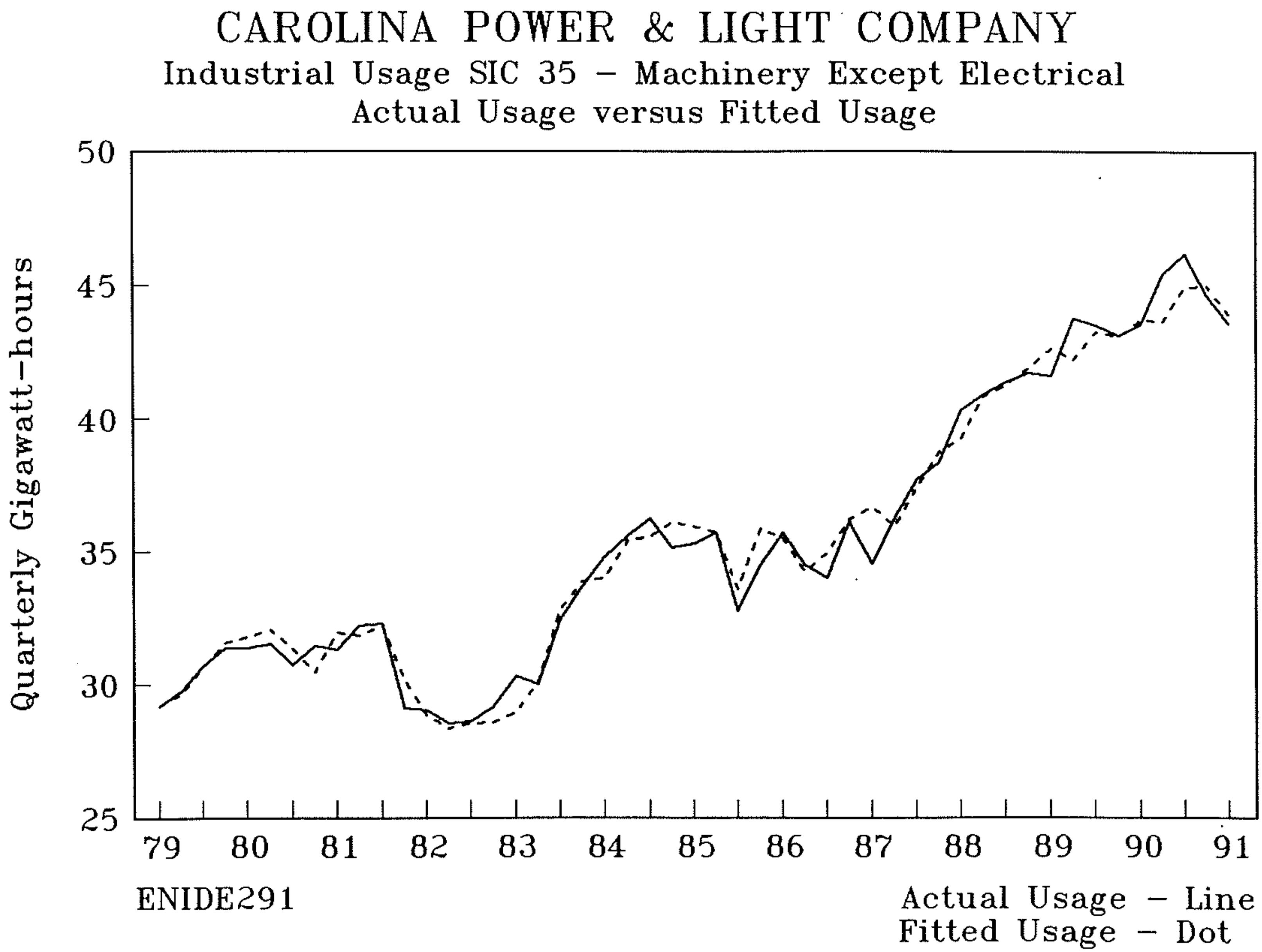
ORDINARY LEAST SQUARES

QUARTERLY(1979:1 TO 1991:1) 49 OBSERVATIONS
DEPENDENT VARIABLE: GHID@35SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00065	0.002965	337.5	EXP(FIT(@RR))

R-BAR SQUARED: 0.9798 (RELATIVE TO Y=0, RBSQ: 0.9996)
F-STATISTIC(1,48): 113917.87
DURBIN-WATSON STATISTIC: 1.9733
SUM OF SQUARED RESIDUALS: 26.58
STANDARD ERROR OF THE REGRESSION: 0.7442 NORMALIZED: 0.02095

Figure 61 (cont'd.)



CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 35 – Machinery Except Electrical
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
50
45
40
35
30
25
79
80
81
82
83
84
85
86
87
88
89
90
91
ENIDE291
Actual Usage – Line
Fitted Usage – Dot

Figure 62

13) **Electrical Equipment** (SIC 36)

We are forecasting that the employment in the Electrical Equipment classification will decrease within the service area, going from 26,481 in 1991 to 22,754 in the year 2010. The output of this industry in the service area is forecast to increase, however, at 4.2% compounded annually and the power consumption to increase at 1.7% annually.

The model and applicable statistics for this classification are shown in Figure 63. A plot of the actual versus the fitted values is shown in Figure 64.

The forecast for Electrical Equipment is shown in Table XI.

ORDINARY LEAST SQUARES

QUARTERLY(1976:1 TO 1991:1) 61 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@36SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	1.10354	0.3154	3.499	CONSTANT
1)	0.780904	0.06273	12.45	LOG(GHID@36SA\1)
2)	0.0658538	0.02763	2.383	LOG(X36@CPL)
3)	0.180788	0.06125	2.952	SHIFT823851*LOG(X36@CPL)
4)	−0.0321762	0.01387	−2.32	SHIFT823851

R−BAR SQUARED: 0.9522
F−STATISTIC(4,56): 299.89759
DURBIN−WATSON STATISTIC: 2.0555
SUM OF SQUARED RESIDUALS: 0.04837
STANDARD ERROR OF THE REGRESSION: 0.02939 NORMALIZED: 0.005973

WHERE:

GHID@36AOSA	GIGAWATT HOUR SALES – ELEC. MACHINERY EXCEPT GE NUCLEAR – SEASONALLY ADJUSTED
X36@CPL	CP&L SERV. AREA PRODUCTION INDEX – ELEC. MACHINERY
SHIFT823851	SHIFT VARIABLE FOR CHANGE IN SIC 36 – 82:3 TO 85:1

Figure 63

ORDINARY LEAST SQUARES

QUARTERLY(1976:1 TO 1991:1) 61 OBSERVATIONS
DEPENDENT VARIABLE: GHID@36SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00024	0.003474	287.9	EXP(FIT(@RR))

R-BAR SQUARED: 0.9553 (RELATIVE TO Y=0, RBSQ: 0.9993)
F-STATISTIC(1,60): 82889.604
DURBIN-WATSON STATISTIC: 1.9813
SUM OF SQUARED RESIDUALS: 858.1
STANDARD ERROR OF THE REGRESSION: 3.782 NORMALIZED: 0.02734

Figure 63 (cont'd.)

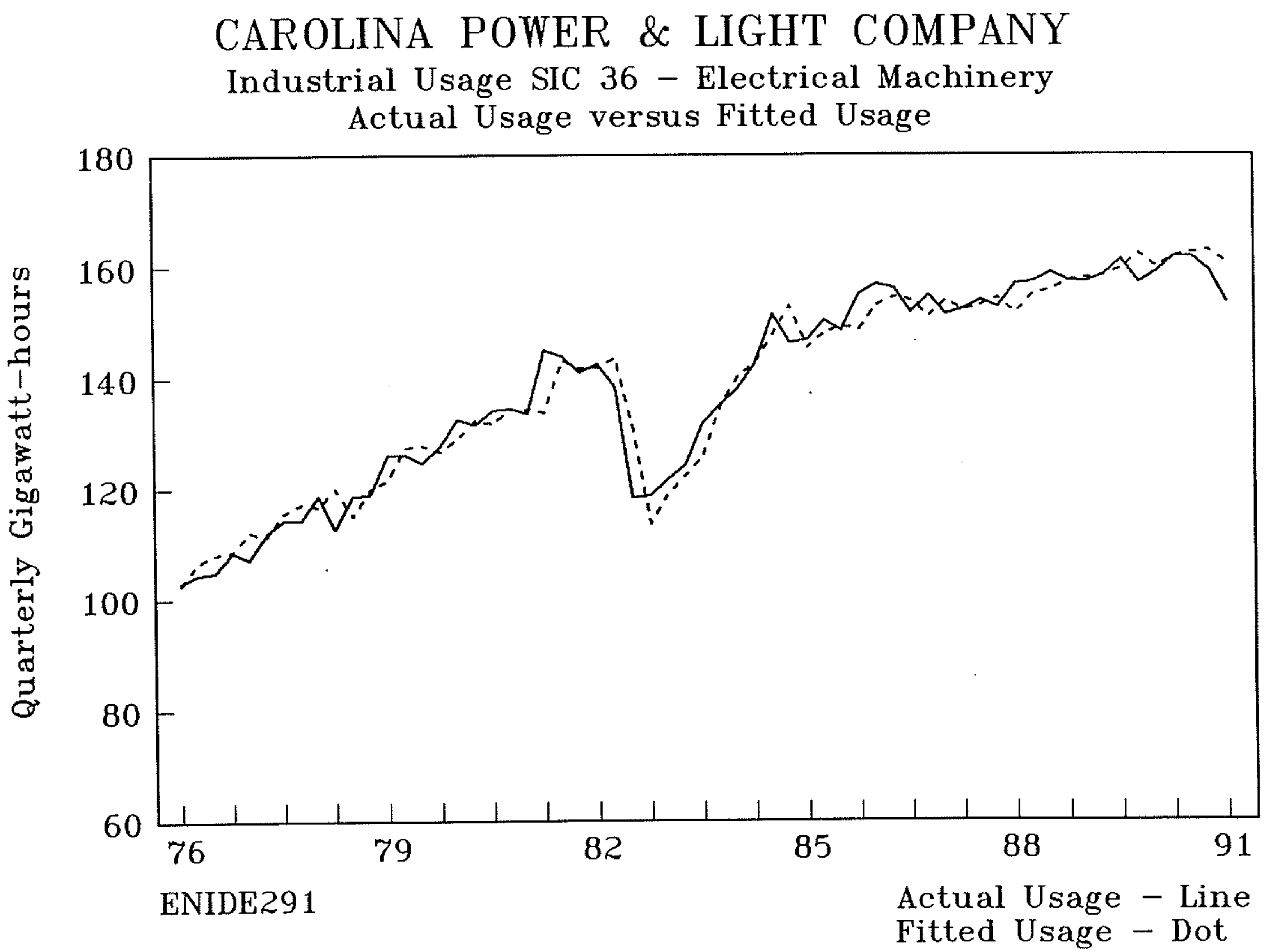

CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 36 – Electrical Machinery
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
180
160
140
120
100
80
60
76
79
82
85
88
91
ENIDE291
Actual Usage – Line
Fitted Usage – Dot

Figure 64

14) **Transportation Equipment** (SIC 37)

The Transportation Equipment industry in the service area is heavily concentrated in motor vehicles and vehicle equipment. Other manufacturers include aircraft parts and boat construction. Employment in this industry within the service area is expected to increase slightly from 13,130 in 1991 to 13,672 in 2010. Industry production is also projected to increase at an average annual rate of 3.4%, and electricity usage is expected to increase at an average 4.9% annual rate.

The model and applicable statistics for this industry are shown in Figure 65. A plot of the actual versus model fitted values is shown in Figure 66.

The forecast for this industry is shown in Table XI.

ORDINARY LEAST SQUARES

QUARTERLY(1979:2 TO 1991:1) 48 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@37SA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	0.704798	0.1976	3.568	CONSTANT
1)	0.793489	0.05863	13.53	LOG(GHID@37SA\1)
2)	0.699336	0.1887	3.705	LOG(X37@CPL)
3)	−0.423367	0.154	−2.75	LOG(X37@CPL\1)
4)	0.0847083	0.03083	2.747	SHIFT802831

R−BAR SQUARED: 0.9864
F−STATISTIC(4,43): 850.84945
DURBIN−WATSON STATISTIC: 2.1060
SUM OF SQUARED RESIDUALS: 0.09787
STANDARD ERROR OF THE REGRESSION: 0.04771 NORMALIZED: 0.01507

WHERE:

GHID@37SA	GIGAWATT HOUR SALES – TRANSPORTATION – SEASONALLY ADJUSTED
X37@CPL	CP&L SERV. AREA PRODUCTION INDEX – TRANSPORTATION
SHIFT802831	SHIFT VARIABLE FOR CHANGE IN SIC 37 – 80:2 TO 83:1

Figure 65

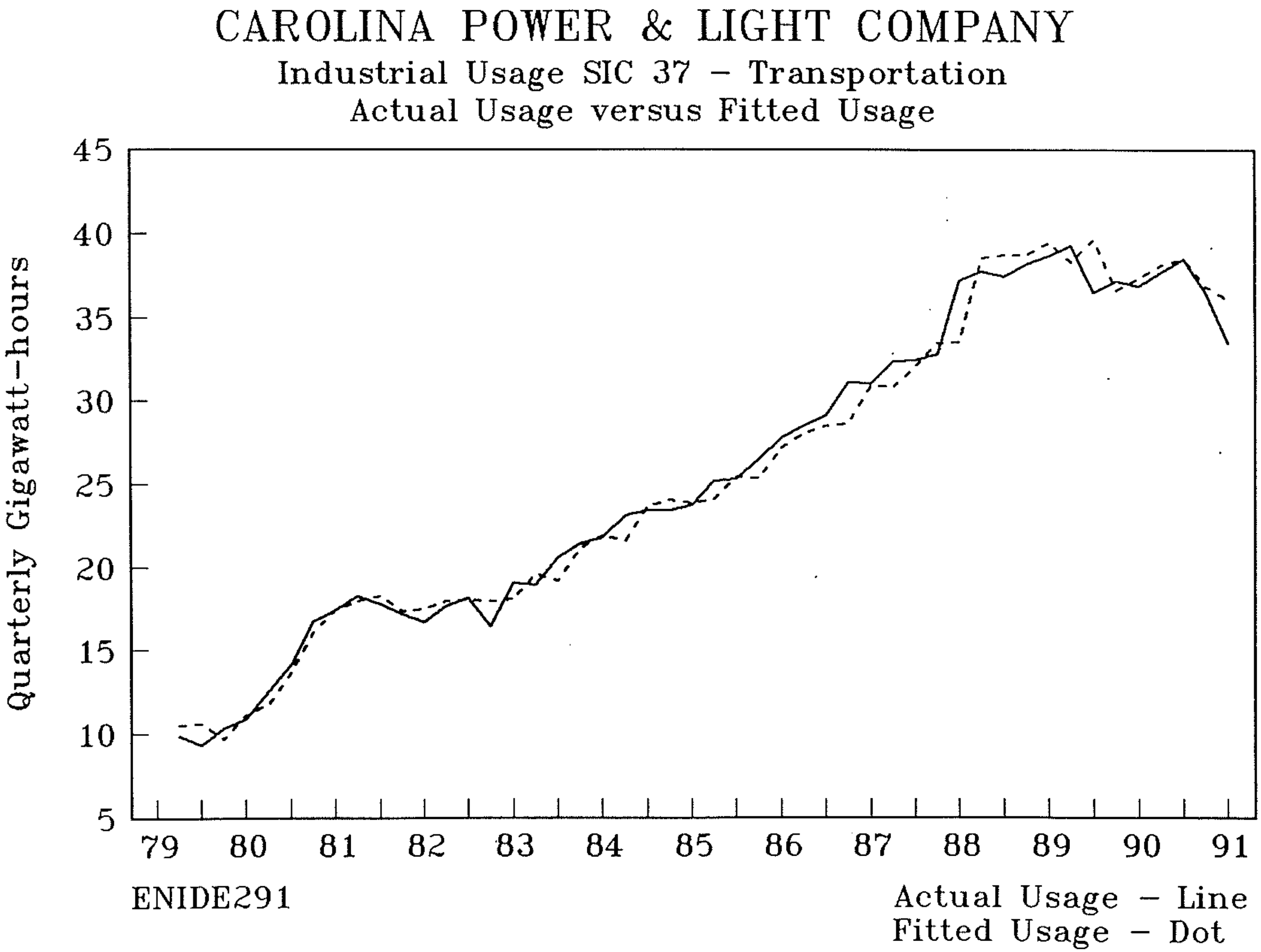
ORDINARY LEAST SQUARES

QUARTERLY(1979:2 TO 1991:1) 48 OBSERVATIONS
DEPENDENT VARIABLE: GHID@37SA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	0.997938	0.006033	165.4	EXP(FIT(@RR))

R-BAR SQUARED: 0.9851 (RELATIVE TO Y=0, RBSQ: 0.9983)
F-STATISTIC(1,47): 27359.793
DURBIN-WATSON STATISTIC: 2.1165
SUM OF SQUARED RESIDUALS: 60.74
STANDARD ERROR OF THE REGRESSION: 1.137 NORMALIZED: 0.04448

Figure 65 (cont'd.)



CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC 37 - Transportation
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
45
40
35
30
25
20
15
10
5
79
80
81
82
83
84
85
86
87
88
89
90
91
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 66

15) **Other Manufacturing**

We have had to combine all of the other industrial SIC Code groups and small users into one group -- Other Manufacturing -- because of data restrictions imposed by the State employment commissions. The employment in this group is expected to decline at an annual rate of 2.4% for the service area, decreasing from 15,905 in 1991 to 9,999 in 2010. While the trend output of this group is projected to increase at an average annual rate of 0.4%, the power consumption for these industries in the service area is forecast to increase at a compounded growth rate of 1.3%.

The model and the applicable statistics for this miscellaneous group are shown in Figure 67. A plot of the actual versus the fitted values is shown in Figure 68.

The forecast for Other Manufacturing is shown in Table XI.

ORDINARY LEAST SQUARES

QUARTERLY(1984:1 TO 1991:1) 29 OBSERVATIONS
DEPENDENT VARIABLE: LOG(GHID@OMSA)

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
	4.84891	0.01699	285.5	CONSTANT
1)	1.3463	0.3218	4.184	LOG(JQINDOM)
2)	0.229383	0.04039	5.679	SHIFT883&
3)	0.24891	0.05649	4.407	DUM852

R-BAR SQUARED: 0.9255
F-STATISTIC(3,25): 116.88870
DURBIN-WATSON STATISTIC: 1.8850
SUM OF SQUARED RESIDUALS: 0.07055
STANDARD ERROR OF THE REGRESSION: 0.05312 NORMALIZED: 0.01073

WHERE:

GHID@OMSA	GIGAWATT HOUR SALES – OTHER INDUS. MANUF. – SIC's 14,21,29,31,38 AND 39 – SEASONALLY ADJUSTED
JQINDOM	INDUSTRIAL PRODUCTION INDEX – SIC OM
SHIFT883&	SHIFT VARIABLE FOR STRUCTURAL CHANGE IN SIC OM
DUM852	UNEXPLAINED INCREASE IN USAGE 85:2

Figure 67

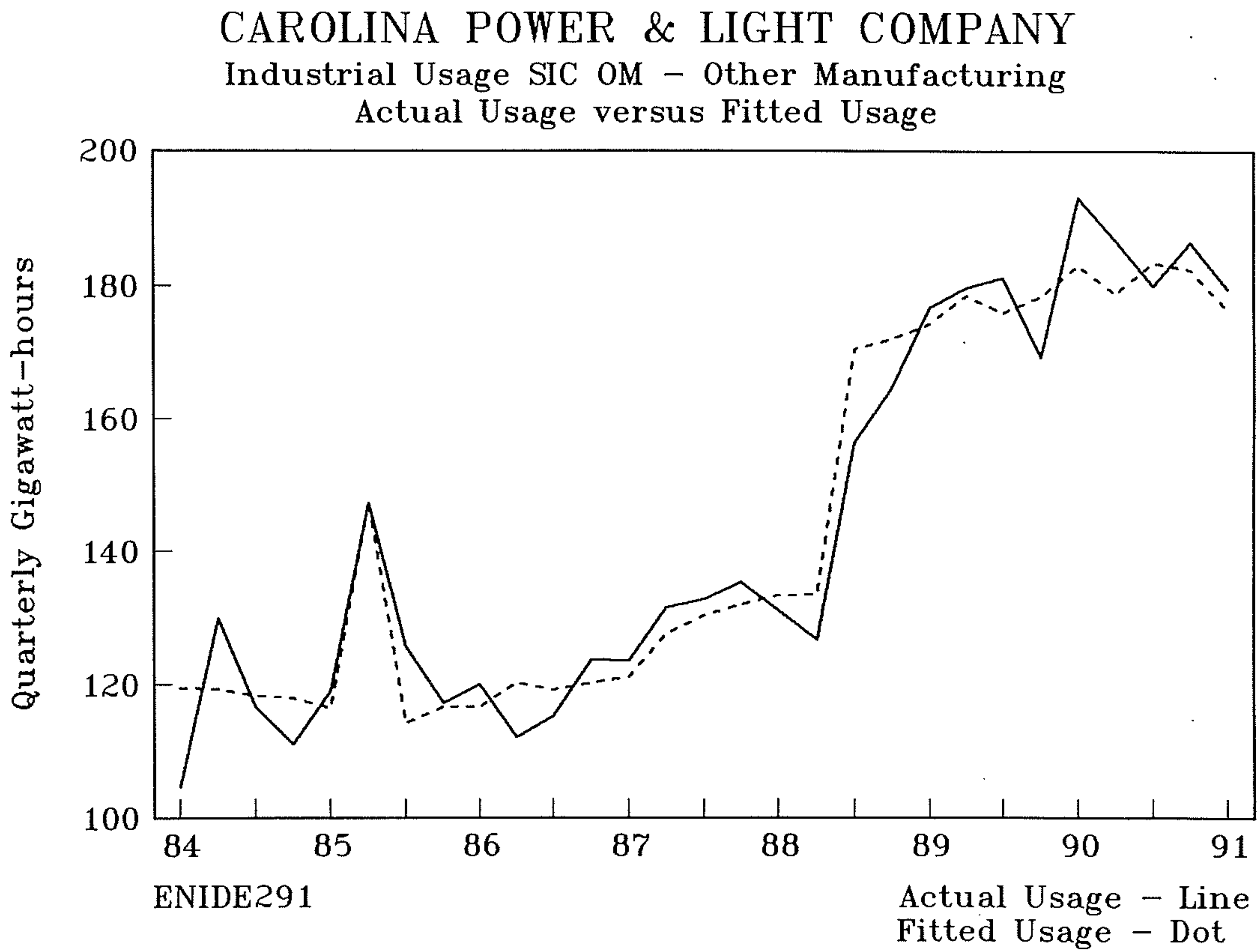
ORDINARY LEAST SQUARES

QUARTERLY(1984:1 TO 1991:1) 29 OBSERVATIONS
DEPENDENT VARIABLE: GHID@OMSA

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	1.00137	0.008632	116	EXP(FIT(@RR))

R-BAR SQUARED: 0.9433 (RELATIVE TO Y=0, RBSQ: 0.9979)
F-STATISTIC(1,28): 13458.302
DURBIN-WATSON STATISTIC: 1.8694
SUM OF SQUARED RESIDUALS: 1296
STANDARD ERROR OF THE REGRESSION: 6.803 NORMALIZED: 0.04724

Figure 67 (cont'd.)



