ENVIRONMENTAL REPORT

Carolina Power & Light Company

SHEARON HARRIS NUCLEAR POWER PLANT

UNITS 1, 2, 3 & 4

Volume 2

4.0 ALTERNATIVES TO THE PROPOSED FACILITY

4.1 SPECIFIC POWER NEEDS

Carolina Power & Light Company provides electrical service to its customers in North and South Carolina. Table 4.1-1 shows the Company's summer peak demands and percent increases for the years 1966 through 1990. The percentage increases for the period of 1966-1976 are based on actual data and, as such, reflect the way the peak demands have actually grown. Summer weather conditions have the greatest influence on summer peak loads, and as such, there is a definite correlation apparent between the years with high percentage increases and the years with extended hot weather periods during the summer. Similarly, there is a correlation with low percentage increases and years with mild summers.

In the forecast methodology used by CP&L, the energy forecast serves as a basis for the demand forecast, therefore, the energy forecast methodology is described first.

Energy Forecast

To develop the forecast of future system energy requirements, data on historical energy usage and anticipated changes in energy requirements are forecast for six classifications of customers (Residential, Commercial, Industrial, Public Street and Highway Lighting, Other Sales to Public Authorities, and Sales for Resale). Predicted energy requirements for these customer classifications are combined with other energy requirements such as system losses, Company use, and energy wheeled for delivery from the federal power project (Kerr Dam in Virginia) to Southeastern Power Administration (SEPA) preference customers. The combined energy requirements for these none energy classifications make up the total system energy requirement.

In developing the forecast of energy requirements for each of the sales classifications, consideration is given to many factors which influence customer electric energy requirements. Among these factors are number and type of new customers; availability of other energy forms; indicated customer preference, and anticipated levels of market saturation for major energy using equipment such as water heaters, electric heat, and air-conditioning; and the anticipated price of electric energy relative to other energy forms.

In developing the forecast for residential customers, each of three residential classifications is forecast independently and the results are combined into the residential energy requirement. The three residential classifications are customers with electric heating, customers without electric heating but with electric water heating, and those without electric heat or water heating. A least squares regression analysis is performed using monthly historical data for each of the three classifications. The independent regression variables include: the summer base load; the winter base load; the rate of growth of energy required as a function of time during the summer; the rate of growth of energy required as a function of time during the winter; summer cooling degree days by months; winter heating degree days by months; the summer unit price; and the winter unit price. From this analysis, a linear regression equation is developed which considers the growth rate in usage as a function of weather and price from a base load as of January, 1970. Forecast energy requirements for each of the three classifications incorporate normal summer and winter weather and a rate of price increase for electricity that is slightly more per year than the general inflation rate.

The forecasts obtained using the regression equations are checked for reasonableness by estimating the growth of various appliances and anticipated usage for these appliances.

The growth in the total number of residential customers and the customer distribution by classifications are determined considering current econometric references including the National Planning Association Projections, Southern Growth Policies Board, U. S. Bureau of the Census, Department of Commerce Industrial Outlook, etc.

It is CP&L's opinion that the competing fuel situations will manifest themselves in the mix of customers rather than the usage for each of the customer classes. For example, if natural gas is not available, dwelling units to be built during the forecast period are more likely to have electric heat. The price of fuel oil anticipated in the future will also influence the distribution of future customers between the classification with electric heat and the one with water heating.

The Commercial Energy Forecast is made using the same techniques used for residential. The independent variables for the regression equation are the same and the correlation is very good. A modification is made to the historical growth rate of commercial customers to remove the effects of large fluctuations in the number of commercial customers resulting from the fact that temporary meters for residential construction have historically been classified as "Commercial." Variations in residential construction activity can result in year-to-year variations of as much as 4,000 in the number of commercial customers.

The Industrial Forecast is basically a concensus of the estimates of the CP&L customers. The Industrial Services Manager calls upon the Headquarters Group of the larger industrial customers to determine what their anticipated loads will be. Industrial Power Engineers call on smaller customers for the same type of information. The customer projections are modified based upon historical knowledge to arrive at the system industrial energy forecast.

Historically, the Sales for Resale customers have maintained a direct correlation to the sum of the CP&L Residential and Commercial classifications. The ratio of the Sales for Resale to the Residential and Commercial total has been increasing, but the increase is at a constant rate. This ratio is projected into the future and used to forecast Sales for Resale based upon the combined Residential and Commercial classification forecasts. As a final check, the ratios of usage between Residential and Industrial, Residential and Commercial, Commercial and Industrial, etc., are assessed from a historical point and calculated for the forecast.

Company use is estimated based on historical data and is forecast as percentage of total energy sales. Southeastern Power Administration (SEPA) energy usage is an estimate that includes the firm and secondary energy (less transmission losses) which could have been generated at Kerr Dam for delivery to SEPA preference customers on the CP&L system under average stream flow conditions during the years 1925-1968. Losses are estimated based on the historical ratio of system losses to total customer use plus Company use and SEPA wheeled energy.

The individual forecasts that have been described for the nine energy classifications are combined for each year of the forecast period to determine the total system energy requirement.

Demand Forecast

The Long-Range-Energy Forecast serves as a basis for the Long-Range-Demand Forecast. Projected annual system load factors are determined for each year of the forecast. The annual system load factors and forecast system energy requirements determine the forecast annual peak loads.

Projected annual system load factors are derived by determining the coincident peak load factor for each of the components of the total system energy requirement. The coincident peak load factor for a sales classification is determined by the ratio of the sales classification's average demand during the year to its demand at the time of the annual system peak. The coincident peak load factors are combined into a total system load factor for each year.

In developing the coincident peak load factor for the Residential classification, coincident peak load factors are developed for each of the three residential classifications. Load survey data for a statistically significant sample of residential customers serves as a basis for the historical determination. The historical coincident peak load factor trend is modified for each classification based on forecast energy usage per customer, residential air-conditioning saturation, and other energy uses. The combined coincident peak load factor for the total Residential classification is then determined taking into consideration the forecast energy usage for each classification.

The Industrial Energy Forecast is subdivided into eleven (11) forecasts of energy usage by Standard Industrial Classification (SIC) Codes. Historical non-coincident peak load factors from customer billing data and ratios of non-coincident peak load factors are used to develop coincident peak load factor estimates for each of the eleven SIC code classifications. The coincident peak load factor for the Industrial classification is then determined taking into consideration the changing mix of industrial customers in the energy forecast.

Commercial, Other Sales to Public Authorities, and Company-use coincident peak load factors are determined by combining the three classifications into one group for forecasting purposes. The coincident peak load factors for these classifications are based on historical data.

The projected coincident peak load factor for the Sales for Resale classification is based on the forecast trend of the Company's combined Commercial and Residential coincident peak load forecasts.

The coincident peak load factor for SEPA wheeled energy is calculated based on the energy expected to be available from SEPA and the contract demand.

Losses are a small percentage of the total system input and assumed to have a coincident peak load factor equal to the system load factor.

Public Street and Highway Lighting demand is not considered in the demand forecast since this load occurs at night and does not contribute to the system peak.

Once the coincident peak load factors for each of the six sales classifications plus Company use, SEPA, and system losses have been determined, the coincident demand for the system is calculated by applying these load factors to the proper class and combining the resulting demands into a system peak load forecast.

The present long lead times required from time of inception to in-service operation of generating facilities have made it necessary to extend the capacity planning period. The construction and operation of the Harris Plant Units 1, 2, 3, and 4 are essential to the ability of Carolina Power & Light Company to meet its load requirements during the period 1984-1990 and beyond. CP&L presently has seven fossil-fired steam electric generating plants with a net capability of 3,851,000 kW, four hydroelectric plants with a net capability of 214,000 kW, two nuclear plants with a net capability of 2,245,000 kW, and internal combustion generating units with a net capability of 1,018,000 kW for a total installed summer time net capability of 7,328,000 kW. Table 4.1-2 shows CP&L's present generating capacity. Including net power available under purchase/sale agreements, system summer capability anticipated for the summer of 1977 is 7,622,500 kW.

Carolina Power & Light Company currently has under construction or projected for the period May 1, 1977, through December 31, 1983, 1545 MW of coal-fired capacity (including 105 MW uprating of existing capacity) and 62 MW of nuclear capacity (uprating of existing capacity) for a total additional capacity during the period of 1607 MW. Even with these additions to the existing generating capacity available, the projected reserves at the time of the summer peak demand will be only 6.7 percent for 1983. Table 4.1-3 shows Carolina Power & Light Company's resources, loads, and reserves for summer 1984-1990 with and without the Harris units. Without the units, CP&L would be unable to meet its load demands during these years with the exception of 1985.

Delay of the project will place CP&L in a position where its reserves will be inadequate for reliable service, while canceling the plant will result in firm power resources approximately 14 percent less than the projected peak demand in 1990. When completed, the Harris Plant will constitute 25 percent of CP&L's generating capability. In terms of actual electrical energy production, it is even more significant than its relative size would indicate since it is a base load plant.

In February, 1977 the North Carolina Utilities Commission issued a report entitled "Report of Analysis and Plan: Future Requirements for Electricity Service to North Carolina". This report covered generation requirements as seen by the Commission for North Carolina during the period 1977-1996.

The following statement concerning reserve margins deemed necessary by the Commission for reliable and adequate service was taken from the above mentioned report: "The Commission concluded that based on the analysis of historical experience, a reserve criterion of a standard percent reserve ranging between 15 and 20 percent for the summer peaking season and a standard percent reserve of not less than 20 percent for the winter peaking season would provide adequate and reliable electric service." CP&L's reserve planning criteria is 12 percent of the forecast peak demand because of indications that CP&L will be unable to attract adequate capital on reasonable terms to provide a 15-20 percent reserve level.

Concerning the specific capacity needs for CP&L the following statements were made: "For CP&L, the total capacity that needs to be added to meet the 15% reserve criterion is about 6000 MW by 1986 and an additional 2000 MW between 1986 and 1996 or a total additional capacity required over a period of 8000 MW. Of the 8000 MW required over the period, under base case cost assumptions we project about 4600 MW nuclear should be installed...". As shown on Table III-9, the Harris Plant is included in the 4600 MW nuclear capacity requirement.

TABLE 4.1-1

CP&L SUMMER PEAK DEMANDS & INCREASES

	Year	Summer Peak (MW)	Annual Increase (MW)	Annual Increase (%)	Compound Rate (%)
	1966	2184	-	-	
	1967	2270	86	3.94	
	1968	2834	564	24.85	
	1969	3055	221	7.80	
Actual	1970	3484	429	14.04	
	1971	3625	141	4.05	8.90
	1972	4119	494	13.63	
	1973	4711	592	14.37	
	1974	4771	60	1.27	
	1975	5060	289	6.06	
	1976	5121	61	1.21	
	1977	5548	427	8.34	
	1978	5975	427	7.70	
	1979	6411	436	7.30	
	1980	6878	467	7.28	
	1981	7367	489	7.11	
	1982	7897	530	7.19	
Forecast	1983	8441	544	6.89	
	1984	9019	578	6.85	6.65
	1985	9590	571	6.33	
	1986	10190	600	6.26	
	1987	10801	611	6.00	
	1988	11444	643	5.95	
Projected	1989	12016	572	5.00	
	1990	12617	601	5.00	

TABLE

4.1-2

CP&L Generation Capacity

		Capacity (Net MW)
NUCLEAR		
Robinson		665
Brunswick	1	790
Brunswick	2	790
TOTAL NUCLEAR		2245
FOSSIL		
Roxboro	1	385
Roxboro	2	670
Roxboro	3	650
Lee	1	79
Lee	2	76
Lee	3	252
Asheville	1	198
Asheville	2	194
Cape Fear	1	14
Cape Fear	2	14
Cape Fear	3	32.5
Cape Fear	4	32.5
Cape Fear	5	143
Cape Fear	6	173
Sutton	1	97
Sutton	2	106
Sutton	3	385
Robinson		174
Weatherspoon	1	49
Weatherspoon	2	49
Weatherspoon	3	78
TOTAL FOSSIL		3851
HYDROELECTRIC(1)		
Walters		105
Tillery		86
Blewett		22
Marshall		1
TOTAL HYDROELECTIC		214

IC Turbine(1)		Capacity (Net MW)
Blewett	1	13
Blewett	2	13
Blewett	3	13
Blewett	4	13
Cape Fear	1A	14
Cape Fear	1B	14
Cape Fear	2A	14
Cape Fear	2B	14
Lee	1	14
Lee	2	27
Lee	3	25
Lee	4	25
Morehead		15
Robinson		15
Roxboro		15
Sutton	1	13
Sutton	2A	26
Sutton	2B	25
Weatherspoon	1	35
Weatherspoon	2	35
Weatherspoon	3	34
Weatherspoon	4	34
Darlington Co.	1-11	572
TOTAL ICs		1018
% OF TOTAL CAPACITY		
NUCLEAR		30.6
FOSSIL		52.6
HYDROELECTRIC		2.9
IC TURBINE		13.9
TOTAL		100.0

(1) Hydroelectric and IC Turbine capacity used for peaking purposes.

TABLE 4.1-3

CP&L POWER RESOURCES, LOAD, AND RESERVES WITH AND WITHOUT SHEARON HARRIS NUCLEAR POWER PLANT, 1984-1990 (SUMMER)

WITH HARRIS PLANT ON SCHEDULE

	1984	1985	1986	1987	1988	1989	1990
Resources (MW)	9910	10630	11530	11530	12430	13580	14480
Load (MW)	9019	9590	10190	10801	11444	12016	12617
Reserve (MW)	891	1040	1340	729	986	1564	1863
Reserve (%)	9.9	10.8	13.2	6.7	8.6	13.0	14.8

WITHOUT HARRIS PLANT

	1984	1985	1986	1987	1988	1989	1990
Resources (MW)	9010	9730	9730	9730	9730	10880	10880
Load (MW)	9019	9590	10190	10801	11444	12016	12617
Reserve (MW)	-9	140	-460	-1071	-1714	-1136	-1737
Reserve (%)	-0.1	1.5	-4.5	-9.9	-15.0	-9.5	-13.8

4.2 IMPORTING POWER

Carolina Power & Light Company and neighboring utilities, with which CP&L is interconnected, are in similar situations with respect to the prospects of importing large quantities of power. Each utility is confronted with long lead times for construction of generation facilities and the uncertainties of maintaining construction schedules. None of these other companies is installing any extra generation capacity in quantities required to allow the selling of power to CP&L on a firm basis in the amounts required if the Harris units are not brought into operation in the years 1984-1990 as scheduled.

Carolina Power & Light Company plans an important role in the Virginia-Carolinas (VACAR) Subregion reserves. Table 4.2-1 shows the reserves of the VACAR Subregion with all units for the region, including Harris, on schedule. Table 4.2-2 shows the reserves for the Subregion without the Harris Plant. Table 4.2-4 shows the subregion reserves with a one-year delay in nuclear units, while Table 4.2-5 shows the reserves with all nuclear units cancelled (see special footnote on each of these tables). These tables show the Harris units are an important part of the planned generating capacity of the Virginia-Carolinas Subregion especially in light of the uncertainties of maintaining construction schedules. The purpose of VACAR, as stated in the Virginia-Carolinas Reliability Agreement dated May 1, 1970, is "to further augment the reliability of each Member System's bulk power supply through coordination of the Member System's planning and operation of their generation and bulk power transmission facilities."

The neighboring utilities are not planning to install extra generating capacity in the quantities required to allow CP&L to import the firm power necessary to serve its load without the Harris Plant. Sufficient transmission interconnection capacity for interchanges of large blocks of power between CP&L and its neighbors is planned under the VACAR Agreement for the primary purpose of providing emergency assistance in the event of equipment failure.

TABLE 4.2-1

VIRGINIA-CAROLINAS SUBREGION RESERVES FOR 1984-1990 WITH ALL UNITS ON SCHEDULE[1]

	Summer Load (MW)	Summer Resources (MW)	Summer Load Responsibility (MW)	Reserve %
1984	40,375	49,447	40,163	22.6
1985	42,780	52,117	42,568	21.9
1986	45,297	54,174	45,085	19.7
1987	48,908	58,360	48,696	19.4
1988	51,815	61,015	51,603	17.8
1989	54,750	65,161	54,538	19.1
1990	57,804	69,038	57,592	19.5

(1) Based on March, 1977, response to FPC Order 383-4.

TABLE 4.2-2

VIRGINIA-CAROLINAS SUBREGION RESERVES FOR 1984-1990 WITHOUT SHEARON HARRIS PLANT[1]

	Summer Load (MW)	Summer Resources (MW)	Summer Load Responsibility (MW)	Reserve %
1984	40,375	48,547	40,163	20.3
1985	42,780	51,217	42,568	19.8
1986	45,297	52,374	45,085	15.7
1987	48,908	56,560	48,696	15.7
1988	51,815	58,315	51,603	12.6
1989	54,750	62,461	54,538	14.1
1990	57,804	65,438	57,592	13.3

(1) Based on March, 1977, response to FPC Order 383-4.

Table 4.2-3 has been deleted by Amendment No. 38.

TABLE 4.2-4

VIRGINIA-CAROLINAS SUBREGION RESERVES
FOR 1984-1990 WITH ALL NUCLEAR UNITS
PLANNED FOR INSTALLATION DURING THIS PERIOD DELAYED ONE YEAR(1)

	Summer Load (MW)	Summer Resources (MW)	Summer Load Responsibility (MW)	Reserve %
1984	40,375	47,267	40,163	17.2
1985	42,780	50,806	42,568	18.9
1986	45,297	53,274	45,085	17.7
1987	48,908	58,360	48,696	19.4
1988	51,815	60,115	51,603	16.1
1989	54,750	64,011	54,538	17.0
1990	57,804	68,138	57,592	17.9

(1) Based on March, 1977, response to FPC Order 383-4. Individual unit information for VACAR member companies other than CP&L was not available beyond 1986. Only delays in CP&L units are indicated beyond this date.

TABLE 4.2-5

VIRGINIA-CAROLINAS SUBREGION RESERVES FOR 1984-1990 WITH ALL NUCLEAR UNITS AFTER JANUARY 1, 1984 CANCELLED[(1)]

	Summer Load (MW)	Summer Resources (MW)	Summer Load Responsibility (MW)	Reserve %
1984	40,375	47,267	40,163	17.2
1985	42,780	48,626	42,568	13.7
1986	45,297	49,783	45,085	10.0
1987	48,908	53,969	48,696	10.4
1988	51,815	55,724	51,603	7.6
1989	54,750	58,720	54,538	7.3
1990	57,804	61,697	57,592	6.8

(1) Based on March, 1977, response to FPC Order 383-4. Individual unit information for VACAR member companies other than CP&L was not available beyond 1986. Only CP&L units are indicated as cancelled beyond this date.

4.3 ALTERNATE MEANS OF POWER GENERATION

Carolina Power & Light Company has reviewed future available power resources to determine the quantity of additional generation required to meet projected load demands. These reviews have shown that additional base load type generation is required in the years 1984-1990, and that four units of approximately 900 MW must be added to the system generating capability during this period.

Among the various generating alternatives evaluated by CP&L for meeting the forecasted demand load requirements were hydroelectric, internal combustion, fossil/steam, and nuclear/steam. Also considered, were various new technologies such as compressed air storage and lead-acid batteries. The new technologies do not offer firm prospects of providing base load generation in the amounts and at the cost which would make them competitive with the more proven types of generation normally used for this purpose. As the state of the art in new technology continues to show advancement, further attention will be given to any proven technology which can meet CP&L generation needs.

Appraisal of the four types of generation already in use on the CP&L system makes it apparent that some of them are less suitable than others for meeting the generation needs of the period being considered.

The first means, hydroelectric, was ruled out as there are no sites having sufficient flow for plants of the size required. The second generation scheme, internal combustion turbine, was ruled out due to the practical size limit of this means of generation, the high cost per KWH of energy generation, and the unsuitability of the units for base load operation.

At the time of the evaluation, the types of fuel available to the CP&L system for steam electric units were: coal, oil, and nuclear. Production costs and capital investment cost studies were performed to aid in

the determination of the type of steam electric plant to be constructed at the site. The results of studies, which projected the operation of the CP&L system for a number of years into the future, indicated an economical advantage in favor of building nuclear units as compared to fossil-fired units. Several important factors are expected to affect the future cost relationship between nuclear and fossil-fired generation units. The elimination of nuclear fuel reprocessing and the requirement to provide scrubbers for all new fossil-fired units will add cost to each respective type of generation. The exact effects are unknown but the nuclear advantage is still indicated.

From an environmental standpoint, the nuclear plant was favored owing to its cleaner operation and more aesthetic appearance. Other factors which strongly influenced these studies were the high cost of fossil fuels, costs associated with control of air pollution, and the uncertainty of availability of low sulfur oil or coal to meet increasing environmental requirements. For these environmental and economical reasons, CP&L elected to construct a nuclear plant to serve its customer requirements.

4.4 ALTERNATE SITES

The process of selecting a site for a steam electric plant begins with development of load projections. Determination of system requirements involves consideration of economic growth, population increase, and industrial development in the service area. The load projections show the amount of additional power required during the next decade; and establish the amount and general location of the additional generation that will be required in each year of the forecast period.

Selection of a site is based on the size and location of the generating facility required to meet load projections. Site selection is a complex process involving analysis and optimization of many environmental and economic factors. The environmental factors include evaluation of the impact of the proposed generating plant on the site area, land use, wildlife habitat, and the aquatic ecology. Involved in the consideration of existing land use are the present and projected area population density, agricultural activities, educational, social, and medical institutions, parks and recreational areas, churches, cemeteries, forests, wetlands, historical monuments and areas of historical interest, and other lands dedicated to public use. Consideration of the wildlife habitat includes identification of endangered species, feeding areas, and determination of any areas essential to the survival of a species in the general area. Evaluation of the aquatic ecology involves identification of fish species, spawning areas, impact on other organisms, and thermal effects of the condenser cooling system. In addition, requirements of governmental agencies involved in environmental protection are evaluated in consideration of potential sites.

Economic considerations include evaluation of the site geology, soils, and site development costs. The quantity and quality of water available for condenser cooling are determined. The adequacy of transportation facilities is evaluated, and interaction with airports and other industries is considered. The types and costs of fuels available to the site are determined, and transmission requirements are evaluated.

Before a site is finally selected, the above factors are evaluated; in addition, meteorology, seismology, and hydrology are considered before the determination is completed.

All potential sites are identified in the general area where additional generating facilities are needed. Six sites were considered potentially adequate for development of the Harris Plant; the site on Buckhorn Creek was selected since it best complies with environmental and economic requirements.

The Buckhorn Creek site, while located within 20 miles of Raleigh, is in a rural environment. Population around the plant is concentrated in relatively few dispersed centers; development of the 14,000 acre site will cause the relocation of approximately 25 families. Large concentrations of industrial activity do not exist.

Major highways and railroads in the area will either be unaffected or relocated to provide continuity of normal service. It is proposed to dead end some roads where they enter the site property boundaries; however, no private property owners will be denied access to their property. The relatively minor changes in transportation facilities and relocation of families from the proposed reservoir will not affect the population trend characteristics of the area nor significantly affect present land usage surrounding the proposed plant area.

There are no national historical landmarks within a five-mile radius of the plant site or within the project boundary. Except for the ruins of an abandoned ironworks utilized by the Confederacy during the

Civil War (approximately 1-1/2 miles from the project boundary on the bank of the Cape Fear River), the area does not have any historical or known archaeological importance. There are no parks, national forests, or other organized recreational facilities within the project boundary. The present Whiteoak and Buckhorn Creeks system, which is the area of the proposed site, appears to offer limited hunting or fishing possibilities. Studies conducted in the area indicate that nutrient input to the lake will be moderate and that water in the reservoir will be of high quality. Withdrawals from the Cape Fear River for makeup in the main reservoir will be made only when flow in the Cape Fear is high enough such that withdrawals will not reduce the flow to less than 600 cfs measured at the U.S.G.S. gage at Lillington, and these withdrawals will never be greater than 25% of the river flow.

The Research Triangle Regional Planning Commission was consulted regarding conformance of the plant site with permissible land use in the area; this agency has indicated that there will be no incompatible land use or zoning infringements resulting from construction of the plant. As the site is in a rural environment, development of the plant and impoundment of the reservoir on Buckhorn Creek will have no significant effect on industrial activity in the area.

The geological and seismological features of the plant site area, as determined from extensive investigations, are compatible with the proposed plant in regard to safety and reliability. There are no active faults in the area; the nearest inactive fault is about four miles to the southeast of the plant area. This fault has been inactive for over 125 million years.

Meteorological conditions at the plant site are similar to those observed in the Raleigh-Durham area. Extreme meteorological events, such as tornadoes, hurricanes, and floods rarely occur in the area.

However, the effects of these unlikely events on the plant have been considered and the design of the facilities will include safeguards against such events affecting the safety and reliability of the plant.

The selected plant site is not in a unique ecological environment. While the region was originally covered by an oak-hickory forest, this was almost completely cleared in the early days of settlement and no virgin tracts now exist in the plant site. The area is a mixture of farmland, fallow fields, and woodlands in various stages of succession. Most of the area is wooded, with second growth pine in the uplands and hardwoods in the valleys. Approximately 80 percent of the woodlands are utilized for the production of timber.

The small creeks in the area are narrow and shallow, with very little or no flow during the drier periods of the year. The streams drain a small, well-defined basin, with no evidence of serious pollution. A survey conducted by U. S. Fish and Wildlife personnel in 1969 found moderate to low quantities of fish in the small, shallow creeks.

In addition to the Buckhorn-Whiteoak Creek site, which was selected for the Harris Plant, five other possible locations were considered for the proposed nuclear units. Four of these sites are in the Northern Division of the CP&L system and would have required the development of a new site. The fifth site considered for the proposed units was the Brunswick Plant, a facility now under construction near the eastern edge of the CP&L system. The Buckhorn-Whiteoak Creek site and each of the other four sites in the Northern Division involved off-stream cooling lakes and would have had similar land requirements and effects on the terrestrial and aquatic environments. In addition, each of these lakes would have possessed similar evaporative water losses. The Brunswick Plant will employ a river intake and ocean discharge and will have substantially different environmental effects.

At the time that the alternate site evaluation was conducted, the final evaluation at the five sites using off-stream lakes was performed for cooling lakes. In light of the recent regulatory decision denying the necessary variance for the cooling lake, the sites were again considered. The relative impacts on the sites are similar to the previous cooling system. Furthermore, a large part of pre-construction impact has occurred. Those relocations necessitated have already occurred. Most of the land has been purchased, and property owners have sold the timber off of their land. An additional factor now favoring the present site is the amount of engineering design completed. Changing sites at this time would cause a severe delay in the project since extensive geological, seismological, and other re-design work would be necessitated.

Alternate Site No. 1 is situated in southern Wake County and western Johnston County. Had this site been chosen, it would have inundated around 40 homes of which 15 to 16 constituted an entire subdivision. Approximately 28 percent of this site is used for agricultural production; most of this is involved in tobacco farms. All of this farmland would have been inundated had this site been selected. Makeup water for the plant would have been pumped through nine miles of pipeline. This site would have caused a larger impact on the land use and on the people than the Buckhorn-Whiteoak site and the laying of nine miles of pipeline would have added to this impact. These factors deterred the selection of this site for the Harris Plant.

Alternate Site No. 2 is located in eastern Wake County and northern Johnston County. It would have been necessary that two creeks be ponded in order to provide the desired effective cooling lake area, as one creek would not be sufficient to support the generation needed. Even with the ponding of the two creeks, the water supply was not as adequate as at the Buckhorn-Whiteoak site. The selection of this site would have necessitated that two lakes currently used extensively for recreational purposes be inundated and that the makeup water from the site include effluent from a municipal sewage treatment plant which might have caused water quality difficulties. In addition, there is a considerable amount of farming that is done in the site area. This is mostly in the form of tobacco farming. The selection of this site would have inundated about 3595 acres of farms which amounted to 30 percent of the total site area.

Alternate Site No. 3 is in southern Granville County. While the selection of this site for the Harris Plant would have had an impact on land use and on people comparable to Buckhorn-Whiteoak, there were other unfavorable factors. The watershed for this site was the lowest of all the sites considered. In assessing this site, it was also determined that it did not possess the transmission possibilities that the Buckhorn-Whiteoak site possesses, and selection of this site would have limited power transmission to one direction while the Buckhorn-Whiteoak site has transmission possibilities in all four directions. Selection of this site would have eliminated about 2685 acres of farmland, which amounted to 23% of the total site area.

Alternate Site No. 4 is located in Harnett County. This site met most of the siting requirements including environmental and economic considerations. However, the number of people affected by developing a steam electric power plant at this site would have been considerably greater than the number of people affected by developing the Buckhorn-Whiteoak Creek site. About 30 percent of the land at this site is involved in farming and would have been inundated. In comparison, the farmland inundated at Buckhorn-Whiteoak consists of only 8 percent of the total site area.

Alternate Site No. 5 is the Brunswick Plant site which is in the Eastern Division of the Carolina Power & Light system. The CP&L system load demand for the year 1975 and after is concentrated in the Northern Division. As a result, the placing of additional generating facilities at Brunswick would have involved heavy transmission to projected load centers. Three new 500 kV lines would have to be built totaling well over 400 miles of new lines. In comparison, Buckhorn-Whiteoak will require only about 100 miles of 500 kV lines.

In comparing the various sites' agricultural potential, Alternate Sites No. 1, 2 and 4 involved land that was of a much higher quality than that at the Buckhorn-Whiteoak site or at Alternate Site No. 3. However, all of the possible sites had land which was being cultivated; much of which was in tobacco production at Alternate Sites No. 1, 2 and 4. Both Site No. 3 and the Buckhorn-Whiteoak Creek site were located in areas where the land was not as suitable for agrarian purposes. Buckhorn-Whiteoak's and Alternate Site No. 3's agricultural potential are quite similar in nature; however, attempts were made to farm the land of Alternate Site No. 3 while this was not true with Buckhorn-Whiteoak. Most of the land of Buckhorn-Whiteoak was devoted to pulpwood products (80-92 percent).

All of the sites investigated except Alternate Site No. 3 and the Buckhorn-Whiteoak Creek site involve the inundation of several farms and the relocation of many homes. Alternate Sites No. 1, 2 and 4 required more farms be inundated and more homes relocated than Buckhorn-Whiteoak or Alternate Site No. 3, and those that would have been relocated were of a higher quality than those at Buckhorn-Whiteoak site or Alternate Site No. 3. The location of Alternate Sites 1, 2 and 4 were such that more road-raising would have been required there than either the Buckhorn-Whiteoak site or Alternate Site No. 3.

It was felt that, at the present time, the impact of a nuclear plant at Alternate Sites No. 1, 2 and 4 with regard to land use and effect on the people of the area would be greater than at either Alternate Site No. 3 or Buckhorn-Whiteoak. Since other land existed where the impact of the plant on land use and on the people would not be as great, the Buckhorn-Whiteoak site was preferred.

Although the Buckhorn-Whiteoak site and Alternate Site No. 3 would have similar effects on land use and people, Alternate Site No. 3 does not possess the advantages that Buckhorn-Whiteoak provides such as nearness to load center, adequacy of cooling water supply and nearness to existing transmission facilities.

While some of the sites offered similar advantages such as nearness to load and adequacy of cooling water supply, problems relating to land availability and conflicting or non-compatible nearby land use caused some of these alternate sites to be ruled out at this time.

Some of the advantages of the Buckhorn-Whiteoak site are listed below:

1. Availability of land to meet schedule
2. Suitable foundation conditions
3. Low seismic activity
4. Low population density
5. Minimum impact on the environment
6. Nearness to transportation facilities
7. Minimum impact on existing land uses
8. Located near system load
9. Located near existing transmission facilities

4.5 COOLING WATER ALTERNATIVES

Any method that provides air-water contact for cooling, including "wet" towers and cooling reservoirs, removes up to 75 percent of the rejected heat through evaporation. As water is vaporized, heat is transferred to the atmosphere at the rate of about 1000 BTU per pound of water vaporized. Almost all of this heat is taken from the water that remains, thereby lowering its temperature.

There are three cooling water alternatives that could be utilized at the Buckhorn-Whiteoak Creek site. These alternatives are a cooling reservoir, evaporative natural draft cooling towers and mechanical draft cooling towers. Multi-discipline analysis of the alternatives available resulted in the selection of a cooling.reservoir for dissipating waste heat from the Harris Plant. However, a regulatory decision by the State of North Carolina Board of Water & Air Resources has now made this type of system unavailable for the Harris Plant. Therefore, it was necessary to reevaluate the cooling systems available to the plant. A necessary factor in this reevaluation was the engineering and environmental analyses performed to date.

Cooling Reservoir

A cooling reservoir is the simplest method of dissipating thermal discharges. In a recirculation system such as originally proposed for the site, warm water is discharged into one end of the reservoir, cooled through heat dissipation to the atmosphere and withdrawn as cooler water from the opposite end of the reservoir. This natural cooling process is relatively slower, and results in less induced air movements than cooling towers.

The advantages of an off-stream cooling reservoir for the Harris site are:

1. Increased quality of the aquatic habitat

2. Provides scenic and waterfowl management benefits
3. Smaller consumptive water use than "wet" cooling towers
4. Provides a measure of flood protection to the Cape Fear River
5. Less concentration of blowdown salts
6. Lower total equivalent investment costs

The disadvantages of a cooling reservoir for this site are:

1. Lower heat transfer rate than "wet" cooling towers necessitating large reservoir surface area
2. Use of larger acreages of land than would be required for cooling towers

Cooling Towers

There are many versions of cooling towers. Terminology applied to towers stems from basic differences in design or operation. The towers which could be used for supplying cooling water for the Harris units are "wet" towers, where the water is exposed directly to the air. There are two types of "wet" towers: mechanical draft towers that employ fans for forced air movement and natural draft towers where the air is moved as a result of the buoyancy effect of heated air.

Dry cooling towers were eliminated from consideration at the Harris site. They are substantially more expensive to construct and operate. As noted in "Considerations Affecting Steam Power Plant Site Selection" issued by the Energy Policy Staff of the Office of Science and Technology (December, 1968), "No dry towers have yet been installed at major thermal electric power plants in the United States. The largest hyperbolic dry tower in operation today is at a 120 MW plant in England. This tower was constructed in 1962 by the Central Electricity Generating Board, primarily to obtain comparative investment and performance data. It is reported that the performance of the tower has been satisfactory. It should be remembered that summer air temperatures tend to be lower in

England than in most areas of the United States." Furthermore, as noted in the Federal Power Commission Staff Study Supporting the Commission's 1970 National Power Survey entitled "Problems in Disposal of Waste Heat From Steam Electric Plants (1969)," "the cooling temperatures achievable in dry-type towers are limited by the dry bulb rather than the wet bulb air temperature with the result that higher turbine exhaust temperatures must be accepted. In the warmer parts of the country this would place a severe penalty upon the efficiency and capability of the power plant."

Since the necessary variance for the cooling lake was denied for the Harris Plant, natural and mechanical "wet" cooling towers were studied in detail. A spray pond would have required a smiliar variance, and therefore, is also not available as an alternative. The evaluation showed natural draft cooling towers to be the most feasible alternative of those left to the Company. The plant will therefore employ four natural draft cooling towers. Each tower will be about 480 feet tall and 430 feet in diameter at the basin.

Mechanical draft towers, although costing less than natural draft towers would have more adverse environmental effects due to their higher drift losses creating low level fogging and icing, higher consumptive water use, requiring more makeup and thus affecting lake drawdown more than natural draft towers. Additionally, rectangular mechanical draft towers could not be utilized at the present site due to the unavailability of necessary land required for the large number of towers that would be necessary.

A further discussion of alternate cooling systems is contained in Subsection 8.4 of this report.

5.0 ENVIRONMENTAL EFFECTS WHICH CANNOT BE AVOIDED

Although the Shearon Harris Nuclear Power Plant will be constructed and operated to comply with all Federal and State of North Carolina regulations designed to protect the environment, some environmental effects will occur. These effects on the environment will be kept to the minimum amount practicable consistent with state-of-the-art-technology and reasonable cost as part of CP&L's continuing efforts to conform to the spirit, as well as the letter, of the environmental protection laws.

Any effort on the part of man to provide a service or product necessary to maintaining or improving human life standards involves some possibility of impact on the environment. CP&L has attempted to balance the benefits of providing electric power against the risks to the environment in such a way that the risks are minimized using technically and economically feasible systems. In order to implement this policy, CP&L evaluated the different methods available for producing electricity and selected a nuclear plant because of its low impact on the environment.

Some broad categories of identifiable environmental effects are the diversion of land use and influences on the water resources of the area. When completed, the Harris site will encompass approximately 14,000 acres, which will include the 4,000 acre reservoir. In order to create the reservoir, it is necessary to impound Buckhorn Creek.

In keeping with its policy of responsible environmental practices, CP&L has kept planned land use to the minimum amount practicable. By long-range planning for the future, land uses can be reduced and minimized. The Harris site is a part of CP&L's continuing effort to minimize effects on the environment. The reservoir will serve both as a source of makeup water for the cooling towers and will have recreational potential for residents of the area. Thus, while this land will be diverted from terrestrial use, a portion of it will still be available to the public and will be in a use that provides some public enjoyment of the area.

In order to create the makeup pond, a dam will be built on Buckhorn Creek, diverting the water to form the pond. The effect of this action on the water resources of the area has been discussed previously in this report. The towers will release warm cooling tower blowdown to the pond, but the small volume of blowdown will minimize the total heating effect on the pond. When it is necessary to release water from the makeup pond to the river, the water will meet all State of North Carolina water quality regulations (which have been approved by the Environmental Protection Agency).

As a result of the operation of any nuclear power plant, there are certain radioactive products produced. To minimize any effects these materials might have on the environment, the plant will be equipped with waste control systems. These systems will collect radioactive and potentially radioactive fluids and these fluids will be sampled, analyzed, and processed as required and then released only under tightly controlled conditions in accordance with all appropriate current regulations of 10 CFR 20 and Appendix I,10 CFR 50, dated June 9, 1971, so that effluents will be held as low as practicable.

Solid wastes, which will consist of waste liquid concentrates, spent resins, and miscellaneous materials such as paper and glassware, will be packaged and shipped offsite for disposal at approved sites in accordance with AEC and U. S. Department of Transportation regulations.

The spent fuel from each fuel cycle will be stored for a time necessary to reduce its radioactivity, and then it will be shipped offsite for reprocessing and disposal in specially designed casks meeting all the necessary AEC and U. S. Department of Transportation regulations. By strictly adhering to these regulations, the environmental impact of any waste material will be minimized.

There will be some small unavoidable biological effects in the site area as the result of the construction and operation of the Harris Plant. Clearing of the site area will destroy some cover used by wildlife, but creation of a wildlife protection area in the land surrounding the reservoir is expected to create additional habitats in the future. Some aquatic mortalities will result from the passage of plankton through the plant condensers; the impact, however, is expected to be negligible due to the small amount of water which will be withdrawn from the pond and used for makeup.

In order to assure that environmental effects are minimized, monitoring programs have been established and will be implemented to detect any environmental change which might be attributed to the operation of the units, thereby assuring safe and healthful surroundings for the area.

Some temporary construction effects are unavoidable during construction of the plant. Temporary construction roads will be constructed in the area. Efforts will be made to minimize dust resulting from use of these roads. While under construction, the aesthetic appearance of the site will unavoidably be disturbed; however, after completion of construction, this effect will be eliminated and the overall design will be architecturally pleasant. There will be some erosion and stream disruption due to clearing operations.

The transmission of electric power results in an effect on the environment which is unavoidable considering present day technology. CP&L will take measures to help minimize the effect of the transmission lines from the Harris Plant. These measures were discussed in subsection 3.11 and 8.7.

The lines will cause no change in population patterns. The only lands committed to the lines will be the areas they will traverse, and this land can be used for pasture or agricultural uses, access roads, recreation areas, or other uses. In addition, the right-of-way will provide a fire break in the event of a forest fire.

By practicing environmental responsibility such as those measures described above and elsewhere in this report, it is the desire of CP&L to attain the widest range of benefits for its consumers through harmonious use of the environment without degradation, risk to health or safety, or other undesirable consequences. If detrimental environmental effects resulting from the operation of the plant are detected by the environmental monitoring program or other surveillance methods, CP&L will take appropriate action to reduce the environmental impact.

6.0 SHORT-TERM USES VERSUS LONG-TERM PRODUCTIVITY

In evaluating the potential environmental impact that a project such as the Harris Plant might have on the environment, it is necessary to assess the benefit of producing electricity from the environment versus any long-term effects on productivity of the environment. The ability of man to harness the energy resources of the earth has been an essential component of man's ability to survive and develop socially. Electrical energy is a key factor in providing food products, wastewater treatment, the manufacture of goods, numerous physical comforts and necessities, and it is vital to the health and welfare of the nation. With the development of our modern society, electricity has advanced from a novel luxury to an essential requirement for the innumerable necessary services and products demanded by our present civilization. Electricity has become essential to the health, welfare, safety and economy of the residents of the area served and the organization entrusted to provide the residents with electrical energy must assure an adequate supply of electricity.

Electric power requirements in this country have been doubling every ten years. CP&L customer requirements for power have more than doubled in the past seven years, and further expansion is expected to continue in much the same pattern. In order to provide the residents of CP&L's service area with the electricity necessary to meet this growth, it will be necessary to build a 900 MWe unit in each of the years 1981, 1982, 1983 and 1984 as scheduled for the Harris Plant. CP&L is aware of its responsibility to provide electricity to its customers in a manner consistent with responsible environmental practices. As described in various parts of this report, detailed consideration has been given to the environmental aspects associated with the plant in making decisions concerning design, construction and operation of the plant.

The short-term use of natural resources to produce electricity for our immediate needs must be evaluated with respect to the enhancement of long-term productivity and any adverse environmental effects which might be realized by future generations. When evaluated in this context, the nuclear units of the Shearon Harris Plant will be compatible with the environment. The resources which must be diverted from the earth's environment to construct and operate the nuclear power plant are small. This utilization of natural resources is an important consideration when attempting to evaluate the quality of environment we are creating or leaving for future generations. In evaluating the short-term use of the environment, it is also important to consider the fact that the electricity being produced will be used to facilitate social progress and technological developments that will aid in protecting our environment.

At this stage in our technology, even with nuclear power and its very low radioactive release concepts, there will be some slight, but inevitable, short-term impacts on the environment. These impacts are associated with the basic principle of steam electric plants, the need to provide cooling water and the resultant heating of the air and water. They include such items as chemical, sanitary and radioactive discharges, temporary construction effects, land use, and cooling tower blowdown. These effects are of a short-term nature, and design of the plant will incorporate methods to minimize their impact. The blowdown discharged to the reservoir will have higher concentrations of chemicals than the reservoir, and be slightly warmer, but will meet applicable water quality standards. When water is discharged to the Cape Fear River, it will meet the State of North Carolina water quality standards (which have been approved by the Environmental Protection Agency). Radioactivity release is tightly controlled by federal regulations and any releases will meet these standards. The construction effects include such measures as road construction and dewatering, and these effects will exist during the construction phase only. The heating of the cooling system water is expected to be the major effect resulting from this short-term use of the environment; however, efforts have been made in to minimize this heating, as explained previously in this report. Any environmental impact associated with the short-term use of resources is expected to be limited by the state of the technology and reasonable cost and then must be evaluated relative to the benefits derived from use of the electricity produced.

The short-term effects resulting from construction and operation of the plant will result in no cumulative adverse effects, and there is no reason why after the plant is decommissioned, the environment in due time could not be returned to its original state of existence prior to the nuclear unit, with no remaining adverse effects on the area's long-term productivity.

In keeping with responsible environmental practices, the land to be used for the plant site was held to the minimum amount practicable. The land selected for the site area consists primarily of old-field vegetation and second-growth pine, which is used mainly as a source for low to medium grade pulpwood. Less than 8 percent of the land was devoted to agricultural activity or pasture land. The land at the site area possesses little or no recreational value and is not amenable to agricultural activities. Construction of the reservoir will create an impoundment which, at the end of the plant's life, could be left intact for recreational purposes, or, if desired, the dam could be removed and the area could be returned to its original environmental condition, with no remaining adverse effects on its long-term productivity.

The construction and operation of the Shearon Harris Nuclear Power Plant will not curtail the range of beneficial short-term uses of the environment. The units will result in increased productivity which will actually enhance long-term productivity in future generations. If future generations elect to convert the reservoir back to terrestrial uses, this can be done over a period of time and the area restored to essentially its natural state.

7.0 IRREVERSIBLE AND IRRETRIEVABLE COMMITMENTS OF NATURAL RESOURCES

The construction and operation of the Shearon Harris Nuclear Power Plant will necessarily involve the commitment and use of a certain amount of natural resources. Only man has the unique ability to alter the environment on a large scale. With this ability, however, comes the responsibility of using the environment in a manner consistent with protecting and preserving the environment to the fullest extent practicable while advancing the standard of living of mankind. With respect to this responsibility, CP&L is fulfilling its obligation to supply electricity to its customers by the methods which minimize the environmental impact. Considering the many benefits to society of electric power, and the small diversion or use of natural resources by the plant, the resulting benefit-cost ratio is very favorable. In terms of the necessary benefits provided by electric power, there is no other available alternative which has so little impact on the environment. In terms of resources which are consumed, converted, or diverted for temporary use, the following commitments have been considered:

1) Land
2) Water (this is only a partial commitment, or diversion, since it is not consumed but only used briefly and returned in essentially its original condition)
3) Materials of Construction
4) Fuel (Uranium)
5) Human Resources

During the life of the plant, the immediate land area occupied by the plant and its structures cannot be used for other purposes, although the makeup pond will create a limited recreational potential which will be available to the public. At the end of the useful life of the plant, there is no intrinsic reason why the land and water use could not be returned to the full range of uses prior to plant construction, since the land, air, and water quality will not be altered by the plant's operation. Upon decommissioning the units, it may be necessary to restrict the use of a small portion of the plant site. Prior to the construction of the plant, the site area has been used primarily as a source of low grade wood products such as pulp wood. Thus, while a number of acres of land will be submerged for creation of the reservoir, no significant productivity will be curtailed.

The materials used in the construction of the plant could, for the most part, be recycled or reused if necessary. However, these materials should probably be considered an irreversible commitment although if it became necessary for future use, some of the materials could be reclaimed.

The fuel consumed by the operation of the unit will be an irretrievable use of a resource. However, to simply state it is irretrievable does not give a full picture. The use of nuclear fuel (uranium) affords an opportunity to conserve our fossil reserves for future generations and also to utilize them for more preferred usage. This is made possible because using uranium as an energy source does not establish a competitive situation, since uranium is not used or required in significant amounts as a resource in other industries or operations necessary for maintaining our modern society. This is in contrast to the depletion of fossil-type resources which are required in many other essential industries and operations. Thus, while the nuclear fuel cannot be recovered in its original form, its depletion will not deprive other activities of essential resources, as does the depletion of fossil resources. In addition, as uranium is consumed, other valuable materials are produced, including additional fuel (plutonium) which will be used in the breeder reactors expected to be in operation in the not too distant future.

As far as uranium is concerned, there were 204,000 tons of U_3O_8 reserves available (at $8.00 per pound) on January 1, 1970, and 243,000 tons as of December 31, 1970.[1] For the reserves of the free world producible at $10.00 per pound, there was an estimated total of 700,000 short tons at the end of 1969, of which an estimated 250,000 tons are estimated to be in the U. S.[2] The cumulative requirements for U_3O_8 in reactors in the United States are expected to reach 212,000 short tons by 1980 and 450,000 short tons by 1985.[2] By the mid 1980's commercial breeder reactors are expected to come onto the scene.

In summary, there appears to be a more than abundant supply of nuclear fuel available for the units during their useful life, without depleting resources necessary for other facets of our society.

In the consideration of human resources as an irreversible resource, the benefit from the human effort expended to design and construct the plant must be evaluated relative to the benefits to society derived from the electricity produced. Considered in terms of the necessity of availability of electricity for normal living conditions, and the instrumental part electricity plays in aiding social and technical progress, the effort to design and build the plant is a good investment in the future of the area being served by the plant.

By seeking to design for a compatible balance between the population and the resources committed to provide customers with the energy supplies necessary to achieve and/or maintain high standards of living, CP&L intends to achieve the production of electricity for its customers in a manner which does not adversely affect the environment in terms of irreversible and/or irretrievable commitment of resources.

REFERENCES FOR SUBSECTION 7.0

1. Annual Report to Congress of the USAEC for 1971.

2. Major Activities in the Atomic Energy Programs. Jan-Dec 1969. USAEC, Jan, 1970.

8.0 BENEFIT-COST ANALYSIS

Carolina Power & Light Company has been an important participant in the social and economic development of the area which it has served for more than 63 years. In more recent years, the Company's increasing commitment to environmental concerns has been reflected in numerous decisions, many of which have been reflected in the Shearon Harris Nuclear Power Plant. In recognizing its obligations to society to supply not only the electrical power required for public health, safety, and comfort, but also a consideration of enhancing the overall quality of life of its customers through responsible environmental management, CP&L has examined ways and means whereby its major decisions on generation capacity will provide additional benefits other than economic.

In the decision making process required for selection and design of a facility such as a nuclear power unit, numerous parameters must be evaluated and compared with feasible alternatives in order to arrive at a completed system design. The term generally applied to this type of evaluation is a Benefit-Cost Analysis. In the past, this type of analyses have been performed and the final design submitted for licensing request. However, these analyses were generally not included as a separate documentation in the license and permit applications for nuclear units. Revised Appendix D of 10 CFR 50 now requires that these analyses be included as a part of all Environmental Reports. In response to this, Carolina Power & Light Company has prepared this Benefit-Cost Analysis, which incorporates the major system decisions which were made in arriving at the plant design, and it is intended to convey to the public the effect of various parameters which have an impact on the service area of CP&L. The Benefit-Cost Analysis includes the benefits and costs of the Shearon Harris Nuclear Power Plant and the alternatives that were looked at in weighing various environmental costs compared to the benefits accrued from the units.

8.1 GENERAL INTRODUCTION

The approach taken to benefit-cost analyzing in the past has generally been done by economists as a tool for governmental decision making where proposed projects could be compared on the basis of the dollar benefit per dollar cost. Various philosophies and approaches have been applied to benefit-cost problems encountered to date and no real uniformity exists in the techniques applied by various individuals in specific cases. With the increasing commitment of CP&L and other utilities to preservation and enhancement of environmental values, has come the need for a formalized benefit-cost technique. In the past, a formalized technique has not been applied extensively to the decisions relative to power plants and their environmental impact, although most of the more important factors were weighed in the decision making process and where Federal and/or State permits were required the Company obtained these approvals.

In view of the above mentioned need for a formalized benefit-cost accounting technique, CP&L has prepared this Benefit-Cost Analysis which addresses those major considerations which were analyzed. In preparing the Benefit-Cost Analysis, an effort was made to present the results of the analyses which were deemed to be of the greatest general interest. Thus, the emphasis of the analyses here is upon the benefits and effects of the proposed units on various environmental values. While cost-effectiveness studies of minor subsystems have, of course, been performed, their relationship to environmental effects are not direct relationships and are therefore not included here.

Because of the diverse applications and approaches of Benefit-Cost Analyses in the past, there is understandably no uniform technique which has evolved. In view of this lack of consensus, some general comments are appropriate to further develop an understanding of the philosophy of the benefit-cost analysis for this report.

The basic approach to most benefit-cost analyses is to evaluate the benefits and costs of the project in quantitative monetary terms wherever possible so that a ratio of dollar benefit to dollar cost can be made. Alternatives can then be compared and selected on the basis of maximum benefit to cost ratio. While this type of approach is amenable to certain decision making fields, it is not capable of being responsive to social and environmental concerns which in the past several years have been of increasing concern to the Company and the residents of its service area.

In order to include an evaluation of important and relevant factors which are not amenable to quantification in monetary terms, this report approaches the benefit-cost analyses using an integrated format whereby benefits and costs are quantified wherever possible using a multidimensional format. When a specified benefit or cost can be feasibly measured in dollars, such as electrical output or capital and operating costs, then these specified benefits or costs are given dollar dimensions. Many of the parameters of interest, however, are of a subjective nature and attempts to quantify these factors in monetary terms would reflect misleading values. Thus in the case of some environmental effects and social concerns the analyses have been based on developing ranges of values for the parameters in the dimensions that best describe the particular effect. This type of multidimensional approach affords a realistic comparison of benefits and costs in that it does not force subjective comparison of parameters incapable of correlation in the present state of the art, but rather allows these factors to be considered in their most meaningful dimension.

Some perspective is now possible on the problems of benefit-cost analyses. The actual environmental cost of a project will be its net environmental impact, since an environmental impact may be beneficial as well as adverse. Yet as explained previously, certain beneficial and adverse impacts are simply not amenable to quantification. Thus, as a simplified example, determining the net environmental cost of a benefit such as reduced thermal loading and a concomitant adverse impact such as destruction of wildlife habitat would require an intermediate conversion requiring subjective correlation of the two impacts. It is the opinion of the Company that such subjective evaluation for the sole purpose of arriving at a numerical correlation would quite possibly result in misleading values and would defeat the true intent of NEPA. For this reason, the multidimensional approach has been retained and in selecting various systems of the plant, the environmental impact of the systems has been compared with the impact of alternative systems. So that the net impact of the plant can be readily viewed, subsection 8.8 defines the benefits and costs which the selected design will achieve.

8.2 ALTERNATIVES TO THE PLANT

Because of its legal, social, and moral responsibility to provide the electrical power demanded by its customers, Carolina Power & Light Company must continually forecast the energy needs of its customers. The effects of CP&L customer energy conservation measures in the 1974 through 1976 period have been taken into account in the CP&L Energy Forecast and thus, the CP&L Load Forecast. These forecasts indicated the need for large amounts of power in the 1984-1990 period to serve CP&L customer loads. However, there are some ongoing and theoretical approaches to load management that are not reflected in the CP&L Load Forecast because their effects are not quantifiable with confidence at this time.

A decision thus had to be made to which of several alternatives would be adopted to provide this additional power. The alternatives which were considered were:

a. To import or purchase the power from producers in or near the area where the need will exist.
b. To expand presently available operating units of the Company.
c. To construct new generating units.

The first alternative is a method often employed by utilities on a temporary basis to fill power demands. However, the availability of long-term purchases of 3600 megawatts is not expected, since no neighboring utilities of CP&L are building or planning to build generation capacity of sufficient amounts to allow selling of this much power to CP&L on a firm basis. To fully understand this, it is necessary to be aware of the electricity supply-demand situation in the Virginia-Carolinas area.

Carolina Power & Light Company serves customers in North and South Carolina and shares the territorial load network with Virginia Electric and Power Company (VEPCO), South Carolina Electric & Gas Company

and Duke Power Company. When future energy requirements are projected, it is also necessary to plan for sufficient reserve power supplies. Sound planning practices involve planning on a regional basis as well as a local one. As a result, the future capability of CP&L is closely planned with the other utilities in the Virginia-Carolina (VACAR) Reliability Subregion of the Southeastern Electric Reliability Council (SERC) to augment Member System's reliability through coordination of planned transmission and generation facilities. The reserve capabilities of the subregion will depend upon CP&L being able to supply its own energy requirements for its customers. Subsections 4.1 and 4.2 indicate in detail the various reserves of CP&L and of VACAR subregion during the period 1984-1990. As shown in these subsections, the supply of power from other utilities during these years would be insufficient for allowing CP&L to purchase the power necessary to meet customer demands. As a consequence of this situation, the possibility for purchase of power by CP&L on a long-term basis was not a practical alternative to meet customer needs.

The second alternative, expansion of presently operating units was evaluated and found to be impractical because of technical, economic, and certain social consequences. Most plants are designed as generating units with all the interrelated equipment such as steam generators and turbines of a compatible size. It would not be technically feasible to increase the capacity of these units by an additional piece of equipment unless the entire unit being removed from service for the long period of time required to rebuild it, with the concomitant high economic cost and loss of system reliability and reserve capabilities.

The third alternative, construction of new units, was found to b the only practical one. It has the highest benefit-cost ratio since it will be all new units and will incorporate the most up-to-date methods for minimizing environmental impacts in all areas, and will allow the Company to maintain the reliability of its service system.

Once the decision was made to build new generation capacity, the decision had to be made as to what method of generation should be used. Four types of generation were considered:

1. Hydroelectric Generation
2. Gas Turbine Generation
3. Fossil Generation
4. Nuclear Generation

A careful examination of the water resources of the area disclosed that no suitable hydroelectric resources existed for the amount of generation required, and so hydroelectric generation was abandoned from further consideration. Gas turbines are useful in providing peak load service, but are not required, gas turbines were ruled out as a feasible alternative. Both the fossil steam and the nuclear steam generating alternatives were given careful scrutiny and an economic comparison was necessary.

The analysis showed that nuclear units would involve higher evaluated costs initially because of the higher capital costs and initial fuel investment. However, the operation of the nuclear units over their expected life would reduce the evaluated cost to less than that of fossil units. In addition, the uncertain future availability of low sulfur fossil fuels necessary for minimizing effluents from future fossil units was part of the decision process favoring nuclear generation.

8.2.1 Load Management

The objective of CP&L's load management activities is to provide for the electrical needs of our customers at the lowest feasible cost. As this objective implies, the implementation cost of any load management activity must be compared with the cost of other load management activities that will accomplish similar results and compared with the cost, and other concerns, of providing the necessary electricity by the addition of electrical capacity.

Carolina Power & Light Company is engaged in a number of load management activities. CP&L believes the practical results of these activities must be reasonably demonstrated as favorable to CP&L customer interest before widespread implementation. CP&L is conducting experiments to determine the value of such approaches. These approaches are not reflected in our forecast since their effects are not known at this time.

Basically, CP&L load management activities are categorized into three primary areas. These areas of load management are:

(1) load management through pricing activities

(2) load management through customer education, contact and assistance

(3) load management through control of customer-owned equipment

Load Management Through Pricing Activities

Pricing is a form of load management and even within the confines of cost-based rates it is a tool that may prove fruitful in controlling system peak. CP&L's present rate structure, which incorporates the allocation of power supply costs on the basis of contribution to peak load, thereby reflects the higher cost of serving those classes which contribute the most to the system peak. This higher cost tends to dampen usage, although the extent to which peak demand is dampened is very uncertain. Additionally, without incurring the extra cost of expensive metering equipment, CP&L has implemented price differentials based on seasonal usage as reflected in the residential seasonal rate and in the minimum billing demand ratchet of the general service rate.

The National Rate Design Study and the Electric Utility Rate Demonstration Project are two pricing experiments in which CP&L is engaged to evaluate their load management potential.

CP&L is also investigating other areas which may aid in controlling the peak, including the possibility of curtailable rates and the use of customer-owned generation at the time of the system peak.

Load Management Through Customer Education, Contact and Assistance

CP&L has been engaged for many years in a continuing program to encourage load management through conservation of electric energy and reduction of the system peak demand. Components of this program include:

1. Radio, TV, and newspaper advertising.
2. Production and distribution of numerous forms of hand-out materials. For example, over 200,000 copies of the booklet entitled, "How to Save on Your Electric Bill" have been distributed.
3. Conservation tips in bill inserts.
4. Direct Customer Assistance - From January, 1973, through February, 1977, over 75,000 conservation calls have been made in residential, commercial, and industrial customers throughout

the CP&L service area. During this same time period over 2,600 talks were made to groups.

5. Project Communicate - In the fall of 1974-75, customer inquiries about rising electricity costs increased considerably. It was apparent that CP&L needed to have additional face-to-face contact with customers in order that they might better understand the Company's rates, operations, and billing practices, and have the opportunity to ask questions. CP&L, therefore, initiated "Project Communicate Program." One of the predominant areas of discussion was conservation measures. Since the program was initiated in 1975, over 65,000 households have been contacted.

6. <u>The Wrap-up Program and the Common Sense House Program</u>

   These programs are aimed at promoting adequate insulation in both existing and new homes. On request, a company Customer Service representative will evaluate the existing thermal protection in a customer's home regardless of the type heating system used and recommend improvements such as additional insulation, storm windows, storm doors and attic ventilators. Whereas the Wrap-up program is aimed at existing homes, the Common Sense House is aimed at the new homes where even more insulation is feasible. The Common Sense House Program emphasizes energy efficient materials such as insulation, storm windows and doors, vapor barriers, power attic ventilators, 2½-foot roof overhangs, super insulated water heaters, and energy efficient appliances. As an example, in a 1500 square foot house constructed to Common Sense House recommendations, the heating, cooling, and water heating energy requirement can be reduced by up to 40 percent from the cost for normal insulation and the air conditioning load requirement can be reduced such that the size of the air conditioning unit necessary to cool the house if one KW less.

Load Management Through Control of Customer-Owned Equipment

CP&L is investigating programs in which the utility can control customer equipment to minimize the peak load and programs in which the customer will install control equipment to minimize his demand. As with the pricing experiments, CP&L has taken advantage of available outside sources for partially financing these programs. The experiments in which CP&L is engaged include:

1. Distribution Line Carrier Communication System

For an effective long-range customer load control program with positive controls which are dependable, it will be necessary for the utility to be able to send a signal to the switching device, have the load management function performed and in return receive a signal that the function has been performed.

CP&L has been experimenting in cooperation with Westinghouse since 1971 with such a system, which was initiated as a remote meter reading experiment. This includes the installation of equipment initially at 250 apartments. In 1973 50 individual residences were added to the experiment.

In 1975, EPRI recognized the need for further demonstration of various options for distribution automation and asked for proposals from utilities and manufacturers. CP&L responded to the request and was successful in receiving funding, in cooperation with Compuguard Company of Pennsylvania, to conduct an experiment on our system. In this experiment, we will test a distribution line carrier communications system at 700 residences in late 1977 and 1978. If proven feasible, the communications system could become the signaling medium for performing a multitude of load management functions. These include remote meter reading, metering for time-of-day rates, customer equipment control, the ability to connect and disconnect service, status monitoring of transformers, capacitor switching and remote sectionalizing. The obvious advantage to this type system is that with such a multitude of functions, the possibility that the system will be cost-justified improves considerably.

2. Fisher Pierce Radio Control Switch

Concurrent with the distribution line carrier communication system research, CP&L is investigating other methods of controlling customer-owned appliances during peak periods. If a utility can disconnect certain customer appliances such as water heaters and air conditioners on a rotating basis during peak periods, the load requirements will be reduced and the load curve improved. Although similar experiments with such equipment are underway in other areas of the country, the questions that must be answered in the CP&L service area include: (1) whether this type of control will provide sufficient reduction below the inherent diversity that we now have between appliances, both within the customer's house and among all customers, to offset the additional cost that would be incurred for the installation and operation of the equipment, and (2) whether the inconvenience customers will experience will be sufficiently minimal for them to accept such control. CP&L, therefore, has accepted an offer by Fisher Pierce Company to test its VHF radio control switch on 25 customer homes. The switch will be supplied by Fisher Pierce at no cost to CP&L. CP&L is presently installing these devices in the Raleigh area and expect to have them in operation during this summer's peak months. This project is not of sufficient size to provide complete answers, of course, but such installations should permit insights into many of the difficulties that will be encountered, the relative cost of individual installations, some information on customer attitudes and some information on the effects on the individual customer's load curve. Although this limited experiment will not give sufficient data to warrant entering into a widespread program, it should indicate the technical feasibility of the program and whether a larger statistically sophisticated experiment would be justified.

3. Interlocking Devices

CP&L is engaged in an Electric Utility Rate Demonstration Project in cooperation with the North Carolina Utilities Commission and the Federal Energy Administration. The first priority of that experiment is to compare the effects on customer usage of residential time-differentiated rates with

CP&L's existing rates. However, CP&L is also investigating the possibility of testing the effects of certain residential load control devices as an additional aspect of this rate experiment. Specifically, CP&L is investigating the feasibility of installing interlocking devices in approximately 64 customer homes. The device will present simultaneous operation of the selected appliances on which it is installed. For example, if it is connected to the range and water heater circuitry, it will present the operation of the water heater when the range is turned on, or if it is connected to the water heater and dryer, it will prevent the water heater from operating when the dryer is on. Whether CP&L will be able to conduct this experiment in connection with the FEA Project has not been fully determined; however, a project subcommittee will investigate this possibility and, if this aspect is added CP&L should gain some insight into the value of these devices in helping the individual customer control his load.

4. Voltage Reduction Study

CP&L has realized for some time that one means of reducing the system load during emergency conditions is to reduce the voltage within the tolerance of customer-owned equipment. The first step in our emergency load reduction plan filed with this Commission is to reduce voltage up to approximately 5%. The quantified results of such load reduction has not been determined until last year.

In the summer of 1976, CP&L conducted an experiment which did quantify the load reducing effects of voltage reduction.

In the experiment, six substations were chosen at random and seven tests were made. The tests were made at 1% reduction, 3% reduction, and approximately 5% reduction. The results of this test showed that at that particular time, a voltage reduction of 1, 3, or 5 percent gave approximately an equal percentage reduction in load. CP&L's experience has also shown that during times of peak load when it was necessary for us to take this step, practically no inconvenience was experienced by the customers. A 5% reduction of voltage does not have any significant effects on the operation of customers' equipment with the possible effects that there may be a slight narrowing of the television picture.

5. Furnishing Meter Data to Large Customers

Obviously, if controlling the customer's loads by the utility is beneficial, a program which encourages the customer to install load control devices is even more advantageous. The rates which were recently approved by both the South Carolina and North Carolina Utility Commissions provide an incentive to CP&L customers to level their load curve. CP&L, therefore, continues to cooperate with customers who wish to purchase and install load management equipment. On a facilities charge basis, CP&L will install devices on its system to provide meter pulses to the customer so he can continuously monitor his load and reduce it when he is approaching the predetermined load which he does not want to surpass. A number of large customers are utilizing this service and effectively limiting their loads.

In summation, CP&L believes every reasonable activity to management load and reduce the system peak should be investigated while providing, within the restraints dictated, the quantity and quality of electric service needed to improve the economy of its service area. CP&L's Load Management Steering Committee is active in the company's load management program described above and is monitoring the progress and results of other experiments under way throughout the nation in search for the most effective load management methods adaptive to the characteristics of the Company's system and its customers' operations.

8.3 SITE SELECTION

8.3.1 General

This subsection describes the studies and analyses which led to the selection of the Buckhorn-Whiteoak Creek site for the Harris Plant. An additional discussion of the alternate sites for the possible location of the proposed nuclear units is given in subsection 4.4 of this report. The initial site studies encompassed a survey of five new sites in the Carolina Power & Light Company service area. The investigation was to determine each site's suitability for the installation of nuclear, coal or gas fired generating units and was limited to areas where makeup water could be obtained with a minimum of storage requirements and diversion facilities, such as in the Cape Fear or Neuse River basins.

The initial site studies were done for a plant utilizing an off-stream cooling lake. The Buckhorn-Whiteoak Creek site was chosen primarily because of its smaller land use impact. When the cooling system was redesigned to use cooling towers and a smaller lake, the Buckhorn-Whiteoak Creek site was still considered the best and detailed studies of new sites were not conducted in light of the new cooling system. The relative impacts on the sites would remain essentially the same for the cooling towers and smaller reservoir. Also, much preconstruction impact on the Buckhorn-Whiteoak Creek site, such as land purchase, relocation, timber sales, etc., has already occurred and abandonment of the site would mean massive redesign of the plant which would cause severe delays in the completion of the plant and the availability of the much needed power it will produce.

In addition to the Buckhorn-Whiteoak Creek site, four other new sites surveyed were considered for the proposed nuclear units. These four sites are in the Northern Division of the CP&L service system. A fifth site considered for the proposed units was the Brunswick Plant, a facility currently under construction near Southport, North Carolina.

The Buckhorn-Whiteoak Creek site and each of the other four sites in the Northern Division would involve cooling towers with makeup reservoirs and would have had similar effects on the aquatic environment. The Brunswick Plant, located in the Eastern Division, will employ a river intake and ocean discharge and will have substantially different environmental effects. Each of the sites exhibited features amenable to the production of electrical power.

8.3.2 Location

The Buckhorn-Whiteoak Creek site is located in Wake and Chatham Counties, approximately 1.3 miles northwest of Bonsal and about 1.2 miles south of Corinth. Alternate Site 1 is located in Southern Wake

County and western Johnston County. Alternate Site 2 is in eastern Wake County and northern Johnston County. Alternate Site 3 is located in southern Granville County. Alternate Site 4 is in Harnett County and Alternate Site 5, the Brunswick Plant, is located in Brunswick County near Southport, North Carolina.

8.3.3 Access

The general area of the Buckhorn-Whiteoak Creek site is served by the Durham and Southern, the Norfolk-Southern and the Seaboard Coast Line Railroads. Road access will be from U. S. No. 1 and N. C. 55. The location for alternate Site 1 is served by the Southern, Norfolk-Southern, and Durham and Southern Railroads. Road access would be from U. S. 401 and N. C. 42, 50, and 210. Alternate Site 2 is served by the Norfolk Southern Railroad. Road access would be from N. C. 42, U. S. 64 and N. C. 1003. Alternate Site 3 is served by the Seaboard Coast Line Railroad and road access would be from N. C. 50 and N. C. 56. Alternate Site 4 access could be by Federal Highway 401 and 421, N. C. 27 and 210, 1291 and 1251. The area is served by the Norfolk-Southern Railroad and Seaboard Coast Lines. The area of alternate Site 5, the Brunswick Site, is served by N. C. 133 and rail access is by the Leland spur off the Seaboard Coast Line Railroad.

8.3.4 Geology

Each of the Northern Division sites is located in very different geological areas. The Buckhorn-Whiteoak Site and Alternate Site 3 are located in the Deep River-Wadesboro Triassic Basin of the Piedmont Physiographic Province. The Basin is a northeast trending down-faulted, trough-shaped block of Triassic sediments that extends from near Oxford, Granville County, to the South Carolina line, south of Wadesboro. Generally the basin is bordered on the west and northwest by the Carolina Slate Belt or Great Slate Formation which to the west continues from Virginia through North Carolina into South Carolina. The Basin is bordered on the east and southeast by a series of belts beginning with long narrow remnants of

Carolina Slate, a belt of gneisses and schists, an eastern belt of Carolina Slate and finally a granite body known as the Rolesville Granite.

The dam and plant of alternate Site 1 would be located in the region of mica gneiss which is thought to be of the Precambrian Era. Fringes of the lake would extend over to the Tuscaloosa Formation on the southwestern side of the site area. The site region is bounded on the eastern side by granite which is massive to even-grained and bounded on the south by the Tuscaloosa Formation.

Alternate Site 2 is located in a region of granite rock foundation of Paleozoic Age. In general the granite in the area is massive, even-granular rocks that show little effects of metamorphism. Jointing is common but not excessive. The textures present are chiefly medium to coarse grained. Outcrops, while not abundant, are found throughout to area. Along stream valleys, outcrops form elongated masses and ledges, while in rolling topography, large boulders are often found. Where it has not been removed by erosion, the granites are covered with a residuum varying from a few inches to as much as 25 to 40 feet thick. This residuum varies in color from buff, yellow, and read, to reddish-brown, depending on the weathering of the underlying granite.

Alternate Site 4 is located primarily in a region of metavolcanic rock (felsic volcanic) and sedimentary Tuscaloosa Formation. The plant site, dam site, and most of the lake area would be located within the felsic volcanic boundary of Lower Paleozoic Age which belong to the volcanic slate series. The rocks are deeply weathered and covered by a thick layer of soil. As a result, outcrops of fresh rock are scarce. In general, the rocks of this area consist of coarse to fine tuff and bedded slate, with bodies of gneiss and schist present in many places. The tuffs and bedded slates are usually altered near igneous intrusions to granetiferour mica schist, mica hornblende schist, or biotite schist. All these rocks have been moderately metamorphosed and contain a cleavage that strikes northeast and stands nearly vertical.

Some of the fringe areas of the lake would be within the Tuscaloosa Formation. Throughout most of the area of outcrop, the Tuscaloosa Formation appears as a series of beds of tan to reddish-brown, loose to fairly well consolidated sandy clay with loose sand at the surface and occasional exposures of massive kaolin. Kaolin. Kaolin is the principal clay mineral in the Tuscaloosa Formation. The clayey beds on the Tuscaloosa Formation are well exposed only in stream valleys or a few road and railroad cuts, where they are mantled by weathered clay. The formation is not very resistant to erosion, but some streams, such as the Cape Fear River, have developed steep valley walls.

The area of the Brunswick Plant has several local geological formations. These are the surficial deposits of Pamlico Terrace, the Yorktown Formation, an unnamed formation of the Oligocene Age in North Carolina, the Castle Hayne and Peedee Formations. The Pamlico Terrace Formation consists mainly of tan to brown fine argillaceous sands, clayey silts and sandy and silty clays. The underlying Yorktown Formation of the Miocene Age consists of a very dense, medium to coarse, sand. The Yorktown Formation, which is generally comprised of plastic clay and fine sand, is not present in the immediate vicinity of the proposed plant, although it does exist in adjacent locations. The Oligocene deposits within the site boundary are lenses of consolidated limestone composed mainly of shells and seams of hard clay and very dense sand. In the upper elevations of the Castle Hayne of the Eocene Age are medium-hard shell limestones which grade to soft sandstone with depth. The Castle Hayne limestones are not cavernous. The Peedee Formation (Upper Cretaceous Period) underlying the Castle Hayne is a hard, calcareous clay and is coreable.

8.3.5 Seismology

An examination was made of the earthquake history in the vicinity of the prospective sites. North Carolina is not usually considered to be a seismically active state, but according to MacCarthy (1957)[1] approximately

100 earthquakes were recorded within its borders between 1774 (the date of the first recorded shock) and October, 1959. Only three of these are listed by the United States Coast and Geodetic Survey as "important" and all three of these occurred west of the Blue Ridge Mountains in the region southwest of Asheville, North Carolina.

Regarding earthquake activity, the eastern region is relatively devoid of major earthquake activity, the nearest epicenters being 80-100 miles south of Alternate Site No. 4. The Jonesboro fault, lying 10 miles west of Raleigh, has not been associated with any major recorded earthquakes through 1963. This fault, therefore, appears inactive with respect to major earthquakes. The U. S. Coast and Geodetic Survey Seismic Risk Map indicates that this region is one of "minor damage" risk, i.e., "distant earthquakes may cause damage to structures with fundamental periods greater than 1.0 seconds; corresponding to Intensities V and VI of the Modified Mercalli Intensity Scale of 1931."

The Buckhorn-Whiteoak Creek and Alternate Site 3 are relatively close to the long unbroken Jonesboro fault, although no site is less than one mile from the fault according to the geological map used (Geologic Map of North Carolina - Department of Conservation and Development, William P. Saunders, Director, 1958). Alternate Sites 1 and 2 are several miles from the Jonesboro fault in a region completely without earthquake activity.

The area of seismic activity nearest alternate Site 5 is in Charleston, South Carolina, about 150 miles southwest of the site. Six earthquakes of Intensities VI or greater and more than 400 minor earthquakes have occurred within 30 miles of Charleston within the last 200 years. With the exception of Charleston, South Carolina, the southeastern United States are considered to be relatively inactive with respect to seismic activity. the largest intensity observed in the vicinity of this site resulted from an earthquake which took place approximately 150 miles from the site in the vicinity of Charleston, South Carolina, on August 31, 1886. The epicentral intensity of this earthquake was at least IX on the Modified Mercalli Scale. Of the approximately 100 earthquakes reported in North Carolina, only eight

of these epicenters were recorded in the Coastal Plain region of the state. From the available data, it appears that these seismic events would have little if any effect at the plant site. Based on the seismic history of the sites, the design basis earthquake for all sites was chosen as a high Intensity VI (M.M.)

8.3.6 Land Use

The Buckhorn-Whiteoak Creek site is on essentially undeveloped, rolling wooded land. The immediate three mile area surrounding the site is a sparsely populated rural area. Based on the assumption of 3.5 inhabitants per house, the residences which existed within 3 mile radius of the site in 1968 were counted and determined to contain 144 families; 110 of these residences were two miles from the site. The rural nature of the area and local historical population changes suggest that this technique of counting residences yields data consistent with the 1970 Census. Population is concentrated in relatively few dispersed centers and large concentrations of industrial activity do not exist. The site area is a mixture of farmland, fallow fields, and woodlands in various stages of development. Approximately 80 to 92 percent of the land is used for timber production and does not possess the potential for effective agricultural production. As a result, there are few farms in the uplands and none in the valleys. Identification of the timber types in the area shows the following acreage breakdown:

pine	2,841.02
pine-hardwood	2,832.98
bottom land hardwood	455.00
hardwood	72.33
hardwood-pine	5,462.34
cutover	2,063.17
field	1,226.82
Total	14,953.66 acres

This breakdown represents areas below elevation 260 feet in the make-up reservoir area, all of the exclusion area, those areas which are inaccessible above elevation 260 feet, and an area below the main dam which was to have been an afterbay reservoir in the original cooling system design. Although not all of this land will be utilized by the plant or smaller makeup pond, it is still a good representation of the site vegetation.

About 8 percent of the site is devoted to farming.

Development of the 14,000 acre site will necessitate the relocation of approximately 25 families. The only major highway in the vicinity of the site is U. S. Highway No. 1 and it will be essentially unaffected by the site development, except for the installation of larger culverts where the highway will cross the upper fingers of the auxiliary reservoir. State Road 1149, which is located near the north end of the reservoir will be elevated and culverts will be installed so that service along the road will be maintained. Several other secondary roads exist in the vicinity of the site and approximately 7 miles of these roads will be affected. A main line and spur of the Norfolk Southern Railroad currently pass through the area. About 2.8 miles of the existing alignment will be inundated by the reservoir; however, both tracks will be relocated to provide a continuation of normal rail service.

It is proposed that some roads in the area be dead-ended where they enter the site property boundaries; however, no private property owners will be denied access to their property. The relatively minor changes in transportation facilities and relocation of families from the proposed reservoir will not affect the population trend characteristics of the area nor significantly affect present land uses surrounding the proposed plant area.

There are no national historical landmarks within a five mile radius of the plant site or within the project boundary. Except for the ruins of an abondoned ironworks utilized by the Confederacy during the Civil War (approximately 1-1/2 miles from the project boundary on the bank of the Cape Fear), the area does not have any historical or known archaeological importance. There are no parks, national forests, or other organized recreational facilities within the project boundary. The present Buckhorn and Whiteoak Creeks system, which is the area of the site, appears to offer limited hunting or fishing possibilities. The site also minimizes land use requirements for transmission facilities. Due to location accessibility, a 500 KV transmission line which was planned for the 1970's will be routed through the Harris Plant to connect with Virginia Electric and Power Company to the north and Duke Power Company in the west. By routing this line through the Harris Plant, new right-of-way acquisition will be minimized. A complete discussion of land use involving transmission lines is contained in subsection 8.7 of this report.

The Research Triangle Regional Planning Commission was consulted regarding conformance of the plant site with permissible land use in the area; this agency has indicated that there will be no incompatible land use or zoning infringements resulting from construction of the plant.

Alternate Site No. 1 is in an area dominated by small partially cultivated farms and some pasturelands. In about four separate areas subdivisions of homes are under construction. One such subdivision contains about 15 to 16 homes and the remaining subdivisions have only a few homes, with others under construction. There is no large concentration of homes and farms in this area, but many stationary and mobile homes exist within the boundary of the site. The lake would follow the general perimeter of the woodlands but several hundred acres of farmland would be inundated. The subdivision of 15 to 16 homes probably would be completely inundated by the lake; however, the other subdivisions would not have been affected as greatly, although two or three homes would need to be relocated. Approximately 35 families in the site area would be relocated in addition to those in the above mentioned subdivisions. An industrial area is located at what would be the head end of one of the fingers of the proposed reservoir near U. S. 401, but it would not be affected by the proposed reservoir. Road alterations or relocations approximately five miles in length would be necessary and about 1/2 mile of railroad tracks would have been raised or relocated. It would have been necessary to lay approximately nine miles of pipeline to provide makeup water from the Neuse River. The transmission capability at this site for delivering power in four directions was comparable to that at the Buckhorn-Whiteoak Creek site; however, the land used for transmission right-of-way is less at the Buckhorn-Whiteoak Creek site than at Alternate Site No. 1.

This site has good development potential physically, but the percentage of land required which is already being used and the extensive relocations required made its utilization relatively unattractive when compared to the Buckhorn-Whiteoak Creek site. About 28 percent of the site is devoted to farming, compared to 8 percent of the Buckhorn-Whiteoak site. In addition, this site does not possess the future development potential which is characteristic of the Buckhorn-Whiteoak Creek site.

Alternate Site No. 2 is in an area which contains land well suited to farming. About 3595 acres, or 30 percent of the site area, is devoted to cultivation and farming. This site has the potential for a large lake and would have presented good foundation material for a generating facility. There is no significant amount of industry existent in this area; however, the population density is higher than at Alternate Site No. 1 and Buckhorn-Whiteoak Creek. Utilization of this site would have involved inundating two lakes which are used extensively for recreational purposes, primarily boating and fishing. About 33 home locations within the site area would be inundated by the reservoir. The perimeter of the lake would follow the outer edge of the woodlands, but in this case more acres of farmland would have been under water than at Alternate Site No. 1. A municipal sewage treatment plant would be near the edge of the proposed lake and the effluent from this plant would have been included in the plant's makeup water for the reservoir, which could cause some water quality problems. Approximately 16 miles of primary and secondary roads would have to be raised or relocated. Utilization of this site would have required that two creeks be ponded in order to provide the desired effective cooling lake area, as one creek would not be sufficient to support the needed generation. Employing the two creeks would not have provided as adequate a water supply as the Buckhorn-Whiteoak Creek site. The transmission possibilities of this site do not exceed those at Buckhorn-Whiteoak Creek, but are comparable to the possibilities at Alternate Site No. 1.

Alternate Site No. 3 is located in a sparsely populated rural area. There is not a significant amount of quality farmland within the boundaries of this site; however, it appears that the people in this area are attempting to cultivate the existing farmland. When compared to the Buckhorn-Whiteoak Creek site, the farmland at this site is similar but is utilized more for agricultural production and exhibited better yield potential. About 2685 acres, or 23 percent of the site area, is devoted to farming. The area is isolated from a population center and homes are scattered throughout the site boundaries. As with the previously mentioned sites, this site mainly encompasses the woodlands of the area; but some farmland would be inundated by the lake. The proposed lake would have inundated about 25 homes within this area and about 5 miles of roads would have to be raised or relocated. No railroad relocations would be necessary. The drainage area for this site is the smallest of all sites considered, representing about 62 percent of the drainage area of the Buckhorn-Whiteoak Creek site. In assessing this site, it was determined that it does not possess the transmission possibilities existent at the Buckhorn-Whiteoak Creek site. The selection of this site would have limited transmission to one direction while Buckhorn-Whiteoak Creek site had transmission capability in four directions.

Alternate Site No. 4 exhibits significant agricultural development. Of the 14,760 acres that would be devoted to the development of this site, about 30 percent of this land is used for farming, compared to only 8 percent of the original 18,000 acres at the Buckhorn-Whiteoak Creek site. The farmland at the Buckhorn-Whiteoak site does not possess the productivity that is characteristic of this site. An examination of the acreage involved at this site shows the following:

pine	1,388
pine-hardwood	3,789
hardwood	234
hardwood-pine	2,049
open	3,140
Total	10,600 acres

The population density at this site is more pronounced than at the Buckhorn-Whiteoak Creek site, and homes are scattered throughout the entire boundary of the site with no concentrations of population. Alternate Site No. 4 possesses adequate stream flow into the reservoir area for makeup water and also has the potential for additional installed capacity at some future date. The proposed lake would have inundated most of the farmland and approximately 51 homes. About 5 miles of primary and secondary roads would be inundated by the reservoir. This site has the capability of transmitting power in four directions as does the Buckhorn-Whiteoak Creek site.

Land within a 50 mile radius of Alternate Site No. 5 (Brunswick Site) is predominantly rural, except for the Southport and Wilmington areas. Less than half the land in this 50 mile radius is designated for farm use. The remainder is undeveloped swampland and woodland. Agricultural activity in Brunswick and surrounding counties is made up of tobacco, poultry, truck, and small dairy farms. In Brunswick County, with only 18 percent of the land area devoted to agriculture, most farming is in the southwestern section, with scattered farms located in the southern and northeastern sections.[2]

The Carolina Power & Light Company system demand for the year 1975 and after is concentrated in the Northern Division; therefore, utilization of the Brunswick Site for additional generating facilities would require construction of three new 500 kV transmission lines totaling over 400 miles. These transmission facilities, coupled with transmission losses, would exceed those at the Buckhorn-Whiteoak Creek site by approximately 300 percent, and the environmental impact of acquiring right-of-way would have been much more significant.

8.3.7 Hydrological Considerations

The unit flows of several streams gaged by USGS in eastern North Carolina within the general area of the Northern Division sites are shown on Table 8.3-2. Since the Middle Creek gage near Clayton is centrally located and has a drainage basin comparable in size to the drainage basins of the sites studied, it was assumed that flows at any site would be in the direct ratio of the size of their drainage basin to the size of the drainage basin of Middle Creek near Clayton. The flows at Middle Creek were analyzed and the critical period was determined. For each site, a determination was made of the amount of storage required to supplement the calculated natural flow in the critical period to supply makeup requirements for evaporation and other losses. In most cases flows from the drainage basins above the dam sites were insufficient and pumping from the main river would be necessary. Water uses for each of the sites employing a cooling lake is a function of lake size and megawatt generating capacity. The reservoir at Alternate Site No. 3 would require the greatest withdrawal from the main river followed by the reservoirs at Alternate Sites No. 1, Buckhorn-Whiteoak, and Alternate Sites No. 2 and 4 respectively.

The Brunswick Plant, which utilizes a once-through method of cooling, withdraws water from the river and uses off-shore ocean discharge.

Two aspects of the surface water hydrology were considered in the area of the Brunswick Site: the normal hydrology of the Cape Fear River and estuary tides and the hydrology assoicated with severe weather conditions. The lower section of the Cape Fear River near the site is characterized by strong semidiurnal tides with a range of about four feet. Salinity data available from the North Carolina Department of Water and Air Resources and the United States Geological Survey were supplemented by salinity data collected at monthly intervals over a period of one year from March of 1969 through February of 1970. Considering the stratification of salinity, only on infrequent occasions does the salinity at the bottom in the vicinity of the plant intake canal fall below about half strength seawater. The net flow of water past the plant intake toward the ocean, which is maintained by fresh water input and vertical mixing of the ocean water, is considerably greater than the flow that would exist if only fresh water were moving toward the ocean in the upper layer. Net flow toward the ocean in the upper layer is approximately 15 times the fresh water input during dry periods. Under a low flow condition of 1400 cfs fresh water input, there would be a net flow toward the ocean in the upper layer of approximately 21,000 cfs.

For the Brunswick Site, the most severe flood that can reasonably be postulated is presumed to be caused by a hurricane more severe than any on record, having a recurrence interval of once in about 2,000 years, and possessing all the qualities in coincidence which would contribute to the severity of the flood. [3]

Since all the Northern Division sites are in close proximity, the effect of each site on the regions water resources would not substantially differ. There would be no significant effect on the stream flows of the Neuse or Cape Fear Rivers, which would serve as the sources of makeup water. It has been pointed out previously that the effect on the aquatic environment by each of the Northern Division sites would be similar. The environmental effect of the Brunswick Site would be quite different since it uses river intake, intake and discharge canals, and off-shore ocean discharge.

8.3.8 Economic Considerations

Economic factors which were considered as significant parameters include transmission costs and land costs. From a land cost economics view, it would have been much less expensive to expand the Brunswick facility by an additional 3600 MWe. However, the Brunswick Site is a much greater distance from the Carolina Power & Light Company load center which the Harris units are required for than are the other alternate sites in the Eastern Division. Locating the additional units at Brunswick would have required a minimum additional $50,000,000 for transmission facilities alone, plus transmission losses. Furthermore, from an environmental standpoint, it was felt by Carolina Power & Light Company that the nearest site to the load center was more desirable. Steel towers are required for 500 kV transmission lines as explained in subsection 8.7.2. If the 3600 MWe were installed at the Brunswick Site, three new 500 kV lines would be required, totaling over 400 miles of new lines. The selected site in Wake County will require slightly over 100 miles of 500 kV lines. Since all the other sites which were evaluated are in very close proximity to the selected site, there would have been minor savings or additional expense for transmission facilities.

8.3.9 Summary

The surveys and analyses which were performed to select a site for the Harris Plant recognized the need for selection of a site which offered the least overall environmental impact. While some of the sites offered similar advantages such as nearness to load, adequacy of cooling water supply, nearness to existing transmission facilities, and low

productivity, problems relating to land availability and conflicting or noncompatible nearby land use caused these alternates to be eliminated at this time. Some of the advantages that the Buckhorn-Whiteoak site offered beyond those listed above are the following:

1. The Buckhorn-Whiteoak Creek site has the greatest potential for future generation development.

2. The site has the fewest number of conflicts with other existing land uses.

3. The site has the capability of transmitting power in four directions.

4. The population density around the site is one of the smallest of the other sites investigated.

5. The amount of productivity was least at this site.

Although several of the alternate sites investigated have factors which are amenable to the production of electricity, the Buckhorn-Whiteoak site will have the least overall environmental impact. Table 8.3-1 summarizes some of the physical characteristics of the six sites evaluated based on the original cooling lake concept.

REFERENCES FOR SUBSECTION 8.3

1. MacCarthy, Gerald R. "An Annotated List of North Carolina Earthquakes. Elisha Mitchell Scientific Society. Journal. Vol. 73. No. 1. 1957.

2. Environmental Report. Brunswick Steam Electric Plant. Carolina Power & Light Company. Docket Nos. 50-324 and 50-325. November, 1971. (Page 2.1-2 - 4).

3. Environmental Report. Brunswick Steam Electric Plant. Carolina Power & Light Company. Docket Nos. 50-324 and 50-325. November 1971. (Page 2.1-14 - 18).

TABLE 8.3-1
GENERAL SITE CHARACTERISTICS OF SITES

SITE	Buckhorn-Whiteoak Creek	Alternate 1	Alternate 2	Alternate 3	Alternate 4	Alternate 5
PLANT LOCATION						
County	Wake	Wake and Johnston	Wake and Johnston	Granville	Harnett	Brunswick
DAM SIZE Length	15,000 ft	5248 ft	5100 & 2500 ft	6000 ft	10,000 ft	---
Max. Height	90 ft	65 ft	100 ft & 30 ft	50 ft	60 ft	
RESERVOIR						
Drainage Area	75 sq mi	80.7 sq mi	55 sq mi combined	42 sq mi	173 sq mi	
Maximum WL	250 ft	250 ft	250 ft	300 ft	200 ft	---
Lake Area	10,000 acres	4600 acres	7900 acres	4900 acres	8200 acres	
OPERATION						
Type	Cooling Pond	Cooling Pond	Cooling Pond	Cooling Pond	Cooling Pond	Once-Through
Required Storage	18,400 acre ft	17,100 acre ft	23,300 acre ft	25,000 acre ft	31,000 acre ft (reg. of Creek flow)	---
ACCESS						
Nearest Rail	Seaboard Coast Line	Norfolk Southern	Norfolk Southern	Seaboard Coast Line	Norfolk Southern	Seaboard Coast Line (Leland Spur)
Nearest Highway	US 1	NC 50	NC 231	US 15	NC 27	NC 133
POPULATION						
Population Center	Raleigh	Raleigh	Raleigh	Durham	Fayetteville	Wilmington
Population	110,000	110,000	110,000	97,000	25,000	46,169
SEISMIC						
Earthquake Factor	Design for Intensity VI	Design for Intensity VI	Design for Intensity VI	Design for Intensity VI	Design for Intensity VI	Design for Intensity VI
FOUNDATION Consideration	undifferentiated sedimentary clay-stones, silt-stones, sand-stone and con-glomerates	Mica gneiss and sedimentary tuscaloosa for-mation (sands and clays)	Massive even grained gran-ite	undifferentiated sedimentary clay-stones, silt-stones, sand-stone and con-glomerates	Metavolcanic rock (felsic volcanic and sedimentary tuscaloosa forma-tion (sands and clays)	Upper layers: argilla-ceous sands and sandy clays; Plastic clay, medium to coarse grained well compacted sand and limestone; Lower layer: hard calcareous clay and cretaceous rocks
ACRES FOR SITE DEVELOPMENT	18,000 acres	8300 acres	14,220 acres	8820 acres	14,760 acres	site developed

TABLE 8.3-2
THE UNIT DISCHARGE OF SEVERAL
STREAMS GAGED BY USGS IN
EASTERN NORTH CAROLINA WITHIN GENERAL SITE AREAS*

Gaging Stations	Drainage Area Square Miles	Average Flow-cfs	Unit Flow cfs/sq. mi.
Neuse River near Clayton, N. C.	1140.0	1209.0	1.06
Middle Creek near Clayton, N. C.	80.7	95.8	1.19
Little River near Princeton, N. C.	229.0	258.0	1.13
Little River at Linden, N. C.	460.0	564.0	1.23
		Average	1.15

*Streams gaged are in the Northern Division of CP&L service area

8.4 ALTERNATIVE COOLING SYSTEMS

8.4.1 General

The selection of a cooling system for the plant is a decision closely integrated with the selection of the site. Once the site has been selected, further study to determine the expected effects of various alternatives and their net impact can be performed. The state of the art of technology of several heat dissipation methods make them practical methods of heat removal from a nuclear power plant. As such, the following methods were examined as alternative cooling systems: closed cycle cooling ponds, natural draft and mechanical draft cooling towers. The approach taken in evaluation of the alternate cooling methods was a multidiscipline one to allow comparison of numerous different parameters that might have an impact on the environment.

An additional cooling method which was given consideration was dry cooling towers. However, a multidiscipline analysis of this type of tower revealed factors inconsistent with proper environmental protection and enhancement. Dry towers avoid the problems of fogging, mist, and icing associated with wet towers, but the concomitant technological and operating problems associated with a dry tower prevent consideration of dry towers at the present time. The technology for constructing dry towers for a large generating station is not presently available. The largest operating dry tower is at a 120 MW plant in England. Towers for a large plant like Harris would have a severe impact on the aesthetics of the area. Dry towers are one-third to one-half larger than comparable capacity wet towers, which themselves are quite large (approximately 400 feet in diameter at the base and over 400 feet high for a 900 MW unit). A dry tower will only cool the water to dry bulb temperature, since only sensible heat is removed from the water. This operation is efficient in dry, cool climates. However in the CP&L service area, this type of cooling system would impose severe limitations on the capacity of the Harris units during hot, humid periods such as the hot summer periods when the electrical demands of the Company's customers are at a peak. The sensitivity of such a cooling system to meteorological factors would create a situation where the reliability of the CP&L system was dependent on uncontrollable factors and would require the addition of additional generation capability reserve to protect against the unavailability of necessary power.

Estimates of the cost of a dry tower for a single nuclear unit in the 900 MW range generally exceed $50,000,000. Because of the adverse impact on regional aesthetics, the lack of available technology, the effect on system reliability, and the high economic costs, dry cooling towers were dismissed as a feasible alternative in the initial investigations of alternate cooling systems.

8.4.2 Discussion of Alternate Cooling Systems

The various alternative cooling systems must be evaluated from several main considerations: environmental impacts, technical feasibility, and economic considerations. As explained previously in this report, it is the policy of CP&L to minimize environmental effects which might have an adverse impact on the environment. The evaluation of a once-through stream cooling system revealed that the thermal releases of such a system on the natural body of water affected (the Cape Fear River) would have an unnecessarily adverse impact, due to periods of low flow in the river. Thus, although the technical feasibility of such a system has been demonstrated, and its economic cost would be the lowest of the alternatives, this system was dismissed from further consideration because of the adverse environmental effects.

Some guidelines are necessary in evaluating potential adverse environmental effects so that design objectives can be established. One of the major effects studied is possible thermal effects from the system. It is, of course, desirable to minimize such effects, and it is for this purpose that water quality standards have been established by Federal and State agencies. Thus, a major design objective of the cooling system is to assure that releases of warm water to the natural body of water will meet all applicable temperature standards. In the case of the Shearon Harris Nuclear Power Plant, the applicable standards are the North Carolina State Water Quality Standards which have been approved by the Environmental Protection Agency. With these standards as a design objective, cooling ponds and cooling towers were studied as feasible alternatives.

8.4.2.1 Cooling Towers

There are many versions of cooling towers and their terminology stems from basic differences in design or operation. The "dry" cooling tower was discussed in subsection 8.4.1. The towers which are technically and economically feasible for use in supplying cooling water at the site for the Harris nuclear units are "wet" towers where the water is exposed directly to the air. Basically, there are two types of "wet" towers: mechanical draft towers where fans are employed for forced air movement and natural draft towers where air is moved as a result of the buoyancy effect of heated air.

As explained in Section 4.5, the Company originally selected a cooling reservoir for the Harris Plant. The closed cycle cooling lake offers substantial advantages over a spray pond or wet towers; however, the construction and operation of this system requires a variance from State stream standards for a portion of the cooling lake. An application for the variance was considered and denied by the North Carolina Board of Water and Air Resources at its July 19, 1973 meeting. Therefore, this alternative is no longer available to the Company. Between spray ponds and evaporative cooling towers, evaporative cooling towers are superior to a spray pond system in terms of available technology and overall economics for an installation of the size required for the Harris Plant. In addition installation of a spray pond system would also require a variance from State stream standards for a pond at this location. The initial evaluation of alternate cooling systems included the 10,000 acre cooling lake and "wet" towers with a 7200 acre makeup pond. The 7200 acre makeup pond was used to be consistent with the 10,000 acre lake, since each provided sufficient storage for future expansion. However, the Environmental Protection Agency recommended that the cooling towers have only a 4000 acre makeup pond. For this reason, cooling towers were reevaluated with a 4000 acre makeup pond. A smaller pond would not be compatible with operational flexibility.

8.4.2.1.1 Mechanical Draft Cooling Towers

Mechanical draft towers were not considered as appropriate as natural draft towers for this site, because of the site topography, environmental impact, electrical power consumption, and possible future plans for adding additional site capacity.

8.4.2.1.1.1 Land Use

Mechanical draft towers require a larger land area than natural draft towers, since mechanical draft towers require a large plan area in order to obtain sufficient ambient air for efficient operation. The utilization of mechanical draft towers at the Harris Plant was found to be totally impractical due to limited land availability in the plant site location. The towers alone would require a minimum of 3,000,000 sq. ft. Because of higher drift rates and lower plume altitudes, mechanical draft towers should be located at least 1,000 feet from electrical switchgear and other plant equipment which could be impaired by this drift. This would assure that salt deposition, icing, and fogging would not adversely affect the plant availability.

Because of plant site topography, the site would need to be modified to add approximately 105 acres of additional fill into the lake area for mechanical draft cooling towers. Approximately 3,400,000 cubic yards of earth would have to be moved and compacted. This material would have to be borrowed from areas not within the immediate plant site, since borrow areas for this much land fill were not considered for the site selection. The 3,400,000 cubic yards of earth would be removed and brought to the plant site by truck. The associated environmental impact of creating.off-site borrow areas and having to truck this fill material onto the site would be substantial. In addition, the fill area would require that a natural flowing creek be diverted from its present creek bed to make room for mechanical draft cooling towers. The above environmental and land use costs were not considered to be acceptable by CP&L when closed cycle systems were evaluated. Therefore, if it were determined during the course of the environmental review that mechanical draft towers were required, a substantial additional delay in the construction and operation of the Shearon Harris Nuclear Power Plant would be incurred with the concommitant economic costs to Carolina Power & Light and its customers.

Since the environmental impact associated with modifying the land at the present site to accept mechanical draft cooling towers is

not considered to be acceptable, the possibility of moving the plant within this site to a location more suitable for mechanical draft cooling towers might be investigated. Such a course of action would result in an additional delay of about 3.7 years. This 3.7 years is based on an approximate 2-year alternate location investigation and boring program and approximately 1.7 years re-engineering and licensing effort to bring the new plant to the present status of the Harris units at the present location. The economic costs associated with such a delay would be enormous and in addition, such a delay would require early commitment to provide large fossil units (with their associated fossil fuel usage) for the CP&L system to replace the 3600 MWe of generation expected from the Harris units, whether or not an alternate location was found. The total delay associated with the Harris units would be nearly six years beyond their original schedule dates of March 1977, 1978, 1979, and 1980.

For the above reasons, mechanical draft cooling towers for the Shearon Harris Nuclear Power Plant are not considered to be a viable cooling water system.

8.4.2.1.1.2 Water Use

A storage reservoir of at least 4,000 acres is necessary for the towers to supply makeup water during low flow periods in the Cape Fear River and for receiving tower blowdowns. The consumptive water use of mechanical draft wet towers would be slightly greater than that of a cooling pond. Water losses would occur by natural evaporation from the 4,000 acre storage reservoir, by forced evaporation in the tower, and by drift losses in the tower. Although some manufacturers claim very small drift losses from their towers, there is presently no reliable method for measuring this loss accurately.

8.4.2.1.1.3 <u>Fogging, Icing, and Drift</u>

The mixing with cooler ambient air above the tower and cooling by condensation causes tower drift water to condense into a visible plume. Theory and experience have shown that the vertical plumes from mechanical draft towers rise less than 600 feet above the emission point under stable atmospheric conditions, due to the lack of buoyancy of the plume. The plume tends to move near the ground with the wind and restriction of visibility can be serious in the plume. In addition, at freezing temperatures icing is

probable through a large section of the plume. The fogging and icing potential due to the plume formed by the evaporating water is highest for mechanical draft cooling towers than for the other alternatives.

8.4.2.1.2 Natural Draft Cooling Towers

Natural draft hyperbolic towers have recently received more attention in this country as a result of improvements in materials and construction techniques. In the natural draft towers, air movement occurs as a result of the buoyancy effect of heated air. The towers are quite large, each one rising to a height of about 480 feet and about 430 feet in diameter at the basin.

8.4.2.1.2.1 Land Use

The land area required for natural draft towers is significantly less than for mechanical draft towers due to several factors. Only four towers are required as compared to several banks of towers for the mechanical draft towers. In addition, the natural draft towers can be located near the plant since fogging is less severe and separation required between towers is not as great as for mechanical draft towers. This also greatly reduces the piping required.

As with the mechanical draft towers, a makeup lake of about 4,000 acres would be required.

8.4.2.1.2.2 Water Use

Consumptive water use by the natural draft towers would be slightly greater than the cooling lake but less than mechanical draft towers, since drift in natural draft towers is smaller than in mechanical towers.

Because of lack of adequate river flow, a reservoir is necessary for makeup water and for receiving tower blowdowns.

8.4.2.1.2.3 Fogging, Icing, and Drift

The natural draft towers will disperse water due to wind drift, plus the evaporation in the tower. The drift is dispersed at an elevated point and on most days of light wind, the moist plume will continue to rise so that little or no ground fogging or icing should occur. However, the potential for fogging and icing is greater than for a cooling lake. This is discussed in detail in Section 3.3.

8.4.2.2 Cooling Lake

The cooling reservoir or lake is the simplest method of removing heat from the plant's condensers. Water would be drawn from the reservoir, passed through the condensers, and subsequently released back to the reservoir where it would dissipate its heat to the atmosphere as it flows through the reservoir. This water eventually would be withdrawn again as cool water.

8.4.2.2.1 Land Use

The cooling reservoir studied for the plant involved an integrated study with long-range planning requirements directed at minimizing land use requirements. The land required for this reservoir plan is larger than that required for the cooling tower-makeup reservoir systems. However, the cooling reservoir offers greater land use benefits to the community. The reservoir would offer numerous recreational benefits such as fishing, boating, etc., and in addition would probably result in an increase in local wildlife. A wildlife management area could be established with better results than the other alternatives since there are no large or noisy structures associated with the cooling reservoir. With almost 200 miles of shoreline, the reservoir would enhance the aesthetic appeal of the area.

The cooling reservoir would occupy approximately 10,000 acres of land. This reservoir, however, could easily serve for cooling future capacity, if added, without requiring additional land.

8.4.2.2.2 Water Use

Evaporative losses from the cooling reservoir would amount to approximately 102 cfs on an annual average basis. This does not represent the net consumptive water use from this cooling system as the evapotranspirative losses from the equivalent land area are eliminated by impoundment of the reservoir. The net consumptive use is less than that of the cooling tower systems.

8.4.2.2.3 Fogging, Icing, and Drift

The fogging and icing potential from the cooling reservoir system is insignificant. During unusual climatological conditions, a light mist might form over the reservoir itself if winds are light. Based on past experience at several cooling lakes, the frequency of such mists is expected to be low, and their effect on the environment minimal.

There is no mineral drift from this system since there is no forced water and air movement as in a tower operation.

8.4.3 Economics

The originally selected 10,000 acre cooling lake was considerably less expensive than the cooling tower system now required. Furthermore, the 10,000 acre lake would have provided for future expansion without requiring the acquisition of additional land.

A summary table on page E.4-1 shows the capital and annual costs for the 10,000 acre lake and natural draft towers. For the benefit of showing the estimated cost differential between the two systems, the following discussion presents the considerations involved:

8.4.3.1 Operating Loss Factors Associated with Cooling Towers

The use of cooling towers results in the consumption of about 0.5 percent power due to pump power requirements. However, pump power requirements are only one operating loss factor associated with cooling towers. Replacement power costs and capacity penalty must be included in the cost of the tower system.

Average wet and dry bulb temperatures were determined for the four seasons based on data from the Raleigh-Durham Airport. This information was then used with the condenser and turbine characteristics to determine net power output and net heat rate. These two values are then used as inputs for a computer model of the CP&L system. The cost calculated by this program is the difference in annual generation cost between a natural draft cooling tower system and a cooling lake design. Factors included are projected fossil and nuclear fuel costs, system demand and the type of generation units available to meet this demand.

Annual Power Cost (4 units)	$2,617,000
Capitalized Annual Power Cost	$16,777,000

Capacity Loss Associated with Cooling Towers

The capacity penalty is the differential capacity at maximum critical weather conditions* between the cooling lake design and the natural draft tower design. A value for gross plant generation at the given weather condition is calculated from condenser and turbine characteristics. The "house load" is subtracted from this value giving the net plant generation.

** 83°F Wet bulb for the natural draft towers and 90°F injection for the cooling lake.

This net generation for the natural draft tower cooling scheme is subtracted from the net generation for the cooling lake system and the resulting number is the capacity penalty in KW. When multiplied by $152/KW (the capital cost of the IC Turbine capacity), a capitalized cost of this penalty results. The following table summarizes the data involved:

	Natural Draft Towers	Cooling Lake
Gross unit generation at Max backpressure (MW)	926.6	950.2
Circulating pump power	12	9
Other auxiliary power	42	42
Total "house load" (MW)	54	51
Net unit generation at Max backpressure (MW)	872.6	899.2
Capacity penalty - 4 units (MW)	106.4	---
Capacity penalty ($)	$16,173,000	---

The following table summarizes the incremental costs of natural draft cooling towers:

LAKE COSTS			
10,000 acre cooling lake - initial capital investment	$64,000,000	1	
4,000 acre makeup pond	24,000,000	2	
COOLING TOWERS			
Circulating Water System Including: Cooling tower, foundation, basin and intake structure; circulating water pumps, motors, and pipe; electrical equipment and condenser changes.	55,500,000	3	
Additional Earthwork	4,500,000	4	
Initial Capital Investment (3+4)	60,000,000	5	
Interest During Construction	13,000,000	6	
Total (5 & 6)	$73,000,000	7	
Capitalized Annual Operating Costs	16,777,000	8	
Capacity Penalty	16,173,000	9	
TOTAL COST ASSOCIATED WITH ADDITION OF COOLING TOWERS (2+7+8+9 - 1)			$65,950,000

This cost, however, does not include the cooling tower blowdown line or diffuser which has not been completely designed at this time.

8.4.3.2 Reasons for Selecting Cooling System

Stream flows in the Buckhorn Creek watershed are not adequate on a continuing basis to support a plant of the Harris size regardless of whether the cooling water requirements are met with a cooling lake or with cooling towers. Even the Cape Fear River does not provide adequate flow at all times to meet the constant makeup requirements that would result from the installation of cooling towers at this site. Therefore, it is necessary to construct a lake and store water for use during low stream flow periods, regardless of which system is selected.

As explained previously, a cooling reservoir was chosen originally for the Harris Plant after a multi-disciplined environmental, engineering, and economic analysis. However, a regulatory decision by the State of North Carolina has made this alternative unavailable. Therefore, cooling towers were necessary. Mechanical draft cooling towers, although less expensive than natural draft towers, were eliminated due to land limitations and low-level fogging potential which might have been hazardous to plant operations. Therefore, natural draft towers were selected. The makeup pond size was reduced to 4000 acres, as recommended by the Environmental Protection Agency.

8.5 CONSIDERATION OF ALTERNATIVE RADWASTE SYSTEM DESIGN

The radioactive waste processing system for the plant was described in subsection 3.7.1 of this report. It was mentioned that the system will be designed to meet the design objectives of the AEC's proposed Appendix I to 10 CFR 50, dated June 9, 1971 (36 F.R. 11113), which gives numerical guidance for radioactive effluents to the environment in meeting the criterion of being "as low as practicable." The waste processing system has been evaluated using the numerical guidance and the system meets the design objectives as set forth in Appendix I to 10 CFR 50. A complete discussion of releases and effects is contained in subsections 3.7.2 through 3.7.4 and subsection 3.6.1.2.

Although radiation protection standards are adequate to insure safety of the public, in the interest of having a minimal effect on the environment, the design objective of the plant will be to release essentially no fission or corrosion product radioactivity to the environment during normal operation.

Accidental release of radioactivity will be safeguarded against so that the likelihood of occurrence is very remote; and if such releases did occur, the radiological consequences would be within applicable AEC guidelines. Accidents and the environmental consequences of accidents are discussed in subsection 3.12.

The AEC, on January 7, 1972, distributed a revised draft "Guide to the Preparation of Benefit-Cost Analyses," which indicated that if the design of the radioactive waste system was able to meet the design objectives of the proposed Appendix I, 10 CFR 50, no further consideration need be given to the reduction of radiological impacts in formulating other alternative plant designs. Therefore, no further consideration is given to alternative designs in this part of the benefit-cost analyses.

8.6 CONSIDERATION OF ALTERNATIVE CHEMICAL EFFLUENT SYSTEMS

All steam electric power plants necessarily use various chemicals in plant operations. These chemicals include corrosion inhibitors such as potassium dichromate, acids and bases such as sulfuric acid and sodium hydroxide, plus small amounts of chemicals used in laboratory procedures. In order to minimize the effect these chemicals might have on the environment, various treatment systems are included in the plant design. The purpose of these systems is to treat these chemical effluents in a manner that will reduce their impact on the environment to a level consistent with the state-of-the-art technology.

Long-range advance planning on the plant is important to thoroughly develop a plant capable of minimizing the environmental impact. With chemical treatment systems, however, design commitments at such an early date could possibly preclude incorporation of advances in technology which might be made between now and the time of operating requests, since a significant research effort is ongoing in this field. The systems for treating chemical releases are in the early design stages and precise information on the design characteristics, types and quantities of materials to be handled, levels and methods of treatment and method of release are in the process of being designed. Therefore, an evaluation of the alternate chemical effluent systems is not feasible at this time. In efforts to balance the effects of any effluents, the design of the chemical treatment systems will incorporate practical state-of-the-art technology and evaluate feasible alternatives to minimize releases and impact.

Although the system is in the early stages of design, some general information can be supplied on systems of this nature. Treatment of chemical effluents will be in accordance with their potential radioactivity or toxicity. All liquid volumes which may be potentially radioactive or toxic will be collected for neutralization, filtration, demineralization or evaporation in the liquid waste disposal system prior to release into the environment. This process results in a waste which will be packaged for off-site disposal in accordance with State and Federal regulations, and a high purity liquid which may be either recycled to the plant or discharged if it meets all applicable Federal and State water quality standards. Those other chemical wastes or chemical uses not subject to radioactive contamination or toxic concentrations are discussed in the following paragraphs.

Little, if any, fouling in the plant heat exchanger equipment is expected to occur. However, chlorination of the condenser cooling water may be required occasionally to inhibit the growth of slime and algae in the condenser, circulating water tunnels, and cooling towers. Chlorine residuals at the plant will be controlled so that concentration does not exceed applicable Federal and State water quality standards.

The domestic wastewater treatment system for the plant will be designed to achieve a tertiary level of treatment. The system will consist of an extended aeration aerobic digestion plant, chemical coagulation, granular filtration, and a chlorine contact chamber. The effluent will be returned to the main reservoir. Although the system has not been designed, it will function as described below.

The plant domestic wastewater will enter the extended aeration plant, in which solids will be retained for a sufficient time to undergo aerobic digestion. The effluent will then pass to the chemical contact tank, where coagulants will be added to further remove solids and nutrients. The effluent from the chemical tank will be filtered, and then treated with chlorine before it is discharged to the reservoir. Sludge will be removed at regular intervals for disposal.

Removal of solids and reduction of biochemical oxygen demand will exceed 95 percent. Nutrient removal is expected to exceed 85 percent.

The plant will be equipped with provisions for neutralizing and pH testing of chemical releases, such as demineralizer regenerates. Again, alternatives such as recycling reconcentration of the regenerates or off-site disposal will be considered.

Since nuclear power plants make use of fission as the process for generating heat and not the burning of fossil fuels, there will be no release of chemical combustion products to the atmosphere except those associated with the occasional operation of auxiliary boilers and the occasional testing of emergency diesel generators. To control ground level concentration of the resulting combustion gases, adequate measures will be taken to minimize this effect to comply with existing air quality regulations.

8.7 TRANSMISSION FACILITIES

8.7.1 Selection of Voltage System

After the benefit-cost decisions on siting, cooling system, and plant type had been made, it then was possible to perform the benefit-cost analysis on selection of a transmission system. The selection of a transmission system involves a complex analysis of technical requirements and environmental effects so that reliable transmission can be assured by a system which minimizes the environmental impact. Decisions must be made as to the terminals of the transmission lines so that the electric power generated at the plant will be delivered to the area load centers. The voltage of the transmission lines must be selected so that the lines will have the capacity to carry the total plant output and provide adequate reserve margin for contingencies. Studies must be made on the proposed transmission system to see that it provides a firm tie between the plant and the transmission grid and to see that it meets the stability criteria for the system. The selected transmission system should mesh well with the existing grid and with proposed future expansion of this grid. Each of these objectives should be achieved without duplication of facilities and with a minimum impact on the environment.

The selected location for the Harris Plant is between three of Carolina Power & Light Company's largest load centers (the Raleigh-Wake County area, the Dunn-Clinton-Cumberland County area, and the Sanford-Southern Pines-Rockingham area). Since these areas are at present strongly tied to the existing transmission grid, lines from the plant to these areas would accomplish three of the objectives: deliver power from the plant to the load centers, firmly connect the plant to the transmission grid, and strengthen the existing transmission system. The number of lines from the plant depends on the voltage selected for the lines.

The power at the Harris Plant will be generated by four 900 megawatt units and will have a total generating capacity of 3600 megawatts. The transmission system must be capable of delivering this 3600 MW to the system on a firm basis.

The existing transmission in the area of the Harris Plant is 115 KV. To develop a Harris Plant transmission system at 115 KV and to intergrate it into the existing 115 KV system would require about 24 lines for adequate capacity. It was obvious that this was too many transmission lines emanating from one location; therefore, no further consideration was given to a system involving 115 KV. If the system were developed using only 230 KV lines, about twelve lines would be required or three lines per unit. For an all 500 KV plant development, about three lines having a firm capability of 3600 MW would be required. The alternate transmission plans that were developed and studied involved 500 KV and combination 500 and 230 KV systems.

Before analyzing these alternate plans, it is necessary to study the transmission grid. As stated above, the existing transmission in the area of the plant site is 115 KV. Area development studies indicate that in the late 1970's and early 1980's, before Harris is installed, many of these lines will have to be converted to 230 KV in order to adequately serve area loads. By routing these converted lines into the Harris Plant, it can be integrated into the Company's 230 KV grid with a minimum impact on the environment.

The plant site is located between the Wake and Richmond 500/230 KV substations. In 1972, CP&L's Wake substation was connected to Virginia Electric and Power Company by a 500 KV interconnection and CP&L's Richmond station was tied to Duke Power Company by another 500 KV interconnection. These interconnections are a part of the long-range regional planning by CP&L and other utilities as recommended in the report of the President's Office of Science and Technology "Electric Power and the Environment" which was jointly sponsored by the U. S. Atomic Energy Commission, the Environmental Protection Agency, the Council of Environmental Quality, and other agencies.

Service to the CP&L system load and the need to enhance system security will require that the Wake and Richmond substations be connected by a 500 KV line in 1985. This line will be routed by the Erwin and Fayetteville load areas so that when required, it can become a strong source to them. This Wake Richmond 500 KV also can be routed via the Harris Plant and can be made to serve several purposes. The 500 KV line, when routed to Harris, will deliver Harris power to the Raleigh and Richmond load areas. The circuit will form a strong EHV transmission backbone to the system between the Wake 500/230 KV substation and the Richmond 500/230 KV substation. It will give strength to the transmission system and will act as a strong source to the 230 KV transmission grid of Carolina Power & Light Company as well as to the interconnections with the 500 KV systems of Virginia Electric and Power Company and Duke Power Company. With these facts in mind, various transmission systems were developed and studied to determine which one would best meet the transmission objectives.

The various transmission alternatives studies for the Harris Plant may be grouped into three basic schemes: Alternative I, Alternative II, and Alternative III. In Alternative I all of the generative units at Harris and all of the lines from the plant would be installed at 500 KV. The three lines required would connect the plant with area load centers. A typical alternate studied in Alternative I is shown in Figure 8.7-1 which shows the proposed grid on the area of interest in the Company's service area. The area of study is shown on Figure 3.11-5 as the blocked in area. These 500 KV lines would be located along new routes requiring new rights-of-way. In addition to the Wake and Richmond 500/230 KV substations, two new 500/230 KV substations at Sanford and Cumberland will be required to securely connect the Harris 500 KV generation to the system 230 KV grid. In order to serve other systems load centers and to tie Sanford Substation firmly to the transmission grid, 230 KV lines are required from the 500/230 KV substation as shown in Figure 8.7-1. This alternative would require a total of 5,334 acres of transmission right-of-way of which 4,514 acres would be new. The 1981-1989 cumulative percent worthed annual cost requirements for Alternative I which covers the period of facility additions to the Harris Plant is $63,301,000.

In Alternative II one unit at Harris would be connected to the Company's transmission grid with 230 KV lines. The other three units would be connected with 500 KV lines. This alternative will require three 500 KV lines and three 230 KV lines from the Harris Plant as shown in Figure 8.7-2. The 500 KV lines would be constructed along new routes requiring new rights-of-way. As in Alternative I, two new 500/230 KV substations would be required. One of these would be in the Erwin load area and the second would be in the Fayetteville load area. The two additional 230 KV lines from Cape Fear shown in Figure 8.7-2 are necessary to deliver power to the Asheboro and Fayetteville load centers and

to provide a strong tie between the plant and the transmission grid. This Alternative would require a total of 5,624 acres of transmission right-of-way of which 4,471 acres would be new. The 1981-1989 cumulative present worthed annual cost requirements for Alternative II is $52,433,700.

Alternative III would place two units of Harris Plant on the 230 KV system and the other two units on the 500 KV lines from Harris as shown in Figure 8.7-3. To form Harris 500 KV transmission, the Wake-Erwin section of the Wake-Richmond 500 KV Line would be looped into the Harris Plant. To form the Harris 230 KV transmission, sections of the area 115 KV transmission lines that have already been converted to 230 KV would be looped into the Harris Plant. The 230 KV lines will follow the routes of the 115 KV lines as far as possible and utilize the existing rights-of-way. This alternative would require a total of 5,157 acres of transmission right-of-way with only 3,672 acres being new. Of the 3,672 acres of new right-of-way, a maximum of 2,185 acres will be cleared. The remaining new right-of-way will be subject to selective clearing. Experience indicates that 85% of the property crossed will be wooded. The 1981-1989 cumulative present worthed annual cost requirement for Alternative III is $43,491,700.

Alternatives I and II each require three new 500 KV lines to be constructed on new routes using new rights-of-way. In addition each of these plans require that two new 500/230 KV substations be installed. Alternative III, however, requires only two new 500 KV lines which are terminated at existing 500/230 KV substations. Alternative III total right-of-way acreage requirements are 800 acres less than the other two alternatives and this fact indicates that this alternative makes optimum use of existing rights-of-way and minimizes land use requirements.

Alternative III also minimizes future requirements. Normal system growth in the late 1970's will require that area 115 KV lines be converted to 230 KV service. These lines will be utilized as part of Harris transmission. In addition, the 500 KV backbone line which will become part of Harris transmission will have to be built in 1985 to meet long-range regional and the Company's internal system requirements, regardless of whether the Harris Plant is built. This normal growth, without the Harris Plant, will require the utilization of 2,705 new acres of right-of-way, so that by integrating the Harris lines with existing land use patterns, only about 991 new acres of new land will actually be necessary. These figures are shown in Tables 8.7-2 and 8.7-3.

Alternative III has been selected as the plan for development of a transmission system for Harris Plant. As stated above, this plan best meets the objectives for developing a transmission system for a new generating plant, and meets these objectives without duplication of facilities and with a minimum impact on the environment. Alternative III is also the most economic plan for the development of Harris Plant Transmission. On a cumulative annual cost basic (1981-1989) Alternative III is more economic than Alternative I and III by $19,809,300 and $8,942,000 respectively.

8.7.2 Selection of Transmission Line Construction

Next, the type of construction to be used on the lines must be determined. The things to be considered in this selection are:

1. Reliability
2. Environmental Impact
3. Inconvenience in case of a fault
4. Cost

Two obvious alternatives are overhead and underground construction.

Carolina Power & Light Company's standard overhead 230 KV construction consists of low-profile, wood H-Frame structures. This type of construction has proven to be very reliable on the CP&L system. If a permanent fault should occur, however, replacement parts are readily available and the outage time would generally be between one and twenty-four hours. The visual impact of this type construction is minimized by the use of low-profile structures and the right-of-way clearing practices of Carolina Power & Light Company. The use of wood enables the structures to blend well with the surroundings. The low profile structures provide the lines with the capability of being screened from the general public view.

For 500 KV lines wood is not a practical structure material due to the increased structural loadings and increased structure size required for electrical clearances. Therefore, the Company has adopted steel lattice type towers as standard structures for 500 KV construction. This type construction provides a high degree of reliability and also requires a minimum repair time in the event of a permanent fault. The environmental impact of this type construction is minimized by right-of-way clearing practices and the fact that the towers require very little land space.

The only practical method of placing 500 KV and 230 KV underground is by use of high pressure pipe type cable. This method consists of three conductors insulated from one another and ground with oil-impregnated paper wrapped around each conductor. The cables are then placed in a pipe which is filled with oil as a pressure and heat dissipation medium. This type of installation requires reactor and pumping stations at regular intervals along the route. These stations will require approximately two acres of land each and a distribution line must be constructed to each station to provide power for the pumps. The number of these stations will depend on the line length and the terrain. At each end of the line about one-half acre will be required for monitoring equipment, circuit protection devices, and towers for bringing the line out of the ground. This space is in addition to the land required for the substation.

This type installation would have a high degree of reliability since it is not exposed to atmospheric conditions such as lightning, insulation contamination, tornado winds, etc. However, every fault on an underground system is a permanent fault. When a fault occurs it must be located, the extent of the fault determined, replacement parts obtained if needed, the pipe excavated, the oil frozen and the cable repaired. The time required to repair a fault on an underground line is usually one month or more.

The environmental impact of an underground transmission line can be greater than a properly designed and constructed overhead line. For example, the banks of streams crossed by an underground line can never be fully restored. No root growth would be allowed over the line thereby making it very difficult to screen the right-of-way from roads and major stream crossings.

It is estimated that the six 230 KV lines and the two 500 KV lines emanating from Harris Plant can be constructed for approximately \$38,165,300. These same lines placed underground would cost a minimum of \$512,500,000. The underground cost is estimated from information contained in a report to the Federal Power Commission entitled "Underground Power Transmission" published in April 1966. The minimum cost ratio of underground to overhead from the above costs is 13.5:1. The FPC Report states that this ratio may be from 10:1 to 40:1 depending on special conditions. Ideal conditions were considered in estimating the cost of underground transmission out of Harris; therefore, this estimate must be considered a minimum.

Because of the environmental impact, the permanence of faults, the state of the art technology, and the cost of underground lines, overhead construction utilizing low-profile, wood H-Frame structures for the 230 KV lines and steel lattice type towers for the 500 KV lines, have been selected for the Harris Plant transmission development.

8.7.3 Selection of Routes

The selection of transmission line routes is a progressive type of analysis. Once the site for the plant has been selected, the system must be planned for distributing the generated power to the load center. The most economical route would normally be a straight line between the load center and the plant. This routing, however, would quite possibly involve some adverse effects upon the environment since certain land uses might be affected.

The first evaluation in route selection is to select a wide corridor area for study. This width of study is selected based upon an examination of the general direction of routing intended to minimize land use requirements and other environmental impacts. After these areas for study have been designated, an intensive effort is begun to study the area on a comprehensive scale. All possible crossings are investigated, alternate crossings are selected, and a final route is selected. These intensive studies involve a great deal of field work which requires a lot of time. As explained in subsection 3.11 of this report, the evaluation of alternate crossings and other routing parameters has not yet been completed owing to the long lead time before plant operation.

The selection of the transmission system, as explained in subsection 8.7.1, was closely integrated with minimization of environmental impact. By choosing to rebuild a number of existing lines, the impact of these lines can be minimized and so the route of these lines has been determined by existing lines. A more detailed analysis of environmental values and proposed routes are contained in subsection 3.11 and is therefore not repeated here.

TABLE 8.7-1

ALTERNATIVE TRANSMISSION LINE VOLTAGE SYSTEMS

Effect Considered	Plan I	Plan II	Plan III
Number of lines and Voltages	3 - 500 KV all new	3 - 500 KV all new 3 - 230 KV	2 - 500 KV* 6-230 KV (rebuilding of 115 KV lines)
Acres of New Right-of-Way Required	4,514	4,471	3,672**
Number of New 500 KV Substations	2	2	0
Estimated New Persent Worthed Annual Cost	$63,301,000	$52,433,700	$43,491,700

*Necessary to tie-in with regional planning regardless of existence of Harris Plant

**Of the 3,672 total acres, only 2,185 acres will be completely cleared for construction and access.

TABLE 8.7-2

LINES WHICH WOULD PROBABLY BE REBUILT
AND NEW LINES REQUIRED IN LATE 1970's OR EARLY 1980's
REGARDLESS OF EXISTENCE OF HARRIS PLANT

Lines Rebuilt to 230 KV	New Right-of-Way Required (acres)
Cape Fear - Asheboro	170
Cape Fear - Erwin	81
Cape Fear - Method	-
Fuquay Tap	34
Angier Tap	17
New 230 KV	New Right-of-Way Required
Lillington - Angier	86
New 500 KV	New Right-of-Way Required
Wake - Richmond	2,293
TOTAL -	2,681 acres

TABLE 8.7-3

COMPARISON OF RIGHTS-OF-WAY REQUIRED WITH AND WITHOUT HARRIS PLANT

Without Harris Plant

	Acres of New Right-of-Way
Rebuilding of 115 KV Lines to 230 KV	302
New 230 KV Lines	86
New 500 KV Lines	2,293
TOTAL -	2,681 acres

Right-of-Way for Harris Plant

Acres of New Right-of-Way for Plan III	3,672
Actual New Acres of Right-of-Way Required by Harris Plant	991 acres

8.8 DISCUSSION OF BENEFITS AND COSTS OF THE FACILITY

8.8.1 Benefits of the Proposed Facility

The addition of the Shearon Harris facility to the resources of the area will have numerous benefits, some of which can be assigned values in monetary terms. Other benefits which will have resultant monetary benefits to the area can only be evaluated in qualitative dimensions at the present time. In determining the overall balance of the facility, it is more relevant to present benefits and impacts or costs in meaningful parameters, rather than assess a numerical benefit-cost ratio.

8.8.1.1 Needed Power

When the plant is completed and in full operation, the units will constitute 25 percent of CP&L generating capability. The annual sales from the units are expected to amount to about 22,075,200,000 kilowatt hours. This power will be necessary to support the residents of the Company's service area in a number of ways. The electrical energy requirements of industry in the area are increasing due to new and expanding industries. During the 5-year period from 1972 through 1976, 316 new plants and 603 expansions were announced for the CP&L service area, with an expected increase of 63,000 jobs. Represented by these figures is an increase in plant investments amounting to more than 2 billion dollars and an annual payroll of approximately 405.5 million dollars. Further industrial growth has been announced and is expected to develop. In addition to this large industrial growth, the energy required to support each industrial job has been increasing and is expected to continue in a similar fashion. Between 1960 and 1970, insured employment in the CP&L eastern North Carolina service area rose from 221,887 to 373,076. The growth to 1980 is expected to reach the total to about 501,300. Energy requirements are also increasing in residential use due to population growth and increasing per capita usage. Various pollution control processes being implemented such as wastewater treatment will require increased energy usage. All these considerations and other have been taken into account in determining what size generation capacity to add to the Company's system. This increased growth could not be supported without the necessary electricity which the Harris Plant will generate, since as discussed in subsection 4.2, outside purchases of power are not available.

The capacity of the Harris Plant was selected based on providing a reliable electrical energy supply for Company customers. As shown in subsection 4.1, the on-schedule completion of the Harris Plant is required to enable CP&L to provide reliable electric energy supply.

8.8.1.2 Taxes

The actual plant itself will be within Wake County in North Carolina, although part of the reservoir will extend into Chatham County. The present tax laws for this area are being revised at this time and as a result, it is not possible to project a precise estimate of property taxes which the Company will pay to the community in the years ahead. To gain a perspective, however, it is possible to make a rough estimate based on 1971 tax rates in Wake County. Assuming current (1971 tax year) property tax rates on a plant the size of the proposed Shearon Harris Nuclear Power Plant, the Company would contribute a substantial percentage to the county property tax revenues. The revenues will in turn benefit the community in numerous fields, such as education, transportation, and others.

Additional revenues to the community will accrue since new jobs in the area due to economic growth and also due to employment at the plant will create new retail sales and property sales in the area, which in turn will generate increased sales and property tax revenues.

8.8.1.3 Educational and Research Benefits

The educational benefit of a facility such as the Shearon Harris Nuclear Power Plant to a community is a parameter which is best described in qualitative terms. Some estimate of quantitative benefits can be made, however, from the tax estimates. In the 1970 tax year in Wake County, 73.4 percent of the property tax revenues went to school support funds of one nature or another. The taxes paid on the Harris Plant will contribute substantially to education. Such an increase in revenue to education will be of considerable benefit to the community.

Most nuclear power plants in the United States have educational information centers associated with them and have a certain intrinsic educational value. However, CP&L felt that because of the tremendous potential educational value of a facility like the Harris Plant, an additional effort should be expended by the Company to increase the value of the plant to the community. Thus, the plans for a true educational center were an integral part of the Harris plans from inception. On April 30, 1971, plans were announced for an Energy and Environmental Center at the Shearon Harris Nuclear Power Plant. The center is being planned to tie into the capabilities of the Research Triangle area of North Carolina and it is hoped that the Center will serve as a focal point for co-ordinating joint research efforts in disciplines ranging from the biological sciences and agriculture to nuclear engineering and health physics. Initial coordination contacts have already been made with universities in the area (Duke University, North Carolina State University, University of North Carolina at Chapel Hill), the National Health Center (Environmental Protection Agency) and Research Triangle Institute. It is hoped that multi-discipline co-ordinated research will be achieved in many of the environmental and energy problems confronting society. Research laboratories, in addition to the normal working laboratories of the plant, are being planned.

The Energy and Environmental Center will provide a true educational benefit to the community, both through the research efforts anticipated and because of the increased educational opportunities which will exist for those who wish to take advantage of them.

8.8.1.4 Economic Benefit in Plant Vicinity

The economic benefits to the service area have been discussed briefly in subsection 8.8.1.2. In addition to these benefits, the plant itself will employ approximately 180 employees with an annual payroll in 1980 of $2 million. After taxes and other withholdings, the employees will take home about $1,500,000 and will spend 95 percent of this during the year. This economic boost to the community will in turn create more income for the community through sales and property taxes.

8.8.1.5 Recreational, Fish and Wildlife Benefits

The construction of the 4,000 acre reservoir complex will create a new reservoir potential capable of providing a multi-use water resource. With almost 75 miles of shoreline, swimming, boating, picnicking, fishing and other water oriented activities in the area will be increased. Considerable new wildlife habitat will be created, especially for waterfowl. Wood duck production in the many wooded coves should be increased. The Company will cooperate with interested agencies in the establishment of our Fish Wildlife Management Programs and the creation of a wildlife area adjacent to the reservoir.

It is extremely difficult to attempt to quantify the recreational benefits, since historical data on such enhancement is not generally available.

The recreational potential for the presently proposed system is not as great as for the 10,000 acre reservoir, but it still represents an improvement over the existing site environment. No further plans for recreational management have been made since the design change in the cooling system.

8.8.1.6 Summary

The benefits of the Shearon Harris Nuclear Power Plant will be numerous and diverse, as shown in the preceding subsections. The economic benefits to the immediate community and the Company service area will be great, although complete quantification of all the benefits simply is not possible. The important point is that the plant is an integrated, well-planned part of the long-range growth planning of the area. It will play an important role in supplying energy needs for research, industry, recreation, pollution control, and residential uses. It is, of course, not possible to quantify the benefits that might result from research or the personal value of recreation but this does not in any way diminish the value to society or the individual.

In planning and in the building of the plant, CP&L feels that the benefits, both quantitative and qualitative, achieve a desirable balance with the costs and impacts discussed in the following subsections.

8.8.2 Environmental Costs and Benefits

8.8.2.1 Aquatic Biota

8.8.2.1.1 Discharges to Natural Water Body

Cooling tower blowdown will be discharged to the main reservoir at an average rate of about 15 cfs and a concentration factor of approximately eight. The blowdown will range from 7°F to 28°F above the ambient temperature in the reservoir. It is not expected that any adverse effects will occur from this release due to the relatively small amount of water discharged. In any case, compliance with water quality standards will be accomplished.

Water discharged from the main reservoir will enter the Cape Fear River. When water is being discharged, it will be released from the main reservoir through an uncontrolled spillway with a sill elevation of 220 feet.

Chlorination will be required for the control of algae and slimes; however, the free chlorine residues should not exceed a trace to 0.5 ppm at the condenser outlet. Chlorination usually is required for one thirty-minute period per day except during the summer when two thirty-minute periods per day may be required. This treatment will cause micro-organism mortality during the treatment period; however, concentrations in the blowdown should be at or below the 0.2 ppm level recommended by the EPA.

In summary, discharges from both the plant to the reservoir and from the main reservoir to the Cape Fear River will be within the North Carolina Water Quality Standards. These discharges should not cause any adverse effects on the biota of the reservoir or the Cape Fear River.

8.8.2.1.2 Impact on Migratory Fish by Heat Discharge

Migratory fish are present in the Cape Fear River during the spring and summer months. These fish, with the exception of the American eel, are categorized as anadromous in that they enter the mouth of the river and move upstream to spawn. Migratory species known to occur in the river are as follows:

American eel (*Anguilla rostrata*)
American shad (*Alosa sapidissima*)
Hickory shad (*Alosa mediocris*)
Alewife (*Alosa pseudoharengus*)
Blueback herring (*Alosa aestivalis*)
Striped mullet (*Mugil cephalus*)

Since the American eel spawns in saltwater, the spawning of this species will not be affected.

A series of five low dams along the Cape Fear River are known to seriously impede fish migration. These dams are Buckhorn Dam near Corinth, Smiley Falls Dam near Lillington, Lock and Dam No. 3 north of Duart, Lock and Dam No. 2 near Elizabethtown, and Lock and Dam No. 1 at King's Bluff. To alleviate the problem of fish blockage due to these structures, the U. S. Army Corps of Engineers, N. C. Wildlife Resources Commission, and U. S. Fish and Wildlife Service agreed in 1961 to open the lock and dam structures for fish passage during spawning runs. Louder (1968)[1] reported that this process of locking fish through the navigational structures had created an appreciable sport fishery as far upstream as Smiley Falls Dam. However, fish migration upstream of this dam site is limited to periods of high water since no means of locking fish through this structure exists; resulting in very few, if any, migratory fishes reaching the mouth of Buckhorn Creek.

In view of the insignificant number of migratory fish reaching the area of the proposed Harris Reservoir and since any discharge to the Cape Fear River will comply with the State water quality requirements, the Harris Reservoir is expected to have no impact on migratory fish in the Cape Fear River.

8.8.2.1.3 Effects on Micro-organisms by Condenser Cooling System

The effects of micro-organisms entrainment in condenser cooling water is discussed in subsection 3.6.1.1.6.

Company studies are now being implemented to obtain baseline information on the number and types of these organisms in both the Cape Fear River and the Whiteoak-Buckhorn Creeks.

8.8.2.1.4 Effects on Fishes by Intake Structure and Condenser Cooling Systems

The make-up reservoir will contain approximately 4,000 acres of habitat suitable for a viable fishery. While there is no appreciable sport fishery in the streams of the Buckhorn-Whiteoak watershed presently (Louder, 1963; Huber, 1969),[2,3] the proposed reservoir should offer a good fishing opportunity to anglers. No species of commercial importance are expected in the lake; however, important game fish expected are as follows:

White crappie (*Pomoxis annularis*)
Black crappie (*Pomoxis nigromaculatus*)
Largemouth bass (*Micropterus salmoides*)
Chain pickerel (*Esox niger*)
Warmouth (*Lepomis gulosus*)
Redbreast sunfish (*Lepomis auritus*)
Bluegill (*Lepomis macrochirus*)
Green sunfish (*Lepomis cyanellus*)

The proposed make-up reservoir is expected to be moderately productive. Carrying capacity projections for the new reservoir should range between 150 to 225 pounds of fish per acre. These estimates are based on rotenone samples by Phillips (1966) [5] on moderately productive reservoirs in the Piedmont of North Carolina. It is felt that these reservoirs would be most typical of the proposed makeup reservoir; however, these lakes are not makeup or cooling facilities.

Concern must be given to the effect of the plant operation on the fish populations of the reservoir and the Cape Fear River. All intake structures will have vertical traveling screens of 3/8 inch mesh. Depletion of adult and fingerling fishes by entrainment and impingement on the intake screens cannot be assessed on a quantitative basis, however, the losses are not expected to be significant. Impact will be limited to the immediate waters adjacent to the intake structures. The intake velocities at the intake screens will be limited to less than 0.5 fps and this should enable all but the smallest fish to swim away from the screens.

Considering that practically no fishery exists in the Buckhorn Whiteoak watershed at the present and that impacts due to thermal and mechanical effects of the cooling system are expected to be negligible, an overall gain in productivity for the watershed is expected.

8.8.2.2 Terrestrial Biota

As discussed in detail in subsection 3.6.1.1.2, the proposed reservoir complex will eliminate approximately 4,000 acres of wildlife habitat. This area, because of its poor fertility, does not support any significant wildlife and no known rare or endangered species exist in the area. Therefore, in considering the enhancement potential of the proposed reservoir system, it is felt that the resulting benefits far outweigh the losses of the terrestrial biota. In addition, implementation of the Wildlife Management Program will replace much of the resources that will be lost initially.

8.8.2.3 Chemical Effluents and Water Quality

The systems for handling chemical discharges are in the early design stages and precise information on the design characteristics, types and quantities of materials to be handled, levels of treatment they will receive, and the methods to be used for their release is in the process of being developed. For other pressurized water reactors, sulfuric acid and caustic soda solutions are used in the water treatment plant for regeneration of ion exchange resins and various cleaning compounds are used throughout the plant. Chromates and borates are used at other locations in the plant. The Harris Plant will include provisions for neutralizing, pH and chemical testing of the chemical discharges. Chemical water handling systems will be provided to assure that discharges meet

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North Carolina Water Quality Standards approved by EPA. A wastewater treatment plant will be installed to process all domestic wastes from the plant. The treatment plant will be designed in accordance with applicable state and local regulations.

The water quality standards of North Carolina have been approved by the EPA and as such these standards will be used as design objectives for releases from the Harris Plant. By meeting these standards, the effect of any releases is expected to be minimal.

8.8.2.4 Consumption of Water

There will be no loss of domestic or municipal water supplies downstream of the plant as a result of construction and operation of the Harris Plant. There are no surface water uses of Buckhorn Creek downstream of the Harris Project. The municipal surface water uses of the Cape Fear River downstream of Buckhorn Dam were discussed in subsection 3.2.2.

The water released to the Cape Fear River from the reservoir will not be degraded in quality due to the cooling uses; therefore, domestic and municipal water consumption will not be affected.

There are no known withdrawals for irrigation from the Cape Fear River. The principal economic crop in the Cape Fear Basin is tobacco; however, the land along the Cape Fear is not generally suited to production of tobacco. Tobacco is grown in the uplands and irrigation water, if used, is taken from farm ponds or wells.

As a result of information from discussions with various federal, state, and local agencies, it has been determined that the Harris Plant will not significantly affect agricultural, municipal, or industrial surface water uses of the Cape Fear River downstream of the Harris Plant.

8.8.2.5 Chemical Discharge to Ambient Air

Because nuclear powered units do not burn fossil fuels for heat production, there will be essentially no chemical discharge to the ambient air as a result of operation of the Harris Plant. There will be some discharges from the occasional testing of emergency diesel generators. This occasional testing will be only for brief periods and not continuous. Those releases that are made, which would be typical combustion products, will comply with appropriate air quality standards.

8.8.2.6 Chemical Contamination of Groundwater

Chemical treatment systems for the plant are in the early design stages as previously mentioned. Although precise information on releases is not yet available, these releases will meet applicable standards.

The effect of these chemicals on groundwater is expected to be negligible. The imperviousness of the soils materials at the site and the distance to the nearest public water supply combine conditions which make it highly improbable for chemical releases to contaminate wells used for public water supply.

8.8.2.7 Radiological Impacts

The Shearon Harris Nuclear Power Plant will be equipped with a comprehensive waste processing system as described in subsection 3.7. The system features hold-up of gaseous wastes except for containment purges and minor leaks and planned releases under controlled conditions. In addition the system is equipped for liquid waste processing by filtration, evaporation, and ion exchange. The release estimates have been made in subsection 3.7.2 of this report and they are within the numerical guides for design objectives set forth in the proposed Appendix I to 10 CFR 50 dated June 9, 1971 and are believed to be as low as practicable. A complete discussion of the radiological effects is contained in subsection 3.6.1.2 and estimated doses are contained in subsections 3.7.3 and 3.7.4.

The imperviousness of the soils materials at the site and the distance to the nearest public water supply combine conditions which make it highly improbable for radioactive liquids to contaminate wells used for public water supply.

8.8.2.8 Fogging and Icing

The potential for increased ground fogging and icing due to the cooling towers is minimal due to the height of the release and the bouyancy of the plume. No icing is expected on structures less than 240 feet tall (half the height of the towers). A light mist may occur over the surface of the reservoir under certain conditions, but this will not extend away from the reservoir far enough to create any hazard to roads.

8.8.2.9 Raising/Lowering of Groundwater Levels

The impoundment of the makeup reservoir will cause no decrease in domestic water supplies in nearby communities. The nearest communities using groundwater for public water supply are Holly Springs and Fuquay-Varina; both are in Wake County. Holly Springs, about seven miles east of the plant site, has two wells which supply about 40,000 gallons per day.

Fuquay-Varina, about ten miles southeast of the plant site, has eight wells which supply about 400,000 gallons per day. These wells produce water from a crystalline rock aquifer which does not exist anywhere in the plant area or its immediate environs, and the plant is not expected to interfere with potable water use in the area.

8.8.2.10 Ambient Noise

Noise levels in the vicinity of the Harris Plant have been investigated using the HUD "Noise Assessment Guidelines" published in August of 1971. These guidelines contain four categories: clearly unacceptable (≥80 dba), normally unacceptable (65-80 dba), normally acceptable (<65 dba), and clearly acceptable (<45 dba). Noise levels are anticipated to be 65 dba at 700 feet from the plant. Assuming no attenuation of the noise other than atmospheric, a noise level of less than 45 dba would be expected 8,000 feet from the plant. The Harris exclusion area extends 7,000 feet from the plant. Based on noise abatement of trees and shrubs (Cook and Van Haverbeke, 1971)[7] noise levels from the Harris

Plant in excess of 45 dba are not expected outside the 7,000 foot exclusion area as a result of plant operations; therefore, noise levels resulting from plant operations should not have an adverse effect upon the area surrounding the plant. In addition a "Sound Control Program" has been developed for the plant and noise levels will be in compliance with the Occupational Safety and Health Act.

8.8.2.11 Aesthectics

The evaluation of the impact upon the aesthetics of an area is difficult to reduce to a single statement indicating enhancement or adverse effects, since the subject itself has diverse meaning to different individuals.

The proposed plant will be situated in a remote, rural, area predominately devoted to low grade timber and pasture area. The impact on aesthetics is discussed in subsection 3.9 of the report. The reservoir is expected to enhance the aesthetic appeal of the area. No loud noises will be associated with the operation of the plant, as discussed in Subsection 8.8.2.10. The major aesthetic impact of the plant will arise from the cooling towers, which will dominate the outline of the plant. The magnitude of this impact is, however, individually subjective and cannot be quantified as a whole.

8.8.2.12 Effects of Construction Activity

The effects of the construction of the plant on the surrounding area were discussed in Subsection 3.8 of this report. The main effect is that of converting the land from its present use to use for generating facilities. As discussed in other portions of this report, the land use requirements of the plant are felt to be a well balanced trade-off and the net effect minimized.

There will be no restriction of accessibility to historical or archaeological sites, nor will the setting of any historical site be modified. Property values in the area should, if previous patterns prevail, rise considerably due to the existence of the reservoir and its recreational attractions. In addition, some measure of benefit to flood control in the region will result from creation of the reservoir.

Erosion control at the site area will be a major consideration during construction of the reservoir. Precise information on the effects of erosion occurring over and above the normal erosion expected is not readily available; however, all efforts will be made to keep erosion to a minimum.

REFERENCES FOR SUBSECTION 8.8

1. Louder, D. E. 1968. Success. Wildlife in North Carolina. N. C. Wildlife Resources Commission. 32:5. pp. 23-24.

2. Louder, D. E. 1963. Survey and Classification of the Cape Fear River and Tributaries, North Carolina. Final Report. Federal Aid in Fish Restoration, Job I-6, Project F-14-R. N. C. Wildlife Resources Commission. Raleigh, N. C. pp. 96.

3. Huber, R. T. 1969. Preliminary Biology Investigation Whiteoak Creek Watershed (NI Watershed 3-14). Unpublished report. Bureau of Sport Fisheries and Wildlife. Raleigh, N. C.

4. Copeland, B. J. 1970. North Carolina State University. Pers. Comm.

5. Phillips, H. A. 1966. Lower Yadkin and Catawba River Reservoirs - 1965 Surveys. Unpublished Report. N. C. Wildlife Resources Commission. Raleigh, N. C.

6. Phillips, H. A. 1969. Fisheries Investigation in Lakes and Streams. S. C. Wildlife Resources Department. Annual Progress Report.

7. Cook, D. I., and D. F. Van Haverbeke. 1971. Trees and Shrubs for Noise Abatement. The Forest Service, USDA; University of Nebraska College of Agriculture. Res. Bull. 246. pp. 77.

TABLE 8.8-1

ENVIRONMENTAL COSTS OF PROPOSED PLANT

Primary Impact	Population or Resource Affected	Description of Effect	Effect
1. Heat Discharge into Cape Fear River	1.1 Cooling Capacity of Water Body	Capacity loss (downstream)	None Lost
	1.2 Aquatic Biota	Change in species diversity or abundance	Slight. State (EPA Approved) Standards will be met for thermal releases.
	1.3 Migratory Fish	Interference with migration or spawning	No migratory fish
2. Effects on Cape Fear River and reservoir of Intake Structure and Condenser Cooling System	2.1 Primary Producers and Consumers	Abundance altered due to thermal and mechanical effects.	Expected losses slight. experimental studies will be initiated. Overall gain for the watershed expected.
	2.2 Fisheries	Abundance altered due to thermal and mechanical effects.	Expected losses slight. Experimental studies will be initiated. Overall gain for the watershed expected.
3. Chemical Discharge to Water Bodies	3.1 People	Recreational use	Increase in recreation for the area. Applicable state standards will be met. No inhibition to new recreation expected. No change in Cape Fear use.

TABLE 8.8-1 CONT'D

Primary Impact	Population or Resource Affected	Description of Effect	Effect
	3.2 Aquatic Biota	Possible toxic effects on biota	Applicable state standards will be met. Treatment systems under design and no significant effects expected.
	3.3 Water Quality - Chemical	Downstream water quality	Applicable state standards will be met. No adverse effects expected.
4. Consumption of Water	4.1 People	Diminish domestic water supply	No loss to users
	4.2 Property	Degradation and loss to agriculture	No significant agricultural users downstream on Cape Fear River
5. Chemical Discharge to Ambient Air	Air Quality - Chemical	Releases to ambient air	Occasional releases auxiliary boilers and from testing of emergency diesel generators. Would meet State Air Quality Standards.
6. Chemical Contamination of Groundwater (excluding salts)	6.1 People	Domestic supplies	Negligible
	6.2 Plants	Trees, deep-rooted vegetation	Negligible
7. Radionuclides Discharged to Water Body	7.1 People - External	Increase over natural background	0.000021 mrem/yr

TABLE 8.8-1·CONT'D

Primary Impact	Population or Resource Affected	Description of Effect	Effect
	7.2 People - ingestion fish & water*	Increase over natural background	0.189 mrem/yr (whole body) 0.190 mrem/yr critical organ
	7.3 Primary Consumers	Increase over natural background	Negligible w.r.t. damage
8. Radionuclides Discharged to Ambient air	People	Increase over natural background	Average: 0.46 mrem/yr per capital
9. Radionuclide Contamination of Groundwater	9.1 People	Increase over natural background in water supplies	Negligible, due to imperviousness of soils and distance to wells.
	9.2 Plants and Animals	Increase over natural background	Negligible due to imperviousness of soils
10. Fogging and Icing	10.1 People	Safety hazards	No road, air hazards. No river navigation.
	10.2 Plants	Damage to trees and crops	No effect

*Hypothetical maximum exposed individual. See Section 3.7 for description

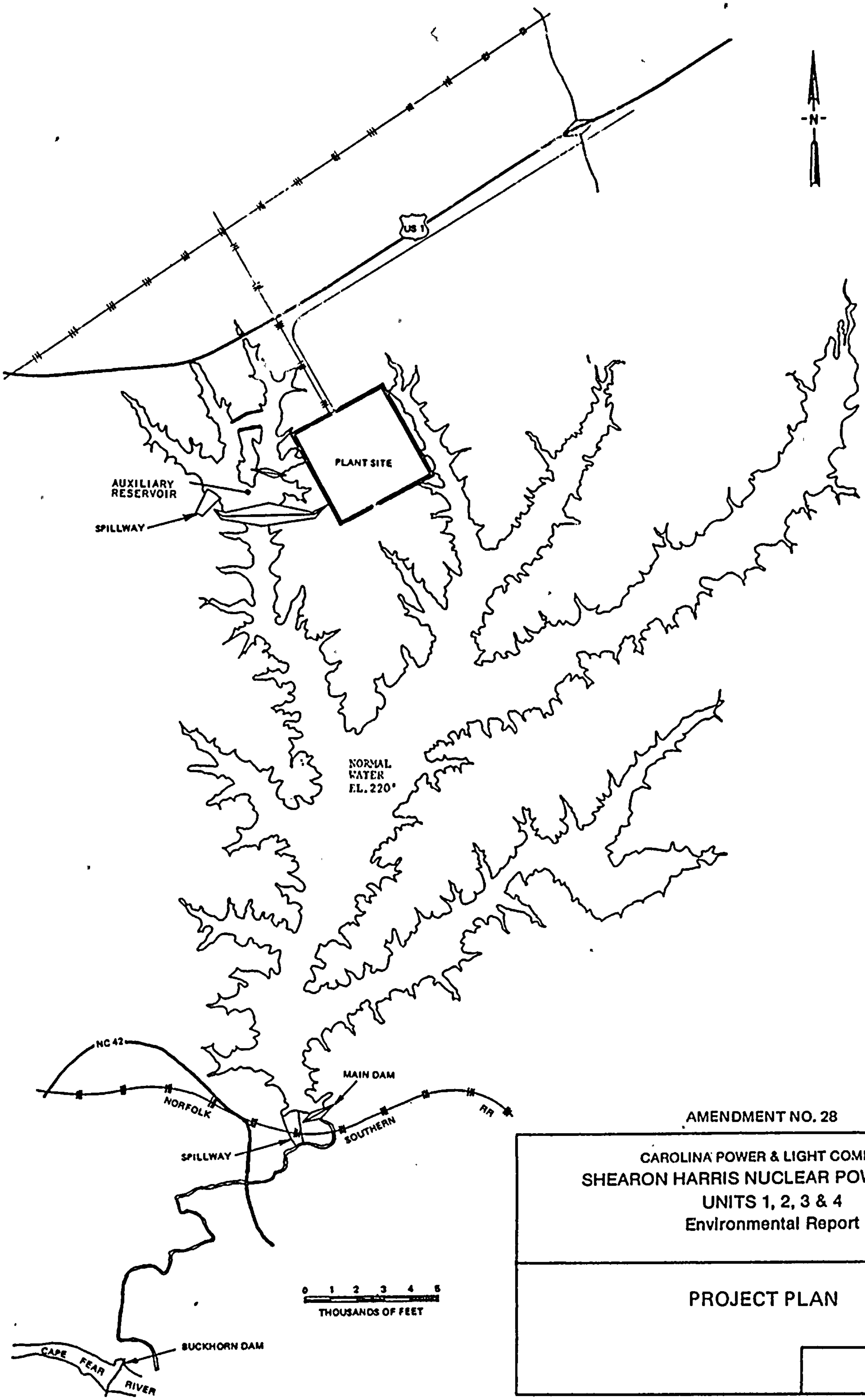
TABLE 8.8-1 CONT'D

	Primary Impact	Population or Resource Affected	Description of Effect	Effect
11.	Raising/Lowering of Groundwater Levels	People	Diminish domestic supply from wells.	No adverse effect.
12.	Ambient Noise	People	Loud noises	No increase over clearly acceptable levels.
13.	Aesthetics	Appearance	In terms of sight, sound, and odor	Visual changes in natural setting
14.	Permanent Residuals of Construction Activity	14.1 Accessibility of Historical and archeological Sites	Displacement or impingement	No effect
		14.2 Setting of Historical Sites	Local landscape viewed from historical sites may be modified	No effect
		14.3 Property	Value of property near site will be affected.	Increase in value expected to owners.
		14.4 Flood Control	Health and safety may be affected	Slight benefit to flood control.
		14.5 Erosion Control	May affect aesthetics, aquatic life, land values.	Soil erosion during construction, but after reservoir is constructed, no adverse effects.

9.0 CONCLUSION

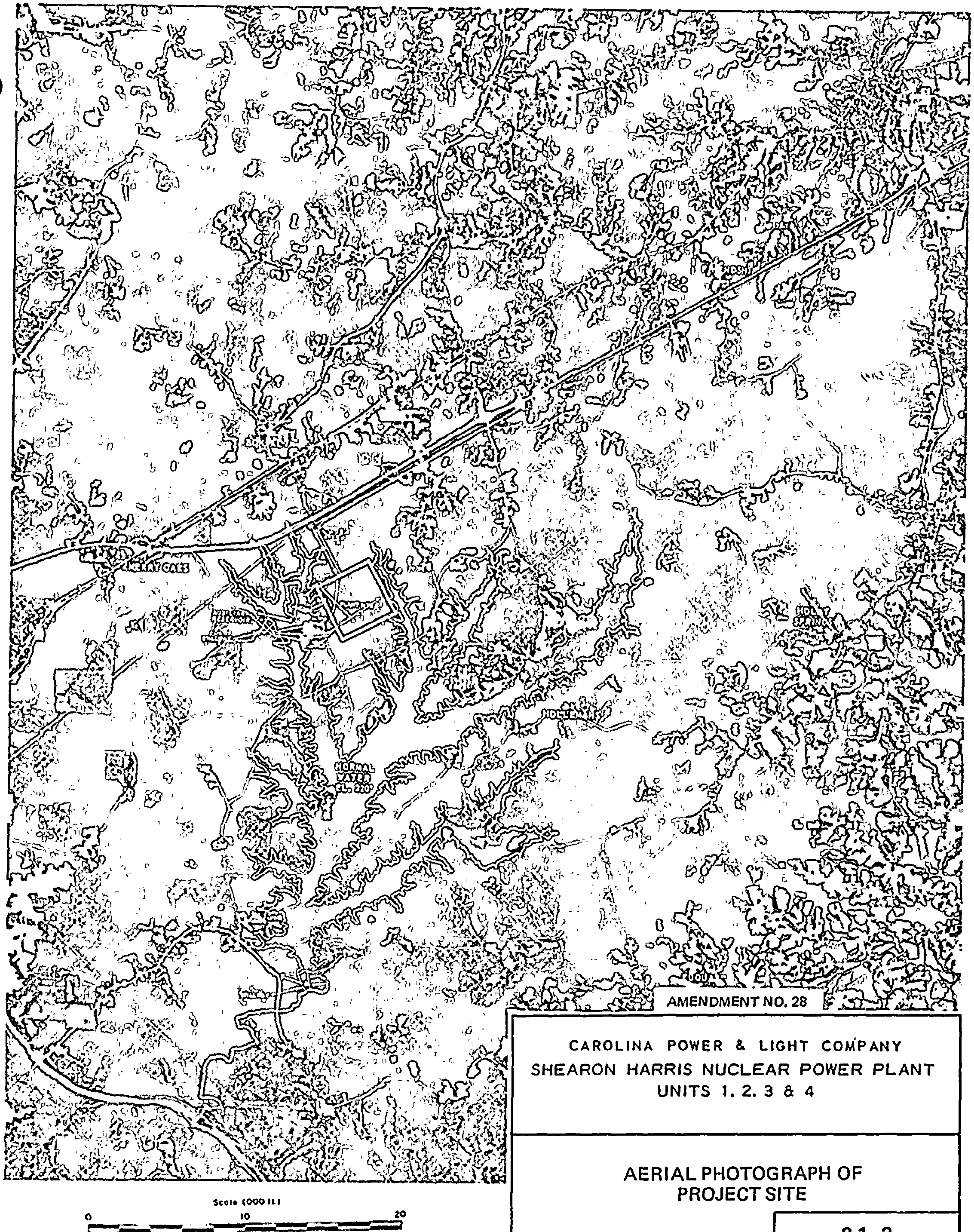
The previous sections of this Environmental Report have presented the details of the Shearon Harris Nuclear Power Plant and evaluated the benefits to society and the environmental impact of the plant. The environmental impact of the plant will not be negligible; however, the various systems of the plant have been selected and designed to minimize the impact. It is an obvious fact that any undertaking of this nature will have an effect upon the environment. The important factor is that any such project should be carefully planned and integrated into the environment in a manner which provides for wise utilization and protection of the environment. This has been a major item of consideration in the overall planning of the plant. The Harris Plant has been designed and will be constructed in accordance with all applicable Federal, State, and local regulations, with the objective of minimizing the environmental impact of the plant.

The Harris Plant will be provided with numerous safety features so that it does not constitute a significant radiation hazard even during any credible event. Considering the direct and indirect benefits to society which will result from building and operating the plant, a desirable balance will be achieved with the impact of the plant.



AMENDMENT NO. 28

CAROLINA POWER & LIGHT COMPANY SHEARON HARRIS NUCLEAR POWER PLANT UNITS 1, 2, 3 & 4 Environmental Report
PROJECT PLAN
2.1-1



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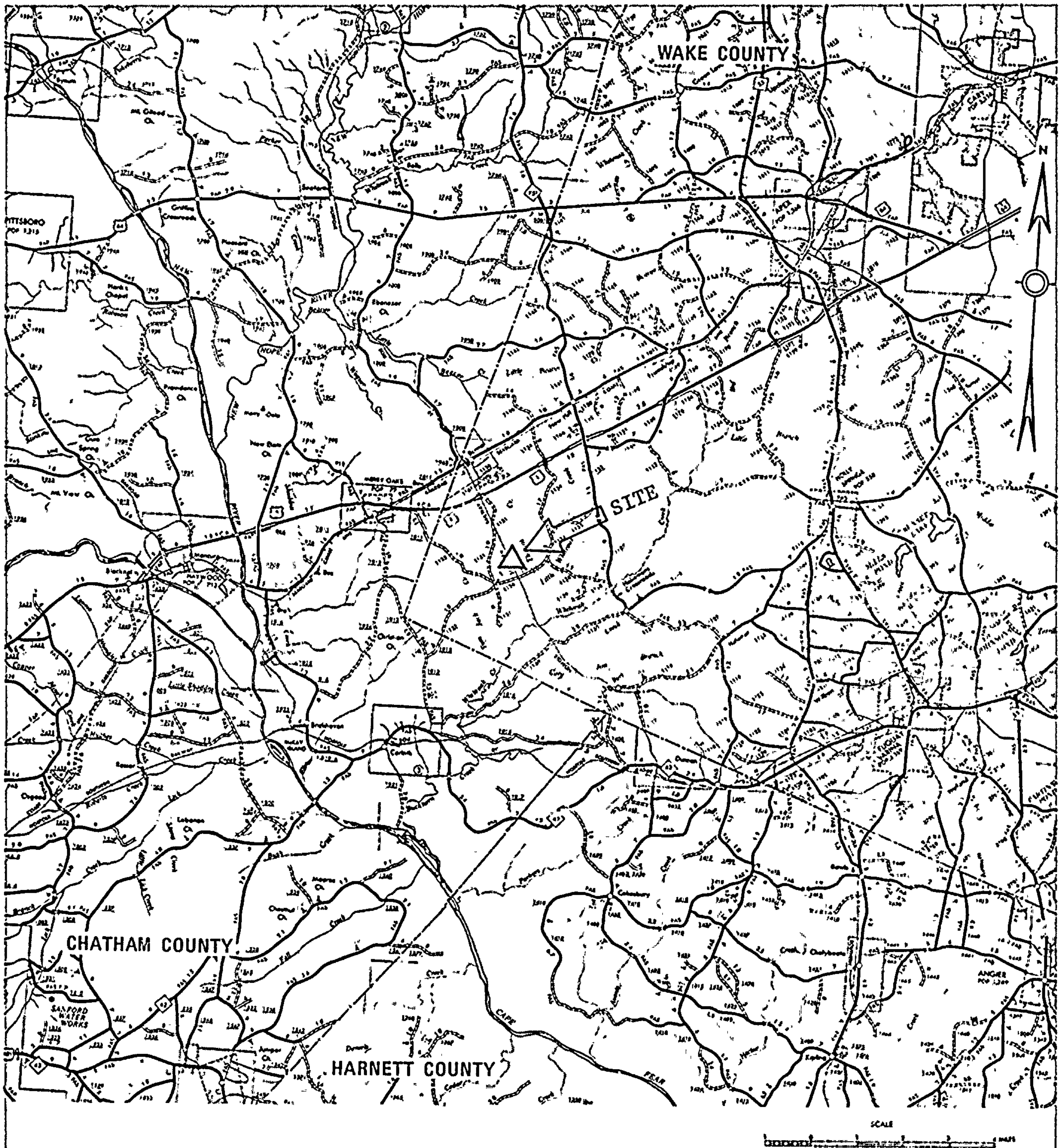
UNITS 1, 2, 3 & 4

AERIAL PHOTOGRAPH OF
PROJECT SITE

2.1–2



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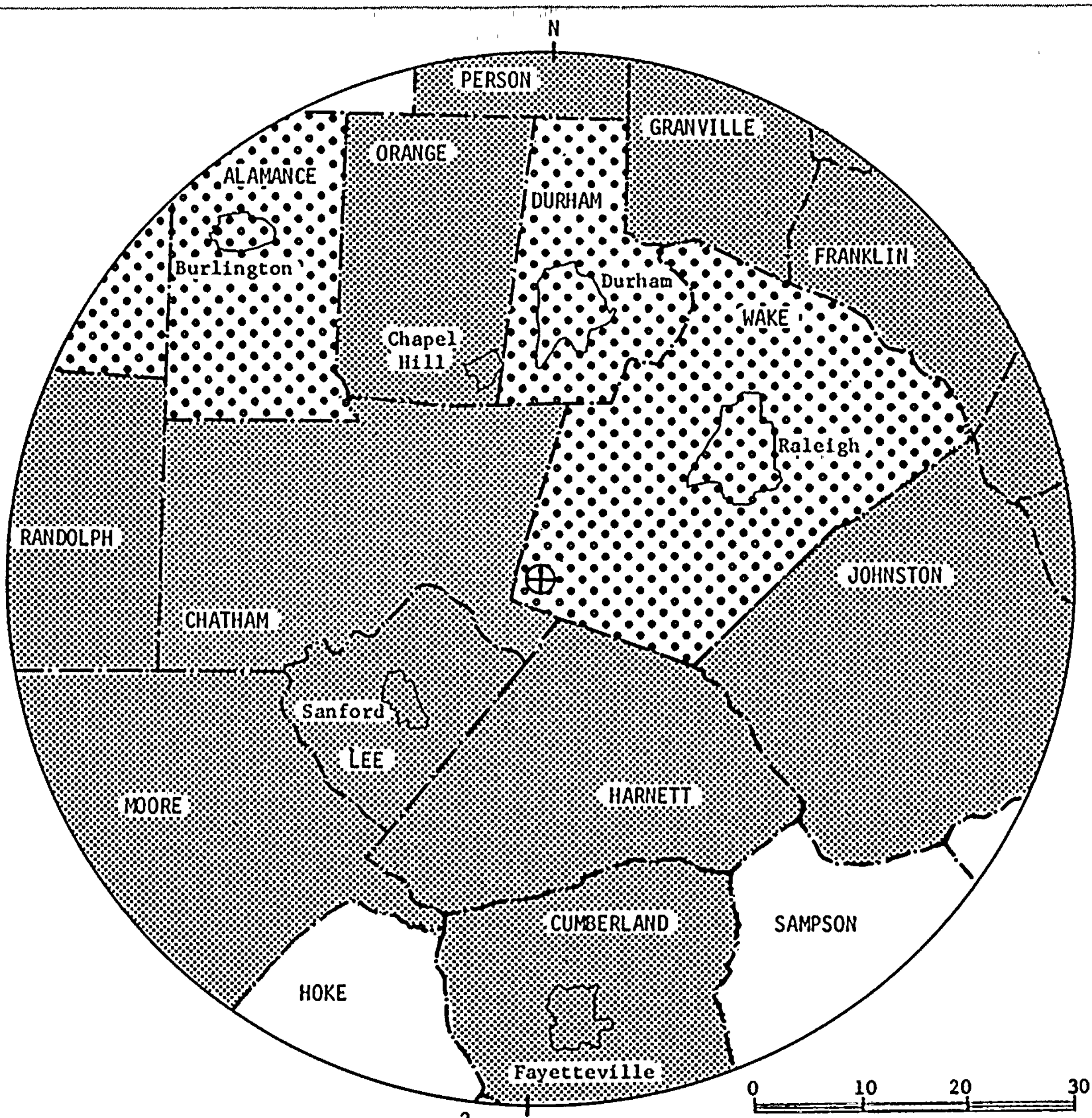
UNITS 1, 2, 3 & 4
Environmental Report

COUNTY MAP OF AREA SURROUNDING THE SITE

2.1-3



less than or equal to $49/mi^2$

$50/mi^2$ to $99/mi^2$

$100/mi^2$ to $149/mi^2$

COUNTY POPULATION DENSITY WITHIN 50-MILE RADIUS OF THE SITE.
DENSITIES EXCLUDES THE CITIES WITH GREATER THAN 10,000 POPULATION.

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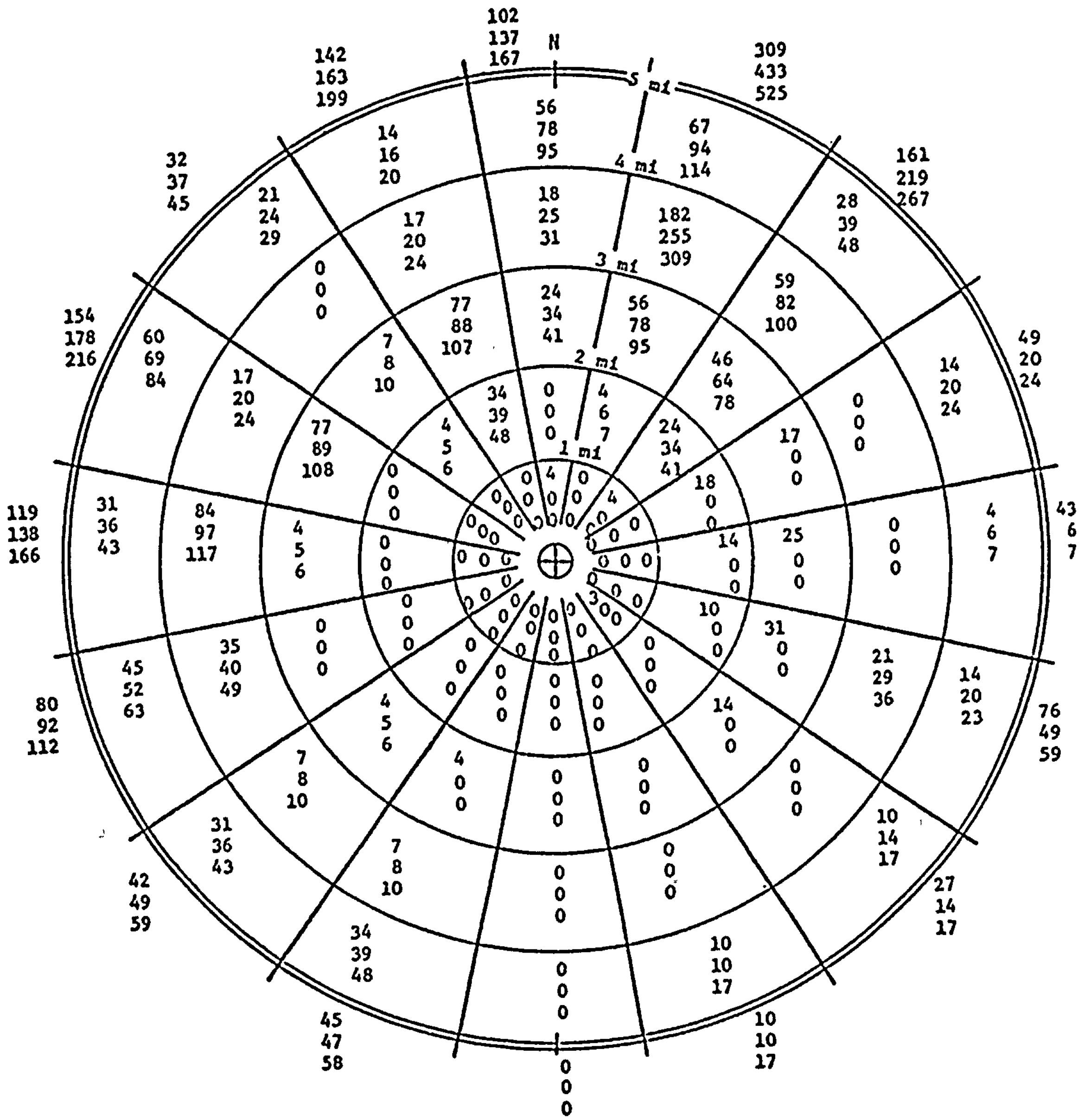
UNITS 1, 2, 3 & 4
Environmental Report

COUNTY POPULATION DENSITY WITHIN
50 MILE RADIUS OF THE SITE

2.1-4



Upper number in each annular sector is for 1970. Middle and lower numbers are projections for 1990 and 2010 respectively. Total of indicated population in each sector is indicated outside the 5-mile radius.