CAROLINA POWER & LIGHT COMPANY
Industrial Usage SIC OM - Other Manufacturing
Actual Usage versus Fitted Usage
Quarterly Gigawatt-hours
200
180
160
140
120
100
84
85
86
87
88
89
90
91
ENIDE291
Actual Usage - Line
Fitted Usage - Dot

Figure 68

I.4 OTHER

A. SALES-FOR-RESALE FORECAST

The ultimate users in the Sales-For-Resale category are subjected to generally the same climatic and economic environment as our retail customers. Energy sales to the ultimate consumer of these distribution systems are primarily residential and commercial customers. This class is expected to grow at a slightly higher rate during the forecast period than the combined retail classifications. This expectation is generally consistent with growth projections developed by NCEMC.

The models shown on the following pages are for the Sales-For-Resale customers served by CP&L. Table XIII shows a complete breakdown of usage by all wholesale subsectors, while the Summary Sheet, Table I, shows only total resale and total NCEMPA.

The Sales-For-Resale models use historical monthly usage, summer weather, winter weather, twelve seasonal dummies, and the relative price of electricity versus natural gas. The models represent total energy usage for each component because energy from the South Eastern Power Administration is included in the historical data.

To forecast with these models, it is necessary to have a monthly series of forecasted values for each independent variable. These values came from the following sources:

Weighted Normal Heating Degree Days - Calculated by CP&L

Weighted Normal Cooling Degree Days - Calculated by CP&L

Relative Price of Electricity to Natural Gas - CP&L economic model

Seasonal Dummies - 1 for the given month and 0 elsewhere

The Sales-for-Resale forecast is shown in Table XII and the model structure is shown in Figure 69. The plot of actual usage versus fitted usage is shown in Figure 70.

SALES FOR RESALE
TOTAL MWH

(Excludes NCEMPA)

1986	5,320,206
1987	5,749,167
1988	5,938,009
1989	6,016,312
1990	6,211,715
1991	6,063,351
1992	6,151,281
1993	6,465,966
1994	6,769,991
1995	6,896,754
1996	7,012,601
1997	7,141,530
1998	7,296,801
1999	7,478,701
2000	7,646,904
2001	7,824,943
2002	8,021,051
2003	8,221,178
2004	8,420,668
2005	8,630,873
2006	8,836,027
2007	9,048,116
2008	9,252,404
2009	9,451,444
2010	9,651,146

Table XII

LEAST SQUARES WITH FIRST-ORDER AUTOCORRELATION CORRECTION

MONTHLY(1972:1 TO 1991:3) 231 OBSERVATIONS
DEPENDENT VARIABLE: MHWHSL&FAYGEN

	COEFFICIENT	STD. ERROR	T-STAT	INDEPENDENT VARIABLE
1)	33.7236	27.98	1.205	WHDD65WHSL@CPL
2)	145.656	69.41	2.098	WCDD65WHSL@CPL
3)	−44006.8	6.680E+04	−0.6588	SEASONM01
4)	−54946.2	6.531E+04	−0.8413	SEASONM02
5)	−114752	6.436E+04	−1.783	SEASONM03
6)	−151571	6.423E+04	−2.36	SEASONM04
7)	−193466	6.480E+04	−2.986	SEASONM05
8)	−169936	6.633E+04	−2.562	SEASONM06
9)	−86407.9	6.989E+04	−1.236	SEASONM07
10)	−9207.87	6.864E+04	−0.1342	SEASONM08
11)	−16618.4	6.603E+04	−0.2517	SEASONM09
12)	−120115	6.654E+04	−1.805	SEASONM10
13)	−167490	6.618E+04	−2.531	SEASONM11
14)	−131889	6.665E+04	−1.979	SEASONM12
15)	31228.1	1608	19.42	RYD@CPL
16)	−17264.6	5276	−3.273	ARPER/ARPNG
	0.606474	0.05494	11.04	RHO

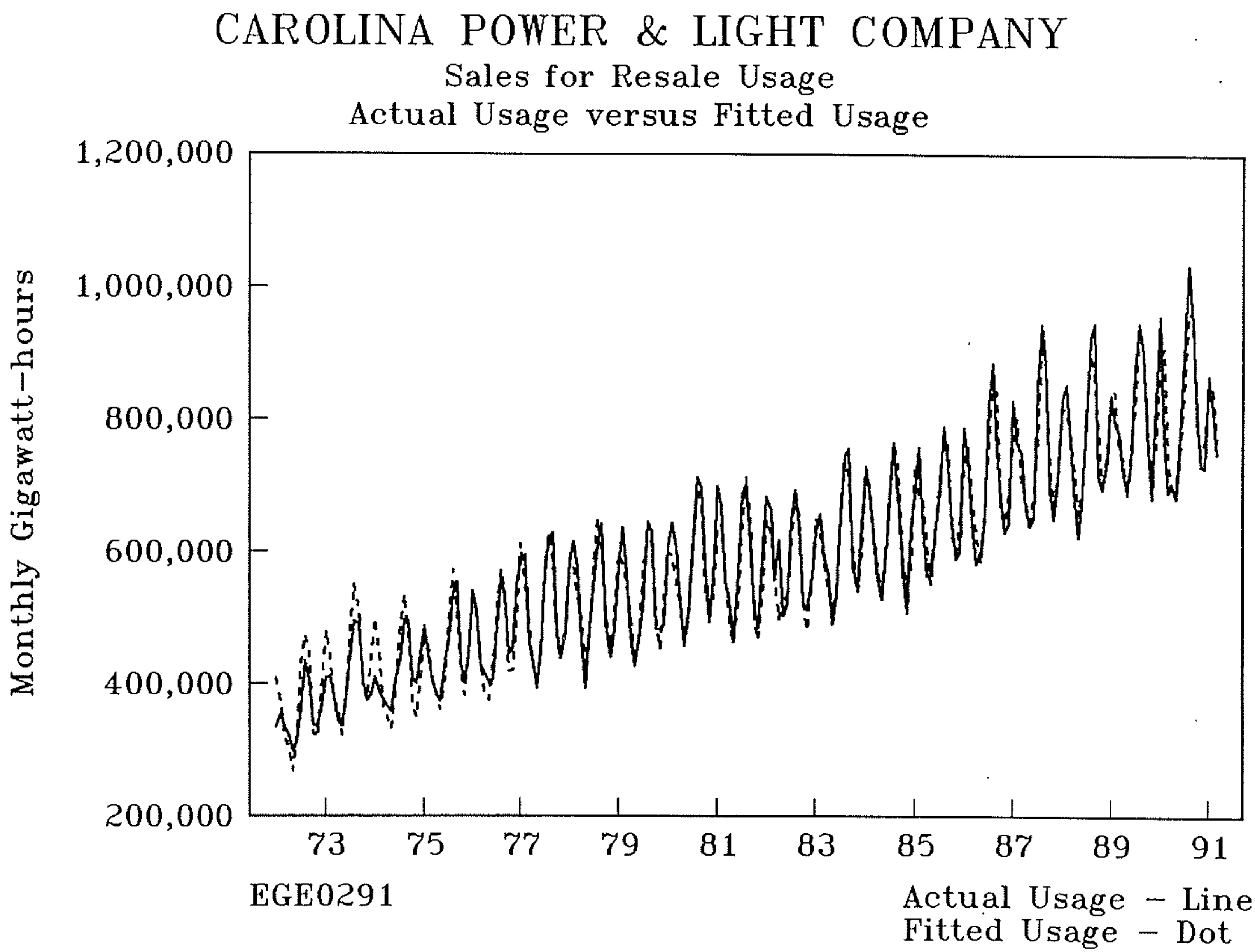
R-BAR SQUARED: 0.9441 (RELATIVE TO Y=0, RBSQ: 0.9964)
F-STATISTIC(17,214): 3744.9380
DURBIN-WATSON STATISTIC: 1.9404
DURBIN H-STATISTIC (LDV= 1): NC
SUM OF SQUARED RESIDUALS: 2.887E+11
STANDARD ERROR OF THE REGRESSION: 3.673E+04 NORMALIZED: 0.06217

Figure 69

WHERE:

MHWHSL&FAYGEN	MEGAWATT HOUR USAGE – SALES FOR RESALE AND FAYETTEVILLE GENERATION
WHDD65WHSL@CPL	HEATING DEGREE DAYS – 65 BASE – WEIGHTED FOR BILLING CYCLES AND WHOLESALE SALES IN CP&L DIVISIONS
WCDD65WHSL@CPL	COOLING DEGREE DAYS – 65 BASE – WEIGHTED FOR BILLING CYCLES AND WHOLESALE SALES IN CP&L DIVISIONS
SEASONM01	SEASONAL DUMMY FOR JANUARY (1=THEREIN, 0 ELSEWHERE)
SEASONM02	SEASONAL DUMMY FOR FEBRUARY (1=THEREIN, 0 ELSEWHERE)
SEASONM03	SEASONAL DUMMY FOR MARCH (1=THEREIN, 0 ELSEWHERE)
SEASONM04	SEASONAL DUMMY FOR APRIL (1=THEREIN, 0 ELSEWHERE)
SEASONM05	SEASONAL DUMMY FOR MAY (1=THEREIN, 0 ELSEWHERE)
SEASONM06	SEASONAL DUMMY FOR JUNE (1=THEREIN, 0 ELSEWHERE)
SEASONM07	SEASONAL DUMMY FOR JULY (1=THEREIN, 0 ELSEWHERE)
SEASONM08	SEASONAL DUMMY FOR AUGUST (1=THEREIN, 0 ELSEWHERE)
SEASONM09	SEASONAL DUMMY FOR SEPTEMBER (1=THEREIN, 0 ELSEWHERE)
SEASONM10	SEASONAL DUMMY FOR OCTOBER (1=THEREIN, 0 ELSEWHERE)
SEASONM11	SEASONAL DUMMY FOR NOVEMBER (1=THEREIN, 0 ELSEWHERE)
SEASONM12	SEASONAL DUMMY FOR DECEMBER (1=THEREIN, 0 ELSEWHERE)
RYD@CPL	REAL DISPOSABLE PERSONAL INCOME
ARPER	AVERAGE REAL PRICE OF ELECTRICITY
ARPNG	AVERAGE REAL PRICE OF NATURAL GAS

Figure 69 (cont'd.)



CAROLINA POWER & LIGHT COMPANY
Sales for Resale Usage
Actual Usage versus Fitted Usage
Monthly Gigawatt-hours
1,200,000
1,000,000
800,000
600,000
400,000
200,000
73
75
77
79
81
83
85
87
89
91
EGE0291
Actual Usage - Line
Fitted Usage - Dot

Figure 70

CAROLINA POWER & LIGHT COMPANY
ENERGY FORECAST

Distribution of All Wholesale Energy

	Cooperatives	CP&L Municipals	NCEMPA CP&L Territory	NCEMPA Northeast Municipalities	Total Wholesale Energy
1986	3,652,574	1,667,632	3,021,258	1,634,450	9,975,914
1987	4,025,198	1,723,969	3,185,693	1,747,558	10,682,418
1988	4,162,586	1,775,423	3,270,467	1,819,962	11,028,438
1989	4,295,348	1,720,964	3,390,576	1,927,606	11,334,493
1990	4,516,021	1,695,694	3,388,200	1,880,512	11,480,427
1991	4,463,746	1,599,605	3,509,167	1,956,144	11,528,662
1992	4,518,291	1,632,990	3,474,895	1,954,658	11,580,834
1993	4,797,349	1,668,617	3,590,181	2,032,526	12,088,672
1994	5,020,737	1,749,255	3,685,786	2,099,727	12,555,504
1995	5,199,229	1,697,524	3,747,867	2,151,861	12,796,482
1996	5,321,751	1,690,850	3,800,067	2,204,525	13,017,194
1997	5,414,582	1,726,947	3,853,983	2,256,877	13,252,390
1998	5,534,185	1,762,617	3,910,879	2,312,180	13,519,861
1999	5,677,142	1,801,559	3,970,700	2,368,150	13,817,551
2000	5,804,355	1,842,548	4,019,719	2,420,089	14,086,712
2001	5,943,494	1,881,449	4,068,303	2,472,233	14,365,480
2002	6,097,508	1,923,543	4,117,689	2,523,809	14,662,548
2003	6,252,437	1,968,741	4,167,294	2,575,123	14,963,594
2004	6,408,745	2,011,922	4,220,369	2,628,769	15,269,806
2005	6,575,058	2,055,815	4,275,953	2,685,365	15,592,190
2006	6,737,021	2,099,006	4,327,992	2,742,033	15,906,052
2007	6,903,846	2,144,270	4,385,484	2,804,490	16,238,091
2008	7,065,729	2,186,675	4,439,377	2,865,239	16,557,019
2009	7,222,038	2,229,407	4,492,609	2,926,234	16,870,287
2010	7,379,940	2,271,206	4,542,905	2,987,569	17,181,620

1991 – Same as Reference Case

Table XIII

B. PUBLIC STREET AND HIGHWAY LIGHTING AND OTHER SALES TO PUBLIC AUTHORITIES FORECAST

Historic Public Street and Highway Lighting usage has been regressed using time. It is expected that this sector would grow similarly to the growth in retail customers; however, actual usage is very erratic. Among other factors, the growth is dependent upon the funds available by municipal bodies and the growth in residential subdivisions. During the forecast period, we are forecasting this sector to grow at 0.5% compounded annually for the 20-year forecast period.

Other Sales to Public Authorities, which include military sales, have also been very erratic. Presently, for example, Fort Bragg and Seymour Johnson AFB are studying joint venture efforts to reduce their dependence on purchased power. Because it is anticipated that military usage will continue to reflect controlled usage, we are showing 0.5% growth for the forecast period.

The forecasts for these sectors are shown in Tables XIV and XV.

PUBLIC STREET & HIGHWAY LIGHTING
TOTAL MWH

	MHSL
1986	92,866
1987	88,835
1988	90,803
1989	93,660
1990	95,640
1991	95,500
1992	96,296
1993	96,777
1994	97,261
1995	97,747
1996	98,236
1997	98,727
1998	99,221
1999	99,717
2000	100,215
2001	100,717
2002	101,220
2003	101,726
2004	102,235
2005	102,746
2006	103,260
2007	103,776
2008	104,295
2009	104,816
2010	105,341

Table XIV

MILITARY USAGE
TOTAL MWH

	MHMIL
1986	961,006
1987	995,020
1988	1,019,641
1989	1,060,617
1990	1,067,179
1991	1,058,731
1992	1,054,321
1993	1,059,592
1994	1,064,890
1995	1,070,215
1996	1,075,566
1997	1,080,944
1998	1,086,348
1999	1,091,780
2000	1,097,239
2001	1,102,725
2002	1,108,239
2003	1,113,780
2004	1,119,349
2005	1,124,946
2006	1,130,570
2007	1,136,223
2008	1,141,904
2009	1,147,614
2010	1,153,352

Table XV

APPENDIX TO CAROLINA POWER & LIGHT COMPANY

ENERGY FORECAST REPORT

DOCKET E-100, SUB 64

Higher Growth and Slower Growth Scenarios

In the 1991 forecast cycle, the slower growth scenario was judged to best typify CP&L's energy future. An explanation of this judgement was provided in the introduction section of this Energy Forecast volume. This technical appendix summarizes the procedures employed to produce two alternative growth scenarios using the reference forecast as a basis. A summary of the reference forecast has also been provided here for comparison purposes.

The alternative growth scenarios are provided to CP&L management and others as one means of assessing forecast uncertainty. While all explicit forecasts are ultimately "point" forecasts, these scenarios should be interpreted as establishing a general bandwidth for future electricity needs served by CP&L. In the 1991 forecast cycle, it was determined that substantial uncertainty exists in electricity markets currently served by CP&L. The most visible uncertainty is manifest in our wholesale and industrial markets because some of these large customers may have increasing opportunities to serve their electricity needs from alternative suppliers. While not as visible, similar forecast uncertainty also exists in our retail markets as described in the introduction of this report. These issues suggest that the projections of the slower growth scenario best typify CP&L's future. The development of this scenario, along with the higher growth scenario, is discussed in the following pages.

The methodology used to develop the higher and slower growth scenario forecasts is identical to that used for the reference forecast. For the higher growth scenario, it is assumed that national economic conditions develop which are more favorable to electricity growth than in the reference forecast; and for the slower growth scenario, the assumption is that conditions are less favorable. These economic assumptions are based on DRI Macro Economic simulations which produce the quantitative details of the conditions which would follow as a result of these changes. For example, if it is assumed that more investment is made in new plant and equipment in the higher growth scenario, the model will indicate higher productivity, lower inflation, less unemployment, and quantify other effects that will flow through to the various segments of the economy.

These new outputs from the DRI Macro Economic Model become new inputs to the CP&L Service Area Economic Model and a new forecast of demography, wealth, and employment is produced which, in turn, is input to the CP&L energy models. The energy growth scenarios produced reflect the prospect of changing electricity needs served by CP&L.

The summary of the slower growth scenario is shown in Tables I and II on Pages 7 and 8. The reference forecast is shown in Tables A.II and A.III on Pages A.4 and A.5. Finally, the higher growth scenario is shown in Tables A.IV and A.V on Pages A.6 and A.7. A comparison of the various revenue classes is discussed on the following pages. Unless otherwise noted, all energies are expressed in megawatt hours.

Table A.I

Contributions to Real Potential GNP Growth
(Average annual percent growth - 1987 to 2013)

	Low	Base	High
Labor Force	0.5	0.7	0.8
Capital Stock	0.7	0.9	1.0
Other Factors	0.7	0.7	0.8
Potential GNP	1.9	2.3	2.6

CAROLINA POWER & LIGHT CO.
ENERGY FORECAST
NOT REDUCED BY CONSERVATION AND LOAD MANAGEMENT
(IN MWH)
REFERENCE CASE

	RESIDENTIAL	% CH	COMMERCIAL	% CH	INDUSTRIAL	% CH	PUB ST. & H. LIGHT.	% CH	MILITARY	% CH	SALES FOR RESALE	% CH	NCEMPA	% CH	TOTAL	% ANN. GR.
1986	9,028,062	9.5	6,364,888	6.9	11,053,697	3.1	92,866	−2.0	961,006	5.8	5,320,207	7.7	4,655,707	4.9	37,476,433	6.17
1987	9,614,322	6.5	6,731,821	5.8	11,477,238	3.8	88,835	−4.3	995,020	3.5	5,749,167	8.1	4,933,251	6.0	39,589,654	5.64
1988	9,854,258	2.5	7,059,737	4.9	11,925,679	3.9	90,803	2.2	1,019,641	2.5	5,938,009	3.3	5,090,429	3.2	40,978,556	3.51
1989	9,942,971	0.9	7,378,331	4.5	12,344,506	3.5	93,660	3.1	1,060,617	4.0	6,016,311	1.3	5,318,182	4.5	42,154,578	2.87
1990	10,013,870	0.7	7,669,623	3.9	12,335,935	−0.1	95,640	2.1	1,067,179	0.6	6,211,715	3.2	5,268,712	−0.9	42,662,674	1.21
1991	10,270,072	2.6	7,411,169	−3.4	11,930,774	−3.3	95,500	−0.1	1,058,731	−0.8	6,063,351	−2.4	5,465,311	3.7	42,294,908	−0.86
1992	10,835,408	5.5	7,650,364	3.2	12,751,907	6.9	96,296	0.8	1,054,321	−0.4	6,283,086	3.6	5,529,994	1.2	44,201,375	4.51
1993	11,353,366	4.8	7,865,351	2.8	13,020,509	2.1	96,777	0.5	1,059,592	0.5	6,519,441	3.8	5,659,820	2.3	45,574,856	3.11
1994	11,856,951	4.4	8,075,910	2.7	13,284,023	2.0	97,261	0.5	1,064,890	0.5	6,781,432	4.0	5,792,057	2.3	46,952,524	3.02
1995	12,304,184	3.8	8,275,249	2.5	13,531,686	1.9	97,747	0.5	1,070,215	0.5	6,934,894	2.3	5,927,980	2.3	48,141,955	2.53
1996	12,687,086	3.1	8,432,476	1.9	13,740,492	1.5	98,236	0.5	1,075,566	0.5	7,101,605	2.4	6,071,130	2.4	49,206,591	2.21
1997	13,024,586	2.7	8,554,683	1.4	13,945,223	1.5	98,727	0.5	1,080,944	0.5	7,277,621	2.5	6,212,181	2.3	50,193,964	2.01
1998	13,336,909	2.4	8,683,235	1.5	14,212,930	1.9	99,221	0.5	1,086,348	0.5	7,480,799	2.8	6,359,508	2.4	51,258,950	2.12
1999	13,636,404	2.2	8,819,204	1.6	14,497,751	2.0	99,717	0.5	1,091,780	0.5	7,711,848	3.1	6,510,916	2.4	52,367,620	2.16
2000	13,925,668	2.1	8,974,431	1.8	14,756,412	1.8	100,215	0.5	1,097,239	0.5	7,944,666	3.0	6,658,974	2.3	53,457,605	2.08
10 yr. Cmpd. 90−2000	3.4		1.4		1.8		0.5		0.3		2.5		2.4		2.3	
2001	14,189,854	1.9	9,124,005	1.7	14,998,979	1.6	100,717	0.5	1,102,725	0.5	8,202,460	3.2	6,817,376	2.4	54,536,116	2.02
2002	14,451,053	1.8	9,238,473	1.3	15,207,893	1.4	101,220	0.5	1,108,239	0.5	8,472,490	3.3	6,970,185	2.2	55,549,553	1.86
2003	14,711,260	1.8	9,352,097	1.2	15,412,377	1.3	101,726	0.5	1,113,780	0.5	8,745,873	3.2	7,121,928	2.2	56,559,041	1.82
2004	14,958,725	1.7	9,466,354	1.2	15,615,589	1.3	102,235	0.5	1,119,349	0.5	9,008,225	3.0	7,271,647	2.1	57,542,123	1.74
2005	15,196,023	1.6	9,591,150	1.3	15,864,861	1.6	102,746	0.5	1,124,946	0.5	9,275,696	3.0	7,422,497	2.1	58,577,918	1.80
2006	15,438,494	1.6	9,730,755	1.5	16,097,404	1.5	103,260	0.5	1,130,570	0.5	9,547,642	2.9	7,576,748	2.1	59,624,874	1.79
2007	15,685,839	1.6	9,869,251	1.4	16,335,278	1.5	103,776	0.5	1,136,223	0.5	9,816,573	2.8	7,734,899	2.1	60,681,839	1.77
2008	15,945,190	1.7	10,003,691	1.4	16,559,574	1.4	104,295	0.5	1,141,904	0.5	10,084,879	2.7	7,892,914	2.0	61,732,446	1.73
2009	16,221,135	1.7	10,131,918	1.3	16,782,191	1.3	104,816	0.5	1,147,614	0.5	10,343,524	2.6	8,047,290	2.0	62,778,488	1.69
2010	16,524,979	1.9	10,269,402	1.4	17,047,463	1.6	105,341	0.5	1,153,352	0.5	10,605,210	2.5	8,200,367	1.9	63,906,113	1.80
20 yr. Cmpd. 90−2010	2.5		1.5		1.6		0.5		0.4		2.7		2.2		2.0	