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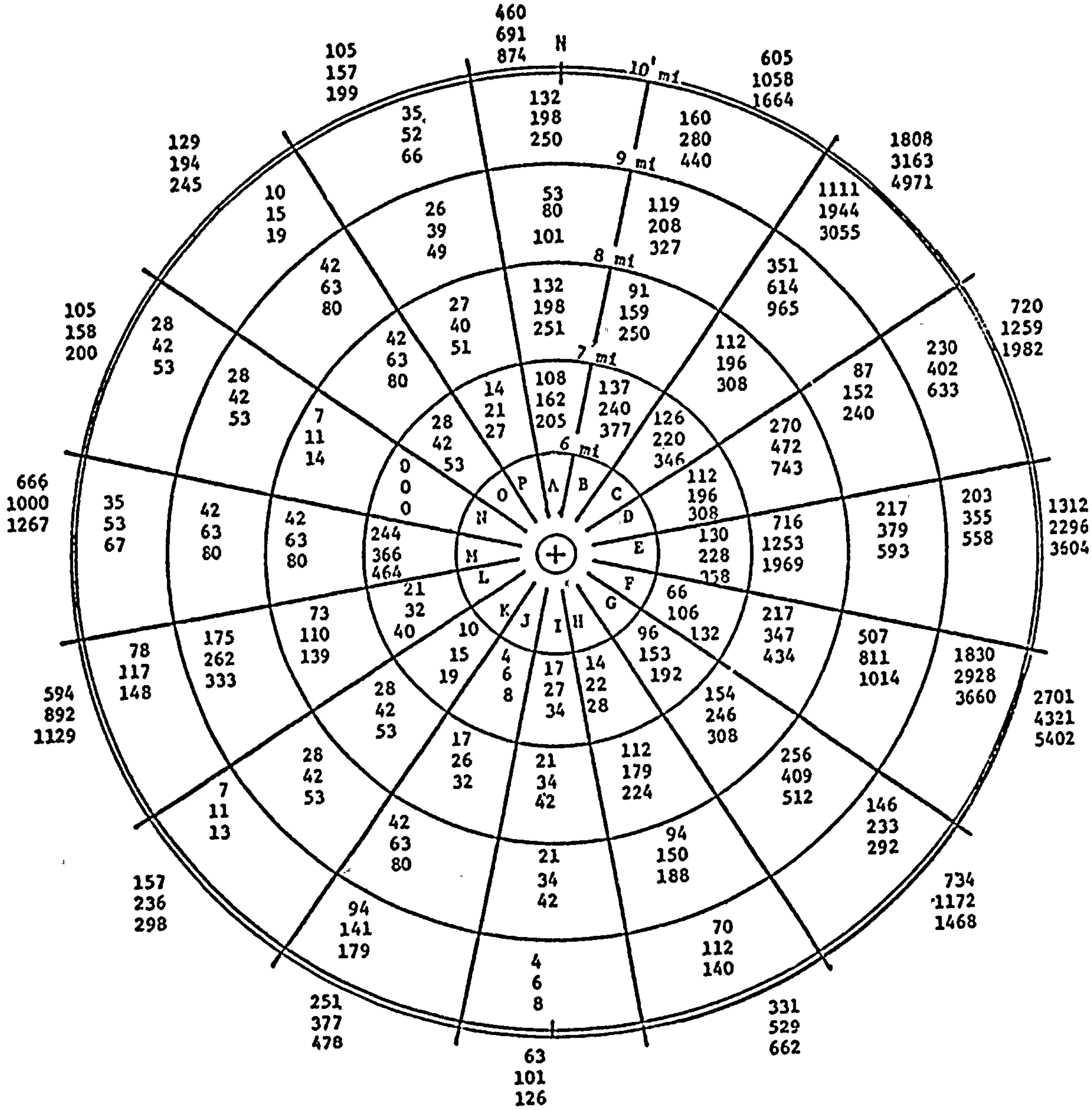
PRESENT AND PROJECTED POPULATION NEAR SITE – 0 TO 5 MILES

2.1-5



	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
1970	35	98	108	21	46	81	82	41	0	94	84	247	303	42	7	3
1990	53	171	189	37	81	129	131	66	0	141	126	371	455	63	11	5
2010	67	270	297	58	126	162	164	82	0	179	160	469	576	80	13	6

Upper number in each annular sector is for 1970. Middle and lower numbers are projections for 1990 and 2010 respectively. A through P represent the populations in the 5 to 6 mile annular sectors. Total of indicated population in each sector is given outside the 10-mile radius.

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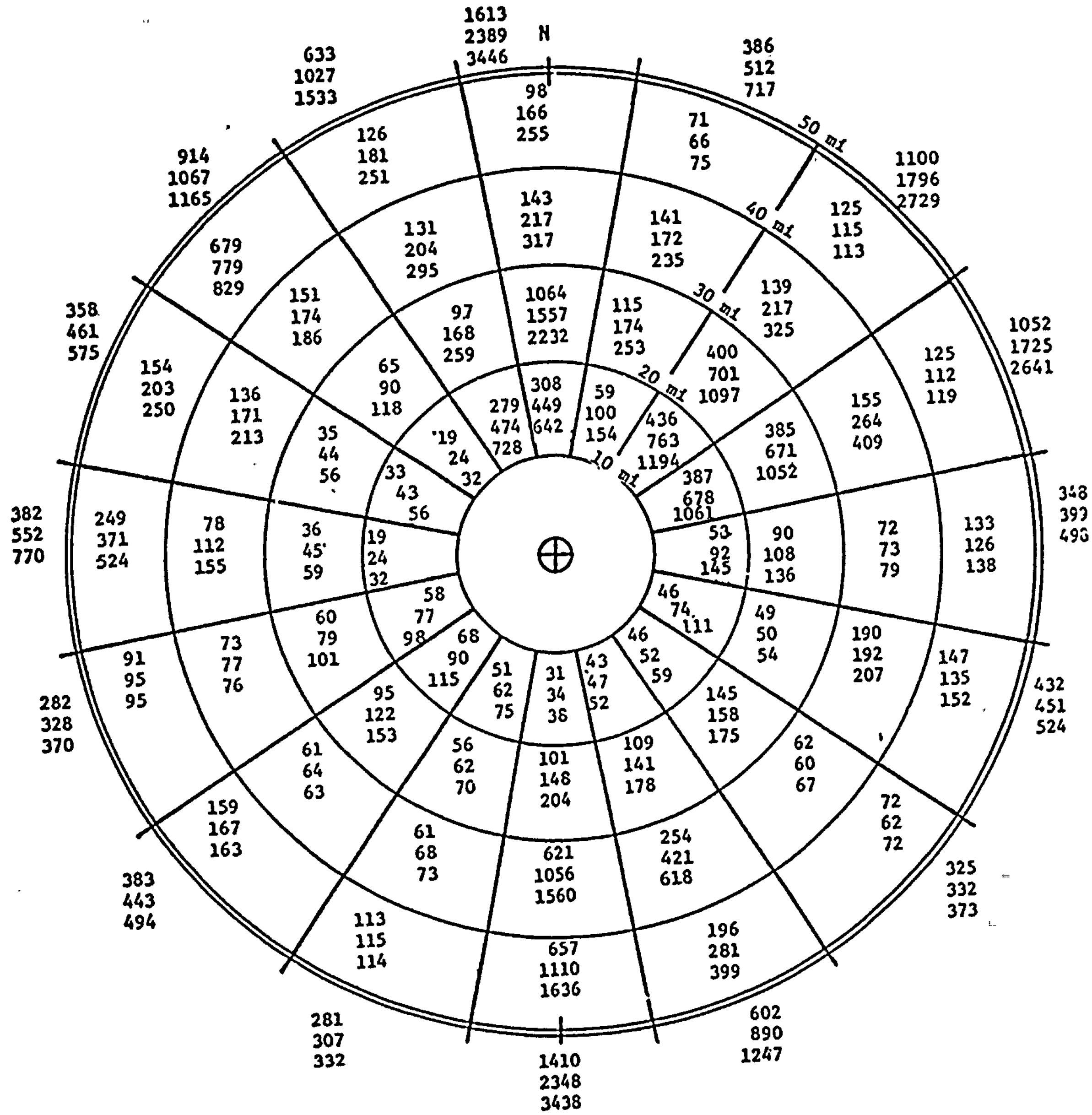
PRESENT AND PROJECTED POPULATION NEAR SITE – 5 TO 10 MILES

2.1-6



Upper number in each annular sector is for 1970 (in hundreds). Middle and lower numbers are projections (in hundreds) for 1990 and 2010 respectively. Total of indicated population in each sector is given outside the 50-mile radius.

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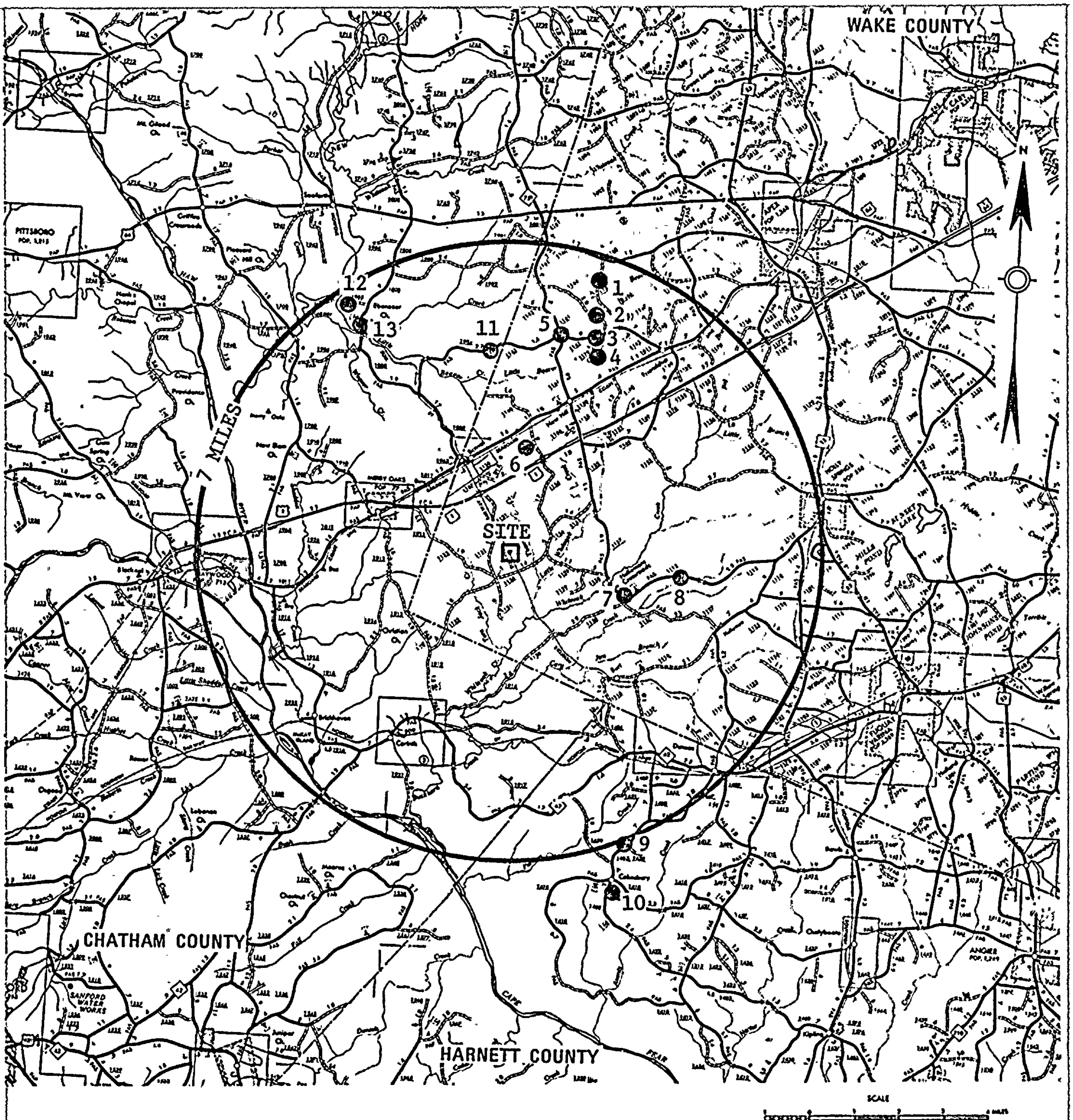
Environmental Report

PRESENT AND PROJECTED POPULATION NEAR SITE – 10 TO 50 MILES

2.1-7



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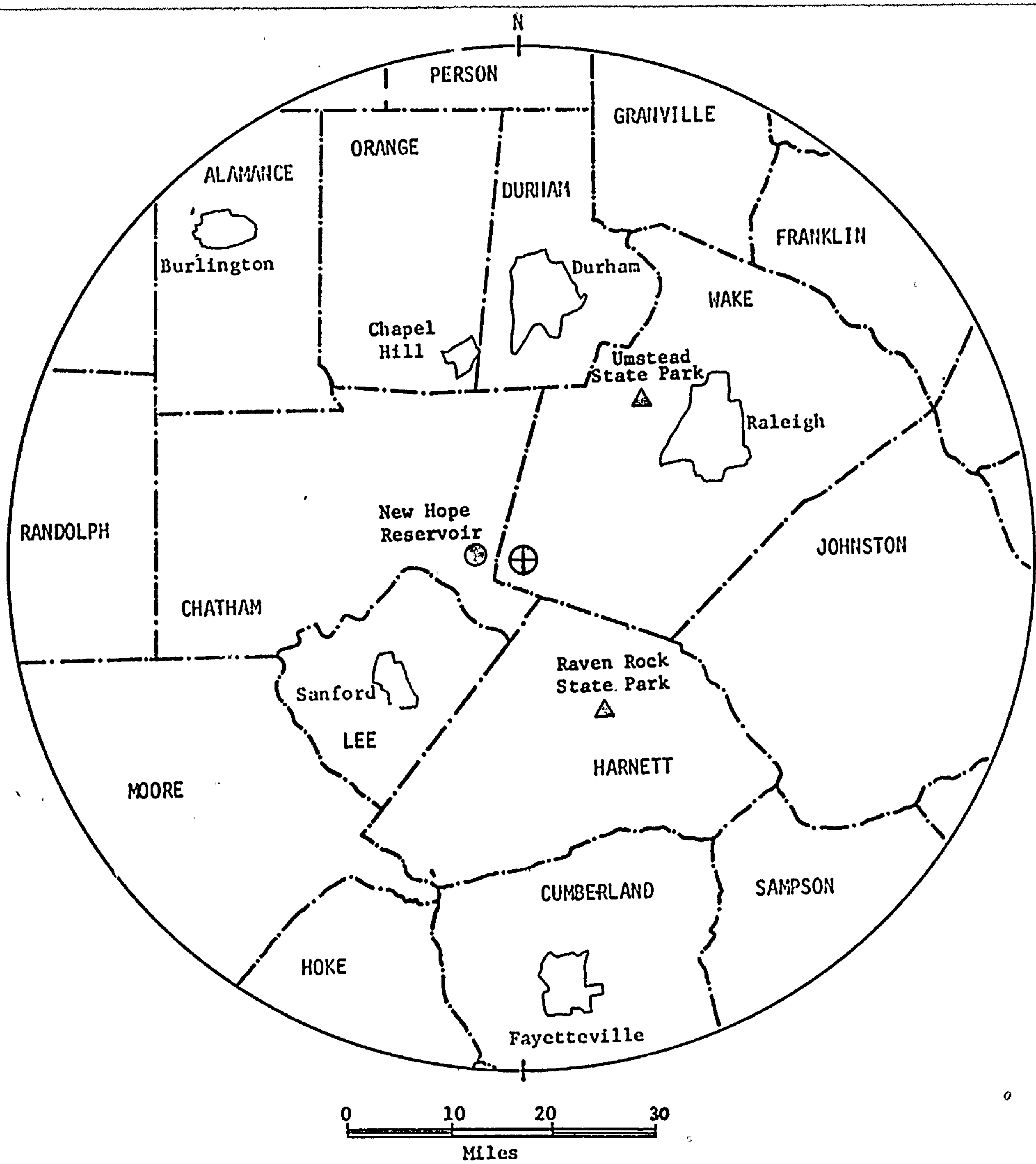
Environmental Report

LOCATION OF DAIRY HERDS NEAR SITE

2.1-8



▲ DENOTES PRINCIPAL EXISTING

● DENOTES PLANNED

CAROLINA POWER & LIGHT COMPANY
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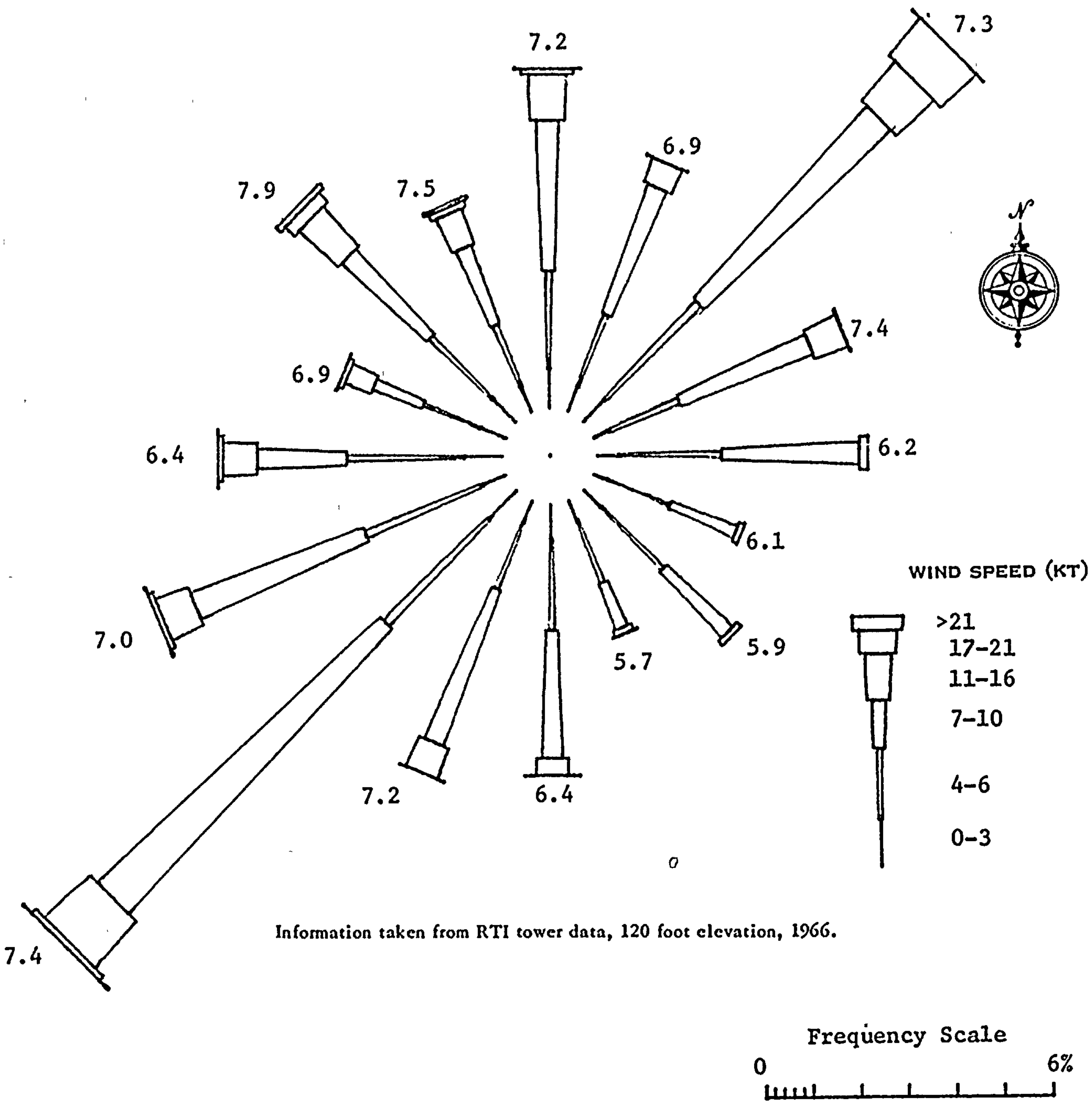
LOCATION OF OUTDOOR RECREATIONAL FACILITIES

2.1-9



Information taken from RTI tower data, 120 foot elevation, 1966.

Average wind speed (all directions): 6.8 kt
Frequency of winds<1 kt: 3.2%

Average wind speed for each direction indicated at extremity of radial.

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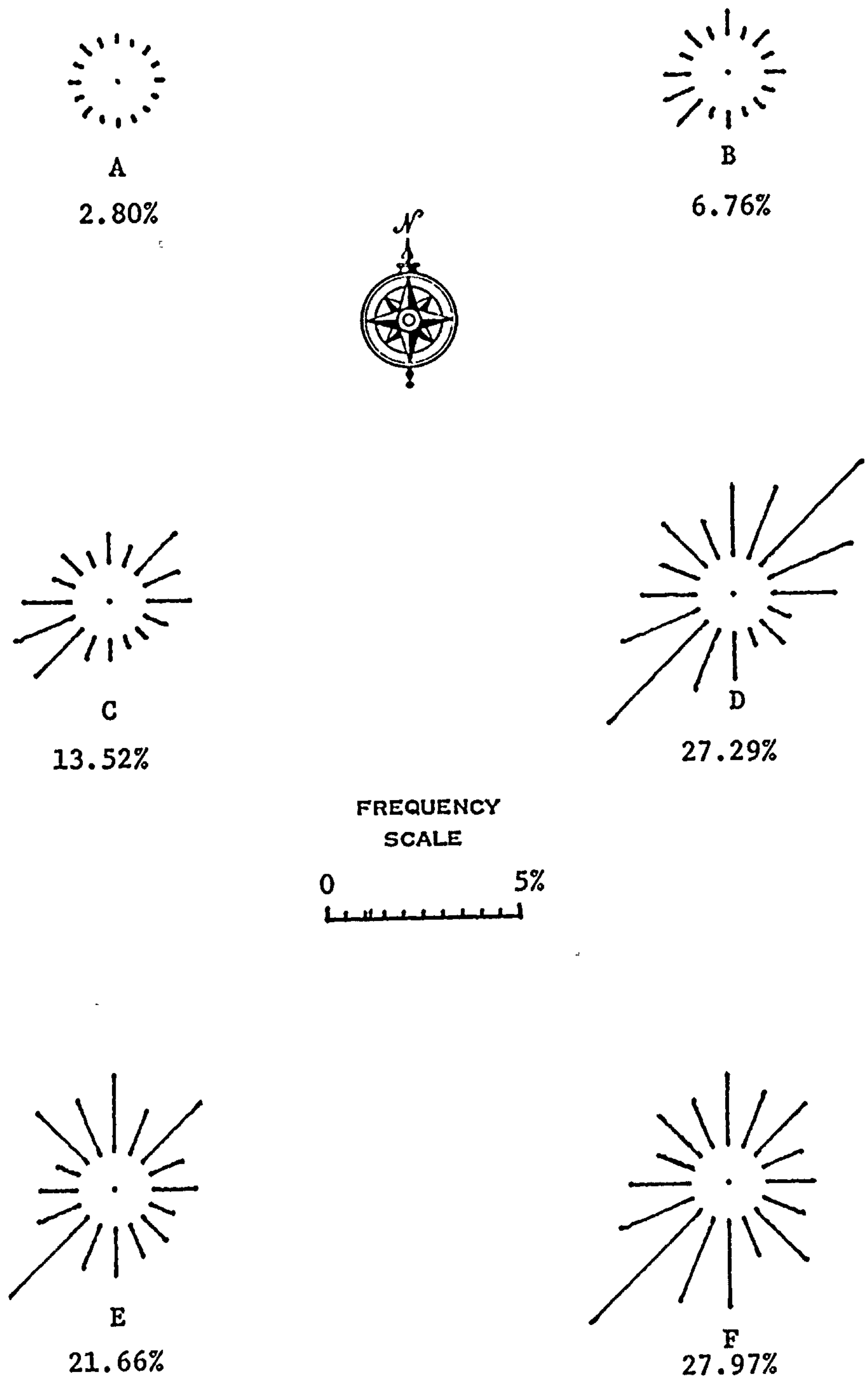
ANNUAL WIND ROSE

2.1-10



Percentage frequency of occurence given for Pasquill stability category. Information taken from RTI tower, 1966.

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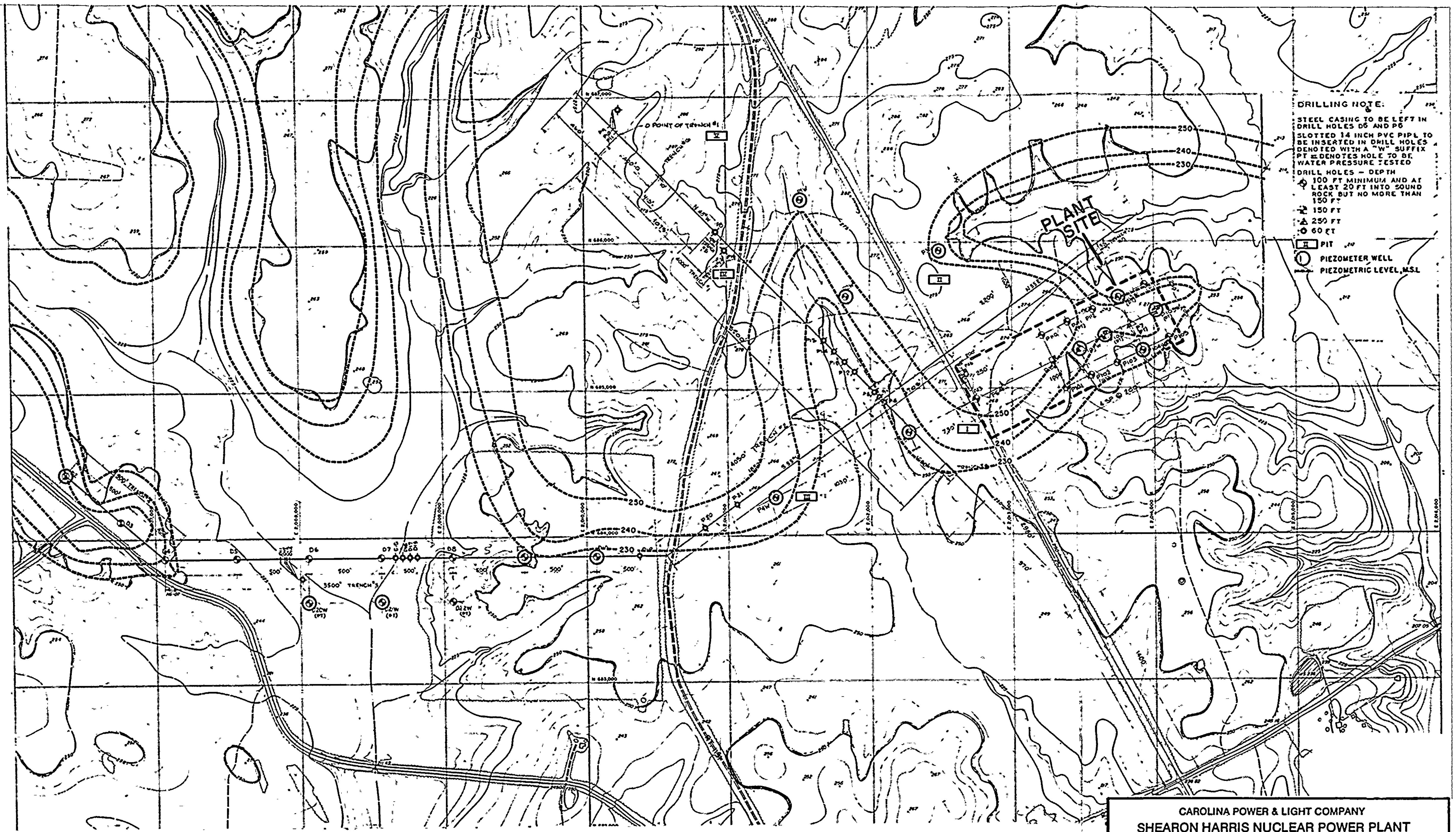
Preliminary Safety Analysis Report

WIND DIRECTION PERCENTAGE FREQUENCY OF OCCURRENCE

2.1-11



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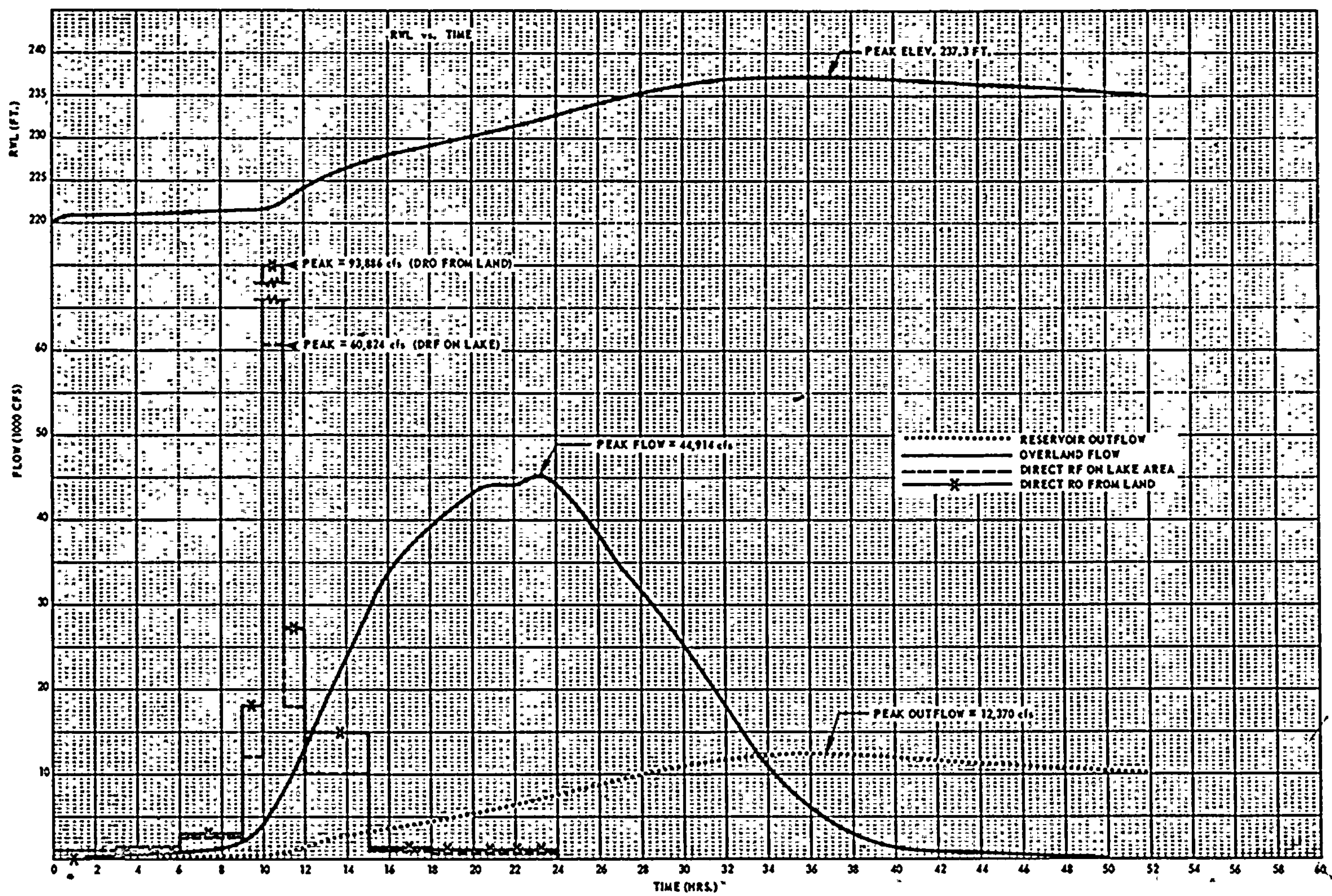
Environmental Report

PIEZOMETRIC LEVELS AND LOCATIONS OF SITE BORINGS

2.1–12



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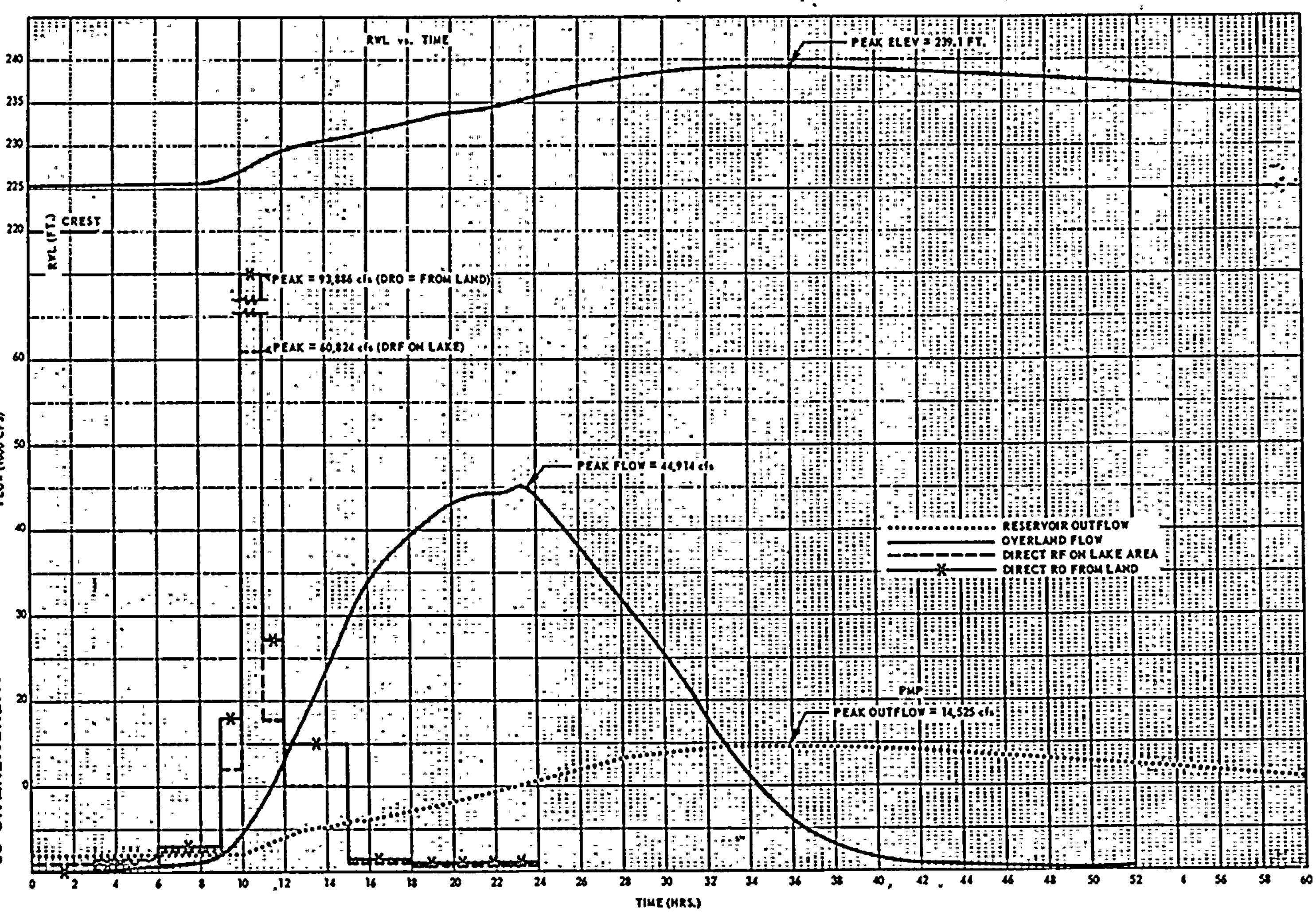
UNITS 1, 2, 3 & 4
Environmental Report

MAIN RESERVOIR INFLOW, OUTFLOW WATER LEVEL HYDROGRAPHS WITHOUT ANTECEDENT FLOOD

2.1-13



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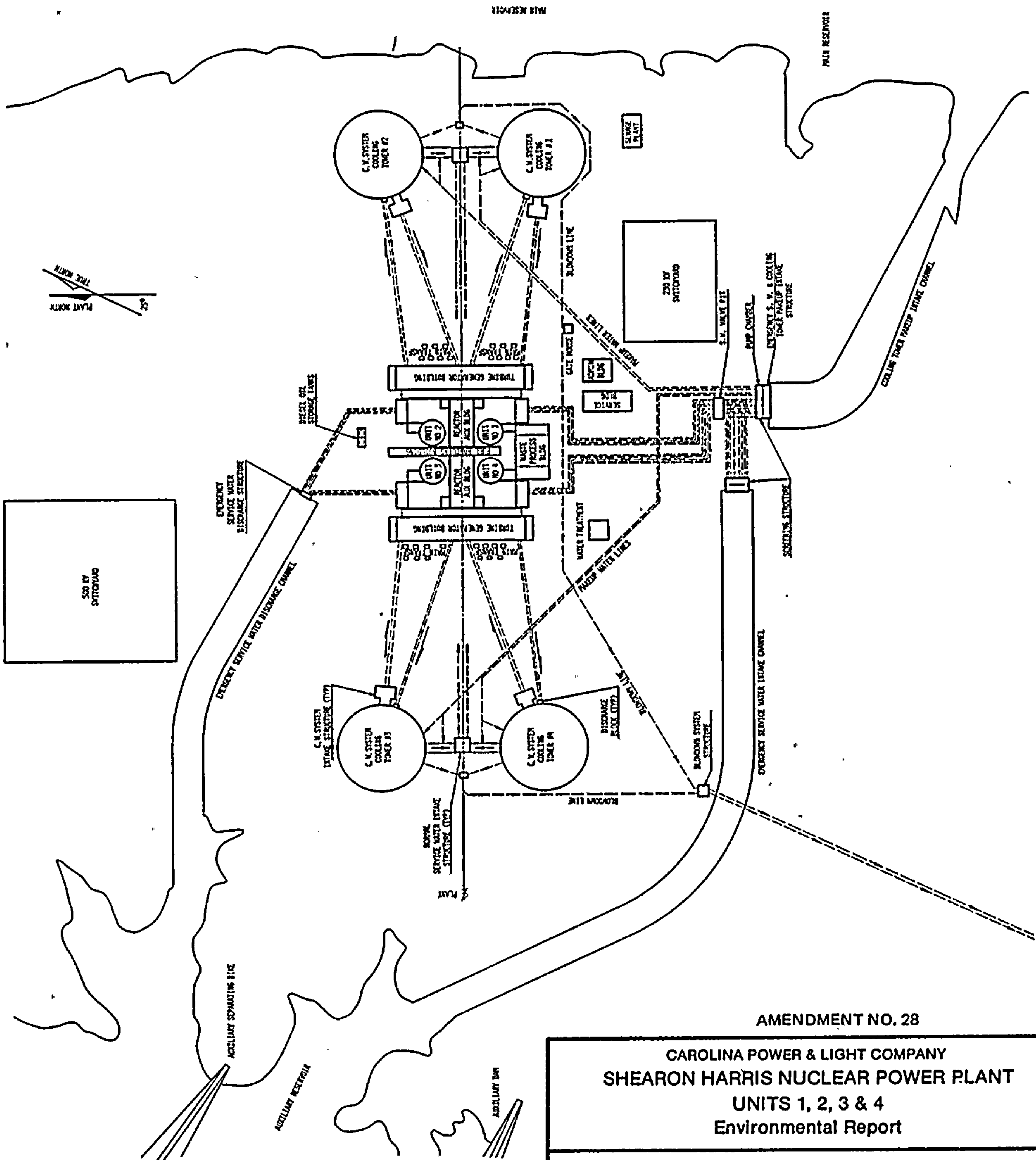
UNITS 1, 2, 3 & 4
Environmental Report

MAIN RESERVOIR INFLOW, OUTFLOW WATER LEVEL HYDROGRAPHS WITH STANDARD PROJECT FLOOD FIVE DAYS PRIOR TO PMP FLOOD

2.1-13A



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SHEARON HARRIS NUCLEAR POWER PLANT

UNITS 1, 2, 3 & 4

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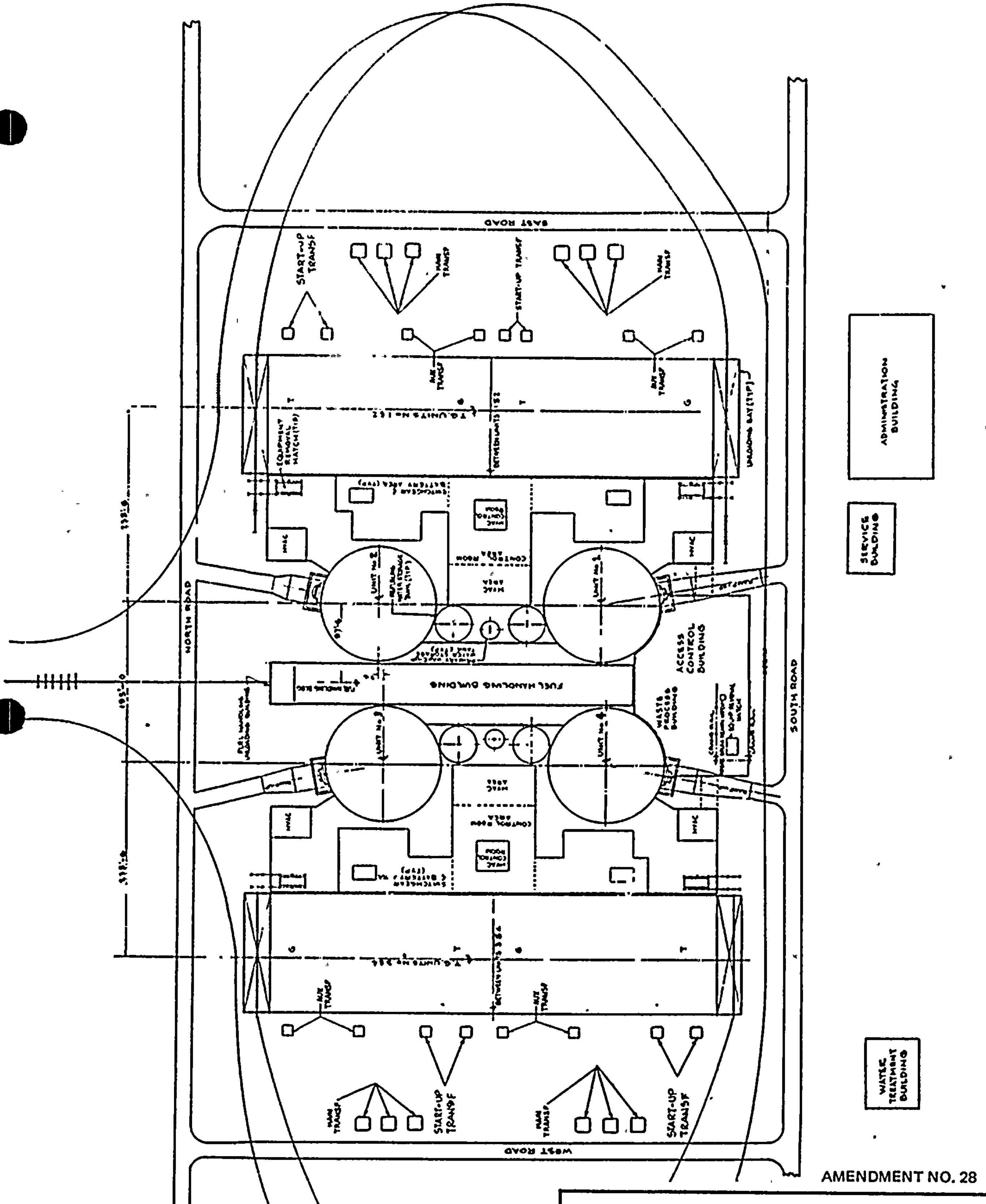
SITE PLAN

2.2—1



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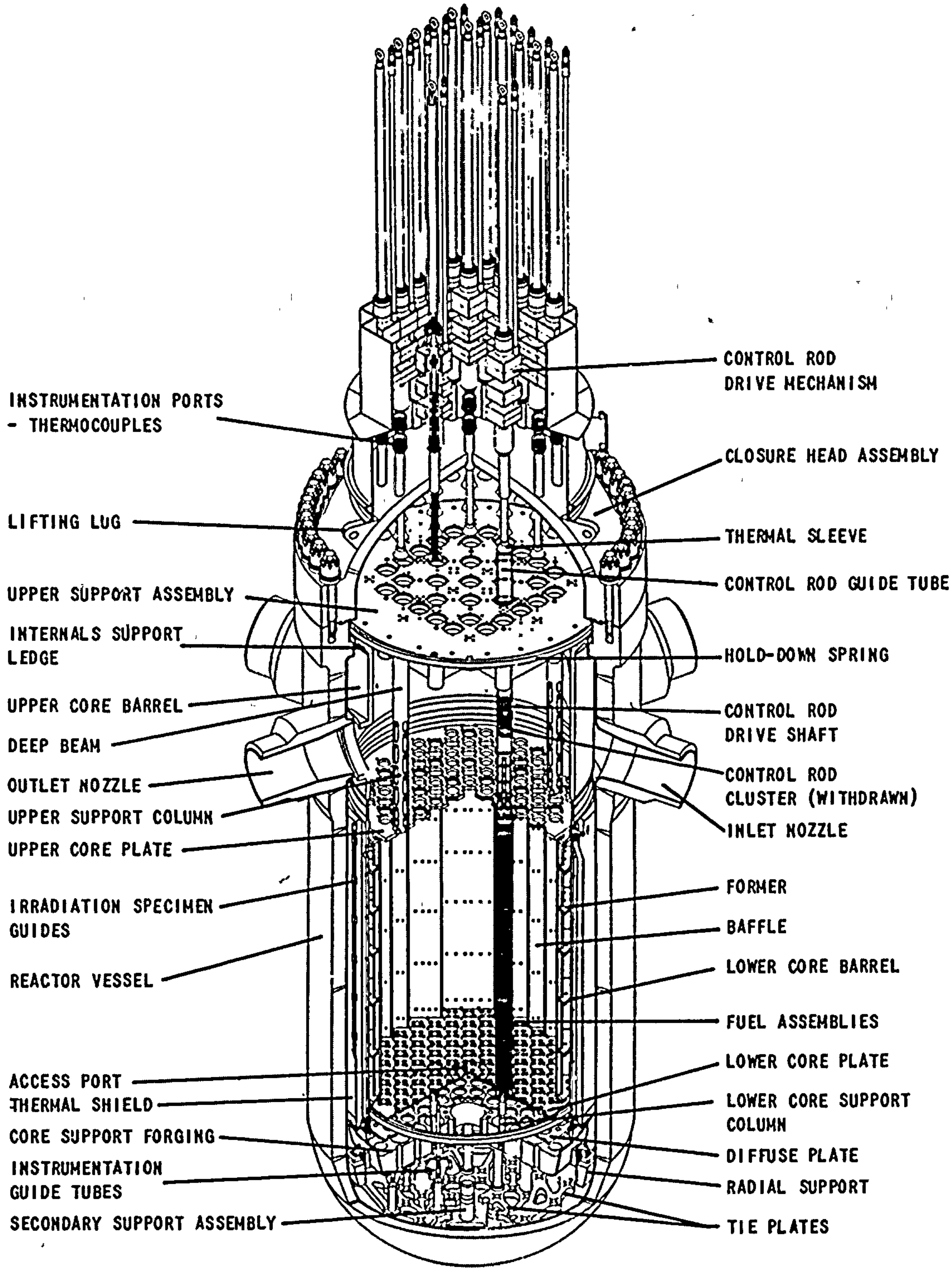
UNITS 1, 2, 3 & 4
Environmental Report

PLOT PLAN

2.2–2



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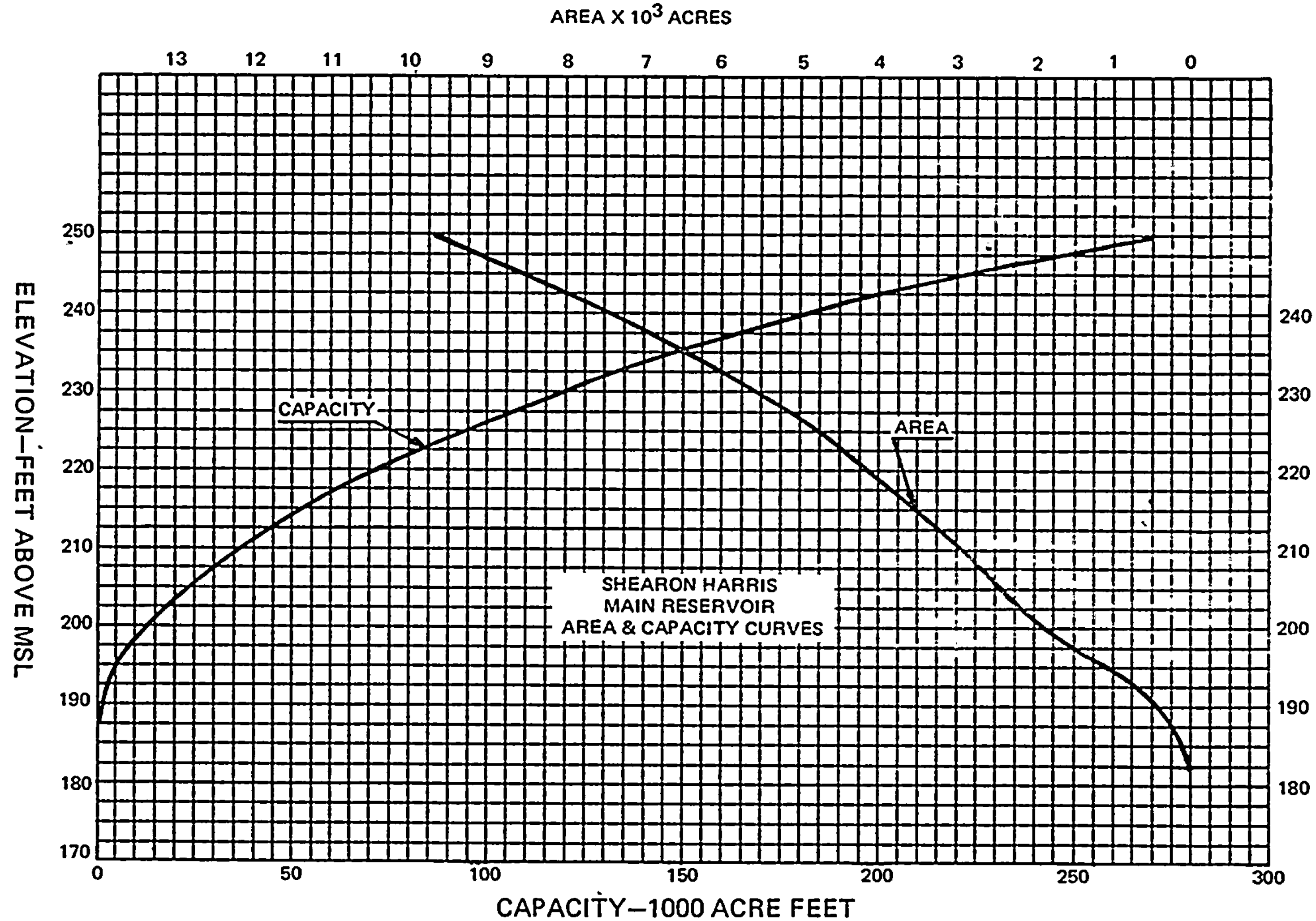
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4

REACTOR VESSEL INTERNALS

2.2-3

FIGURE 2.2-4 WAS DELETED BY
AMENDMENT NO. 28



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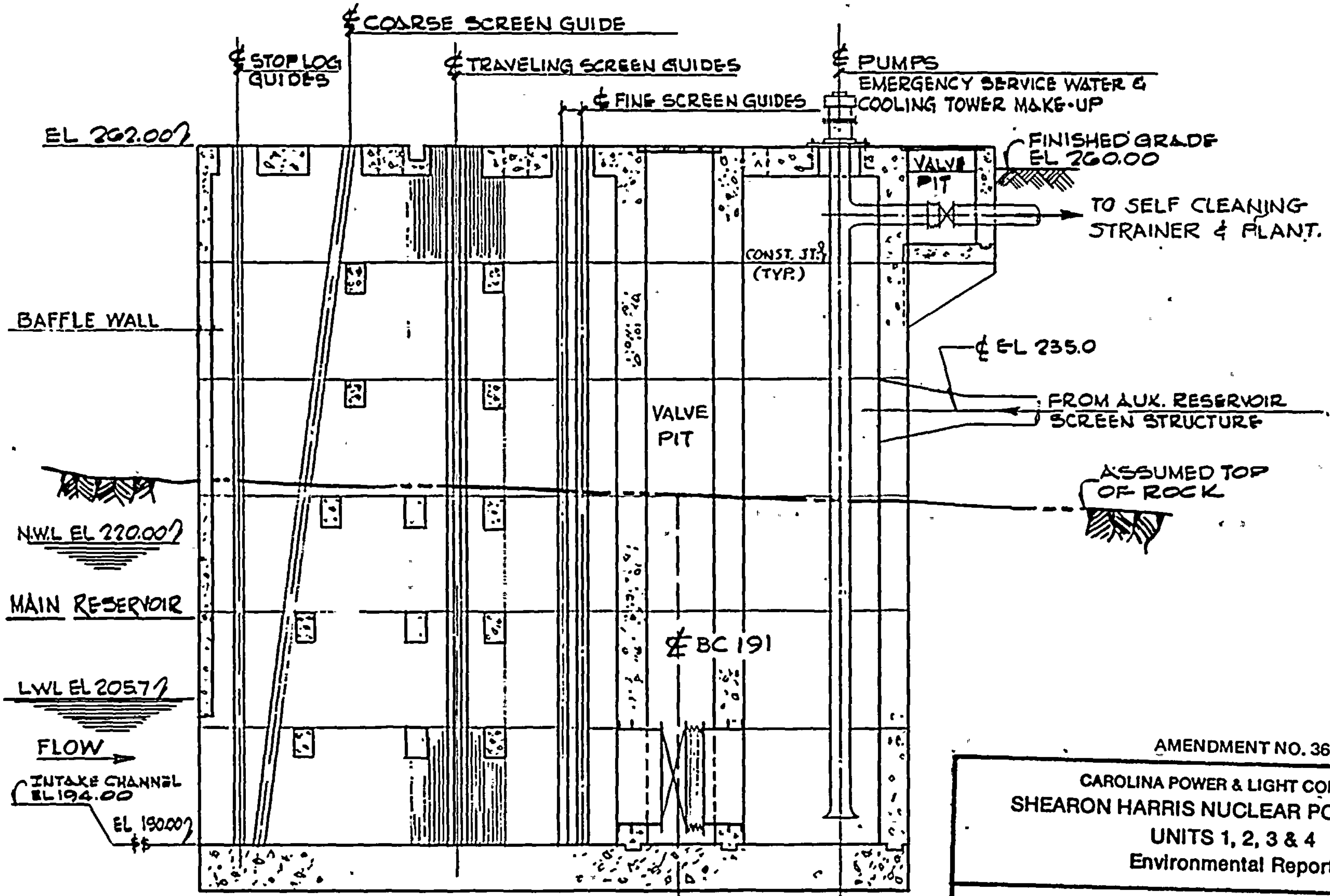
SHEARON HARRIS NUCLEAR, POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

MAIN RESERVOIR AREA–CAPACITY CURVE

2.2–5



LONGITUDINAL SECTION

AMENDMENT NO. 36

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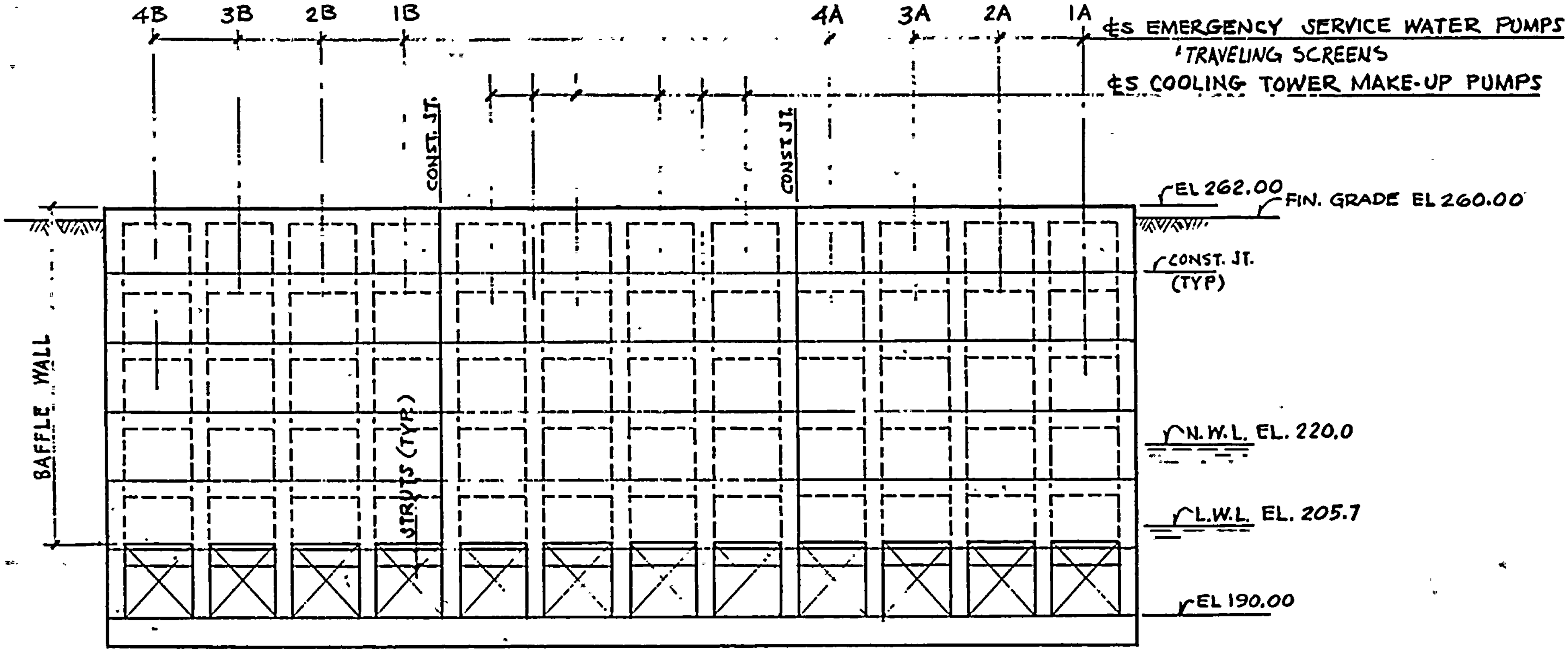
UNITS 1, 2, 3 & 4
Environmental Report

EMERGENCY SERVICE WATER AND COOLING TOWER MAKEUP WATER INTAKE STRUCTURE

2.2–6



FRONT ELEVATION OF FACE OF INTAKE STRUCTURE

AMENDMENT NO. 36

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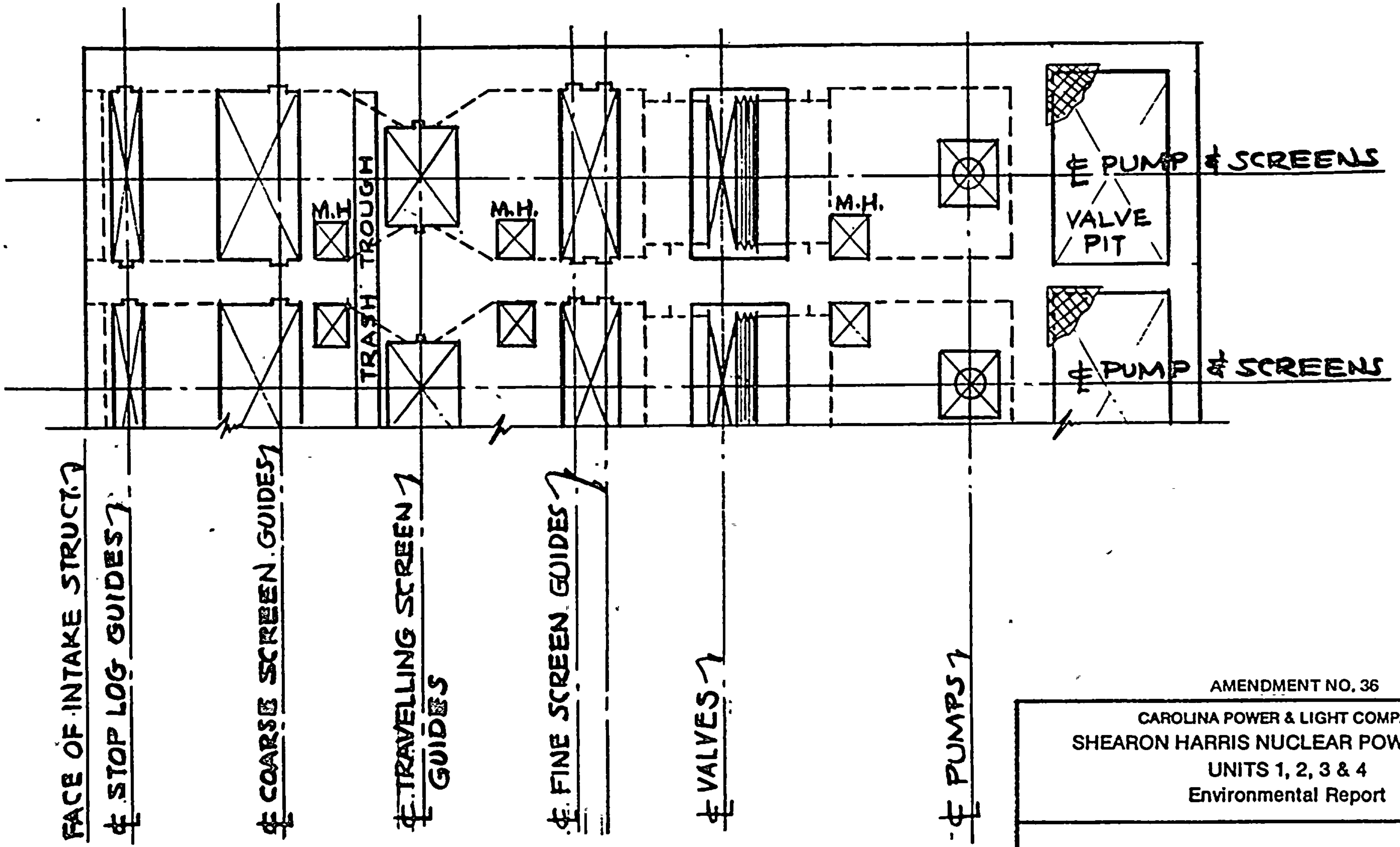
UNITS 1, 2, 3 & 4
Environmental Report

EMERGENCY SERVICE WATER AND COOLING TOWER MAKEUP WATER INTAKE STRUCTURE

2.2–6a



TOP DECK PART PLAN - EL 262.0

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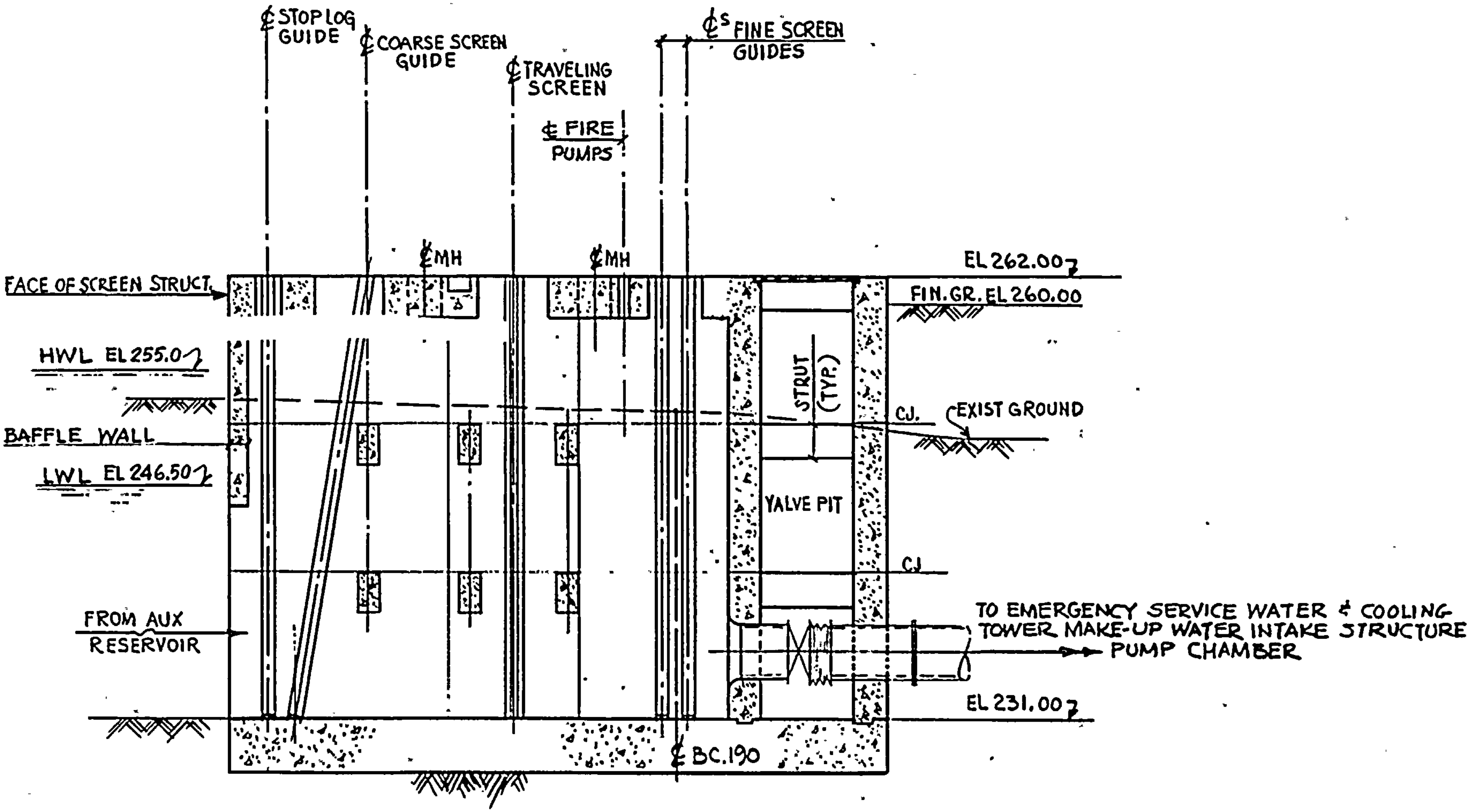
UNITS 1, 2, 3 & 4
Environmental Report

EMERGENCY SERVICE WATER AND COOLING TOWER MAKEUP WATER INTAKE STRUCTURE

2.2–6b



LONGITUDINAL SECT.

AMENDMENT NO. 36

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UNITS 1, 2, 3 & 4
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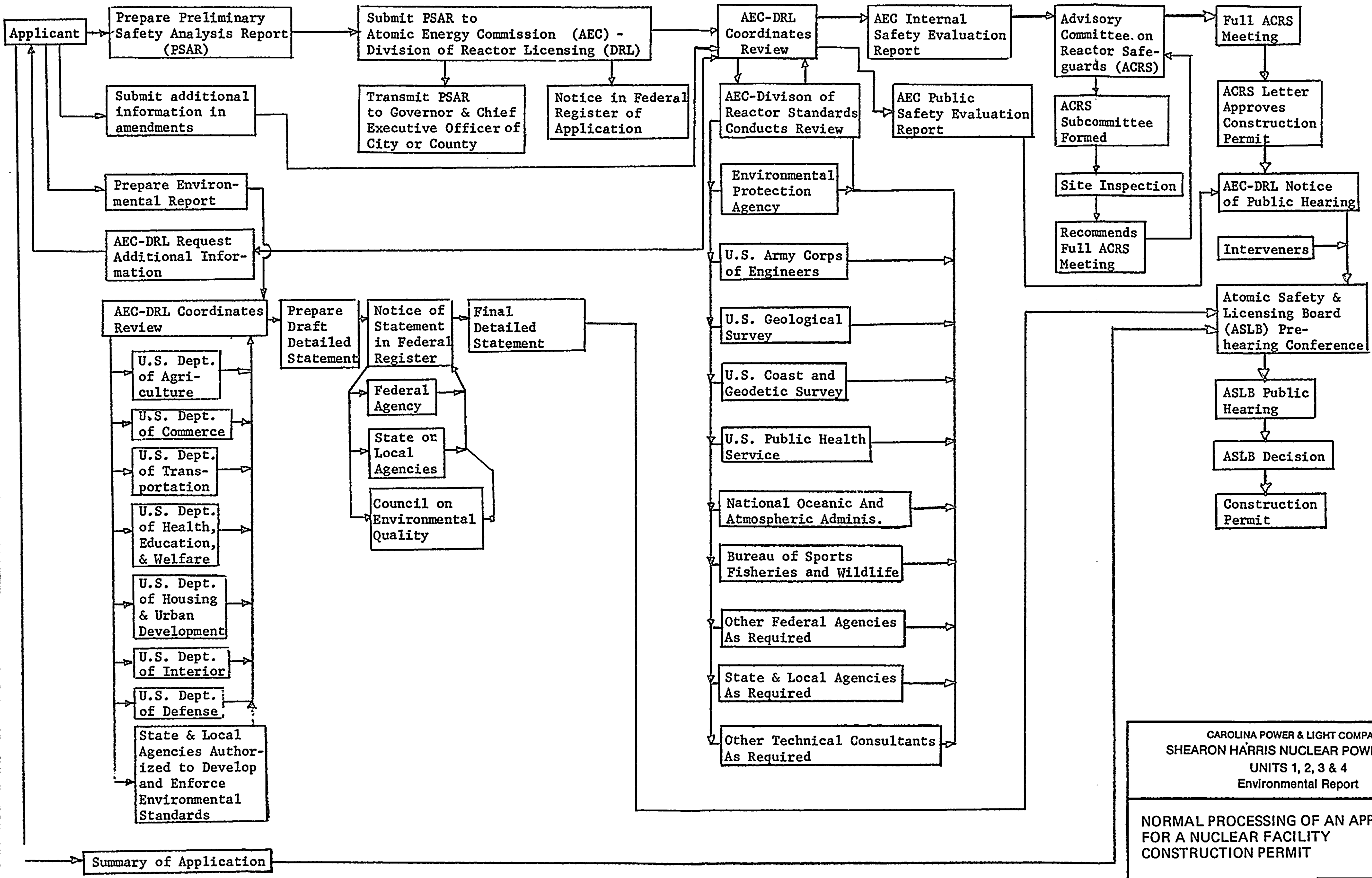
EMERGENCY SERVICE WATER SYSTEM AUXILIARY RESERVOIR SCREEN STRUCTURE

2.2–7



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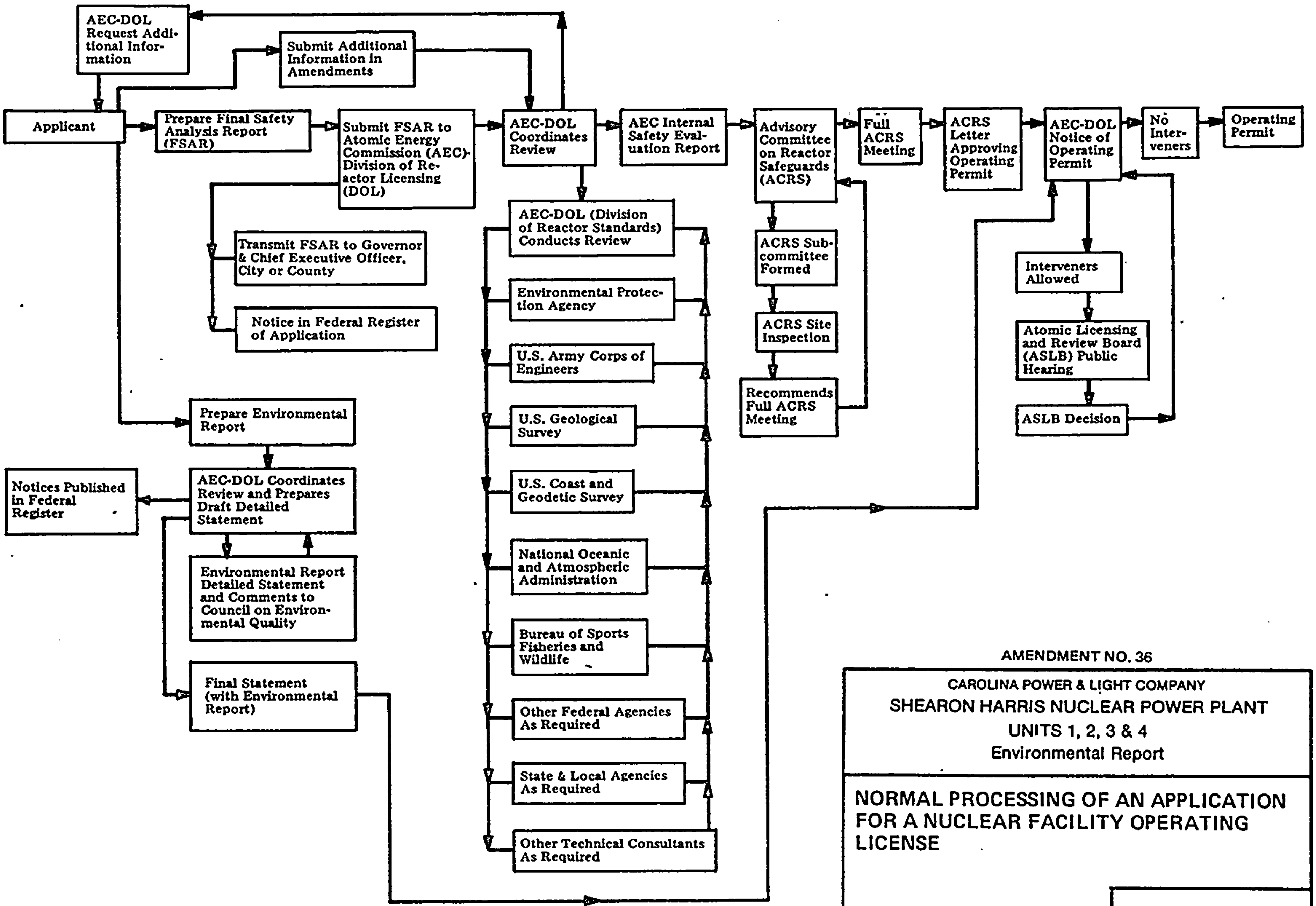
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

NORMAL PROCESSING OF AN APPLICATION FOR A NUCLEAR FACILITY CONSTRUCTION PERMIT

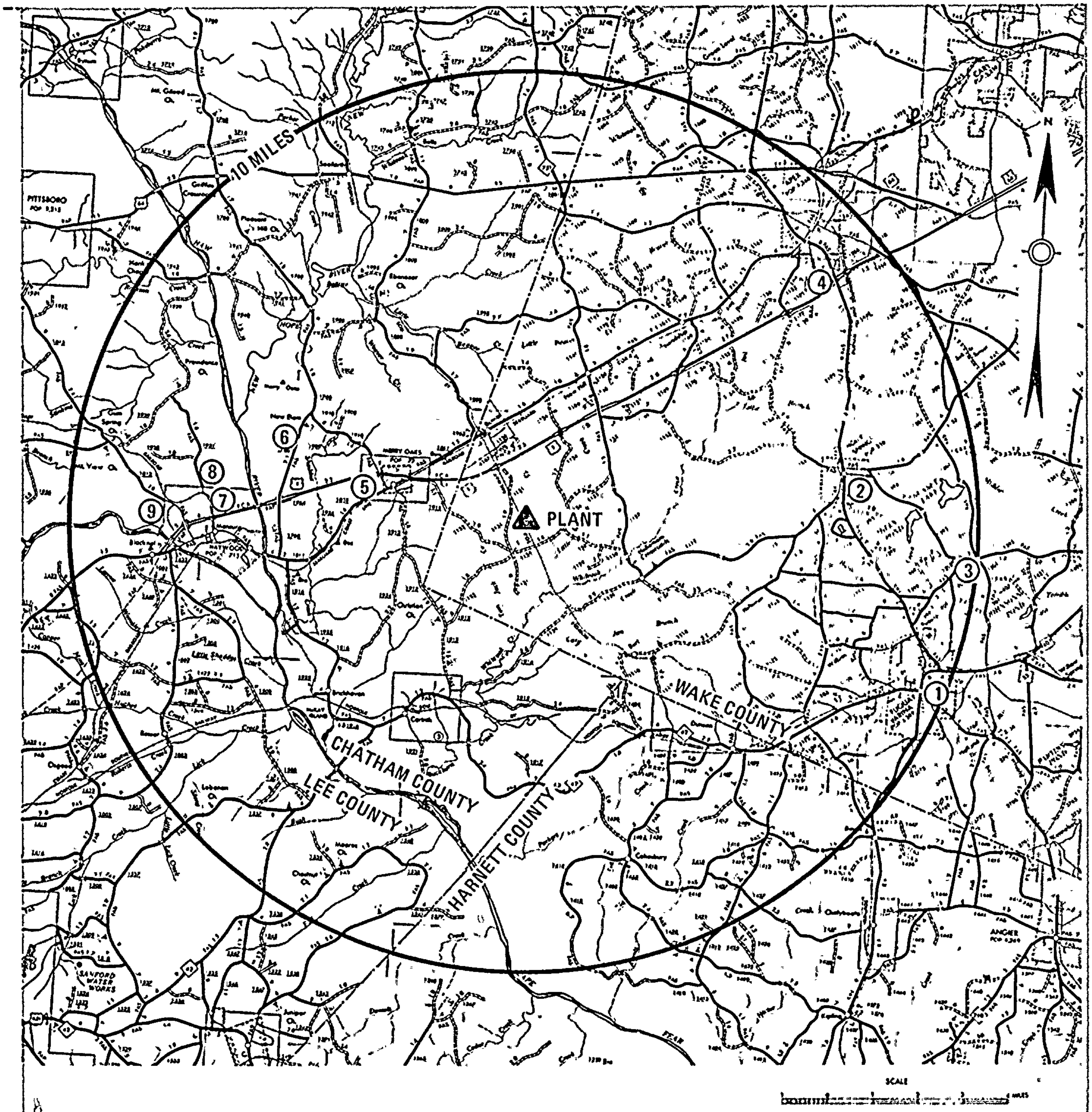
2.3–1



AMENDMENT NO. 36

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

NORMAL PROCESSING OF AN APPLICATION FOR A NUCLEAR FACILITY OPERATING LICENSE



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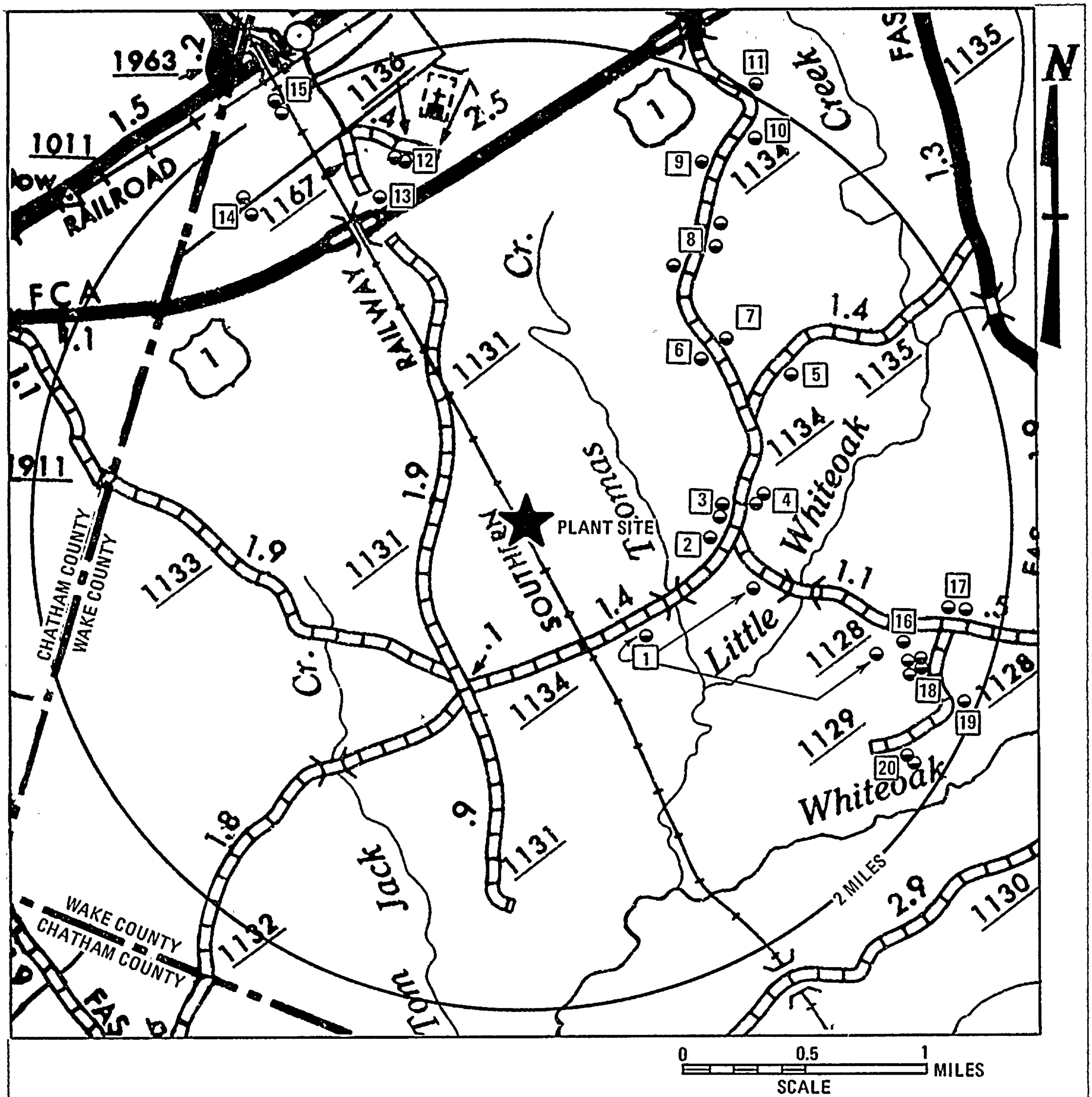
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

PUBLIC WELLS WITHIN 10–MILE RADIUS OF PLANT

3.2–1



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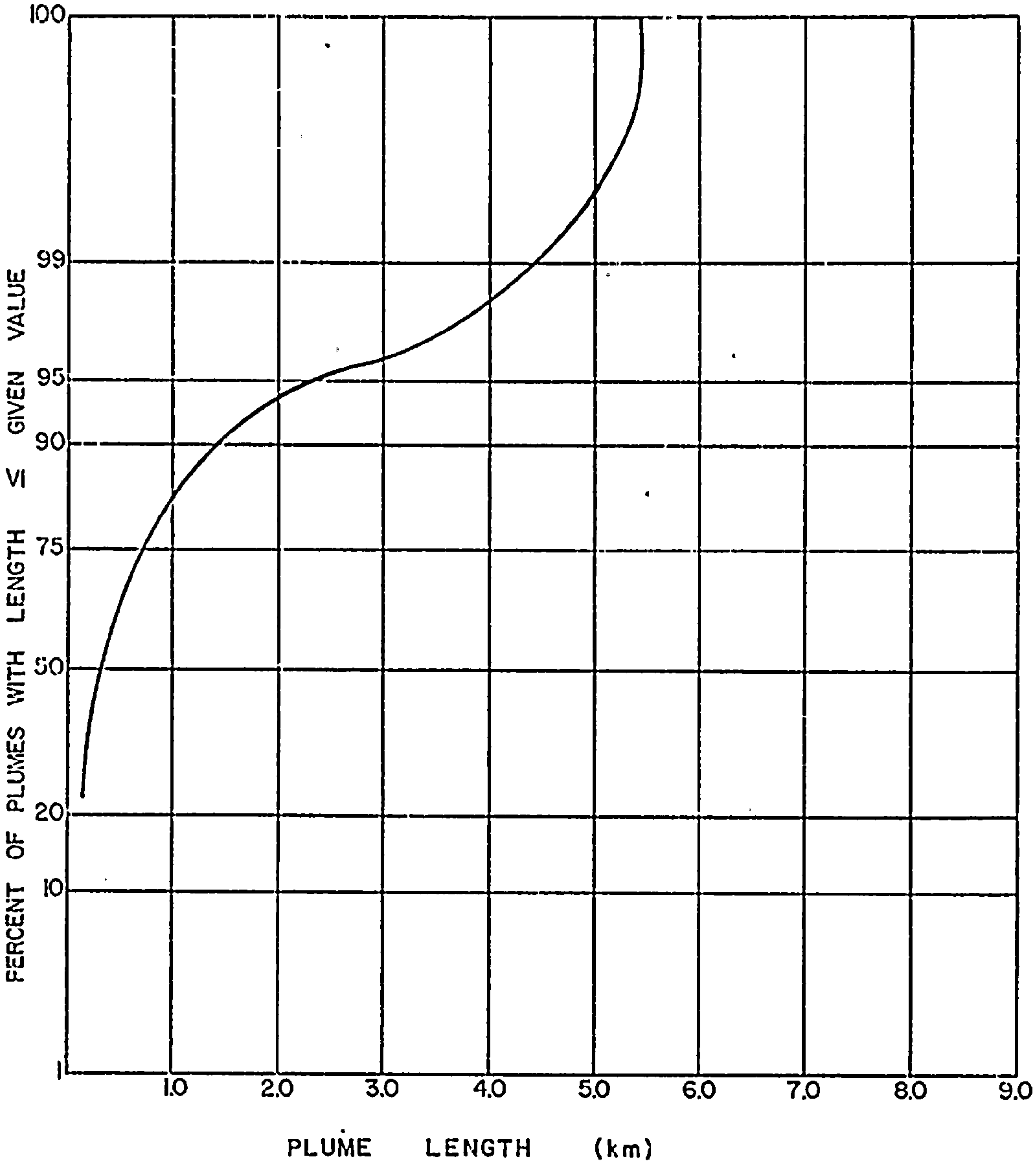
UNITS 1, 2, 3 & 4
Environmental Report