1991 − 7 months actual and 5 months forecast

Table A.II

CAROLINA POWER & LIGHT CO.
ENERGY FORECAST
REDUCED BY CONSERVATION AND LOAD MANAGEMENT
(IN MWH)
REFERENCE CASE

	RESIDENTIAL	% CH	COMMERCIAL	% CH	INDUSTRIAL	% CH	PUB ST. & H. LIGHT.	% CH	MILITARY	% CH	SALES FOR RESALE	% CH	NCEMPA	% CH	TOTAL	% ANN. GR.
1986	9,028,062	9.5	6,364,888	6.9	11,053,697	3.1	92,866	−2.0	961,006	5.8	5,320,207	7.7	4,655,707	4.9	37,476,433	6.17
1987	9,614,322	6.5	6,731,821	5.8	11,477,238	3.8	88,835	−4.3	995,020	3.5	5,749,167	8.1	4,933,251	6.0	39,589,654	5.64
1988	9,854,258	2.5	7,059,737	4.9	11,925,679	3.9	90,803	2.2	1,019,641	2.5	5,938,009	3.3	5,090,429	3.2	40,978,556	3.51
1989	9,942,971	0.9	7,378,331	4.5	12,344,506	3.5	93,660	3.1	1,060,617	4.0	6,016,311	1.3	5,318,182	4.5	42,154,578	2.87
1990	10,013,870	0.7	7,669,623	3.9	12,335,935	−0.1	95,640	2.1	1,067,179	0.6	6,211,715	3.2	5,268,712	−0.9	42,662,674	1.21
1991	10,282,550	2.7	7,410,470	−3.4	11,906,891	−3.5	95,500	−0.1	1,058,731	−0.8	6,063,351	−2.4	5,465,311	3.7	42,282,803	−0.89
1992	10,877,324	5.8	7,645,442	3.2	12,624,976	6.0	96,296	0.8	1,054,321	−0.4	6,283,086	3.6	5,529,994	1.2	44,111,438	4.32
1993	11,407,494	4.9	7,857,537	2.8	12,875,691	2.0	96,777	0.5	1,059,592	0.5	6,519,441	3.8	5,659,820	2.3	45,476,352	3.09
1994	11,924,350	4.5	8,065,436	2.6	13,117,440	1.9	97,261	0.5	1,064,890	0.5	6,781,432	4.0	5,792,057	2.3	46,842,866	3.00
1995	12,386,009	3.9	8,262,485	2.4	13,341,586	1.7	97,747	0.5	1,070,215	0.5	6,934,894	2.3	5,927,980	2.3	48,020,915	2.51
1996	12,768,454	3.1	8,419,046	1.9	13,523,689	1.4	98,236	0.5	1,075,566	0.5	7,101,605	2.4	6,071,130	2.4	49,057,726	2.16
1997	13,105,553	2.6	8,540,672	1.4	13,702,218	1.3	98,727	0.5	1,080,944	0.5	7,277,621	2.5	6,212,181	2.3	50,017,916	1.96
1998	13,417,467	2.4	8,668,628	1.5	13,944,177	1.8	99,221	0.5	1,086,348	0.5	7,480,799	2.8	6,359,508	2.4	51,056,148	2.08
1999	13,716,548	2.2	8,803,996	1.6	14,202,242	1.9	99,717	0.5	1,091,780	0.5	7,711,848	3.1	6,510,916	2.4	52,137,047	2.12
2000	14,005,398	2.1	8,958,620	1.8	14,434,830	1.6	100,215	0.5	1,097,239	0.5	7,944,666	3.0	6,658,974	2.3	53,199,942	2.04
10 yr. Cmpd. 90−2000	3.4		1.6		1.6		0.5		0.3		2.5		2.4		2.2	
2001	14,269,163	1.9	9,107,581	1.7	14,652,255	1.5	100,717	0.5	1,102,725	0.5	8,202,460	3.2	6,817,376	2.4	54,252,277	1.98
2002	14,529,934	1.8	9,221,428	1.3	14,833,677	1.2	101,220	0.5	1,108,239	0.5	8,472,490	3.3	6,970,185	2.2	55,237,172	1.82
2003	14,789,696	1.8	9,334,404	1.2	15,010,678	1.2	101,726	0.5	1,113,780	0.5	8,745,873	3.2	7,121,928	2.2	56,218,085	1.78
2004	15,036,701	1.7	9,447,993	1.2	15,183,926	1.2	102,235	0.5	1,119,349	0.5	9,008,225	3.0	7,271,647	2.1	57,170,076	1.69
2005	15,273,530	1.6	9,572,106	1.3	15,402,231	1.4	102,746	0.5	1,124,946	0.5	9,275,696	3.0	7,422,497	2.1	58,173,750	1.76
2006	15,515,453	1.6	9,710,913	1.5	15,604,243	1.3	103,260	0.5	1,130,570	0.5	9,547,642	2.9	7,576,748	2.1	59,188,830	1.74
2007	15,762,236	1.6	9,848,592	1.4	15,811,883	1.3	103,776	0.5	1,136,223	0.5	9,816,573	2.8	7,734,899	2.1	60,214,182	1.73
2008	16,021,015	1.6	9,982,200	1.4	16,008,387	1.2	104,295	0.5	1,141,904	0.5	10,084,879	2.7	7,892,914	2.0	61,235,594	1.70
2009	16,296,369	1.7	10,109,568	1.3	16,199,239	1.2	104,816	0.5	1,147,614	0.5	10,343,524	2.6	8,047,290	2.0	62,248,419	1.65
2010	16,599,603	1.9	10,246,163	1.4	16,430,613	1.4	105,341	0.5	1,153,352	0.5	10,605,210	2.5	8,200,367	1.9	63,340,648	1.75
20 yr. Cmpd. 90−2010	2.6		1.5		1.4		0.5		0.4		2.7		2.2		2.0	

1991 − 7 months actual and 5 months forecast

Table A.III

CAROLINA POWER & LIGHT CO.
ENERGY FORECAST
NOT REDUCED BY CONSERVATION AND LOAD MANAGEMENT
(IN MWH)
HIGHER GROWTH SCENARIO

	RESIDENTIAL	% CH	COMMERCIAL	% CH	INDUSTRIAL	% CH	PUB ST. & H. LIGHT	% CH	MILITARY	% CH	SALES FOR RESALE	% CH	NCEMPA	% CH	TOTAL	% ANN. GR.
1986	9,028,062	9.5	6,364,888	6.9	11,053,697	3.1	92,866	−2.0	961,006	5.8	5,320,207	7.7	4,655,707	4.9	37,476,433	6.17
1987	9,614,322	6.5	6,731,821	5.8	11,477,238	3.8	88,835	−4.3	995,020	3.5	5,749,167	8.1	4,933,251	6.0	39,589,654	5.64
1988	9,854,258	2.5	7,059,737	4.9	11,925,679	3.9	90,803	2.2	1,019,641	2.5	5,938,009	3.0	5,090,429	3.2	40,978,556	3.51
1989	9,942,971	0.9	7,378,331	4.5	12,344,506	3.5	93,660	3.1	1,060,617	4.0	6,016,311	1.3	5,318,182	4.5	42,154,578	2.87
1990	10,013,870	0.7	7,669,623	3.9	12,335,935	−0.1	95,640	2.1	1,067,179	0.6	6,211,715	3.2	5,268,712	−0.9	42,662,674	1.21
1991	10,270,072	2.6	7,411,169	−3.4	11,930,774	−3.3	95,500	−0.1	1,058,731	−0.8	6,063,351	−2.4	5,465,311	3.7	42,294,908	−0.86
1992	10,852,319	5.7	7,701,868	3.9	12,893,926	8.1	96,296	0.8	1,054,321	−0.4	6,347,890	4.7	5,579,117	2.1	44,525,737	5.27
1993	11,379,809	4.9	7,925,206	2.9	13,141,325	1.9	96,777	0.5	1,059,592	0.5	6,605,141	4.1	5,723,452	2.6	45,931,304	3.16
1994	11,891,481	4.5	8,139,460	2.7	13,443,629	2.3	97,261	0.5	1,064,890	0.5	6,860,338	3.9	5,849,204	2.2	47,346,262	3.08
1995	12,348,453	3.8	8,352,987	2.6	13,775,285	2.5	97,747	0.5	1,070,215	0.5	7,046,575	2.7	6,010,115	2.8	48,701,376	2.86
1996	12,757,522	3.3	8,551,261	2.4	14,088,701	2.3	98,236	0.5	1,075,566	0.5	7,282,592	3.3	6,205,377	3.2	50,059,254	2.79
1997	13,130,354	2.9	8,707,612	1.8	14,371,523	2.0	98,727	0.5	1,080,944	0.5	7,530,729	3.4	6,399,946	3.1	51,319,834	2.52
1998	13,478,231	2.6	8,872,096	1.9	14,726,143	2.5	99,221	0.5	1,086,348	0.5	7,814,889	3.8	6,606,907	3.2	52,683,836	2.66
1999	13,816,128	2.5	9,052,815	2.0	15,112,050	2.6	99,717	0.5	1,091,780	0.5	8,138,011	4.1	6,825,348	3.3	54,135,848	2.76
2000	14,147,631	2.4	9,249,277	2.2	15,474,514	2.4	100,215	0.5	1,097,239	0.5	8,474,578	4.1	7,048,559	3.3	55,592,014	2.69
10 yr. Cmpd. 90−2000	3.5		1.9		2.3		0.5		0.3		3.2		3.0		2.7	
2001	14,454,686	2.2	9,432,660	2.0	15,806,362	2.1	100,717	0.5	1,102,725	0.5	8,822,429	4.1	7,270,607	3.2	56,990,187	2.52
2002	14,759,103	2.1	9,582,669	1.6	16,102,198	1.9	101,220	0.5	1,108,239	0.5	9,186,950	4.1	7,489,287	3	58,329,666	2.35
2003	15,063,682	2.1	9,728,615	1.5	16,397,939	1.8	101,726	0.5	1,113,780	0.5	9,551,367	4	7,703,523	2.9	59,660,632	2.28
2004	15,355,187	1.9	9,873,748	1.5	16,688,786	1.8	102,235	0.5	1,119,349	0.5	9,893,669	3.6	7,907,536	2.6	60,940,510	2.15
2005	15,635,865	1.8	10,027,363	1.6	17,021,554	2.0	102,746	0.5	1,124,946	0.5	10,240,992	3.5	8,112,311	2.6	62,265,777	2.17
2006	15,919,758	1.8	10,177,445	1.5	17,324,405	1.8	103,260	0.5	1,130,570	0.5	10,563,413	3.1	8,298,426	2.3	63,517,277	2.01
2007	16,206,052	1.8	10,317,738	1.4	17,632,558	1.8	103,776	0.5	1,136,223	0.5	10,877,846	3	8,485,957	2.3	64,760,151	1.96
2008	16,506,883	1.9	10,462,452	1.4	17,934,597	1.7	104,295	0.5	1,141,904	0.5	11,201,128	3	8,680,310	2.3	66,031,569	1.96
2009	16,826,656	1.9	10,611,726	1.4	18,243,711	1.7	104,816	0.5	1,147,614	0.5	11,515,073	2.8	8,871,406	2.2	67,321,003	1.95
2010	17,175,958	2.1	10,776,038	1.5	18,599,732	2.0	105,341	0.5	1,153,352	0.5	11,830,964	2.7	9,059,783	2.1	68,701,168	2.05
20 yr. Cmpd. 90−2010	2.7		1.7		2.1		0.5		0.4		3.3		2.7		2.4	

Table A.IV

CAROLINA POWER & LIGHT CO.
ENERGY FORECAST
REDUCED BY CONSERVATION AND LOAD MANAGEMENT
(IN MWH)
HIGHER GROWTH SCENARIO

	RESIDENTIAL	% CH	COMMERCIAL	% CH	INDUSTRIAL	% CH	PUB ST. & H. LIGHT	% CH	MILITARY	% CH	SALES FOR RESALE	% CH	NCEMPA	% CH	TOTAL	% ANN. GR.
1986	9,028,062	9.5	6,364,888	6.9	11,053,697	3.1	92,866	-2.0	961,006	5.8	5,320,207	7.7	4,655,707	4.9	37,476,433	6.17
1987	9,614,322	6.5	6,731,821	5.8	11,477,238	3.8	88,835	-4.3	995,020	3.5	5,749,167	8.1	4,933,251	6.0	39,589,654	5.64
1988	9,854,258	2.5	7,059,737	4.9	11,925,679	3.9	90,803	2.2	1,019,641	2.5	5,938,009	3.3	5,090,429	3.2	40,978,556	3.51
1989	9,942,971	0.9	7,378,331	4.5	12,344,506	3.5	93,660	3.1	1,060,617	4.0	6,016,311	1.3	5,318,182	4.5	42,154,578	2.87
1990	10,013,870	0.7	7,669,623	3.9	12,335,935	-0.1	95,640	2.1	1,067,179	0.6	6,211,715	3.2	5,268,712	-0.9	42,662,674	1.21
1991	10,282,550	2.7	7,410,470	-3.4	11,906,891	-3.5	95,500	-0.1	1,058,731	-0.8	6,063,351	-2.4	5,465,311	3.7	42,282,803	-0.89
1992	10,894,235	5.9	7,696,946	3.9	12,766,995	7.2	96,296	0.8	1,054,321	-0.4	6,347,890	4.7	5,579,117	2.1	44,435,800	5.09
1993	11,433,937	5.0	7,917,392	2.9	12,996,507	1.8	96,777	0.5	1,059,592	0.5	6,605,141	4.1	5,723,452	2.6	45,832,800	3.14
1994	11,958,880	4.6	8,128,986	2.7	13,277,046	2.2	97,261	0.5	1,064,890	0.5	6,860,338	3.9	5,849,204	2.2	47,236,605	3.06
1995	12,430,278	3.9	8,340,223	2.6	13,585,184	2.3	97,747	0.5	1,070,215	0.5	7,046,575	2.7	6,010,115	2.8	48,580,337	2.84
1996	12,838,890	3.3	8,537,831	2.4	13,871,898	2.1	98,236	0.5	1,075,566	0.5	7,282,592	3.3	6,205,377	3.2	49,910,390	2.74
1997	13,211,321	2.9	8,693,601	1.8	14,128,518	1.8	98,727	0.5	1,080,944	0.5	7,530,729	3.4	6,399,946	3.1	51,143,786	2.47
1998	13,558,789	2.6	8,857,489	1.9	14,457,390	2.3	99,221	0.5	1,086,348	0.5	7,814,889	3.8	6,606,907	3.2	52,481,034	2.61
1999	13,896,272	2.5	9,037,607	2.0	14,816,541	2.5	99,717	0.5	1,091,780	0.5	8,138,011	4.1	6,825,348	3.3	53,905,276	2.71
2000	14,227,361	2.4	9,233,466	2.2	15,152,932	2.3	100,215	0.5	1,097,239	0.5	8,474,578	4.1	7,048,559	3.3	55,334,351	2.65
10 yr. Cmpd. 90-2000	3.6		1.9		2.1		0.5		0.3		3.2		3.0		2.6	
2001	14,533,995	2.2	9,416,236	2.0	15,459,638	2.0	100,717	0.5	1,102,725	0.5	8,822,429	4.1	7,270,607	3.2	56,706,348	2.48
2002	14,837,984	2.1	9,565,624	1.6	15,727,982	1.7	101,220	0.5	1,108,239	0.5	9,186,950	4.1	7,489,287	3	58,017,285	2.31
2003	15,142,118	2.0	9,710,922	1.5	15,996,240	1.7	101,726	0.5	1,113,780	0.5	9,551,367	4.0	7,703,523	2.9	59,319,676	2.24
2004	15,433,163	1.9	9,855,387	1.5	16,257,123	1.6	102,235	0.5	1,119,349	0.5	9,893,669	3.6	7,907,536	2.6	60,568,463	2.11
2005	15,713,372	1.8	10,008,319	1.6	16,558,924	1.9	102,746	0.5	1,124,946	0.5	10,240,992	3.5	8,112,311	2.6	61,861,609	2.14
2006	15,996,717	1.8	10,157,603	1.5	16,831,244	1.6	103,260	0.5	1,130,570	0.5	10,563,413	3.1	8,298,426	2.3	63,081,234	1.97
2007	16,282,449	1.8	10,297,079	1.4	17,109,163	1.7	103,776	0.5	1,136,223	0.5	10,877,846	3.0	8,485,957	2.3	64,292,494	1.92
2008	16,582,708	1.8	10,440,961	1.4	17,383,410	1.6	104,295	0.5	1,141,904	0.5	11,201,128	3.0	8,680,310	2.3	65,534,717	1.93
2009	16,901,890	1.9	10,589,376	1.4	17,660,759	1.6	104,816	0.5	1,147,614	0.5	11,515,073	2.8	8,871,406	2.2	66,790,935	1.92
2010	17,250,582	2.1	10,752,799	1.5	17,982,882	1.8	105,341	0.5	1,153,352	0.5	11,830,964	2.7	9,059,783	2.1	68,135,703	2.01
20 yr. Cmpd. 90-2010	2.8		1.7		1.9		0.5		0.4		3.3		2.7		2.4	

1991 – Same as Reference Case

Table A.V

A. RESIDENTIAL - HIGHER/SLOWER GROWTH SCENARIOS

1. Residential Customers

Because long-term demand for housing is primarily determined by demographic factors, there are differences in the forecast of the number of residential customers in these scenarios. The higher interest rates on mortgages and the relative higher cost of money in the slower growth scenario are less favorable for home building than the assumed economic conditions in the reference forecast or higher growth scenario. Differences in the scenarios are attributable to differences in the housing stocks in the different scenarios.

2. Residential All-Electric Use Per Customer

The all-electric use per customer is expected to be the same across the alternative growth scenarios. Because there is no explicit wealth term in this particular forecast equation, changes in economic conditions will not cause a model change in per capita usage. In all cases, however, electricity usage per customer continues to vary due to assumed price patterns, appliance efficiency improvements, and conservation. During the 15-year forecast period, it is forecast that use per customer for the all-electric classification will increase on average by 0.3% per year.

A comparison of the total usage for the all-electric customers is shown in Table A.VI on Page A.9.

TOTAL ALL-ELECTRIC USAGE

	ALL-ELECTRIC USAGE HIGHER GROWTH SCENARIO	ALL-ELECTRIC USAGE REFERENCE FORECAST	ALL-ELECTRIC USAGE SLOWER GROWTH SCENARIO
1986	4,795,429	4,795,429	4,795,429
1987	5,305,924	5,305,924	5,305,924
1988	5,563,393	5,563,393	5,563,393
1989	5,647,227	5,647,227	5,647,227
1990	5,657,102	5,657,102	5,657,102
1991	5,695,661	5,695,661	5,695,661
1992	6,371,351	6,366,950	6,351,121
1993	6,978,488	6,969,727	6,942,265
1994	7,607,083	7,593,273	7,561,579
1995	8,134,577	8,114,578	8,069,247
1996	8,551,724	8,518,753	8,457,579
1997	8,935,828	8,885,490	8,809,795
1998	9,308,099	9,239,240	9,148,246
1999	9,666,658	9,577,835	9,468,312
2000	10,022,449	9,911,311	9,788,307
2001	10,339,383	10,204,777	10,065,494
2002	10,653,517	10,494,275	10,339,214
2003	10,968,812	10,783,245	10,606,622
2004	11,266,566	11,053,895	10,849,133
2005	11,557,689	11,317,245	11,082,433
2006	11,872,869	11,603,582	11,345,802
2007	12,204,034	11,904,375	11,619,517
2008	12,546,738	12,214,679	11,906,871
2009	12,900,111	12,534,012	12,202,308
2010	13,278,682	12,876,703	12,515,922

Table A.VI

3. Residential Water Heating Customers Use Per Customer

In all growth scenarios, the number of water heating customers is very similar. The usage per customer, however, varies appreciably. In the 1990s, it is assumed that most new appliances are more efficient; but, nonetheless, the net effect is an increase in usage per customer due to an increase in the total saturation of air conditioners.

In the regression equation for the water heating customers, real disposable income in the CP&L service area is a significant factor. As disposable income varies in the higher and slower growth scenarios, a corresponding variation in usage is expected.

In 1991, a water heating customer used approximately 10,300 kwh per year. The use per customer slowly increases to approximately 11,100 kwh per customer in the reference forecast, 10,900 kwh per customer in the slower growth scenario, and 11,400 kwh per customer in the higher growth scenario by 2006.