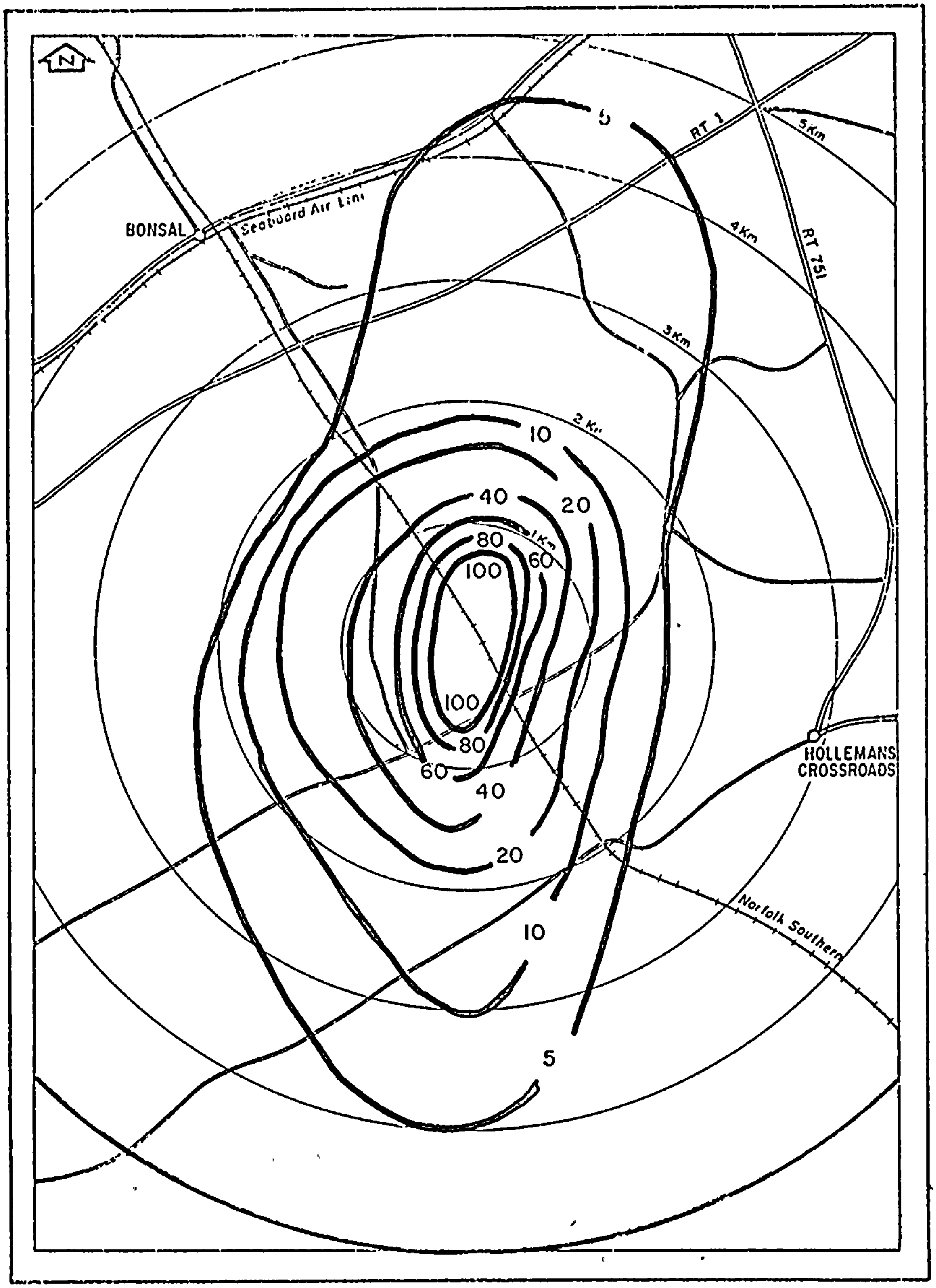
PRIVATELY OWNED WELLS WITHIN 2–MILE RADIUS OF PLANT

3.2–2



AMENDMENT NO. 28

CAROLINA POWER & LIGHT COMPANY SHEARON HARRIS NUCLEAR POWER PLANT UNITS 1, 2, 3 & 4 Environmental Report
ANNUAL CUMULATIVE FREQUENCY OF PLUME LENGTHS – FOUR COOLING TOWERS
3.3–1



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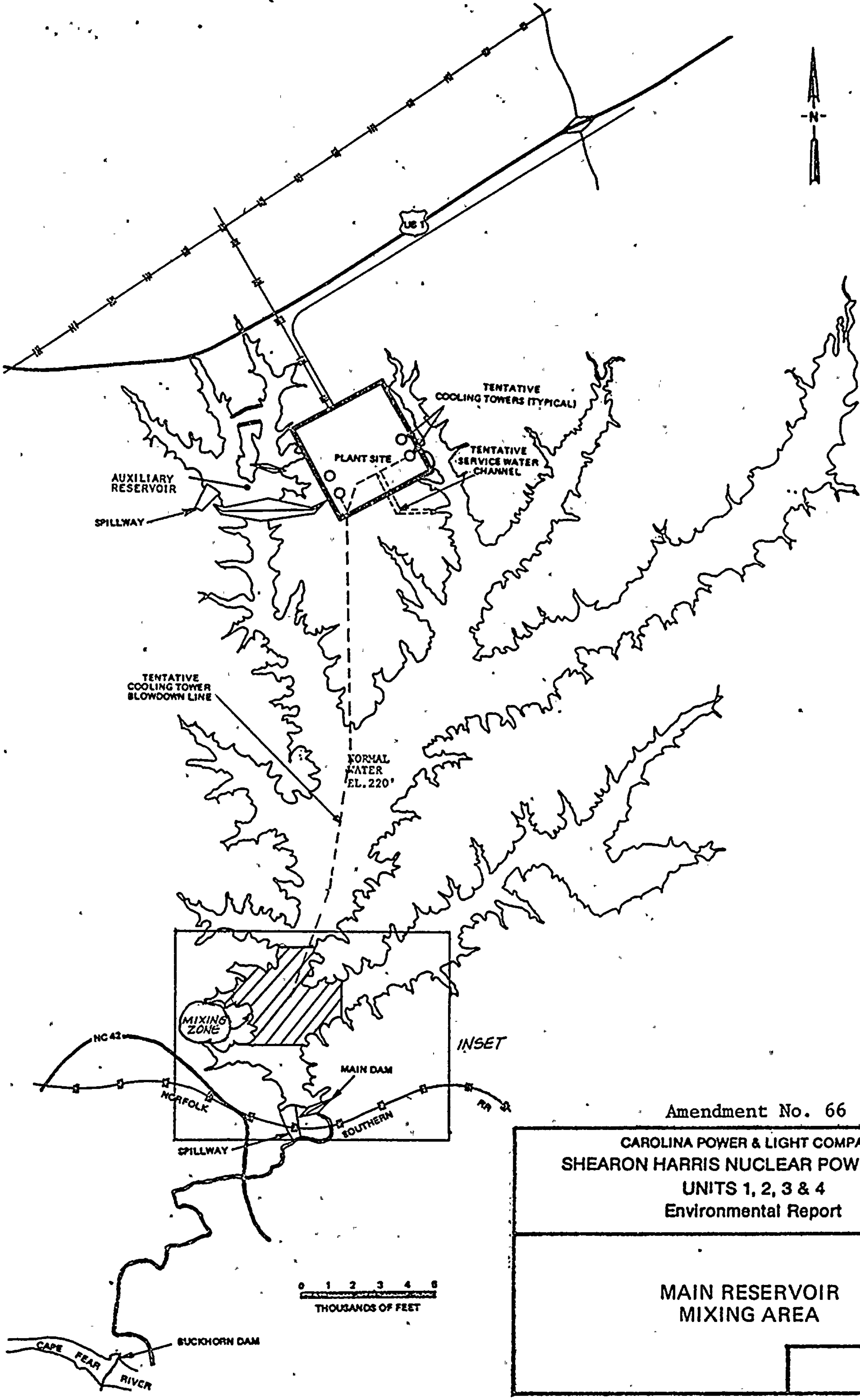
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

ANNUAL HOURLY FREQUENCY OF PLUMES
FOUR COOLING TOWERS

3.3–2

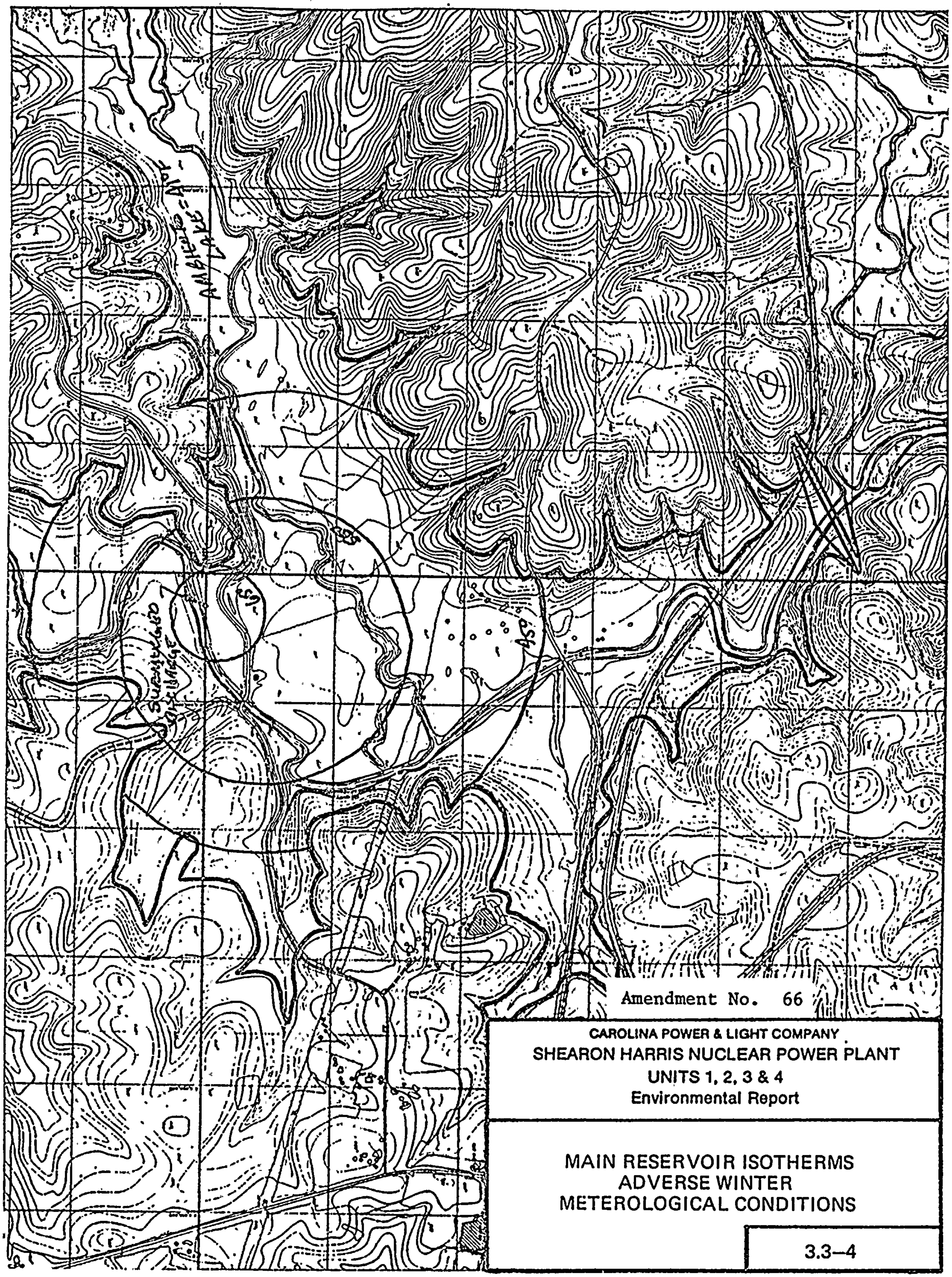


Amendment No. 66

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

MAIN RESERVOIR
MIXING AREA

3.3–3

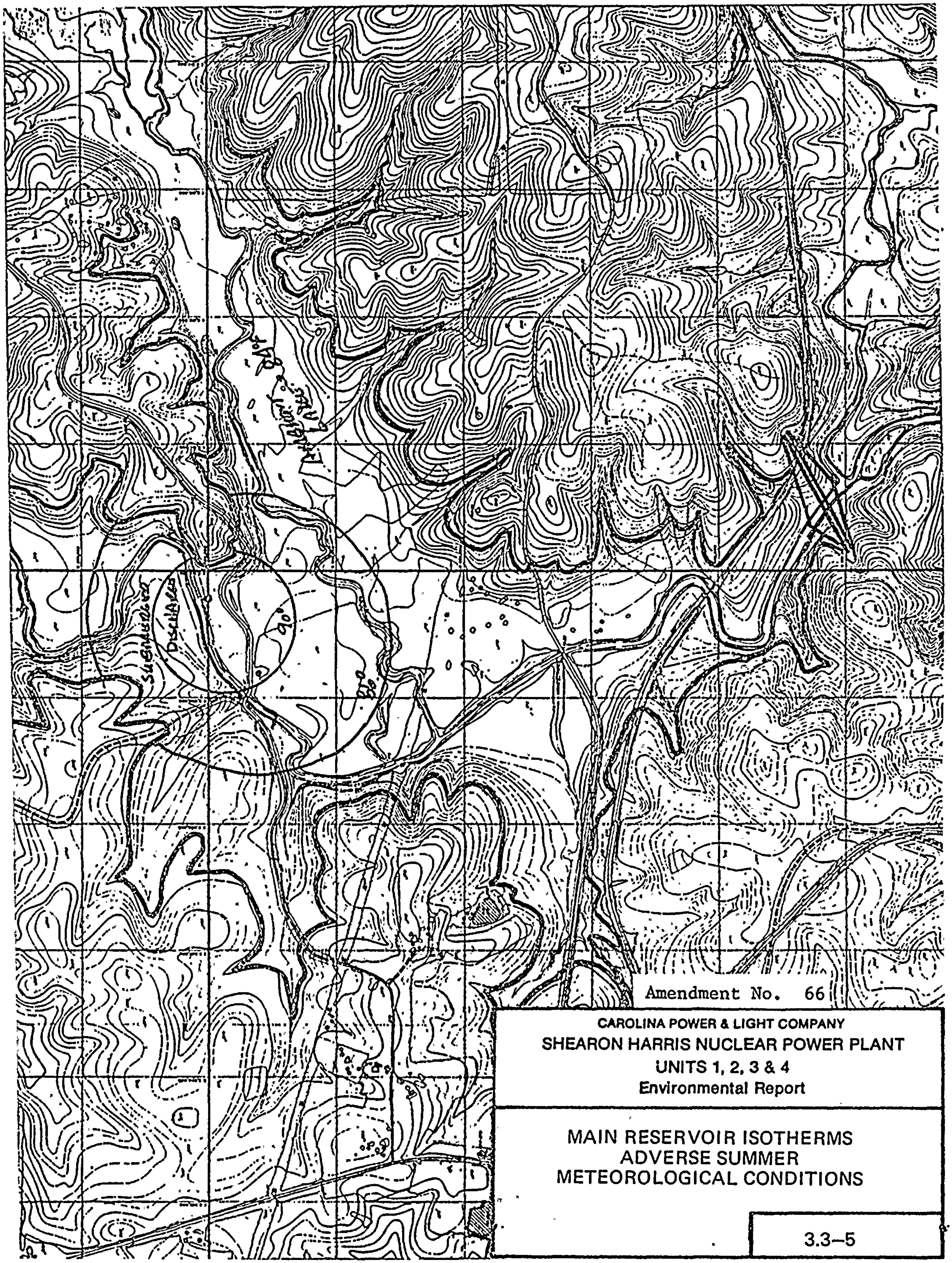


Amendment No. 66

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

MAIN RESERVOIR ISOTHERMS
ADVERSE WINTER
METEROLOGICAL CONDITIONS

3.3–4

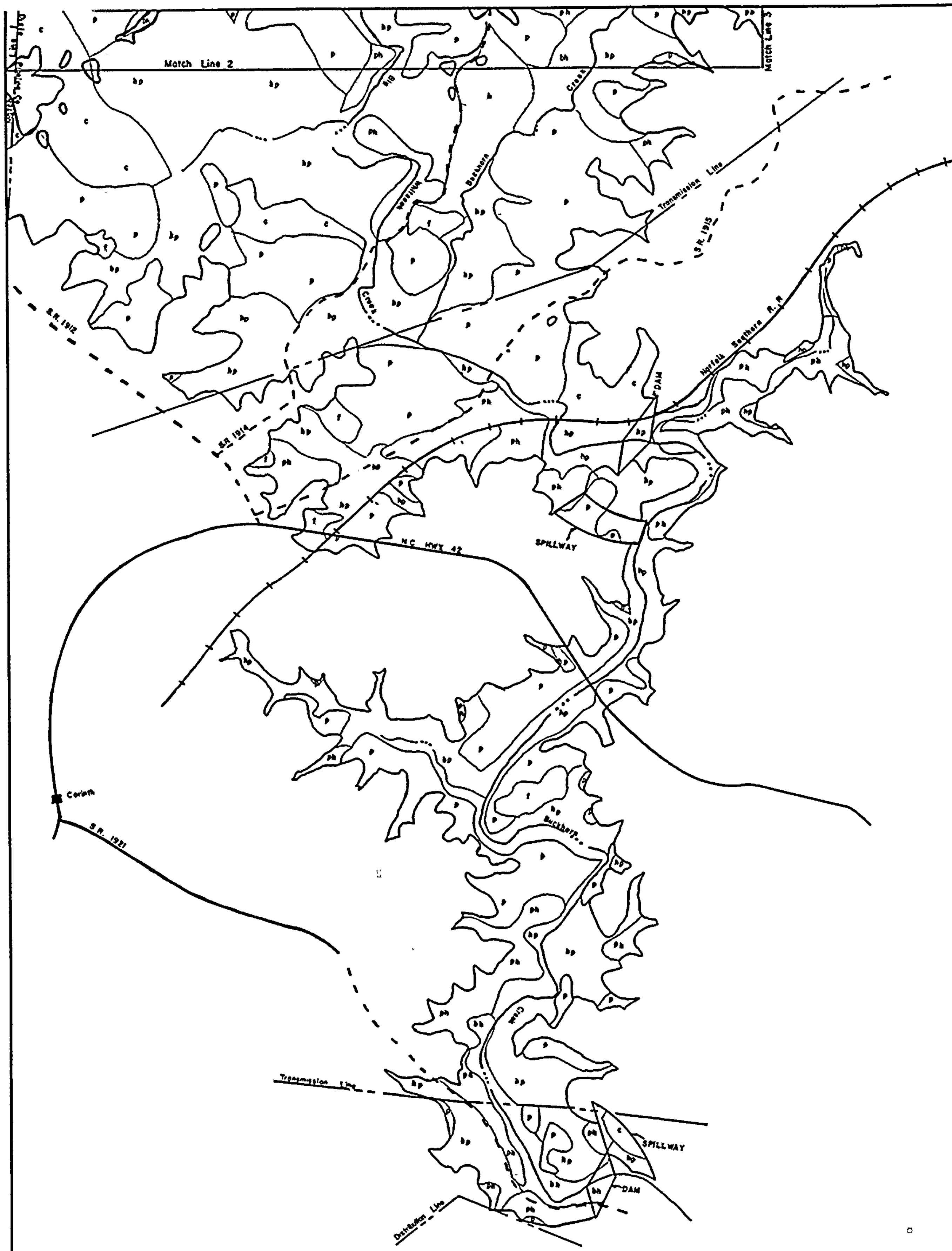


Amendment No. 66

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

MAIN RESERVOIR ISOTHERMS
ADVERSE SUMMER
METEOROLOGICAL CONDITIONS

3.3–5



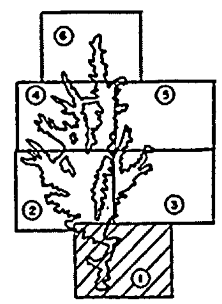
LEGEND

Unimproved Roads	
Improved Roads	
Railroads	
Creeks, Streams	
Transmission & Distribution Lines	
Pipelines	
Exclusion Area Boundary	
Contour	
Timber Type Boundary	
Lakes	

Timber Type Identification

p	pine
ph	pine hardwood
bh	bottomland hardwood
h	hardwood
hp	hardwood pine
c	cutover
f	farmland

0 5 10 FEET x 100

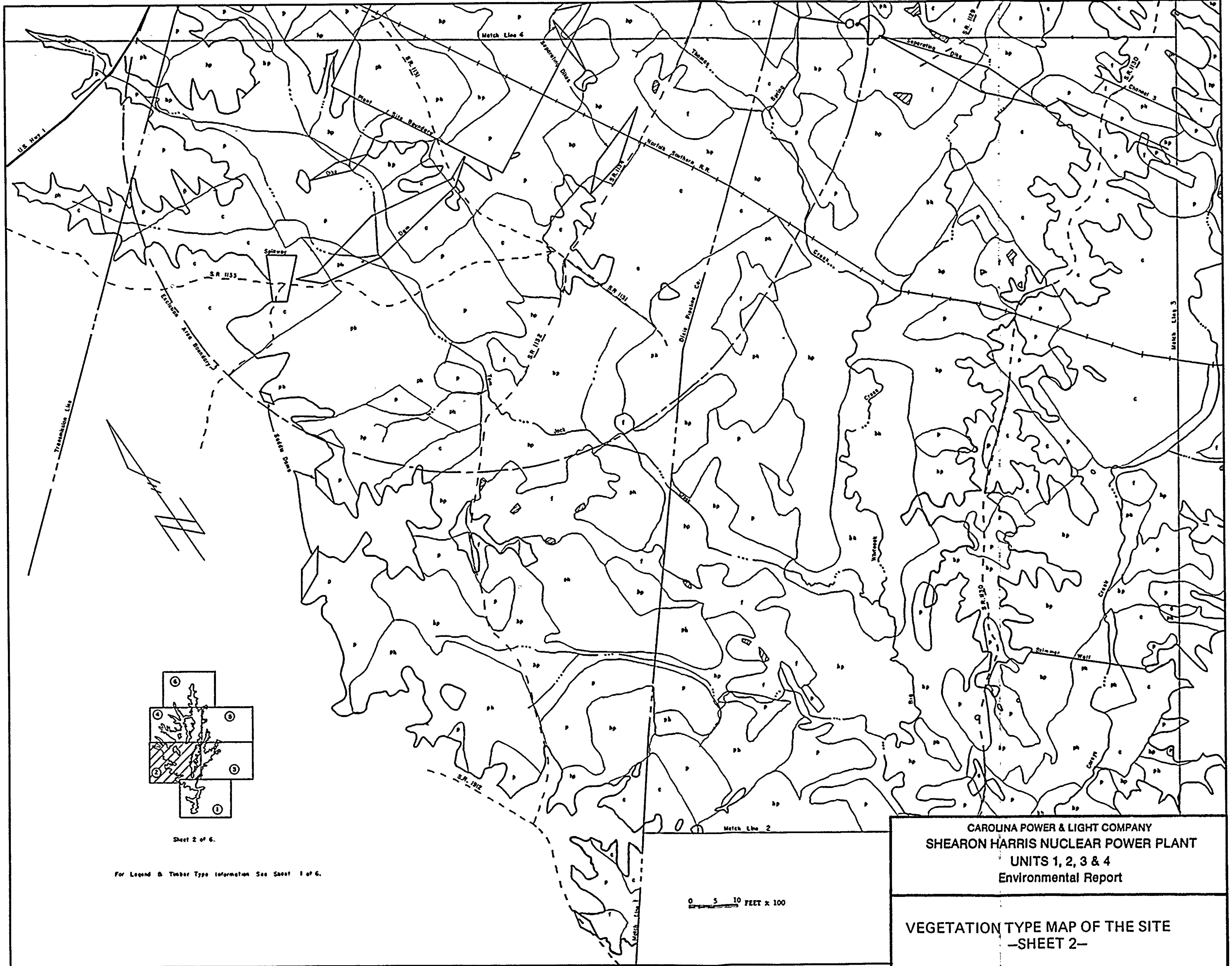


Sheet 1 of 6.

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

VEGETATION TYPE MAP OF THE SITE
–SHEET 1–

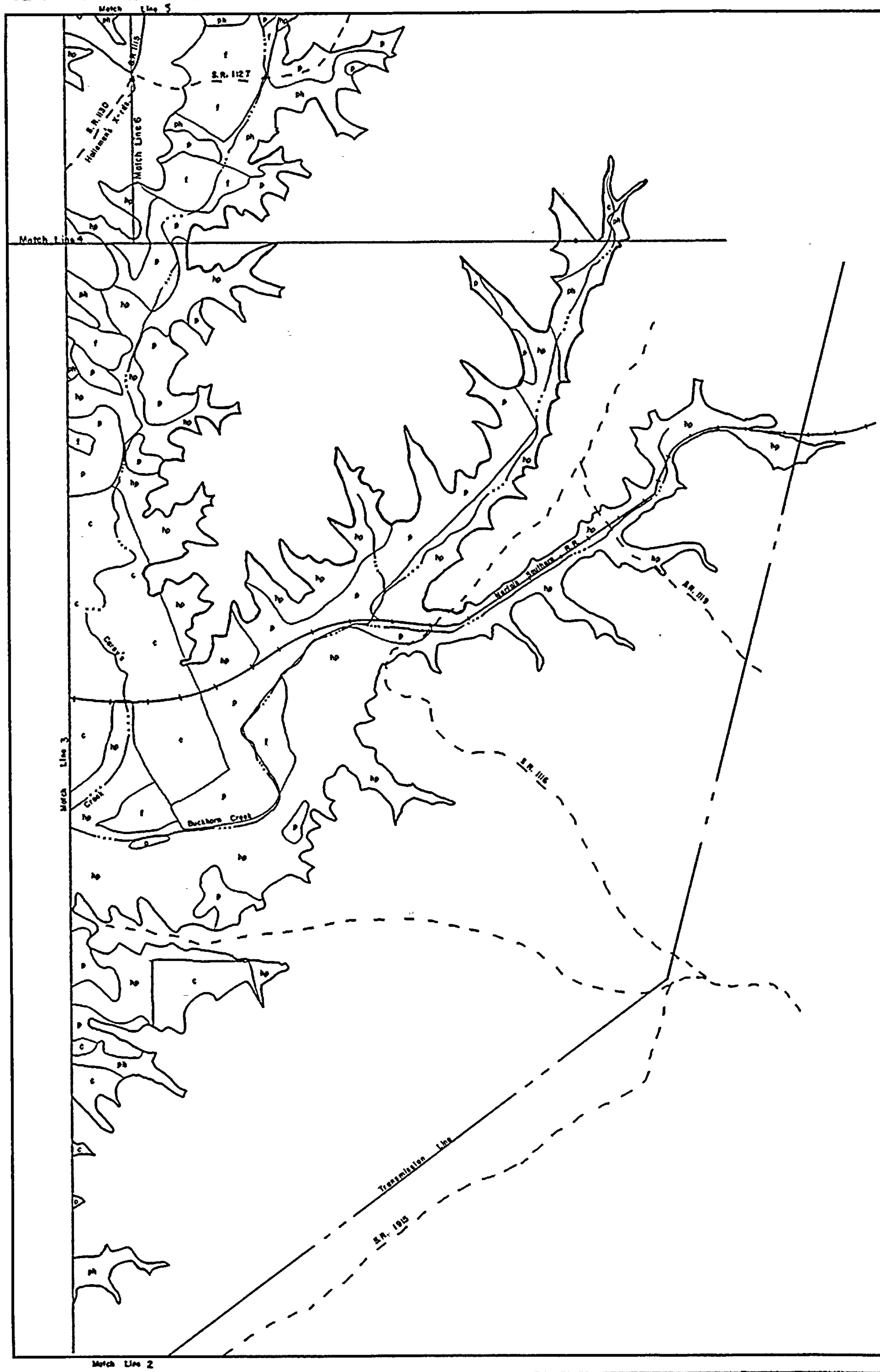
3.6–1

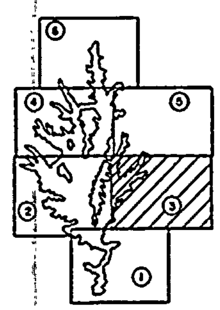


CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

VEGETATION TYPE MAP OF THE SITE
—SHEET 2—

3.6–2





Sheet 3 of 6.

For Legend & Timber Type Information See Sheet 1 of 6.

0 5 10 FEET x 100

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

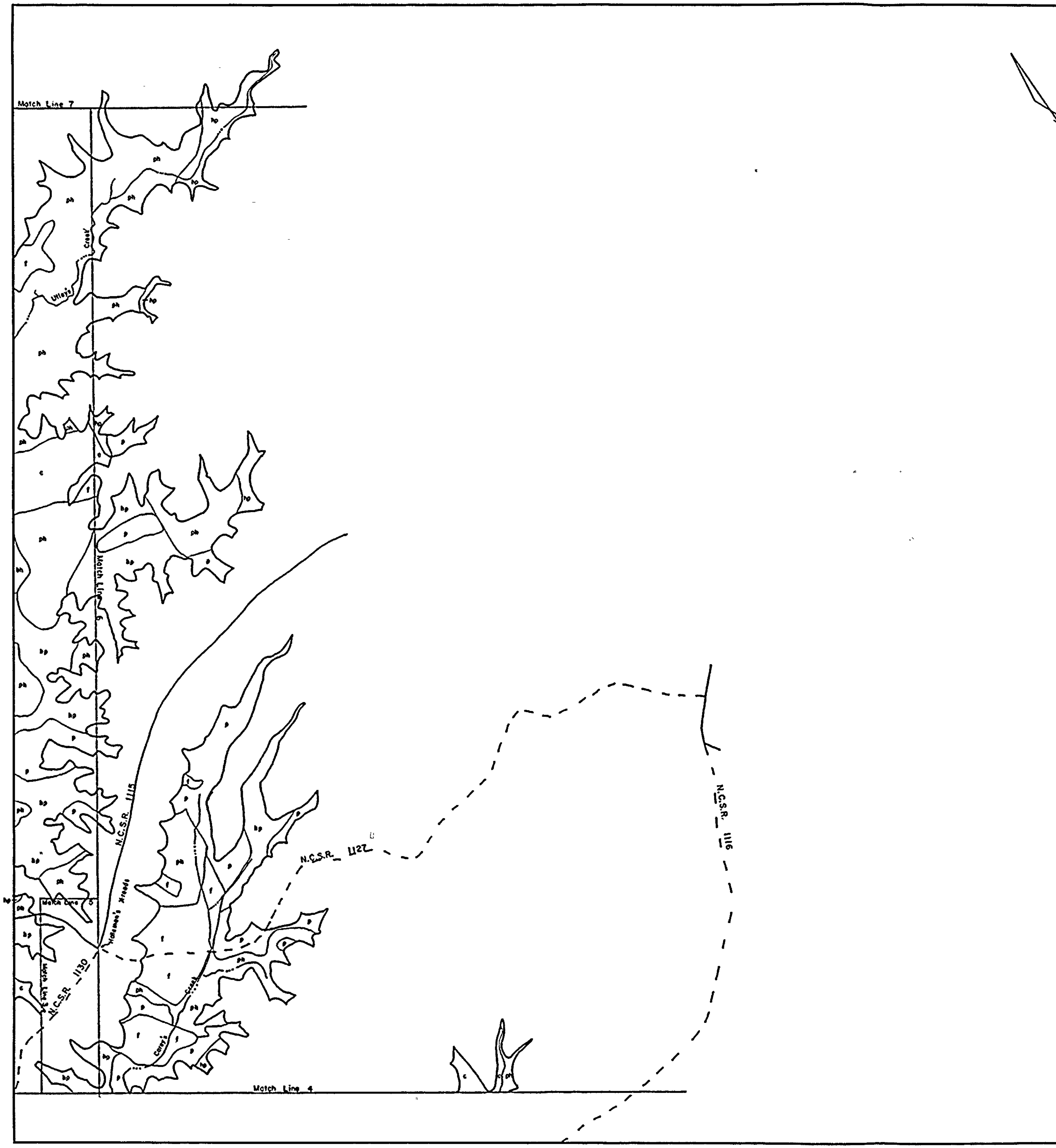
VEGETATION TYPE MAP OF THE SITE
—SHEET 3—

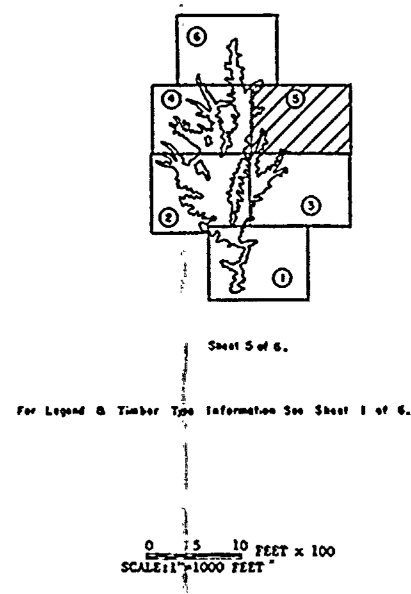
3.6–3

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

VEGETATION TYPE MAP OF THE SITE
—SHEET 4—

3.6–4

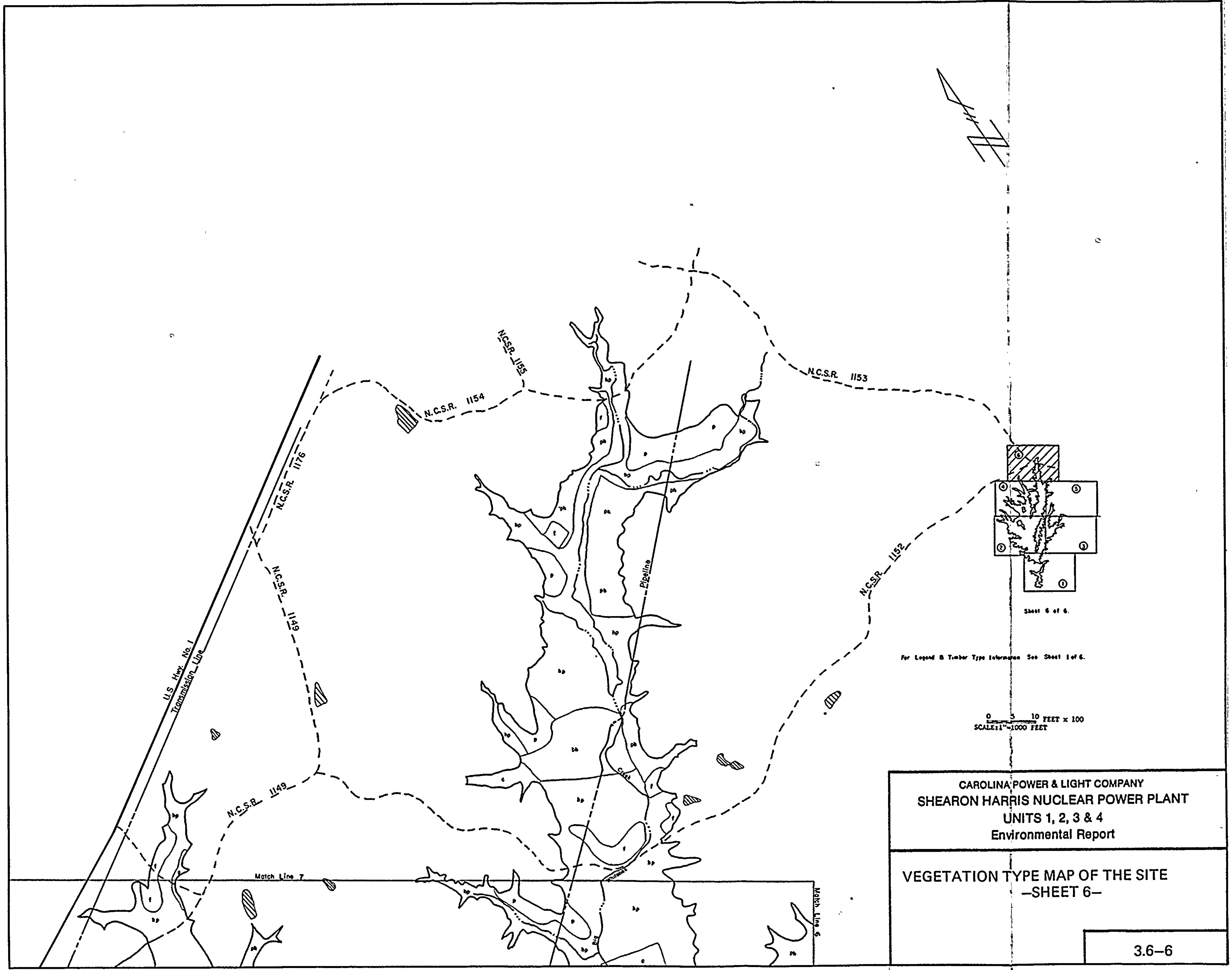




CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

VEGETATION TYPE MAP OF THE SITE
–SHEET 5–

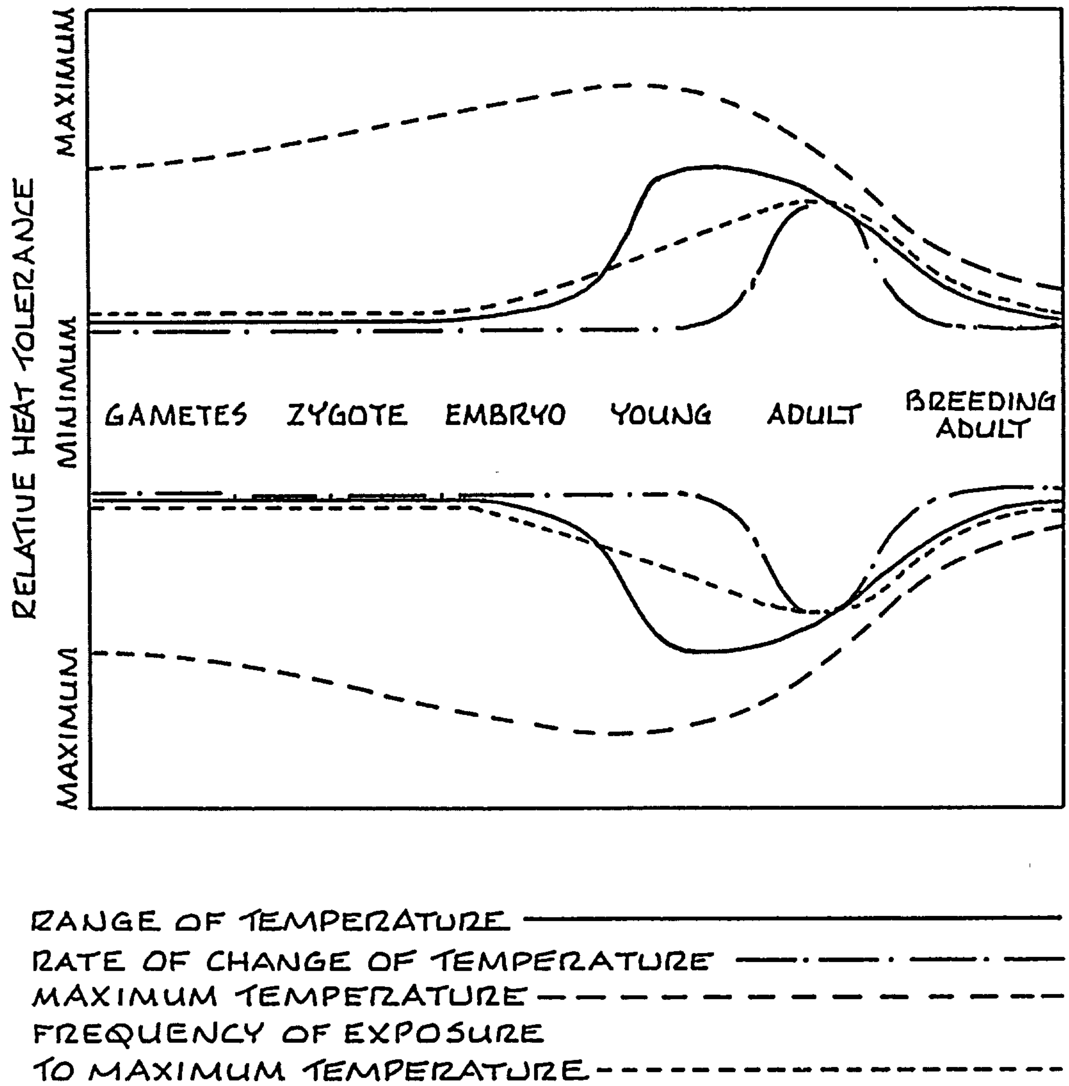
3.6–5



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

VEGETATION TYPE MAP OF THE SITE
—SHEET 6—

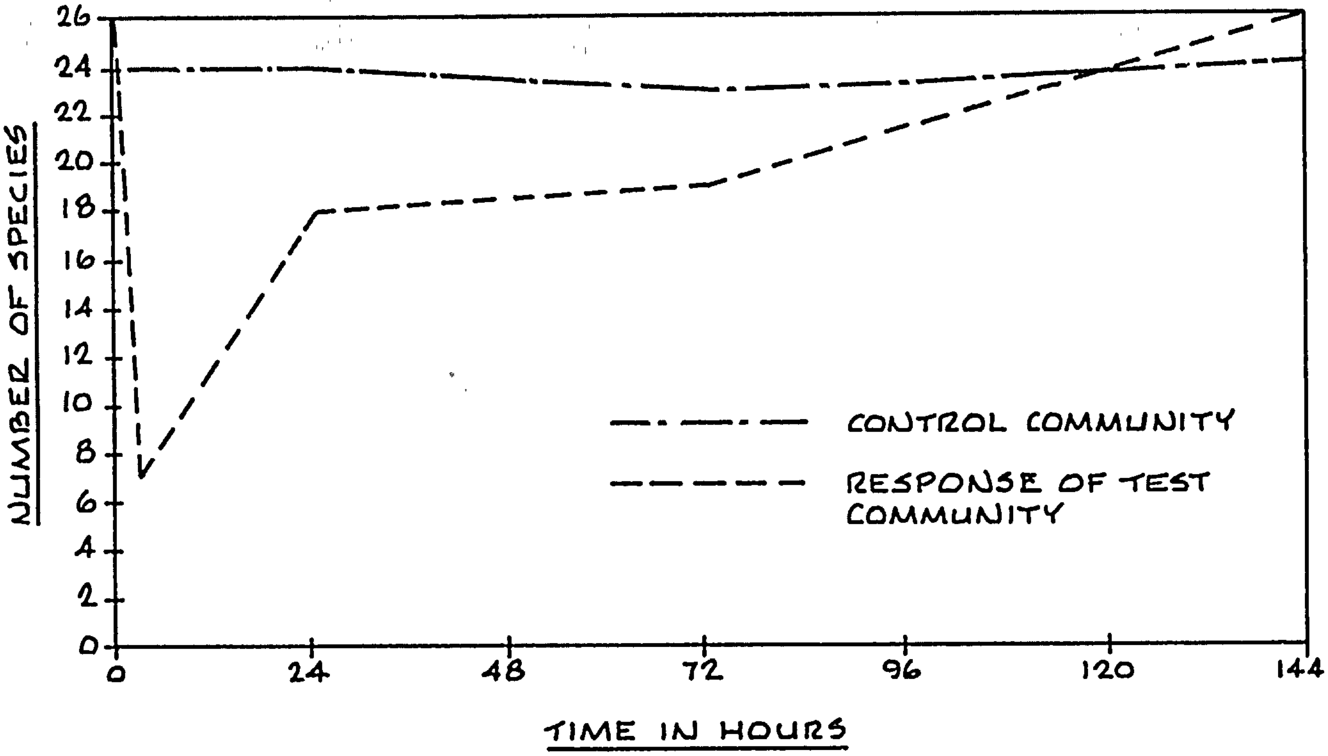
3.6–6



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

THERMAL TOLERANCE OF LIFE STAGES
(JENSEN, 1969)

3.6–7

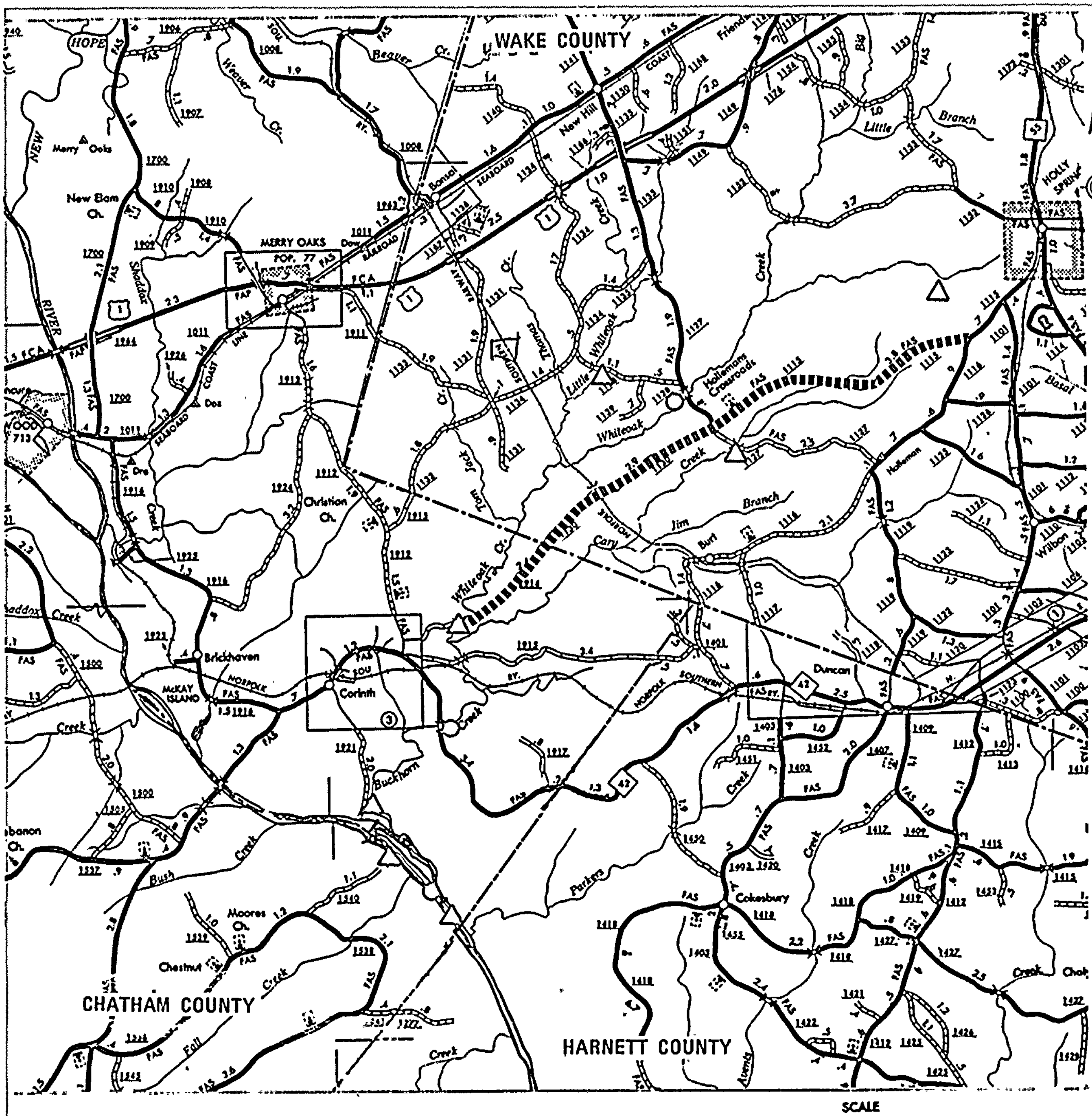


CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

RESPONSE OF THE PROTOZOAN COMMUNITY TO A BRIEF TEMPERATURE SHOCK OF 48 F (CAIRNS, 1969)

3.6–8

citx



LEGEND

△ WATER QUALITY AND BIOLOGICAL SAMPLING STATION

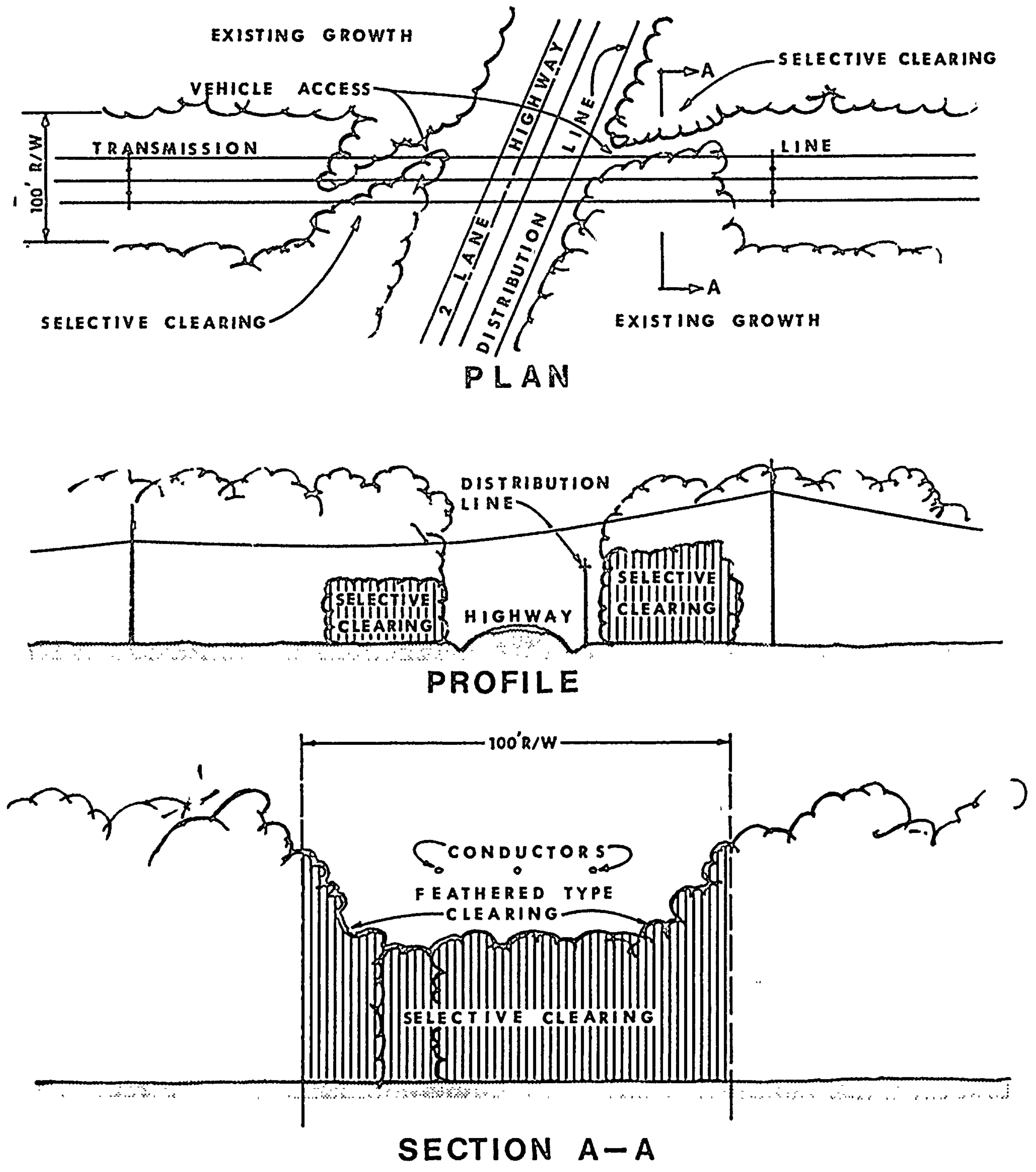
○ WATER QUALITY SAMPLING STATION

▮▮▮▮▮ WILDLIFE SURVEY ROUTE

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

SAMPLE STATIONS & WILDLIFE SURVEY ROUTE

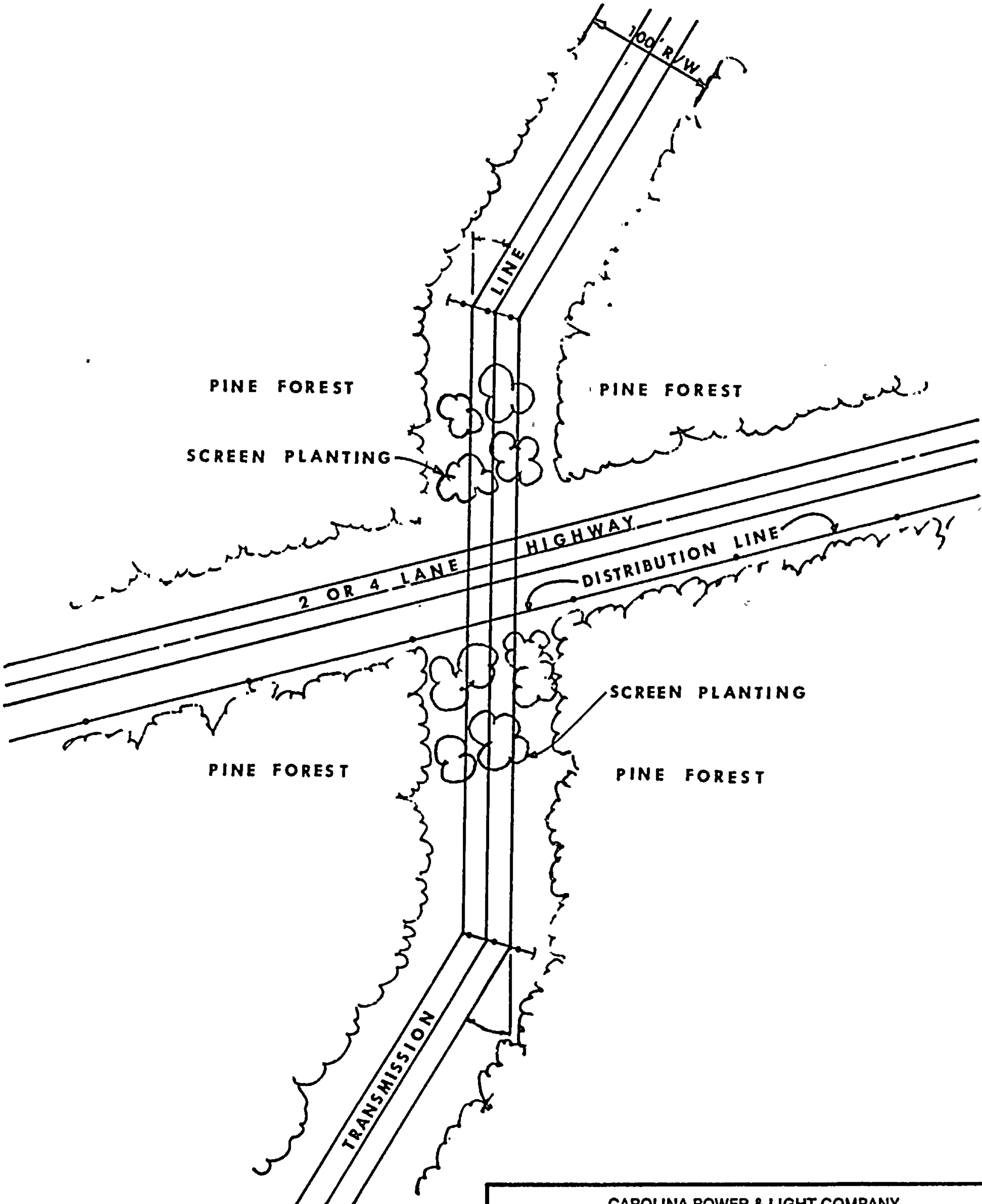
3.6–9



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

SELECTIVE CLEARING AT HIGHWAY CROSSING

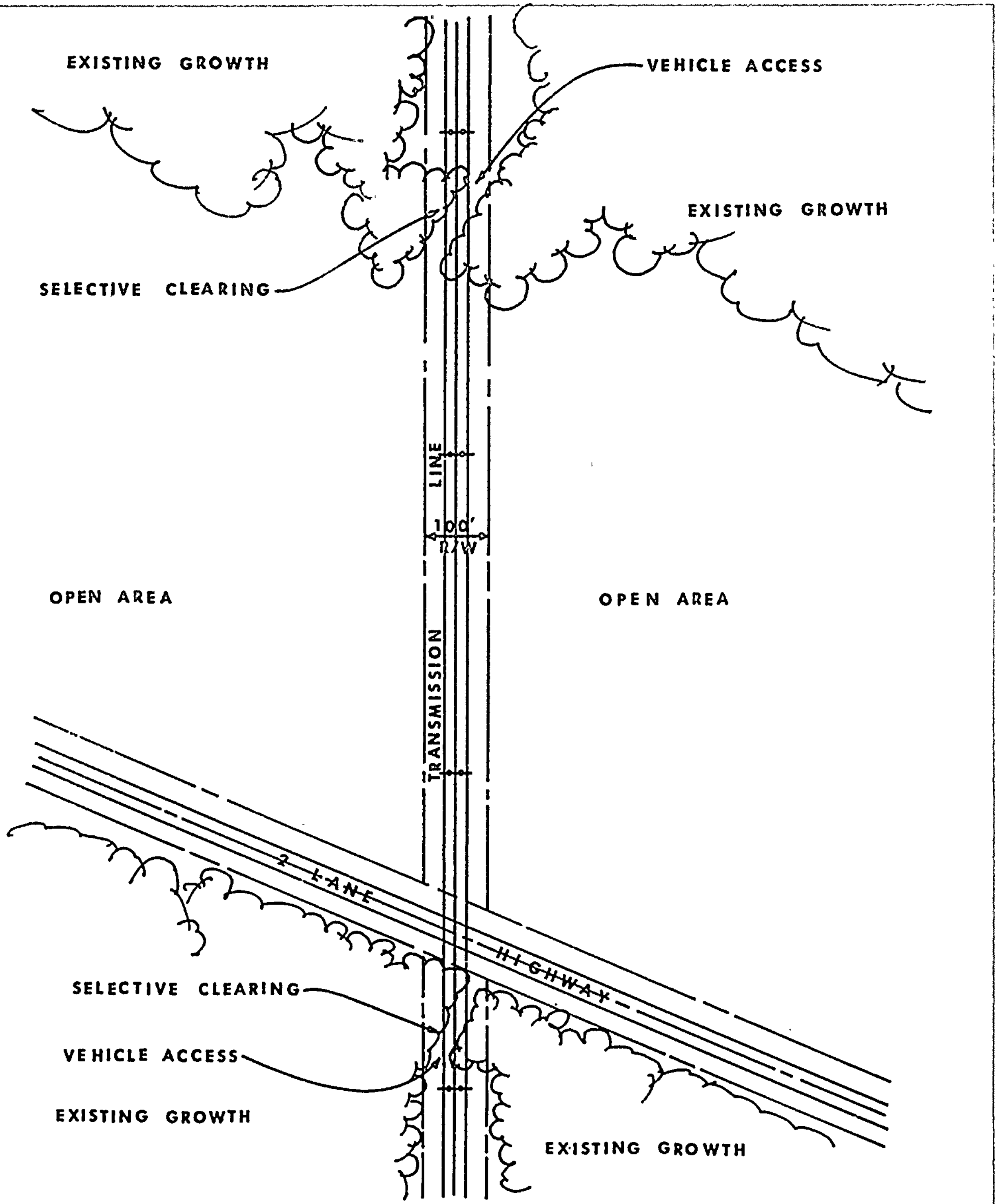
3.11–1



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

HIGHWAY CROSSING IN PINE FOREST

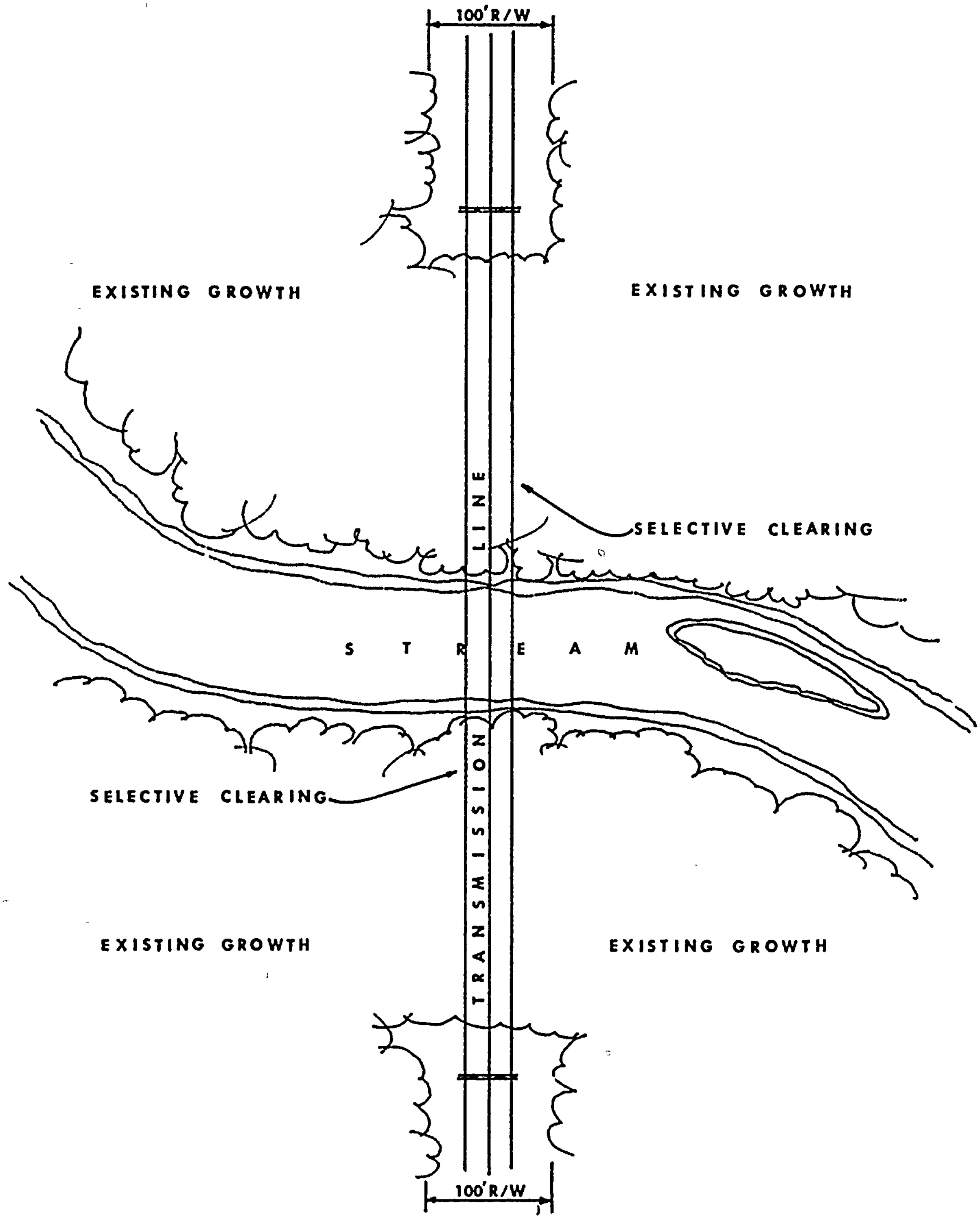
3.11–2



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

SELECTIVE CLEARING PROCEDURE AT CLEARED AREAS

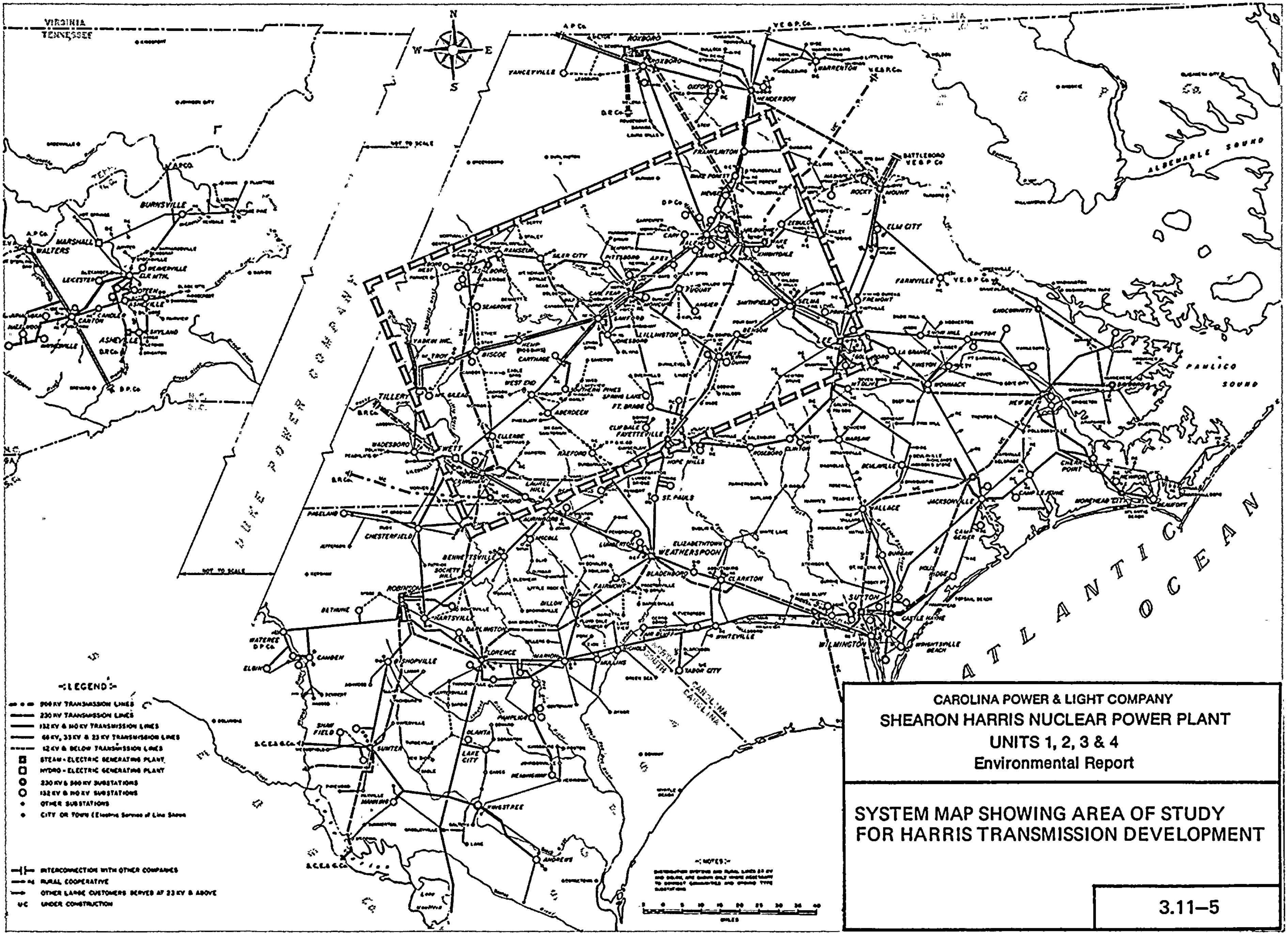
3.11–3



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

STREAM CROSSING WITH SELECTIVE CLEARING

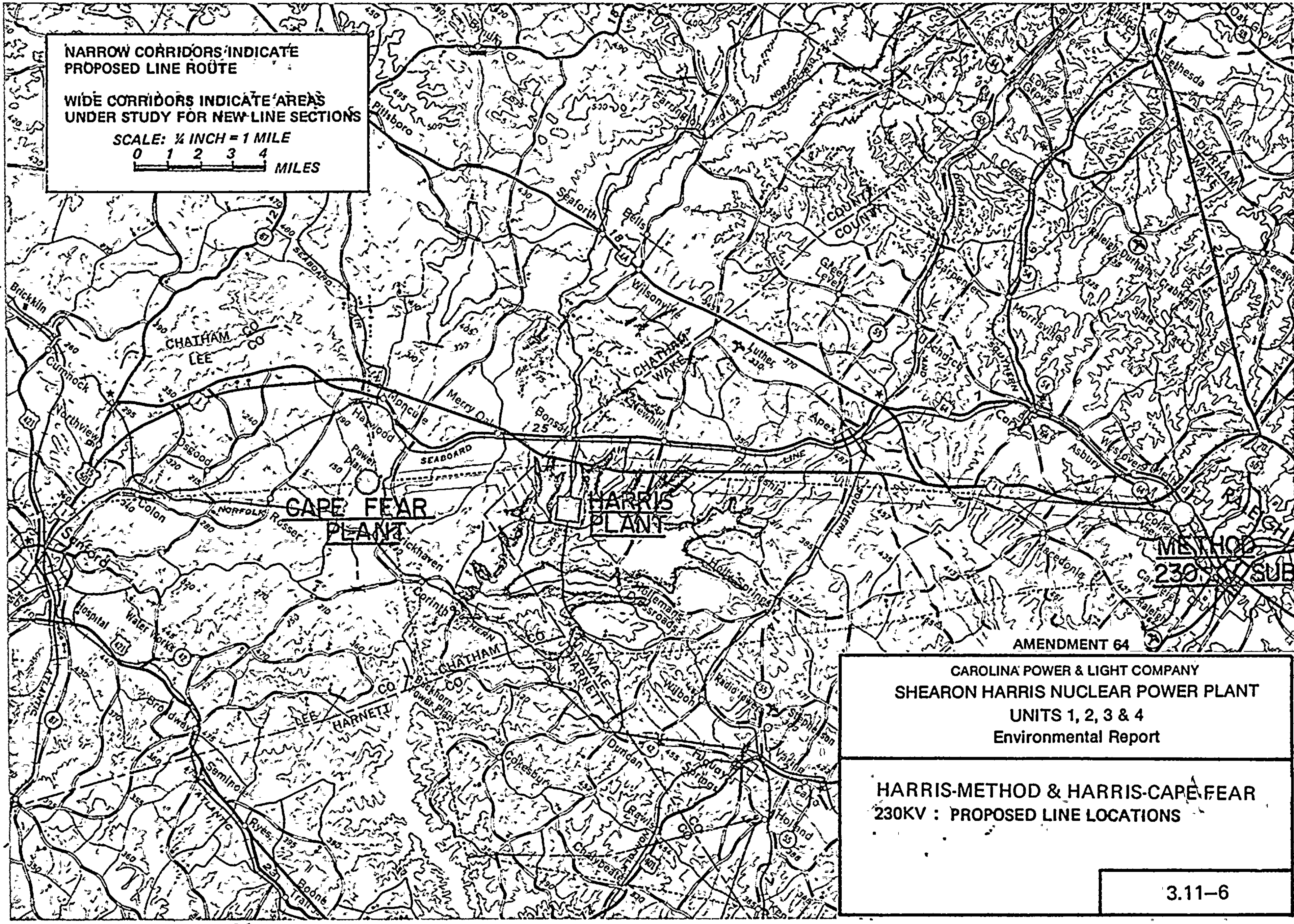
3.11–4



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

SYSTEM MAP SHOWING AREA OF STUDY FOR HARRIS TRANSMISSION DEVELOPMENT

3.11-5

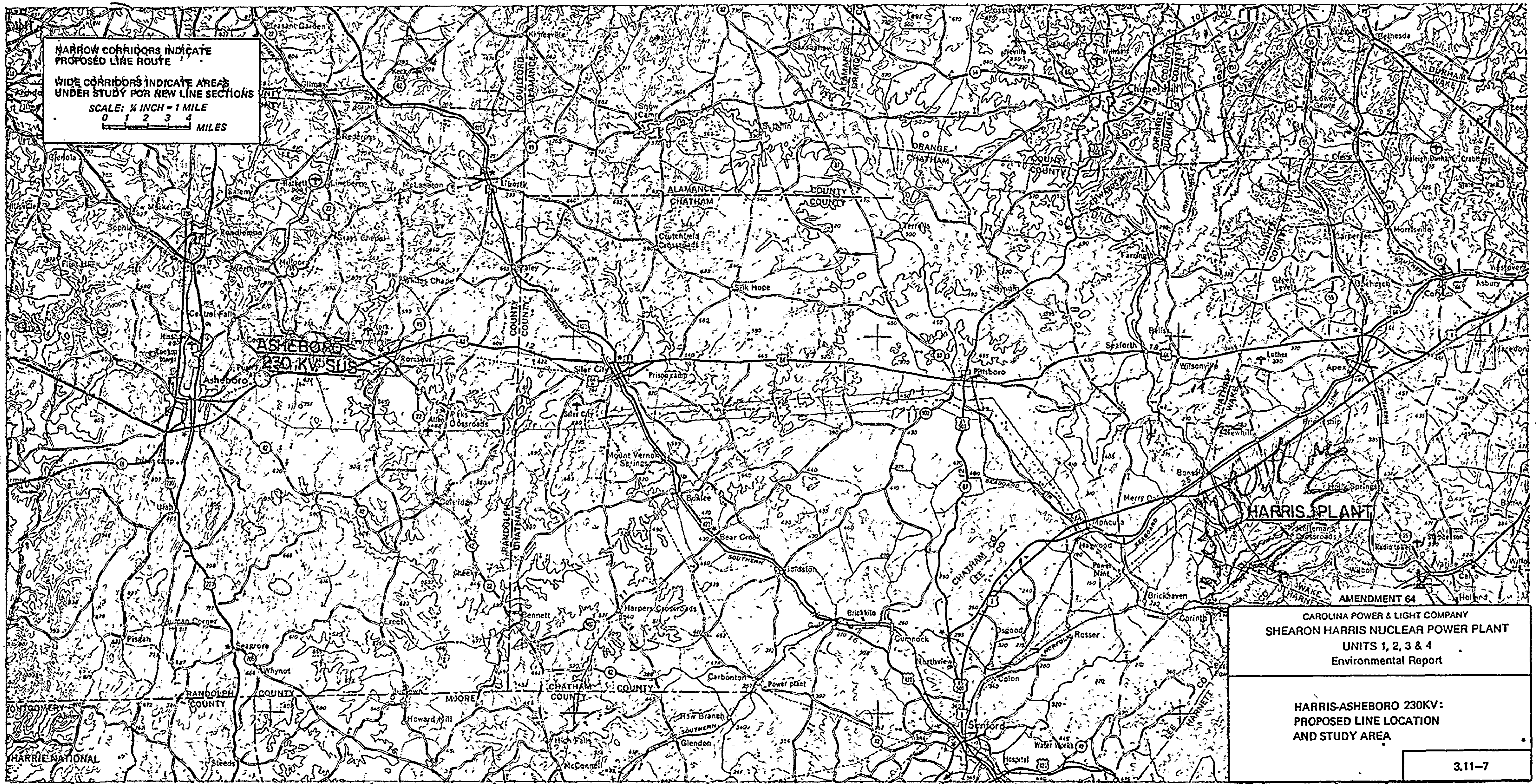


AMENDMENT 64

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

HARRIS-METHOD & HARRIS-CAPE FEAR
230KV : PROPOSED LINE LOCATIONS

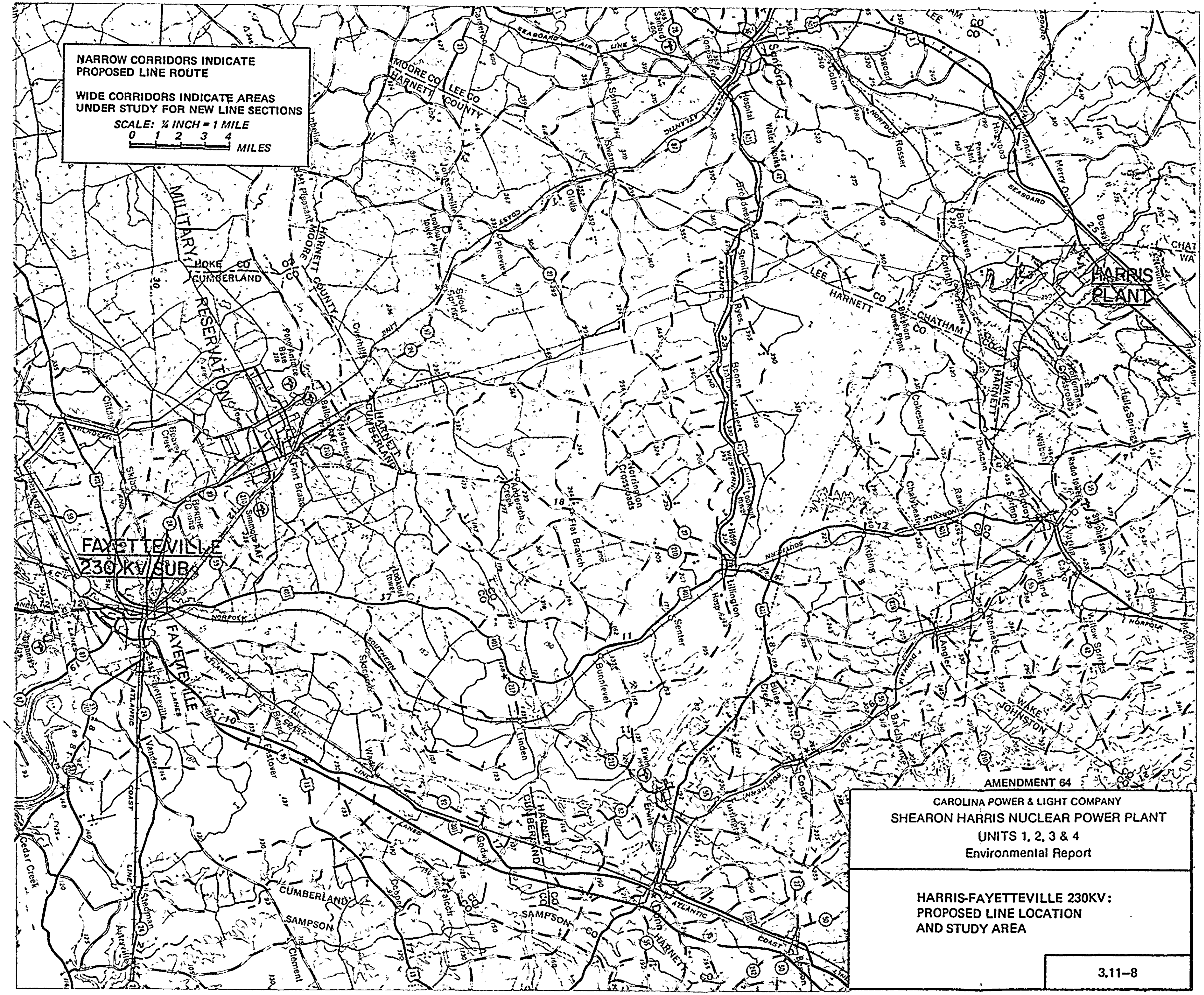
3.11–6



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

HARRIS-ASHEBORO 230KV: PROPOSED LINE LOCATION AND STUDY AREA

3.11-7



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

HARRIS-FAYETTEVILLE 230KV: PROPOSED LINE LOCATION AND STUDY AREA

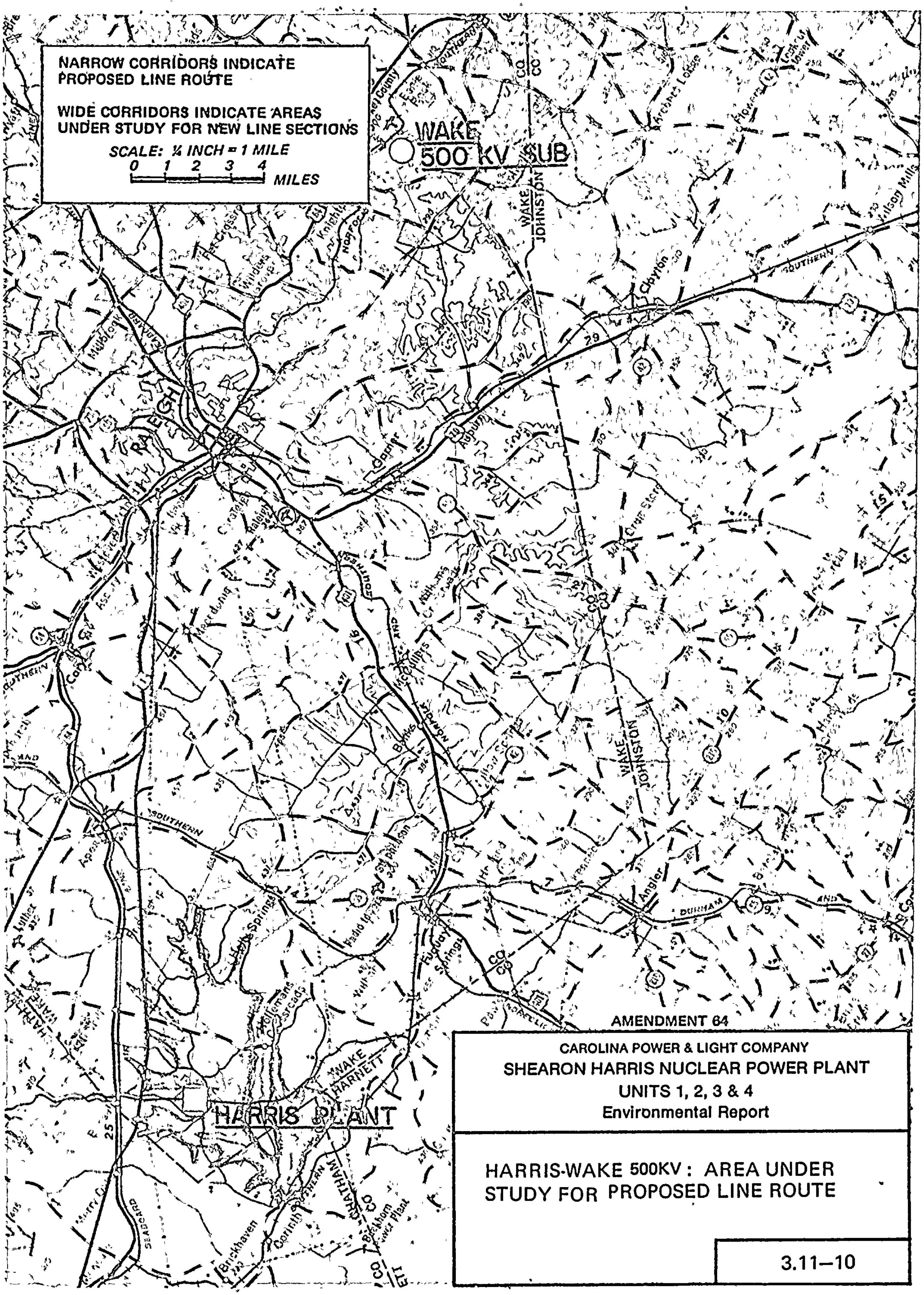
3.11–8

AMENDMENT 64

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

HARRIS-LILLINGTON-ERWIN SOUTH &
HARRIS-FUQUAY-ERWIN NORTH 230KV :
PROPOSED LINE LOCATIONS

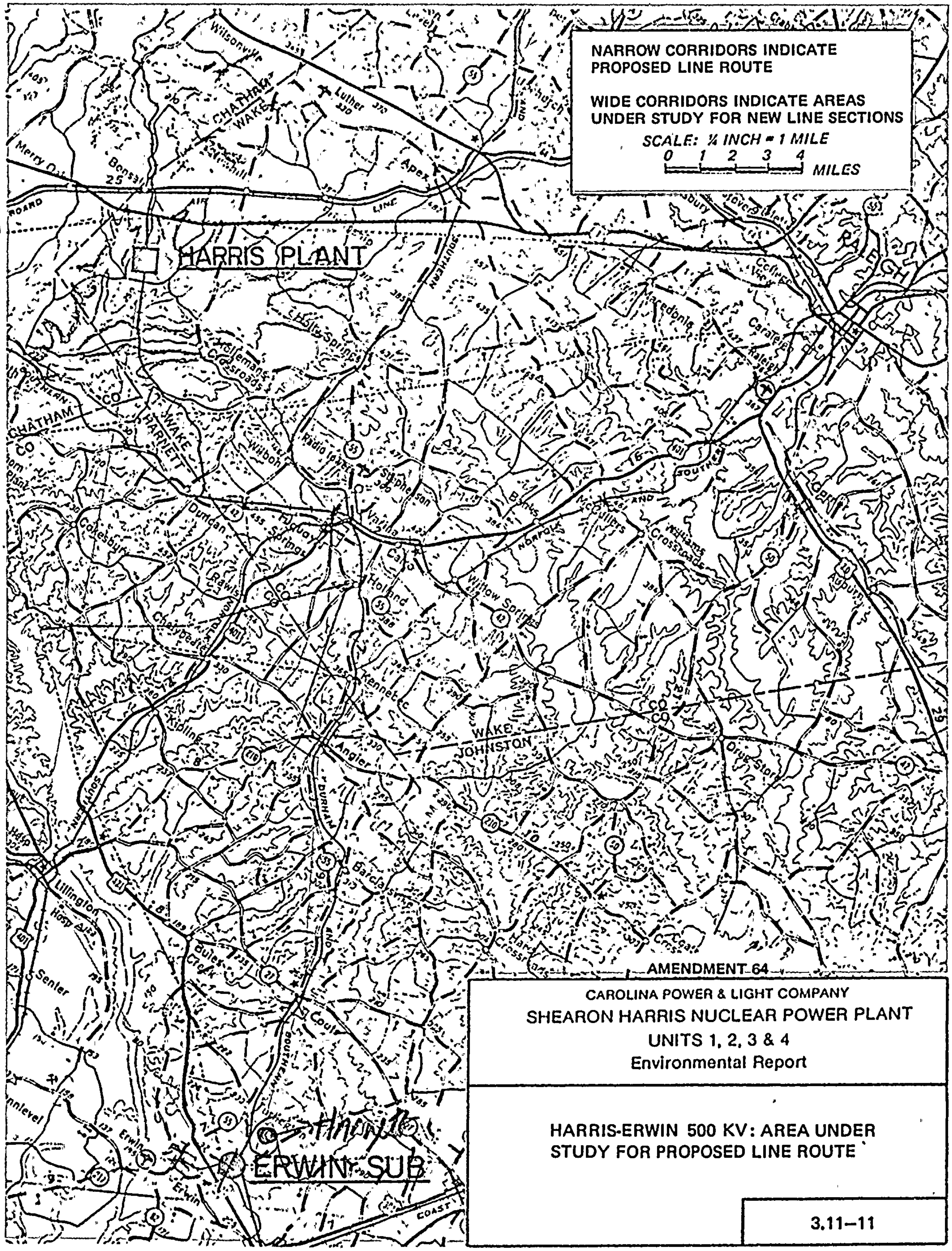
3.11–9



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

HARRIS-WAKE 500KV : AREA UNDER STUDY FOR PROPOSED LINE ROUTE

3.11–10

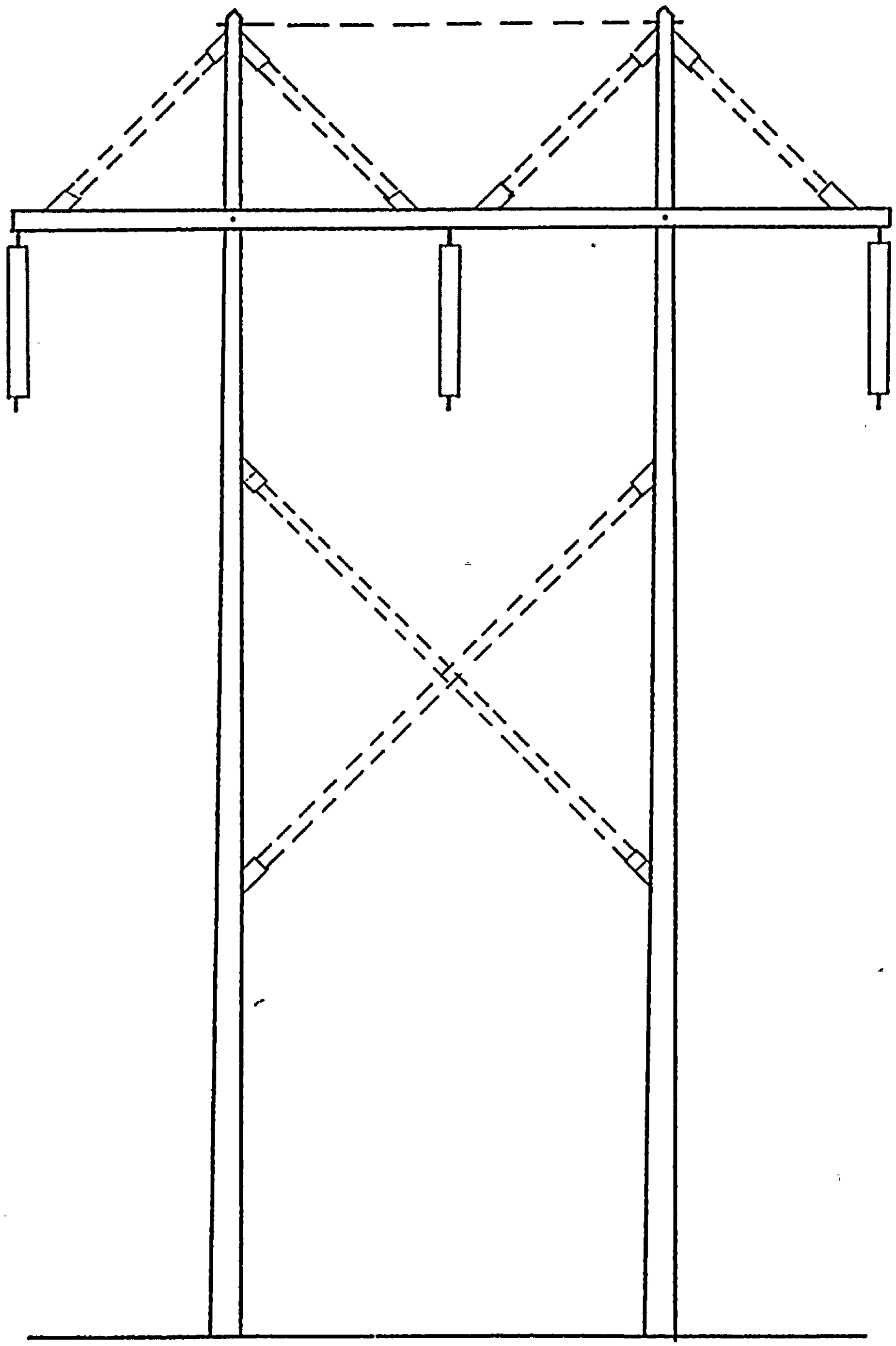


AMENDMENT 64

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

HARRIS-ERWIN 500 KV: AREA UNDER STUDY FOR PROPOSED LINE ROUTE

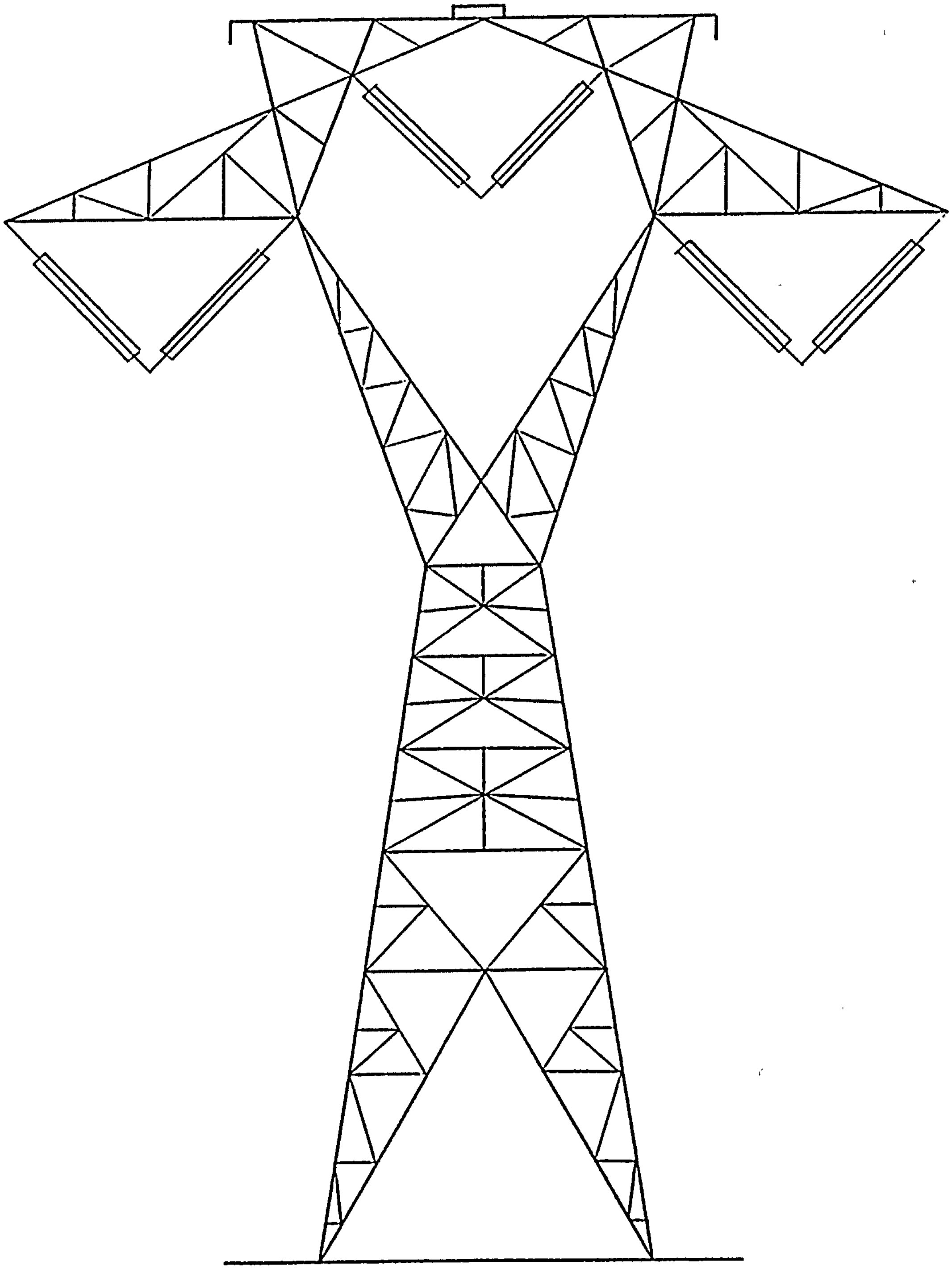
3.11-11



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

CP&L LOW PROFILE H-FRAME STRUCTURE

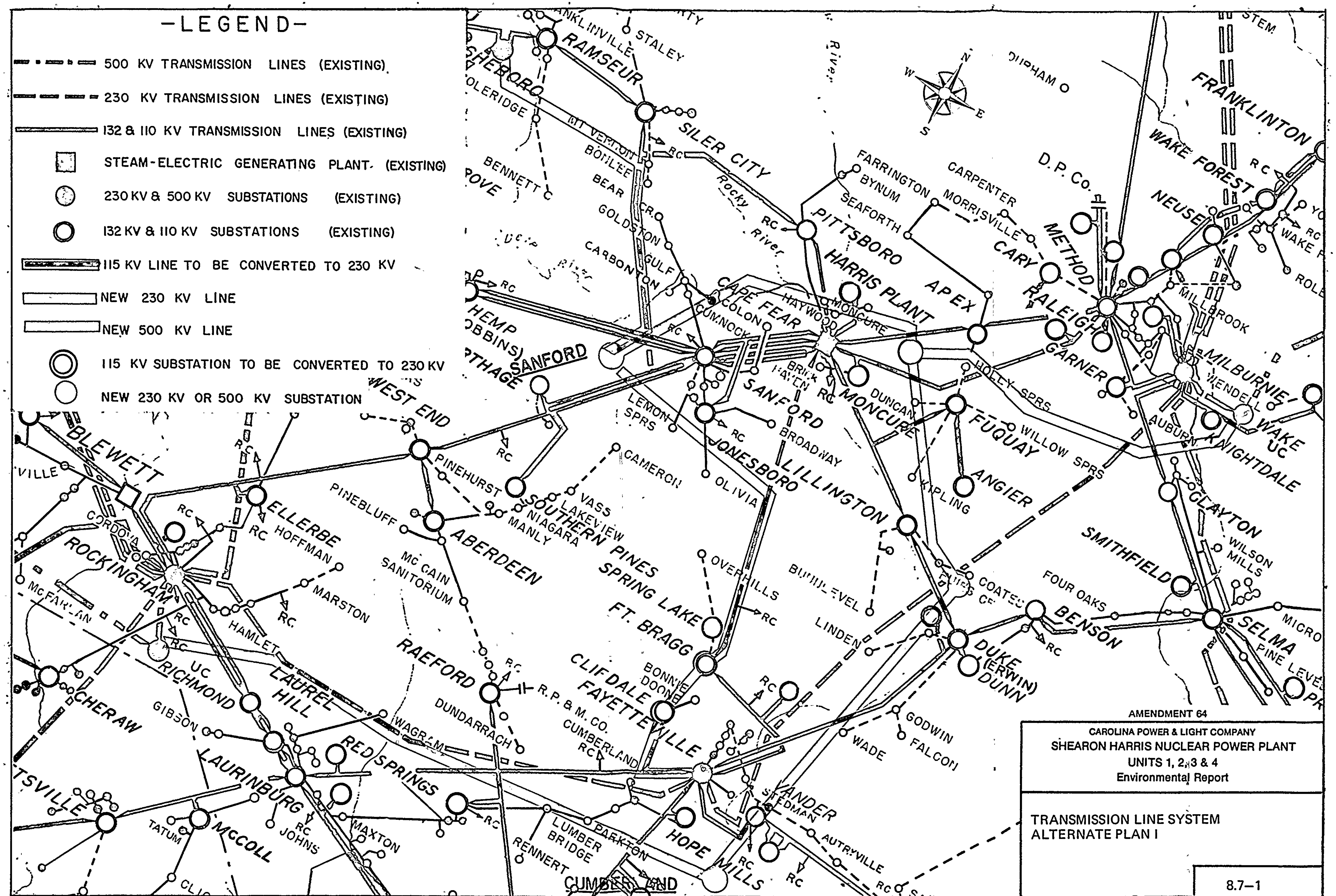
3.11–12



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

500 KV LATTICE TOWER

3.11–13

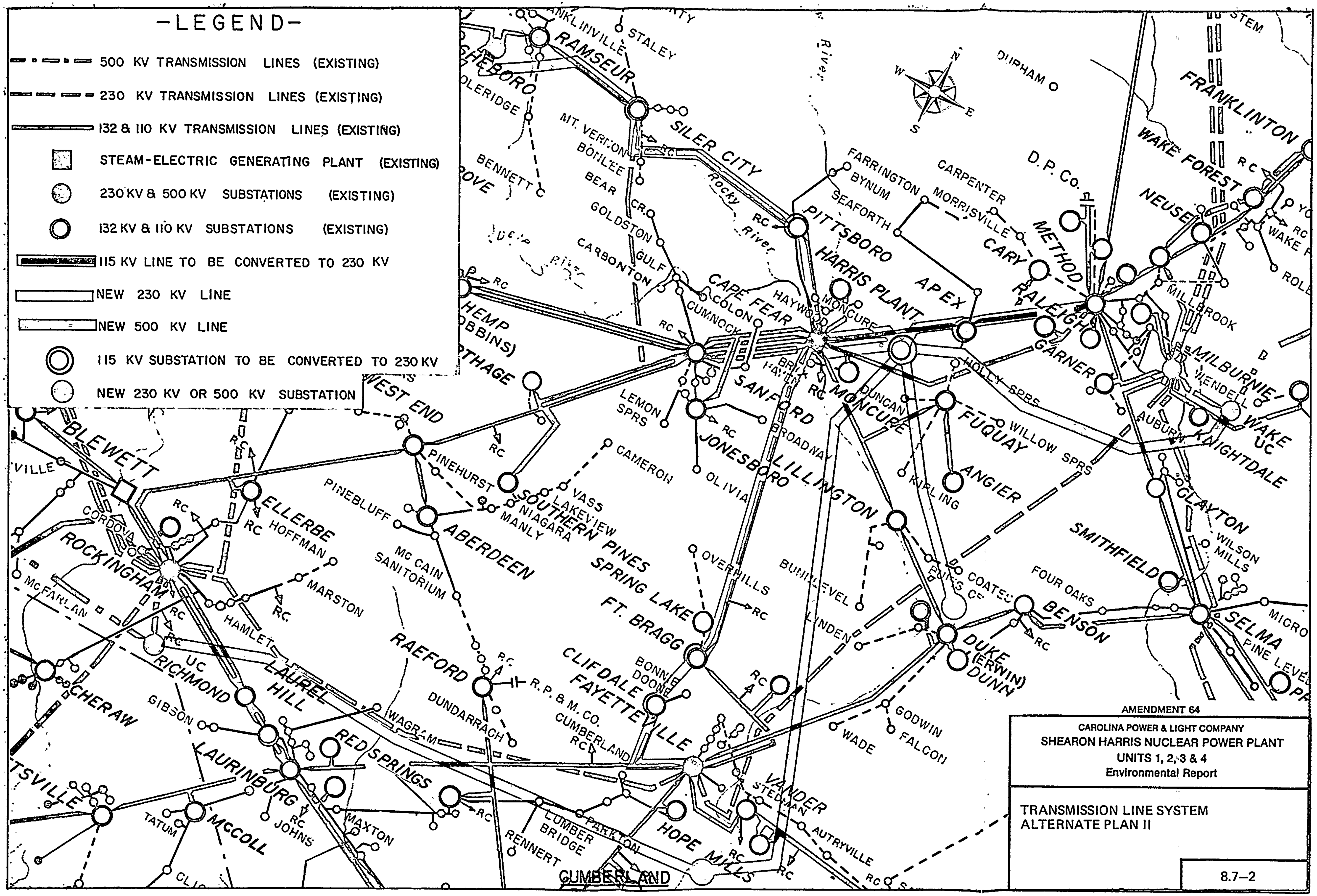


AMENDMENT 64

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

TRANSMISSION LINE SYSTEM
ALTERNATE PLAN I

8.7–1

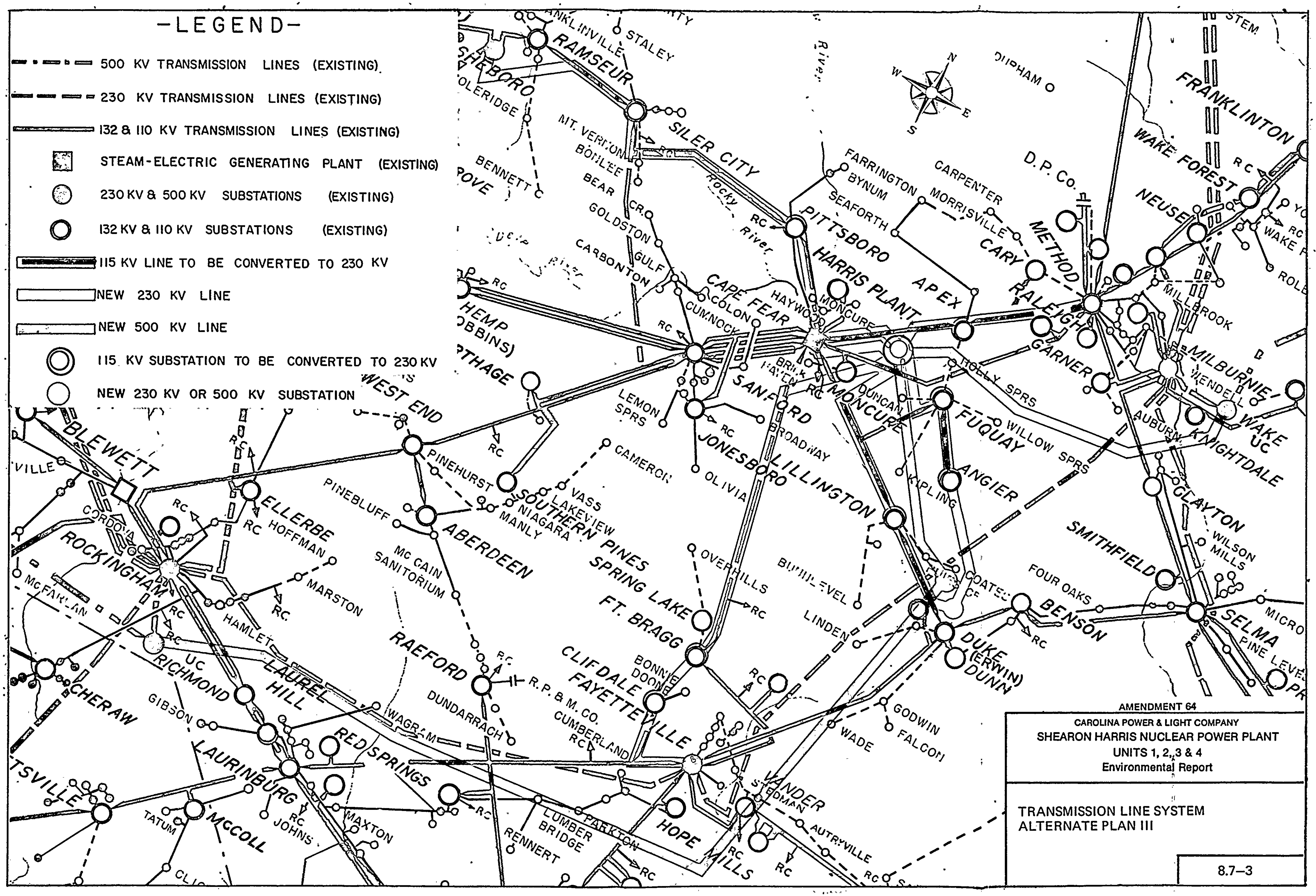


AMENDMENT 64

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

TRANSMISSION LINE SYSTEM
ALTERNATE PLAN II

8.7–2



AMENDMENT 64

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

TRANSMISSION LINE SYSTEM
ALTERNATE PLAN III

8.7–3

UNITED STATES
ATOMIC ENERGY COMMISSION
WASHINGTON, D.C. 20545

JUL 0 3 1972

Docket Nos. 50-400
50-401
50-402
and 50-403

Carolina Power & Light Company
ATTN: Mr. J. A. Jones, Senior Vice Pres.
Engineering and Operating Group
336 Fayetteville Street
Raleigh, North Carolina 27602

Gentlemen:

A visit to the proposed Shearon Harris Nuclear Power Plant site was made on June 13, 14, 1972, by a team from the Directorate of Licensing and Battelle Memorial Institute, Pacific Northwest Laboratories, to review environmental factors related to the construction and operation of the plant.

As a result of this visit and our continuing review, additional information will be required to continue our review. Accordingly, please submit the information requested as identified in the enclosure to this letter. Your reply should consist of three signed originals and 297 additional copies as a sequentially numbered supplement to your Environmental Report.

In order to maintain our licensing review schedule we will need a completely adequate response by July 21, 1972. Please inform us within seven days after receipt of this letter to your confirmation of the schedule or the date you will be able to meet. If you cannot meet our specific date or if your reply is not fully responsive to our requests, it is highly likely that the overall schedule for completing the licensing review for this project will have to be extended. Since reassignment of the staff's efforts will require completion of the new assignment prior to returning to this project, the extent of extension will most likely be greater than the extent of delay in your response.

Sincerely,

Daniel R. Muller

Daniel R. Muller, Assistant Director
for Environmental Projects
Directorate of Licensing

Enclosure:
Request for Additional Information

cc: Mr. George F. Trowbridge, Esq.
Shaw, Pittman, Potts, Trowbridge
and Madden
910 Seventeenth Street, N.W.
Washington, D. C. 20006

Mr. C. D. Barham, Jr., Esq.
Carolina Power & Light Company
336 Fayetteville Street
Raleigh, North Carolina 27602

REQUEST FOR ADDITIONAL INFORMATION

ENVIRONMENTAL REVIEW

SHEARON HARRIS UNITS 1, 2, 3 AND 4

Please provide detailed information on the following:

A. PHYSICAL PLANT

1. The elevation of the bottom of the intake aperture.

2. The water velocity at the intake screens, maximum rate of water intake, and intake screen mesh size.

3. The transit time of water through the condenser cooling system.

4. A description of the outfall structure; the water velocity at the point of discharge.

5. The expected average annual flow through the culvert in the dike.

6. Plans to make the color and texture of the plant aesthetically compatible with the natural environs; how the plant profile fits with the natural environs and the surrounding topography.

7. A description of the load cycle expected for the Harris Plant over a 24-hour period and the associated circulating water temperature fluctuations.

8. Heat-rate curves for various turbine back pressures in order to permit evaluation of thermal effects and operational costs of the various alternatives.

9. Detailed diagrams or plans of the circulating water system intake and discharge structures.

B. WATER QUALITY

1. The temperature differential between the water discharged from the Harris Reservoirs and the Cape Fear River and the expected seasonal variation in temperature and volume of the reservior discharge.

2. The increase in the silt load discharged to the Cape Fear River from White Oak and Buckhorn Creeks which will result from the construction of Harris Units 1, 2, 3, and 4, if any.

3. The kinds, amounts and concentrations of chemicals to be discharged in the liquid wastes released to the cooling reservoir.

4. A description of the method of chlorination and concentrations of chlorine which will be introduced into the condenser cooling system to control fouling.

5. The rate of head dissipation of the condenser cooling discharge in the cooling reservoir and data, computations and diagrams of the thermal plume (isotherms at the water surface) and temperature stratification expected in the Harris Reservoir during winter and summer climatic extremes.

6. Describe the program that will be used to monitor thermal patterns in the Harris Reservoir during plant operation.

7. Data relating to suspended sediment that is available for Buckhorn Creek and the Cape Fear River in the vicinity of Buckhorn Dam.

8. A detailed description of the program that will be used to minimize silt load discharge to the Cape Fear River during construction.

9. The volume and residual chlorine concentration of the sanitary waste treatment system and whether this discharge will be combined with or separate from the condenser cooling discharge.

10. The D.O. of the bottom water (below the thermocline) in the reservoir and the expected seasonal variation in the D.O.

C. <u>ECOLOGY OF SITE AND SURROUNDINGS</u>

1. A description of the extent that vegetation will be removed from the land that will be inundated by the cooling reservoir.

2. Results of entrainment studies on the Cape Fear River and Whiteoak-Buckhorn Creek waters, and laboratory studies made on aquatic organism passage through the condenser cooling system at the Brunswick Nuclear Power Plant (research directed by Dr. B. J. Copeland).

3. Results of recent limnological studies conducted by Carolina Power and Light.

4. The kinds of organisms that will be sampled, at what frequency, and for what kinds of analyses, in the pre- and post-impoundement biological studies.

5. A description of fish management programs that are contemplated for the cooling water reservoir (stocking, rehabilitation, etc.).

6. A discussion of the potential for breeding, feeding, and resting by waterfowl on the cooling afterbay reservoirs.

D. RADIOLOGICAL DOSE

1. A detailed description of the proposed radiation monitoring program including sampling sites, types of samples, frequency of sampling, types of analysis, description of analyzing equipment, consultants for the program and who will conduct the sampling and anlyzing.

2. The exact locations and projected usage (man-hrs/yr) of anticipated recreational sites on Harris Reservoir.

3. The proposed plans for public access to the exclusion area; when, where and how often.

4. The location and average annual occupancy for the proposed "Energy and Environmental Center."

E. NEED FOR POWER AND COST BENEFIT

1. System peak load and capacity data for the years 1965-1976.

2. Estimates of capital and fuel costs for nuclear, oil, and coal plants.

3. Based on 1971 Wake County tax structure, the expected county tax payments on the Harris plant.

4. Capital and annual operating costs for the following cooling options all designed for the same net generating capacity:

   a. Cooling lake (ref. case)
   b. Mechnical draft tower (including 7,200 acre pond)
   c. Natural draft tower (including 7,200 acre pond)

5. Any land use plans made by the county planning board for the area to be occupied by the plant; typical land costs in this area.

6. The requirements for nuclear fuels, in terms of kilograms of uranium and the percentage of U-235, for the initial loadings of Units 1, 2, 3 and 4, and for the subsequent reloading during steady state operation.

F. ATMOSPHERE

1. Describe the basic data, assumptions, and methods used to determine the evaporation from the proposed reservoirs.

2. The variation, by month, of the following reservoir energy budget components for the 10,000 and 400 acre reservoirs.

   a) natural evaportation,
   b) forced evaporation,
   c) natural heat conduction to the atmosphere,
   d) forced heat conduction to the atmosphere.

3. Describe the assumptions, data, and methods used to determine these components.

4. Quantitatively describe the annual frequency of occurrence of fogging and icing resulting from the proposed reservoirs for the region of influence. What would be the extent of fogging and icing for a worse case condition? If operating experience is available and cited, demonstrate its applicability to the Shearon Harris plant and site. Describe the basis data, assumptions, and methods used.

5. What local features and activities might be affected by reservoir fogging and icing, and in what way?

6. Quantitatively describe how the results of the analysis conducted in 4. would change for the 7000 acre make-up water reservoir necessary for a closed-cycle cooling alternative, where only the heat of the blowdown is added to the reservoir.

7. Describe more fully the physical and operating characteristics and environmental impact of the cooling tower system which would meet the requirements of the Shearon Harris plant, including:

   a) size,
   b) numbers,
   c) probable placement on property
   d) evaporation,
   e) blowdown,

      (1) quantity
      (2) temperature
      (3) chemical content

f) drift
g) fogging and icing.

8. Develop a description similar to that called for in 7. for feasible spray cooling systems (ponds and/or canals).

9. What would be the feasibility cost, physical and operating characteristics and water consumption of a hybrid cooling tower (Marley Co., dry in winter, evaporative in summer) for the Shearon Harris plant?

PHYSICAL PLANT

Question A.1

The elevation of the bottom of the intake aperture.

Response

Cooling tower makeup water is taken from the main reservoir by the cooling tower makeup water pumps. These pumps are located in the emergency service water and cooling tower makeup water intake structure, and the bottom level of the makeup pit is at Elevation 190 feet. (Center line of the pumps is at Elevation 195 feet).

Question A.2

The water velocity at the intake screens, maximum rate of water intake, and intake screen mesh size.

Response

The approach velocity at the intake screens will be 0.5 feet per second, or less. Water will be withdrawn for cooling tower makeup at various rates depending on requirements for makeup. Under average meteorological conditions estimated withdrawal is 106 cfs, and under extremely adverse conditions is estimated at 125 cfs. The intake screen mesh size will be 3/8 inch.

Question A.3

The transit of water through the condenser cooling system.

Response

This item is no longer applicable with the change to closed-cycle towers. Entrainment of organisms is discussed in subsection 3.6.

Question A.4

A description of the outfall structure; the water velocity at the point of discharge.

Response

With the adoption of a closed-cycle cooling system, circulating water is no longer discharged to the reservoir. Only blowdown, which is discussed in detail elsewhere, is released.

Question A.5

The expected average annual flow through the culvert in the dike.

Response

The culvert does not exist in the smaller 4,000 acre reservoir. Therfore, this question is no longer applicable.

Question A.6

Plans to make the color and texture of the plant aesthetically compatible with the natural environs; how the plant profile fits with the natural environs and the surrounding topography.

Response

The exterior of the permanent plant buildings will be aesthetically compatible with the environs. The Containment and Reactor Auxiliary Buildings will have as-poured natural concrete exterior finish, while the Fuel Handling Building will have siding with an exterior finish that will be compatible with the environment. In addition, the exposed steel areas of the Turbine Building will be painted in a color to harmonize with the buildings. The plant profile will be dominated by the four natural draft cooling towers, each approximately 480 feet hight. They will have as-poured natural concrete surface

The plant area will be completely leveled to approximately Elevation 260 feet. The surrounding terrain will be undisturbed as far as possible. In general, the terrain is rising to the north of the plant. The main reservoir is to the south, east and west of the plant.

Question A.7

A description of the load cycle expected for the Harris Plant over a 24-hour period and the associated circulating water temperature fluctuations.

Response

With the adoption of proposed closed-cycle cooling towers at the Harris Plant, the heat loading on the reservoir will be insignificant, as discussed in the main text of the Environmental Report. Blowdown will average only about 15 cfs, and will vary from 7F to 24F above ambient temperatures of the main reservoir

Question A.8

Heat-rate curves for various turbine back pressures in order to permit evaluation of thermal effects and operational costs of the various alternatives.

Response

Heat-rate data for various condenser back pressures are shown on Table A.8-1.

TABLE A.8-1

CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT UNITS 1-4

HEAT RATE DATA PER UNIT

** Condenser Pressure inch Hg abs	100%	105%	80%	60%	40%	
1.5	6164.555	6442.899	5056.509	4076.577	2838.996	Condenser Heat Duty (x 10^6 BTU/HR)
	9764.806	9793.976	9717.644	9881.368	10196.876	GSHR* (BTU/KW-HR)
2.0	6170.101	6447.767	5069.764	4100.096	2870.867	Condenser Heat Duty
	9781.117	9805.595	9764.090	9989.438	10435.892	GSHR
3.0	6210.375	6480.535	5127.142	4164.486	2928.853	Condenser Heat Duty
	9897.376	9897.643	9968.484	10295.386	10884.610	GSHR
4.0	6542.652	6271.668	5188.611	4223.157	2978.046	Condenser Heat Duty
	10082.849	10077.801	10201.220	10593.184	11295.185	GSHR

*GSHR - Gross Station Heat Rate

**Condenser Pressure is assumed to be an average of two (2) zones.

LOAD	THROTTLE FLOW	
100%	12,207,500	#/HR
105%	12,819,361	#/HR
80%	9,767,132	#/HR
60%	7,325,349	#/HR
40%	4,883,566	#/HR

Question A.9

Detailed diagrams or plans of the circulating water system intake and discharge structures.

Response

With the changeover to closed-cycle cooling towers, circulating water is not discharged. Make-up water constitutes the only withdrawal.

WATER QUALITY

Question B.1

The temperature differential between the water discharged from the Harris Reservoirs and the Cape Fear River and the expected seasonal variation in temperature and volume of the reservoir discharge.

Response

Downstream releases from the makeup pond are discussed in subsection 3.2

Question B.2

The increase in the silt load discharged to the Cape Fear River from Whiteoak and Buckhorn Creeks which will result from the construction of Harris Units 1, 2, 3, and 4, if any.

Response

Construction of the Harris project is not expected to result in major increases in the silt load of the Cape Fear River. The silt load will be minimized by the erosion control program described in answer B.8.

The Cape Fear Basin is characterized by fine-grained soils that result in a typically turbid appearance of the river after moderate precipitation. This turbidity is caused by the suspension of the fine-grained soils and not by heavy amounts of silt.

The Buckhorn Creek Basin also has clayey and silty-clay soils; runoff results in a turbid appearance while the silt load is light to moderate.

The main reservoir dam will be one of the first items of construction. While erosion control practices will be employed in construction of the dams, there will be moderate amounts of silt as a result of erosion of the dam sites during construction. Completion of the dam will create sediment basins that will trap most of the silt resulting from erosion of the remainder of the construction sites.

The water quality monitoring program described in the Environmental Report will indicate the amount of silt caused by construction and the effectiveness of the erosion control practices.

Question B.3

The kinds, amounts and concentrations of chemicals to be discharged in the liquid wastes released to the cooling reservoir.

Response

Some chemicals will be released to the make-up pond. Because of the change in cooling methods, the chemical waste treatment system at the plant is currently undergoing extensive review and revisions to the systems are being evaluated. Therefore, chemical releases are not available at this time. However, since water quality standards must be met in the makeup pond, and water quality certification obtained, the chemicals in the main reservoir, due to plant operation, will meet the appropropriate standards. As soon as detailed information becomes available it will be incorporated into the environmental report.

Question B.4

A description of the method of chlorination and concentrations of chlorine which will be introduced into the condenser cooling system to control fouling.

Response

Chlorination will be required for one thirty-minute period per day except during the summer when two thirty-minute periods per day may be required. It is expected that the chlorine demand will range from 2 to 5 ppm. Free chlorine residuals in the water leaving the cooling towers in the blowdown to the lake, however, will be limited to concentrations that will meet applicable water quality standards.

Question B.5

The rate of heat dissipation of the condenser cooling discharge in the cooling reservoir and data, computations and diagrams of the thermal plume (isotherms at the water surface) and temperature stratification expected in the Harris Reservoir during winter and summer climatic extremes.

Response

With the utilization of closed-cycle cooling towers, heat is dissipated to the atmosphere. The only heat load on the makeup pond is cooling tower blowdown, and this is discussed in detail in Subsection 3.3.

Question B.6

Describe the program that will be used to monitor thermal patterns in the Harris Reservoir during plant operation.

Response

Periodic monitoring will be established to assure compliance with applicable permits issued with regard to operation of the plant. These programs cannot be developed until conditions of these permits are known.

Question B.7

Data relating to suspended sediment that is available for Buckhorn Creek and the Cape Fear River in the vicinity of Buckhorn Dam.

Response

Water samples from the Cape Fear River and Buckhorn Creek have been analyzed for suspended solids. The samples are representative grab samples collected on a monthly basis. Sample analysis data are listed in Tables B.7-1 and B.7-2; sampling points are shown on Figure B.7-1. Analyses are by Standard Methods, 13th Edition.

TABLE B.7-1

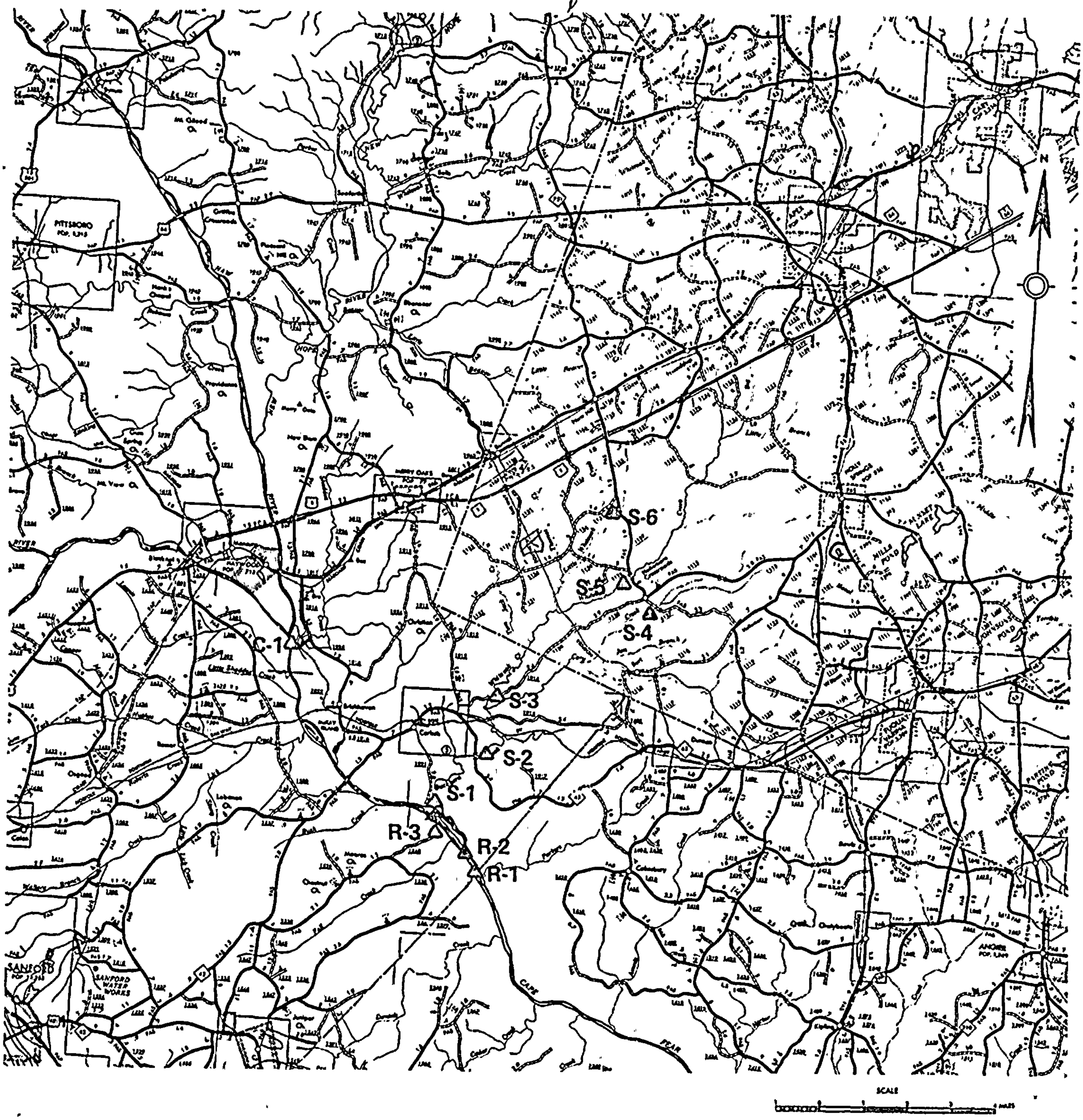
CAPE FEAR RIVER

Sample Date	Suspended Solids, mg/l C-1	R-1	R-2	R-3
August 26, 1971	76			
November 1, 1971	30			
December 1, 1971	46			
January 4, 1972	62			
February 7, 1972	100			
February 23, 1972		4	2	26
March 1, 1972	24			
March 30, 1972		8	12	41
April 6, 1972	6			
April 20, 1972		24	14	38
May 1, 1972	40			
May 31, 1972		22	10	37

TABLE B.7-2

BUCKHORN CREEK

Sample Date	Suspended Solids, mg/l S-1	S-2	S-3	S-4	S-5	S-6
February 23, 1972	6	6	14	10	14	17
March 30, 1972	9	19	3	25	8	7
April 20, 1972	16	23	17	14	24	18
May 31, 1972	9	8	6	21	18	7



CAROLINA POWER & LIGHT COMPANY
SHEARON HARRIS NUCLEAR POWER PLANT
UNITS 1, 2, 3 & 4
Environmental Report

WATER SAMPLE POINTS ON CAPE FEAR RIVER AND BUCKHORN CREEK

B.7–1

Question B.8

A detailed description of the program that will be used to minimize silt load discharge to the Cape Fear River during construction.

Response

The silt load discharge to the Cape Fear River resulting from construction of the Harris Plant will be minimized by use of standard erosion and sediment control measures.

Early construction of the main dam will create sediment basins which will trap most of the silt resulting from erosion of the remainder of the construction sites. During construction of the dam, smaller sediment traps, collection ditches, and intercepts will be used to reduce the silt load.

Controlled grading and clearing will reduce erosion exposure. Only those areas needed immediately for construction will be cleared; grading will be limited to areas that can be handled by erosion control practices. In clearing the reservoir, the root-mat will remain except in the area between the low water level and a zone just above normal water level. In this area, stumps will be cut flush with the ground or they will be removed and the area rough graded.

Runoff from upland areas will be prevented from crossing construction sites by bench terraces and diversion ditches. Downspouts will be paved or vegetated when practicable.

Brush plug dams, burlap fences, or log dams will be used in ditches to trap sediment and reduce the silt load to the river.

Areas outside the reservoir which involve grading or the construction of embankments, spoil areas, ditches and channels will be stabilized by the re-establishment of a vegetative cover as soon as practicable.

Mulch will be used to protect these areas until the vegetation is established.

Question B.9

The volume and residual chlorine concentration of the sanitary waste treatment system and whether this discharge will be combined with or separate from the condenser cooling discharge.

Response

The sanitary waste treatment facility is in the early stages of design. Although specific details of the system are not available, it is assumed that the tertiary treating facility will handle approximately 15,000 gallons per day. The chlorine dose is expected to be 3-4 ppm with a residual chlorine concentration of approximately 0.5 ppm. The amount of chlorine discharged from the sewage treatment facility will be approximately 0.063 $\frac{\text{lbs}}{\text{day}}$ for the 15,000 gallon per day treatment facility. The liquid from the sanitary waste treatment facility will be released to the makeup reservoir.

Question B.10

The D. O. of the bottom water (below the thermocline) in the reservoir and the expected seasonal variation in the D. O.

Response

Dissolved oxygen concentrations in the hypolimnion of a reservoir are dependent upon several factors. These factors are 1) the amount of DO released in the euphotic zone by green plant photosynthesis, 2) aeration by physical factors, 3) the degree of interchange between the surface and bottom waters, and 4) the temperature regimes within the lake. In a typical Piedmont North Carolina lake, DO concentrations are near saturation in the surface waters due to photosynthesis and wind action while the bottom waters are DO poor due to decomposition of organic material which settles from the epilimnion into these waters. However, during spring and fall overturns, DO is restored to the bottom waters as the vertical water column mixes completely due to isothermal conditions within the water column. The makeup pond is expected to have similar characteristics.

Depletion of oxygen in the hypolimnion during the summer months is a natural phenomenon in natural lakes of Piedmont North Carolina and should not be viewed with alarm. During fall and spring, DO concentrations are expected to be similar in surface and bottom waters as a result of mixing the isothermal summer-like stratification. Short cold periods would result in rapid surface cooling and this in turn would tend to cause another isothermal mixing condition. Thus, the hypolimnetic waters are not expected to be without DO for an extended time with the exception of the summer months when stratification prohibits interchange with the surface waters.

ECOLOGY OF SITE AND SURROUNDINGS

Question C.1

A description of the extent that vegetation will be removed from the land that will be inundated by the cooling reservoir.

Response

Vegetation removal from the reservoir site is regulated by the North Carolina Board of Health. Although final plans have not been approved by this agency, it is anticipated that the formulated plans will meet with approval and thus be employed at the Harris Plant site.

The method of vegetation removal will vary with different elevations. Below elevation 202 ft., stumps shall neither exceed 18 inches in height nor an elevation 202 ft. From an elevation 202 feet to a line either 15 feet horizontally outward or 5 feet vertically from elevation 221 ft., whichever is less, all vegetation shall be cut flush with the ground or removed and the area rough graded. Above this fifteen foot horizontal or five foot vertical line, vegetation will be managed for efficient timber and wildlife production.

Question C.2

Results of entrainment studies on the Cape Fear River and Whiteoak-Buckhorn Creek waters, and laboratory studies made on aquatic organism passage through the condenser cooling system at the Brunswick Nuclear Power Plant (research directed by Dr. B. J. Copeland).

Response

Entrainment studies on the Cape Fear River and Whiteoak-Buckhorn Creek waters are not planned. Experience at Lake Robinson near Hartsville, South Carolina, Lake Julian near Asheville, North Carolina, and the Hyco Lake near Roxboro, North Carolina, has been that entrainment apparently is not a serious problem in these cooling lakes. Also, the literature is abundant with both field and laboratory studies of thermal tolerance of freshwater organisms.

The research on marine organisms being performed under the direction of Dr. B. J. Copeland in connection with the Brunswick Plant is still in the preliminary stages. In order to realistically evaluate the subtle effects of increased temperature on organisms, the research was designed to integrate laboratory experimentation with field studies. Ultimately, the critical thermal maximum (CTM) of various organisms will be related to physiological and ecological parameters which can be combined with the field work to determine the effects of entrainment.

The following is a copy of the preliminary results of this research, as reported to CP&L in the first annual report. These results on the lower Cape Fear River in connection with the Brunswick Plant, however, are not considered particularly applicable to the Harris Plant which is located upstream approximately 190 river miles. The river in the vicinity of the Harris Plant is not inhabited by shrimp.

Preliminary Results

The CTM for white shrimp (<u>Penaeus setiferus</u>) collected from the Cape Fear River Estuary during October (see Section II.2.) and tested during October and November are shown in Tables C.2-1 and -2. The shrimp were acclimated to 19.5 C for two weeks prior to subjecting them to CTM tests. This acclimation temperature is very similar to water temperatures expected in the area during October and November (Hobbie 1971; Section III of this report). The shrimp were tested at four salinity levels which represent the expected low to mean salinities (Hobbie 1971; Section III). Although Bridges (1971) concluded that salinity within the range expected in the Cape Fear System did not significantly influence the CTM of spot (<u>Leiostomus xanthurus</u>), this conclusion will have to be tested for white shrimp and other species.

Although it was difficult to identify the CTM for white shrimp, we recorded CTM's between 32.1 and 36.4 C for the October 28, 1971, test. It was decided to use permanent loss of equilibrium as the CTM end point for this test. Shrimp of random lengths and weights were tested. The lengths and weights (79 to 133 mm and 3.0 to 14.1 gm, respectively) were larger than the mean juvenile sizes in North Carolina waters (Williams 1955). No obvious difference between the CTM of sexes could be noted.

Several shrimp were placed in water of ambient temperature (19.5 C) immediately following achievement of CTM to test their ability to recover (shown by * in Table C.2-1). Of the nine shrimp tested, only two recovered. Thus, acceptance of the criteria of permanent loss of equilibrium as CTM may be questionable for white shrimp.

Different CTM criteria were used in the November 10, 1971, test; <u>i.e.</u>, first loss of equilibrium and point of death. Lengths and weights of shrimp were 62 to 118 mm and 2.1 to 14.8 gm, respectively. The

CTM at loss of equilibrium ranged between 26.4 and 32.8 C, whereas the death point temperature ranged between 30.2 and 38.0 C. To test the relationship of CTM defined in terms of equilibrium loss (Fig. C.2-1) and heat death (Fig.C.2-2) with shrimp size, we plotted the temperature data versus length. Although there is considerable scatter, it seems that the larger shrimp are more tolerant, at least in terms of heat death.

The data show that the CTM of white shrimp might well exceed effluent temperatures during autumn (19.5 C ambient plus about 10 C condenser heating is about 30 C). The CTM of smaller shrimp may be within the heat range, but considerable additional testing will be necessary to verify this point.

Reference

Copeland, B. J. and Birkhead, William S., (1972). Some Ecological Studies of the Lower Cape Fear River Estuary, Ocean Outfall and Dutchman Creek, 1971, First Annual Report to Carolina Power & Light Company. Pamlico Marine Laboratory, N. C. State University, Raleigh, N. C.

Table C.2-1 CTM, Sex, Length and Weight for White Shrimp (*Penaeus setiferus*), 28 October 1971.

Tank	Salinity (ppt)	Shrimp	CTM	Sex	Length (mm)	Weight (gms)
I	5	1	36	m	95	5.5
		2	33	f	108	7.65
		3	34.1	m	95	5.45
		4	33.5	f	101	6.15
		5	34.7	m	82	3.0
		6	34.1	f	133	14.1
		7	34.3	m	95	4.75
II	10	1	34.7	f	114	5.8
		2	33.5	f	128	11.2
		3	34.8	f	125	10.3
		4	34.2	m	112	7.1
		5	34.1	f	118	8.8
		6	34.8	f	119	9.35
		7	35.1	f	122	10.2
		8	35.1	f	113	8.15
		9	35.4	f	122	11.7
		10	35.4	f	96	5.4
		11	34.75	m	118	10.0
		12	35.47	m	100	6.0
		13	35.0	m	115	8.5
		14	35.2	f	120	11.05
		15	35.8	m	118	9.8
		16	35.4	f	118	7.5
		17	34.45	m	121	11.1
III	15	1	34.3	f	96	5.6
		2	34.3	m	109	8.8
		3	32.1	f	84	4.35
		4	34.4	m	104	7.7
		5	35.0	f	98	6.1
		6	34.8	m	105	7.8
		7	35.3	f	108	8.7
		8	34.8	m	105	7.4
		9	34.2	m	99	6.5
		10	34.0	m	88	4.0
		11	35.4	m	99	6.8
		12	34.8	m	88	5.0
		13	34.8	m	102	7.4
		14	34.5	f	94	5.7
		15	36.0	m	113	10.1
		16	36.3	f	93	5.2
		17	36.4	m	105	7.8
		18	34.7	f	96	6.4

Table C.2-1 (Continued)

Tank	Salinity	Shrimp	CTM	Sex	Length (mm)	Weight (gms)
IV	20	1	32.65	f	96	5.3
		2	34.47	m	107	7.35
		3*	32.4	m	106	7.5
		4*	34.95	-	--	---
		5	34.25	m	96	4.85
		6	35.1	f	108	6.80
		7*	33.8	-	--	---
		8*	33.8	f	79	3.25
		9	34.8	f	109	8.15
		10	34.8	m	95	5.3
		11*	35.5	f	120	11.35
		12*	34.6	f	98	6.2
		13*	34.4	f	99	6.5
		14*	34.6	m	102	7.4
		15*	35.6	f	108	8.1

*Shrimp removed to ascertain survival. No.s 4 and 7 recovered.

Table C.2-2 First Equilibrium Loss, Death, Sex, Length, and Weight for White Shrimp (Penaeus setiferus), CTM run 10 November 1971.

Tank	Salinity	Shrimp	Eq. Loss	Death	Sex	Length (mm)	Weight (gms)
I	5ppt	1*	17.0	30.65	f	94	6.8
		2*	17.0	30.0	m	83	4.4
		3	30.1	35.1	f	91	5.7
II	10ppt	1	27.7	32.9	m	73	3.3
		2	30.4	36.15	f	103	9.2
		3	30.0	37.65	m	98	7.3
		4	29.5	35.1	f	72	2.9
		5	30.1	35.1	f	103	9.1
		6	26.4	32.1	f	65	2.6
		7	30.9	34.8	m	100	8.2
		8	31.0	35.2	m	92	6.3
		9	29.9	34.7	f	110	10.6
		10	29.2	36.8	m	118	12.8
		11	26.6	34.2	m	102	8.6
III	15ppt	1	31.7	35.4	f	92	6.4
		2	30.6	34.7	m	77	3.9
		3	30.9	35.6	f	84	4.6
		4	31.7	34.9	m	88	5.2
		5	26.4	32.8	f	78	3.8
		6	28.4	33.6	m	66	2.1
		7	31.8	33.4	m	81	3.8
		8	31.4	34.2	f	70	2.8
		9	29.0	32.5	f	81	4.3
		10	31.6	35.2	f	95	6.6
		11	32.3	35.2	m	77	3.4
		12	31.2	34.9	f	72	3.2
IV	20ppt	1	30.4	34.25	f	116	12.9
		2	32.6	35.6	m	66	2.1
		3	31.2	38.0	m	109	10.2
		4	32.0	37.7	f	80	4.3
		5	31.0	35.8	f	84	5.0
		6	30.8	34.2	m	62	2.15
		7	31.7	36.4	f	83	5.2
		8	31.5	34.2	f	73	2.8
		9	30.8	38.0	f	117	14.8
		10	31.7	36.8	f	78	4.25
		11	30.8	36.0	f	74	3.2
		12	32.8	37.3	f	75	3.4
		13	31.4	34.25	f	103	8.9
		14	31.4	32.7	f	84	4.1
		15	31.0	37.5	m	91	6.3
		16	28.8	30.2	f	69	2.4

*Specimens were in poor physical condition, as evidenced by the fact that they lost equilibrium upon being placed in the flask.

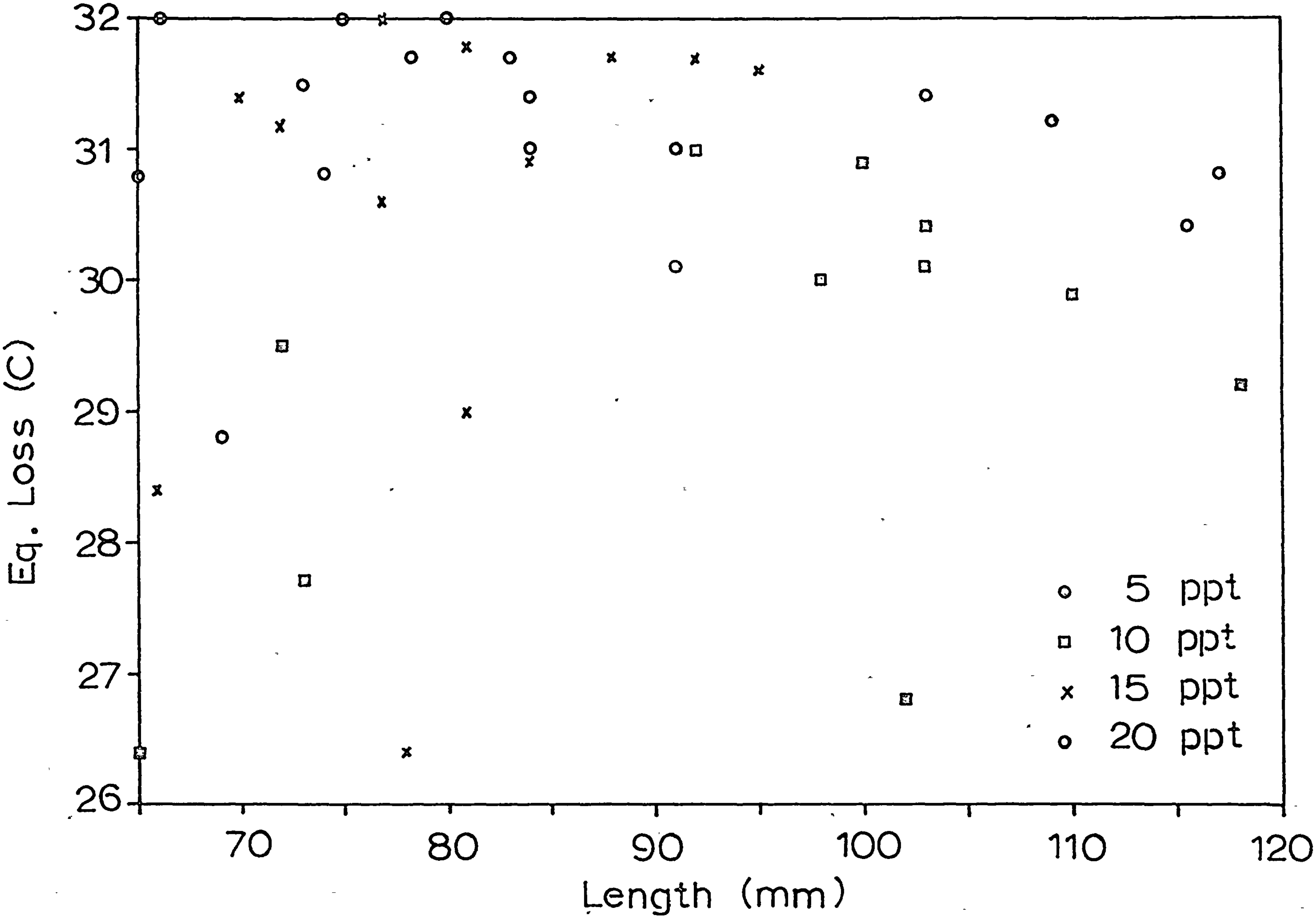


Fig. C.2-1 CTM as measured by initial loss of equilibrium versus total length of each shrimp (mm).

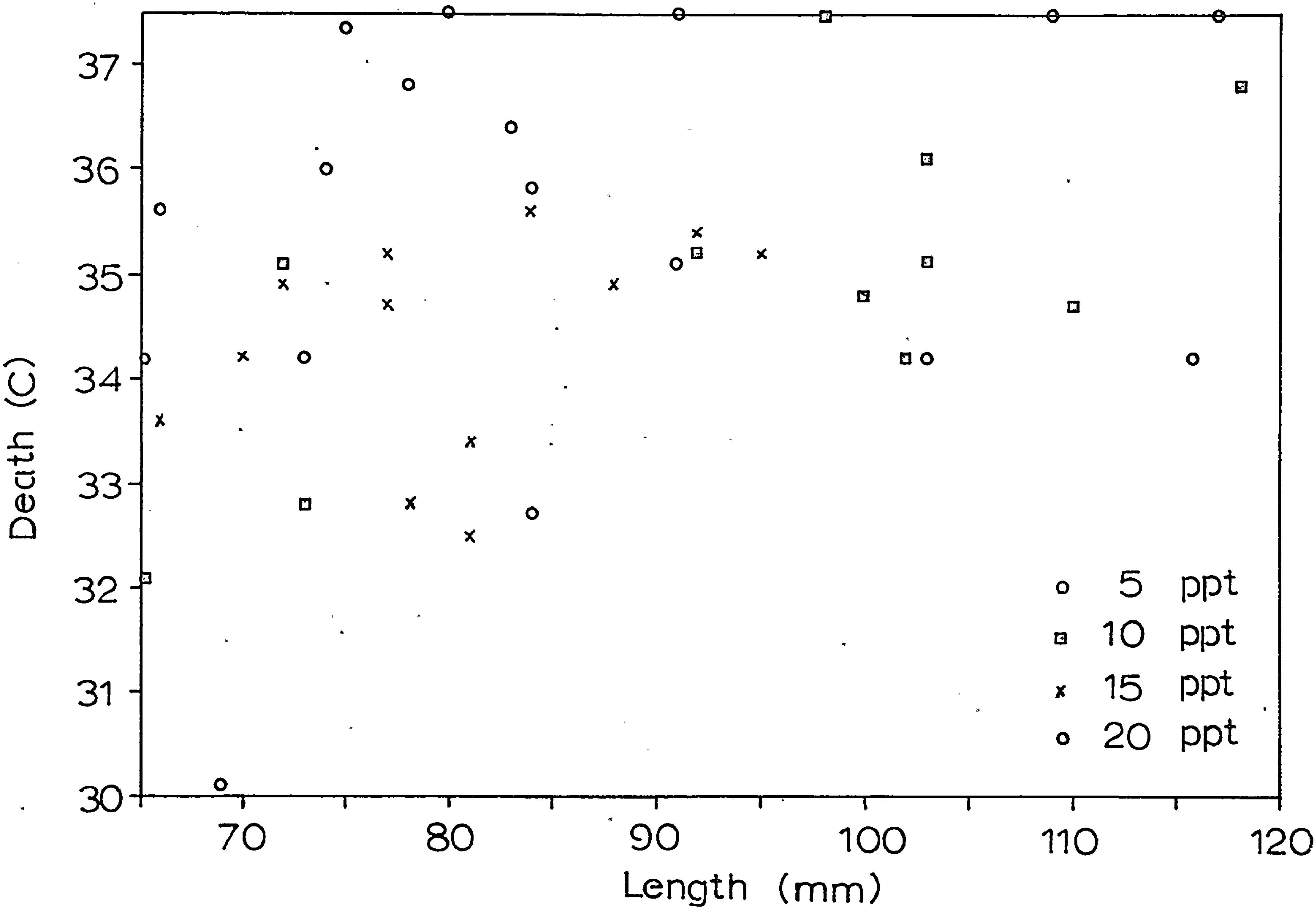


Fig. C.2-2 Temperature at which death occurred versus the total length of each shrimp (mm).

Question C.3

Results of recent limnological studies conducted by Carolina Power and Light.

Response

Initially, Dr. B. J. Copeland and Dr. J. E. Hobbie of N. C. State University conducted a preliminary limnological investigation of the Whiteoak-Buckhorn Watershed in preparation of an "Ecological Report to Carolina Power & Light on Whiteoak Creek Site." This report was utilized in design of a more thorough limnological study of water quality and aquatic biota. Beginning in February 1972, 10 water samples were taken monthly at three river, one pond, and six stream stations. Benthos, plankton, periphyton, perifauna, and macrophyton samples were collected at two river transects (four sampling points per transect) and seven stream stations in April 1972. Fishery investigations were incorporated into this quarterly biological program in July 1972.

The results of the preliminary study conducted by Dr. Copeland and Dr. Hobbie are summarized as follows:

The present streams (Little Whiteoak, Whiteoak, Cary Jim Branch, and Buckhorn Creeks) are narrow, shallow, and with low flow (less than about 10 cfs) with little or no flow during drier portions of the year. These streams drain a small, well-defined basin, which shows no evidence of serious pollution. The streams are a succession of ripple areas with occasional shallow pools. The pools contain a few species of small fishes (these streams are generally regarded as "bass-feeder streams").

Water samples were taken from seven locations in the Whiteoak Creek basin and analyzed for various species of phosphorus and nitrogen.

The results for nitrate, ammonia and total nitrogen, and reactive, filtered and unfiltered phosphorus are presented in the Table C.3-1. In general, the concentration of nutrients in the Whiteoak system was relatively low. The only nitrate concentration approaching "high" levels was the 12.8 ug-at N/1 at station 8 on Cary Jim Branch. One high ammonia nitrogen concentration (12.25 up-at N/1) was observed at station 7 on the combined Whiteoak-Buckhorn Creeks. Total nitrogen, ranging between 17 and 88 ug-at N/1, was relatively low (less than 0.5 mg/1). Total phosphorus concentration at station 7 (in the combined streams) was 9.1 ug-at P/1, which approaches eutrophication levels of 0.3 mg/1.

Nutrient samples were taken from a pond located in the Whiteoak watershed (station 10) in an attempt to determine the nutrient buildup in impounded waters of the Whiteoak drainage basin. It was thought that perhaps this would offer some indication of what the nutrient concentration in the proposed Harris Reservoir might be. As indicated in Table C.3-1, the concentrations were all within the limits observed in the streams. If, indeed, the pond on the watershed is an indication of the characteristics of the proposed reservoir, one can argue that the reservoir will not have extremely high nutrient concentrations which often lead to so-called "eutrophic conditions." There are, however, enough nutrient materials in the Whiteoak drainage to support moderate to high productivity.

Results from the water quality study for February-May 1972 are presented in Table C.3-2. Laboratory analyses were made in accordance with Standard Methods for the Examination of Water and Wastewater, 13th Edition.

The benthos, plankton, perifauna, periphyton, and macrophyton sample collected in April 1972 have not yet been fully processed. Most of the sorting of benthos has been done but the identification and counts are incomplete. A summary of the first sampling operation, compiled from field notes, is presented in Table C.3-3.

TABLE C.3-1

ANALYSIS OF WATER SAMPLES FROM THE WHITEOAK CREEK SYSTEM FOR NUTRIENT CONCENTRATIONS

Station Number	Concentration in ug-at N or P/1					
	Nitrate Nitrogen	Ammonia Nitrogen	Total Nitrogen	Reactive Phosphorus	Unfiltered Phosphorus	Filtered Phosphorus
4	0.41	5.73	17.24	0.65	1.20	0.85
5	2.54	5.01	25.39	0.85	1.80	1.70
6	0.60	1.79	26.49	0.58	2.20	3.33
7	1.40	12.25	18.76	1.27	9.10	1.85
8	12.80	2.94	33.27	0.58	4.15	2.50
9	3.06	2.13	20.84	1.00	2.20	1.27
10	3.61	6.44	33.35	0.85	1.60	1.15

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
COD (ppm)										
February 1972	8	11	15	10	12	11	8	10	11	14
March	5	5	9	6	5	5	5	6	8	9
April	9	7	11	9	9	10	10	11	11	9
May	9	7	11	7	6	13	7	15	9	7
June	18	12	22	8	9	15	11	14	17	14
July	18	16	21	13	12	16	10	10	21	4
August	10	11	13	7	7	14	8	10	14	7
September	9	12	12	8	8	14	14	15	15	14
October	10	7	16	9	7	14	10	12	16	9
November	23	26	23	26	20	26	16	21	16	8
December	--	--	13	19	22	25	8	11	9	14
January 1973	3	5	6	6	7	4	8	8	5	8
February	7	6	10	6	7	9	9	9	7	--
Total Solids (ppm)										
February 1972	46	112	118	86	32	54	64	60	90	64
March	82	68	142	108	90	34	92	50	78	72
April	75	66	111	27	50	54	55	40	41	36
May	112	81	94	68	109	61	38	60	70	70
June	119	81	196	61	46	70	77	65	59	64
July	161	149	165	36	47	57	112	47	660	47
August	91	111	150	48	60	46	77	50	98	35
September	220	152	223	74	98	90	110	91	94	72
October	101	90	82	92	74	190	93	80	91	87
November	154	105	167	149	140	132	92	104	102	73
December	---	---	124	82	78	109	366	113	81	77
January 1973	68	65	119	99	62	55	62	119	59	72
February	83	54	105	52	69	68	84	83	94	--

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Total Volatile Solids (ppm)										
February 1972	16	44	26	18	8	30	6	22	52	8
March	20	28	74	36	56	12	32	40	62	46
April	28	48	60	14	26	31	37	16	16	21
May	38	33	39	24	49	17	25	44	16	26
June	59	19	53	23	37	21	34	47	21	32
July	38	13	14	6	12	30	37	22	82	12
August	32	22	35	6	8	16	25	25	64	12
September	115	46	71	37	29	76	77	57	51	49
October	51	63	53	61	44	70	65	47	61	56
November	56	63	60	83	83	68	40	92	82	23
December	--	--	48	40	40	66	308	77	36	42
January 1973	43	27	68	69	51	45	26	36	23	39
February	60	50	37	26	47	42	67	74	61	--
Total Suspended Solids (ppm)										
February 1972	4	2	26	6	6	14	10	14	17	8
March	8	12	41	9	19	3	25	8	7	12
April	24	14	38	16	23	17	14	24	18	16
May	22	10	37	9	8	6	21	18	7	9
June	27	4	110	16	12	3	12	10	11	11
July	26	15	33	7	3	16	44	17	350	2
August	18	16	50	8	5	26	7	10	5	7
September	24	24	19	10	13	17	22	13	14	5
October	4	6	5	6	3	20	6	11	9	3
November	76	48	80	88	46	48	16	27	24	15
December	--	--	26	7	6	8	5	6	6	5
January 1973	7	7	8	17	3	5	8	41	8	24
February	15	13	31	5	6	8	2	9	12	--

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Total Dissolved Solids (ppm)										
February 1972	42	110	92	80	26	40	54	46	73	56
March	74	56	101	99	71	31	67	42	71	60
April	51	52	73	11	27	37	41	16	23	20
May	90	71	57	59	101	55	17	42	63	61
June	92	77	86	45	34	67	65	55	48	53
July	135	134	132	29	44	41	68	30	310	45
August	73	95	100	40	55	20	70	40	93	28
September	196	128	204	64	85	73	88	78	80	67
October	97	84	77	86	71	170	87	69	82	84
November	78	57	87	61	94	84	76	77	78	58
December	--	--	98	75	72	101	361	107	75	72
January 1973	61	58	111	82	59	50	54	78	51	48
February	68	41	74	47	63	60	82	74	82	--
Ammonia (N) (ppm)										
February 1972	0.40	0.54	1.22	0.30	0.22	0.30	0.20	0.34	0.32	0.44
March]	0.29	0.09	0.16	0.10	0.03	0.12	0.05	0.15	0.02	0.12
April	0.32	0.40	0.42	0.20	0.23	0.34	0.21	0.31	0.32	0.44
May	0.36	0.15	0.23	0.18	0.11	0.23	0.12	0.48	0.25	0.15
June	0.34	0.30	0.55	0.20	0.18	0.33	0.33	0.40	0.54	0.18
July	0.75	0.79	0.88	1.00	0.60	1.08	0.49	1.00	0.75	1.10
August	0.38	0.44	0.41	0.36	0.39	0.53	0.32	0.55	0.57	0.55
September	0.11	0.15	0.20	0.06	0.15	0.44	0.14	0.24	0.45	0.43
October	0.21	0.28	0.48	0.32	0.26	0.52	0.33	0.44	0.46	0.29
November	0.73	0.97	0.71	0.93	0.94	1.07	0.74	0.86	0.81	0.36
December	--	--	0.15	0.18	0.18	0.25	0.27	0.31	0.37	1.05
January 1973	<0.05	<0.05	0.34	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
February	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	----

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Nitrate (N) (ppm)										
February 1972	0.25	0.26	0.47	0.13	0.10	<0.05	0.11	<0.05	0.24	<0.05
March	0.25	<0.05	0.79	0.05	<0.05	<0.05	<0.05	<0.06	<0.05	<0.05
April	0.25	<0.01	0.59	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01	<0.01
May	0.12	0.01	0.25	0.05	0.08	0.04	0.17	0.03	0.02	<0.01
June	0.21	0.04	0.18	0.05	0.04	0.01	0.13	0.08	0.01	<0.01
July	0.67	0.50	0.59	0.02	0.08	<0.01	0.25	0.15	0.12	0.02
August	0.23	0.18	0.41	<0.01	<0.01	0.04	0.25	0.12	0.01	<0.01
September	0.31	0.27	0.43	<0.01	<0.01	0.02	<0.01	<0.01	0.03	<0.01
October	0.18	<0.01	<0.01	<0.01	<0.01	0.57	<0.01	<0.01	<0.01	<0.01
November	0.21	<0.01	0.38	<0.01	<0.01	<0.01	0.03	0.04	<0.01	0.04
December	--	--	0.27	0.02	<0.01	<0.01	0.07	<0.01	<0.01	0.23
January 1973	0.10	0.06	0.52	0.08	0.11	<0.01	0.16	0.08	0.06	0.06
February	0.17	0.17	0.80	0.15	0.15	0.06	0.10	0.09	0.06	--
Kjeldahl (N) (ppm)										
February 1972	0.84	0.84	1.68	1.12	1.40	1.12	1.12	1.40	1.40	1.40
March	0.84	0.56	0.56	0.28	0.28	0.28	0.28	0.84	0.84	0.28
April	0.56	0.56	0.84	0.56	0.56	0.56	0.56	0.56	0.56	0.84
May	0.56	0.34	1.12	0.34	0.45	0.67	0.45	0.78	0.34	0.45
June	0.68	0.34	0.80	0.23	0.23	0.34	0.34	0.46	0.68	0.34
July	1.12	1.23	1.01	1.12	0.90	1.12	1.01	1.12	1.34	1.23
August	0.95	0.90	1.23	0.90	0.73	0.90	1.01	1.01	1.12	1.06
September	0.45	0.90	1.01	0.39	0.34	0.45	0.90	0.78	0.62	0.62
October	0.34	0.34	0.56	0.45	0.45	1.12	0.45	0.56	0.56	0.56
November	1.23	1.01	1.34	1.06	1.18	1.19	0.90	1.02	0.90	0.78
December	--	--	0.90	0.73	0.62	0.62	0.62	0.62	0.73	1.23
January 1973	0.11	0.17	0.78	0.22	0.17	0.22	0.22	<0.05	0.11	0.11
February	0.50	0.39	1.45	0.39	0.39	0.39	0.39	0.34	0.39	--

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Ortho Phos. (ppm)										
February 1972	0.10	0.40	0.50	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10
March	0.30	<0.10	0.60	0.10	<0.10	<0.10	<0.10	0.10	0.20	<0.10
April	0.20	<0.10	1.10	<0.10	0.10	0.10	<0.10	<0.10	<0.10	<0.10
May	0.20	0.10	0.40	0.10	0.10	0.20	<0.10	0.40	0.20	0.10
June	0.20	<0.10	0.40	0.10	<0.10	0.20	0.10	0.20	0.10	<0.10
July	1.32	1.12	1.30	0.15	0.08	0.15	0.23	0.07	<0.01	0.02
August	0.33	0.42	0.60	0.01	0.02	0.03	0.22	0.60	0.20	0.22
September	1.02	0.75	1.88	0.02	0.08	0.19	0.37	0.24	0.06	0.48
October	0.37	<0.01	0.04	0.05	0.03	1.62	0.12	0.08	0.01	0.03
November	0.50	0.03	0.80	0.05	0.08	0.10	0.09	0.19	0.04	0.04
December	--	--	0.43	0.19	0.29	0.15	0.10	0.15	0.11	0.29
January 1973	0.08	0.19	0.57	0.18	0.12	0.10	0.20	0.14	0.21	0.21
February	0.27	0.17	0.80	0.17	0.05	0.05	0.08	0.11	0.12	--
Poly Phosphate (ppm)										
February 1972	0.10	<0.10	0.10	<0.10	<0.10	<0.10	<0.10	0.10	<0.10	0.10
March	0.10	0.20	<0.10	<0.10	0.10	0.10	0.10	<0.10	<0.10	<0.10
April	0.10	0.10	<0.10	0.10	0.20	0.20	0.10	0.10	0.10	0.10
May	0.10	0.20	0.10	<0.10	0.20	0.10	0.10	0.10	<0.10	0.20
June	<0.10	<0.10	<0.10	0.10	<0.10	<0.10	0.10	<0.10	<0.10	<0.10
July	0.09	0.01	<0.10	0.05	0.07	0.03	0.07	0.03	0.04	0.07
August	0.02	0.07	0.01	0.07	0.03	0.06	0.09	0.05	0.08	0.03
September	0.02	0.54	0.52	0.02	0.08	0.08	0.01	0.01	0.01	0.04
October	0.06	0.19	0.04	0.11	0.15	0.04	0.10	0.01	0.06	0.20
November	0.02	0.01	0.03	0.01	0.01	0.02	0.17	1.24	0.03	<0.01
December	--	--	0.26	0.26	0.21	0.12	0.28	0.19	0.11	0.29
January 1973	0.65	0.76	0.84	1.03	0.69	0.58	0.58	0.43	0.71	0.71
February	0.38	0.53	0.28	0.51	0.76	0.54	0.87	0.51	0.48	--

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973)

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Phosphate										
February 1972	<0.10	0.40	0.60	<0.10	<0.10	<0.10	<0.10	0.10	<0.10	0.10
March	0.40	0.20	0.60	0.10	0.10	0.10	0.10	0.10	0.20	<0.10
April	0.30	0.10	1.10	0.10	0.30	0.30	0.10	0.10	0.10	0.10
May	0.30	0.30	0.50	0.10	0.30	0.30	0.10	0.50	0.20	0.30
June	0.20	<0.10	0.40	0.20	<0.10	0.20	0.20	0.20	0.10	<0.10
July	1.41	1.13	1.30	0.20	0.15	0.18	0.30	0.10	0.04	0.09
August	0.35	0.49	0.61	0.08	0.05	0.09	0.31	0.65	0.28	0.25
September	1.04	1.29	2.40	0.04	0.16	0.27	0.38	0.25	0.07	0.52
October	0.43	0.19	0.08	0.16	0.18	1.66	0.22	0.09	0.07	0.23
November	0.52	0.04	0.83	0.06	0.09	0.12	0.26	1.43	0.07	0.04
December	----	----	0.69	0.45	0.50	0.27	0.38	0.34	0.22	0.58
January 1973	0.73	0.95	1.41	1.21	0.81	0.68	0.78	0.57	0.92	0.92
February	0.65	0.70	1.08	0.68	0.81	0.59	0.95	0.62	0.60	----
Alkalinity (ppm)										
February 1972	22	21	33	16	15	12	12	12	13	11
March	26	20	41	21	17	17	20	15	14	16
April	23	19	34	19	23	19	27	16	19	19
May	28	22	28	22	20	20	24	20	23	19
June	17	18	18	19	19	12	26	19	18	18
July	43	43	43	28	24	26	25	15	15	21
August	25	28	31	21	21	13	27	14	19	20
September	43	37	51	26	22	17	23	27	12	22
October	30	24	15	23	24	42	30	21	20	23
November	26	11	31	11	11	10	23	12	11	24
December	--	--	26	15	15	13	18	14	12	15
January 1973	17	14	29	29	18	12	10	13	11	12
February	18	17	28	17	16	14	20	16	16	--

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Chlorides (ppm)										
February 1972	3	5	13	2	2	2	3	2	3	1
March	11	6	11	6	6	8	6	5	6	3
April	8	7	11	6	6	8	9	14	7	4
May	11	8	12	9	9	10	11	9	10	9
June	5	5	5	5	5	7	6	6	7	4
July	20	19	20	3	3	4	4	4	3	15
August	10	9	11	3	4	4	4	5	5	6
September	22	18	32	5	5	5	7	6	5	8
October	7	4	5	4	4	15	6	5	5	3
November	10	6	12	6	6	6	7	6	6	4
December	--	--	13	11	11	14	13	10	11	7
January 1973	13	12	24	24	12	13	15	13	13	14
February	12	8	14	11	10	11	11	9	13	--
Phenols (ppm)										
February 1972	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
March	<0.015	0.007	0.012	0.003	0.011	0.005	0.018	<0.001	<0.001	<0.001
April	0.006	0.013	0.013	0.012	0.001	0.009	0.006	0.003	0.001	0.015
May	0.011	0.024	0.024	<0.001	0.031	<0.001	0.011	<0.001	0.009	0.080
June	<0.001	<0.001	<0.001	0.003	0.045	0.054	<0.001	0.012	<0.001	0.014
July	<0.001	<0.001	0.002	<0.001	0.004	<0.001	<0.001	<0.001	<0.001	<0.001
August	0.010	<0.001	0.013	0.002	<0.001	0.004	0.065	<0.001	0.007	<0.001
September	0.016	0.005	0.032	0.012	0.018	0.027	0.018	0.023	0.027	0.007
October	<0.001	<0.001	0.010	0.002	0.003	0.003	<0.001	0.008	0.002	0.013
November	<0.001	0.021	<0.001	0.006	0.014	0.040	0.007	0.028	<0.006	<0.001
December	--	--	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
January 1973	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001
February	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	<0.001	--

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Sulfates (ppm)										
February 1972	10	10	20	5	10	5	6	10	10	10
March	5	4	10	6	6	7	8	7	6	3
April	6	4	6	3	4	5	4	4	4	3
May	4	3	6	2	3	4	3	3	3	8
June	8	6	9	3	4	4	2	5	5	2
July	10	11	10	1	< 1	< 1	1	2	8	1
August	5	4	7	3	3	3	2	4	1	1
September	9	7	12	2	3	1	6	2	6	2
October	6	5	8	6	6	17	7	6	5	4
November	5	6	6	5	6	6	2	4	7	1
December	--	--	7	3	2	5	4	4	7	5
January 1973	9	8	16	16	10	--	7	4	5	7
February	13	11	19	10	11	13	13	10	15	--
Chromium (ppm)										
February 1972	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
March	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
April	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
May	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
June	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
July	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
August	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
September	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
October	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
November	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
December	--	--	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
January 1973	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
February	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Copper (ppm)										
February 1972	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04
March	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04
April	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04
May	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04
June	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	20	<0.04	<0.04
July	<0.04	<0.04	<0.04	<0.04	<0.04	0.09	<0.04	<0.04	0.07	<0.04
August	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04
September	<0.04	<0.04	0.49	<0.04	1.00	<0.04	<0.04	<0.04	0.31	<0.04
October	<0.04	<0.04	0.08	<0.04	<0.04	0.07	<0.04	<0.04	<0.04	<0.04
November	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04
December	--	--	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04
January 1973	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04
February	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04	<0.04
Iron										
February 1972	0.28	0.16	0.17	0.44	0.44	0.28	0.22	0.23	0.30	0.28
March	0.74	0.71	0.76	0.75	0.70	0.90	0.60	0.93	1.00	0.61
April	0.96	0.91	0.76	0.88	0.96	1.12	0.76	1.16	1.02	0.76
May	1.28	1.28	1.25	1.05	1.19	2.23	1.05	1.77	1.30	1.10
June	3.93	1.46	2.06	0.91	1.13	1.91	1.33	2.37	1.55	1.63
July	0.79	0.92	0.77	0.87	1.00	1.96	1.02	1.78	1.56	1.24
August	1.58	1.58	1.82	1.16	1.27	2.35	1.20	2.13	1.50	0.78
September	1.09	1.28	1.31	1.56	1.58	1.74	1.84	4.55	1.82	0.68
October	0.97	0.97	1.32	0.83	0.74	1.08	0.88	1.56	0.79	0.52
November	1.00	0.91	0.91	1.03	0.85	0.83	0.78	0.85	0.58	0.50
December	--	--	1.12	0.56	0.59	0.56	0.56	0.63	0.60	0.50
January 1973	0.63	0.63	0.93	0.93	0.48	0.65	0.59	0.63	0.58	0.58
February	0.68	0.61	0.97	0.57	0.57	0.62	0.58	0.62	0.70	--

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Manganese										
February 1972	<0.10	<0.10	0.13	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	0.10
March	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10
April	<0.10	<0.10	<0.10	<0.10	<0.10	<0.01	<0.10	<0.10	<0.10	0.10
May	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	0.23
June	0.16	0.25	0.26	0.12	<0.10	0.11	<0.10	0.20	0.12	0.44
July	0.20	0.10	0.10	<0.10	<0.10	1.00	<0.10	0.20	0.70	0.20
August	0.12	0.09	0.13	0.21	0.11	0.22	0.07	0.12	0.09	0.12
September	<0.10	<0.10	<0.10	0.12	<0.10	0.56	<0.10	1.14	0.10	<0.10
October	<0.01	0.11	0.24	0.12	<0.10	0.11	<0.10	0.13	0.14	<0.10
November	0.13	<0.10	<0.10	0.14	<0.10	0.12	<0.10	<0.10	<0.10	0.16
December	--	--	0.10	<0.10	<0.10	<0.10	<0.01	<0.10	<0.10	0.33
January 1973	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	--
February	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	<0.10	--
Zinc										
February 1972	<0.05	<0.05	<0.05	<0.05	0.08	<0.05	<0.05	<0.05	0.18	<0.05
March	<0.05	<0.05	<0.05	<0.05	<0.05	0.05	<0.05	<0.05	<0.05	<0.05
April	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
May	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
June	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
July	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
August	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
September	0.24	<0.05	0.08	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
October	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
November	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
December	--	--	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
January 1973	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	--
February	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	--

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Sodium										
February 1972	7.40	9.32	15.84	6.00	5.80	5.96	7.32	5.34	6.54	4.56
March	9.65	6.25	14.10	6.65	6.10	6.40	7.75	5.45	9.20	6.10
April	7.29	6.06	11.40	6.08	6.08	6.34	7.28	5.50	7.09	5.04
May	8.60	5.80	10.00	8.20	6.06	8.70	7.96	5.45	9.10	4.70
June	5.20	5.80	6.15	5.85	5.80	6.05	6.35	5.55	6.60	4.88
July	26.00	24.00	28.75	5.60	5.35	5.45	6.15	4.85	5.90	5.20
August	9.53	11.28	13.95	5.63	5.78	5.13	6.40	5.25	6.23	4.93
September	29.75	20.55	36.25	5.45	5.25	4.27	5.75	4.82	4.35	5.05
October	10.55	6.07	5.91	5.98	5.95	5.20	6.19	5.27	6.40	4.75
November	13.00	5.75	16.10	5.35	6.08	5.63	5.90	5.00	5.85	5.40
December	--	--	10.90	6.10	6.00	6.80	6.75	5.50	6.40	4.75
January 1973	6.70	5.73	19.10	6.30	5.76	6.12	5.12	5.12	6.42	--
February	9.67	7.45	10.25	6.37	8.02	5.84	8.03	5.80	7.62	--
Magnesium										
February 1972	1.93	2.54	3.74	1.43	1.50	1.55	1.72	1.44	1.75	1.40
March	2.10	1.63	2.75	1.63	1.60	1.70	2.05	1.48	1.90	1.50
April	1.78	1.30	2.72	1.22	1.22	1.42	2.08	1.20	1.80	1.08
May	1.98	1.44	2.46	1.44	1.46	1.48	1.80	1.52	1.84	1.44
June	1.93	1.77	2.73	1.67	1.54	1.63	2.02	1.53	1.98	1.58
July	3.67	2.79	3.74	1.40	1.18	2.10	2.10	1.32	2.08	1.62
August	2.22	2.38	2.69	1.43	1.46	1.40	1.86	1.41	1.93	1.62
September	2.64	2.36	3.45	1.44	1.31	1.74	1.82	2.38	1.56	1.80
October	2.06	1.59	1.84	1.53	1.52	3.38	2.12	1.91	2.14	1.69
November	3.08	1.93	3.30	1.45	2.25	2.30	2.33	1.41	1.49	1.61
December	--	--	2.73	1.37	1.37	1.57	1.79	1.32	1.52	1.40
January 1973	1.28	1.12	2.78	2.78	1.13	1.14	1.21	1.32	1.07	1.35
February	1.67	1.23	2.42	1.13	1.32	1.02	1.48	0.98	1.28	--

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Calcium										
February 1972	3.50	4.50	7.60	3.50	3.50	3.50	5.10	2.80	3.50	3.50
March	5.00	3.31	8.19	3.60	2.88	3.18	5.13	2.88	3.88	3.31
April	5.54	3.89	7.67	3.66	3.66	3.30	5.31	3.07	3.89	3.42
May	5.81	4.06	7.31	4.06	4.19	3.38	5.19	4.06	3.75	4.06
June	5.41	4.16	7.35	3.47	4.16	2.91	4.72	3.47	3.47	3.47
July	10.25	7.88	11.13	3.19	3.19	4.13	6.38	2.69	4.94	3.44
August	5.72	5.51	6.62	3.43	3.80	2.94	4.78	2.94	3.92	2.58
September	7.56	5.19	9.00	3.93	3.62	3.25	4.56	5.31	3.38	3.62
October	4.83	2.90	2.50	2.80	2.84	7.45	5.06	3.34	3.23	2.50
November	8.00	4.44	8.44	6.25	5.56	5.44	4.63	3.25	3.00	3.63
December	--	--	6.73	3.23	3.23	3.70	4.88	3.25	3.25	3.25
January 1973	3.50	4.06	8.00	3.38	3.50	3.38	3.63	3.19	3.63	--
February	2.75	2.00	5.50	2.50	2.50	2.13	3.00	1.88	2.00	--
Silica										
February 1972	11	11	10	11	9	10	13	9	9	9
March	11	10	9	11	10	8	11	8	9	9
April	8	9	9	10	10	6	10	7	6	8
May	11	12	9	12	11	8	15	8	9	10
June	7	12	7	11	13	7	17	7	9	7
July	13	12	12	13	16	5	17	6	5	1
August	10	10	10	11	14	5	17	6	7	< 1
September	12	13	11	17	17	4	9	6	9	2
October	13	16	6	16	18	12	17	5	8	4
November	9	7	9	7	7	6	10	6	7	6
December	--	--	10	8	7	7	9	6	7.5	6
January 1973	11	11	12	12	10	9	9	10	9	--
February	7	7	9	6	7	6	9	5	6	--

TABLE C.3-2

RESULTS OF WATER QUALITY ANALYSES (FEB. 1972 - FEB. 1973) CONT'D

Parameter-Month	River Station 1	River Station 2	River Station 3	Stream Station 1	Stream Station 2	Stream Station 3	Stream Station 4	Stream Station 5	Stream Station 6	Pond Station 1
Aluminum										
February 1972	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
March	0.05	0.06	0.05	<0.05	0.06	0.09	<0.05	0.05	0.06	<0.05
April	0.06	0.07	<0.05	0.06	0.03	0.06	0.06	0.06	0.05	0.07
May	0.10	0.11	0.11	0.08	0.12	0.15	0.10	0.20	0.12	0.07
June	0.11	0.07	0.13	0.07	0.08	0.08	0.08	0.13	0.11	0.05
July	0.05	0.07	<0.05	0.07	0.09	0.09	0.12	0.10	<0.05	<0.05
August	0.07	<0.05	0.06	<0.05	0.08	0.08	0.08	0.11	0.05	<0.05
September	<0.05	<0.05	<0.05	0.05	<0.05	<0.05	0.05	0.09	0.07	<0.05
October	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
November	<0.05	0.08	<0.05	0.08	0.08	0.15	<0.05	0.03	<0.05	<0.05
December	--	--	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05
January 1973	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	<0.05	--
February	0.05	0.07	0.05	0.07	0.07	0.05	0.05	0.05	0.05	--
Water Temperature (°F)										
February 1972	--	--	--	--	--	--	--	--	--	--
March	54.5	51.9	58.5	52.3	52.0	55.0	53.0	52.0	52.0	55.8
April	70.0	67.5	76.1	70.0	66.9	67.5	69.0	65.7	70.0	72.0
May	72.0	70.0	75.0	69.7	66.0	66.5	67.5	66.5	66.5	--
June	71.8	67.0	69.5	70.5	66.1	66.6	66.5	66.0	66.5	81.7
July	83.9	82.1	86.5	80.0	75.0	75.2	74.9	76.0	76.0	82.3
August	80.3	84.0	86.1	75.0	76.0	72.0	72.0	71.0	71.0	84.0
September	80.0	77.5	82.9	72.1	70.5	70.2	70.2	69.5	70.9	83.9
October	54.2	51.0	65.1	51.5	50.0	51.4	53.8	50.5	51.0	59.0
November	--	--	--	--	--	--	--	--	--	--
December	--	--	58.8	52.0	51.5	52.2	50.1	52.0	51.0	52.5
January 1973	--	--	49.9	40.1	39.5	38.0	41.5	39.9	49.5	--
February	--	--	--	--	--	--	--	--	--	--

TABLE C.3-3: QUARTERLY BIOLOGICAL SAMPLING SUMMARY, APRIL 4-8, 1972

Station Number		Air Temp. (°C)	Water Temp. (°C)	pH	Dissolved Oxygen (PPM)	Maximum Depth (Meters)	Secchi Reading (Meters)	Bottom Type Eckman	Bottom Type Surber	Qualitative Sample	Date	Time	Notes
1	Transect No. 1	25.5	15.5	7.0	10	0.8	Clear to bottom	1) Silt sand	1) Rock, coarse sand	Across stream	4/6/72	1606	
2	Transect No. 1	25.5	14.0	6.5	10	0.3	Visible to bottom	-	1) Rock, gravel, riffle	Riffle	4/6/72	1413	Observed whirligig beetles (Gyrinidae).
	Transect No. 2	*	*	*	*	*	*	1) Coarse sand, pool	-	Pool	4/6/72	1413	
3	Transect No. 1	23.0	12.0	6.5	10	0.7	Visible to bottom	-	1) Gravel, riffle	Riffle	4/6/72	1245	Unknown larvae collected at station on 4/4/72. Identified as Simulidae.
	Transect No. 2	*	*	*	*	*	*	1) Coarse gravel	-	Pool	4/6/72	1245	
4	Transect No. 1	18.0	10.0	6.5	11	0.5	Visible to bottom	1) Coarse sand, pool	1) Gravel, riffle	Pool & Riffle	4/5/72	0954	
5	Transect No. 1	11.5	11.0	6.5	10	2.0	0.8	1) Silt, gravel, debris, pool	-	Pool	4/6/72	0830	
	Transect No. 2	*	*	*	*	*	*	-	1) Gravel, riffle	Pool & Riffles	4/6/72	0830	
6	Transect No. 1	10.0	9.5	6.5	10	0.3	Visible to bottom	1) Firm sand, pool	-	X-Section of stream	4/5/72	0830	
	Transect No. 2	*	*	*	*	*	*	-	1) Gravel & sand, riffle	Pool & Rapids	4/5/72	0830	

TABLE C.3-3: QUARTERLY BIOLOGICAL SAMPLING SUMMARY, APRIL 4-8, 1972 CONT'D.