A comparison of the total usage for the water heating customers is shown in Table A.VII on Page A.11.

TOTAL WATER HEATER USAGE

	WATER HEATER USAGE HIGHER GROWTH SCENARIO	WATER HEATER USAGE REFERENCE FORECAST	WATER HEATER USAGE SLOWER GROWTH SCENARIO
1986	3,555,602	3,555,602	3,555,602
1987	3,602,931	3,602,931	3,602,931
1988	3,565,085	3,565,085	3,565,085
1989	3,539,334	3,539,334	3,539,334
1990	3,554773	3,554,773	3,554,773
1991	3,527,732	3,527,732	3,527,732
1992	3,697,750	3,688,661	3,666,862
1993	3,622,167	3,609,193	3,583,219
1994	3,518,800	3,503,427	3,486,089
1995	3,448,350	3,430,227	3,408,970
1996	3,429,470	3,401,531	3,370,635
1997	3,412,333	3,371,083	3,330,983
1998	3,382,258	3,328,449	3,279,898
1999	3,351,796	3,284,586	3,227,280
2000	3,319,147	3,237,531	3,172,770
2001	3,294,629	3,199,173	3,125,361
2002	3,267,581	3,159,078	3,075,908
2003	3,239,619	3,118,569	3,025,450
2004	3,216,227	3,083,482	2,979,634
2005	3,189,498	3,046,120	2,932,624
2006	3,146,791	2,994,979	2,874,634
2007	3,095,026	2,937,517	2,810,596
2008	3,045,982	2,882,501	2,750,589
2009	3,004,550	2,834,636	2,697,473
2010	2,966,364	2,790,275	2,647,716

Table A.VII

4. Residential Minimum-Use Customers Use Per Customer

As in the reference forecast, the number of minimum-use customers slowly declines to approximately 82,000 in 2006. The usage per customer, however, is influenced by real disposable income and electricity price in the CP&L service area. Through the forecast period, usage per customer increases due to the effects of real disposable income and electricity prices in the service area.

In 1991, the use per customer was approximately 7,200 kwh per customer. Increases in disposable income and air conditioning saturation trends cause the reference forecast usage to increase to approximately 8,800 kwh in the year 2006. Because this usage is affected by income in the service area, the slower growth scenario shows an increase to approximately 8,400 kwh in the year 2006, while the higher growth scenario indicates approximately 9,200 kwh in the year 2006.

A comparison of the total usage for the minimum-service customers is shown in Table A.VIII on Page A.13.

TOTAL MINIMUM SERVICE USAGE

	MINIMUM SERVICE USAGE HIGHER GROWTH SCENARIO	MINIMUM SERVICE USAGE REFERENCE FORECAST	MINIMUM SERVICE USAGE SLOWER GROWTH SCENARIO
1986	618,159	618,159	618,159
1987	643,128	643,128	643,128
1988	658,197	658,197	658,197
1989	683,146	683,146	683,146
1990	723,715	723,715	723,715
1991	712,107	712,107	712,107
1992	711,578	708,191	700,816
1993	705,151	700,508	692,519
1994	689,198	683,951	679,893
1995	686,684	680,679	675,950
1996	694,985	685,688	677,864
1997	698,351	684,512	673,569
1998	701,535	683,346	669,519
1999	708,819	685,729	668,895
2000	714,638	686,184	666,425
2001	726,716	692,869	669,411
2002	741,464	702,263	674,701
2003	756,093	711,586	679,820
2004	770,615	721,074	685,023
2005	784,299	730,001	690,063
2006	793,155	734,935	691,698
2007	797,510	736,644	690,337
2008	802,139	738,414	689,414
2009	807,421	740,600	688,764
2010	813,766	743,814	689,168

Table A.VIII

5. Residential Total Forecast

As the total number of customers and the effects of general economic growth vary among the scenarios, an appreciable difference in total residential usage is projected.

A comparison of total residential usage is shown in Table A.IX on Page A.15.

A plot of total residential sales and the forecast for these scenarios and the reference forecast is shown in Figure A.1 on Page A.16.

TOTAL RESIDENTIAL USAGE

	RESIDENTIAL USAGE HIGHER GROWTH SCENARIO	RESIDENTIAL USAGE REFERENCE FORECAST	RESIDENTIAL USAGE SLOWER GROWTH SCENARIO
1986	9,028,062	9,028,062	9,028,062
1987	9,614,322	9,614,322	9,614,322
1988	9,854,258	9,854,258	9,854,258
1989	9,942,971	9,942,971	9,942,971
1990	10,013,870	10,013,870	10,013,870
1991	10,008,547	10,008,547	10,008,547
1992	10,852,319	10,835,408	10,790,284
1993	11,379,809	11,353,366	11,291,733
1994	11,891,481	11,856,951	11,803,623
1995	12,348,453	12,304,184	12,232,536
1996	12,757,522	12,687,086	12,586,750
1997	13,130,354	13,024,586	12,897,301
1998	13,478,231	13,336,909	13,182,872
1999	13,816,128	13,636,404	13,451,944
2000	14,147,631	13,925,668	13,717,234
2001	14,454,686	14,189,854	13,952,265
2002	14,759,103	14,451,053	14,184,089
2003	15,063,682	14,711,260	14,408,415
2004	15,355,187	14,958,725	14,612,524
2005	15,635,865	15,196,023	14,806,015
2006	15,919,758	15,438,494	15,015,181
2007	16,206,052	15,685,839	15,225,589
2008	16,506,883	15,945,190	15,454,115
2009	16,826,656	16,221,135	15,697,877
2010	17,175,958	16,524,979	15,964,217

Table A.IX

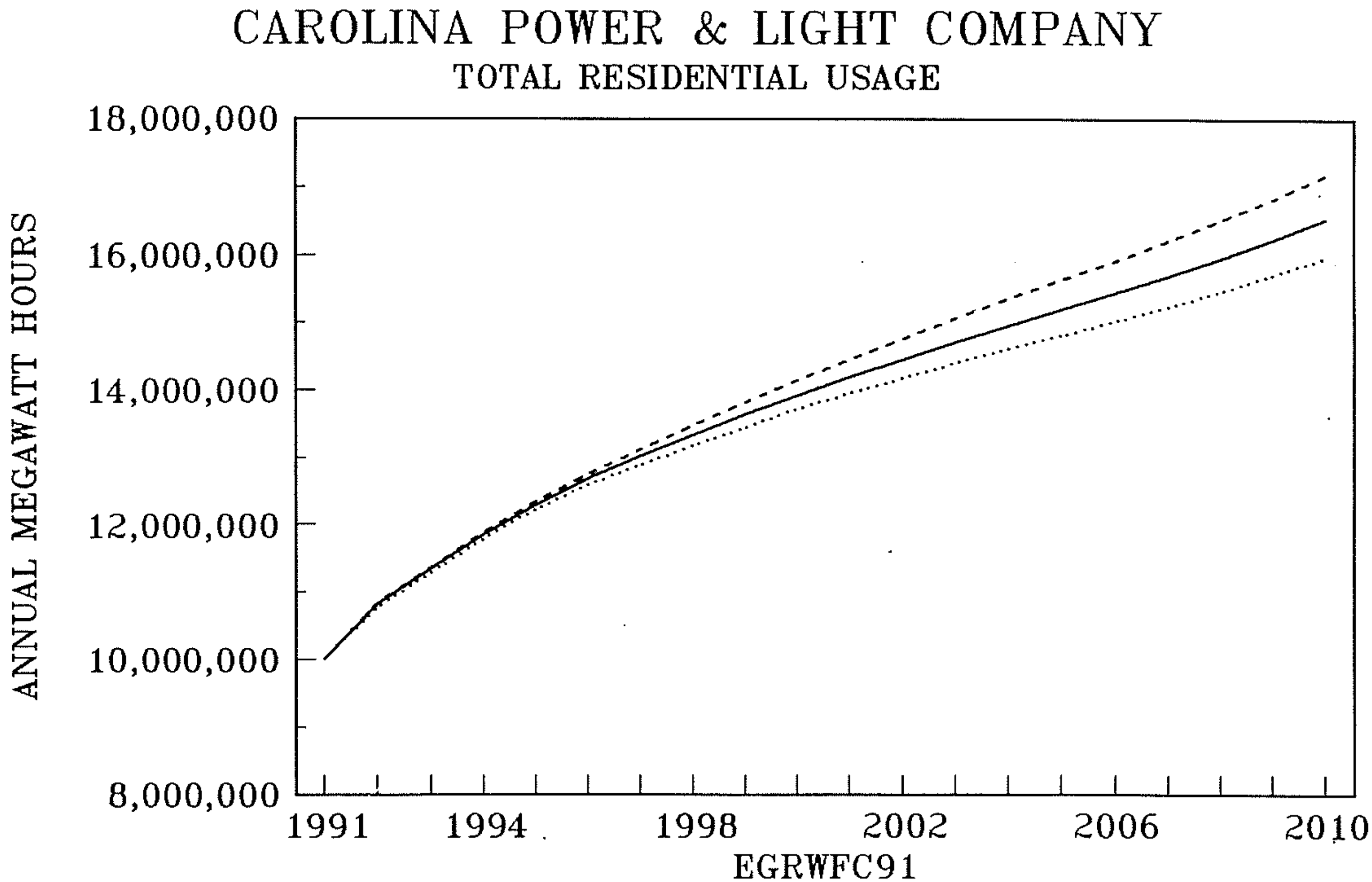

CAROLINA POWER & LIGHT COMPANY
TOTAL RESIDENTIAL USAGE
ANNUAL MEGAWATT HOURS
18,000,000
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
1991
1994
1998
2002
2006
2010
EGRWFC91

Figure A.1

B. COMMERCIAL - HIGHER/SLOWER GROWTH SCENARIOS

There are two considerations affecting total commercial usage in the slower growth scenario and the higher growth scenario. These economic conditions are the number of commercial employees and the changing mix among the various segments of the commercial sector. For example, in a higher growth scenario there will be more construction taking place in the commercial sector. Because the annual MWH per employee varies considerably across the commercial sector, usage among the one-digit commercial SIC Codes has appreciable variation.

In 1991, there were approximately 992,000 employees in the non-manufacturing one-digit commercial SIC sectors in the CP&L service area. The reference forecast is for approximately 1,271,000 total non-manufacturing employees in 2006. This is a compounded growth rate of 1.7% for the 15-year period. In the slower growth scenario, it is forecast that there will be approximately 1,173,000 total employees in the non-manufacturing sector by the year 2006. This is a compounded growth rate for the 15-year period of only 1.1%, resulting in approximately 98,000 fewer employees at the end of the 15-year horizon. In the higher growth scenario, there are approximately 1,349,000 employees in the year 2006. This is a compounded growth rate of 2.1% and the result is approximately 78,000 more employees in the higher growth scenario than in the reference forecast.

The total commercial usage in the reference forecast is projected to increase at a compounded growth rate of 1.8% from 1991 to 2006. In the slower growth scenario, this compounded growth rate is 1.4% from 1991 to 2006. In the higher growth scenario, the compounded growth rate is forecast to be 2.1% from 1991 to the year 2006. The difference in total commercial energy between the higher and the slower scenarios in the year 2006 is almost 1.1 million megawatt-hours.

A comparison of commercial usage by one-digit SIC is shown in Table A.X on Page A.18.

A plot of total commercial energy for the alternative growth scenarios and the reference forecast is shown in Figure A.2 on Page A.19.

TOTAL COMMERCIAL USAGE

	COMMERCIAL USAGE HIGHER GROWTH SCENARIO	COMMERCIAL USAGE REFERENCE FORECAST	COMMERCIAL USAGE SLOWER GROWTH SCENARIO
1986	6,364,888	6,364,888	6,364,888
1987	6,731,821	6,731,821	6,731,821
1988	7,059,737	7,059,737	7,059,737
1989	7,378,331	7,378,331	7,378,331
1990	7,669,623	7,669,623	7,669,623
1991	7,410,470	7,410,470	7,410,470
1992	7,696,946	7,645,442	7,536,644
1993	7,917,392	7,857,537	7,805,383
1994	8,128,986	8,065,436	8,035,255
1995	8,340,223	8,262,485	8,179,257
1996	8,537,831	8,419,046	8,270,082
1997	8,693,601	8,540,672	8,337,808
1998	8,857,489	8,668,628	8,417,990
1999	9,037,607	8,803,996	8,508,859
2000	9,233,466	8,958,620	8,610,956
2001	9,416,236	9,107,581	8,692,760
2002	9,565,624	9,221,428	8,753,703
2003	9,710,922	9,334,404	8,819,827
2004	9,855,387	9,447,993	8,891,294
2005	10,008,319	9,572,106	8,975,700
2006	10,157,603	9,710,913	9,070,201
2007	10,297,079	9,848,592	9,180,834
2008	10,440,961	9,982,200	9,286,832
2009	10,589,376	10,109,568	9,389,832
2010	10,752,799	10,246,163	9,503,562

Table A.X

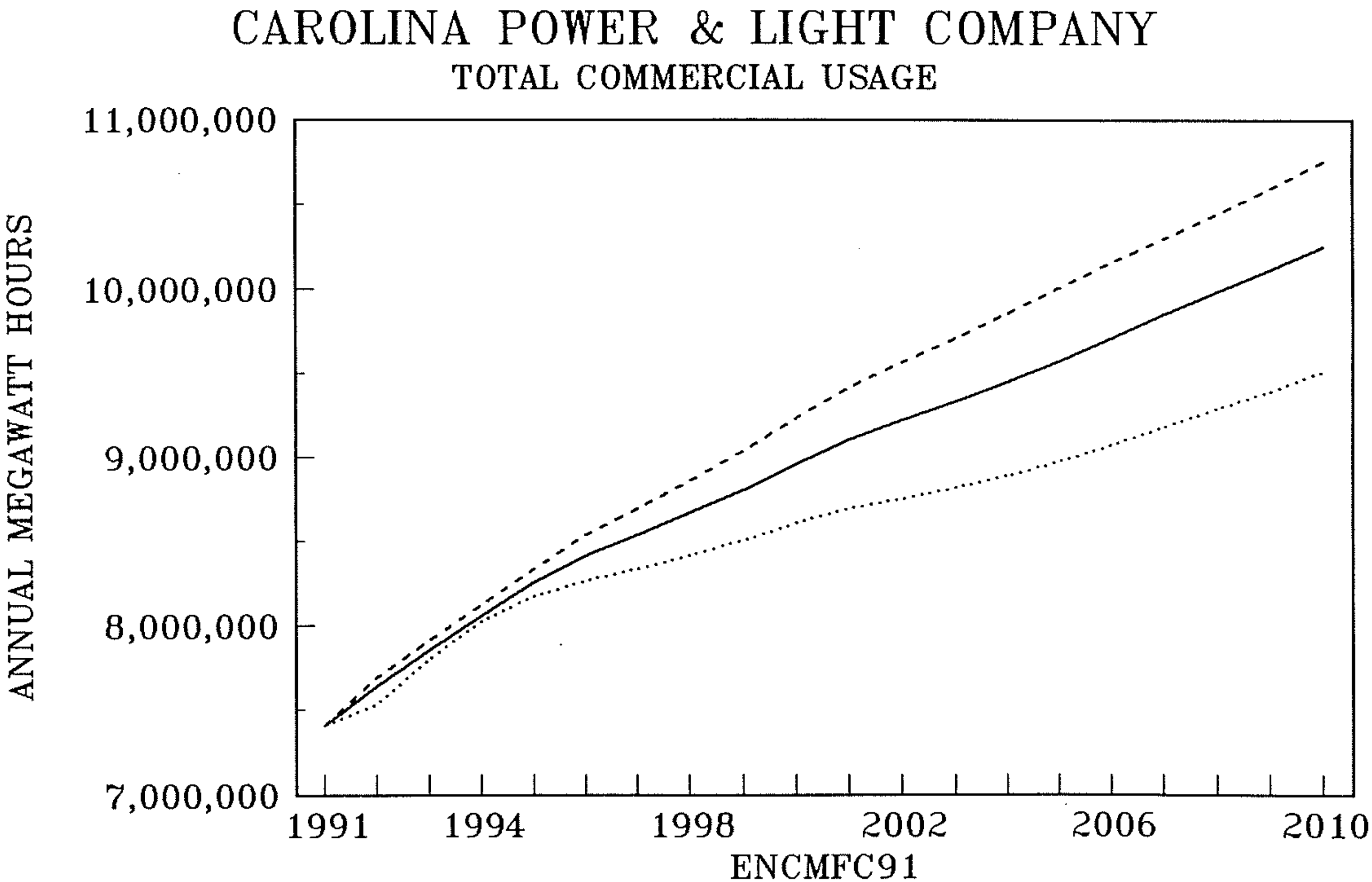

CAROLINA POWER & LIGHT COMPANY
TOTAL COMMERCIAL USAGE
ANNUAL MEGAWATT HOURS
11,000,000
10,000,000
9,000,000
8,000,000
7,000,000
1991
1994
1998
2002
2006
2010
ENCMFC91

Figure A.2

C. TOTAL INDUSTRIAL - HIGHER/SLOWER GROWTH SCENARIO

In the reference forecast, total manufacturing employment decreases from approximately 338,000 employees in 1991 to approximately 305,000 in the year 2006. In the slower growth scenario, employment decreases to approximately 274,000 in 2006. This forecast indicates that approximately 30,500 fewer jobs will exist by the year 2006 under the slower growth scenario. In the higher growth scenario, employment is projected to be approximately 327,000 by 2006. This indicates approximately 22,500 more jobs or around 7% more than in the reference forecast by 2006.

The energy use in the reference forecast is projected to increase for the Industrial sector at an annual rate of 1.8% from 1991 to 2006. In the slower growth scenario, total use is forecast to increase at an annual rate of 1.2% from 1991 to 2006. In the higher growth scenario, the rate of total usage is projected to increase at 2.3% per year from 1991 to 2006.

A comparison of Total Industrial Usage is shown in Table A.XI on Page A.21.

TOTAL INDUSTRIAL USAGE

	INDUSTRIAL USAGE HIGHER GROWTH SCENARIO	INDUSTRIAL USAGE REFERENCE FORECAST	INDUSTRIAL USAGE SLOWER GROWTH SCENARIO
1986	11,053,697	11,053,697	11,053,697
1987	11,477,238	11,477,238	11,477,238
1988	11,925,679	11,925,679	11,925,679
1989	12,344,506	12,344,506	12,344,506
1990	12,335,935	12,335,935	12,335,935
1991	11,906,891	11,906,891	11,906,891
1992	12,766,995	12,624,976	12,401,369
1993	12,996,507	12,875,691	12,938,376
1994	13,277,046	13,117,440	13,097,994
1995	13,585,184	13,341,586	13,156,908
1996	13,871,898	13,523,689	13,227,114
1997	14,128,518	13,702,218	13,317,067
1998	14,457,390	13,944,177	13,472,713
1999	14,816,541	14,202,242	13,613,987
2000	15,152,932	14,434,830	13,711,465
2001	15,459,638	14,652,255	13,800,477
2002	15,727,982	14,833,677	13,877,105
2003	15,996,240	15,010,678	13,934,726
2004	16,257,123	15,183,926	14,034,092
2005	16,558,924	15,402,231	14,195,639
2006	16,831,244	15,604,243	14,324,012
2007	17,109,163	15,811,883	14,455,455
2008	17,383,410	16,008,387	14,580,037
2009	17,660,759	16,199,239	14,704,503
2010	17,982,882	16,430,613	14,852,314

Table A.XI

Figure A.3 on Page A.23 is a plot of the historical energy usage and a comparison of the two scenarios and the reference forecast for the total Industrial sector.

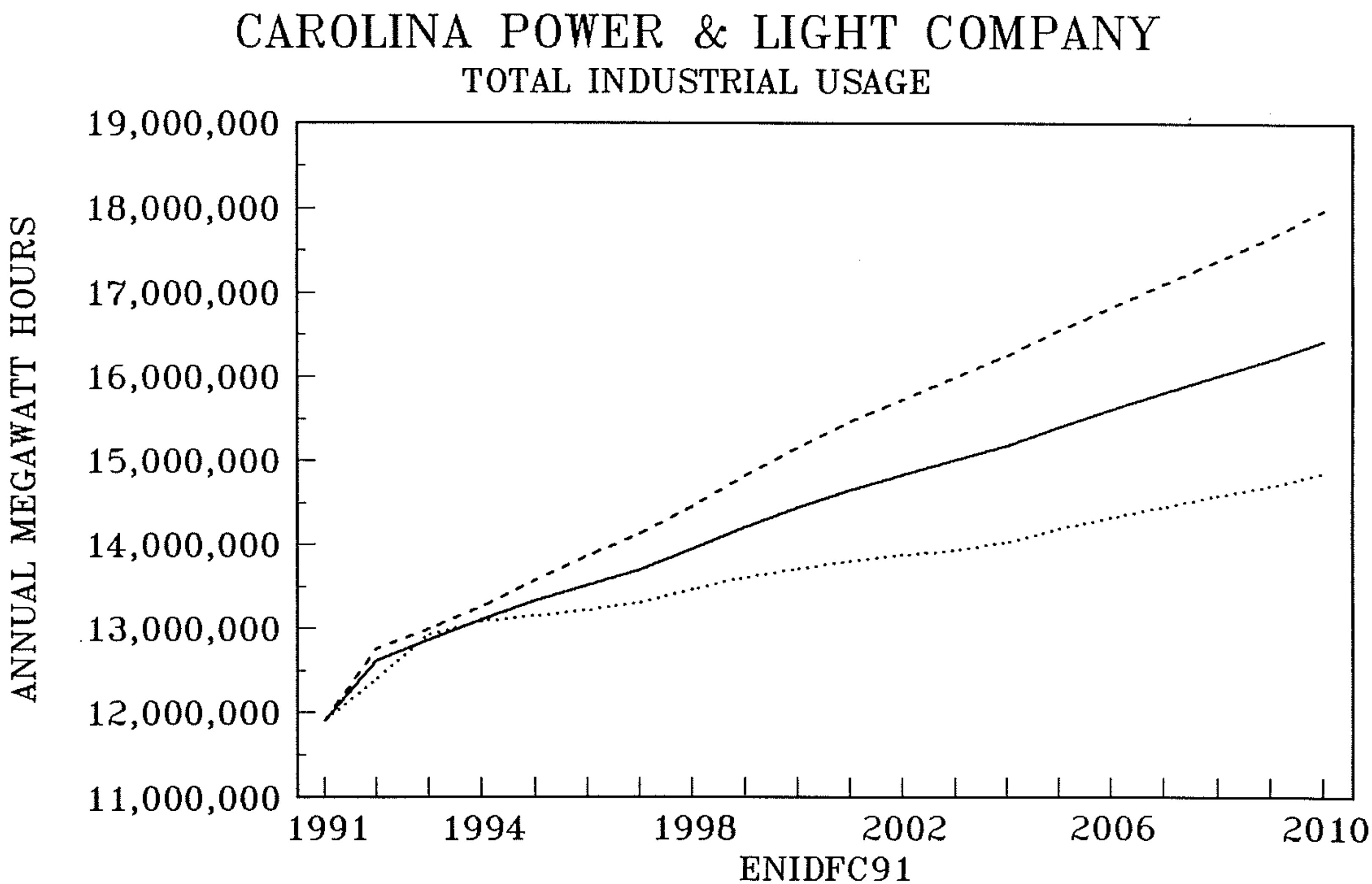

CAROLINA POWER & LIGHT COMPANY
TOTAL INDUSTRIAL USAGE
ANNUAL MEGAWATT HOURS
19,000,000
18,000,000
17,000,000
16,000,000
15,000,000
14,000,000
13,000,000
12,000,000
11,000,000
1991
1994
1998
2002
2006
2010
ENIDFC91

Figure A.3

D. SALES-FOR-RESALE - HIGHER/SLOWER GROWTH SCENARIOS

As in the reference forecast, it is assumed that for the higher and slower growth scenarios, the ultimate customers in the wholesale sector will be subjected to the same economic conditions as the CP&L retail customers. Consequently, Sales-For-Resale in the higher and slower growth scenarios were simulated using the reference forecast models using the higher and slower growth values used in the residential and commercial retail growth scenarios.

The usage forecasted for this sector is total usage for wholesale customers and Power Agency.

In the reference forecast, the compounded growth rate for the Sales-For-Resale classification is projected to be 3.1% from 1991 to 2006. In the slower growth scenario, the compounded growth rate is projected to be 2.5% from 1991 to 2006. In the higher growth scenario, an average annual growth rate of 3.8% is projected from 1991 to 2006.

The comparable growth rate for the Power Agency is 2.2% in the reference forecast from 1991 to 2006. For the slower growth scenario, the comparable growth rate is 1.7%. For the higher growth scenario, the comparable growth rate is 2.8%.

Table A.XII on Page A.25 shows a comparison in the forecast for the two growth scenarios and the reference forecast. Figure A.4 on Page A.26 is a plot of the historical usage for the combined wholesale and Power Agency sector and a comparison of the scenarios and reference forecast through the year 2006.

TOTAL SALES FOR RESALE USAGE
(INCLUDING NCEMPA)

	SALES FOR RESALE USAGE HIGHER GROWTH SCENARIO	SALES FOR RESALE USAGE REFERENCE FORECAST	SALES FOR RESALE USAGE SLOWER GROWTH SCENARIO
1986	9,979,868	9,979,868	9,979,868
1987	10,700,411	10,700,411	10,700,411
1988	11,028,438	11,028,438	11,028,438
1989	11,334,493	11,334,493	11,334,493
1990	11,480,427	11,480,427	11,480,427
1991	11,528,661	11,528,661	11,528,661
1992	11,927,007	11,813,080	11,580,834
1993	12,328,594	12,179,261	12,088,672
1994	12,709,542	12,573,489	12,555,504
1995	13,056,690	12,862,874	12,796,482
1996	13,487,969	13,172,735	13,017,194
1997	13,930,675	13,489,802	13,252,390
1998	14,421,796	13,840,307	13,519,861
1999	14,963,359	14,222,764	13,817,551
2000	15,523,138	14,603,640	14,086,712
2001	16,093,036	15,019,836	14,365,480
2002	16,676,237	15,442,675	14,662,548
2003	17,254,889	15,867,801	14,963,594
2004	17,801,206	16,279,872	15,269,806
2005	18,353,302	16,698,193	15,592,190
2006	18,861,839	17,124,390	15,906,052
2007	19,363,803	17,551,472	16,238,091
2008	19,881,438	17,977,793	16,557,019
2009	20,386,479	18,390,814	16,870,287
2010	20,890,748	18,805,577	17,181,620

Table A.XII

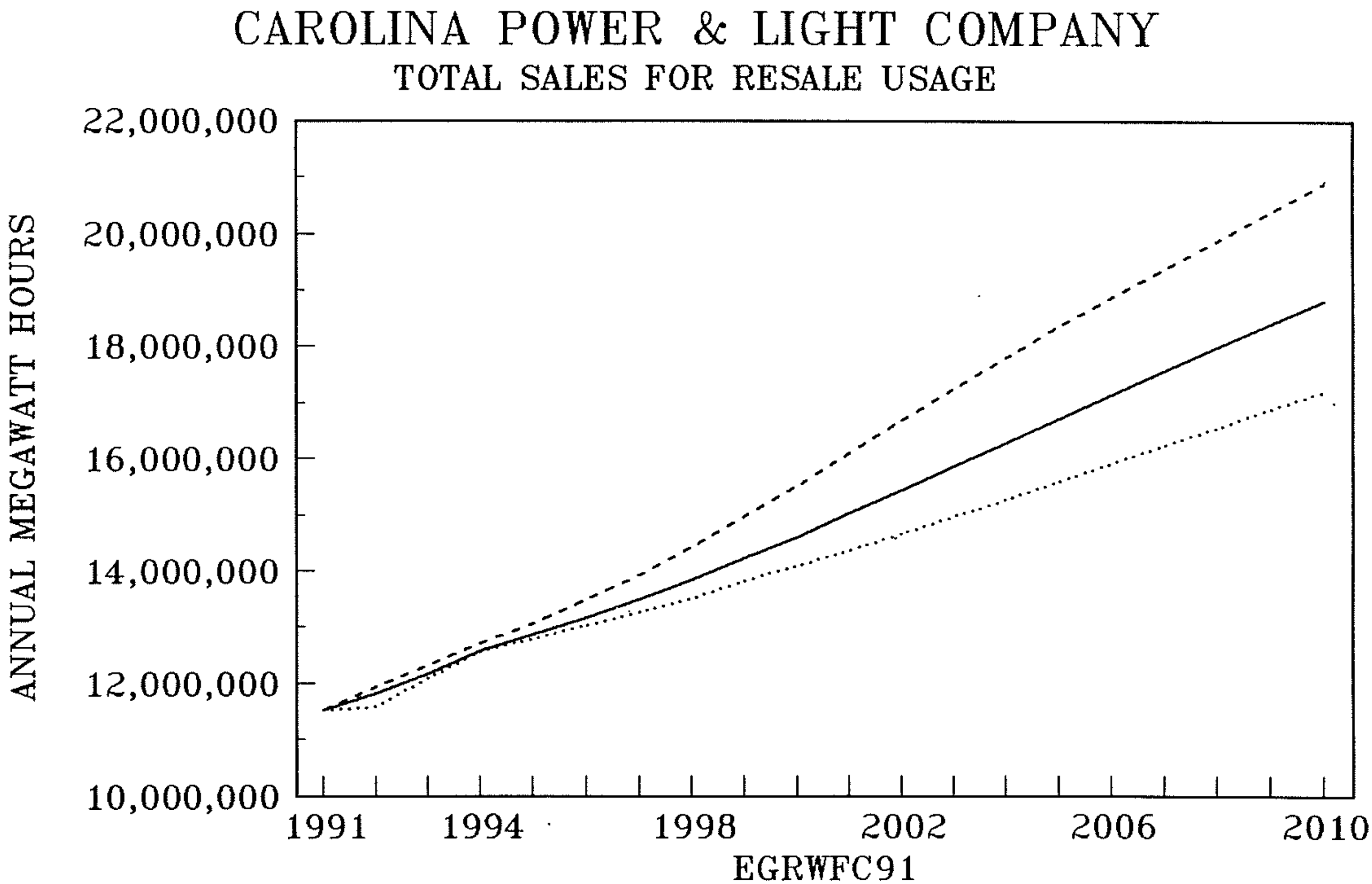

CAROLINA POWER & LIGHT COMPANY
TOTAL SALES FOR RESALE USAGE
ANNUAL MEGAWATT HOURS
22,000,000
20,000,000
18,000,000
16,000,000
14,000,000
12,000,000
10,000,000
1991
1994
1998
2002
2006
2010
EGRWFC91

Figure A.4

E. PUBLIC STREET AND HIGHWAY LIGHTING AND OTHER SALES TO PUBLIC AUTHORITIES - HIGH/LOW

In the Public Street and Highway Lighting sector, there are no economic variables which would cause the usage to change under the higher growth scenario or the slower growth scenario. In the scenarios, the values are assumed to be the same as in the reference forecast.

In the Military sector, the values used in these scenarios are the same as in the reference forecast.

F. SUMMARY - HIGHER/SLOWER GROWTH SCENARIOS

Table A.III on Page A.5 shows the projections by sectors for the slower growth scenario. This scenario results in a compounded growth rate for total usage of 1.8% from 1991 to 2006. The slower growth scenario results in approximately 3,500,000 MWH less electricity usage than the reference forecast.

The summary table by sectors for the higher growth scenario is shown in Table A.V on Page A.7. The projected average annual compounded growth rate for total usage in this scenario from 1991 to 2006 is 2.7%. The higher growth scenario results in approximately 7,500,000 MWH more usage in 2006 than the reference forecast.

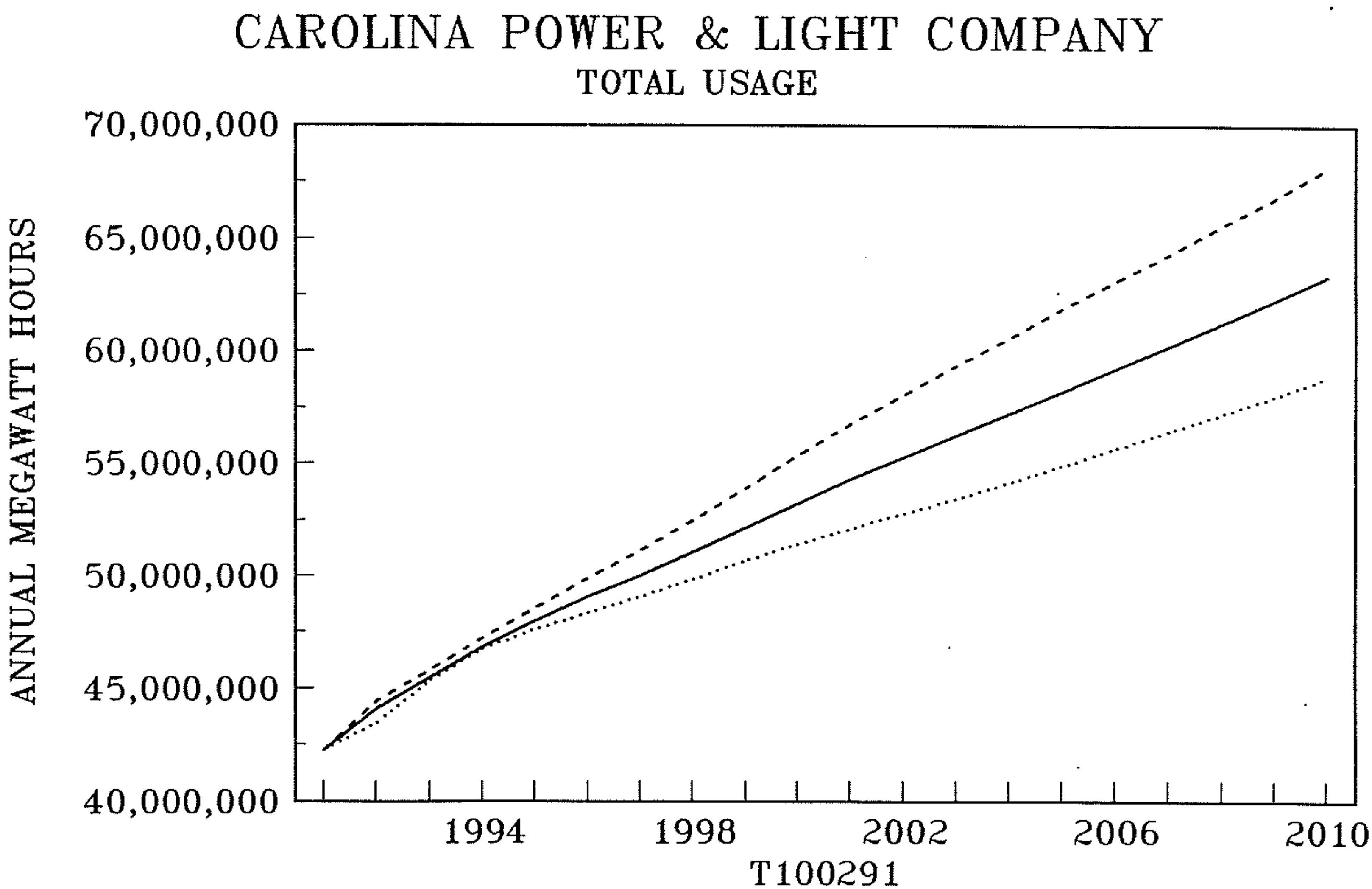
A comparison of total electricity usage for the two growth scenarios and the reference forecast is shown in Table A.XIII on Page A.29.

Figure A.5 on Page A.30 is a plot of total historical usage for the system and a comparison of the two scenarios and the reference forecast to the year 2006.

TOTAL USAGE

	TOTAL USAGE HIGHER GROWTH SCENARIO	TOTAL USAGE REFERENCE FORECAST	TOTAL USAGE SLOWER GROWTH SCENARIO
1986	37,476,433	37,476,433	37,476,433
1987	39,589,654	39,589,654	39,589,654
1988	40,978,556	40,978,556	40,978,556
1989	42,154,578	42,154,578	42,154,578
1990	42,662,674	42,662,674	42,662,674
1991	42,282,803	42,282,803	42,282,803
1992	44,435,800	44,111,438	43,501,663
1993	45,832,800	45,476,352	45,334,661
1994	47,236,605	46,842,866	46,721,926
1995	48,580,337	48,020,915	47,614,969
1996	49,910,390	49,057,726	48,356,311
1997	51,143,786	50,017,916	49,065,203
1998	52,481,034	51,056,148	49,859,564
1999	53,905,276	52,137,047	50,663,982
2000	55,334,351	53,199,942	51,403,552
2001	56,706,348	54,252,277	52,093,733
2002	58,017,285	55,237,172	52,765,786
2003	59,319,676	56,218,085	53,420,504
2004	60,568,463	57,170,076	54,107,276
2005	61,861,609	58,173,750	54,874,743
2006	63,081,234	59,188,830	55,626,234
2007	64,292,494	60,214,182	56,416,366
2008	65,534,717	61,235,594	57,200,026
2009	66,790,935	62,248,419	57,990,163
2010	68,135,703	63,340,648	58,835,029

Table A.XIII



CAROLINA POWER & LIGHT COMPANY
TOTAL USAGE
ANNUAL MEGAWATT HOURS
70,000,000
65,000,000
60,000,000
55,000,000
50,000,000
45,000,000
40,000,000
1994
1998
2002
2006
2010
T100291

Figure A.5

COMPARISON OF SELECTED ECONOMIC VARIABLES
Higher and Slower Growth Scenarios

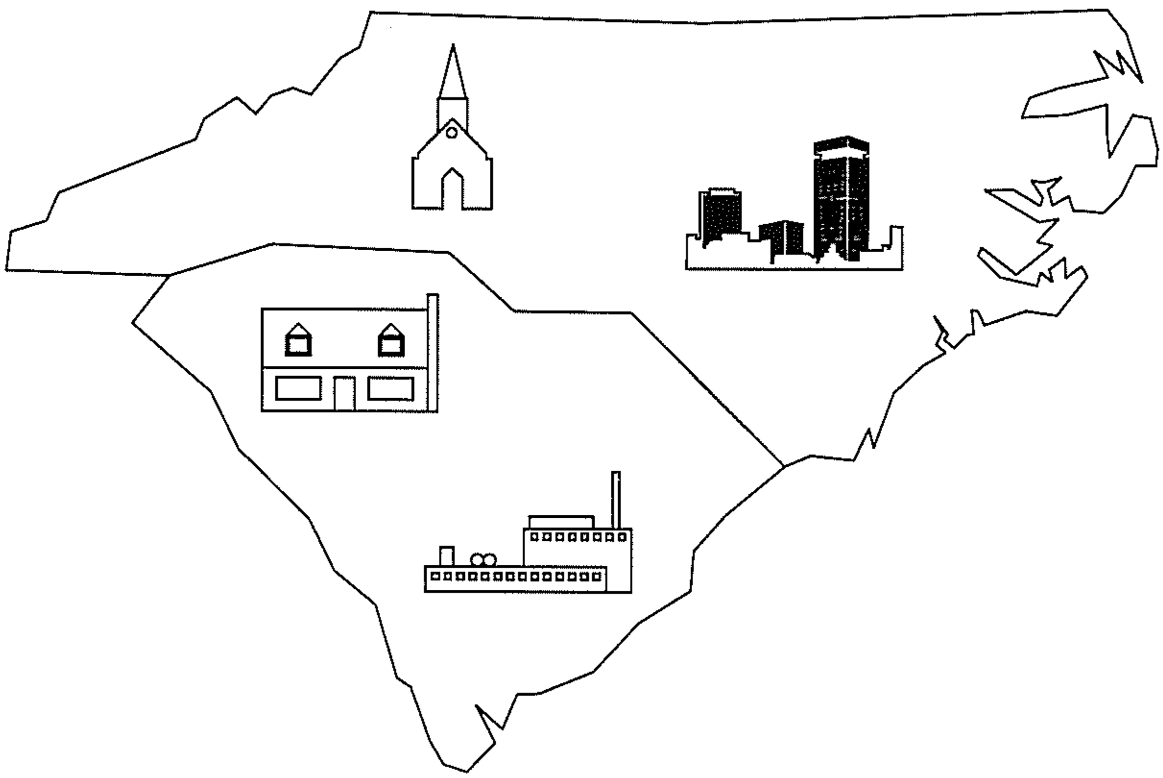
	1991	2006
REAL GNP (Bil 1982 $):		
Reference Forecast	4154	5915
Higher - % Difference	0.0	9.6%
Slower - % Difference	0.0	-9.7%
INDUSTRIAL PRODUCTION (1977=1.0):		
Reference Forecast	1.073	1.615
Higher - % Difference	0.0	10.3%
Slower - % Difference	0.0	-10.3%
CONSUMER PRICE INDEX (% - Annual Rate): (All Wage Earners)		
Reference Forecast	3.9	4.7
Higher - p.p. Difference	0.0	-1.2 p.p.
Slower - p.p. Difference	0.0	1.9 p.p.
INFLATION (% - Annual Rate): (GNP Deflator)		
Reference Forecast	3.1	4.4
Higher - p.p. Difference	0.0	-1.1 p.p.
Slower - p.p. Difference	0.0	1.9 p.p.
PRODUCTIVITY - OUTPUT PER HOUR: (% - Annual Rate)		
Reference Forecast	1.1	1.2
Higher - p.p. Difference	0.0	0.4 p.p.
Slower - p.p. Difference	0.0	-0.2 p.p.

- - - - -

p.p.: percentage points

SYSTEM PEAK LOAD FORECAST

CAROLINA POWER & LIGHT COMPANY



1991

PREFACE

Each year, Carolina Power & Light Company adopts a long-range forecast of System Peak Load as a part of the Company's Integrated Resource Planning Process. The forecast presented in this report is for CP&L's integrated system which geographically covers over 30,000 square miles of eastern North Carolina, northeastern South Carolina, and far western North Carolina. The Company System Peak Load includes the Company's retail load (residential, commercial, industrial, and military) and wholesale load (cooperatives and municipal), as well as the North Carolina Eastern Municipal Power Agency load (NCEMPA) and reductions associated with the Company's Conservation and Load Management (CLM) activities.

Because the Peak Load Forecast best typifies future customer demand in the CP&L service area, it does not reflect the extreme loads which can occur in any year as a result of abnormal seasonal temperatures or abrupt changes in economic growth. Temperature extremes alone can raise the system peak from five to seven percent above normal.

This report provides the results of the December 1991 System Peak Load Forecast and a description of the methodology used in its development. In addition to the forecast of system summer and winter peak loads, the report also provides the Company's eastern and western service area coincident summer peak load forecast. Additionally, annual system energy input is provided. This is the total energy which is required of the Company's power resources consisting of energy usage (reduced by load management), losses, and Company uses.

TABLE OF CONTENTS

APPENDICES

EXECUTIVE SUMMARY

Substantial differences exist between this forecast and the December 1990 projections, primarily due to a changed view of CP&L's future. Each year, three separate forecasts are prepared: a Reference or Base forecast, a Higher Growth scenario, and a Slower Growth scenario. Each scenario is based on different economic and demographic assumptions. For example, such things as employment, income, industrial production, and population are varied to produce the different scenarios. In 1990, the Reference forecast best reflected CP&L's future. By contrast, in 1991 the Slower Growth forecast best typifies CP&L's long-run future.

Future load growth is highly uncertain due to changing relationships and power availability in our Wholesale markets. For example, the City of Camden has given notice that it will no longer receive service from CP&L effective May 1, 1995. In addition, other issues involving increasing appliance efficiency, stricter building codes, conservation awareness, industrial cogeneration, and the possible expansion of natural gas in our Eastern Piedmont and Tidewater regions tend toward slower electricity growth. For all these reasons, the Slower Growth forecast best typifies CP&L's future. This scenario can be interpreted as a collective proxy for the prospect of reduced growth in future electricity needs served by CP&L.

The following figure shows the December 1990 and December 1991 forecasts. These data are also provided in a table on the following page. A tabulation of the December 1991 forecast results is also available at the end of the Executive Summary, page 5.