Station Number	Air Temp. (°C)	Water Temp. (°C)	pH	Dissolved Oxygen (PPM)	Maximum Depth (Meters)	Secchi Reading (Meters)	Bottom Type Eckman	Bottom Type Surber	Qualitative Sample	Date	Time	Notes
7 Transect No. 1	*	*	*	*	*	*	-	1) Gravel, riffle	Riffle	4/6/72	1030	Observed 4 <u>Moxostoma</u>, 1 <u>Lepomis</u> and Gyrindae at station on 4/4/72.
Transect No. 2	25.5	10.5	7.0	11	1.0	Visible to bottom	1) Coarse sand, pool	-	Pool	4/6/72	1030	
River Transect 1												
Sampling Point No. 1	*	*	*	*	.5	+	≠	1) Rock, veget., swiftwater	Rapids & eddies	4/8/72	0900	Numerous unknown Dipterans emerging.
Sampling Point No. 2	7.5	16.5	7.0	9	1	+	≠	1) Rock, veget., swiftwater	Swiftwater	4/8/72	0900	
Sampling Point No. 3	*	*	*	*	1	+	≠	1) Rock, veget., swiftwater	Swiftwater	4/8/72	0900	
Sampling Point No. 4	*	*	*	*	1	+	≠	1) Silt, debris, riffle	Riffle	4/8/72	0900	
River Transect 2												
Sampling Point No. 1	28.0	15.0	7.0	9	0.1	+	≠	1) Silt, swiftwater	River bank, bottom	4/7/72	0830	4 Wood ducks, 2 Ospreys, 1 great blue heron and numerous turtles observed while working at Transect No. 2

TABLE C.3-3: QUARTERLY BIOLOGICAL SAMPLING SUMMARY, APRIL 4-8, 1972 CONT'D.

Station Number	Air Temp. (°C)	Water Temp. (°C)	pH	Dissolved Oxygen (PPM)	Maximum Depth (Meters)	Secchi Reading (Meters)	Bottom Type Eckman	Bottom Type Surber	Qualitative Sample	Date	Time	Notes
Sampling Point No. 2	27.6	15.8	7.5	10	0.3	+	≠	1) Rock, swiftwater	Swiftwater & eddies	4/7/72	1040	
Sampling Point No. 3	26.5	17.5	7.0	9	0.2	+	≠	1) Firm clay-silt, swiftwater	Swiftwater	4/7/72	1115	
Sampling Point No. 4	32.0	18.1	7.0	10	.5	+	≠	1) Rock, riffle	Base of rock outcropping	4/7/72	1410	
Sampling Point No. 5	*	*	*	*	.5	+	≠	1) Silt, debris, riffle	Riffle	4/7/72	1410	

*Chemical and physical measurements not made due to close proximity or uniformity of neighboring sample points or transects.

+Current too swift for accurate measurements.

≠Bottom type prohibited use of Eckman dredge at these stations.

Question C.4

The kinds of organisms that will be sampled, at what frequency, and for what kinds of analyses, in the pre- and post-impoundment biological studies.

Response

The pre-impoundment biological studies sample plankton, benthos, macrophyton, Aufwuch's, game and non-game fishes, vascular vegetation, and small mammals. Also, a wildlife survey route has been established to determine species composition and relative abundance of bird and mammal populations. All samples are taken on a quarterly basis. The first plankton, benthos, macrophyton and Aufwuch's samples were collected April 5 - 8, 1972.

The data collected during the pre-impoundment studies will be analyzed statistically for diversity and variance within and between sample stations. Species lists will be compiled; the abundance, growth and food habits of important fishes determined; relative abundance of songbirds, game birds, and small mammals determined; and habitat evaluated based on vegetation surveys. The objective of these pre-impoundment studies is to establish the baseline ecology of the area.

The nature of the post-impoundment studies will greatly depend on the findings in the pre-impoundment studies. However, these studies will be management-oriented for proper management of the fishery and wildlife resources in and near the Harris reservoir. Studies in the Cape Fear River will continue in the same manner as in the pre-impoundment studies in order to detect any change in the baseline data which might be attributed to discharges from the reservoir.

Question C.5

A description of fish management programs that are contemplated for the cooling water reservoir (stocking, rehabilitation, etc.).

Response

A task force composed of representatives from the N. C. Department of Natural and Economic Resources and CP&L has been formed to develop an overall plan for land and reservoir recreation, land and reservoir use, and land, reservoir and wildlife management for the Shearon Harris Nuclear Power Plant Project. One task force responsibility is the design of a fish management program which will provide recreational fishing in the reservoir. The N. C. Wildlife Resources Commission, a division of the Department of Natural and Economic Resources, is directly involved in the design of the fish management programs.

Although no programs have yet been outlined, it is expected that natural stocking will occur as water is pumped from the Cape Fear River into the makeup pond. Once a fishery has been established by this process, studies of that fishery will define the management needs and thus the management programs.

Question C.6

A discussion of the potential for breeding, feeding, and resting by waterfowl on the cooling afterbay reservoirs.

Response

The makeup pond (main reservoir) will provide waterfowl with approximately 4000 acres of open water with 74 miles of shoreline. Puddle ducks and diving ducks are expected to utilize the shallow coves, open water and shoreline for resting and feeding. Since the only native nesting duck in this region of North Carolina is the wood duck, the reservoir is expected to be utilized primarily by migrant waterfowl although the potential for establishing nesting wood ducks in nest boxes is great. Use of the main reservoir for makeup water will be compatible with feeding, nesting and resting of native and migrant birds.

According to White and Mahler (1964), nearly all reservoirs with permanent water storage provide some resting opportunities for waterfowl. However, the extent of the value of reservoirs to waterfowl depends on the local available food supply.[1] Initially the main reservoir will offer little food, but submergent and emergent vegetation (which will serve as a food source) is expected to eventually invade the littoral zones especially during drawdowns. Also, swamps and sloughs along the nearby Cape Fear River will provide sources of food for puddle ducks, especially.

The only species of waterfowl which nests in the project area is the wood duck. Wood ducks normally nest in the cavities of hollow trees but wood duck nest boxes are readily utilized in the absence of suitable nesting trees. These nest boxes have been successfully employed to develop dense breeding colonies of wood ducks near Wendell, North Carolina (Hester, 1965)[2] which is only 40 miles east of the Harris site. However, suitable brood rearing habitat must be available in order to maintain nesting within the nest boxes. The makeup pond should offer potential for wood duck nesting in that the 74 miles of shoreline and nearby Cape Fear River will provide the required brood rearing areas.

Raleigh City reservoirs have been utilized for feeding and resting of migrant waterfowl for years. Primarily mallards, black ducks, pintails, shovelers, ringnecks, lesser scaup, buffleheads, ruddy ducks and hooded mergansers have been observed on these reservoirs during the winter months. Also, pied-bill grebes, great blue herons, common egrets, little green herons, and common snipe are known to utilize these reservoirs. The makeup pond is expected to be utilized to a greater degree due to its larger size and by these same species due to proximity of the project area to Raleigh.

Utilization of reservoirs is expected to increase in the future as more winter habitat will be lost to the increasing demands on our natural resources. The fact that the use of reservoirs by waterfowl is increasing due to the ability of several important species to adapt to changing conditions has been noted.[3] The potential for feeding and resting by waterfowl on the makeup pond will be comparable to that of other similar reservoirs in North Carolina.

1, 3

White, William M. and G. W. Malaher. 1964. "Reservoirs." IN J. P. Linduska (ed.) Waterfowl Tomorrow. The United States Department of the Interior, BSFW, FWS. pp. 381-389.

2

Hester, F. Eugene. 1965. Survival, Renesting, and Return of Adult Wood Ducks to Previously Used Nest Boxes. Proc. of the S. E. Association of Game and Fish Commissioners. 16 (1962): 67-70.

RADIOLOGICAL DOSE

Question D.1

A detailed description of the proposed radiation monitoring program including sampling sites, types of samples, frequency of sampling, types of analysis, description of analyzing equipment, consultants for the program and who will conduct the sampling and analyzing.

Response

Maximum engineering and design efforts will be made in the design and construction of the Shearon Harris Nuclear Power Plant to minimize the release of radioactive material to the environment. As a further awareness of its responsibilities to protect the environment, the Carolina Power & Light Company will conduct a comprehensive radiological monitoring program to ensure that this design objective is maintained.

The radiological monitoring program will be divided into two parts. The first part involves continuous monitoring (or sampling) of possible release pathways to the environment. This program will be designed to meet the requirements of the AEC Safety Guide No. 21. This part of the program utilizes the in-plant process and area radiation monitoring equipment and other specialized monitoring and sampling equipment with sufficient sensitivity to adequately detect and identify releases to the environment. The other part of the program involves periodic analysis of various environmental samples to further verify that the design objective is being maintained and to substantiate that releases of radioactivity to the environment are being maintained as low as practicable. The environmental monitoring program utilizes specialized low level detection instruments capable of identifying a build-up of radioactivity to the environment.

A preoperational radiological monitoring program will be conducted to determine the magnitude and nature of radioactivity in the environment surrounding the site prior to the startup of the first nuclear unit. The information obtained will serve as a baseline in evaluating any changes in environmental radioactivity levels that may result from plant operation.

Table D.1-1 outlines the initial preoperational radiological monitoring program for the Shearon Harris Nuclear Power Plant. Sampling stations, sampling frequency, and sampling media were established on the basis of population density and distribution, meteorological, hydrological, ecological and topological conditions, and critical pathways to man.

The preoperational program will be closely coordinated with any existing state programs for monitoring radioactivity levels in the environment. Discussions will be held with interested state agencies before the program is begun and during the program to ensure a cooperative effort between this program and existing monitoring programs. The results of the program will be reviewed periodically with other interested parties to assure maximum effectiveness.

The preoperational program will begin at least one year prior to initial criticality of the first nuclear unit. In addition to establishing baseline radiation levels in the environment, the preoperational program serves as a test for the equipment, sampling and analytical procedures, the suitability of selected sampling points, and to investigate the overall statistical variability of the results. This program will be closely coordinated with other ecological studies to assure that the most sensitive indicators in the pathway to man are being monitored and it is expected that there may be some alteration of the program as experience is gained.

The preoperational monitoring program will ensure an efficiently operating operational environmental monitoring program from the first day of reactor operation. The operational environmental monitoring program will follow the schedule established during the preoperational phase. It is expected that this program will follow closely the outline shown in Table D.1-1 with only minor modifications which are found to be necessary or desirable during the preoperational program.

The sampling program has been designed to incorporate measurements to provide background data and to assess possible effects on the environment from the operation of the nuclear plants. Samples collected at points where concentrations of effluents in the environment are expected to be greatest will be compared with samples collected concurrently at points expected to be essentially unaffected by plant effluents. The latter samples, along with preoperational data, will provide background measurements that will be used as a basis for distinguishing radioactivity introduced into the environment by the operation of the nuclear units from that radioactivity due to natural background or from other man-made sources. If significant radioactivity is detected, the primary radionuclides involved will be identified and efforts made to determine the source of the radioactivity.

Results of the sample analyses will be evaluated to demonstrate the effectiveness of plant effluent control and compliance with the requirements of 10 CFR 20, the Technical Specifications, and the design objectives of the waste processing system which are in accordance with the low as practicable concept of Appendix I, 10 CFR 50.

It is expected that after one to three years of operation the plants will have demonstrated the ability to operate within the design specifications and the environmental monitoring program will have verified that there is no buildup of radioactivity in the environment. At this time, the number of samples and the sampling frequency may be reduced. This reduced monitoring program would continue as long as the plant continued to operate within the stated requirements.

Presently the analysis of radiological environmental samples is being contracted to an outside firm--Eberline Instrument Company, Inc. CP&L has designed and administers existing environmental monitoring programs and collects all samples associated with these programs. The samples are then sent to Eberline Instrument Company for analysis by approved procedures. Eberline Instrument Company also summarizes the data and prepares the associated six month reports in cooperation with CP&L.

Plans are presently being formulated for construction of an environmental monitoring laboratory in conjunction with the Energy and Environmental Center located near the Harris Nuclear Plant. Plans are to have this laboratory facility complete and operational prior to the start of the Shearon Harris Preoperational Environmental Monitoring Program and the analysis of all samples from this program would be performed at this facility. If, however, this laboratory is delayed and is not complete prior to starting the preoperational monitoring program, the sample analyses will be performed by an outside firm.

TABLE D.1-1

PREOPERATIONAL RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM
SHEARON HARRIS NUCLEAR POWER PLANT

Sample Type		Sampling Point & Description	Sampling Frequency	Sample Analysis
Air Samples (Particulate & Iodine)	(8) -	4-Plant exclusion area boundary (NE, SE, NW, SW) 1-Fuquay-Varina 1-Apex 1-Raleigh 1-Sanford	Weekly	(1) Gross beta (2) Gross alpha on one set per quarter (3) Quarterly composite for isotopic identification
Air Radiation TLD	(28)-	8-Air sampling locations 4-Plant exclusion area radius 8-3 to 5 mile radius 8-7 to 10 mile radius	Quarterly	
Surface Water	(7) -	1-Main reservoir near the intake 1-Main reservoir near plant discharge 1-Main reservoir 1-Discharge from main reservoir 1-Cape Fear River - Upstream 1-Cape Fear River - Downstream 1-Lillington Water Supply	Weekly	(1) Gross beta (2) Quarterly composite at each location for tritium (3) Quarterly composite at each location for isotopic identification
Groundwater	(5) -	1-Well at plant site 1-Fuquay-Varina Municipal Supply 1-Holly Springs Municipal Supply 1-Private Well near East Shore of Lake 1-Private Well in vicinity of Corinth	Monthly	Same as surface water
Bottom Sediments	(5) -	1-Main reservoir near plant discharge 1-Main reservoir 1-Buckhorn Creek 1-Cape Fear River - Upstream (Not affected by plant effluents) 1-Cape Fear River - Downstream	Quarterly	Gross beta isotopic identification

TABLE D.1-1 Continued

Sample Type	Sampling Point & Description	Sampling Frequency	Sample Analysis
Aquatic Vegetation	(4) - 1-Main reservoir near plant discharge 1-Main reservoir 1-Cape Fear River - Upstream 1-Cape Fear River - Downstream	Quarterly	Gross beta isotopic identification
Fish	(3) - 1-Main reservoir near plant discharge 1-Main reservoir 1-Cape Fear River	Quarterly	Gross beta isotopic identification Sr-89 & 90
Milk	(3) - 1-Dairy 2 miles north 1-Dairy 2 miles east 1-Dairy 7 miles south	Monthly	Gross beta less K-40 I-131, Sr-89, Sr-90
Food Crops	(2) - Local food crops (Leafy vegetables)	2 times during growing season	Gross beta isotopic identification
Meat Products	(1) - Locally grown meat	Annually if a source can be located	Gross beta isotopic identification Sr-89 & 90
Tobacco	(1) - Local tobacco farm	3 times during growing season	Gross beta isotopic identification Sr-89 & 90

Note: Isotopic identification is by Gamma Spectrometry.

Question D.2

The exact location and projected usage (man-hrs/yr.) of anticipated recreational sites on Harris Reservoir.

Response

A task force composed of representatives from th N. C. Department of Natural and Economic Resources and CP&L has been formed to develop an overall plan for land and pond recreation, land and pond use, and land, pond, and wildlife management for the Shearon Harris Nuclear Power Plant Project. The representatives of the Department of Natural and Economic Resources represent the Offices of Fish & Wildlife Resources, Forest Resources, Recreation Resources, Earth Resources, and Water and Air Resources. The task force has not met since the decision for closed cycle cooling towers was made. Previously, when the 10,000 acre cooling lake was planned, programs were discussed which would have incorporated lake zoning for water sports such as fishing, swimming, water skiing, and hunting; nature trails, bicycle trails, picnic areas, boat ramps, etc.; and land management programs which would include forestry management practices, natural wood lands, and agriculture uses.

Property around the makeup pond or plant area will not be sold or leased by CP&L for private development. However, to permit the greatest use by the greatest number of people, the Company will cooperate with state agencies and other governmental bodies in providing public access areas for boating, fishing, skiing, swimming and other uses, which are not inconsistent with the primary purpose of the pond.

The Company will cooperate in providing nature trails, wildlife refuges, and other developments of the forest lands deemed to be of public value. The Company also will cooperate with universities and other educational institutions in the use of the lands and waters for whatever agricultural or other experimental purposes the Company deems to be in the public interest.

It is the desire of Carolina Power & Light Company that the public benefits of this Harris Plant property shall add a new dimension to the quality of life in this area of North Carolina, in addition to helping meet the power needs of all its customers.

Use of the makeup pond for recreation is difficult to estimate since the recreational attractiveness will depend to some extent on the fluctuation of the pond's water level. During severe drought periods, drawdown may expose large amounts of shallow areas making the pond less conducive to water oriented sports. It is possible to obtain a prediction by examining records of such use from other locations in North Carolina as to what recreational use might be for the originally planned 10,000 acre cooling lake. The approximately 5000 acre Umstead State Park, located approximately twelve miles west of Raleigh, North Carolina, serves as a recreational resource for the Raleigh-Durham-Chapel Hill triangle of North Carolina. Visitors to the park average 30,000 per month with about 50,000 visitors during the peak month. Records from Lake Julian, a 325 acre reservoir which serves as a source of cooling water for the CP&L Asheville Plant, indicate that an average of 2500 fishermen per month utilize the reservoir. Morrow Mountain State Park, located adjacent to the 5000 acre CP&L Tillery Hydroelectric Impoundment, has approximately 8000 per month. Proximity of the U. S. Army Corps of Engineers New Hope Reservoir which is being constructed about six miles from the Harris Plant, should result in fewer visitors to the Harris Plant than would be expected if the New Hope Reservoir was not being constructed. Considering the size of the Harris Reservoir. proximity to population centers, proximity to other recreational resources, and other factors, it was anticipated that the number of visitors could have averaged approximately 8000 per month with the original 10,000 acre lake. Assuming three hours per visit, the Harris Reservoir would provide approximately 288,000 man-hours per year of recreational use. However, in view of the previously discussed drawdown effects, the reduced reservoir size from 10,000 acres to about 4,000 acres, and the presence of large cooling towers, the recreational potential will now be considerably less than the above estimate for the original 10,000 acre lake.

Question D.3

The proposed plans for public access to the exclusion area; when, where and how often.

Response

Efforts to develop programs for recreation and wildlife management are discussed in Question D.2. At this time, these efforts have not progressed to a point that the activities and proposed plans for public access to the exclusion area can be identified. Criteria will be applied in developing these plans, however, which will limit activities within the exclusion area.

Question D.4

The location and average annual occupancy for the proposed "Energy and Environmental Center."

Response

The Center is located outside the exclusion area, approximately 1.5 miles north northeast of the plant, as shown on Figure 2.1-1.

The Center is to consist of several entities, including a training section, a health physics section, an environmental laboratory, and a visitor center. The number of CP&L employees at the Center is not expected to exceed 30 permanently assigned to the Center and 100 temporarily assigned to the Center for operator training.

Based on experience gained at other CP&L visitor centers, it is anticipated that visitors to the information center will average less than 2,000 per month. Each visitor is expected to remain at the center for approximately 30-45 minutes.

Using the above estimates, and assuming that the 130 CP&L employees remain at the center 40 hours per week, 50 weeks per year, and that the visitors remain for 45 minutes, the average annual occupancy factor will be approximately 32.

NEED FOR POWER AND COST BENEFIT

Question E.1

System peak load and capacity data for the years 1965-1976.

Response

System load and capacity data for the years 1965 through 1976 are shown in Table E.1-1.

TABLE E.1-1

CAROLINA POWER & LIGHT COMPANY POWER RESOURCES AT TIME OF SUMMER AND WINTER PEAKS, 1965-1980

Units Are in Megawatts	Month of Peak	INSTALLED CAPACITY Hydro	Fossil Steam	Nuclear Steam	IC Turbine	Total Cap. Installed.	Net Purchases	Net Sales	Total Resources	Peak Load	Reserve	% Reserve
1965 Summer	Aug. 65	211.5	1606	-	-	1817.5	314.2	-	2131.7	1931	200.7	10.4
1965-66 Winter	Jan. 66	211.5	1632	-	-	1843.5	333.8	-	2177.3	1943	234.3	12.1
1966 Summer	Aug. 66	211.5	2007	-	-	2220	222.3	-	2440.8	2184	256.8	11.8
1966-67 Winter	Dec. 66	211.5	2038	-	-	2249.5	262.8	-	2512.3	2127	385.3	18.1
1967 Summer	July 67	213.5	2015	-	-	2228.5	407.3	-	2635.8	2270	365.8	16.1
1967-68 Winter	Jan. 68	211.5	2043	-	18	2272.5	420.8	-	2693.3	2445	248.3	10.2
1968 Summer	Aug. 68	213.5	2700	-	80	2993.5	272.3	358	2907.8	2834	73.8	2.6
1968-69 Winter	Dec. 68	211.5	2728	-	90	3029.5	232.8	358	2904.3	2660	244.3	9.2
1969 Summer	July 69	213.5	2700	-	197.5	3111.0	271.3	168	3214.3	3055	159.3	5.2
1969-70 Winter	Jan. 70	211.5	2728	-	233	3172.0	222.8	114	3281.3	3171	110.3	3.5
1970 Summer	Aug. 70	213.5	2700	-	267	3180.5	386.3[a]	-	3566.8	3484	82.8	2.4
1970-71 Winter	Jan. 71	211.5	2728	-	312	3251.5	436.2[a]	-	3687.7	3400	287.7	8.5
1971 Summer	July 71	213.5	2894	663	431	4201.5	304.7[a]	450	4056.2	3625	431.2	11.9
1971-72 Winter	Jan. 72	211.5	2922	700	560	4393.5	297.2[a]	876	4210.7	3625	585.7	16.2
1972 Summer	Aug. 72	213.5	3245	685	487	4630.5	471.7[a]	547	4555.2	4119	436.2	10.6
1972-73 Winter	Jan. 73	211.5	3273	700	560	4744.5	285.2[a]	424	4605.7	3957	647.7	16.4
1973 Summer	Aug. 73	213.5	3865	715	487	5280.5	284.5[a]	196	5369.0	4711	658.0	14.0
1973-74 Winter	Feb. 74	211.5	3878	700	560	5349.5	285.0[a]	196	5438.5	4219	1219.5	28.9

[a] INCLUDES RESERVE ALLOCATION ON CALL FROM SCPSA: 1970-43 MW; 1971-32 MW; 1972-20 MW; 1973-5 MW

Amendment No. 24, 32, 36, 38

TABLE E.1-1

CAROLINA POWER & LIGHT COMPANY POWER RESOURCES AT TIME
OF SUMMER AND WINTER PEAKS, 1965-1980

Units Are in Megawatts	Month of Peak	Installed Capacity: Hydro	Installed Capacity: Fossil Steam	Installed Capacity: Nuclear Steam	Installed Capacity: IC Turbine	Installed Capacity: Total Cap. Installed	Net Purchases	Net Sales	Total Resources	Peak Load	Reserve	% Reserve
1974 Summer		214.0	3817	665	1076	5772	279.5	160	5891.5	5019	872.5	17.4
1974-75 Winter		211.5	3878	700	1280	6069.2	280.0	160	6189.5	5019	1170.5	23.3
1975 Summer		214.0	3956	1486	1076	6732	227.5	140	6819.5	5117	1102.5	19.3
1975-76 Winter		211.5	4017	2342	1280	7850.5	228.0	140	7938.5	5117	2221.5	38.9
1976 Summer		214.0	3956	2307	1076	7553	227.5	140	7640.5	6274	1366.5	21.8
1976-77 Winter		211.5	4017	2342	1280	7850.5	228.0	140	7938.5	6274	1664.5	26.5
1977 Summer		214.0	3956	2307	1076	7553	227.5	-	7780.5	6872	908.5	13.2
1977-78 Winter		211.5	4017	2342	1280	7850.5	228.0	-	8078.5	6872	1206.5	17.6
1978 Summer		214.0	4676	2307	1076	8273	227.5	-	8500.5	7479	1021.5	13.7
1978-79 Winter		211.5	4737	2342	1280	8570.5	228.0	-	8798.5	7479	1319.5	17.6
1979 Summer		214.0	5396	2307	1076	8993	227.5	-	9220.5	8127	1093.5	13.5
1979-80 Winter		211.5	5457	2342	1280	9290.5	228.0	-	9518.5	8127	1391.5	17.1
1980 Summer		214.0	6116	2307	1076	9713	127.5	-	9840.5	8845	995.5	11.3
1980-81 Winter		211.5	6177	2342	1280	10010.5	75.0	-	10085.5	8845	1240.5	14.0

Question E.2

Estimates of capital and fuel costs for nuclear, oil, and coal plants.

Response

Estimates of capital and fuel oil costs for nuclear, oil and coal plants are listed on Table E.2-1.

TABLE E.2-1

COMPARATIVE CAPITAL AND FUEL COSTS FOR NUCLEAR, COAL AND OIL PLANTS

	Nuclear[1]	Coal[2]	Oil[2]
Plant Cost ($/KW)	267	196	160
Annual Fixed Charge Rate	14.6%	14.6%	14.6%
Heat Rate (BTU/KWH)	10,469	9,370	9,370
Capacity Factor	0.80	0.80	0.80
Fuel Cost (¢/MBTU)	17.85	75.33	79.02

NOTES:

1. Nuclear fuel costs are 10 year levelized costs.

2. Coal and oil costs are mid-1978 costs only. Escalation is 4.73¢/MBTU/year.

Question E.3

Based on 1971 Wake County tax structure, the expected county tax payments on the Harris Plant.

Response

Based on the 1975 Wake County tax structure the county tax payment on the Harris plant, had it been completed in 1975, would have been $32,775,303. This is based on a tax rate of $.78/$100.00. The calculation is shown below.

Harris Total Projected Cost	$4,201,962,000
	.7800%
	$ 32,775,303

The total property tax revenue for Wake County in 1975 was $27,876,841. Based on this a lower tax rate was derived as described below

A.	Wake County assessed value -100%	$1,978,101,570
B.	Add: Harris addition to Wake Co. base*	4,023,197,012
C.	Total taxable	$6,001,298,582
D.	Derived Rate (E÷C)	.4645
E.	1975 Property tax revenue	$ 27,876,841

Therefore a lower projected tax for Harris was calculated as described below.

Harris Total Projected Cost	$4,201,962,000
Derived Rate (D)	.4645
Property Tax on Harris	$ 19,815,113

It is anticipated that the Wake County required tax revenue stated above ($27,876,841) will increase in future years. As illustrated above, however, the inclusion of the Harris plant in the Wake County base should help to hold down the tax rate due to the large addition to the assessed value.

* Harris Total Projected Cost	$4,201,962,000
Loss: WIP Included in 1975 County Evaluation	178,764,988
Harris Addition to Wake County Tax Base	4,023,197,012

Question E.4

Capital, annual operating, maintenance, and capacity penalty costs for the following options, all designed for the same net generating capacity:

a. Cooling lake (ref. case)
b. Spray pond (including 7,200 acre pond)
c. Mechanical draft tower (including 7,200 acre pond)
d. Natural draft tower (including 7,200 acre pond)

Response

The above cases of a cooling lake or spray pond are no longer available to the Company due to a regulatory decision by state authorities. The 7,200 acre makeup ponds referenced in cases c and d would have provided sufficient storage that the site capacity could have been expanded, if needed in the future. However, the Environmental Protection Agency recommended a 4,000 acre makeup pond be used.

For comparative purposes, the following table shows a cost comparison between the natural draft towers required, and the 10,000 acre multi-use reservoir which the Company was required to abandon.

Item	10,000 Acre Cooling Lake	Natural Draft Towers With 4,000 Acre Makeup Pond
Initial Capital Cost	$64,000,000	$97,000,000
	ANNUAL CHARGES	
Carrying-Charge on Investment	$9,985,000	$15,150,000*
**Power Cost	10,000	860,000
**Capacity Penalty	Base Case	1,390,000
Maintenance	30,000	240,000
Annual Charges Total	$10,025,000	$17,640,000

*Based on 15.6% levelized fixed charge rate

**initial study estimates, these values may be subject to change

Question E.5

Any land use plans made by the county planning board for the area to be occupied by the plant; typical land costs in this area.

Response

The county planning board has not developed land use plans for the project area.

Land transactions recorded during 1969 were reviewed to obtain typical land costs in the project area prior to the influence of the Harris Plant. The acreage involved in the transactions ranged from 57 to 969. After subtracting the estimated value of buildings and other improvements and farm allotments from the sale price, the per acre price varied from $170.88 to $258.10 with an average of $227.81. Using the total sale price which includes the value of buildings and other improvements and farm allotments, the per acre price varied from $175.44 to $399.00 with an average of $253.91.

Question E.6

The requirements for nuclear fuels, in terms of kilograms of uranium and the percentage of U-235, for the initial loadings of Units 1, 2, 3, and 4, and for the subsequent reloading during steady state operation.

Response

The uranium loading of the initial core for all four units is 73,500 kilograms, each. The estimated equilibrium loading is 73,500 kilograms. The first cores will contain 2.51% of U-235 by weight and subsequent cores will contain 3.2% of U-235 by weight.

ATMOSPHERE

Question F.1

Describe the basic data, assumptions, and methods used to determine the evaporation from the proposed reservoirs.

Response

The basic data, assumptions, and methods used to estimate evaporation from the proposed reservoirs are contained within the answer to Question F.3.

Question F.2

The variation, by month, of the following reservoir energy budget components for the 10,000 and 400 acre reservoirs.

a) natural evaporation,

b) forced evaporation,

c) natural heat conduction to the atmosphere,

d) forced heat conduction to the atmosphere.

Response

With the adoption of closed-cycle towers, this question is no longer applicable.

Question F.3

Describe the assumptions, data, and methods used to determine these components.

Response

The heat of evaporation and the heat of conduction for cooling pond surfaces were calculated by the method outlined in the publication, "The Capacity of Cooling Ponds to Dissipate Heat," by W. D. Patterson, J. L. Leporati, and M. J. Scarpa, for presentation at the 33rd Annual Meeting of the American Power Conference, held in Chicago, Illinois during April 1971.

Excerpted from this publication is the following:

1. Heat of Conduction

$$Hc = .26\ (73 + 7.3W)(Ts - Ta)\ (P/760)\ BTU/ft^2/\ day$$

where:

Hc = heat of conduction in $BTU/ft^2/day$
W = wind speed in MPH
Ts = pond surface temperature in degrees F
Ta = dry bulk air temperature in degrees F
P = station atmosphere pressure in mm Hg.

This equation relates heat lost by conduction to heat lost by evaporation and was first explored by I. S. Bowen in "The Ratio of Heat Losses by Conduction and Evaporation from any Water Surface," Physical Review 27, No. 2, June 1926.

2. Heat of Evaporation

$$He = (73 + 7.3W)\ (e_s - e_a)\ \text{BTU/ft}^2\text{/day}$$

where:

He = heat of evaporation in BTU/ft^2/day

W = wind speed in MPH

e_s = saturation vapor pressure determined from the water surface temperature in mm Hg

e_a = air-vapor pressure in mm Hg

This evaporation known as the Meyer evaporation equation expresses the relationship known even to Dalton (1802) that evaporation is directly proportional to the product of the vapor pressure gradient between the air and water surface and the wind speed. Meyer's work is summarized in J. Edinger and J. Geyer's, "Heat Exchange in the Environment," EEI Publication No. 65-902, June 1965. Although many equations have been proposed to calculate the evaporation from a water surface, the Meyer equation has been chosen because it is very compatible with the meteorological data available at most sites.

Table F.3-1 is a tabulation of the meteorological data used in this study. These average monthly meteorological parameters were compiled from observations made at the first order weather station at Raleigh, North Carolina.

TABLE F.3-1

METEOROLOGICAL DATA

Month	Ho	S	Ta	W	P	Dp
January	1140	49	41.6	8.5	760	32
February	1510	56	43.0	9.1	760	31
March	2210	60	49.5	9.6	760	35
April	2580	64	59.3	9.4	760	45
May	2915	67	67.6	7.8	760	56
June	2950	65	75.1	7.0	760	64
July	2950	62	77.9	6.7	760	68
August	2765	62	76.9	6.6	760	67
September	2385	65	71.2	7.0	760	61
October	1845	66	60.5	7.2	760	50
November	1440	61	50.5	7.9	760	38
December	1105	51	41.9	8.0	760	30

Definitions:

Ho - Solar radiation constant determined by latitude of site and month of the year in BTU/ft^2/DAY

S - Percentage of sunshine

Ta - Average dry bulk air temperature in degrees F

W - Wind speed in miles per hour

P - Station pressure in mm Hg

Dp - Dew Point in degrees F

Question F.4

Quantitatively describe the annual frequency of occurrence of fogging and icing resulting from the proposed reservoirs for the region of influence. What would be the extent of fogging and icing for a worse case condition? If operating experience is available and cited, demonstrate its applicability to the Shearon Harris plant and site. Describe the basic data, assumptions, and methods used.

Response

A quantitative estimate of the annual frequency of occurrence of fogging and icing resulting from the proposed reservoirs is not available. Phillip Altomare, in a paper presented at the 1971 Air Pollution Control Association Annual Meeting, stated that, "An attempt to develop a model for the purposes of predicting fog would be a complicated and difficult procedure and would not necessarily serve the purposes of determining with what increase the frequency of fog occurrence is due to operation of an evaporative heat dissipation system."

According to Altomare, induced fog will not occur as a discrete incident but is more likely to be observed as a fog forming somewhat earlier than natural and lasting somewhat longer.

Carolina Power & Light Company presently operates cooling lakes at six steam electric plants located in the Carolinas. These cooling lakes range in size up to 3750 acres. Experience at these facilities indicate that there will be no problems associated with increased icing and fogging due to the operation of the Harris cooling reservoir. There have been no known adverse effects from icing and fogging in the vicinity of any of the six Carolina Power & Light Company cooling lakes.

Lake Julian, a CP&L cooling lake, located approximately 12 miles south of Asheville in the mountains of western North Carolina, is located in a densely populated area. The Asheville climate is more severe than is the climate in the vicinity of the Harris Plant. However, there have been no complaints from residents in the area, and plant personnel report that no problems from either fogging or icing due to the cooling lake have been detected. Hyco Lake, a CP&L cooling lake, located about 15 miles southeast of Danville, Virginia, is also located in a more severe climate than is the Harris Plant, and there are many residences constructed adjacent to the lake. Again, there have been no complaints from residents in the area, and plant personnel report that no problems from either fogging or icing due to the cooling lake have been detected.

Question F.5

What local features and activities might be affected by reservoir fogging and icing, and in what way?

Response

Fogging and icing due to operation of the Harris Reservoir is not expected to be a problem as explained in the response to Question F.4. Fog and ice are expected to form at the reservoir, only when these conditions occur throughout the region. Therefore, increased effects on local features and activities due to reservoir fogging and icing are considered negligible.

Question F.6

Quantitatively describe how the results of the analysis conducted in F.4 would change for the 7000 acre makeup water reservoir necessary for a closed-cycle cooling alternative, where only the heat of the blowdown is added to the reservoir.

Response

The results of the analysis in F.4 would not change materially for a 7000 acre make-up water reservoir with only the heat of blowdown added to the reservoir.

Question F.7

Describe more fully the physical and operating characteristics and environmental impact of the cooling tower system which would meet the requirements of the Shearon Harris plant, including:

a) size,
b) numbers,
c) probable placement on property,
d) evaporation,
e) blowdown,
   (1) quantity
   (2) temperature
   (3) chemical content
f) drift,
g) fogging and icing.

Response

Thorough discussions of these items are contained in Sections 2 and 3 of the main text.

Question F.8

Develop a description similar to that called for in F.7 for feasible spray cooling systems (ponds and/or canals).

Response

The topography of the present Harris Plant site indicates a spray cooling pond rather than a canal. Spray modules each require an area of approximately 40 feet by 160 feet. The system, consisting of approximately 650 spray modules, would require a minimum area of approximately 100 acres; this area is smaller than the surface area of the required make-up water storage reservoir. The spray cooling pond would be located in the same general area as the proposed main cooling lake.

Evaporation from the spray cooling system and make-up water storage reservoir is estimated to average approximately 115 cfs.

A spray pond impounded on Buckhorn Creek would not be expected to require continual blowdown. Occasional high stream flows should reduce the dissolved solids content of the pond to acceptable levels. Chemicals in the pond discharge would be the same as those in Buckhorn Creek and the make-up water from the Cape Fear River.

Fog and icing from a spray cooling pond should not be extensive. Drift from a spray pond should be deposited in the immediate area of the pond and should not present significant problems. There probably would be an occasional increase in icing in the immediate vicinity of the pond; however, the limited magnitude and duration would not be expected to present extensive problems.

Question F.9

What would be the feasibility, cost, physical and operating characteristics, and water consumption of a hybrid cooling tower (Marley Co., dry in winter, evaporative in summer) for the Shearon Harris plant?

Response

This type of cooling tower seems to be a working concept; apparently none have been designed or constructed. Therefore, any information about this type of tower is speculative due to a lack of construction and operation experience. However, the manufacturer believes that it would reduce water consumption for installations in the Southeast up to an average of about 20 percent and that mechanical draft towers of this type would cost 75 to 100 percent more than conventional towers.

The concept of this type of tower involves a series path of water and a parallel path of air. The tower is assumed to have less environmental effects as a result of plume abatement and the reduction in water consumption.

RESPONSES

TO

MR. W.H. REGAN, JR'S

LETTER OF JULY 8, 1977

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

JUL 8 1977

Docket Nos. 50-400, 50-401
and 50-402, 50-403

Carolina Power & Light Company
ATTN: Mr. J. A. Jones, Executive
Vice President
Engineering, Construction
and Operations
336 Fayetteville Street
Raleigh, North Carolina 27602

Gentlemen:

So that we may continue a timely and thorough review of the Shearon Harris Nuclear Plant CP application, please provide responses to the "Need for Power" inquiries transmitted by this letter (enclosure). A prompt and complete response by July 18, 1977 is required to enable the Staff to complete its analysis in time for an October, 1977 hearing.

Should you have any questions, please contact the Environmental Project Manager, Dr. F. S. Echols (301) 492-8445.

Sincerely,

Wm. H. Regan, Jr.

Wm. H. Regan, Jr., Chief
Environmental Projects Branch 2
Division of Site Safety and
Environmental Analysis

Enclosure:
Need for Power

cc: G. F. Trowbridge, Esquire
Shaw, Pittman, Potts, & Trowbridge
1800 M Street, N. W.
Washington, D. C. 20036

Richard E. Jones, Esquire
Carolina Power & Light Company
336 Fayetteville Street
Raleigh, North Carolina 27602

I. Need for Power

1. Provide a map indicating the geographical and political boundaries of the service area including major electrical load centers and major transmission interconnections. Provide area of service area in square miles.

2. Provide estimate of a) current population served, b) current number of each type of customer.

3. Provide further description of the nature and operation of VACAR and SERC, including a) member commitment in terms of reserve margin requirement, b) planning and coordinating functions.

4. Provide map of VACAR and SERC regions identifying geographical boundaries, utility service areas, and power supply areas.

5. Provide historical yearly (1966 to present) electrical energy use by major category. Also include monthly data from 1976 to date.

6. Provide much more detailed information and description of energy forecasting methodology. In general, adequate response includes: a) list of all factors considered, b) description of how those factors are introduced, and c) estimates of individual effect of each factor on energy growth. Specifically,

   a) Explain in detail and explicitly how factors were considered and the effect of each.

   b) Present results of least squares regression analysis; what is dependent variable?; present regression equation developed from the analysis; present estimates of future values of independent variables; present details of forecast check against appliance growth, etc.; describe and explain procedure for determining number of industrial customers and their distribution; present explicit assumptions on how factors listed affect customer mix.

   c) Present and describe commercial energy forecast.

7. Provide explanation and description of the "wheeled" energy operation.

8. Provide projected peakload demand from 1977 to 1993 (year of commercial operation of last unit plus succeeding three years).

9. Provide historical and projected load factors 1966 to 1993. If shifts in load factor or load factor trends are evident, identify contributing factors.

10. Describe in detail how historical peak load factor trends are modified based on forecast energy use, A/C situation, etc.

11. Provide load duration curves for 1976.

12. Provide copies of all forecasts made during the previous 10 years for aggregate long-range consumption of system peak load demand.

13. Actual data suggest severe reduction in peak demand in 1974, 1976 (a common experience). Provide results of any analysis performed including relative influence of voluntary conservation appeals following embargo, rising prices, economic conditions, weather, etc.

14. Provide historical and projected growth for the service area of the following variables: population, number of households, saturation by major appliances, prices of alternative fuels.

15. For period from present to 1993, present assumptions made regarding availability of oil and gas to ultimate customers. What assumptions, if any, are made regarding future substitution of electricity for oil and gas in the service area and what is resulting affect on energy forecasts?

16. Provide current and project rate structures for major customer classes.

17. Describe in detail: a) analyses performed of effect to date of previous energy conservation efforts; b) assumption made regarding future effect of conservation and how introduced with forecast.

18. Load management: in general, document all statements. a) How ongoing programs have been effective and are taken into account in forecast; detailed description of participation in pricing experiments; b) anticipated effects of other load management schemes and how reflected in projected load factors.

19. Present planned generating capability at peakload period for each year 1991-1993.

20. Provide a listing of each generator 100 MWe or greater at present, plus planned and proposed additions each year thereafter to 1993. Include scheduled date of operation, retirements or deratings, redesignations and upratings. Categorize each generator as to type and function.

21. Provide CP&L's definitions of the following terms: baseload, intermediate, peaking, firm and non-firm sales and purchases.

22. Present the ratio of baseload capacity to total capacity for each year in the period 1966 through 1993.

23. For 1990, estimate energy to be generated by function and type of all generators.

24. Provide estimates of net firm and non-firm power sales and purchases or interchange agreements for each year of the period 1976 to 1993.

25. Provide projected baseload demand for each year 1976 to 1993.

26. Provide copies of the following reports:

    a) CP&L Annual Report, last 2 years.

    b) Annual Report of VACAR and/or SERC to FPC in response to Order No. 383-3.

    c) FPC Forms 3, 5, and 12.

    d) Uniform Statistical Report to American Gas Assoc, EEI, and Financial Analysts.

    e) Consultant energy forecasts for past two years.

II. <u>Alternatives</u>

1. Document any conclusions that new technologies are not currently viable, i.e., references used, internal studies undertaken, etc. What specific technologies were reviewed?

TABLE 2

COST INFORMATION FOR NUCLEAR AND ALTERNATIVE POWER GENERATION METHODS

1. Interest during construction ______ %/year, ______ compound rate
2. Length of construction workweek ______ hours/week
3. Estimated site labor requirement ______ man-hours/kWe
4. Average site labor pay rate (including fringe benefits) effective at month and year of NSSS order ______ $/hour
5. Escalation rates
   - Site labor ______ %/year
   - Materials ______ %/year
   - Composite escalation rate ______ %/year

6. Power Station Cost[a]

Direct Costs	Unit 1	Unit 2 → 4
a. Land and land rights	______	______
b. Structures and site facilities	______	______
c. Reactor (boiler) plant equipment	______	______
d. Turbine plant equipment not including heat rejection systems	______	______
e. Heat rejection system	______	______
f. Electric plant equipment	______	______
g. Miscellaneous equipment	______	______
h. Spare parts allowance	______	______
i. Contingency allowance	______	______
Subtotal	______	______

Indirect Costs	Unit 1	Unit 2 3 4
a. Construction facilities, equipment, and services	______	______
b. Engineering and construction management services	______	______
c. Other costs	______	______
d. Interest during construction (@______ %/year)	______	______
Escalation		
Escalation during construction @______ %/year	______	______
Total Cost		
Total Station Cost, @ Start of Commercial Operation	______	______

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[a]Cost components of nuclear stations to be included in each cost category listed under direct and indirect costs in Part 6 above are described in "Guide for Economic Evaluation of Nuclear Reactor Plant Designs," U.S. Atomic Energy Commission, NUS-531, Appendix B, available from National Technical Information Service, Springfield, Virginia 22161.

TABLE 3

ESTIMATED COSTS OF ELECTRICAL ENERGY GENERATION

	Mills/Kilowatt-Hour
Fixed Charges[a]	
Cost of money	________
Depreciation	________
Interim replacements	________
Taxes	________
Fuel Cycle Costs[b]	
For fossil-fueled plants, costs of high-sulfur coal, low-sulfur coal, or oil	________
For nuclear stations:	
Cost of U_3O_8 (yellowcake)	________
Cost of conversion and enrichment	________
Cost of conversion and fabrication of fuel elements	________
Cost of processing spent fuel	________
Carrying charge on fuel inventory	________
Cost of waste disposal[c]	________
Costs of Operation and Maintenance[d]	
Fixed component	________
Variable component	________
Costs of Insurance	
Property insurance	________
Liability insurance	________

[a]Give the capacity factor assumed in computing these charges, and give the total fixed-charge rate as a percentage of station investment.
[b]Include shipping charges as appropriate. Give the heat rate in Btu/kilowatt-hour.
[c]If no costs are available, the applicant may use the cost assumptions as listed in the most recent publication of *Nuclear Industry*.
[d]Give separately the fixed component that in dollars per year does not depend on capacity factor and the variable component that in dollars per year is proportional to capacity factor.

NEED FOR POWER

Question 1:

Provide:

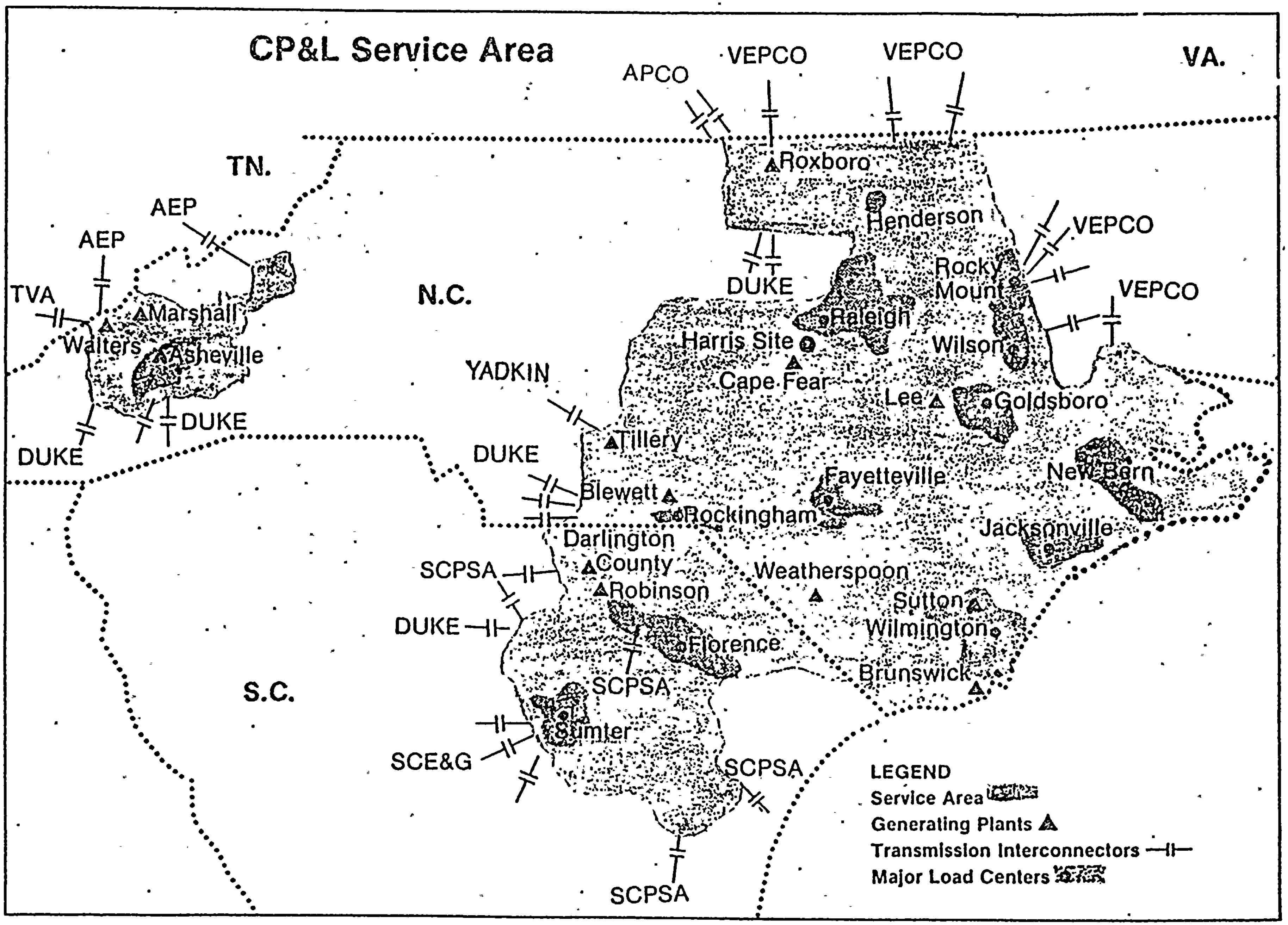
a. Map - Service Area, Load Centers, Interconnections

b. Area In Square Miles

Answer:

a. Map Attached

b. At the end of 1976, CP&L was providing electric service to about 670,000 customers in an area of 78,000 square kilometers (30,000 square miles) - almost half of North Carolina and about one fourth of South Carolina. (This territory is comparable in size to the combined areas of Connecticut, Massachusetts, Rhode Island, New Jersey, and New Hampshire. It includes part of the Mountain and Piedmont regions, but is largely in the Coastal Plains section.)



CP&L Service Area
APCO
VEPCO
VEPCO
VA.
TN.
AEP
AEP
TVA
Marshall
Walters
Asheville
DUKE
DUKE
N.C.
Roxboro
Henderson
DUKE
VEPCO
Rocky Mount
VEPCO
Raleigh
Harris Site
Wilson
Cape Fear
Lee
Goldsboro
YADKIN
Tillery
DUKE
Blewett
Rockingham
Fayetteville
New Bern
Jacksonville
Darlington County
SCPSA
Robinson
Weatherspoon
Sutton
Wilmington
DUKE
Florence
Brunswick
S.C.
SCPSA
Sumter
SCE&G
SCPSA
SCPSA
LEGEND
Service Area
Generating Plants
Transmission Interconnectors
Major Load Centers

Question 2:

Provide estimate of: a) Current Population Served
b) Current Number of Each Type of Customer

Answer:

a) 2.8 Million

b)

Residential:	569,026
Commercial:	97,770
Industrial:	3,302
Public Street and Highway Lighting:	677
Other Sales to Public Authorities:	1,023
Sales for Resale:	52

Question 3:

If not provided in response to question 2 above, provide the following information both for nuclear and for coal-fired units using a) low sulfur coal and b) high sulfur coal with stack gas cleaning:

a) information requested in Table 2 attached.

b) estimated costs of generating electric energy in mills per kilowatt-hour in the detail shown in Table 3 attached. State whether the costs of fuel and of operation and maintenance are initial costs or levelized costs over some period of operation and, in the latter case, what assumptions are made about escalation.

c) In responding to a and b above, carefully document sources of information and assumptions employed. Provide supporting studies if available.

Answer:

See following pages.

Levelized Fixed Charge Rates

The levelized fixed charge rates are as follows:

	Nuclear	Fossil
Cost of Capital	6.0%	6.5%
Depreciation	4.2%	3.5%
Income Taxes	4.0%	3.9%
Property Tax	.64%	.64%

Assuming installed capacity of 3600 MW at a cost of $1107/kW being used at a 70% capacity factor, this translates to fixed charges of 26.8 Mills/kWh for nuclear capacity.

It should be noted that this $/kW figure differs from that provided in Table 2 due to the fact that Table 2 costs exclude the switchyard and include the land, while the $1107/kW includes the switchyard and excludes the land. It is assumed that there will be no differential costs associated with land procurement due to the type of units to be built at the Harris site.

Fuel Costs - Fossil

Based on discussions with suppliers and current market conditions, CP&L estimates that long-term contracts for low-sulphur (0.7% sulphur) coal with a heat content of 12,000 Btu/lb. can now be obtained at prices of approximately $30/ton and that delivered low-sulphur coal would average $36.50/ton. This translates to 152¢/MBtu.

Escalating this cost at 6%/yr. compounded, deliver low-sulfur coal costs for the initial year of operation for each of the Harris units would be approximately as following assuming a heat rate of 9500 Btu/kWh:

1984 - 21.2 Mills/kWh
1986 - 24.4 Mills/kWh
1988 - 27.4 Mills/kWh
1990 - 30.8 Mills/kWh

Assuming 6%/yr. compounded escalation and a discount rate for levelizing of 8669%, the levilized coal cost over the 25-year projected life for each of the units would be:

1984 Unit - 39.5 Mills/kWh
1986 Unit - 44.4 Mills/kWh
1988 Unit - 49.9 Mills/KWH
1990 Unit - 56.0 Mills/kWh

Fuel Costs - Nuclear

Attached Table A provides a breakdown of the estimated initial core costs and the estimated 25-year levelized costs for each unit. Where the services to be provided are under contract, the prices were escalated in accordance with the

terms and conditions of those contracts. For those not under contract, costs were escalated in accordance with projections based on market conditions. In converting to the 25-year levelized figure, a discount rate of 8.669% was used along with a heat rate of 10,523 Btu/kWh and an assumed plant utilization of 70%.

O&M Costs - Fossil

Based on an analysis of our present costs, and assuming an escalation of 7% per year compounded and plant utilization of 70%, O&M costs for the initial year of operation of fossil units would be:

1984 Unit - 1.316 Mills/kWh
1986 Unit - 1.507 Mills/kWh
1988 Unit - 1.725 Mills/kWh
1990 Unit - 1.975 Mills/kWh

Continuing to escalate at 7% and using a discount rate of 8.669%, this translates to a 25-year levelized cost of:

1984 Unit - 2.722 Mills/kWh
1986 Unit - 3.116 Mills/kWh
1988 Unit - 3.568 Mills/kWh
1990 Unit - 4.085 Mills/kWh

O&M Costs - Nuclear

Based on the same assumptions, O&M costs for nuclear units in their first year of operation would be:

1984 Unit - 2.487 Mills/kWh
1986 Unit - 2.848 Mills/kWh
1988 Unit - 3.260 Mills/kWh
1990 Unit - 3.733 Mills/kWh

The 25-year levelized costs for these units would then be:

1984 Unit - 5.14 Mills/kWh
1986 Unit - 5.889 Mills/kWh
1988 Unit - 6.743 Mills/kWh
1990 Unit - 7.720 Mills/kWh

All costs used in this analysis are assumed to be variable.

Cost of Insurance

It is estimated that nuclear liability insurance in 1990 will be approximately $1,000,000/year, and the differential property insurance will be approximately $2.8 million for all risk coverage including nuclear contamination. Assuming a 3600 MW plant being used at a 70% capacity factor, this translates to approximately .17 Mills/kWh.

8/5/77

TABLE A

SHEARON HARRIS NUCLEAR PLANT

	Initial Core Cost Breakdown Mills/kwhe	25-Year Levelized Mills/kwhe
Harris 1		
U_3O_8	0.6	13.4
Conversion, Enrichment	1.7	
Fabrication	0.6	
Shipping & Disposal	1.9	
Indirect	-0.1	
Total	4.7	
Harris 2		
U_3O_8	1.6	16.1
Conversion, Enrichment	1.8	
Fabrication	0.7	
Shipping & Disposal	2.1	
Indirect	0.2	
Total	6.4	
Harris 4		
U_3O_8	4.8	19.5
Conversion, Enrichment	2.0	
Fabrication	0.8	
Shipping & Disposal	2.3	
Indirect	1.6	
Total	11.5	
Harris 3		
U_3O_8	5.6	22.3
Conversion, Enrichment	2.2	
Fabrication	0.8	
Shipping & Disposal	2.6	
Indirect	1.8	
Total	13.0	

TABLE 2

COST INFORMATION FOR NUCLEAR GENERATION

1. Interest during construction — 8 %/year compound rate

2. Length of construction workweek — 40 hours/week

3. Estimated site labor requirement — 17 man-hours/kWe

4. Average site labor pay rate (including fringe benefits) effective at month and year of NSSS order — 5.29 $/hour

5. Escalation rates
   - Site labor — 7 %/year
   - Materials — 7 %/year
   - Composite escalation rate — 7 %/year

6. Power Station Cost - Nuclear (Thousands of dollars)

Direct Costs	Unit 1	Unit 2	Unit 3	Unit 4
a. Land and land rights	36,374	-	-	-
b. Structures and site facilities	252,078	85,277	98,345	103,435
c. Reactor (boiler) plant equipment	186,468	133,036	219,133	228,078
d. Turbine plant equipment not including heat rejection systems	57,134	56,928	111,796	66,643
e. Heat rejection system	Incl. Above	Incl. Above	Incl. Above	Incl. Above
f. Electric plant equipment	46,182	35,841	39,657	38,813
g. Misc. equipment	11,283	1,809	2,120	2,083
h. Spare parts allowance	Incl. Above	Incl. Above	Incl. Above	Incl. Above
i. Contingency allowance	70,577	35,125	48,241	50,205
Subtotal	623,722	348,016	519,292	489,257

Indirect Costs	Unit 1	Unit 2	Unit 3	Unit 4
a. Construction facilities, equipment, and services	74,205	19,777	29,216	27,031
b. Engineering and construction management services	135,505	56,034	80,906	61,269
c. Other costs	112,920	88,995	114,618	91,904
d. Interest during construction (@ 8%/year)	351,039	196,493	253,460	232,764
Escalation				
Escalation during construction @ 7%/year	Incl. Above	Incl. Above	Incl. Above	Incl. Above
Total Cost				
Total station cost, @ start of commercial operation	1,333,765	709,315	997,492	902,225

Carolinas (VACAR) sub-region. Other systems comprising VACAR are Duke Power Company (DUKE), South Carolina Electric & Gas Company (SCE&G), South Carolina Public Service Authority (SCPSA), Southeastern Power Administration (SEPA), Virginia Electric and Power Company (VEPCO), and Yadkin, Inc.

There are no specified reserve margin requirements set by SERC or VACAR for CP&L. VACAR's stated purpose is to "further augment reliability of each Member System's bulk power supply through coordination of the Member Systems' planning and operation of their generation and bulk power transmission facilities." Each VACAR Member System retains sole control over and use of its own facilities.

The VACAR Agreement establishes an Executive Committee consisting of a representative from each member system. The duties of the VACAR Executive Committee as stated in Section 4.5 of the May 1, 1970 Reliability Agreement, Virginia-Carolinas Group, are listed below:

"Section 4.5 Duties: The Executive Committee shall establish and periodically review principles and procedures with respect to matters affecting reliability of bulk power supply. These matters shall include but not necessarily be limited to:

1. Joint studies and investigations of emergency performance of bulk power supply facilities;

2. Generation and transmission planning, construction, operating and protection arrangements;

3. Maintenance schedules of generating units and transmission lines;

4. Requirements for and adequacy of communication facilities;

5. Load relief measures and restoration procedures;

6. Spinning reserve requirements;

7. Coordination of voltage levels and reactive interchange;

8. Exchange of information on such items as:

    a. Magnitude and characteristics of actual and forecasted loads;

    b. Additions, deletions, and modifications of bulk power supply facilities;

    c. Programs of capacity additions;

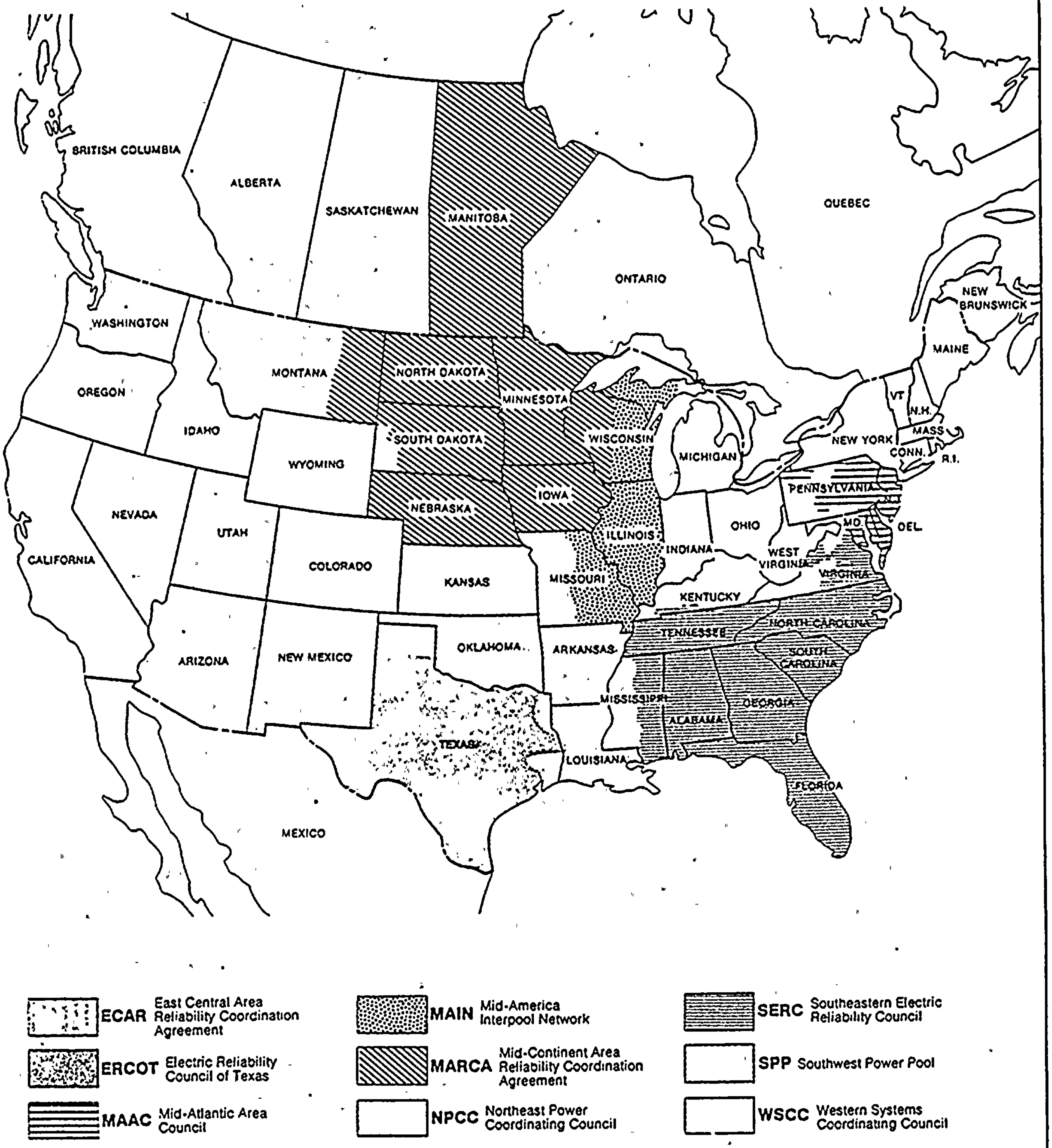
    d. Capability of bulk power generating and interchange facilities;

    e. Plant and system emergencies such as generating unit outages, transmission line outages, etc."

The Executive Committee can appoint or employ such Task Forces at it deems necessary to carry out its assigned duties.

Because CP&L is not a member of any power pool, specific regional generation planning studies are not conducted. However, CP&L's active participation in VACAR and SERC reliability studies indirectly results in a high degree of generation coordination. Reliability studies center on transmission system coordination to enable normal and emergency transfer of reserves among the VACAR member companies.

NATIONAL ELECTRIC RELIABILITY COUNCIL

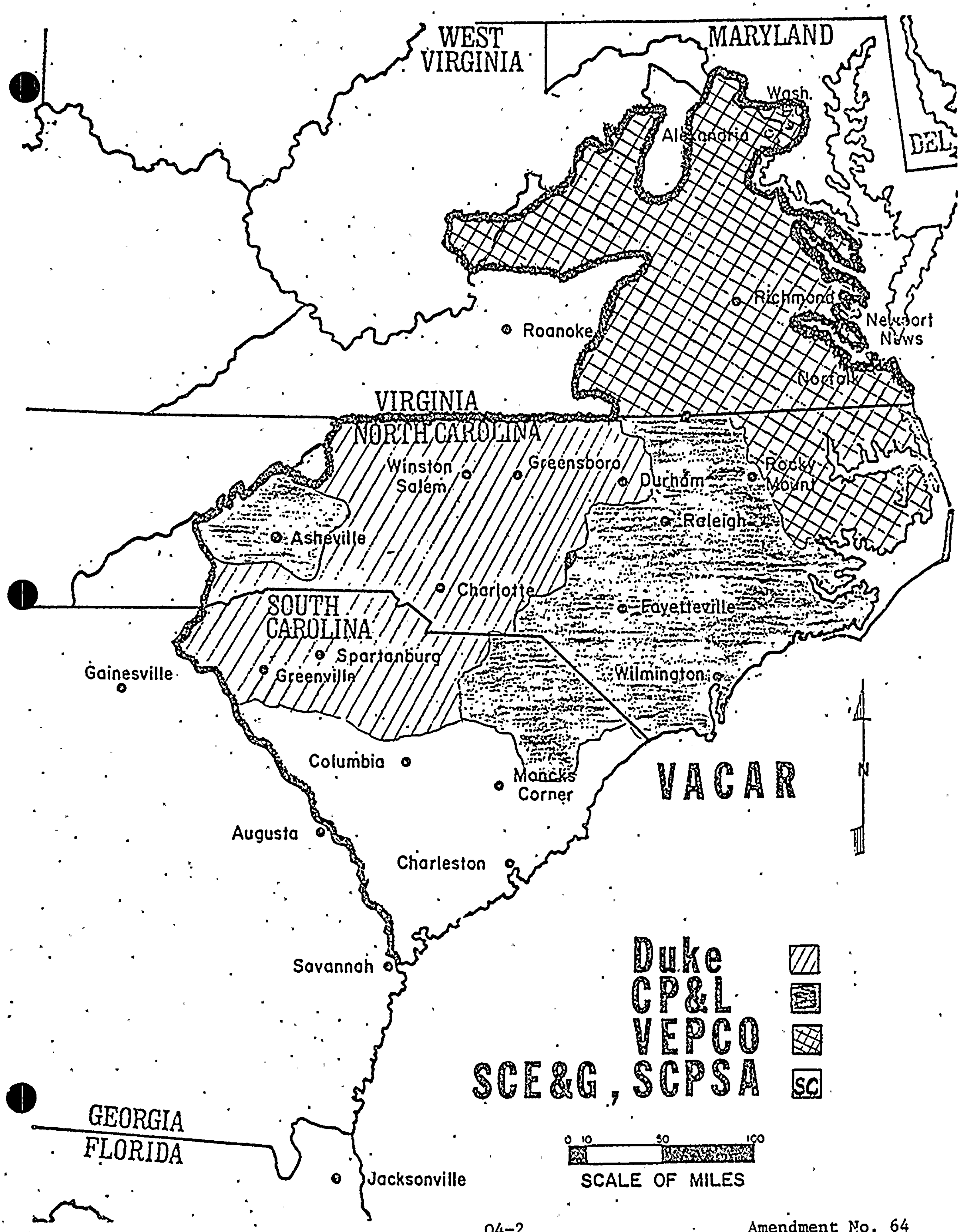


Question 4:

Provide map of VACAR and SERC regions indentifying geographical boundaries, utility service areas, and power supply areas.

Answer:

Maps attached.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Newport News
Norfolk
Roanoke
VIRGINIA
NORTH CAROLINA
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Greensboro
Durham
Rocky Mount
Raleigh
Asheville
Charlotte
Fayetteville
SOUTH CAROLINA
Spartanburg
Greenville
Gainesville
Wilmington
Columbia
Moncks Corner
Augusta
Charleston
Savannah
GEORGIA
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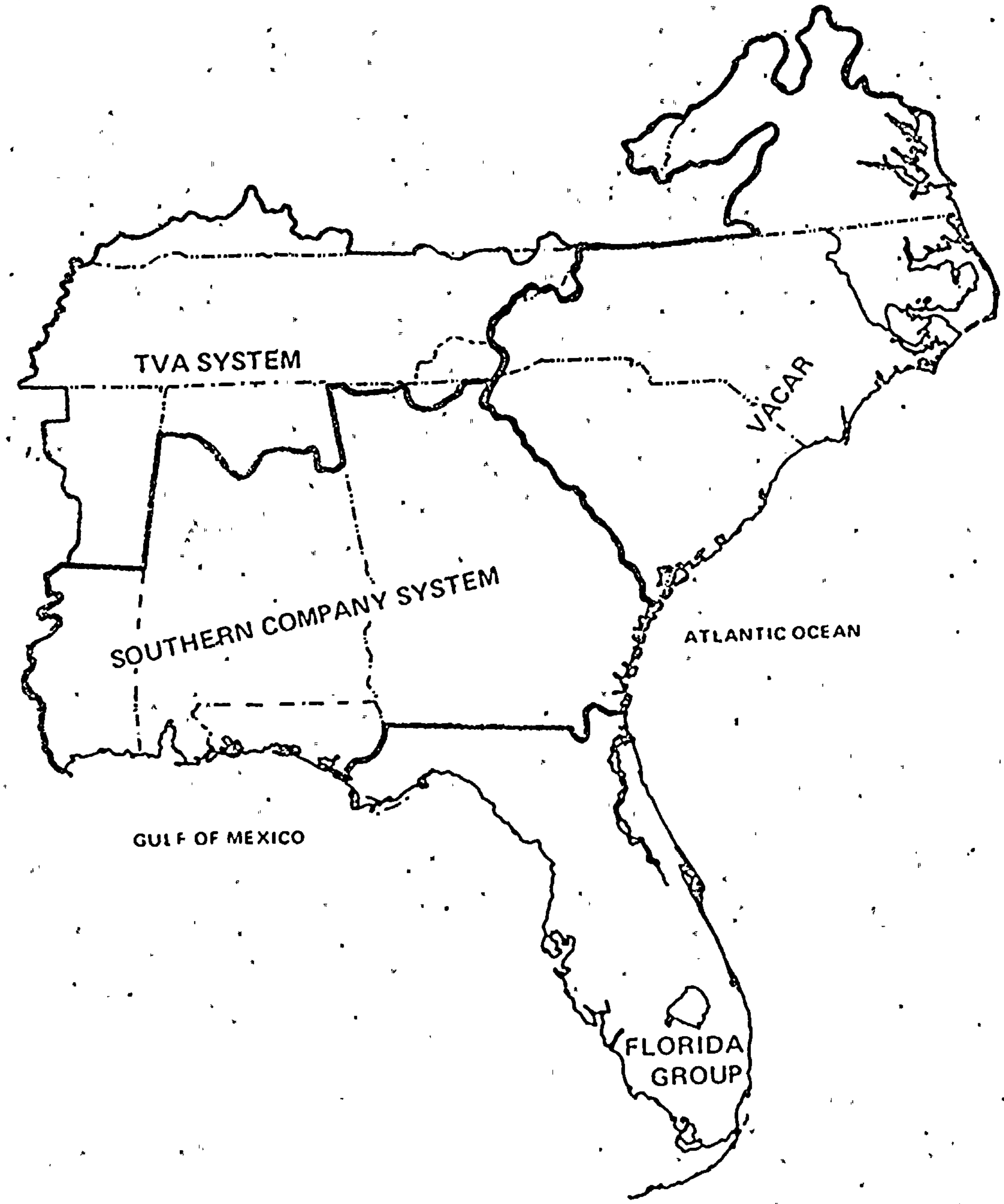
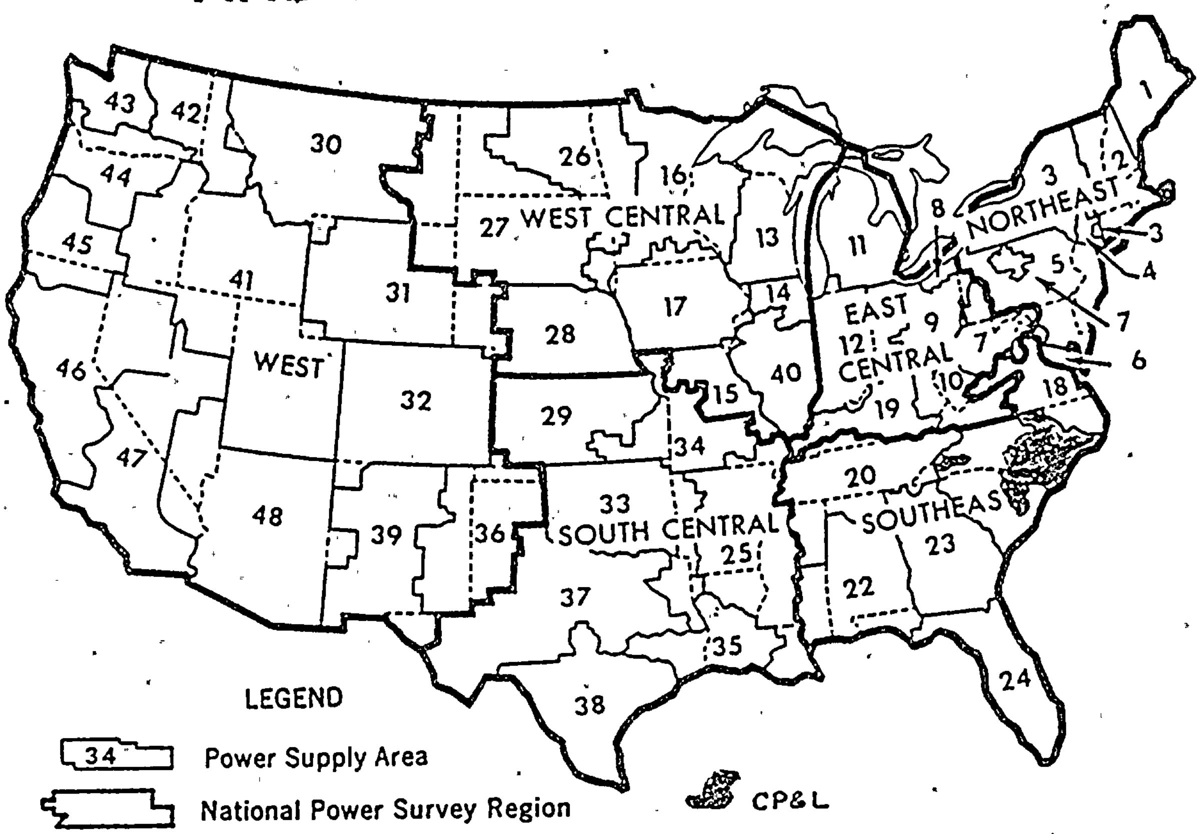


The Southeastern Electric Reliability Council Region (SERC)

NATIONAL POWER SURVEY REGIONS AND POWER SUPPLY AREAS



Question 5:

Provide historical (1966 to present) electrical energy use by major category.

Answer:

1977	Jan.	Feb.	Mar.
RES	809,897,100	782,513,100	586,349,600
COM	405,861,300	394,662,500	318,784,300
IND	669,010,300	654,234,700	671,731,600
SFR	580,486,600	592,494,900	460,978,900
PS&H	7,208,900	7,244,100	7,229,300
OTHER	70,026,100	68,916,100	61,358,300

	Apr.	May	June
RES	476,513,300	414,992,400	462,151,000
COM	299,654,400	295,478,000	330,641,500
IND	738,693,500	719,203,200	776,635,500
SFR	432,325,800	393,054,200	448,859,300
PS&H	7,258,400	7,239,500	7,177,700
OTHER	51,865,000	61,231,400	72,147,400

	1976	1975	1974
RES	6,491,041,329	6,152,464,510	5,916,808,226
COM	4,016,382,513	3,797,561,260	3,576,528,807
IND	8,759,189,138	7,833,191,728	8,273,238,179
SFR	5,735,114,851	5,369,998,406	4,991,730,151
PS&H	85,067,059	82,555,773	77,740,491
OTHER	828,728,042	821,445,597	771,255,550

All figures in kwH

	1973	1972	1971
RES	5,936,973,744	5,208,235,288	4,973,640,469
COM	3,627,738,620	3,202,067,171	2,944,735,480
IND	7,884,513,200	7,037,060,241	6,231,506,547
SFR	4,856,882,199	4,197,432,767	3,852,548,719
PS&H	74,129,354	70,110,610	65,493,699
OTHER	848,403,005	802,601,002	792,435,880

	1970	1969	1968
RES	4,634,149,028	4,149,834,680	3,700,844,676
COM	2,693,338,380	2,388,694,730	2,149,841,456
IND	5,622,592,766	5,188,474,380	4,721,267,107
SFR	3,518,368,569	3,089,154,912	2,706,523,129
PS&H	62,255,973	59,755,817	57,575,709
OTHER	770,582,886	740,864,346	689,971,928

	1967	1966
RES	3,228,074,491	2,990,802,490
COM	1,864,619,334	1,666,015,663
IND	4,046,906,512	3,585,663,798
SFR	2,323,953,968	2,094,257,345
PS&H	55,363,930	53,136,488
OTHER	620,626,590	615,697,589

All figures in kwH

Legend:

RES - Residential
COM - Commercial
IND - Industrial
SFR - Sales for Resale
PS&H - Public Streets and Highway Lighting
OTHER - Other Sales to Public Authorities

Question 6:

Provide much more detailed information and description of energy forecasting methodology. In general, adequate response includes: a) list of all factors considered, b) description of how those factors are introduced, and c) estimates of individuals effect on each factor on energy growth. Specifically,

a) Explain in detail and explicitly how factors were considered and the effect of each.

b) Present results of least squares regression analysis; what is dependent variable?; present regression equation developed from the analysis: present estimates of future values of independent variables; present details of forecast check against appliance growth, etc.; describe and explain procedure for determining number of industrial customers and their distribution; present explicit assumptions on how factors listed affect customer mix.

c) Present and describe commercial energy forecast.