FORECAST COMPARISON
DECEMBER 1990 and DECEMBER 1991 SUMMER PEAK LOAD FORECASTS

YEAR	DECEMBER 1991 SLOWER GROWTH SCENARIO (MW)	DECEMBER 1990 REFERENCE FORECAST (MW)	CHANGE (MW)	CHANGE (%)
1991		8,600		
1992	8,631	8,827	-196	-2.2%
1993	8,969	8,978	-9	-0.1%
1994	9,226	9,202	24	0.3%
1995	9,364	9,400	-36	-0.4%
1996	9,516	9,638	-122	-1.3%
1997	9,646	9,855	-209	-2.1%
1998	9,796	10,073	-277	-2.7%
1999	9,949	10,286	-337	-3.3%
2000	10,095	10,493	-398	-3.8%
2001	10,227	10,698	-471	-4.4%
2002	10,356	10,901	-545	-5.0%
2003	10,483	11,113	-630	-5.7%
2004	10,615	11,330	-715	-6.3%
2005	10,753	11,549	-796	-6.9%
2006	10,896	11,779	-883	-7.5%
2007	11,052	12,011	-959	-8.0%
2008	11,210	12,242	-1,032	-8.4%
2009	11,368	12,479	-1,111	-8.9%
2010	11,526	12,723	-1,197	-9.4%

DECEMBER 1991 SUMMER PEAK LOAD FORECAST SUMMARY
SLOWER GROWTH SCENARIO

YEAR	SYSTEM SUMMER PEAK LOAD (MW)	* ANNUAL SYSTEM ENERGY INPUT (MWH)	ANNUAL LOAD FACTOR
1992	8,631	45,675,990	60.4%
1993	8,969	47,600,880	60.6%
1994	9,226	49,057,620	60.7%
1995	9,364	49,995,340	60.9%
1996	9,516	50,773,820	60.9%
1997	9,646	51,518,170	61.0%
1998	9,796	52,352,270	61.0%
1999	9,949	53,196,950	61.0%
2000	10,095	53,973,570	61.0%
2001	10,227	54,698,220	61.1%
2002	10,356	55,403,910	61.1%
2003	10,483	56,091,380	61.1%
2004	10,615	56,812,540	61.1%
2005	10,753	57,618,460	61.2%
2006	10,896	58,407,580	61.2%
2007	11,052	59,237,140	61.2%
2008	11,210	60,059,900	61.2%
2009	11,368	60,889,550	61.1%
2010	11,526	61,776,780	61.2%

* System Energy Input is the sum of Energy Sales (reduced for Load Management), Losses and Company Uses.

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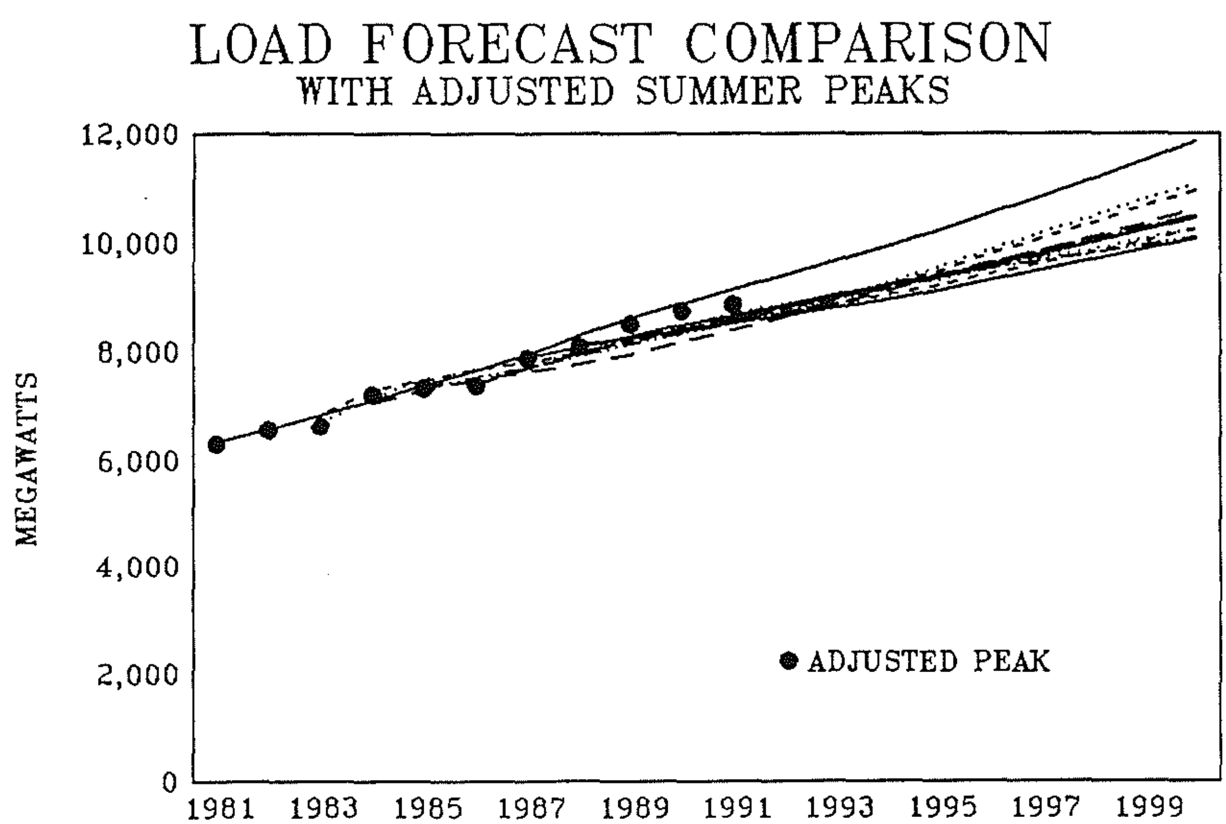
A. FORECAST PERSPECTIVE

A.1. Forecast Comparisons

The 1991 System Peak Load Forecast continues the same growth trend which was set with the 1981 forecast. The figure below shows the forecasts since 1980 plotted against the adjusted actual summer peak load values for each year. The 1980 forecast alone stands out since this was the last forecast before the Company's intensified conservation and load management activities. The remaining forecasts are very similar with only minor shifts from forecast to forecast. While the forecasts since 1981 have remained very stable, they have also been very close to comparable actual peak loads.



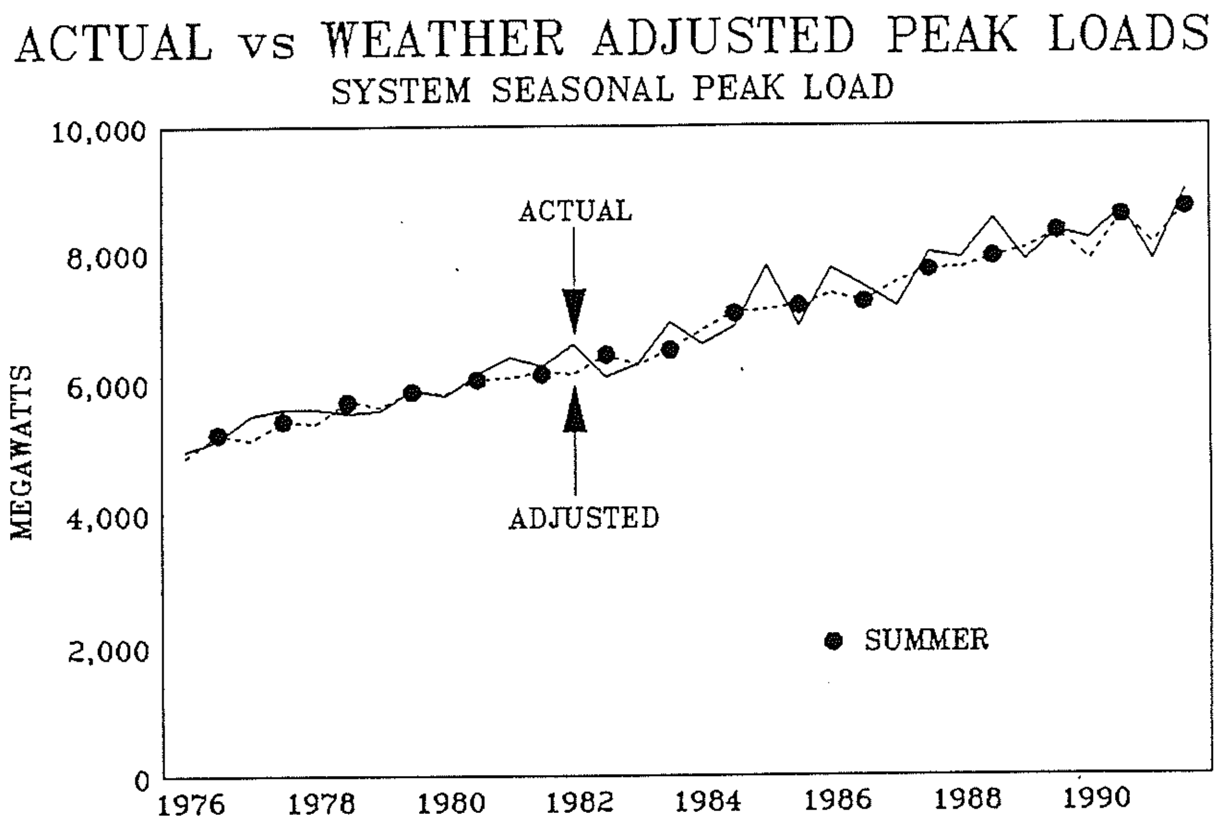
B. ADJUSTMENT OF HISTORIC PEAK LOADS

The System Peak Load forecast is based upon the assumption of normal peaking weather conditions occurring during each season of the forecast period. Abnormal weather conditions can increase system peak load five to seven percent above normal. During those seasons when the weather was abnormally mild, the resulting peak loads were significantly less than forecast. Likewise, abnormally severe weather has raised peak loads above forecast. The 8,523 MW peak load experienced in August 1988 was set during a period when actual temperatures exceeded peaking normals and reached all-time highs. As a result, actual peak load in this case significantly exceeded the forecast load of 8,129 MW.

One reason for planning a capacity reserve margin above forecast load is the possibility of severe weather and the associated higher than expected peak load. The Company's actual seasonal system peak loads have been adjusted for abnormal temperatures to better represent trends in load growth and the relationship between summer and winter peak loads.

The figure on the following page presents the actual and adjusted peak loads since 1976. The adjustment process uses a statistical procedure to model the relationship between load and weather for a given year and season. The adjusted value is then estimated from this relationship using normal peaking temperatures.

A noticeable increase in adjusted load occurs from Summer 1983 to Winter 1983-1984 as the result of the combined effects of many factors. Two of these factors stand out as major influences: the accelerating recovery from the depressed economic conditions which ended in late 1982 and the addition of nearly 200 MW of additional NCEMPA load in January 1984.



Our review of adjusted historic loads indicates a stable pattern of summer and winter peaks. From this information, the winter peak load is expected to continue to be approximately equal to the preceding summer peak load.

C. PEAK LOAD FORECAST

C.1. Development of System Peak Load Forecast

The three steps involved in the development of the System Peak Load forecast are described below and shown graphically in the accompanying figure.

(1) Calculation of Peak Load For CP&L Customer Sales Classifications Including Conservation Effects

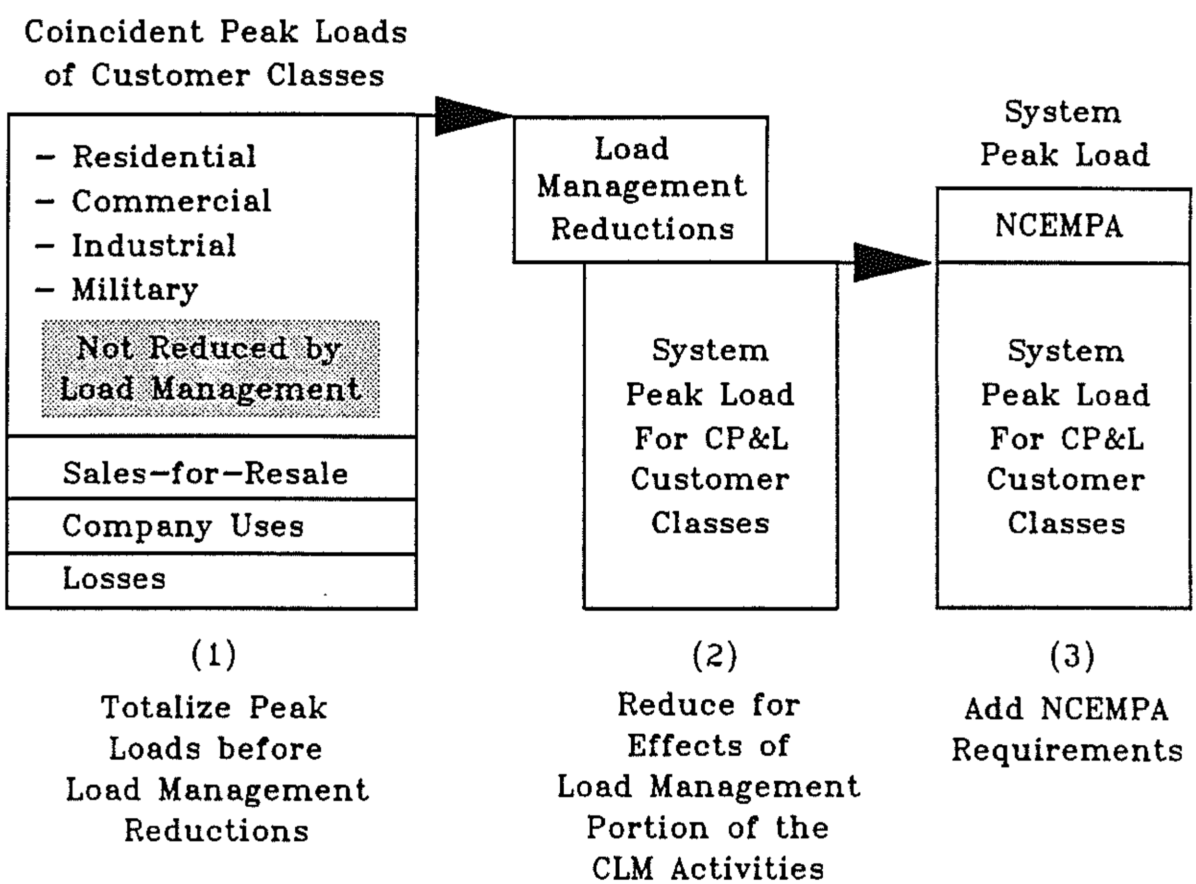
Annual coincident peak load forecasts for the Residential, Commercial, Industrial, Sales-For-Resale, and Military Sales classifications are calculated from annual energy usage provided in the Company's System Energy forecast. Because these loads are at the customer level, the system losses incurred in making these sales and use by Company facilities must also be estimated.

(2) Load Management Reductions

The estimate of energy usage which was the basis for calculating peak loads in Step (1) includes the effects of conservation but not the effects of load management. Likewise, loads calculated in that step also reflect the future effects of conservation but not load management. In Step (2), the load management capability of the Company's CLM activities is subtracted from the forecast total of Step (1). This method prevents double-counting or the effect of incorrectly reducing conservation from the forecast twice. The resulting system peak load is for CP&L customer classes solely and is totaled with NCEMPA load requirements in Step (3).

(3) <u>Addition Of NCEMPA Load Requirements</u>

The NCEMPA peak load includes losses incurred in transferring the load from the power resources to the individual NCEMPA members, reflecting the total load requirements from the power resources. The forecast NCEMPA peak load is added to the forecast peak load for CP&L customer classes obtained in Step 2 above. The result is the forecast System Peak Load.



DECEMBER 1991 PEAK LOAD FORECAST
SLOWER GROWTH SCENARIO

SUMMARY OF SUMMER COINCIDENT PEAK LOAD COMPONENTS

	AT THE METER - NOT REDUCED FOR LOAD MANAGEMENT								AT THE GENERATOR		
YEAR	RESIDENTIAL (MW)	COMMERCIAL AND MUNI. PUMPING (MW)	INDUSTRIAL (MW)	MILITARY (MW)	HIGHWAY & STREET LIGHTING (MW)	(1),(2) SALES-FOR -RESALE (MW)	COMPANY USE (MW)	LOSSES (MW)	LOAD MANAGEMENT REDUCTIONS (MW)	(1) NCEMPA (MW)	TOTAL SYSTEM (MW)
1992	2,526	1,722	1,863	241	0	1,273	24	390	543	1,135	8,631
1993	2,644	1,784	1,949	242	0	1,350	25	408	607	1,175	8,969
1994	2,763	1,837	1,979	243	0	1,414	26	421	666	1,209	9,226
1995	2,864	1,870	1,990	244	0	1,427	27	429	721	1,233	9,364
1996	2,947	1,891	2,004	246	0	1,461	27	436	751	1,255	9,516
1997	3,020	1,907	2,020	247	0	1,487	27	443	781	1,277	9,646
1998	3,086	1,925	2,045	248	0	1,521	28	451	810	1,301	9,796
1999	3,149	1,946	2,070	249	0	1,559	28	459	836	1,325	9,949
2000	3,211	1,970	2,090	251	0	1,594	29	466	862	1,346	10,095
2001	3,267	1,988	2,106	252	0	1,632	29	473	887	1,367	10,227
2002	3,321	2,003	2,122	253	0	1,674	29	479	912	1,388	10,356
2003	3,373	2,018	2,135	254	0	1,717	30	485	938	1,409	10,483
2004	3,421	2,034	2,154	256	0	1,760	30	492	963	1,431	10,615
2005	3,466	2,054	2,183	257	0	1,805	31	498	996	1,455	10,753
2006	3,515	2,075	2,207	258	0	1,848	31	505	1,020	1,477	10,896
2007	3,565	2,101	2,231	259	0	1,895	31	513	1,045	1,503	11,052
2008	3,618	2,125	2,254	261	0	1,940	32	521	1,068	1,526	11,210
2009	3,675	2,149	2,278	262	0	1,983	32	529	1,091	1,550	11,368
2010	3,738	2,175	2,304	263	0	2,025	33	537	1,123	1,574	11,526

(1) Includes load provided by SEPA.
(2) Reduced to reflect generation by City of Fayetteville peak shaving facilities.

C.2. Component Peak Loads

The sections that follow provide brief descriptions of the forecast process for each component load. Additional details are provided in Appendices 8 through 18.

Residential Coincident Peak Load

In developing this forecast, an adjusted coincident peak load factor (CPLF) is applied to the forecast annual Residential energy sales component to produce the forecast of Residential coincident summer peak load. This represents the class peak load under normally expected peaking temperatures without any load management reductions. The CPLF is derived from actual Residential peak loads and energy which have been adjusted for abnormal temperatures. Also, the actual load management during the historic period is added back to the actual loads to establish a data base of historic loads not reduced by load management.

Average usage for all-electric customers is expected to increase slightly during the forecast period. The trends toward energy-efficient appliances, high-efficiency heat pumps, and the decreasing use of electric resistance heat are expected to continue. Real electricity prices are expected to generally decrease over the forecast period. The net effect of these trends is a slight increase in average usage for all-electric residential consumers.

Commercial Coincident Peak Load

Like Residential, the Commercial forecast coincident summer peak load is also derived by applying an adjusted coincident peak load factor (CPLF) to forecast annual Commercial energy sales. The Commercial CPLF is derived in the same manner as Residential and is used to produce the class peak load under normal peaking temperatures without any load management reductions.

Peak load growth for the Commercial class is forecast to be 453 MW over the forecast period. This reflects the relatively high employment growth expected in the Commercial class, especially in the services and trade sectors.

Industrial Coincident Peak Load

Non-coincident peak (NCP) load factors for eleven Standard Industrial Classifications (SIC) are derived from historic Industrial peak loads. Actual load management reductions have been added back to the historic metered loads, resulting in load factors which are not reduced by the effects of load management. These load factors are then applied to the forecast energy by SIC to produce non-coincident peak loads by SIC and summed to produce the Industrial class NCP not reduced by load management. An historic coincidence factor (ratio of non-coincident peak to coincident peak) for the total Industrial classification is used to convert the forecast of non-coincident peaks to a forecast of coincident peaks.

Growth in the Industrial class is led by the plastics and rubber, foods, electrical, and metals sectors.

Sales to the Military Coincident Peak Load

The relatively small Sales to the Military classification is estimated on the basis of the Commercial class because of the similarities in the mix of facilities between the classifications. The annual coincident peak load for this classification is developed by applying the annual Commercial CPLF to the annual forecast of energy sales to the Military class.

Sales-For-Resale Coincident Peak Load

The Sales-For-Resale coincident peak load is the sum of coincident peak load components of the electric cooperatives (co-ops) served by CP&L, the City of Fayetteville, and the municipalities that are not members of NCEMPA. The Sales-For-Resale classification is expected to grow at a rate of 2.6% compounded annually over the 1992-2010 forecast period. This compares with a compounded growth rate of approximately 1.4% for the remainder of the CP&L system load (reduced by conservation and load management) without NCEMPA and Sales-For-Resale.

An annual coincident peak for each component is forecast by applying a coincident peak load factor to the forecast of annual energy sales for that component. The coincident peak loads of the components are totaled to produce the Sales-For-Resale annual coincident peak load. The annual coincident peak and energy of the class are used to calculate the annual coincident peak load factor for the class.

Fayetteville peak loads are initially calculated using total load and energy data, not reduced for any peak shaving generation by Fayetteville. An adjustment is then made to total load and energy for expected peak shaving based on projected fuel costs.

All Sales-for-Resale component loads represent the total loads supplied through and by the CP&L system. These loads include the power transferred by the Company from the Southeastern Power Administration (SEPA) for the resale customers.

Company Use Coincident Peak Load

Company Use energy is estimated as a percentage of the total energy for all sales classifications, based on the historic relationship between Company Use energy and combined sales. The Company Use load pattern is similar to the load pattern of the Commercial sales classification. The annual Commercial CPLF is therefore applied to the annual Company Use energy forecast to produce the annual coincident peak load for Company Use.

Loss Component of Coincident Peak Load

System energy losses are based on an historic percentage of the annual total of sales and Company uses, including deliveries for SEPA. Demand losses are calculated from the annual energy loss using the corresponding system CPLF for each year.

Load Management Reduction

The System Peak Load forecast methodology is structured to provide a base forecast which does not reflect the reductions resulting from the Company's load management programs. Conservation, however, is reflected in the methodology and the base forecast does reflect future conservation effects. Since conservation is reflected in the forecast and load management reductions are not, load management alone is subtracted from the base forecast. To also subtract conservation would lead to a double counting of conservation effects.

Load management has provided significant reductions to system peak load and is expected to continue to do so in the future. Between 1992 and the end of the forecast period in 2010, load management reductions are expected to increase 580 MW. This represents a reduction of 17% of the total forecast load growth during this time period.

C.3. Component Energy Inputs

System Energy Input is the total energy required of the Company power resources. This includes not only the energy sales made at the customer meter, but also uses by Company facilities and the losses incurred in transferring energy to customer locations. A summary of annual energy components is presented on the following page.

Sub-section C.2., Component Loads, described the method of calculating coincident peak loads for the various sales classifications from their forecast energy sales. Energy sales are forecast for the Residential, Commercial, Industrial, Military, Sales-For-Resale, and Highway & Street Lighting classifications in the Company's annual Energy Sales Forecast. Sub-section C.2. also described the process of forecasting the additional energy requirements for Company Uses and Losses to use for determining these component loads.

The forecast component energy is not reduced for the effects of the Company's load management program which is consistent with the component load factors used to produce component peak loads. Therefore, a single adjustment is made for the energy resulting from Residential, Commercial, and Industrial load management programs to produce the System Energy Input not reduced by load management.

Further details of the Sales-For-Resale and NCEMPA energy sales are provided in Appendices 3 and 4, respectively.

DECEMBER 1991 PEAK LOAD FORECAST
SLOWER GROWTH SCENARIO

SUMMARY OF ANNUAL ENERGY COMPONENTS

	AT THE METER - NOT REDUCED FOR LOAD MANAGEMENT								AT THE GENERATOR		
YEAR	RESIDENTIAL (MWH)	COMMERCIAL AND MUNI. PUMPING (MWH)	INDUSTRIAL (MWH)	MILITARY (MWH)	HIGHWAY & STREET LIGHTING (MWH)	(1),(2) SALES-FOR -RESALE (MWH)	COMPANY USE (MWH)	LOSSES (MWH)	LOAD MANAGEMENT REDUCTIONS (MWH)	(1) NCEMPA (MWH)	SYSTEM ENERGY INPUT (MWH)
1992	10,790,280	7,541,567	12,528,300	1,054,321	96,296	6,151,281	106,175	1,950,187	91,846	5,549,424	45,675,990
1993	11,291,730	7,813,197	13,083,190	1,059,592	96,777	6,465,966	110,672	2,033,498	100,602	5,746,844	47,600,880
1994	11,803,620	8,045,729	13,264,580	1,064,890	97,261	6,769,991	114,067	2,096,190	111,948	5,913,243	49,057,620
1995	12,232,540	8,192,021	13,347,010	1,070,215	97,747	6,896,754	116,240	2,136,308	123,462	6,029,978	49,995,340
1996	12,586,750	8,283,513	13,443,920	1,075,566	98,236	7,012,602	118,067	2,170,035	152,025	6,137,156	50,773,820
1997	12,897,300	8,351,819	13,560,070	1,080,944	98,727	7,141,530	119,811	2,202,129	179,929	6,245,768	51,518,170
1998	13,182,870	8,432,597	13,741,470	1,086,348	99,221	7,296,801	121,764	2,238,152	207,392	6,360,443	52,352,270
1999	13,451,940	8,524,067	13,909,500	1,091,780	99,717	7,478,701	123,743	2,274,617	235,899	6,478,789	53,196,950
2000	13,717,230	8,626,767	14,033,050	1,097,239	100,215	7,646,904	125,566	2,308,328	263,710	6,581,974	53,973,570
2001	13,952,270	8,709,184	14,147,200	1,102,725	100,717	7,824,944	127,259	2,339,587	290,581	6,684,924	54,698,220
2002	14,184,090	8,770,748	14,251,320	1,108,239	101,220	8,021,051	128,914	2,370,092	319,878	6,788,112	55,403,910
2003	14,408,420	8,837,520	14,336,430	1,113,780	101,726	8,221,178	130,526	2,399,761	349,212	6,891,258	56,091,380
2004	14,612,520	8,909,655	14,465,760	1,119,349	102,235	8,420,668	132,220	2,430,924	381,128	7,000,335	56,812,540
2005	14,806,020	8,994,744	14,658,270	1,124,946	102,746	8,630,872	134,114	2,465,865	414,100	7,114,988	57,618,460
2006	15,015,180	9,090,043	14,817,170	1,130,570	103,260	8,836,027	135,967	2,500,092	446,824	7,226,093	58,407,580
2007	15,225,590	9,201,493	14,978,850	1,136,223	103,776	9,048,116	137,904	2,535,785	479,278	7,348,690	59,237,140
2008	15,454,120	9,308,323	15,131,220	1,141,904	104,295	9,252,404	139,822	2,571,208	509,253	7,465,858	60,059,900
2009	15,697,880	9,412,182	15,287,460	1,147,614	104,816	9,451,444	141,766	2,607,143	543,354	7,582,604	60,889,550
2010	15,964,220	9,526,801	15,469,160	1,153,352	105,341	9,651,146	143,854	2,645,897	579,691	7,696,697	61,776,780

(1) Includes load provided by SEPA.
(2) Reduced to reflect generation by City of Fayetteville peak shaving facilities.

D. SYSTEM WINTER PEAK LOAD FORECAST

The System Winter Peak has been calculated on the basis of the historic relationship between adjusted summer and winter peaks.

DECEMBER 1991 PEAK LOAD FORECAST
SLOWER GROWTH SCENARIO
WINTER PEAK LOAD FORECAST

YEAR	SYSTEM WINTER PEAK LOAD (MW)
1991/92	8,484
1992/93	8,817
1993/94	9,069
1994/95	9,205
1995/96	9,354
1996/97	9,482
1997/98	9,629
1998/99	9,780
1999/00	9,923
2000/01	10,053
2001/02	10,180
2002/03	10,305
2003/04	10,435
2004/05	10,570
2005/06	10,711
2006/07	10,864
2007/08	11,019
2008/09	11,175
2009/10	11,330

The winter peak is forecast to occur during the continuous period of December through February.

E. EASTERN AND WESTERN SERVICE AREA PEAK LOAD FORECASTS

As mentioned in the Preface, the Company provides electric service to a wide geographical area. Because the far western North Carolina service area is separated from the eastern service area, separate forecasts are required as part of the Company's Electric System Planning Process.

Eastern and western area summer coincident peak load forecasts, shown below, are developed from the statistical relationship between historic loads and the System Peak Load forecast. The western service area non-coincident winter peak load forecast is developed on a similar basis and is included in Appendix 2.

DECEMBER 1991 PEAK LOAD FORECAST
SLOWER GROWTH SCENARIO

EASTERN AND WESTERN SERVICE AREA COMPONENTS

YEAR	SYSTEM SUMMER PEAK LOAD (MW)	SUMMER COINCIDENT PEAK LOAD COMPONENTS	
		EASTERN DIVISION (MW)	WESTERN DIVISION (MW)
1992	8,631	8,138	493
1993	8,969	8,462	507
1994	9,226	8,709	517
1995	9,364	8,842	522
1996	9,516	8,989	527
1997	9,646	9,114	532
1998	9,796	9,259	537
1999	9,949	9,407	542
2000	10,095	9,547	548
2001	10,227	9,674	553
2002	10,356	9,799	557
2003	10,483	9,921	562
2004	10,615	10,049	566
2005	10,753	10,182	571
2006	10,896	10,320	576
2007	11,052	10,470	582
2008	11,210	10,622	588
2009	11,368	10,775	593
2010	11,526	10,927	599

F. FORECAST SCENARIOS

Each year, three separate forecasts are prepared: a Reference or Base forecast, a Higher Growth scenario, and a Slower Growth scenario. Each scenario is based on different economic and demographic assumptions. For example, such things as employment, income, industrial production, and population are varied to produce the different scenarios. In 1990, the Reference forecast best reflected CP&L's future. By contrast, in 1991 the Slower Growth forecast best typifies CP&L's long-run future.

DECEMBER 1991 LOAD FORECAST SCENARIOS

	SLOWER GROWTH SCENARIO		REFERENCE FORECAST		HIGHER GROWTH SCENARIO	
YEAR	SYSTEM SUMMER PEAK LOAD (MW)	ANNUAL SYSTEM ENERGY INPUT (MWH)	SYSTEM SUMMER PEAK LOAD (MW)	ANNUAL SYSTEM ENERGY INPUT (MWH)	SYSTEM SUMMER PEAK LOAD (MW)	ANNUAL SYSTEM ENERGY INPUT (MWH)
1992	8,631	45,675,990	8,760	46,315,960	8,817	46,596,560
1993	8,969	47,600,880	9,012	47,749,430	9,080	48,061,410
1994	9,226	49,057,620	9,256	49,184,680	9,327	49,533,920
1995	9,364	49,995,340	9,446	50,421,790	9,582	51,066,650
1996	9,516	50,773,820	9,663	51,510,450	9,872	52,523,480
1997	9,646	51,518,170	9,850	52,518,590	10,116	53,820,210
1998	9,796	52,352,270	10,047	53,608,680	10,381	55,226,640
1999	9,949	53,196,950	10,258	54,743,610	10,665	56,724,880
2000	10,095	53,973,570	10,470	55,859,580	10,954	58,228,400
2001	10,227	54,698,220	10,677	56,964,300	11,233	59,673,150
2002	10,356	55,403,910	10,873	57,998,260	11,499	61,054,140
2003	10,483	56,091,380	11,066	59,028,050	11,764	62,426,130
2004	10,615	56,812,540	11,257	60,027,510	12,017	63,741,240
2005	10,753	57,618,460	11,444	61,081,290	12,271	65,102,810
2006	10,896	58,407,580	11,647	62,146,960	12,514	66,387,070
2007	11,052	59,237,140	11,848	63,223,340	12,757	67,662,350
2008	11,210	60,059,900	12,057	64,295,490	13,014	68,970,580
2009	11,368	60,889,550	12,263	65,358,730	13,269	70,293,030
2010	11,526	61,776,780	12,472	66,505,480	13,536	71,707,820

APPENDICES

APPENDIX 1

COMPARISON AND TABULATION OF ADJUSTED SEASONAL PEAK LOADS, SUMMER and WINTER

SUMMER			WINTER		
YEAR	ACTUAL (MW)	ADJUSTED (MW)	YEAR	ACTUAL (MW)	ADJUSTED (MW)
			1975/76	4,968	4,878
1976	5,121	5,236	1976/77	5,509	5,120
1977	5,597	5,436	1977/78	5,605	5,388
1978	5,538	5,717	1978/79	5,588	5,647
1979	5,907	5,875	1979/80	5,809	5,839
1980	6,139	6,055	1980/81	6,402	6,079
1981	6,253	6,183	1981/82	6,602	6,144
1982	6,089	6,435	1982/83	6,290	6,277
1983	6,926	6,507	1983/84	6,598	6,810
1984	6,869	7,079	1984/85	7,799	7,119
1985	6,876	7,188	1985/86	7,763	7,370
1986	7,485	7,243	1986/87	7,163	7,543
1987	7,987	7,737	1987/88	7,921	7,766
1988	8,523	7,945	1988/89	7,883	8,059
1989	8,327	8,342	1989/90	8,209	7,871
1990	8,681	8,584	1990/91	7,875	8,135
1991	8,960	8,707			

Note: This table contains the values plotted on Page 9. Analysis of the complex dynamics of seasonal peak variations resulting from weather and other variables is continual. As improvements are made to data analysis methods and additional data becomes available, the current adjusted values will likely be changed to reflect these enhancements.

APPENDIX 2

WESTERN SERVICE AREA
WINTER NON-COINCIDENT PEAK LOAD FORECAST
SLOWER GROWTH SCENARIO

YEAR	WESTERN WINTER NCP (MW)
1991/92	642
1992/93	659
1993/94	671
1994/95	675
1995/96	681
1996/97	687
1997/98	693
1998/99	700
1999/00	707
2000/01	713
2001/02	718
2002/03	724
2003/04	729
2004/05	735
2005/06	742
2006/07	749
2007/08	756
2008/09	763
2009/10	771

NOTE: The winter season includes the continuous period of December through February.

APPENDIX 3

SALES FOR RESALE SUMMER COMPONENT ENERGY AND LOAD FORECAST
SLOWER GROWTH SCENARIO

	ENERGY AT THE METER				LOAD AT THE METER				
YEAR	ELECTRIC COOP * (GWH)	CITY OF FAYETTEVILLE (GWH) **	CP&L MUNICIPALS (GWH)	TOTAL ENERGY SALES (GWH)	ELECTRIC COOP * (MW)	CITY OF FAYETTEVILLE (MW) **	CP&L MUNICIPALS (MW)	TOTAL PEAK (MW)	TOTAL CPLF (%)
1992	4,518	1,338	295	6,151	1,018	187	68	1,273	55.2%
1993	4,797	1,365	304	6,466	1,081	199	70	1,350	54.7%
1994	5,021	1,437	313	6,770	1,131	211	72	1,414	54.7%
1995	5,199	1,494	149 ***	6,842	1,171	221	35 ***	1,427	54.7%
1996	5,322	1,540	151	7,013	1,199	227	35	1,461	54.8%
1997	5,415	1,574	152	7,142	1,220	232	35	1,487	54.8%
1998	5,534	1,608	154	7,297	1,247	238	36	1,521	54.8%
1999	5,677	1,646	156	7,479	1,279	244	36	1,559	54.8%
2000	5,804	1,685	158	7,647	1,307	250	37	1,594	54.8%
2001	5,943	1,722	160	7,825	1,339	256	37	1,632	54.7%
2002	6,098	1,762	162	8,021	1,373	264	37	1,674	54.7%
2003	6,252	1,805	163	8,221	1,408	271	38	1,717	54.7%
2004	6,409	1,847	165	8,421	1,444	278	38	1,760	54.6%
2005	6,575	1,888	167	8,631	1,481	285	39	1,805	54.6%
2006	6,737	1,930	169	8,836	1,517	292	39	1,848	54.6%
2007	6,904	1,973	171	9,048	1,555	300	40	1,895	54.5%
2008	7,066	2,013	173	9,252	1,592	308	40	1,940	54.4%
2009	7,222	2,054	175	9,451	1,627	315	41	1,983	54.4%
2010	7,380	2,094	177	9,651	1,662	322	41	2,025	54.4%

* Includes Energy and Load provided by SEPA

** Adjusted for Peak Shaving Energy and Load

*** Camden departure scheduled for 05/01/95

APPENDIX 4

NCEMPA SUMMER COINCIDENT PEAK LOAD AND ANNUAL COMPONENT ENERGY FORECAST SLOWER GROWTH SCENARIO

	AT THE METER			AT THE GENERATOR	
YEAR	FORMER CP&L CUSTOMERS (MWH)	NOT FORMER CP&L CUSTOMERS (MWH)	TOTAL (MWH)	TOTAL ENERGY (GWH)	TOTAL COINCIDENT PEAK (MW)
1992	3,475,161	1,954,804	5,429,965	5,549	1,135
1993	3,590,457	2,032,678	5,623,135	5,747	1,175
1994	3,686,068	2,099,885	5,785,953	5,913	1,209
1995	3,748,152	2,152,022	5,900,174	6,030	1,233
1996	3,800,356	2,204,689	6,005,045	6,137	1,255
1997	3,854,277	2,257,042	6,111,319	6,246	1,277
1998	3,911,175	2,312,351	6,223,526	6,360	1,301
1999	3,971,000	2,368,324	6,339,324	6,479	1,325
2000	4,020,023	2,420,265	6,440,288	6,582	1,346
2001	4,068,609	2,472,413	6,541,022	6,685	1,367
2002	4,117,998	2,523,990	6,641,988	6,788	1,388
2003	4,167,605	2,575,308	6,742,913	6,891	1,409
2004	4,220,685	2,628,958	6,849,643	7,000	1,431
2005	4,276,272	2,685,557	6,961,829	7,115	1,455
2006	4,328,313	2,742,228	7,070,541	7,226	1,477
2007	4,385,809	2,804,691	7,190,500	7,349	1,503
2008	4,439,703	2,865,443	7,305,146	7,466	1,526
2009	4,492,938	2,926,441	7,419,379	7,583	1,550
2010	4,543,236	2,987,779	7,531,015	7,697	1,574

APPENDIX 5

SYSTEM SUMMER PEAK LOAD AND ENERGY REDUCTIONS
LOAD MANAGEMENT PORTION OF DSM ACTIVITIES
SLOWER GROWTH SCENARIO

	PEAK LOAD			ENERGY		
YEAR	TOTAL LOAD MGMT (MW)	QUALIFYING FACILITIES PURCHASES (MW)	REDUCTION TO SYSTEM SUMMER PEAK (MW)	TOTAL LOAD MGMT (MWH)	QUALIFYING FACILITIES PURCHASES (MWH)	REDUCTION TO ANNUAL SYSTEM ENERGY (MWH)
1992	734	196	543	1,613,676	1,183,680	91,846
1993	796	196	607	1,661,835	1,183,680	100,602
1994	854	196	666	1,712,218	1,183,680	111,948
1995	907	196	721	1,763,105	1,183,680	123,462
1996	937	196	751	1,813,211	1,183,680	152,025
1997	967	196	781	1,858,775	1,183,680	179,929
1998	996	196	810	1,902,937	1,183,680	207,392
1999	1,022	196	836	1,947,479	1,183,680	235,899
2000	1,048	196	862	1,989,483	1,183,680	263,710
2001	1,073	196	887	2,029,984	1,183,680	290,581
2002	1,098	196	912	2,073,202	1,183,680	319,878
2003	1,124	196	938	2,116,721	1,183,680	349,212
2004	1,149	196	963	2,162,160	1,183,680	381,128
2005	1,182	196	996	2,208,737	1,183,680	414,100
2006	1,207	196	1,020	2,255,234	1,183,680	446,824
2007	1,231	196	1,045	2,301,906	1,183,680	479,278
2008	1,254	196	1,068	2,345,950	1,183,680	509,253
2009	1,277	196	1,091	2,394,437	1,183,680	543,354
2010	1,309	196	1,123	2,445,288	1,183,680	579,691

APPENDIX 6

SUMMER PEAK LOAD
HISTORIC AND FORECAST *

YEAR	SYSTEM SUMMER PEAK (MW)	SYSTEM MW INCREASE	SYSTEM % INCREASE	EASTERN DIVISION SUMMER CP (MW)	WESTERN DIVISION SUMMER CP (MW)	
1968	2,834	564	24.8	2,571	263	
1969	3,055	221	7.8	2,807	248	
1970	3,484	429	14.0	3,204	280	
1971	3,625	141	4.0	3,360	265	
1972	4,119	494	13.6	3,822	297	
1973	4,711	592	14.4	4,377	334	
1974	4,771	60	1.3	4,444	327	
1975	5,060	289	6.1	4,745	315	
1976	5,121	61	1.2	4,785	336	
1977	5,597	476	9.3	5,253	344	
1978	5,538	-59	-1.1	5,186	352	
1979	5,907	369	6.7	5,532	375	
1980	6,139	232	3.9	5,755	384	
1981	6,253	114	1.9	5,861	392	
1982	6,089	-164	-2.6	5,706	383	
1983	6,926	837	13.7	6,509	417	
1984	6,869	-57	-0.8	6,462	407	
1985	6,876	7	0.1	6,455	421	
1986	7,485	609	8.9	7,033	452	
1987	7,987	502	6.7	7,527	460	
1988	8,523	536	6.7	8,019	504	
1989	8,327	-196	-2.3	7,847	480	
1990	8,681	354	4.3	8,168	513	
1991	8,960	360	4.2	8,432	528	HISTORIC
1992	8,631	-329	-3.7	8,138	493	FORECAST
1993	8,969	338	3.9	8,462	507	
1994	9,226	257	2.9	8,709	517	
1995	9,364	138	1.5	8,842	522	
1996	9,516	152	1.6	8,989	527	
1997	9,646	130	1.4	9,114	532	
1998	9,796	150	1.6	9,259	537	
1999	9,949	153	1.6	9,407	542	
2000	10,095	146	1.5	9,547	548	
2001	10,227	132	1.3	9,674	553	
2002	10,356	129	1.3	9,799	557	
2003	10,483	127	1.2	9,921	562	
2004	10,615	132	1.3	10,049	566	
2005	10,753	138	1.3	10,182	571	
2006	10,896	143	1.3	10,320	576	
2007	11,052	156	1.4	10,470	582	
2008	11,210	158	1.4	10,622	588	
2009	11,368	158	1.4	10,775	593	
2010	11,526	158	1.4	10,927	599	

* SLOWER GROWTH SCENARIO

APPENDIX 7

ANNUAL SYSTEM ENERGY INPUT, LOAD, AND LOAD FACTOR HISTORIC AND FORECAST **

YEAR	* SYSTEM ENERGY INPUT (GWH)	ANNUAL SYSTEM PEAK LOAD (MW)	ANNUAL SYSTEM LOAD FACTOR (%)	
1968	15,238	2,834	0.61	
1969	16,914	3,055	0.63	
1970	18,617	3,484	0.61	
1971	20,296	3,625	0.64	
1972	22,329	4,119	0.62	
1973	24,882	4,711	0.60	
1974	25,303	4,771	0.61	
1975	25,907	5,060	0.58	
1976	27,578	5,121	0.61	
1977	29,026	5,597	0.59	
1978	29,850	5,605	0.61	
1979	30,470	5,907	0.59	
1980	32,330	6,139	0.60	
1981	32,497	6,402	0.58	
1982	32,411	6,602	0.56	
1983	34,765	6,926	0.57	
1984	36,059	6,869	0.60	
1985	37,433	7,799	0.55	
1986	39,314	7,763	0.58	
1987	41,513	7,987	0.59	
1988	43,060	8,523	0.58	
1989	44,624	8,327	0.61	
1990	43,832	8,681	0.58	
1991	45,556	8,960	0.58	HISTORIC
1992	45,676	8,631	0.60	FORECAST
1993	47,601	8,969	0.61	
1994	49,058	9,226	0.61	
1995	49,995	9,364	0.61	
1996	50,774	9,516	0.61	
1997	51,518	9,646	0.61	
1998	52,352	9,796	0.61	
1999	53,197	9,949	0.61	
2000	53,974	10,095	0.61	
2001	54,698	10,227	0.61	
2002	55,404	10,356	0.61	
2003	56,091	10,483	0.61	
2004	56,813	10,615	0.61	
2005	57,618	10,753	0.61	
2006	58,408	10,896	0.61	
2007	59,237	11,052	0.61	
2008	60,060	11,210	0.61	
2009	60,890	11,368	0.61	
2010	61,777	11,526	0.61	

* System Energy Input is the sum of Energy Sales (reduced for Load Management), Losses, and Company Uses.