Answer: See following pages.

The following is a detailed description of the energy forecasting methodology used by Carolina Power & Light Company.

ANALYSIS:

The factors considered are:

Residential:

R-2

Winter Base Load
Winter Growth Rate
Monthly Heating Degree Days
Monthly Price
Summer Base Load
Summer Growth Rate
Monthly Cooling Degree Days
Monthly Price

R-3

Winter Base Load
Winter Growth Rate
Monthly Heating Degree Days
Monthly Price
Summer Base Load
Summer Growth Rate
Monthly Cooling Degree Days
Monthly Price

R-4

Winter Base Load
Winter Growth Rate
Monthly Heating Degree Days
Monthly Price
Summer Base Load
Summer Growth Rate
Monthly Cooling Degree Days
Monthly Price

Commercial

Winter Base Load
Winter Growth Rate
Monthly Heating Degree Days
Monthly Price
Summer Base Load
Summer Growth Rate
Monthly Cooling Degree Days
Monthly Price

Industrial

Known loads to be added.
Known loads being considered.
Historical relationship of unknown loads to known loads.
Headquarters interviews with largest customers.
Plant interviews with medium sized customers.

Sales for Resale

Historical Relationships between CP&L Retail Sales and Sales for Resale.

PS and HW Lighting:

Historical Time Trends

Other Sales to Government Authorities:

Historical Average Growth Rates

They are introduced into the analysis as follows:

All Residential Rate Schedules

Winter Months (October through May)

$$kWh = A + B\ (HDD) + C(T) + D(P)$$

Where:

A, B, C, and D are constants
kWh = Monthly billed kWh/customer
HDD = Heating Degree Days, lagged one month
T = Month number from January, 1970
P = Average billed Unit Price for the class, lagged one month

Summer Months (June through September)

$$kWh = E +(CDD) + G(T) + H(P)$$

Where:

E, F, G, and H are constants
kWh = Monthly billed kWh/customer
CDD = Cooling Degree Days, lagged one month
T = Month number from January, 1970
D = Average billed Unit Price for the class, lagged one month

These two equations are estimated with kWh/customer being the dependent variable using monthly data from January 1970 to the latest available. The regression analysis made February 1976, and used in our current forecast, gave the following values for the coefficients:

R-2

A = 1252	E = 1187
B = 2.46	F = 1.22
C = - .88	G = 2.00
D = -147	H = -127

R-3

A = 720	E = 680
B = 0.14	F = 0.94
C = 1.15	G = 2.51
D = - 22.2	H = -59.6

R-4

A = 342	E = 374
B = 0.02	F = 0.49
C = 1.12	G - 2.58
D = -12.8	H = -52.7

Commercial:

A = 2542	E = 2749
B = 0.47	F = 1.63
C = 12.3	G - 16.4
D = - 95.8	H = -300

From these coefficients the following equations were developed for simulation:

R-2

$$kWh = 14699 + 2.46(HDD) + 1.22(CDD) + 10.0(T_1) + (-6.16)(T_2) - 1669(P)$$

R-3

$$kWh = 8440 + 0.14(HDD) + .94(CDD) + 8.05(T_1) + 12.6(T_2) - 453(P)$$

R-4

$$kWh = 4271 + 0.02(HDD) + .49(CDD) + 7.84(T_1) + 12.9(T_2) - 353(P)$$

Commercial:

$$kWh = 31539 + .469(HDD) + 1.63(CDD) + 86.1(T_1) + 82.0(T_2) - 2171(P)$$

Where:

kWh = Annual kWh/customer
HDD = Annual Heating Degree Days
CDD = Annual Cooling Degree Days

T_1 = Average number of months numbered from January 1970 for June-October

T_2 = Average number of months numbered from January 1970 for January-May and November-December

<u>From these estimations the following conclusions are indicated:</u>

For each Heating Degree Day, the following usage occurred:

R-2	2.46 kWh
R-3	0.14 kWh
R-4	0.02 kWh
Commercial	.47 kWh

This implies that the average dwelling unit with electric heat uses 8364 kWh/year for heating. This is confirmed by our estimates for the service area.

Assume: 10 kW HL
3400 HDD
16 Constant
70 Temp. Diff.

Annual Usuage for Heating:

$$kWh = \frac{HL \times DD \times XC}{TD}$$

$$= \frac{10 \times 3400 \times 16}{70}$$

$$= 7771 \text{ kWh/year}$$

It is further implied that for the average R-3 customer, 476 kWh are used as a result of cold weather.

The average R-3 customer has oil heat which uses approximately 1 kWh/gal. of oil for the burner and fan. For the same HL dwelling unit, this would account for 473 kWh/year.

It is further implied that the R-4 customers use only 68 kWh during the winter due to extra lighting, TV, etc.

During the cooling season the following conclusions are indicated:

For each cooling Degree Day, the following usuage occurred:

R-2	1.22 kWh
R-3	0.94 kWh
R-4	0.49 kWh
Commercial	1.63 kWh

When saturations are considered, the following verification may be made:

R-2 A/C saturation = 81.8%
R-3 A/C saturation = 63.8%
R-4 A/C saturation = 36.0%

R-2

$$\frac{1.22 \text{ kWh/DD}}{.818 \text{ Saturation}} = 1.49 \text{ kWh/DD/Unit}$$

R-3

$$\frac{0.94 \text{ kWh/DD}}{.638 \text{ Saturation}} = 1.47 \text{ kWh/DD/Unit}$$

R-4

$$\frac{0.49 \text{ kWh/DD}}{.36 \text{ Saturation}} = 1.36 \text{ kWh/DD/Unit}$$

The growth-time trend coefficients are confirmed by the annual differences during the least weather-affected months--May and October. Since this coefficient quantifies growth without a price response effect, the coefficients were verified from 1966 to 1973. These time trends can be seen graphically on the figures in Exhibit A.

The "price response" coefficient is the least precise of any. Price elasticity, cross elasticity, and conservation effect are so multi-correlated that the matrix is not stable if they are specified separately. In the third quarter of 1973, electricity started going up rapidly along with fuel oil prices and a national effort to conserve. It has not been possible to accurately determine the magnitude of these factors separately.

As a means of incorporating these effects collectively, we have used the current average price of electricity as the independent variable. The coefficient for this variable has been estimated separately for the winter and summer.

The derived coefficients indicate that the "price response" during the cooling months are directly proportioned to the saturation of air conditioners of the given rate classes. The magnitude of the response ranges from 93 kWh/mon per one cent change in price for the R-3 customers (who have twice the saturation of window A/C as central units) to 156 kWh/mon per one cent change for R-2 customers (who have 82% more central units than window A/C). These relative values seem to verify the reasonableness of the coefficients.

The "price response" during the heating months is not as simply verified but appears quite reasonable logically. The indicated response is 147 kWh/mon, 22.2 kWh/mon, and 12.8 kWh/mon for R-2, R-3, and R-4 customers, respectively.

Using the same logic, each heating degree day, the average commercial customer uses 0.469 kWh, and for each cooling degree day, 1.63 kWh. The corresponding growth constants are 86.1 kWh per month each summer month and 82.0 kWh each winter month. The "price response" is 95.8 kWh/one cent change in price for the winter and 300 kWh/one cent price change for the summer. It is believed that these are reasonable in view of the CP&L emphasis on reduced thermostat settings and elimination of unnecessary lighting. Saturations are not available for verification.

FORECASTING:

Residential:

Residential forecasting is done by simulation. For each rate class, the regression equation is used with the following assumptions:

1. Base load 1970 is constant for winter and for summer.

2. Unconstrained growth will remain constant. This implies new appliances, improved standard of living, and appliances "X."

3. Normal weather as reported by the U. S. Weather Bureau for winter.

4. The price of electricity will increase 1% more than the general cost of living including competitive fuels--all in 1975 dollars. This price response term also includes a continuation of the conservation effect, which includes the 1974-76 period of steep reduction.

The customer mix assumes that:

1. Natural gas will not be available to new areas or developments. Consequently, abandonment of low use services in redevelopment areas, rural dwellings, and urban renewal areas will not be replaced with new gas heat or water heat. The drop in R-4s (minimum use customers) is expected to continue to drop with present gas customers continuing to get service.

2. With the unpredictability of fuel oil availability, the physiological influence is considered to be a major factor in selecting all-electric service over an oil-electric combination. Historically, CP&L has connected about half its new residential customers under the R-3 rate (customers with electric water heating but no electric space heating). Uncertainty has drastically changed this ratio and it is expected that in the forecast period, the net R-3 connects will go as low as 15 to 20 percent of new connects.

3. With all-electric service being very competitive with other types of fuels for heating, as many as 2000 customers per year will convert to a heat pump. These conversions are included in the net assumptions above.

Using the above assumptions, estimated customers are multiplied by simulated consumption per customer for each class and added for the total usuage.

Commercial:

The commercial forecast is made exactly like the residential. There are no saturations to verify the results. Recent rate consolidations have made it impossible to look at each rate schedule individually.

The usage per customer is the dependent variable in the regression analysis. The independent variables are base load for January 1970, winter and summer growth rates, heating degree days, cooling degree days, and average unit price. The weather variables and the price variables are lagged one month. The assumptions are the same as for residential.

Over a period from 1965 to 1975, the ratio of commercial customers to residential customers has generally risen from 0.166 to 0.171, reaching a maximum in 1972 of 0.177. As a check on the forecasted number of commercial customers, this ratio is calculated through 1996. It remains at approximately 0.17 throughout the forecast period. The actual sales for the years 1973, 1974, 1975, and 1976, and the forecast sales for the years through 1996 are:

Year	MWH	Year	
1973	3,627,739	1986	7,266,600
1974	3,576,529	1987	7,680,060
1975	3,797,561	1988	8,110,930
1976	4,016,379	1989	8,559,800
1977	4,224,270	1990	9,020,440
1978	4,515,420	1991	9,492,820
1979	4,815,350	1992	9.976,940
1980	5,123,540	1993	10,472,800
1981	5,440,000	1994	10,980,400
1982	5,775,190	1995	11,499,600
1983	6,124,860	1996	12,030,600
1984	6,489,590	Compound Annual Growth	
1985	6,869,980	Rate	5.7%
Compound Annual Growth Rate	6.2%		

Industrial:

The industrial forecast is made primarily from three sources. The large users are treated as one group, the medium users as one group, and the small users still a third group.

Three SIC code groups, textiles, paper, and chemicals, use approximately 70% of our industrial kWhs. Chemicals and paper are concentrated in large installations few in number. Among the textile users, there are several large multi-plant operations who collectively account for a large portion of the textile usage.

CP&L and a consultant call on the headquarters planning people of the large user companies and discuss the future plans of the users. These large loads require long lead times to build facilities, get right-of-way, etc. The usercompanies have an equal desire to have power when they need it. Historically, they have shared their planning on a confidential basis quite freely because we have treated such information confidentially in the past. Among these companies are DuPont, Hercules, Burlington Industries, J. P. Stevens, etc. Their plans are pretty firm for 5 to 10 years into the future.

The medium size users are called upon by the district Industrial Power Engineers. Known loads, good prospects, and fair prospects are tabulated for each district. While these plans are not as dependable as the large users, there is a definite correlation for each district between previously indicated plans and actual connects. These prospects are then expanded for unknown loads based on experience. A copy of the prospects by district by SIC code is included in Exhibit B.

The expanded prospect list is compared with the history of the growth by SIC code for reasonableness. The curves for historical growth by SIC codes are included in Exhibit C.

A further comparison is made of growth by SIC code with the U.S. Department of Commerce, Industrial Outlook for expected national growth.

Sales for Resale:

Wholesale customers serve primarily residential and commercial users. These ultimate users are subject to the same environment as our retail customers. A number of the larger wholesale customers have rates equal to or approximating our retail rates. Consequently, the usage patterns of these ultimate customers is very similar to our retail customers.

None of the wholesale customers have records which will allow a detailed study of their usage.

Of all the methodologies tried so far, the most accurate has been to trend the ratio of the wholesale usage to the sum of our residential and commercial customers.

Specifically, we sum the total usage of our residential customers and our commercial customers. Annually, we ratio first the sales to the municipalities to this retail sum and then the E.M.C.'s. These ratios indicate that both the municipalities and E.M.C.'s are growing faster than our retail residential and commercial customers. Trending this ratio into the forecast period and applying it to the sum of the forecasted sum of the residential and commercial customers.

Public Street and Highway Lighting:

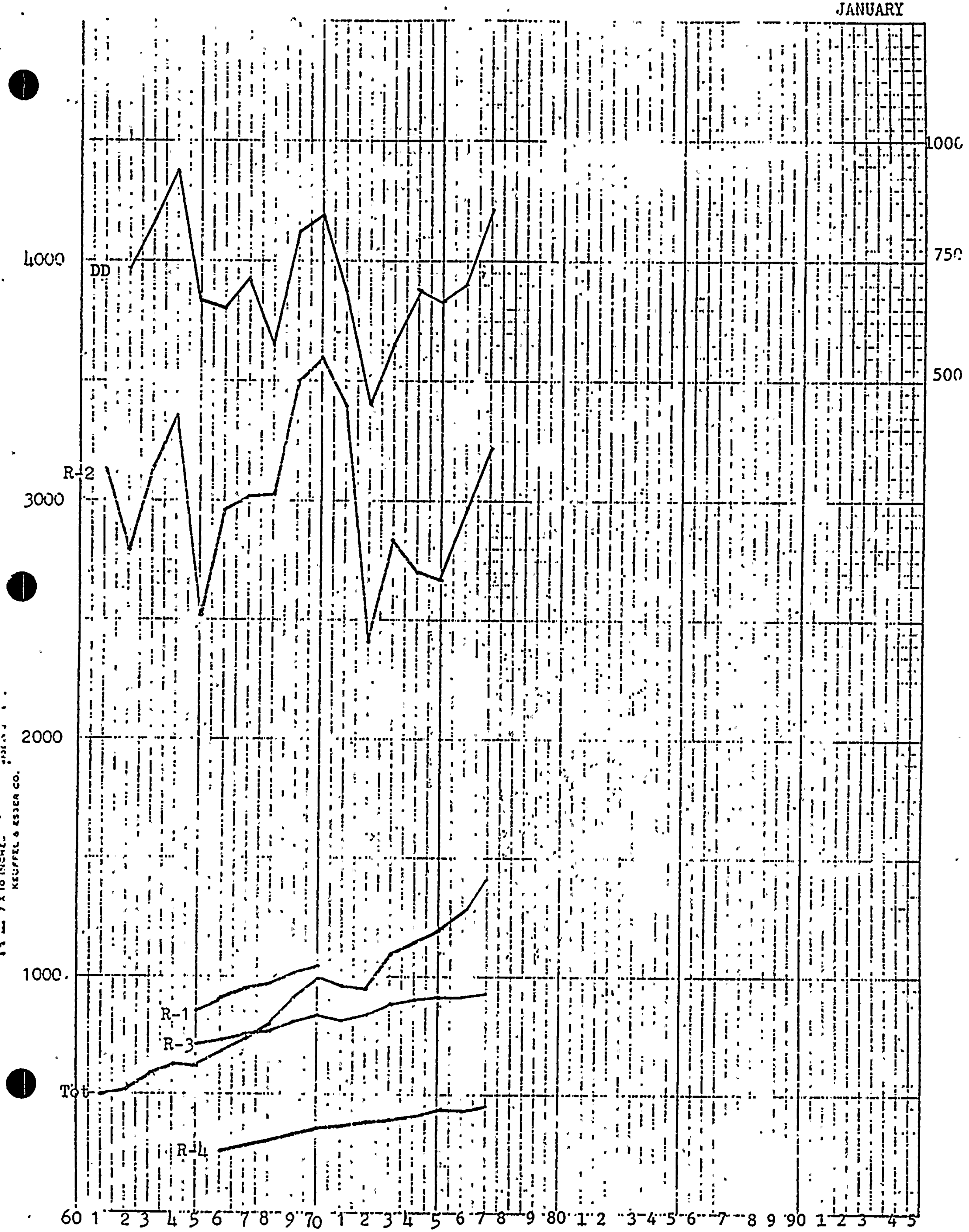
This customer class is simply time trended.

Other Sales to Government Authorities:

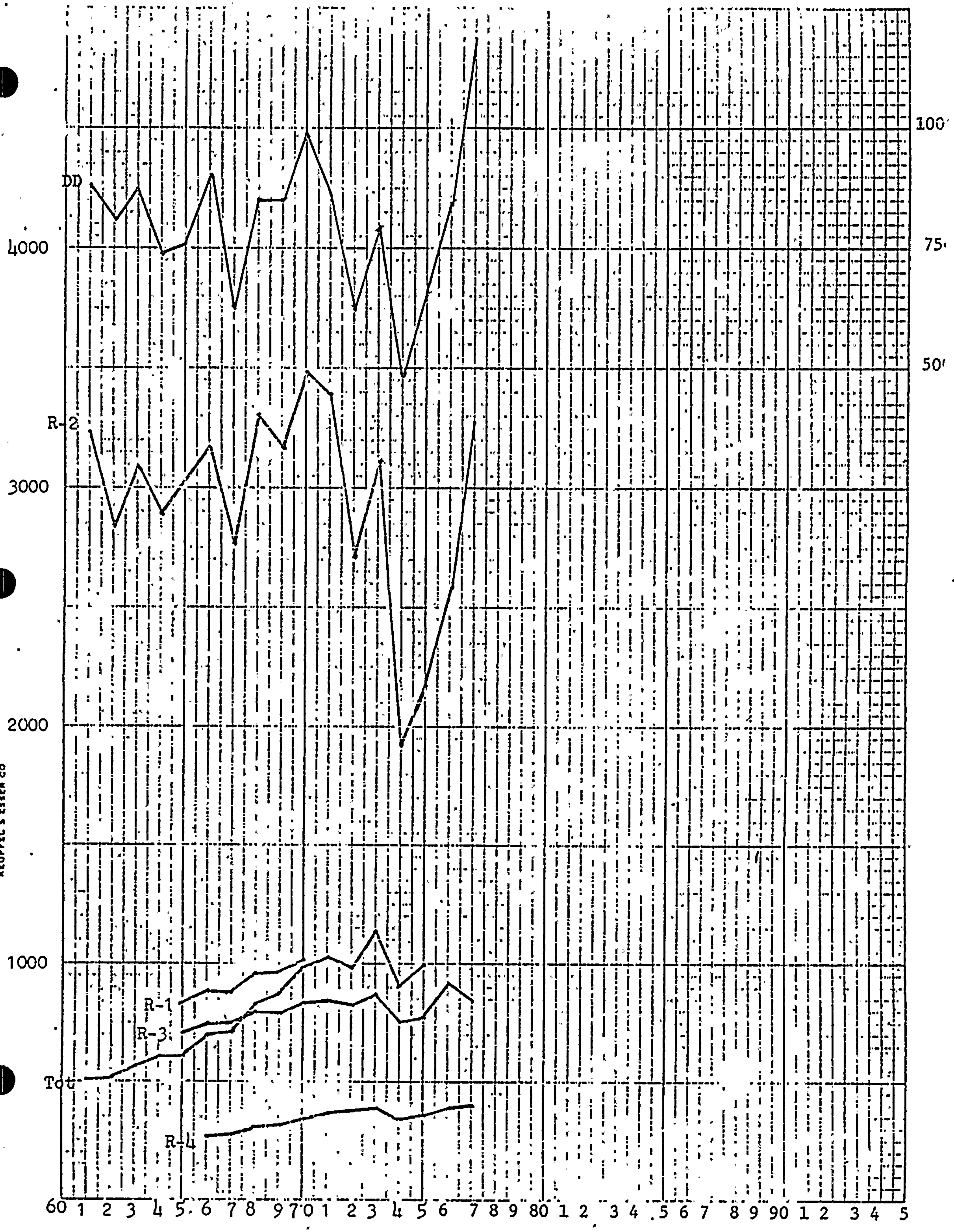
This customer class has municipal pumping which is rather predictable and military bases which are very volitile in usage. Historically, the usage has averaged an increase of approximately 6%. With the event of the oil embargo, an executive directive to reduce consumption 10% was strictly obeyed. For forecasting purposes, we have assumed that these bases will continue to practice conservation and consequently have forecasted a growth rate in usage of 3.9%.

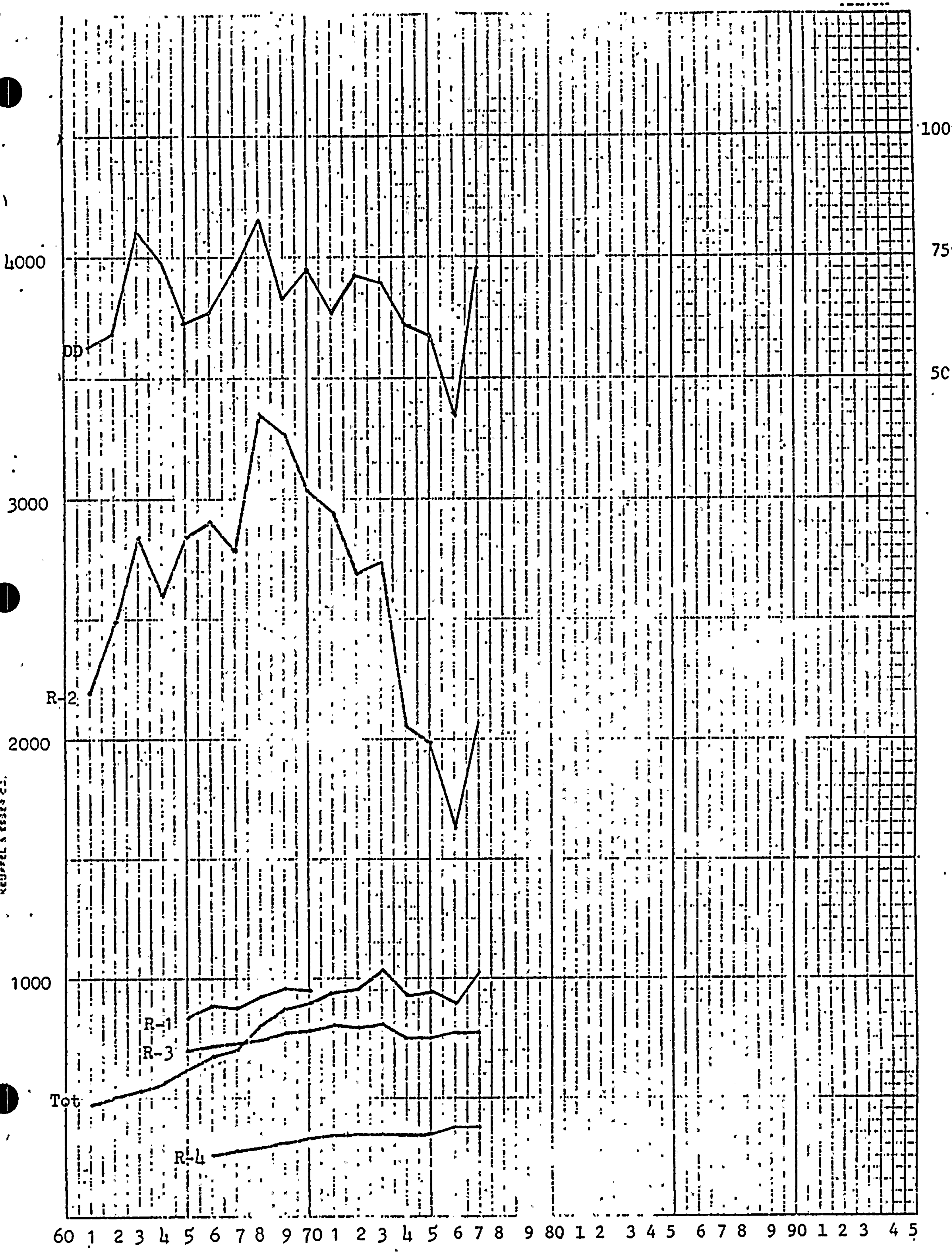
AWF:fdc

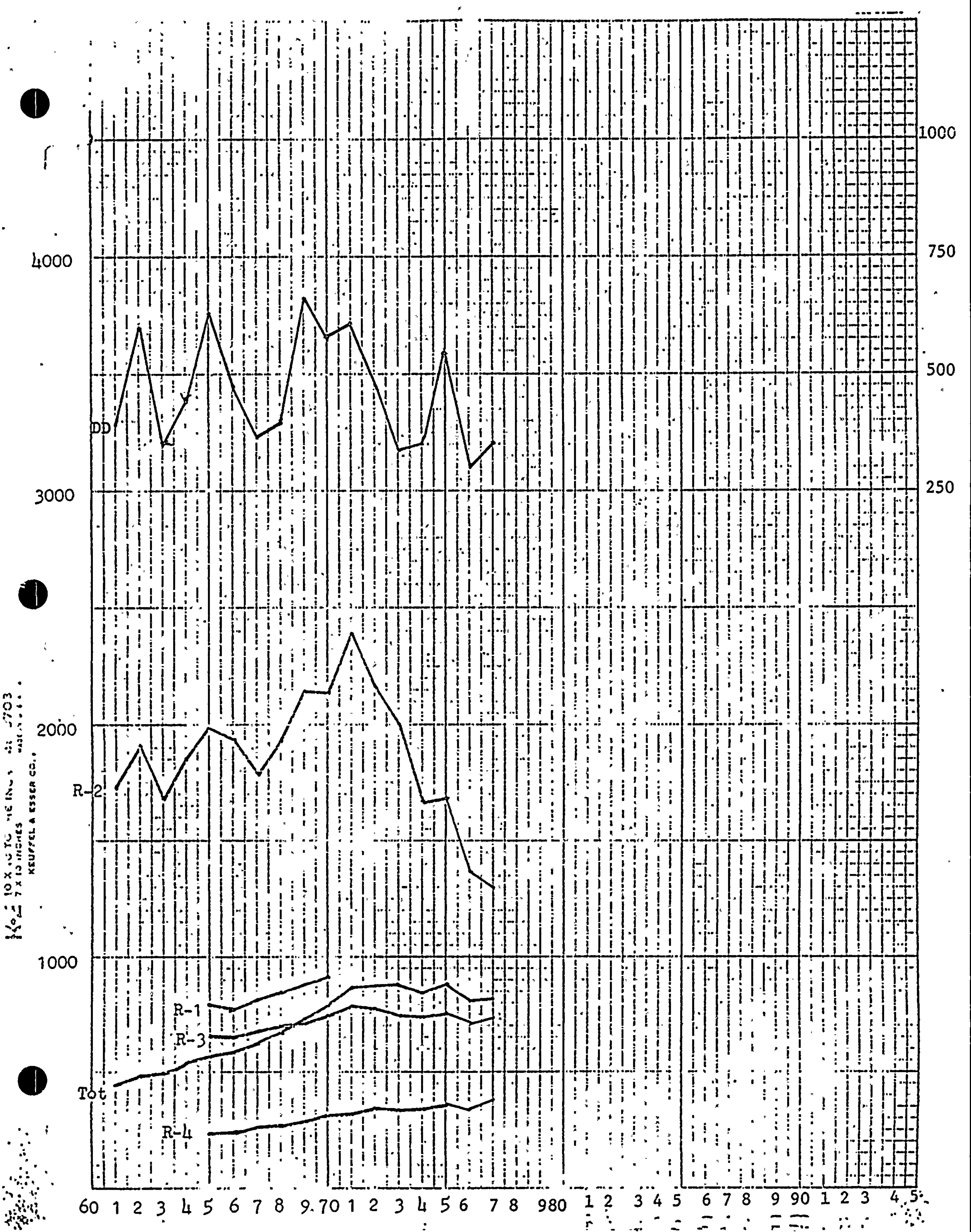
EXHIBIT A



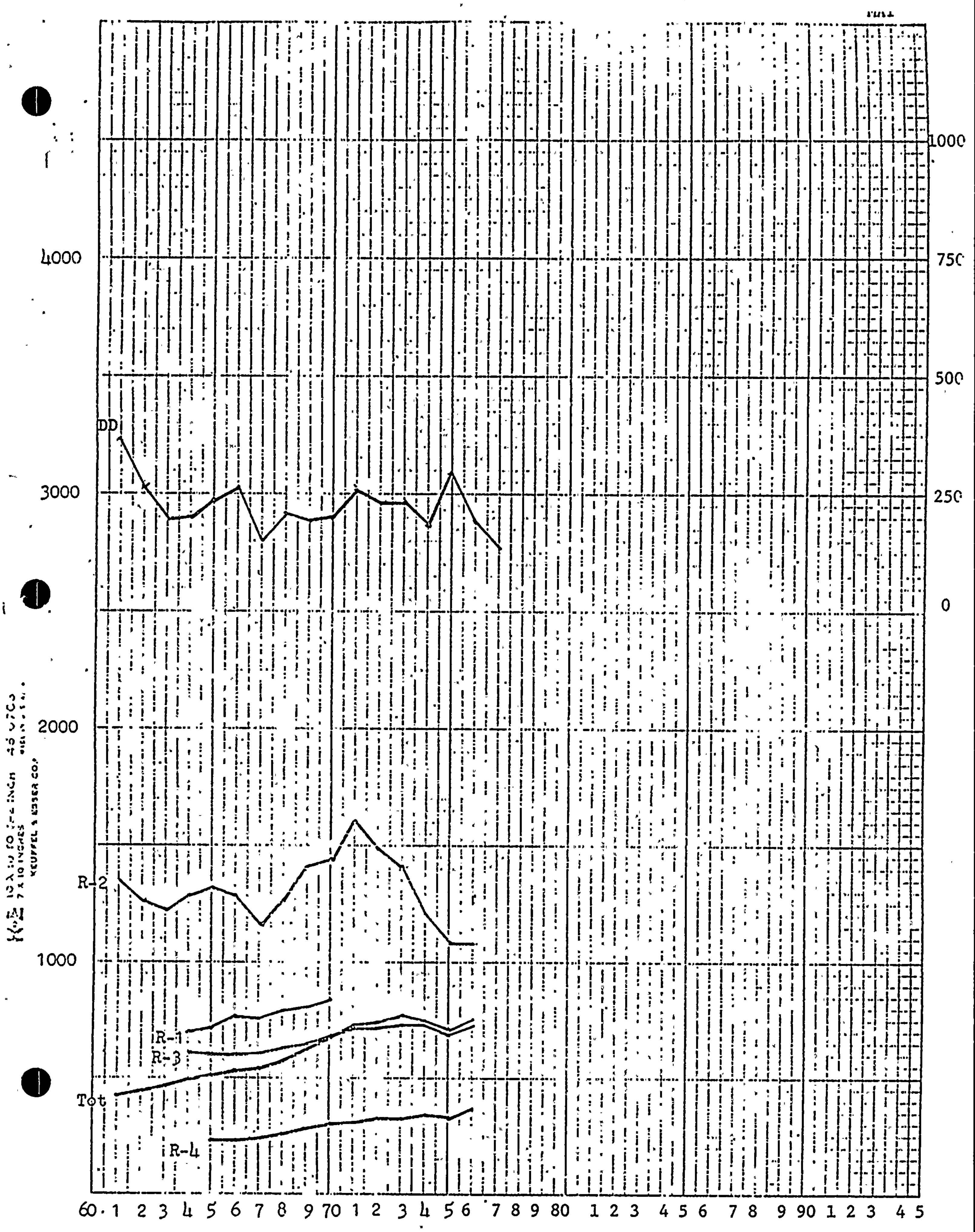
JANUARY
4000
3000
2000
1000
1000
750
500
DD
R-2
R-1
R-3
Tot
R-4
60 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5
KEUFFEL & ESSER CO.

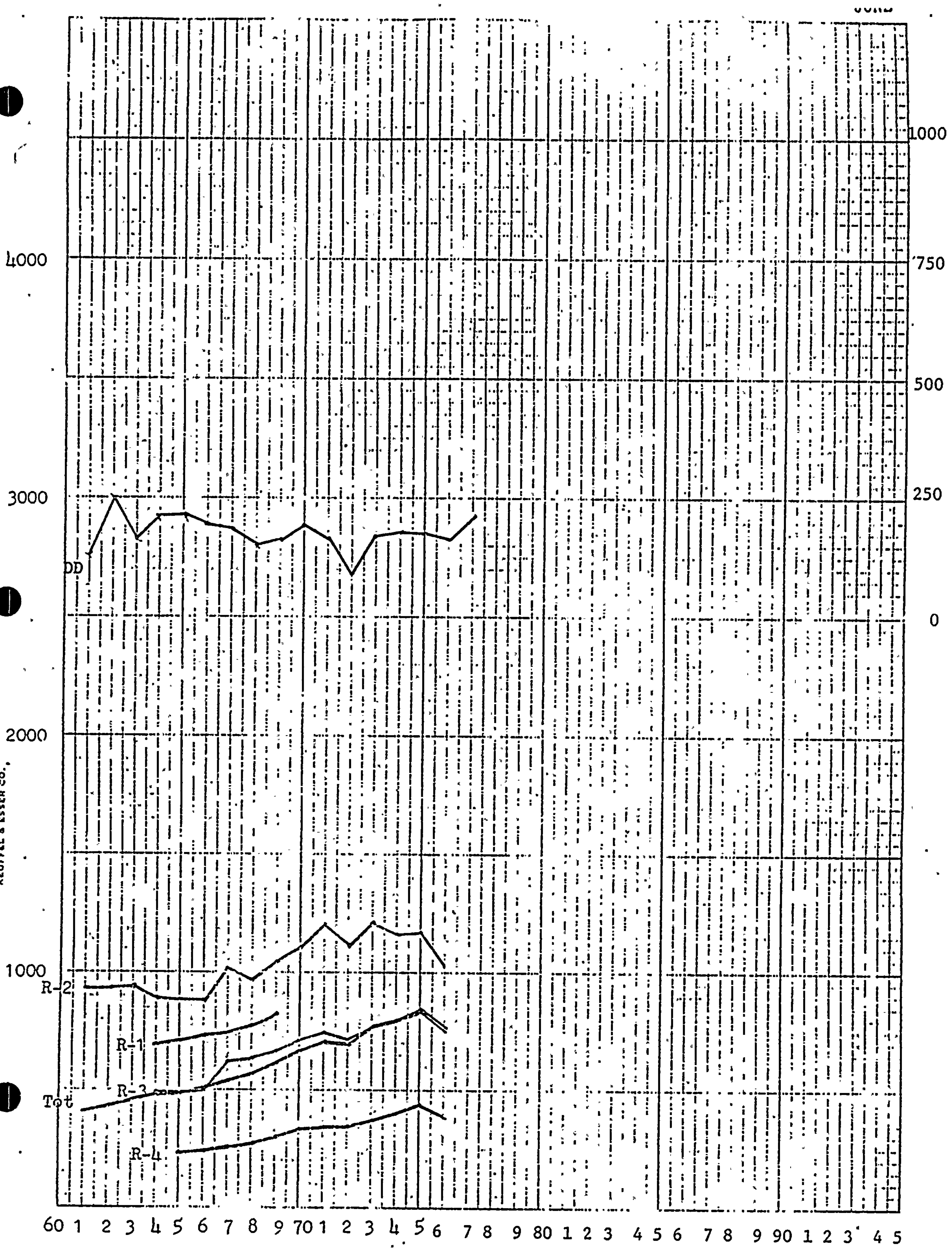

DD
R-2
R-1
R-3
Tot
R-4
4000
3000
2000
1000
100
75
50
60 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5

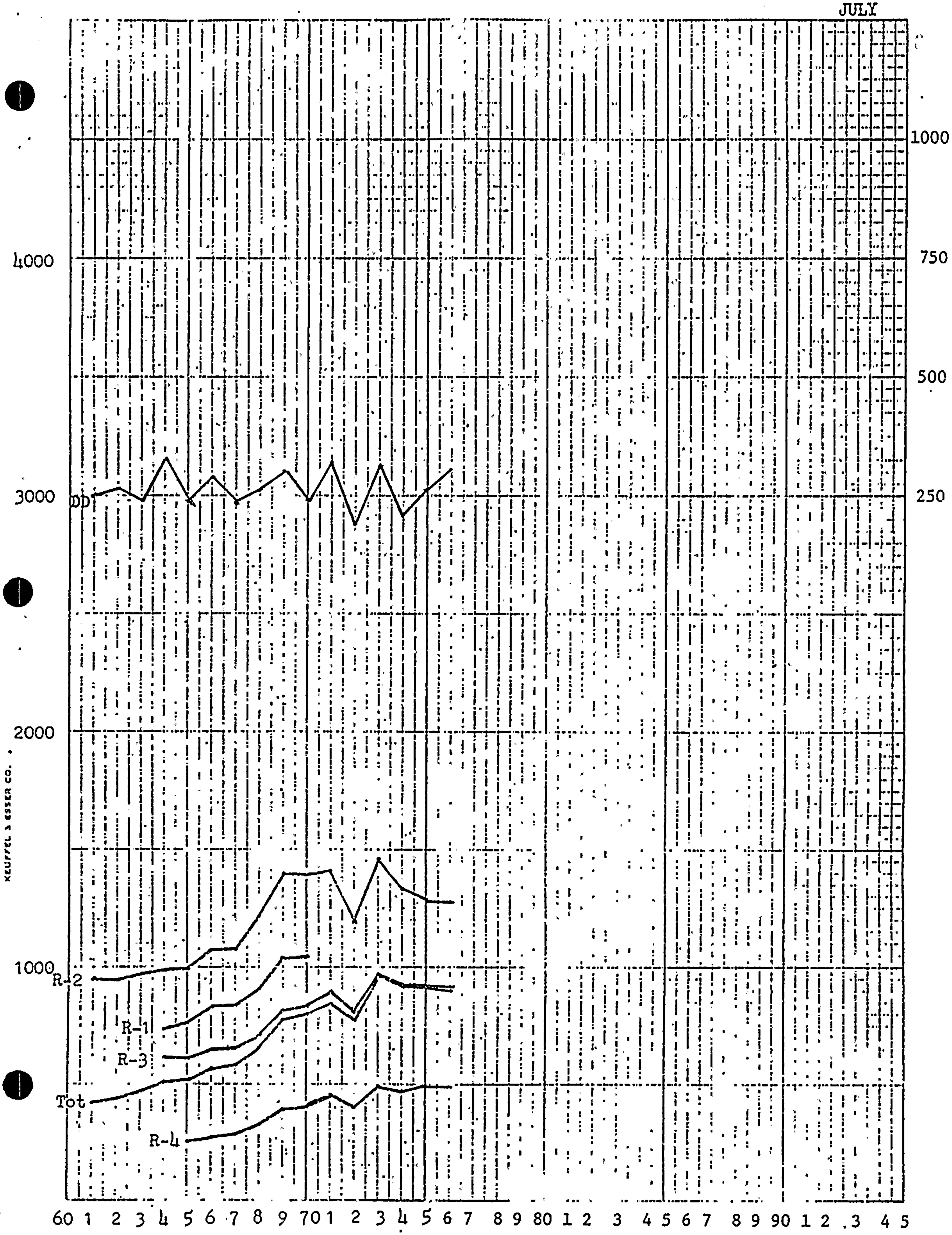

4000
3000
2000
1000
100
75
50
DD
R-2
R-1
R-3
Tot
R-4
60 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5



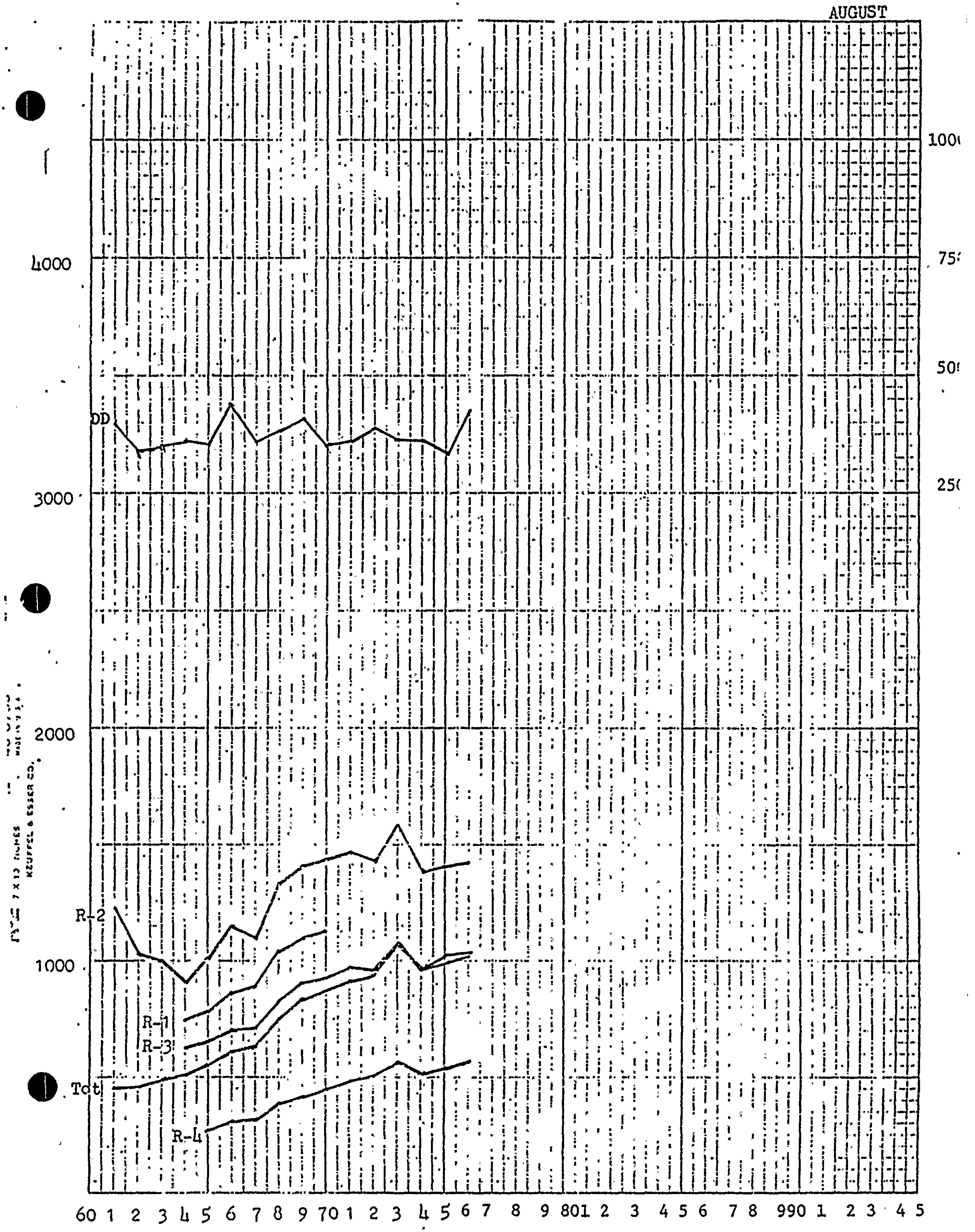
1000
750
500
250
4000
3000
2000
1000
DD
R-2
R-1
R-3
Tot
R-4
60 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 980 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5
KEUFFEL & ESSER CO.

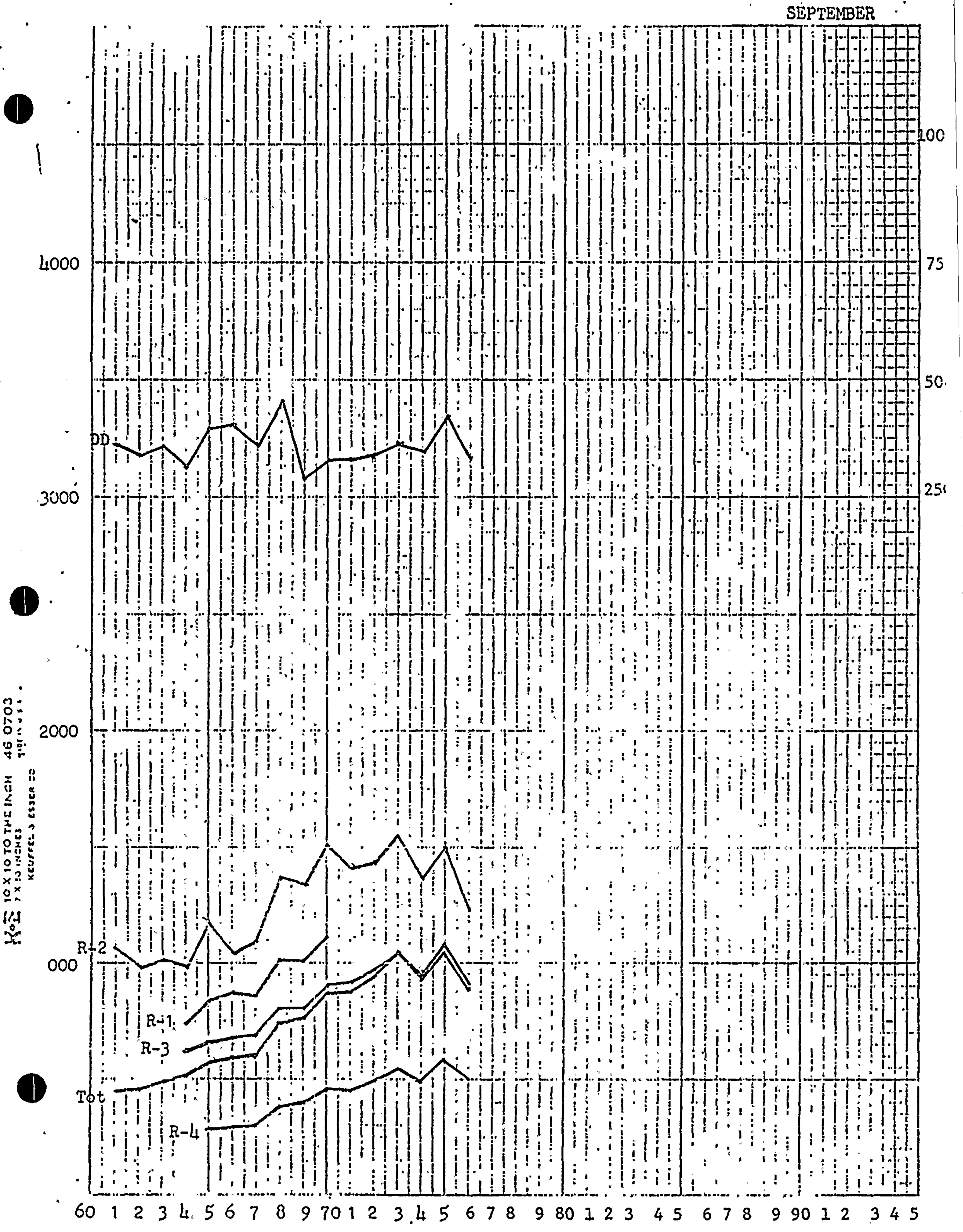

4000
3000
2000
1000
1000
750
500
250
0
DD
R-2
R-1
R-3
Tot
R-4
60·1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5
7 X 10 INCHES
KEUFFEL & ESSER CO.

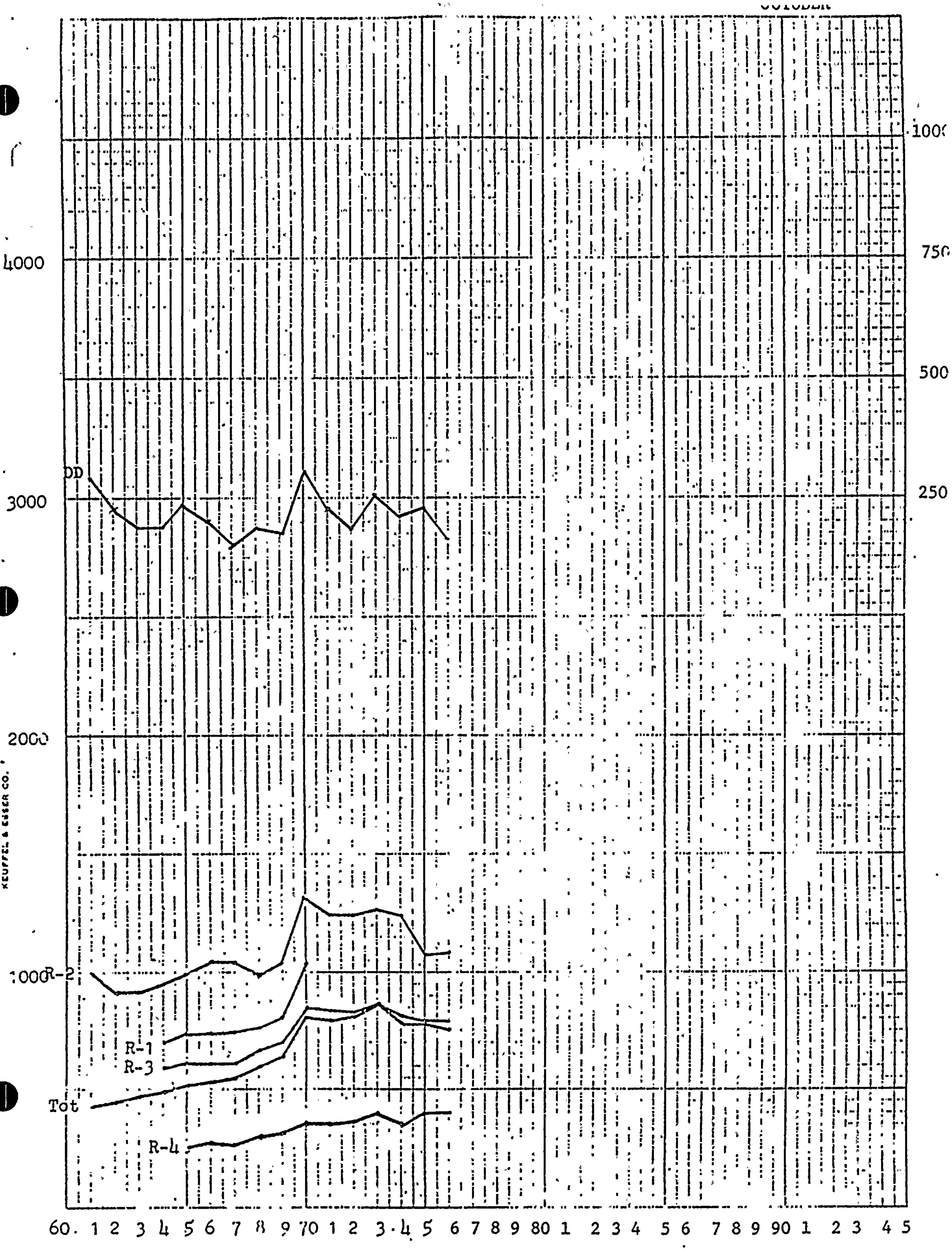

4000
3000
2000
1000
1000
750
500
250
0
DD
R-2
R-1
R-3
Tot
R-4
60 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5



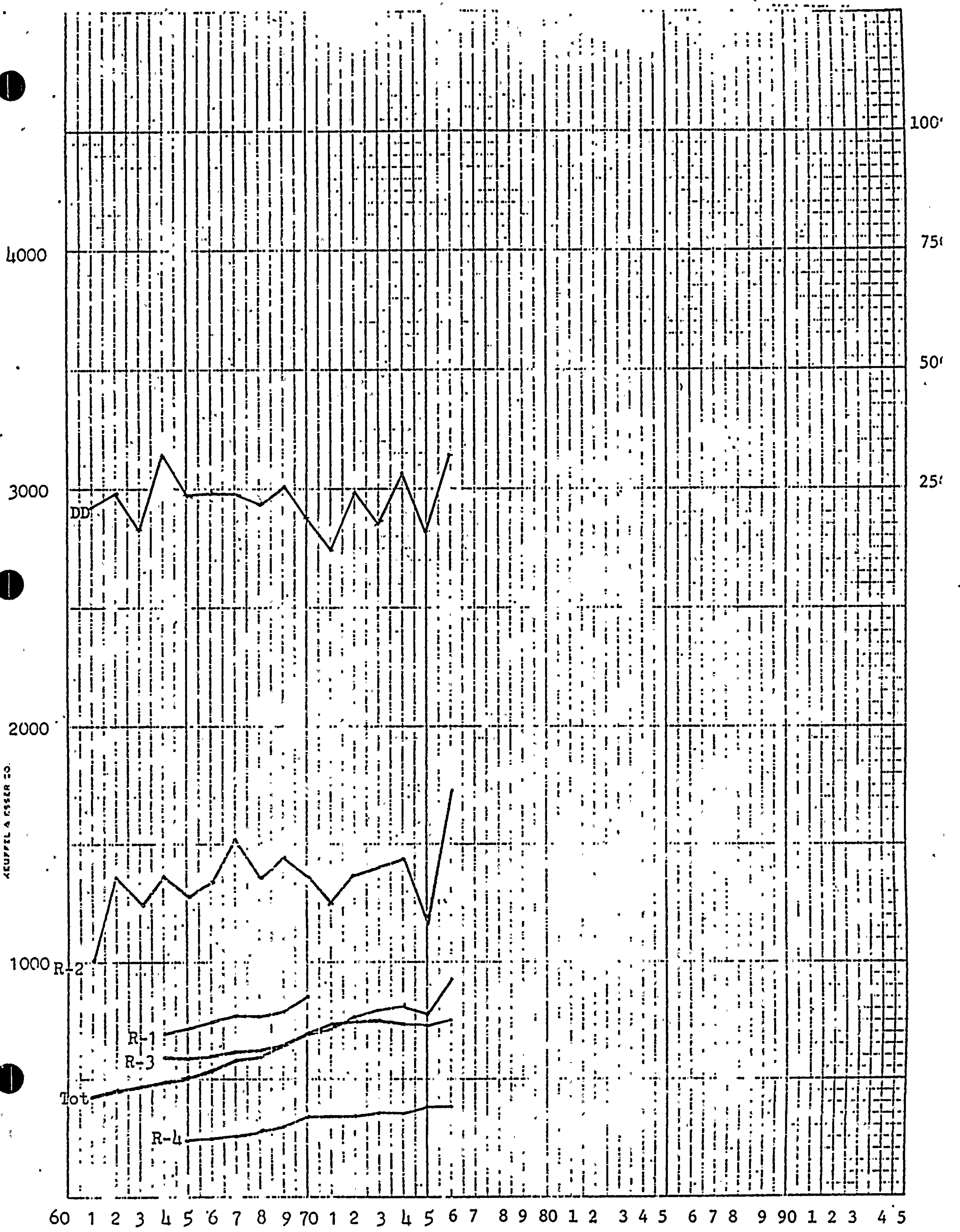
JULY
1000
750
500
250
4000
3000
2000
1000
DD
R-2
R-1
R-3
Tot
R-4
60 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5
KEUFFEL & ESSER CO.


AUGUST
4000
3000
2000
1000
100
75
50
25
DD
R-2
R-1
R-3
Tot
R-4
60 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5
KEUFFEL & ESSER CO.

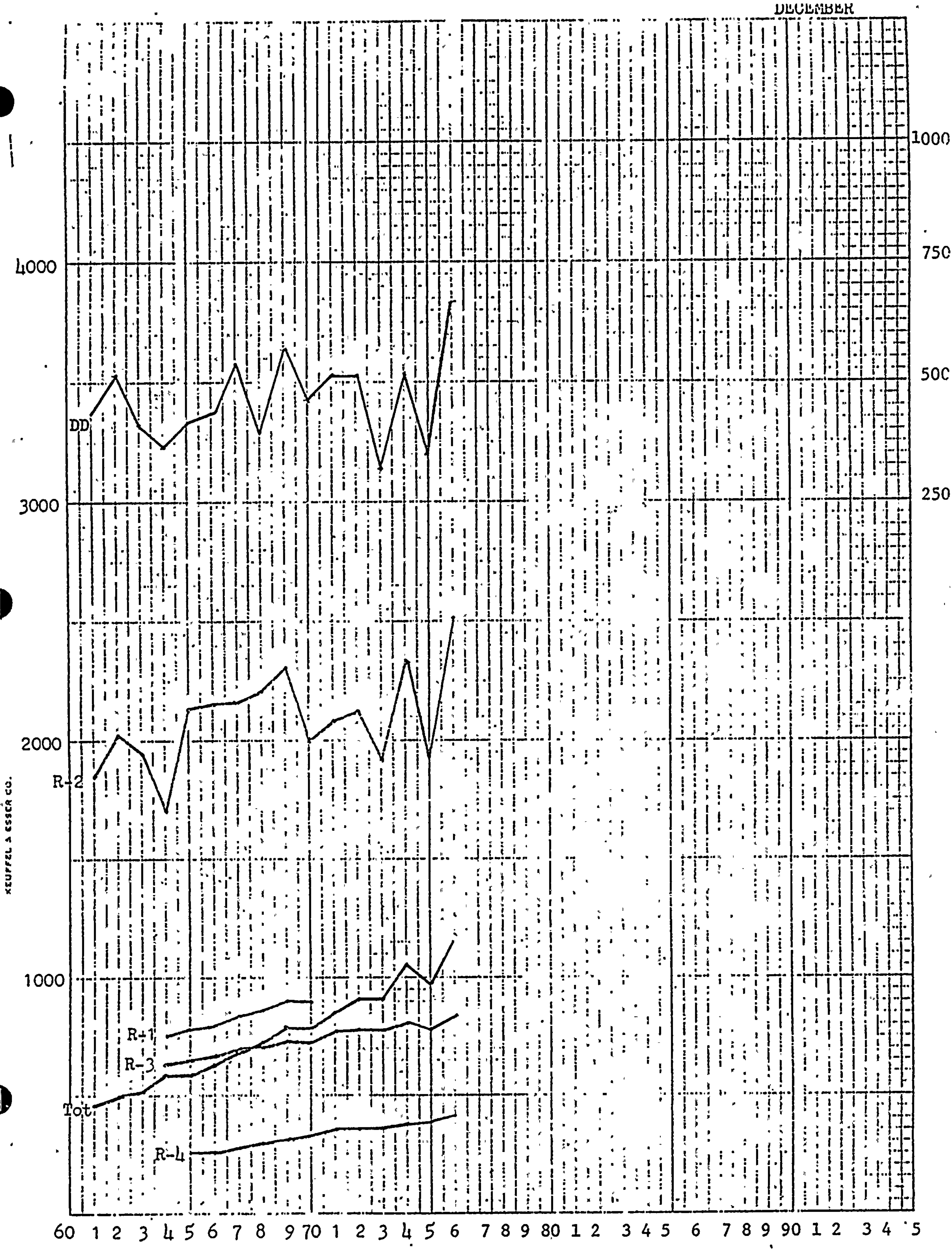

SEPTEMBER
4000
3000
2000
000
100
75
50
25
DD
R-2
R-1
R-3
Tot
R-4
60 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5
K&E 10 X 10 TO THE INCH 46 0703
7 X 10 INCHES
KEUFFEL & ESSER CO



OCTOBER
4000
3000
2000
1000
1000
750
500
250
DD
R-2
R-1
R-3
Tot
R-4
60. 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5
KEUFFEL & ESSER CO.

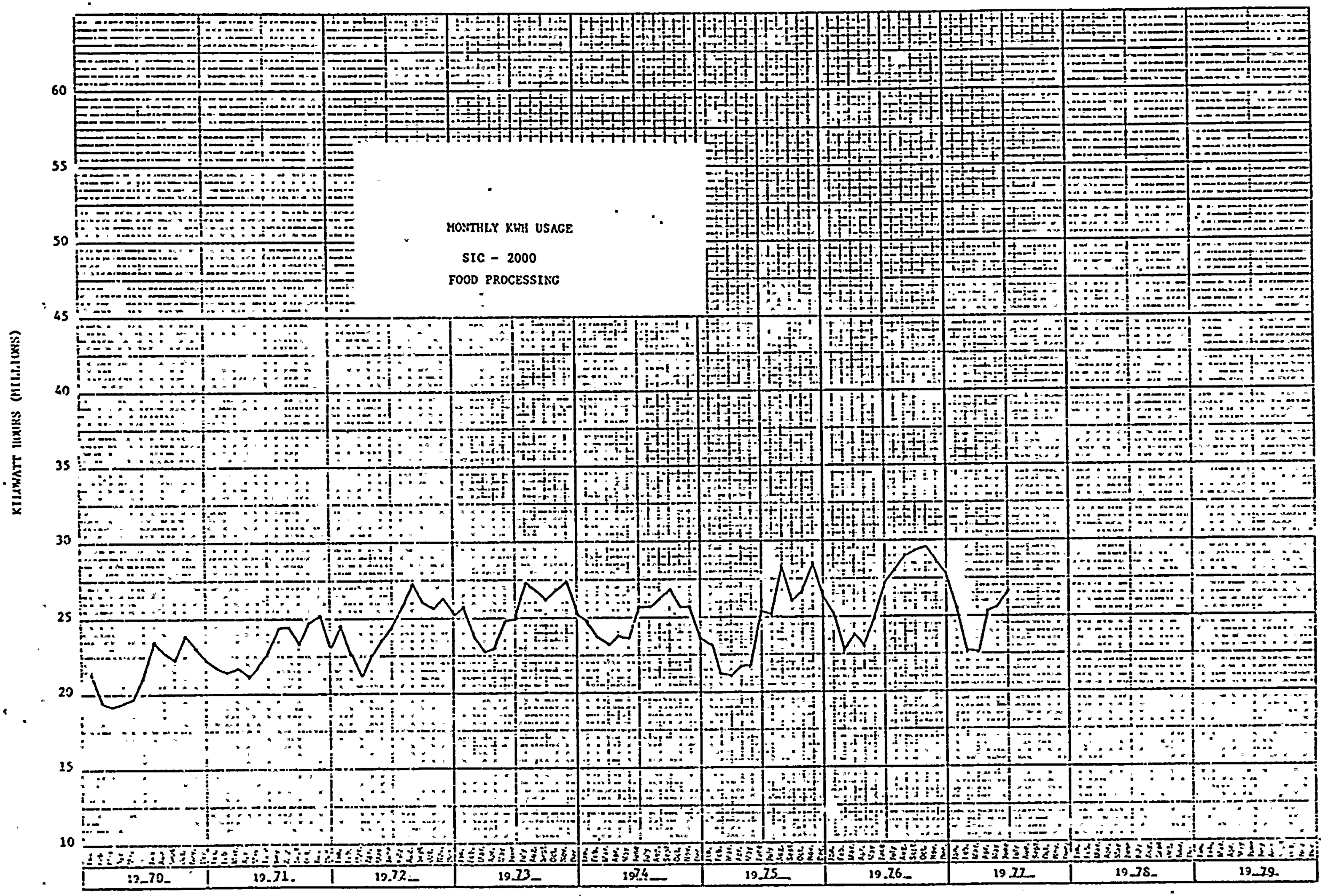


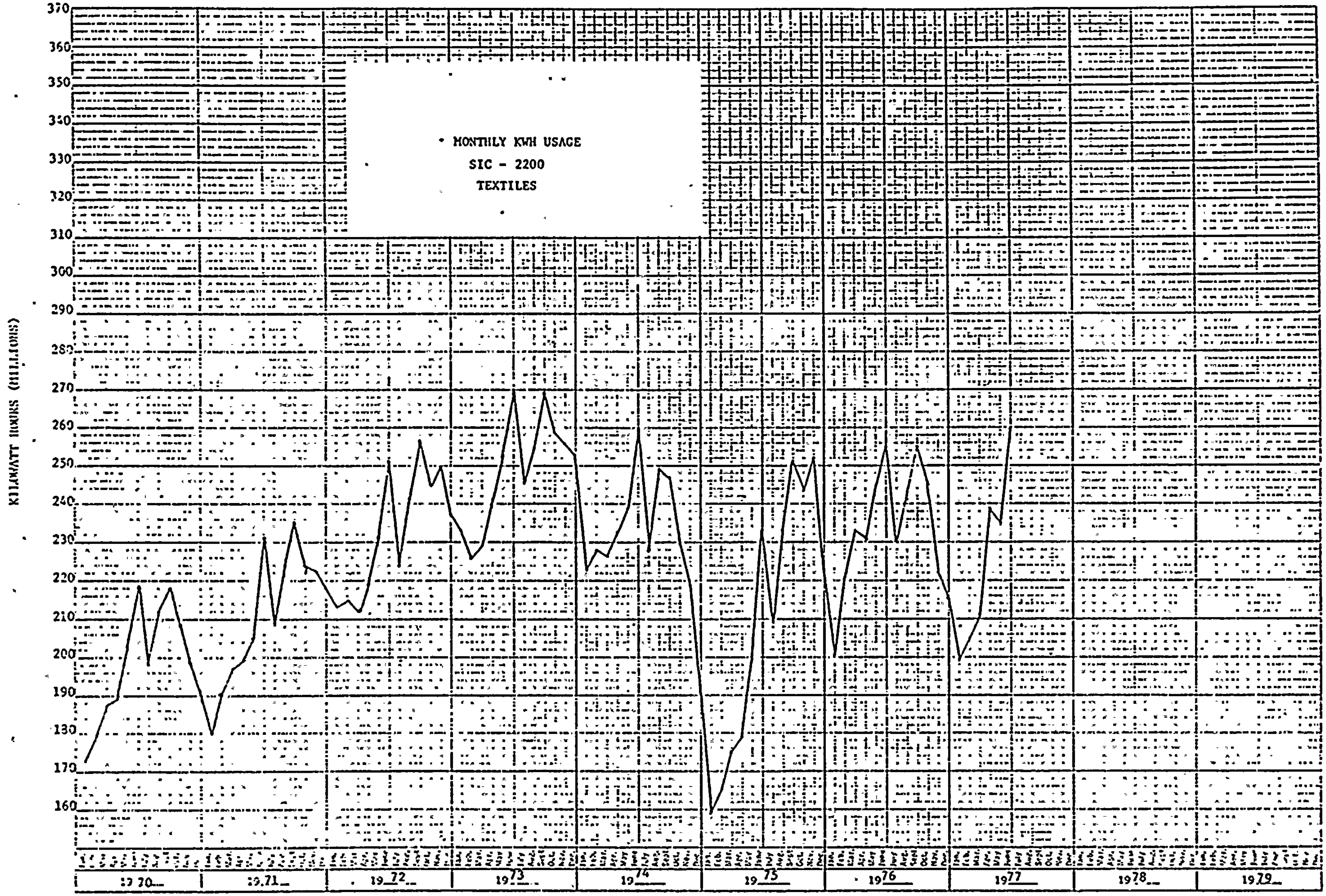
4000
3000
2000
1000
DD
R-2
R-1
R-3
Tot
R-4
100
75
50
25
60 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5

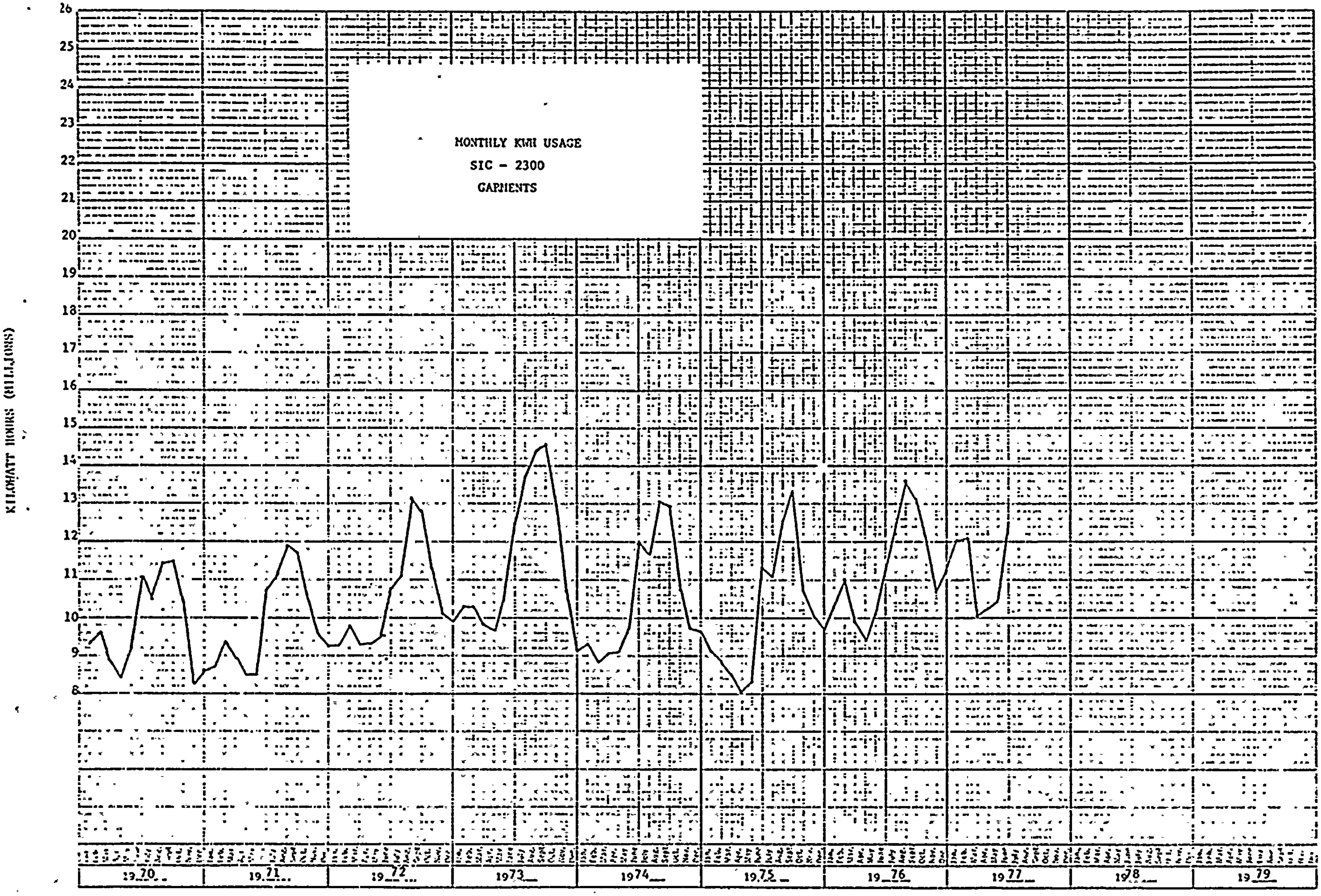


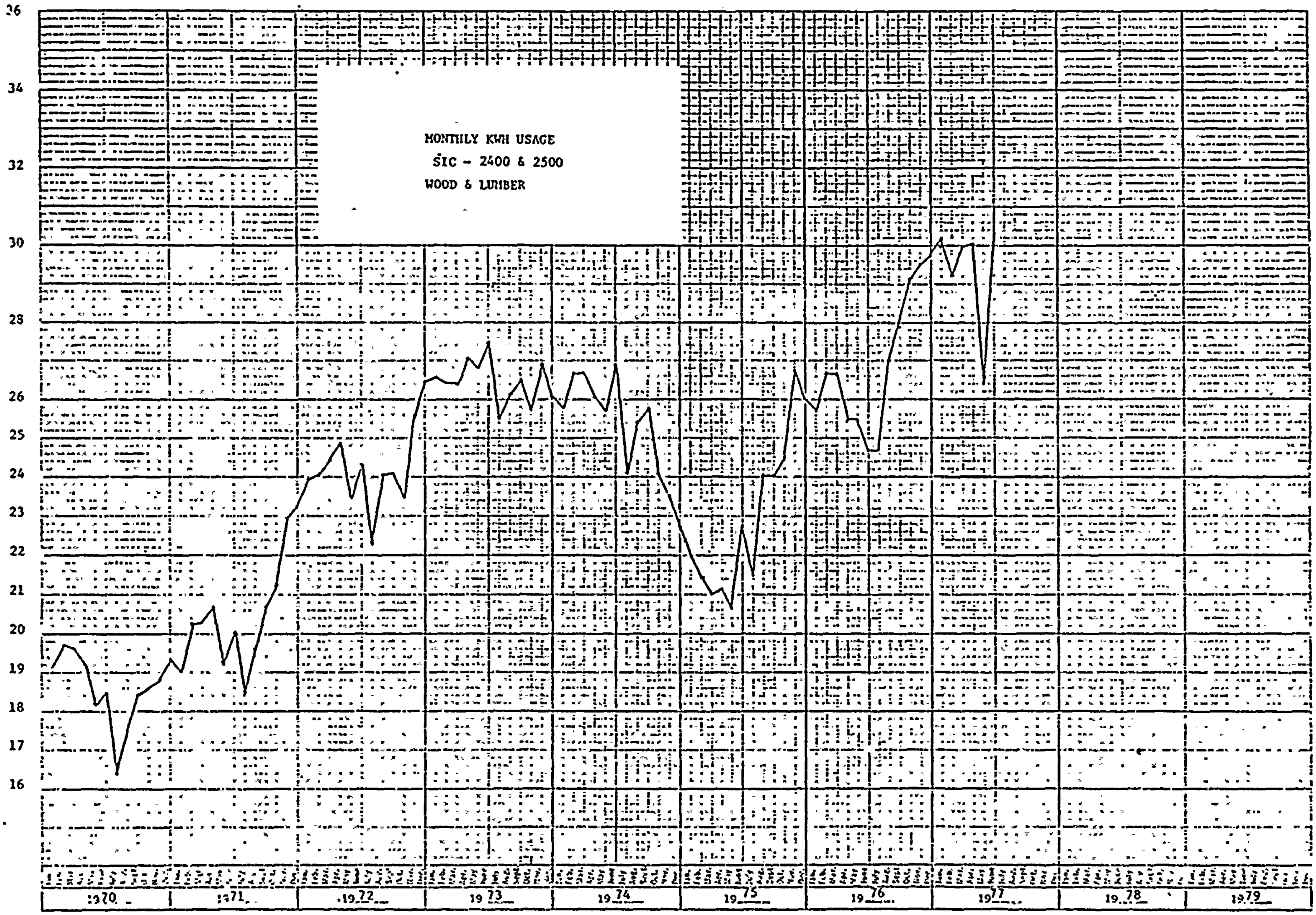
DECEMBER
4000
3000
2000
1000
1000
750
500
250
DD
R-2
R-1
R-3
Tot
R-4
60 1 2 3 4 5 6 7 8 9 70 1 2 3 4 5 6 7 8 9 80 1 2 3 4 5 6 7 8 9 90 1 2 3 4 5
KEUFFEL & ESSER CO.