** Slower Growth Scenario

APPENDIX 8

RESIDENTIAL PEAK LOAD CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

$$\text{CP Demand} = \frac{\text{Energy}}{\text{CP Load Factor} * \text{Hours}}$$

Energy (MWH)	10,790,280	From Energy Forecast
Load Factor (CP)	0.488	(See below)
Hours	8,760	
Calculated Peak Load (MW)	2,526	

YEAR	WEATHER NORMALIZED ENERGY (MWH)	WEATHER NORMALIZED CP DEMAND (MW)	WEATHER NORMALIZED CP LOAD FACTOR
1983	7,826,815	1,774	50.4%
1984	8,131,120	1,881	49.3%
1986	8,850,240	2,131	47.4%
1989	9,929,715	2,366	47.9%
		Average =	48.8%

FORECAST

YEAR	SUMMER PEAK LOAD (MW)	ANNUAL ENERGY AT THE METER (MWH)	ANNUAL LOAD FACTOR
1992	2,526	10,790,280	48.8%
1993	2,644	11,291,730	48.8%
1994	2,763	11,803,620	48.8%
1995	2,864	12,232,540	48.8%
1996	2,947	12,586,750	48.8%
1997	3,020	12,897,300	48.8%
1998	3,086	13,182,870	48.8%
1999	3,149	13,451,940	48.8%
2000	3,211	13,717,230	48.8%
2001	3,267	13,952,270	48.8%
2002	3,321	14,184,090	48.8%
2003	3,373	14,408,420	48.8%
2004	3,421	14,612,520	48.8%
2005	3,466	14,806,020	48.8%
2006	3,515	15,015,180	48.8%
2007	3,565	15,225,590	48.8%
2008	3,618	15,454,120	48.8%
2009	3,675	15,697,880	48.8%
2010	3,738	15,964,220	48.8%

Note: Energy represents sales at the meter, not including losses and not reduced by Load Management.

Source: December 1991 System Peak Load Forecast

APPENDIX 9

COMMERCIAL PEAK LOAD CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

$$\text{CP Demand} = \frac{\text{Energy}}{\text{CP Load Factor} * \text{Hours}}$$

Energy (MWH)	7,541,567	From Energy Forecast
Load Factor (CP)	0.50	See below
Hours	8,760	
Calculated Peak Load (MW)	1,722	

YEAR	WEATHER NORMALIZED ENERGY (MWH)	WEATHER NORMALIZED CP DEMAND (MW)	WEATHER NORMALIZED CP LOAD FACTOR
1981	4,941,171	1,131	49.9%
1982	5,220,012	1,133	52.6%
1985	5,976,520	1,257	54.3%
1988	7,005,808	1,604	49.9%
1990	7,640,582	2,090	41.7%
		Average =	50%

FORECAST

YEAR	SUMMER PEAK LOAD (MW)	ANNUAL ENERGY AT THE METER (MWH)	ANNUAL LOAD FACTOR *
1992	1,722	7,541,567	50%
1993	1,784	7,813,197	50%
1994	1,837	8,045,729	50%
1995	1,870	8,192,021	50%
1996	1,891	8,283,513	50%
1997	1,907	8,351,819	50%
1998	1,925	8,432,597	50%
1999	1,946	8,524,067	50%
2000	1,970	8,626,767	50%
2001	1,988	8,709,184	50%
2002	2,003	8,770,748	50%
2003	2,018	8,837,520	50%
2004	2,034	8,909,655	50%
2005	2,054	8,994,744	50%
2006	2,075	9,090,043	50%
2007	2,101	9,201,493	50%
2008	2,125	9,308,323	50%
2009	2,149	9,412,182	50%
2010	2,175	9,526,801	50%

Note: Energy represents sales at the meter, not including losses and not reduced by Load Management.

* Values have been rounded.

Source: December 1991 System Peak Load Forecast

APPENDIX 10

INDUSTRIAL PEAK LOAD CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

$$\text{SIC NCP} = \frac{\text{MWH}}{\text{NCPLF} * \text{Hours}}$$

For 1992:

SIC	MWH	NCPLF	NCP
20	565,814	0.459	141
22	3,375,838	0.626	616
23	174,593	0.310	64
24&25	508,482	0.372	156
26	1,054,724	0.646	186
28	3,334,550	0.764	498
30	572,583	0.549	119
32	253,771	0.599	48
33&34	967,606	0.464	238
36	636,252	0.533	136
OM	1,084,089	0.383	323
Total	12,528,300	0.566	2,525

$$\text{CP} = \frac{\text{Sum of SIC NCPs}}{\text{NCP/CP Ratio}}$$

Sum of SIC NCPs	2,525	(See above)
NCP/CP Ratio	1.355	(See below)
CP (MW)	1,863	

Year	Total Industrial NCP	Total Industrial CP	Annual Industrial NCP to CP ratio
1981	1,972	1,484	1.328
1982	1,952	1,426	1.369
1983	2,126	1,548	1.373
1984	2,141	1,581	1.354
1985	2,211	1,545	1.431
1986	2,235	1,630	1.372
1987	2,344	1,758	1.334
1988	2,428	1,819	1.335
1989	2,478	1,919	1.291
1990	2,520	1,847	1.364
		Average =	1.355

APPENDIX 10 (CONTINUED)

INDUSTRIAL PEAK LOAD CALCULATION FOR 1992 (continued)
SLOWER GROWTH SCENARIO

FORECAST

YEAR	SUMMER PEAK LOAD (MW)	ANNUAL ENERGY AT THE METER (MWH)	ANNUAL LOAD FACTOR
1992	1,863	12,528,300	76.8%
1993	1,949	13,083,190	76.6%
1994	1,979	13,264,580	76.5%
1995	1,990	13,347,010	76.6%
1996	2,004	13,443,920	76.6%
1997	2,020	13,560,070	76.6%
1998	2,045	13,741,470	76.7%
1999	2,070	13,909,500	76.7%
2000	2,090	14,033,050	76.6%
2001	2,106	14,147,200	76.7%
2002	2,122	14,251,320	76.7%
2003	2,135	14,336,430	76.7%
2004	2,154	14,465,760	76.7%
2005	2,183	14,658,270	76.7%
2006	2,207	14,817,170	76.6%
2007	2,231	14,978,850	76.6%
2008	2,254	15,131,220	76.6%
2009	2,278	15,287,460	76.6%
2010	2,304	15,469,160	76.6%

Note: Energy represents sales at the meter, not including losses and not reduced by Load Management.

Source: December 1991 System Peak Load Forecast

APPENDIX 11

MILITARY PEAK LOAD CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

$$\text{CP Demand} = \frac{\text{Energy}}{\text{CP Load Factor} * \text{Hours}}$$

Energy (MWH)	1,054,321	From Energy Forecast
Load Factor (CP)	0.50	(Same as Commercial)
Hours	8,760	
Calculated Peak Load (MW)	241	

FORECAST

YEAR	ANNUAL SUMMER PEAK LOAD (MW)	ENERGY AT THE METER (MWH)	ANNUAL LOAD FACTOR *
1992	241	1,054,321	50%
1993	242	1,059,592	50%
1994	243	1,064,890	50%
1995	244	1,070,215	50%
1996	246	1,075,566	50%
1997	247	1,080,944	50%
1998	248	1,086,348	50%
1999	249	1,091,780	50%
2000	251	1,097,239	50%
2001	252	1,102,725	50%
2002	253	1,108,239	50%
2003	254	1,113,780	50%
2004	256	1,119,349	50%
2005	257	1,124,946	50%
2006	258	1,130,570	50%
2007	259	1,136,223	50%
2008	261	1,141,904	50%
2009	262	1,147,614	50%
2010	263	1,153,352	50%

Note: Energy represents sales at the meter, not including losses and not reduced by Load Management.

* Values have been rounded.

Source: December 1991 System Peak Load Forecast

APPENDIX 12

HIGHWAY AND STREET LIGHTING PEAK LOAD CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

Highway and Street Lighting load is zero at the time of summer peak.

Annual Energy (MWH) 96,296 From Energy Forecast

FORECAST

YEAR	SUMMER PEAK LOAD (MW)	ANNUAL ENERGY AT THE METER (MWH)	ANNUAL LOAD FACTOR
1992	0	96,296	NA
1993	0	96,777	NA
1994	0	97,261	NA
1995	0	97,747	NA
1996	0	98,236	NA
1997	0	98,727	NA
1998	0	99,221	NA
1999	0	99,717	NA
2000	0	100,215	NA
2001	0	100,717	NA
2002	0	101,220	NA
2003	0	101,726	NA
2004	0	102,235	NA
2005	0	102,746	NA
2006	0	103,260	NA
2007	0	103,776	NA
2008	0	104,295	NA
2009	0	104,816	NA
2010	0	105,341	NA

Note: Energy represents sales at the meter, not including losses and not reduced by Load Management.

Source: December 1991 System Peak Load Forecast

APPENDIX 13

SALES-FOR-RESALE PEAK LOAD CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

$$\text{CP Demand} = \frac{\text{Energy}}{\text{CP Load Factor} * \text{Hours}}$$

Cooperatives:	Energy (MWH)	4,518,292	From Energy Forecast
	Load Factor (CP)	0.5068	See next page
	Hours	8,760	
	Calculated Peak Load (MW)	1,018	
Fayetteville Total Load:			
	Energy (MWH)	1,605,382	From Energy Forecast
	Load Factor (CP)	0.5451	See next page
	Hours	8,760	
	Calculated Peak Load (MW)	336	
Fayetteville Load on CP&L:			
	Peak Shaving Generation (MW)	149	
	Calculated Peak Load (MW)	187	
Municipals:	Energy (MWH)	295,116	From Energy Forecast
	Load Factor (CP)	0.4957	See next page
	Hours	8,760	
	Calculated Peak Load (MW)	68	
Total Calculated Wholesale Peak Load		1,273	

APPENDIX 13 (CONTINUED)

SALES-FOR-RESALE PEAK LOAD CALCULATION FOR 1992 (continued)
SLOWER GROWTH SCENARIO

LOAD FACTOR CALCULATION

Cooperatives:

Year	Weather Normalized Energy (MWH)	Weather Normalized CP Demand (MW)	Weather Normalized CP Load Factor
1986	3,528,464	820	49.11%
1987	3,887,265	925	47.97%
1988	4,093,791	832	56.02%
1989	4,364,640	988	50.41%
1990	4,426,495	1,012	49.91%
		Average =	50.68%

Fayetteville:

Year	Weather Normalized Energy (MWH)	Weather Normalized CP Demand (MW)	Weather Normalized CP Load Factor
1986	1,441,872	302	54.49%
1987	1,494,885	310	55.07%
1988	1,541,249	316	55.56%
1989	1,576,742	335	53.80%
1990	1,591,074	339	53.64%
		Average =	54.51%

Municipals:

Year	Weather Normalized Energy (MWH)	Weather Normalized CP Demand (MW)	Weather Normalized CP Load Factor
1986	268,992	62	49.56%
1987	273,485	62	50.64%
1988	275,175	62	50.92%
1989	287,813	69	47.53%
1990	292,601	68	49.18%
		Average =	49.57%

FORECAST

YEAR	SUMMER PEAK LOAD (MW)	ANNUAL ENERGY AT THE METER (MWH)	ANNUAL LOAD FACTOR
1992	1,273	6,151,281	55.2%
1993	1,350	6,465,966	54.7%
1994	1,414	6,769,991	54.7%
1995	1,427	6,896,754	55.2%
1996	1,461	7,012,602	54.8%
1997	1,487	7,141,530	54.8%
1998	1,521	7,296,801	54.8%
1999	1,559	7,478,701	54.8%
2000	1,594	7,646,904	54.8%
2001	1,632	7,824,944	54.7%
2002	1,674	8,021,051	54.7%
2003	1,717	8,221,178	54.7%
2004	1,760	8,420,668	54.6%
2005	1,805	8,630,872	54.6%
2006	1,848	8,836,027	54.6%
2007	1,895	9,048,116	54.5%
2008	1,940	9,252,404	54.4%
2009	1,983	9,451,444	54.4%
2010	2,025	9,651,146	54.4%

Note: Energy represents sales at the meter, not including losses and not reduced by Load Management.

Source: December 1991 System Peak Load Forecast

APPENDIX 14

COMPANY USE PEAK LOAD CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

Company Use Percentage is 0.025%

	MWH
Residential	10,790,280
Commercial	7,541,567
Industrial	12,528,300
Military	1,054,321
Highway & Street Lighting	96,926
Wholesale	6,151,281
NCEMPA-CPL	3,475,161
Total	46,137,210

Company Use MWH 106,175

Company Use CPLF 50% (Same as Commercial)

Company Use Peak Load 24

FORECAST

YEAR	SUMMER PEAK LOAD (MW)	ANNUAL ENERGY AT THE METER (MWH)
1992	24	106,175
1993	25	110,672
1994	26	114,067
1995	27	116,240
1996	27	118,067
1997	27	119,811
1998	28	121,764
1999	28	123,743
2000	29	125,566
2001	29	127,259
2002	29	128,914
2003	30	130,526
2004	30	132,220
2005	31	134,114
2006	31	135,967
2007	31	137,904
2008	32	139,822
2009	32	141,766
2010	33	143,854

Note: Energy represents sales at the meter, not including losses and not reduced by Load Management.

Source: December 1991 System Peak Load Forecast

APPENDIX 15

LOSSES PEAK LOAD CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

	MW	MWH
Residential	2,526	10,790,280
Commercial	1,722	7,541,567
Industrial	1,863	12,528,300
Military	241	1,054,321
Highway & Street Lighting	0	96,926
Wholesale	1,273	6,151,281
Company Use	24	106,175
NCEMPA-CPL	715	3,475,161
Total	8,364	41,743,380

Loss Percentage is 4.855%

Loss MWH = Total MWH * Loss % = 2,026,641

$$\text{Loss CPLF} = \frac{\text{Total MWH}}{\text{Total MW * Hours}} = 0.57$$

$$\text{Loss MW} = \frac{\text{Loss MWH}}{\text{Loss CPLF * Hours}} = 406$$

NCEMPA-CPL Loss MWH = 76,454

NCEMPA-CPL Loss MW = 16

CP&L System Losses (MWH) = 1,950,187

CP&L System Losses (MW) = 390

FORECAST

YEAR	SUMMER PEAK LOAD (MW)	ANNUAL ENERGY AT THE METER (MWH)
1992	390	1,950,187
1993	408	2,033,498
1994	421	2,096,190
1995	429	2,136,308
1996	436	2,170,035
1997	443	2,202,129
1998	451	2,238,152
1999	459	2,274,617
2000	466	2,308,328
2001	473	2,339,587
2002	479	2,370,092
2003	485	2,399,761
2004	492	2,430,924
2005	498	2,465,865
2006	505	2,500,092
2007	513	2,535,785
2008	521	2,571,208
2009	529	2,607,143
2010	537	2,645,897

Note: Energy represents sales at the meter, not including losses and not reduced by Load Management.

Source: December 1991 System Peak Load Forecast

APPENDIX 16

LOAD MANAGEMENT REDUCTION TO PEAK LOAD
CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

(Data in MW)

Residential	
Air Conditioner Control	114.00
Water Heater Control	26.90
Voltage Reduction	20.52
Time-of-Use Rates	18.60
Heat Pump Strategic Sales	4.70
Total Residential Load Management	184.72
Commercial	
Audit	19.51
Energy Efficient Design	64.59
Voltage Reduction	29.84
Total Commercial Load Management	113.94
Industrial	
Large Load Curtailment	67.20
Post December 1980 Displacement	23.60
Time-of-Use Rates and Thermal Energy Storage	141.70
Voltage Reduction	11.81
Total Industrial Load Management	244.31
Total Load Management Reduction to System Load Forecast	542.97

FORECAST

YEAR	SUMMER PEAK LOAD (MW)	ANNUAL ENERGY AT GENERATION (MWH)
1992	543	91,846
1993	607	100,602
1994	666	111,948
1995	721	123,462
1996	751	152,025
1997	781	179,929
1998	810	207,392
1999	836	235,899
2000	862	263,710
2001	887	290,581
2002	912	319,878
2003	938	349,212
2004	963	381,128
2005	996	414,100
2006	1,020	446,824
2007	1,045	479,278
2008	1,068	509,253
2009	1,091	543,354
2010	1,123	579,691

Source: December 1991 System Peak Load Forecast

APPENDIX 17

NCEMPA PEAK LOAD CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

$$\text{CP Demand} = \frac{\text{Energy Forecast}}{\text{NCEMPA Load Factor} * \text{Hours}}$$

NCEMPA Load Factor from forecast provided by NCEMPA, shown below

NCEMPA PROVIDED FORECAST

YEAR	OLD CONNECTED (MWH)	NEW CONNECTED (MWH)	NOT CONNECTED (MWH)	OLD CONNECTED (MW)	NEW CONNECTED (MW)	NOT CONNECTED (MW)
1992	3,617,316	1,333,471	701,296	744	277	135
1993	3,693,667	1,374,933	716,176	760	286	138
1994	3,771,422	1,417,140	731,369	776	294	141
1995	3,848,955	1,464,259	745,639	792	304	144
1996	3,927,002	1,519,084	759,076	807	315	147
1997	4,004,382	1,572,830	772,113	823	326	149
1998	4,084,865	1,629,452	785,587	840	338	152
1999	4,168,525	1,686,651	799,477	857	349	155
2000	4,248,286	1,745,075	812,617	873	361	157
2001	4,334,118	1,806,796	826,961	891	374	160
2002	4,416,877	1,866,404	840,774	908	386	163
2003	4,499,036	1,925,598	854,513	924	398	166
2004	4,579,633	1,984,536	868,001	941	410	169
2005	4,659,880	2,045,276	881,192	957	423	171
2006	4,740,579	2,109,245	894,177	974	436	174
2007	4,822,007	2,176,438	907,198	990	449	177
2008	4,902,807	2,244,195	920,141	1,007	463	179
2009	4,980,751	2,311,478	932,695	1,023	477	182
2010	5,056,234	2,380,280	944,863	1,038	491	184

FORECAST LOAD FACTORS

	OLD CONNECTED	NEW CONNECTED	NOT CONNECTED
1992	55.48%	54.94%	59.37%
1993	55.49%	54.96%	59.30%
1994	55.50%	54.98%	59.23%
1995	55.51%	55.01%	59.17%
1996	55.52%	55.04%	59.11%
1997	55.53%	55.07%	59.06%
1998	55.54%	55.10%	59.01%
1999	55.54%	55.12%	58.95%
2000	55.55%	55.15%	58.91%
2001	55.55%	55.17%	58.85%
2002	55.56%	55.19%	58.81%
2003	55.56%	55.22%	58.76%
2004	55.57%	55.23%	58.72%
2005	55.57%	55.26%	58.68%
2006	55.58%	55.28%	58.64%
2007	55.58%	55.30%	58.60%
2008	55.59%	55.32%	58.56%
2009	55.59%	55.34%	58.53%
2010	55.59%	55.36%	58.49%

APPENDIX 17 (CONTINUED)

NCEMPA PEAK LOAD CALCULATION FOR 1992 (continued)
SLOWER GROWTH SCENARIO

For 1992:	MWH	Load Factor	CP
Old Connected	3,551,615	55.48%	731
New Connected	1,309,251	54.94%	272
Not Connected	688,558	59.37%	132
Total	5,549,424		1,135

FORECAST

YEAR	SUMMER PEAK LOAD (MW)	ANNUAL ENERGY AT GENERATION (MWH)	ANNUAL LOAD FACTOR
1992	1,135	5,549,424	55.8%
1993	1,175	5,746,844	55.8%
1994	1,209	5,913,243	55.8%
1995	1,233	6,029,978	55.8%
1996	1,255	6,137,156	55.8%
1997	1,277	6,245,768	55.8%
1998	1,301	6,360,443	55.8%
1999	1,325	6,478,789	55.8%
2000	1,346	6,581,974	55.8%
2001	1,367	6,684,924	55.8%
2002	1,388	6,788,112	55.8%
2003	1,409	6,891,258	55.8%
2004	1,431	7,000,335	55.8%
2005	1,455	7,114,988	55.8%
2006	1,477	7,226,093	55.8%
2007	1,503	7,348,690	55.8%
2008	1,526	7,465,858	55.8%
2009	1,550	7,582,604	55.8%
2010	1,574	7,696,697	55.8%

Note: Forecast detail by NCEMPA component is provided in Appendix 4.

Source: December 1991 System Peak Load Forecast

APPENDIX 18

SYSTEM PEAK LOAD CALCULATION FOR 1992
SLOWER GROWTH SCENARIO

	MW	MWH
Residential	2,526	10,790,280
Commercial	1,722	7,541,567
Industrial	1,863	12,528,300
Military	241	1,054,321
Highway & Street Lighting	0	96,296
Wholesale	1,273	6,151,281
Company Use	24	106,175
Losses	390	1,950,187
Load Management	543	91,846
NCEMPA	1,135	5,549,424
Total	8,631	45,675,990

FORECAST

YEAR	SUMMER PEAK LOAD (MW)	ANNUAL ENERGY INPUT (MWH)	ANNUAL LOAD FACTOR
1992	8,631	45,675,990	60.4%
1993	8,969	47,600,880	60.6%
1994	9,226	49,057,620	60.7%
1995	9,364	49,995,340	60.9%
1996	9,516	50,773,820	60.9%
1997	9,646	51,518,170	61.0%
1998	9,796	52,352,270	61.0%
1999	9,949	53,196,950	61.0%
2000	10,095	53,973,570	61.0%
2001	10,227	54,698,220	61.1%
2002	10,356	55,403,910	61.1%
2003	10,483	56,091,380	61.1%
2004	10,615	56,812,540	61.1%
2005	10,753	57,618,460	61.2%
2006	10,896	58,407,580	61.2%
2007	11,052	59,237,140	61.2%
2008	11,210	60,059,900	61.2%
2009	11,368	60,889,550	61.1%
2010	11,526	61,776,780	61.2%

Source: December 1991 System Peak Load Forecast