EXHIBIT B

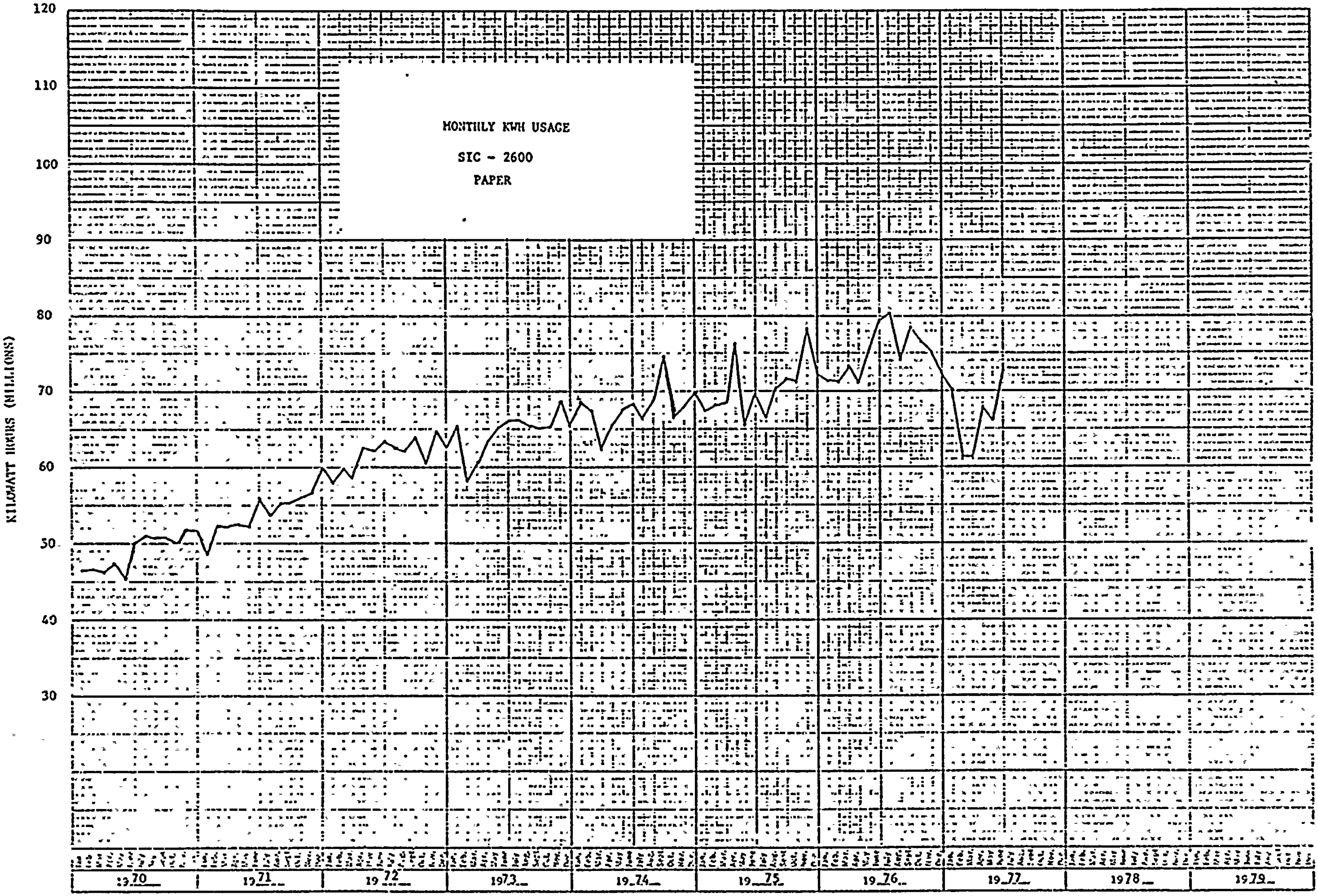

MONTHLY KWH USAGE
SIC - 2000
FOOD PROCESSING
KILOWATT HOURS (MILLIONS)
60
55
50
45
40
35
30
25
20
15
10
19 70
19 71
19 72
19 73
19 74
19 75
19 76
19 77
19 78
19 79


MONTHLY KWH USAGE
SIC - 2200
TEXTILES
KILOWATT HOURS (MILLIONS)
370
360
350
340
330
320
310
300
290
280
270
260
250
240
230
220
210
200
190
180
170
160
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979

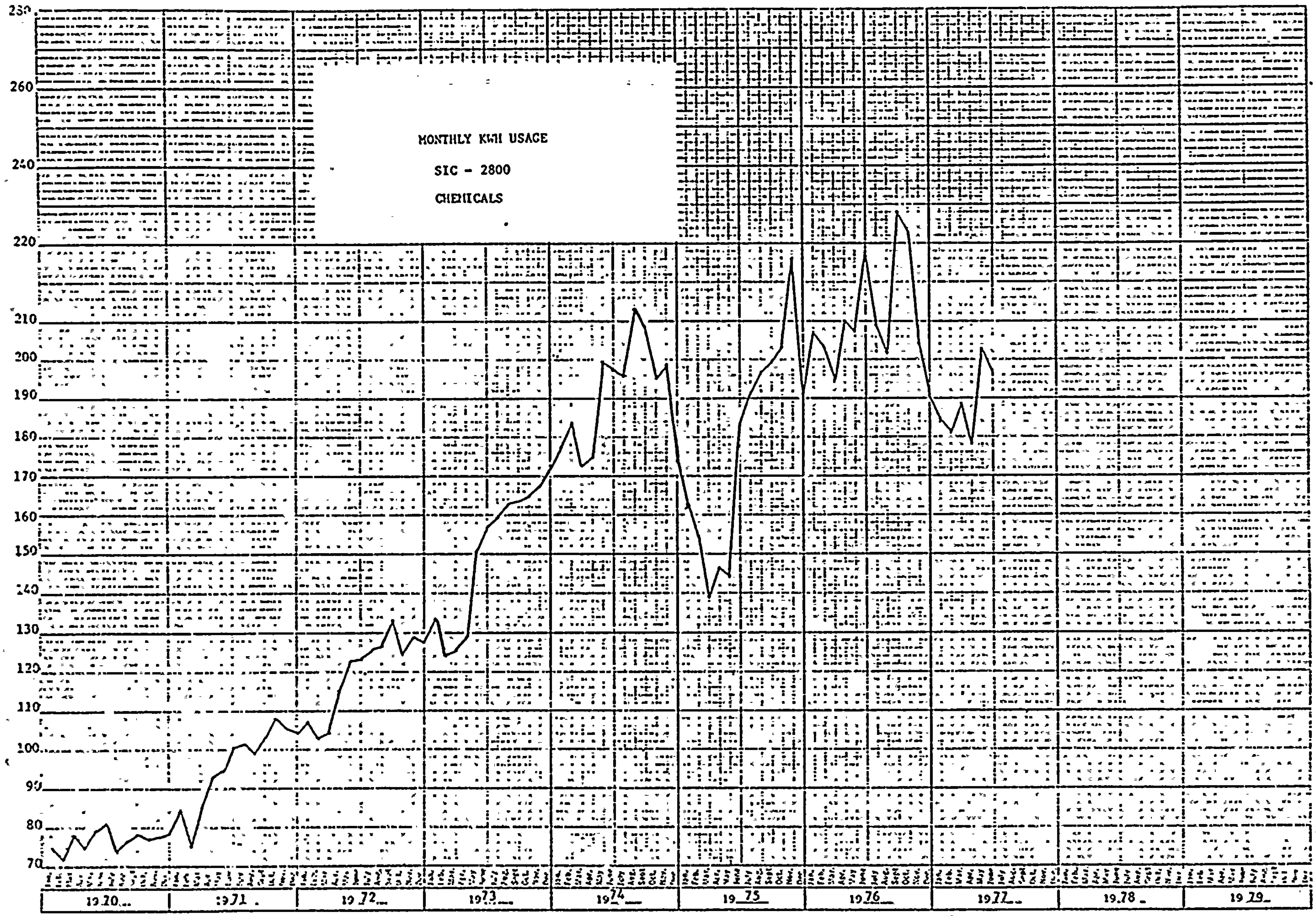

MONTHLY KWH USAGE
SIC - 2300
GARMENTS
KILOWATT HOURS (MILLIONS)
26
25
24
23
22
21
20
19
18
17
16
15
14
13
12
11
10
9
8
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979



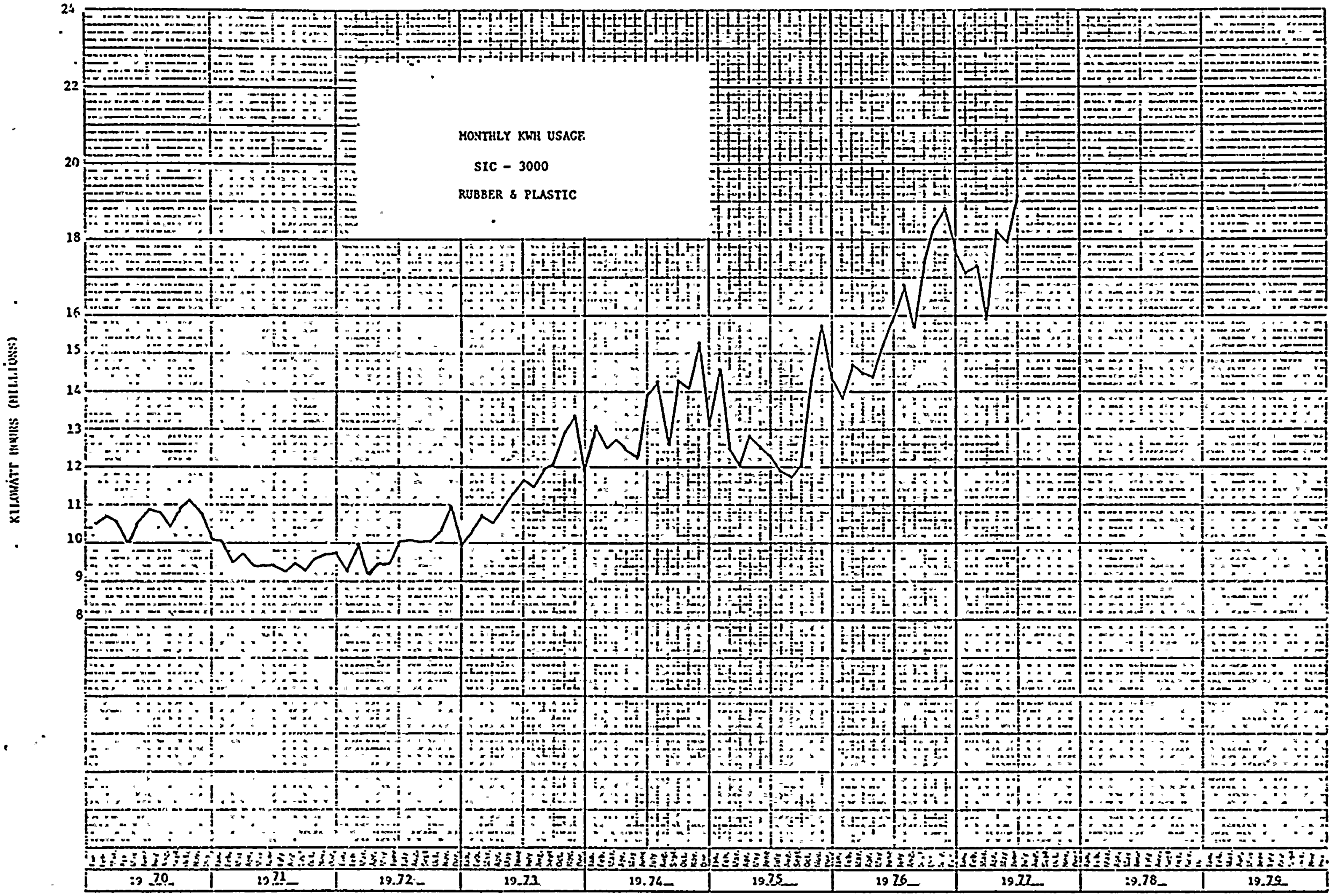
MONTHLY KWH USAGE
SIC - 2400 & 2500
WOOD & LUMBER
KILOWATT HOURS (MILLIONS)
36
34
32
30
28
26
25
24
23
22
21
20
19
18
17
16
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979

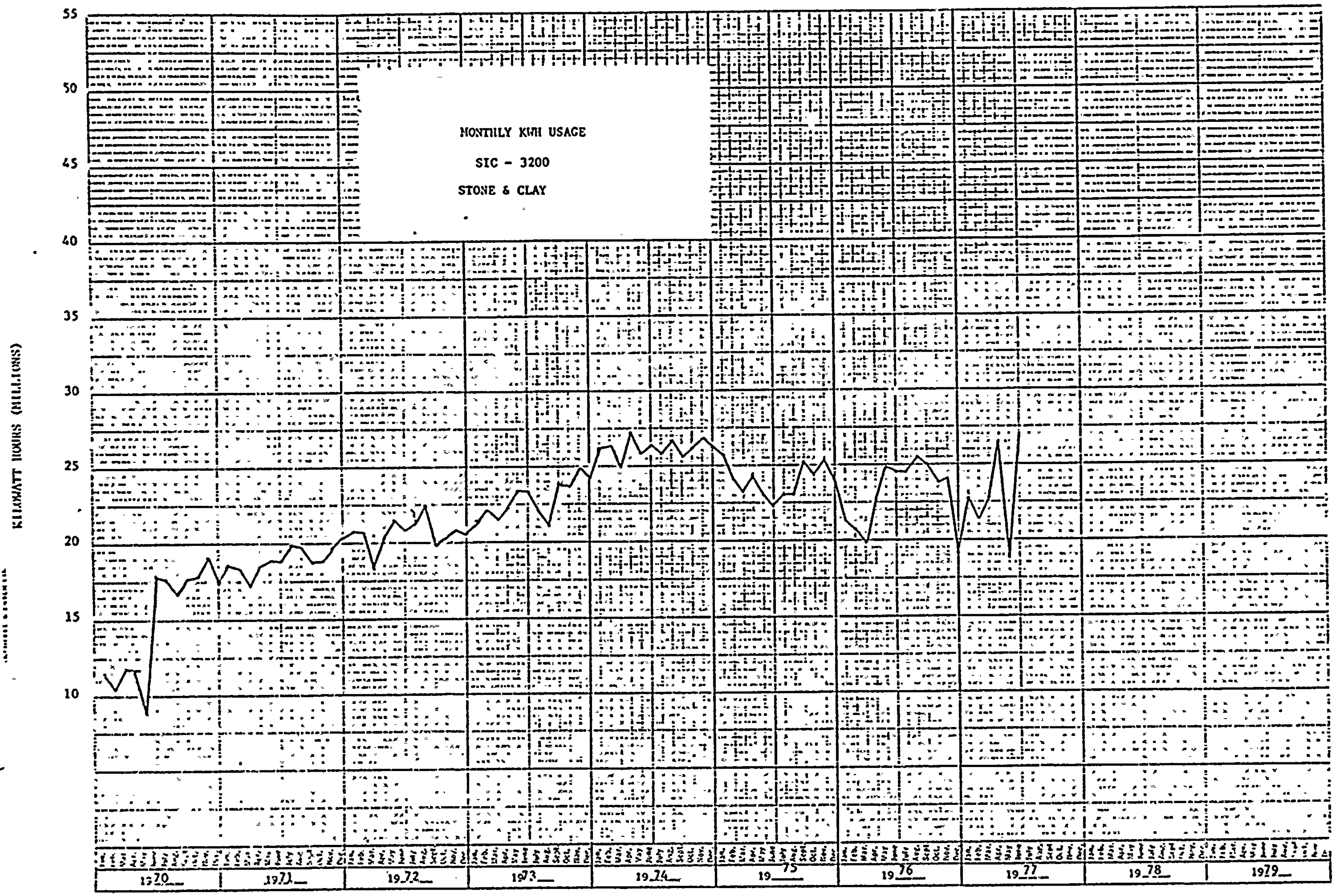


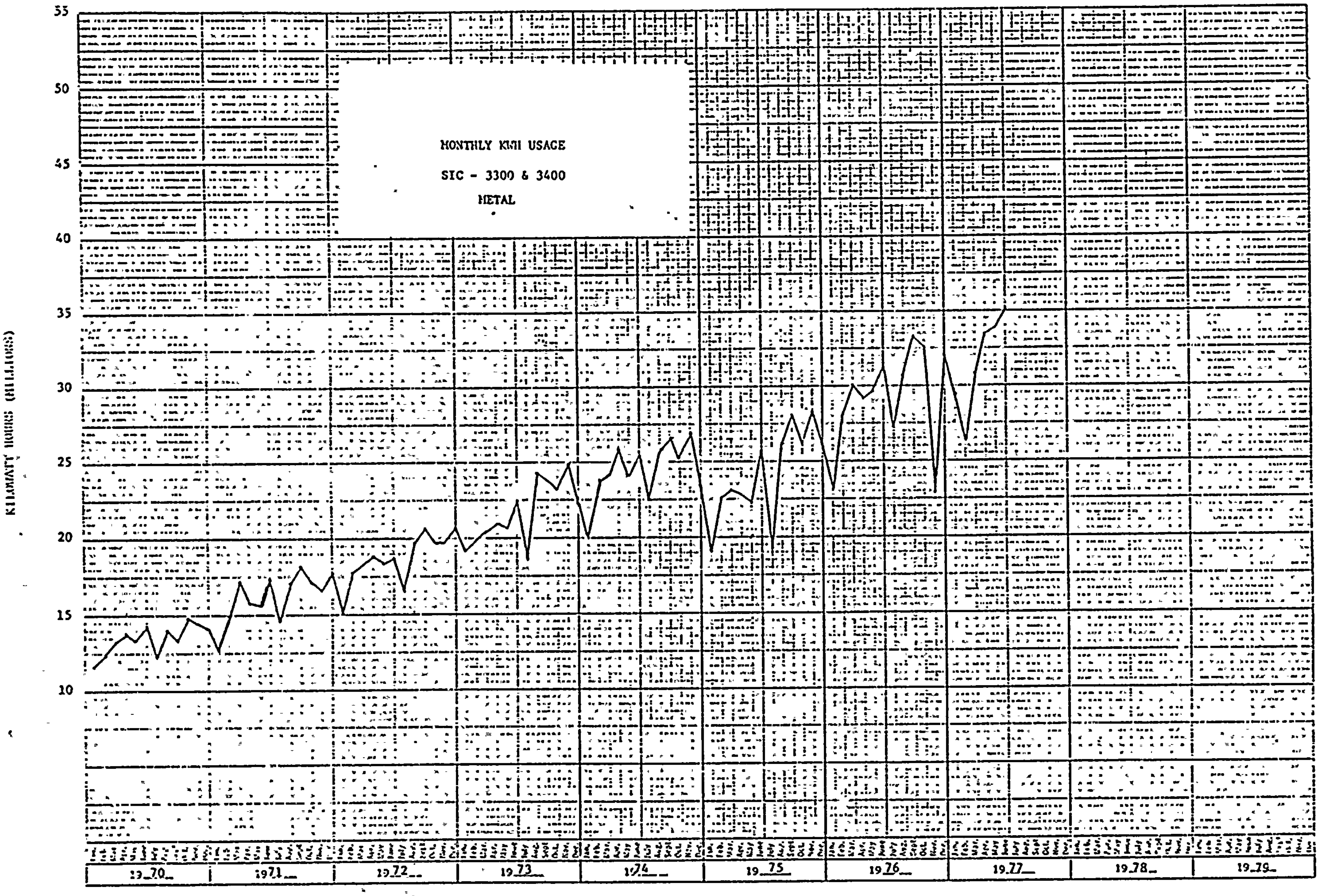
MONTHLY KWH USAGE
SIC - 2600
PAPER
KILOWATT HOURS (MILLIONS)
120
110
100
90
80
70
60
50
40
30
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979



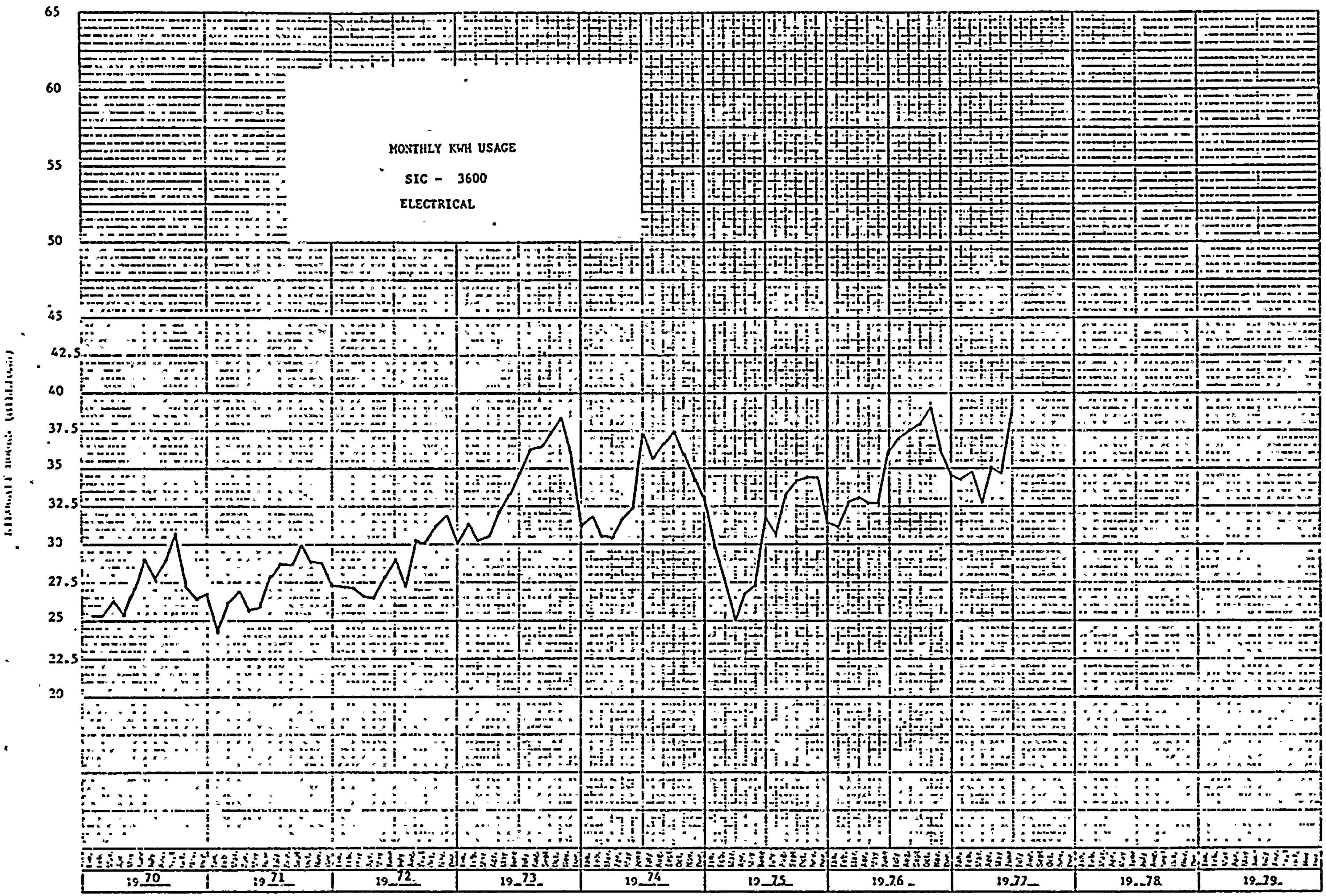
MONTHLY KWH USAGE
SIC - 2800
CHEMICALS
260
240
220
210
200
190
180
170
160
150
140
130
120
110
100
90
80
70
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979

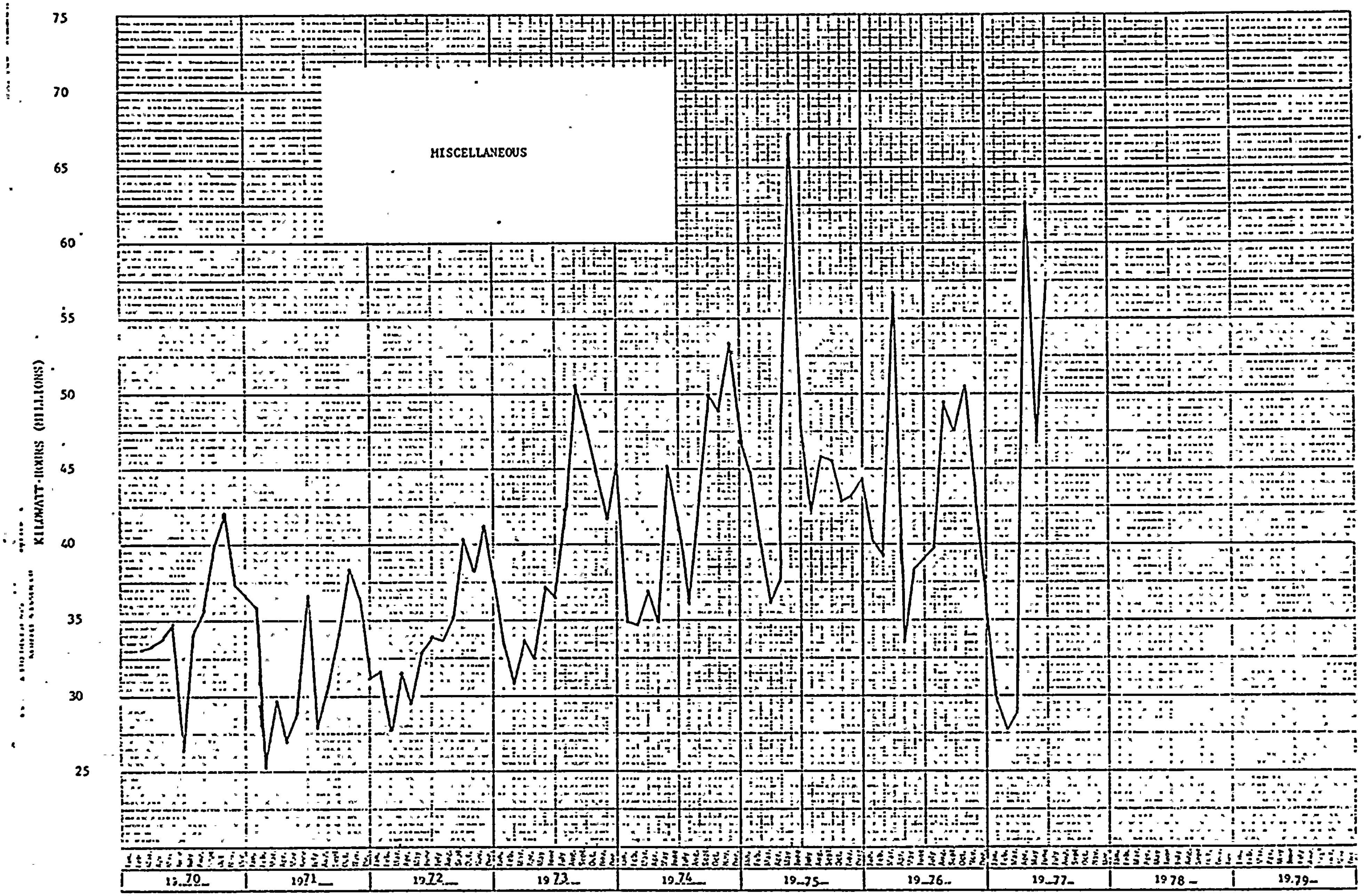

MONTHLY KWH USAGE
SIC - 3000
RUBBER & PLASTIC
KILOWATT HOURS (MILLIONS)
24
22
20
18
16
15
14
13
12
11
10
9
8
19 70
19 71
19 72
19 73
19 74
19 75
19 76
19 77
19 78
19 79

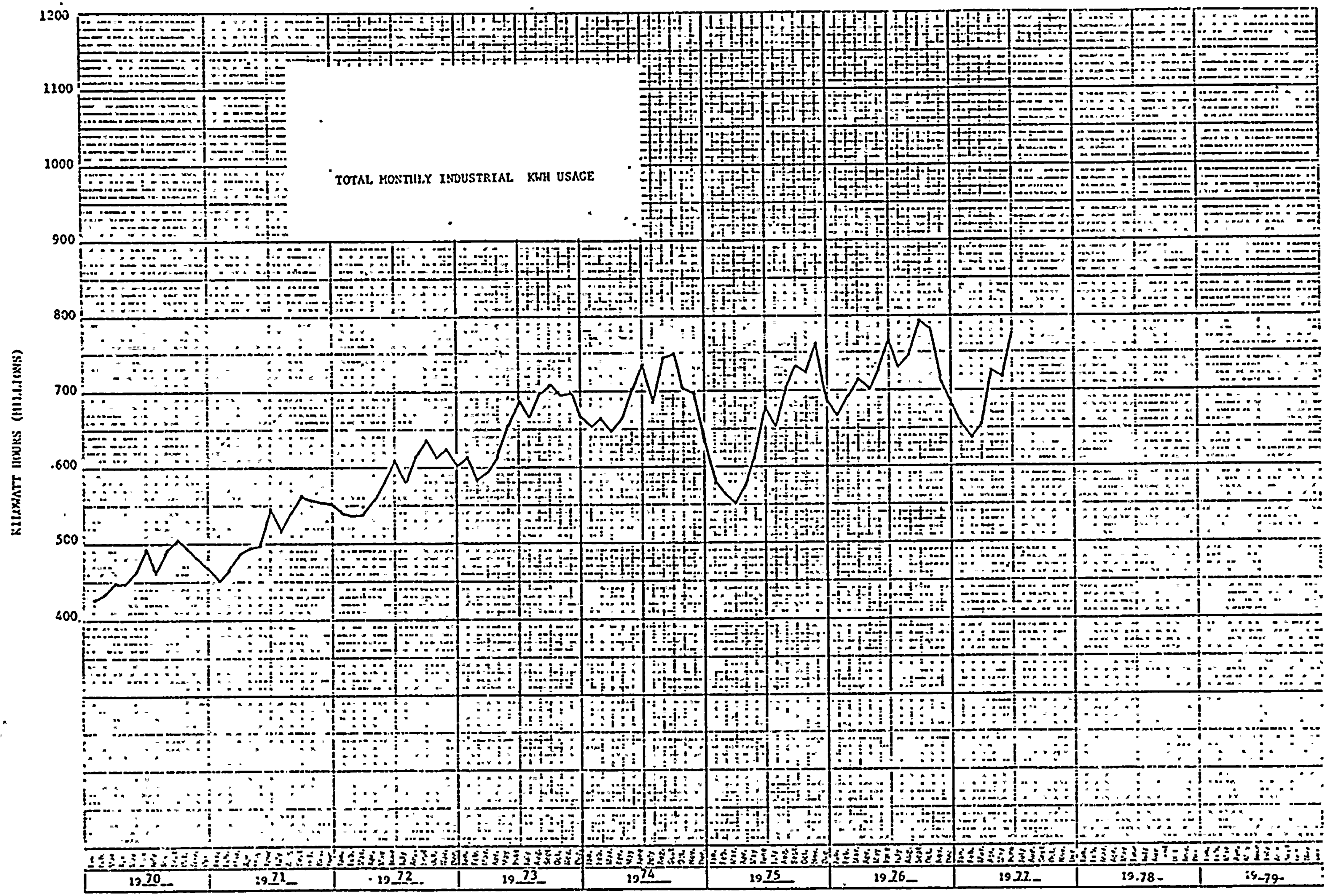

MONTHLY KWH USAGE
SIC - 3200
STONE & CLAY
KILOWATT HOURS (MILLIONS)
55
50
45
40
35
30
25
20
15
10
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979



MONTHLY KWH USAGE
SIC - 3300 & 3400
METAL
KILOWATT HOURS (MILLIONS)
55
50
45
40
35
30
25
20
15
10
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979


MONTHLY KWH USAGE
SIC - 3600
ELECTRICAL
65
60
55
50
45
42.5
40
37.5
35
32.5
30
27.5
25
22.5
20
19 70
19 71
19 72
19 73
19 74
19 75
19 76
19 77
19 78
19 79


MISCELLANEOUS
KILOWATT-HOURS (MILLIONS)
75
70
65
60
55
50
45
40
35
30
25
1970
1971
1972
1973
1974
1975
1976
1977
1978
1979



TOTAL MONTHLY INDUSTRIAL KWH USAGE
KILOWATT HOURS (MILLIONS)
1200
1100
1000
900
800
700
600
500
400
19 70
19 71
19 72
19 73
19 74
19 75
19 76
19 77
19.78
19-79

EXHIBIT C

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

As[illegible]ille District

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW					500						500
			MKWH					2,900						2,900
		PC	KW						500					
			MKWH						2,900					
			KW					500	500					500
			MKWH					2,900	2,900					2,900
		PC	KW				500					500		
			MKWH				1,500					1,500		
		PC	KW	500				500			500			500
			MKWH	1,500				1,500			1,500			1,500
		PC	KW						500					
			MKWH						3,000					
		PC	KW		500					500				
			MKWH		2,500					1,500	1,000			1,000
		PC	KW					500	500	500	500		500	
			MKWH					3,000	3,000	3,000	3,000		3,000	
			KW	500	500		500	1,000	1,000	1,000	1,000	500	500	500
			MKWH	1,500	2,500		1,500	4,500	6,000	4,500	5,500	1,500	3,000	2,500
		PC	KW			1,000					500			
			MKWH			3,500					1,500			
		PC	KW			500		500	500					500
			MKWH			1,500		3,000	2,000					3,000
			KW			1,500		500	500		500			500
			MKWH			5,000		3,000	2,000		1,500			3,000

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
Jan. 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

Asheville District

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW								500			
			MKWH								2,500			
		PC	KW		500									500
			MKWH		3,000									3,000
			KW		500						500			500
			MKWH		3,000						2,500			3,000
		NI	KW		3,500				500					
			MKWH		5,000	16,500			3,000					
		PC	KW	1,000			2,000						500	
			MKWH	5,547			10,000						2,000	
		NI	KW	1,000	1,000		2,000	2,000						
			MKWH	3,504	2,600		5,200	5,200						
		NI	KW	2,350				500						500
			MKWH	7,000	2,057			1,300						1,300
			KW	3,350	1,000		2,000	2,500						500
			MKWH	10,504	4,657		5,200	6,500						1,300
		PC	KW					500				500		
			MKWH					1,000	1,000			2,000		
		PC	KW					500					500	
			MKWH					2,000					2,000	
			KW					1,000				500	500	
			MKWH					3,000	1,000			2,000	2,000	

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
Jan. 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

Asheville District

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW						500					
			MKWH						1,500					
		PC	KW		500									500
			MKWH		1,300									1,300
			KW	4,850	6,000	1,500	4,500	5,500	3,000	1,000	2,000	1,000	1,500	3,000
			MKWH	17,551	16,457	21,500	16,700	19,900	16,400	4,500	9,500	3,500	7,000	14,000

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
Jan. 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

WILMINGT DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW		1,000								500	
			MKWH		1,200								2,000	
		PC	KW					500					500	
			MKWH					3,000					3,000	
		PC	KW				1,000					1,000		
			MKWH				6,000					6,000		
			KW				1,000	500				1,000	500	
			MKWH				6,000	3,000				6,000	3,000	
		NI	KW			500								
			MKWH			1,500								
		PC	KW		1,500		1,500							
			MKWH		4,000	4,000	8,000							
			KW		1,500	500	1,500							
			MKWH		4,000	5,500	8,000							
		PC	KW	3,000	(20,000)			2,000						2,000
			MKWH	20,000	(104,000)			15,000						15,000
		NI	KW	10,000		20,000	10,000		20,000	10,000				
			MKWH	100,000	50,000	60,000	100,000	50,000	60,000	100,000	50,000			
		PC	KW		2,500									
			MKWH		20,000									
		PC	KW			3,000			1,000	1,000				
			MKWH			10,000	10,000		3,000	10,000	2,000			
		PC	KW	6,000	2,000	1,000	22,000	5,000	2,000			2,000		2,000
			MKWH	48,000	16,000	8,000	80,000	120,000	16,000			16,000		16,000
		PC	KW		6,000		5,000	2,000		1,500				2,000
			MKWH		4,500	35,000	39,000	14,000		8,500				9,000

*NI NEW INDUSTRY PC PRESENT CUSTOMER
JAN. 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

WILMINGTON D[illegible]ICT

[illegible]TOMER [illegible]ATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW	2,000	3[illegible],000			15,000		3,000		2,000		
			MKWH	15,000	23[illegible],000		60,000	55,000	60,000	23,000		15,000		
		NI	KW		3[illegible],000								500	
			MKWH	50,000	5[illegible],000	20,000							3,000	
			KW	18,000	16[illegible],500	24,000	37,000	22,000	23,000	15,500		4,000	500	4,000
			MKWH	213,000	118[illegible],500	133,000	289,000	239,000	139,000	141,500	52,000	31,000	3,000	25,000
		PC	KW		1[illegible],000							500		
			MKWH		2[illegible],500							2,500		
		PC	KW	1,500	3[illegible],000	3,000							500	500
			MKWH	14,000	14[illegible],000	20,000	10,000						3,000	3,000
			KW	22,500	3[illegible],000	27,500	39,500	24,500	23,000	15,500		5,500	2,000	6,500
			MKWH	247,000	36[illegible],200	158,500	313,000	257,000	139,000	141,500	52,000	39,500	11,000	43,000

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JAN. 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

FLORENCE [illegible]STRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW										500	
			MKWH										2,500	
		PC	KW						2,000			5,000		
			MKWH						8,000			25,000		
		PC	KW					500						
			MKWH					3,000						
		PC	KW					500						500
			MKWH					2,000						2,000
		PC	KW							500				
			MKWH							2,000				
		PC	KW				500						500	
			MKWH				2,500						2,500	
		PC	KW							500				
			MKWH							2,000				
			KW				500	1,000	2,000	1,000		5,000	500	500
			MKWH				2,500	5,000	8,000	4,000		25,000	2,000	2,000
		NI	KW						500					
			MKWH	6,000					1,000					
		PC	KW	(4,000)**			5,000					5,000		
			MKWH	(30,000)**			16,000	16,000				16,000	16,000	

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

** DEFICIT DUE TO INSTALLATION OF ADDITIONAL ON-SITE GENERATION BY CUSTOMER.

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

FLORENCE I RICT

USTOMER OCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW								2,000			
			MKWH								10,000			
		PC	KW					500						500
			MKWH					3,000						3,000
			KW					500			2,000			500
			MKWH					3,000			10,000			3,000
		NI	KW	6,900										
			MKWH	34,453										
		NI	KW				1,000			2,000				
			MKWH				2,000			4,000				
			KW	6,900			1,000			2,000				
			MKWH	34,453			2,000			4,000				
		PC	KW		3,000	10,000	12,000				2,000			
			MKWH		13,400	65,000	78,000				10,000			10,000
		PC	KW	500				1,000				1,000		
			MKWH	2,190				3,000				3,000		
		PC	KW					500						500
			MKWH					1,000						1,000
		PC	KW	800							500			
			MKWH	3,500							3,000			
			KW	1,300				1,500			500	1,000		500
			MKWH	5,690				4,000			3,000	3,000		1,000

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

FLORENCE [illegible]RICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW				500						500	
			MKWH				2,000						2,000	
		PC	KW		2,000			1,000						500
			MKWH		12,000			5,000						2,500
			KW		2,000		500	1,000					500	500
			MKWH		12,000		2,000	5,000					2,000	2,500
			KW	4,200	5,000	10,000	19,000	4,000	2,500	3,000	4,500	11,000	1,500	2,000
			MKWH	16,143	25,400	65,000	100,000	33,000	9,000	8,000	23,000	44,000	22,500	18,500

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

Jacksonvil District

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW			1,000							500	
			MKWH			2,000							2,000	
		PC	KW				1,000					1,000		
			MKWH				4,000					4,000		
		PC	KW					2,500					500	
			MKWH					10,000					3,000	
		PC	KW			2,000				1,000	1,000			
			MKWH			2,000				7,000	7,000			
		PC	KW	2,000	3,000					10,000				
			MKWH	17,000	17,000					80,000				17,000
		PC	KW				5,000							
			MKWH				30,000	10,000						
		NI	KW				10,000		5,000			10,000		
			MKWH				72,000		35,000			70,000		
		PC	KW	10,000		18,000			5,000		1,500			1,500
			MKWH	70,000		130,000			30,000		9,000			9,000
		NI	KW			25,000			12,000					
			MKWH			100,000			60,000					
			KW	12,000	3,000	43,000	15,000		22,000	10,000	1,500	10,000		1,500
			MKWH	87,000	17,000	230,000	102,000	10,000	125,000	80,000	9,000	70,000		26,000
		NI	KW							7,500				
			MKWH							40,000				

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
Jan. 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

Jacksonvi District

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		NI	KW		2,000				2,000					
			MKWH		10,000				10,000					
			KW	12,000	5,000	46,000	16,000	2,500	24,000	11,000	2,500	11,000	1,000	1,500
			MKWH	87,000	27,000	234,000	106,000	20,000	175,000	87,000	16,000	74,000	5,000	26,000

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JAN. 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SUMTER DISTRICT

STOMER CATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		NI	KW	500									500	
			MKWH	600	760								2,000	
		PC	KW		500		500			500				500
			MKWH		3,000		3,000			3,000				3,000
		NI	KW	500	1,000									
			MKWH	1,500	2,000	1,200								
		PC	KW		600								500	
			MKWH		3,000								2,500	
			KW	500	2,100		500			500			500	500
			MKWH	1,500	8,000	1,200	3,000			3,000			2,500	3,000
		PC	KW		600						600			
			MKWH		3,000						3,000			
		NI	KW		500			500						500
			MKWH		2,000			2,500						2,000
		NI	KW		700				500			500		
			MKWH		2,500				2,000			2,000		
		NI	KW			500					500			
			MKWH			2,000					2,000			
		PC	KW			500					500			
			MKWH			2,000					2,000			
		PC	KW			500			500					500
			MKWH	2,200		2,300			2,000					2,000
		PC	KW	800			500							
			MKWH	4,500	500		2,500							500

NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SUMTER DISTRICT

STOMER CATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW		500				500					
			MKWH		1,500				3,500					
		PC	KW	500	1,000	200							500	
			MKWH	2,500	4,500	2,000	1,500						2,000	
		PC	KW	500									500	
			MKWH	1,000	1,500								2,000	
		PC	KW	500				500						
			MKWH	1,500	1,000			3,000						
		PC	KW						500					
			MKWH	1,000	1,000				2,500					1,000
		PC	KW		500							500		
			MKWH		3,000							3,000		
		PC	KW				500				500			
			MKWH				2,500				2,500			
		PC	KW	500			500							
			MKWH	1,500	1,000		2,000							1,000
			KW	2,800	3,800	1,700	1,500	1,000	2,000		2,100	1,000	1,000	1,000
			MKWH	14,200	21,500	8,300	8,500	5,500	10,000		9,500	5,000	4,000	6,500
		PC	KW		500			500			1,000			
			MKWH	300	1,000			2,000			3,000			
		PC	KW	500				500						
			MKWH	400	1,200			2,000						1,200
			KW	500	500			1,000			1,000			
			MKWH	700	2,200			4,000			3,000			1,200

NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

Sumter District

STOMER CATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW		500	1,000	500		500		500			
			MKWH		5,000	3,000	2,000		2,500		3,000			
		PC	KW			1,000			1,000			1,000		
			MKWH			7,000			7,000			7,000		3,000
		PC	KW	3,000	5,000	7,000	1,000	4,000	5,000	4,000	1,000	2,000	1,000	
			MKWH	7,000	37,000	52,000	37,500	30,000	37,000	30,000	7,500	15,000	7,500	
		PC	KW				1,000			500				500
			MKWH				6,000			3,000				2,000
			KW	3,000	5,000	8,000	2,000	4,000	6,000	4,500	1,000	3,000	1,000	500
			MKWH	7,000	37,000	59,000	43,500	30,000	44,000	33,000	7,500	22,000	7,500	5,000
		PC	KW			500					500			
			MKWH			2,500					2,500			
		NI	KW		500			500				500		
			MKWH		3,500			2,000				2,000		
			KW		500	500		500			500	500		
			MKWH		3,500	2,500		2,000			2,500	2,000		
		PC	KW	500		1,000			500					500
			MKWH	1,000	2,000	2,000	4,000		2,500					2,500
		PC	KW					500						500
			MKWH					2,500						2,500
		NI	KW										500	
			MKWH	1,000									2,000	
		NI	KW	2,000	1,600							1,000		
			MKWH	20,000	11,000	3,000						5,000		

NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SUMTER DISTRICT

TOMER ATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		NI	KW				500					500		
			MKWH	900			2,500					2,500		
			KW	2,000	1,600		500	500				1,500	500	500
			MKWH	21,900	11,000	3,000	2,500	2,500				7,500	2,000	2,500
		PC	KW					500					500	
			MKWH	3,000				2,000					2,000	
		PC	KW		500								500	
			MKWH		800								2,000	
		PC	KW	1,500			500					500		
			MKWH	4,000	5,000		2,000					2,000		
			KW	1,500	500		500					500	500	
			MKWH	4,000	5,800		2,000					2,000	2,000	
			KW	11,300	14,500	12,200	5,500	7,500	9,000	4,500	5,100	6,500	4,500	3,000
			MKWH	53,700	96,760	79,000	65,500	46,000	59,000	36,000	25,500	38,500	22,000	20,700

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SANFORD D[illegible]ICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW			500					500			
			MKWH			2,500					2,500			
		PC	KW		500			500					500	
			MKWH		2,500			3,600					3,600	
		PC	KW						500					500
			MKWH						3,600					3,600
		PC	KW		500					500				
			MKWH		3,600					3,600				
		PC	KW			500				500				
			MKWH			3,600				3,600				
		PC	KW			500				500				
			MKWH			2,000				2,000				
		PC	KW			500						500		
			MKWH			2,500						2,500		
		PC	KW				500				500			
			MKWH				2,000				2,000			
		PC	KW		500					500				
			MKWH		1,800					1,800				
		PC	KW						500				500	
			MKWH						2,500				2,500	
		PC	KW					500						500
			MKWH					2,400						2,400

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SANFORD I RICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW			500			500				500	
			MKWH		1,000	1,000	1,000		1,000	1,000			2,000	
		PC	KW	500								500		
			MKWH	2,000	1,000							3,000		
		PC	KW				500				500			
			MKWH				2,500				2,500			
		PC	KW				500					500		
			MKWH				2,500					2,000		
		PC	KW			500								500
			MKWH			2,000								3,000
		PC	KW		500					500				
			MKWH		3,000					3,000				
		PC	KW		500				500					
			MKWH		3,000				3,000					
			KW	500	2,500	3,000	1,500	1,000	2,000	2,500	1,500	1,500	1,500	1,500
			MKWH	2,000	15,900	13,600	8,000	6,000	10,100	15,000	7,000	7,500	8,100	9,000
		NI	KW			2,000	2,000						1,000	
			MKWH			1,000	2,500						2,900	
		NI	KW			5,000						2,000		
			MKWH			1,000	7,500					3,500		
			KW			7,000	2,000					2,000	1,000	
			MKWH			2,000	10,000					3,500	2,900	

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SANFORD DI ICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		NI	KW					500						500
			MKWH					2,500						2,500
		PC	KW	500		500					500			
			MKWH	1,500	1,000	1,500	1,000				1,500			
			KW	500		500		500			500			500
			MKWH	1,500	1,000	1,500	1,000	2,500			1,500			2,500
		PC	KW		500	500			1,000					
			MKWH		2,500	2,500			2,500	2,500				
		PC	KW		500				500				500	
			MKWH		1,500				1,500				1,500	
			KW		1,000	500			1,500				500	
			MKWH		4,000	2,500			4,000	2,500			1,500	
		PC	KW	2,300		9,000	1,000	1,000	1,000	4,000	1,000	1,000	500	
			MKWH	22,400	5,000	45,000	30,000	3,000	6,000	15,000	15,000	7,500	3,500	4,000
		NI	KW		1,000		1,000		2,000		1,500			
			MKWH		3,000	5,000	3,000	4,000	5,000	7,000	5,000	6,000		
		PC	KW						500				500	
			MKWH						2,000				2,000	
		PC	KW		500					500				500
			MKWH		4,200					4,200				4,200
		PC	KW	4,825	10,000	9,250	5,600	9,250	5,600	5,000	1,000	2,000	1,000	1,000
			MKWH	30,000	40,000	80,000	44,000	73,000	44,000	30,000	20,000	15,000	7,000	7,000
			KW	7,125	11,500	18,250	7,600	10,250	9,100	9,500	3,500	3,000	2,000	1,500
			MKWH	52,400	52,200	130,000	77,000	80,000	57,000	56,200	40,000	28,500	12,500	15,200

NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SANFORD DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
			KW			500					500			
			MKWH			1,000	1,000				1,000	1,000		
			KW	500			500			500				
			MKWH	1,000	1,000		1,000	1,000		1,000	1,000			1,000
			KW	500		500	500			500	500			
			MKWH	1,000	1,000	1,000	2,000	1,000		1,000	2,000	1,000		1,000
			KW				500					500		
			MKWH				1,000	1,000				1,000		
			KW				500				500			
			MKWH				2,000				2,000			
			KW			500			1,000				500	
			MKWH			2,000			2,000	2,000			1,000	
			KW			500	500		1,000		500		500	
			MKWH			2,000	2,000		2,000	2,000	2,000		1,000	
			KW	3,000	4,500	2,000		2,000			2,000		2,000	
			MKWH	4,500	12,000	9,000	3,000	3,000	3,000		3,000	3,000	3,000	
			KW				500				500		500	
			MKWH				1,000	2,000			1,000	2,000	1,500	
			KW	4,900		500			500			500		
			MKWH	13,000	13,000	1,000	1,000		1,000	1,000		1,000		1,000
			KW	500	1,000		500				500		500	
			MKWH	1,000	2,000		1,000	1,000			1.000		1.000	
			KW	500	500			500				500		
			MKWH	2,500	2,500			1,000	1,500			1,500	1,000	
			KW	5,900	1,500	500	1,000	500	500		1,000	1,000	1,000	
			MKWH	16,500	17,500	1,000	3,000	4,000	2,500	1,000	2,000	4,500	3,500	1,000

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SANFORD 'TRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW				1,000					1,000		
			MKWH				2,500					2,500		
			KW	17,525	21,000	32,750	14,600	14,250	14,100	12,500	9,500	9,000	8,500	3,500
			MKWH	77,900	103,600	162,600	109,500	97,500	78,600	77,700	57,500	51,500	32,500	28,700

KNOWN GOOD [illegible]

SOUTHERN PINES DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW										500	
			MKWH										2,500	
		PC	KW						500					
			MKWH						2,500					
		PC	KW					500						500
			MKWH					2,500						2,500
			KW					500	500					500
			MKWH					2,500	2,500					2,500
		PC	KW							500				
			MKWH							3,000				
		PC	KW				500							500
			MKWH				3,000							3,000
		PC	KW								500			
			MKWH								3,000			
		PC	KW				500				500			
			MKWH				3,000				3,000			
		PC	KW											500
			MKWH											3,000
		PC	KW					500						
			MKWH					3,000						
		PC	KW				1,000						500	
			MKWH				6,000						3,000	
		PC	KW	500	500		500							500
			MKWH	3,000	3,000		3,000							2,500

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SOUTHERN PINES DISTRICT

STOMER CATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW			500								
			MKWH			3,000								
		PC	KW					500						
			MKWH					3,000						
		PC	KW			500						500		
			MKWH			3,000						3,000		
		PC	KW				500							500
			MKWH				3,000							3,000
		PC	KW			500								
						2,000								
		PC	KW			500								
			MKWH			2,000								
		PC	KW		500									
			MKWH		3,000									
		PC	KW								500			
			MKWH								2,500			
		PC	KW			500								
			MKWH			2,500								
		PC	KW		500		500							
			MKWH		3,000		3,000							
		PC	KW					500						
			MKWH					2,500						

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SOUTHERN PINES DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW			500								
			MKWH			2,500								
		PC	KW				500							
			MKWH				2,500							
		PC	KW			500					500			
			MKWH			3,000					3,000			
		PC	KW		500				500					500
			MKWH		3,000				3,000					3,000
		PC	KW				500							
			MKWH				2,500							
		PC	KW						500					
			MKWH						3,000					
		PC	KW					500						
			MKWH					3,000						
		PC	KW				500							500
			MKWH				3,000							3,000
		PC	KW						500					
			MKWH						3,000					
		PC	KW			500								
			MKWH			2,500								
		PC	KW	500				500						
			MKWH	2,500				2,500						
		PC	KW	500					1,500					
			MKWH	5,000					9,500					

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SOUTHERN PINES DISTRICT

USTOMER OCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW					500						
			MKWH					3,000						
		NI	KW	500	500			1,000						1,000
			MKWH	3,000	3,000			6,000						6,000
		PC	KW	1,000					500					
			MKWH	7,000					3,000					
		PC	KW							500				
			MKWH							3,000				
		PC	KW				500							
			MKWH				3,000							
			KW	3,000	2,500	4,000	5,000	4,500	3,500	1,000	2,000		1,000	4,000
			MKWH	20,500	15,000	20,500	29,000	26,000	21,500	6,000	11,500		6,000	23,500
		PC	KW					600						
			MKWH					3,500						
		PC	KW		500								500	
			MKWH		2,000								2,000	
			KW		500			600					500	
			MKWH		2,000			3,500					2,000	
		PC	KW		500									500
			MKWH		2,000									2,000
		PC	KW				500					500		
			MKWH				2,500					2,500		

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

[illegible]

SOUTHERN PINES DISTRICT

USTOMER OCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW		500				500					500
			MKWH		3,000				3,000					3,000
		PC	KW		500									
			MKWH		2,000									
		PC	KW				500							
			MKWH				1,500							
		NI	KW										500	
			MKWH										3,000	
			KW		1,000		1,000		500			500	500	500
			MKWH		5,000		4,000		3,000			2,500	3,000	3,000
		PC	KW						2,000					
			MKWH						13,000					
		PC	KW					500						
			MKWH					2,000						
			KW					500	2,000					
			MKWH					2,000	13,000					
		NI	KW						500					
			MKWH						1,000					
		PC	KW					500						500
			MKWH					2,500						2,500

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

SOUTHERN PINES DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW						500					
			MKWH						2,000					
		PC	KW									500		
			MKWH									2,400		
		PC	KW				500							
			MKWH				2,500							
			KW				500	500	1,000			500		500
			MKWH				2,500	2,500	3,000			2,400		2,500
		NI	KW										500	
			MKWH										2,500	
		NI	KW				500							
			MKWH				1,500							
			KW				500						500	
			MKWH				1,500						2,500	
		NI	KW		500						500			
			MKWH		1,500						1,500			
		PC	KW						500					500
			MKWH						3,000					1,200
		PC	KW			500				500				
			MKWH			2,000				2,500				
		NI	KW			500					500			
			MKWH			3,000					3,000			
		NI	KW				500							
			MKWH				800							
			KW		500	1,000	500		500	500	1,000			500
			MKWH		1,500	5,000	800		3,000	2,500	4,500			1,200

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

SOUTHERN PINES DISTRICT

USTOMER OCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW					500					500	
			MKWH					2,000					2,000	
		NI	KW	2,800		1,000			1,000			1,000		
			MKWH	71,000		7,000			7,000			7,000		
			KW	2,800		1,000		500	1,000			1,000	500	
			MKWH	71,000		7,000		2,000	7,000			7,000	2,000	
		PC	KW					500						
			MKWH					2,200						
		PC	KW				500							500
			MKWH				2,500							2,500
			KW				500	500						500
			MKWH				2,500	2,200						2,500
		PC	KW								500			
			MKWH								2,000			
		NI	KW		1,200								600	
			MKWH		4,000								2,000	
		PC	KW	600										600
			MKWH	3,000										3,000
			KW	600	1,200								600	600
			MKWH	3,000	4,000								2,000	3,000
			KW	6,400	6,200	6,000	8,000	7,600	9,000	1,500	3,500	2,000	4,100	7,600
			MKWH	94,500	29,500	32,500	40,300	40,200	53,000	8,500	18,000	11,900	20,000	40,200

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

HENDERSO[illegible]ISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW	1,200				500						
			MKWH	500	1,600			850						
		PC	KW				500			2,000				
			MKWH				2,500			10,000				
		PC	KW		500		500					1,000		
			MKWH		3,000		2,500					5,000		
		PC	KW			500			500					
			MKWH			2,500			2,500					
		PC	KW			500					500			
			MKWH			2,500					2,500			
		PC	KW				1,000						500	
			MKWH				5,000						2,000	
		PC	KW		1,000			1,000						
			MKWH		7,000			7,000						
		PC	KW			500							500	
			MKWH	7,000		2,250							2,000	
		PC	KW			500								500
			MKWH			2,500								2,000
		PC	KW			1,500					500			
			MKWH			8,000					3,000			
		PC	KW			1,000						700		
			MKWH			7,000						4,200		
		PC	KW			1,000								
			MKWH	16,400		4,100								
			KW		1,500	5,500	2,000	1,000	500	2,000	1,000	1,700	1,000	500
			MKWH	23,400	10,000	28,850	10,000	7,000	2,500	10,000	5,500	9,200	4,000	2,000

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

HENDERSON DI[illegible]TRICT

STOMER CATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW										500	
			MKWH										1,500	
		PC	KW				500					500		
			MKWH				2,000					2,000		
			KW				500					500	500	
			MKWH				2,000					2,000	1,500	
		PC	KW			3,000				4,000				1,000
			MKWH	8,000		22,500				30,000				7,000
		NI	KW			1,500	3,000							
			MKWH			9,000	22,000							
		PC	KW		750		500				800			
			MKWH		3,000		2,000				4,000			
		PC	KW			12,000			1,000					12,000
			MKWH			90,000			5,000					90,000
		PC	KW		500						1,000			
			MKWH		2,000						7,000			
		PC	KW										500	
			MKWH										1,500	
		PC	KW		550							500		
			MKWH		1,000							1,000		
		PC	KW		500		500							500
			MKWH		1,500		1,970							1,500
		PC	KW		500			500			500			
			MKWH		3,250			3,250			1,300			
			KW		1,550		500	500			500	500		500
			MKWH		5,750		1,970	3,250			1,300	1,000		1,500

NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

HENDERSON DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		NI	KW				500	500	10,000		10,000	10,000	10,000	
			MKWH				500	500	32,000	43,000	75,000	75,000	30,000	16,000
		PC	KW		500		500				500			
			MKWH		2,150		2,600				2,150			
			KW		500		1,000	500	10,000		10,500	10,000	10,000	
			MKWH		2,150		3,100	500	32,000	43,000	77,150	75,000	30,000	16,000
		PC	KW			500							500	
			MKWH			2,000							2,000	
			KW	1,200	4,800	22,500	7,500	2,500	11,500	6,000	13,800	12,700	12,500	14,000
			MKWH	31,900	24,500	152,350	41,070	11,600	39,500	83,000	94,950	87,200	39,000	116,500

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

GOLDSBORO DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW			500							500	
			MKWH			875							1,000	
		PC	KW				500					500		
			MKWH				2,500					2,500		
		PC	KW		1,000									
			MKWH		5,300									
			KW		1,000		500					500		
			MKWH		5,300		2,500					2,500		
		PC	KW	2,400			500	500						
			MKWH	29,500			3,000	3,000						
		PC	KW			500			500					
			MKWH			1,500			1,500					
		PC	KW			500								
			MKWH			2,500								
		PC	KW				500						500	
			MKWH				4,000						3,000	
		PC	KW		500					500				
			MKWH		2,500					2,500				
		PC	KW		750				500					
			MKWH		4,000				3,000					
		PC	KW		500									
			MKWH		1,500									

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

GOLDSBORO DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW			500						500		
			MKWH			4,000						3,000		
		PC	KW				500		500					
			MKWH				3,000		3,000					
		PC	KW				500					500		
			MKWH				3,000					3,000		
		PC	KW		500						500			
			MKWH		1,500						1,500			
			KW	2,400	2,250	1,500	2,000	500	1,500	500	500	1,000	500	
			MKWH	29,500	9,500	8,000	13,000	3,000	7,500	2,500	1,500	6,000	3,000	
		PC	KW										500	
			MKWH										2,000	
		NI	KW			500								
			MKWH			1,500								
		PC	KW				500				500			
			MKWH				1,500				1,500			
		PC	KW			500								
			MKWH			1,500								
		L	KW			1,000	500				500		500	
			MKWH			3,000	1,500				1,500		2,000	
		NI	KW		2,000							3,000	4,000	3,000
			MKWH		2,200	2,200						22,000	30,000	22,000

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

GOLDSBORO DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW		600								500	
			MKWH		2,500								2,500	
		PC	KW			500								
			MKWH			2,500								
		PC	KW		500							500		
			MKWH		2,000							2,000		
		NI	KW				500							
			MKWH				1,000							
		PC	KW			500								
			MKWH			2,500								
		PC	KW	750										
			MKWH	4,000										
			KW	750	500	1,000	500					500		
			MKWH	4,000	2,000	5,000	1,000					2,000		
		NI	KW			1,000		2,500						
			MKWH			4,000		7,000						
		NI	KW			500								
			MKWH			2,000								
			KW			1,500		2,500						
			MKWH			6,000		7,000						
			KW	3,150	6,350	5,500	3,500	3,000	1,500	500	1,000	5,000	6,000	3,000
			MKWH	33,500	21,500	25,075	18,000	10,000	7,500	2,500	3,000	32,500	38,500	22,000

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
JANUARY 1976

KNOWN GOOD INDUSTRIAL PROSPECTS OVER 500 KW (KWH IN THOUSANDS)

RALEIGH DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW			1,000			1,000			500		
			MKWH			4,500			4,500			2,750		
		PC	KW				500				500			
			MKWH				1,000				2,000			
			KW			1,000	500		1,000		500	500		
			MKWH			4,500	1,000		4,500		2,000	2,750		
		PC	KW			1,000					1,000			500
			MKWH			4,500					4,500			2,200
		PC	KW			500	500					300		
			MKWH			1,000	2,500					1,500		
		PC	KW			1,000			1,000			500		
			MKWH			5,000			5,000			2,500		
			KW			2,500	500		1,000		1,000	800		500
			MKWH			10,500	2,500		5,000		4,500	4,000		2,200
		PC	KW			500							500	
			MKWH			1,500		500					1,500	
		PC	KW		500		1,000					500		
			MKWH	2,600	2,700		5,000					2,500		
		NI	KW		1,000			1,000			1,000			
			MKWH		4,000			4,000			4,000			

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
Jan. 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)
RALEIGH DISTRICT

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW		500				500					500
			MKWH		800				800					800
			KW		2,000		1,000	1,000	500		1,000	500		500
			MKWH	2,600	7,500		5,000	4,000	800		4,000	2,500		800
		PC	KW		800	500		500					500	
			MKWH		4,000	4,000		2,000					2,000	
		NI	KW			500						500		
			MKWH			2,000						2,000		
		PC	KW				500					250		
			MKWH				1,500					750		
		PC	KW		500						500			
			MKWH		1,800						1,800			
		PC	KW	600						500				500
				500						300				300
		PC	KW			500						500		
			MKWH			1,500						1,500		
		PC	KW	700		600		600			600			
			MKWH	400	3,000	2,200		2,500			2,500			
			KW	1,300	500	1,100	500	600		500	1,100	750		500
			MKWH	900	4,800	3,700	1,500	2,500		300	4,300	2,250		300
		PC	KW			1,200		800						
			MKWH			4,000		4,000				3,000		2,000
		PC	KW			500						250		
			MKWH			1,000	1,000	500				500		

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
Jan. 1976

KNOWN GOOD PROSPECTS OVER 500 KW (KWH IN THOUSANDS)
RALIGH DIST T

CUSTOMER LOCATION	SIC CODE	TYPE OF CUST. *		1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
		PC	KW					500				500		
			MKWH					2,200				2,200		
		PC	KW		970			500						500
			MKWH		1,800			2,000						2,000
		PC	KW		1,000		1,000					300		
			MKWH		2,500		2,000					600		
		PC	KW	2,000							500			
			MKWH	4,500	1,000						1,500			1,000
		PC	KW			1,000				1,000		200		
			MKWH			2,000				2,000		400		
			KW	2,000	1,970	2,700	1,000	1,800		1,000	500	1,250		500
			MKWH	4,500	5,300	7,000	3,000	8,700		2,000	1,500	6,700		5,000
		PC	KW			1,000			1,000					500
			MKWH			4,500			4,500					2,000
		PC	KW		800		1,000					500		
			MKWH		4,000		5,000					2,500		
		PC	KW			1,000					500			
			MKWH			4,500					2,000			
		NI	KW	2,700			500						500	
			MKWH	2,000	8,000		2,000						2,000	
			KW	2,700	800	1,000	1,500				500	500	500	
			MKWH	2,000	12,000	4,500	7,000				2,000	2,500	2,000	
			KW	6,000	6,070	10,800	5,000	3,900	3,500	2,000	4,600	4,800	1,500	2,500
			MKWH	10,000	33,600	42.200	20,000	17,700	14,800	4,300	18,300	22,700	5,500	10,300

* NI NEW INDUSTRY
PC PRESENT CUSTOMER
Jan 1976

Question 7:

Provide an explanation and description of "wheeled" energy operation.

Answer:

CP&L and the Southeastern Power Administration (SEPA) initially joined in a power and energy wheeling contract on December 7, 1955. This contract was terminated and another agreement was reached on March 30, 1973. A resume of this agreement is attached.

Essentially CP&L agrees to make its transmission lines and other necessary facilities continously available for transmitting and delivering power and energy from the John H. Kerr Project, on the NC/VA border, to preference customers of the Government in North Carolina upon terms and conditions mutually agreeable to the Government and CP&L.

SEPA makes available from the Kerr Project to CP&L, 75,000 kW of dependable capacity, of which CP&L is to "wheel" 30,000 kW to preference customers.

Preference customers are either municipalities (owning a transmission or distribution system) or electric cooperatives located in the CP&L service area with whom SEPA has contracted to supply part of the electrical requirements.

Listed below are the present SEPA "preference customers" to which power and energy is being wheeled.

SEPA PREFERENCE CUSTOMERS*

Brunswick Electric Membership Corporation (EMC)	5 Points of Delivery (P.O.D.)
Carteret-Craven EMC	10 P.O.D.
Central EMC	6 P.O.D.
Four County EMC	2 P.O.D.
Halifax EMC	2 P.O.D.
Jones-Onslow EMC	11 P.O.D.
Town of Louisburg (N.C.)	

Lumbee River EMC	7 P.O.D.
Pee-Dee EMC	6 P.O.D.
Piedmont EMC	4 P.O.D.
Pitt & Green EMC	3 P.O.D.
Randolph EMC	8 P.O.D.
South River EMC	13 P.O.D.
Tideland EMC	3 P.O.D.
Tri-County EMC	9 P.O.D.
Wake EMC	7 P.O.D.

*FCC Form 1, Year Ending December 31, 1976

In 1976, CP&L wheeled 135,077,209 kWh's to SEPA preference customers.

Wheeling according to the FPC is "transportation of electricity by a utility over its lines for another utility; also includes the receipt from and delivery to another system of like amounts but not necessarily the same energy."**

** FPC '1970 National Power Survey' Part 1

CAROLINA POWER & LIGHT COMPANY
AGREEMENT WITH
SOUTHEASTERN POWER ADMINISTRATION

(Resume)

Date of Agreement

March 30, 1973

Summary of Contents

Section 1. Project Capacity to be Made Available

SEPA shall make available from the Kerr Project to Carolina 75,000 KW of dependable capacity, of which Carolina is to wheel 30,000 KW to preference customers. SEPA shall also make available one-third of the project capacity in excess of 226 MW in exchange for Carolina's waiver of credit for nondelivery of dependable capacity resulting from scheduled maintenance of the project's generating units.

Section 2. Project Energy to be Made Available

SEPA will make the following megawatt hours available as a minimum declaration:

Month	Total (MWH)	Month	Total (MWH)
January	1,125	July	1,125
February	750	August	1,125
March	750	September	1,125
April	750	October	750
May	750	November	750
June	750	December	1,125

SEPA may declare energy available in excess of the minimum declaration, and Carolina shall accept such energy up to one-third of the total project energy available (including minimum) up to a weekly rate of 84 kilowatt-hours for each kilowatt of total capacity available for scheduling by the Company at the time. Such declaration of excess energy shall be made for a period not shorter than the remainder of the week in which they become effective.

Carolina shall also accept one-third of any energy available because of water releases in connection with river regulation. SEPA may offer dump energy to Carolina and Carolina may accept or reject such energy.

Section 3. Delivery Point

Power will be transferred from SEPA to Carolina at the existing interconnection point between Carolina and Virginia Electric and Power Company in the vicinity of the project.

Section 4. Preference Customers

Preference customer shall be either a municipality (owning a transmission or distribution system) or electric cooperative located in Carolina service area whose requirement SEPA has contracted to supply.

Section 5. Determination of Preference Customer Demand and Energy Requirements

The energy to be supplied by Carolina with the above-contract demands, in the case of preference customers without generating facilities, shall be an amount equal to the product of the total energy consumption of the customer at all points of delivery during the month multiplied by the ratio of the contract demand to the maximum 30-minute demand as measured at all points of delivery. The energy to be supplied by Carolina with the above-contract demands, in the case of preference customers with generating facilities, shall be an amount equal to the product of 100/106 of the total energy declared and made available to Carolina by SEPA multiplied by the ratio of the customer's contract demand to the dependable capacity made available to Carolina by SEPA. In the event a preference customer has more than one point of delivery, for the purpose of determining transmission service charge, each particular point of delivery will receive a proportionate part of the energy allocated to such customer based on the ratio of the energy requirements at said point of delivery to the sum of the energy requirements of all points of delivery of said customer.

Section 6. Energy Accounting

SEPA shall maintain an energy bank and store excess energy with this energy being used in subsequent months to supply preference customers energy requirements not supplied by declared energy or made available from SEPA.

In those months when declared energy (minimum plus excess) multiplied by 100/106 is equal to or greater than the total energy requirements of preference customers, such energy requirements shall be deemed to have been supplied by SEPA. In those months when declared energy (minimum plus excess) multiplied by 100/106 is less than the total energy requirement of preference customer, the available energy from SEPA deemed to have been used by preference customers shall be 100/106 of the total declared energy received by Carolina from SEPA. In such months, preference customers owning generating facilities shall receive that portion of the available energy that results from multiplying the ratio of each preference customer's contract demand to the dependable capacity made available to Carolina by 100/106 of the total energy declared. Preference customers (without generation) shall receive a proportionate part of the remaining available energy based on the ratio of such preference customers' individual energy requirements to the sum of the individual requirements of all such preference customers.

Section 7. Rates for Power & Energy

The cost of power and energy sold each month by SEPA to Carolina shall be: $1.25 per kilowatt of dependable capacity. For dump energy - 80 percent of the calculated saving in the cost of fuel for operating Carolina's generating units avoided by the delivery of such dump energy.

The rates and charges for sale of power and energy shall be subject to periodic adjustment every five years beginning June 30, 1975. Carolina must be notified by SEPA of any proposed adjustment in rates at least six months in advance, and promptly in writing of any rate adjustments when confirmed or approved by the Federal Power Commission. If adjusted rates result in increased cost to Carolina, Carolina, after being notified of such change and effective date, must give written notice within 60 days in the event it elects to terminate the contract and must specify the date of termination which must not be less than one nor more than three years subsequent to such notification date. In the event of any rate changes, Carolina shall pay the adjusted rates from the effective date until the effective date of the cancellation of the contract.

Section 8. Rates and Charges for Transmission Service

SEPA shall compensate Carolina monthly in the amount of $16,250 per billing month based on transmission service charge rates set forth in Exhibit A.

Section 9. Delivery by Carolina to SEPA Preference Customers

Carolina will deliver over its transmission and distribution system power and energy to SEPA preferred customers. SEPA will furnish Carolina one copy of each contract between SEPA and preference customer. Carolina will discontinue delivery of electric energy to preference customers upon written request from the administrator of SEPA, Carolina receiving the written request 15 days prior to the effective date.

Section 10. Conditions of Service to Preference Customers

Preference customers shall pay for facilities necessitated by preference customer's operating generating facilities in parallel with Carolina. Preference customers may not receive power from another electric system without coordinating with

Carolina. Preference customers with generating facilities must schedule and receive their proportionate share of the minimum monthly declaration and any excess energy declared by SEPA. Carolina will not be obligated to deliver energy to customers with generating facilities at any time at a power factor below .85 lagging.

Section 11. Supply by Company Beyond Supply by Government
Carolina agrees to furnish preference customers (without generating facilities) the energy represented by the difference between the energy supplied by SEPA and the energy resulting from multiplying the customer's total energy requirements by the ratio of its contract demand to its maximum 30-minute integrated demand for the month, at the project energy rate (minimum of 4.5 mills per kilowatt hour). Carolina further agrees to furnish preference customers any additional power and energy at its applicable rate schedule.

Section 12. Metering and Records
Power and energy delivered by Carolina to preference customers will be measured at existing and future points of delivery. Meters at the project used for measuring power and energy shall be owned by SEPA. Meters used for measuring power and energy to preference customers shall be owned or provided by Carolina. If a meter is found to register in excess of two percent either above or below normal, the readings previously taken will be adjusted according to the percentage of inaccuracy found not to exceed sixty days.

Section 13. Energy Characteristics
Electric energy will be three-phase alternating current at sixty hertz.

Section 14. Billing and Payments
Statements shall be prepared after the end of each calendar month, shall be mailed on or before the 15th day of the following month, and shall be paid on or before the 20th day after the date of mailing.

Section 15. Service Interruption
SEPA will not allow credit to Carolina for any curtailment or interruptions of power for less than an hour or of longer duration which had been planned and agreed to in advance between Carolina and SEPA. Carolina shall be billed a reduced amount when SEPA dependable capacity is less than the total declared available.

Section 16. Breakdown or Emergency Service
Either party will make energy available to the other in emergencies to the extent necessary without impairing prior commitments and service to its own system load. Reimbursement

will be made by return of an equal amount of energy at a mutually agreeable time. If a substantial additional cost is imposed on the supplying party, repayment shall be to fully compensate the supplying party in energy, monetary payment or both.

Section 17. Scheduled Maintenance
Both parties shall coordinate scheduled outages of their facilities to maintain continuity and reliability of service.

Section 18. Power Factor
Carolina shall not impose a power factor of less than .85 lagging on SEPA's facilities.

Section 19. Energy Storage
At Carolina's request SEPA will store declared energy in any unused storage capacity available for this purpose and will deliver energy which Carolina has in storage. SEPA will also deliver to Carolina from storage, energy which Carolina does not have in storage up to three million kilowatt hours; additional energy will be provided if SEPA and Carolina jointly determine that this energy is necessary and desirable to maintain the integrity of Carolina's system. Any deviation in delivery of declared energy to Carolina by SEPA shall be accounted for as a credit or debit to Carolina in the storage account. In the event SEPA spills or releases water in order to keep the reservoir under proper control, the kilowatt-hours which could have been generated from such water will be deducted proportionately from any credits existing in the storage account.

Section 20. Uncontrollable Force
Neither party will be held liable for failing to fulfill any obligation due to uncontrollable forces, excluding drought.

Section 21. Provisions Relative to Employment
Carolina shall not discriminate against employees or potential employees based on race, color, religion, sex, or national origin. Carolina shall comply with all provisions of Executive Order No. 11246 of September 24, 1965, governing relations with labor unions. Carolina will contract only from companies complying with these provisions unless exempted by rule, regulation or order of the Secretary of Labor.

Section 22. Notices
All notices shall be written and mailed postage prepaid to the President of Carolina or his designated representative or the Administrator of SEPA.

Section 23. Officials not to Benefit

No members of congress or Resident Commissioner shall derive any benefits that may arise under this contract.

Section 24. Waivers

Any waiver of rights in a given matter shall not be deemed a waiver of rights in any subsequent matter.

Section 25. Transfer of Interest in Contract

Neither this contract nor the rights of Carolina under this contract may be transferred without the written approval of the Secretary of the Interior. Successor to or assignee of the rights of Carolina shall be subject to the provisions of this agreement.

Section 26. Adjustment of Existing Customers Contract by Company

Carolina will, for a customer that has newly contracted for SEPA power, adjust its contract with such customer so as to permit the customer to receive project power.

Section 27. Approval of Contract

This contract is subject to approval by those agencies having jurisdiction.

Section 28. Effective Date and Term of Contract

This agreement is effective March 31, 1973. Carolina may terminate this agreement on June 30 of any year by giving written notification to SEPA 37 months in advance of termination. SEPA must notify Carolina 36 months in advance. Termination of this contract will not be effective prior to June 30, 1980.

Section 29. Termination of Existing Contract

Contract between SEPA and Carolina dated December 7, 1955, shall terminate on March 31, 1973, with all liabilities, charges or credits being transferred to accounts under this contract.

5/22/73

Question 8:

Provide projected peak load demand to 1993 (year of commercial operation of last unit plus succeeding three years.)

Answer:

Year	MW
1977	5548
1978	5975
1979	6411
1980	6878
1981	7367
1982	7897
1983	8441
1984	9019
1985	9590
1986	10190
1987	10801
1988	11444
*1989	12016
*1990	12617
*1991	13248
*1992	13910
*1993	14606

*Projected

Question 9:

Provide historical and projected load factors 1966 to 1993. If shifts in load factor or load factor trends are evident, identify contributing factors.

Answer:

Year	%	Year	%
1966	62.7	1977	60.6
1967	65.8	1978	60.4
1968	61.2	1979	60.4
1969	63.2	1980	60.3
1970	61.0	1981	60.3
1971	63.9	1982	60.2
1972	61.7	1983	60.2
1973	60.3	1984	60.2
1974	60.5	1985	60.0
1975	58.4	1986	59.9
1976	61.3	1987	59.9
		1988	60.0
		*1989	60.5
		*1990	60.9
		*1991	61.2
		*1992	61.5
		*1993	61.8

*Projected

Question 10:

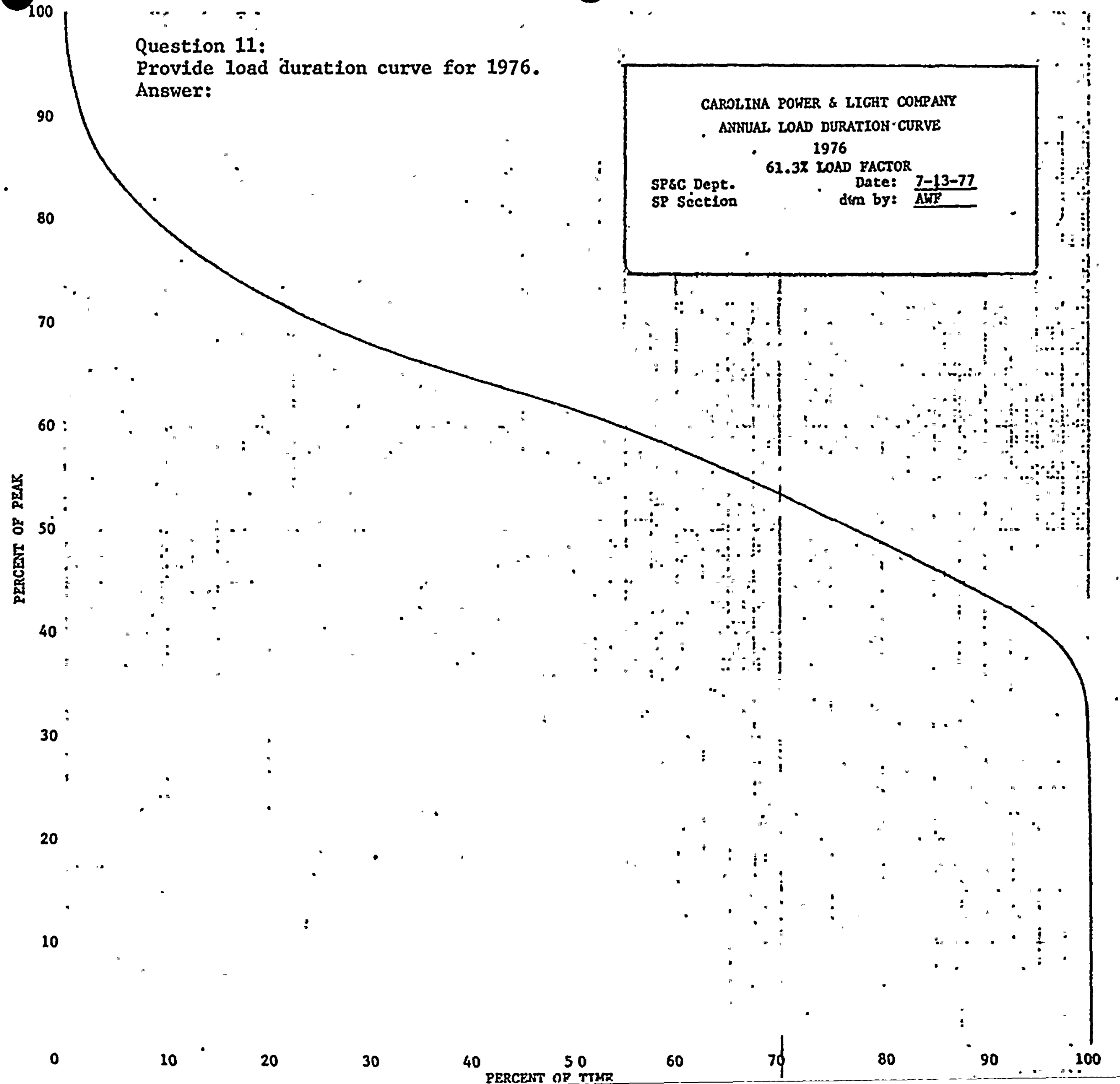
Describe in detail how historical peak load factor trends are modified based on forecast energy use A/C saturation, etc.

Answer:

In the residential classification, for example, load factor trends are modified to take into account such factors as forecasted energy use per customer, type of customer, projected air-conditioning saturation and utilization, insulation levels, and other energy uses.

Based on historical appliance survey data, air conditioning saturations are projected for each residential customer classification (all electric, water heating, and general). Using these saturations, the forecasted number of customers in each class, and estimated annual energy use per air conditioner, the forecasted AC energy use is separated from "other" residential energy use. Judgement concerning the effects of expected improvements in insulation levels and of conservation in the utilization of air-conditioning are factored into the estimate of its annual energy use. Applying estimated AC load factors and "other load" load factors based on load survey data and appliance survey data, demands are calculated for the two energy components. These demands are then combined and used to calculate a single load factor for each residential class for each year. The three classes are also combined to give a single residential load factor for each year. Load factors calculated in this manner are then compared with historical peak load factor trends for reasonableness.

Question 11:
Provide load duration curve for 1976.
Answer:



Question 12:

Provide copies of all forecasts made during the previous 10 years for aggregate long-range consumption of system peak load demand.

Answer:

See following table.

CAROLINA POWER & LIGHT COMPANY
LOAD FORECAST SUMMARY

Year	Date Load Forecast Made												
	4-67	3-68	3-69	11-69	10-70	7-71	3-73	5-73	6-74	11-74	3-75	10-75	9-76
1967	2437												
1968	2709	2650											
1969	2964	2910	3043										
1970	3285	3167	3338	3415									
1971	3623	3472	3662	3764	3818	3818							
1972	3960	3810	4017	4143	4238	4279							
1973	4316	4212	4407	4561	4718	4766	4717	4679					
1974	4704	4628	4834	5002	5222	5315	5258	5206	5019				
1975	5127	5076	5303	5529	5765	5942	5836	5783	5717	5292	5001		
1976	5588		5817	6087	6332	6591	6482	6440	6274	5718	5407	5396	
1977			6381	6702	7025	7318	7194	7152	6872	6180	5881	5836	5548
978			7000		7743	8106	7996	7943	7479	6678	6350	6330	5975
1979						8971	8866	8819	8127	7217	6854	6821	6411
1980						9912	9834	9776	8845	7800	7394	7342	6878
1981						10951	10873	10801	9566	8429	7976	7904	7367
1982							12005	11859	10364	9110	8541	8492	7897
1983							13234	13005	11172	9846	9145	9086	8441
1984								14037	12025	10642	9762	9707	9019
1985								15004	12928			10363	9590
1986								15960	13889				10190
1987								16924	14913				10801
1988								17850	15953				11444
1989								18800	17040				12016
1990								19784	18177				12617
1991								20782	19403				13248
1992								21781	20662				13910
1993									21987				14606

Question 13:

Actual data suggest severe reduction in peak demand in 1974, 1976 (a common experience). Provide results of any analysis performed including relative influence of voluntary conservation appeals following embargo, rising prices, economic conditions, weather, etc.

Answer:

Results of Load-Weather Correlation Studies for the 1974 and 1976 Summers indicated that the demand on the peak day would have been approximately 2.4% higher in 1974 and 3.6% higher in 1976, if more typical peaking weather conditions had occurred.

Question 14:

Provide historical and projected growth for the service area of the following variables: population, number of households, saturation by major appliances, prices of alternative fuels.

Answer:

Attached Table A provides historical and projected growth in population and in dwelling units. Attached Table B provides historical and projected saturation by major appliances. Also included are the results of the Company's most recent applicance/heating and cooling saturation study. The Company does not attempt in any way to project prices of alternate fuels into the future.

CAROLINA POWER & LIGHT COMPANY
TWENTY-YEAR FORECAST [illegible] TO 1995

POPULATION AND HOUSING PROJECTIONS

	1960	1970	1980	1985	1990	1995
Population						
North Carolina						
Total State Population	4,556,155	5,082,059	5,651,821	5,977,000	6,258,500	6,459,300
Average Annual Rate of Growth	1.2%	1.1%	1.1%	1.1%	0.9%	0.7%
Estimated Population Served by CP&L	2,083,302	2,220,219	2,448,141	2,590,001	2,701,019	2,804,862
Percent of State	45.7%	43.7%	43.3%	43.3%	43.2%	43.2%
South Carolina						
Total State Population	2,382,594	2,590,516	2,998,700	3,135,200	3,250,200	3,464,000
Average Annual Rate of Growth	1.2%	0.8%	1.5%	0.9%	0.9%	1.1%
Estimated Population Served by CP&L	451,538	444,401	489,045	504,099	520,051	543,043
Percent of State	19.0%	17.2%	16.3%	16.1%	[illegible]	15.7%
Total Population Served by CP&L	2,534,840	2,664,620	2,937,186	3,094,100	3,221,100	3,347,905
Average Annual Rate of Growth	-	0.5%	1.0%	1.0%	0.8%	0.8%
Dwelling Units						
North Carolina						
Total State	1,322,957	1,641,194	1,942,517	2,092,635	2,254,349	2,404,737
Average Annual Rate of Growth	2.2%	2.2%	1.7%	1.5%	1.5%	1.3%
Units in CP&L Territory	541,707	699,315	876,622	959,971	1,037,645	1,110,836
South Carolina						
Total State	672,837	815,148	964,809	1,039,369	1,119,699	1,194,394
Average Annual Rate of Growth	2.0%	1.9%	1.7%	1.5%	1.5%	1.3%
Units in CP&L Territory	118,426	132,673	165,778	176,877	188,435	201,127
Total Dwelling Units in CP&L Territory	660,133	831,988	1,042,400	1,136,848	1,226,080	1,311,963
Average Annual Rate of Growth	-	2.3%	2.3%	1.7%	1.5%	1.4%
Ratio of Population to Dwelling Units	3.84	3.20	2.82	2.72	2.63	2.55

Table A

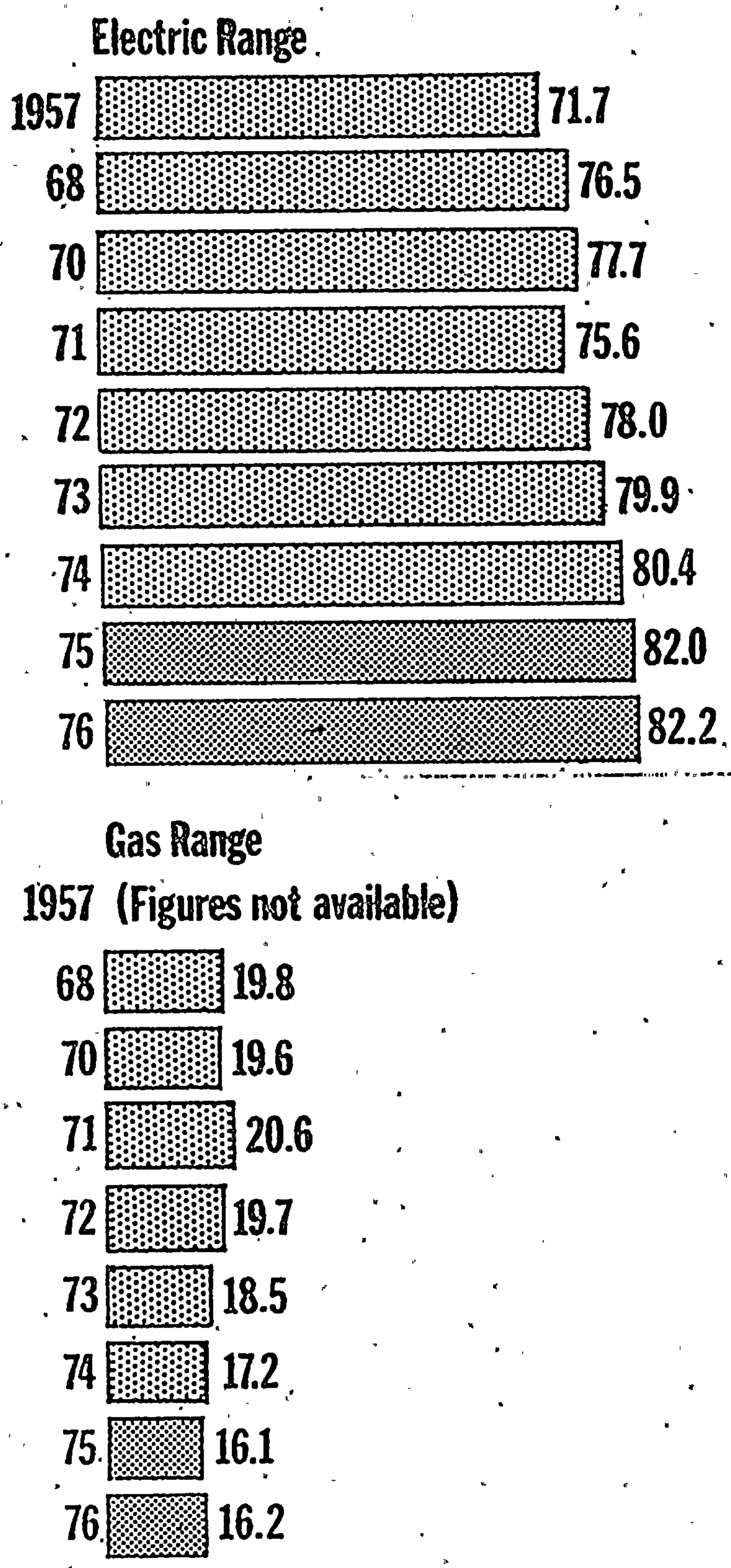
Table B

CAROLINA POWER & LIGHT COMPANY
TWENTY-YEAR FORECAST 1975 TO 1995

RESIDENTIAL ELECTRIC APPLIANCE AND
HEATING SATURATION

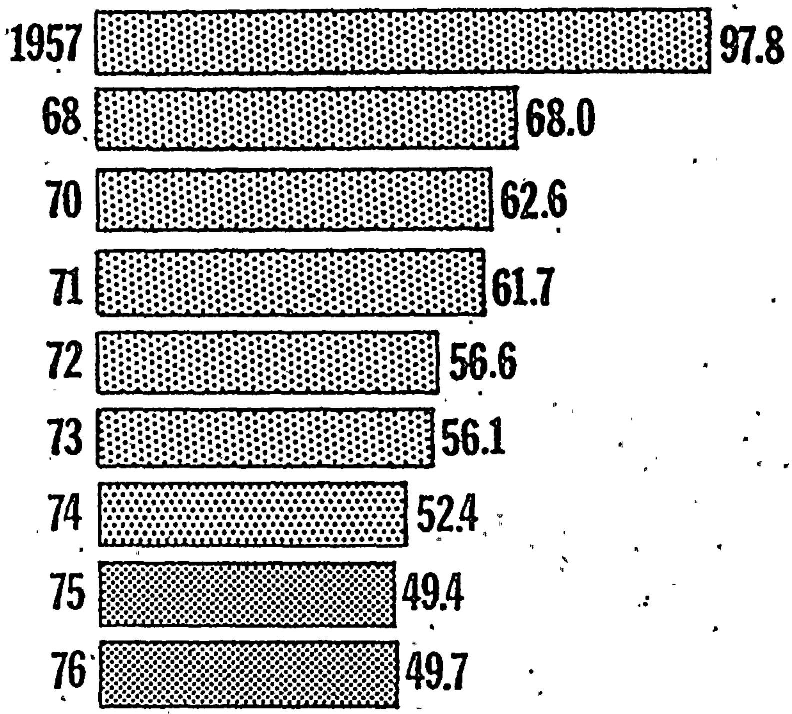
	Actual						Estimated					
	1970			1975			1985			[illegible]		
	Annual Kwh Requirement	Percent Saturation	Kwh Use Per Average Requirement	Annual Kwh Requirement	Percent Saturation	Kwh Use Per Average Customer	Annual Kwh Requirement	Percent Saturation	Kwh Use Per Average Customer	Annual Kwh Requirement	Percent Saturation	Kwh Use Per Average Customer
Refrigerator - 1 Door	720	63	454	722	49.4	357	750	35	253	750	25	188
- 2 Door	1,173	35	409	1,165	50.4	587	1,300	63	819	1,300	75	975
Range	1,175	78	916	1,175	82.0	964	1,200	84	1,003	1,200	89	1,063
Dishwasher	350	12	42	350	22.4	78	350	34	119	350	62	217
Clothes Washer	103	60	62	100	67.9	68	110	74	81	110	93	102
Clothes Dryer	980	23	225	1,000	43.1	431	1,000	56	560	1,000	67	670
Television - Color	600	30	180	540	55.1	298	435	91	396	325	98	319
- Black and White	350	73	256	320	55.1	176	280	44	123	110	20	22
Water Heating	4,219	74	3,122	4,350	79.0	3,437	4,500	87	3,915	4,500	93	[illegible]
Electric Heating	10,051	14	1,407	9,350	21.3	1,992	9,500	37	3,515	9,500	47	4,465
Air Conditioning - Room	1,613	35	565	1,600	34.9	558	2,100	45	945	2,650	51	1,352
- Central	4,193	13	545	4,000	26.2	1,048	4,000	38	1,520	4,000	49	1,960
Lighting, Freezer, and Miscellaneous			1,062	1,600		1,105			1,618			2,052
Electric Passenger Car			-			-			111			851
Average Use Per Average Residential Customer			9,245			11,098			14,943			18,426

% OF SATURATION

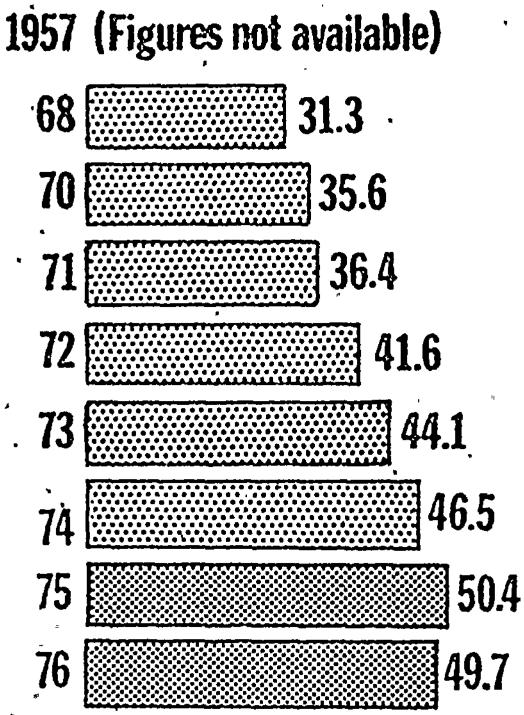


% OF SATURATION

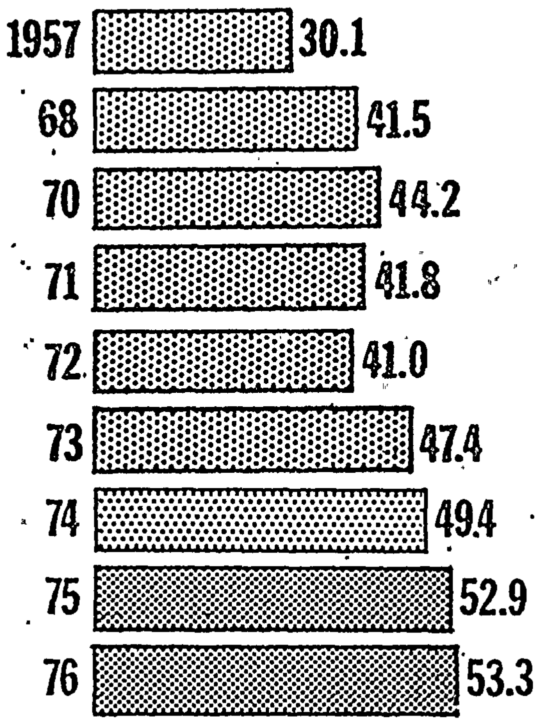
One Door Refrigerator



Two Door Refrigerator

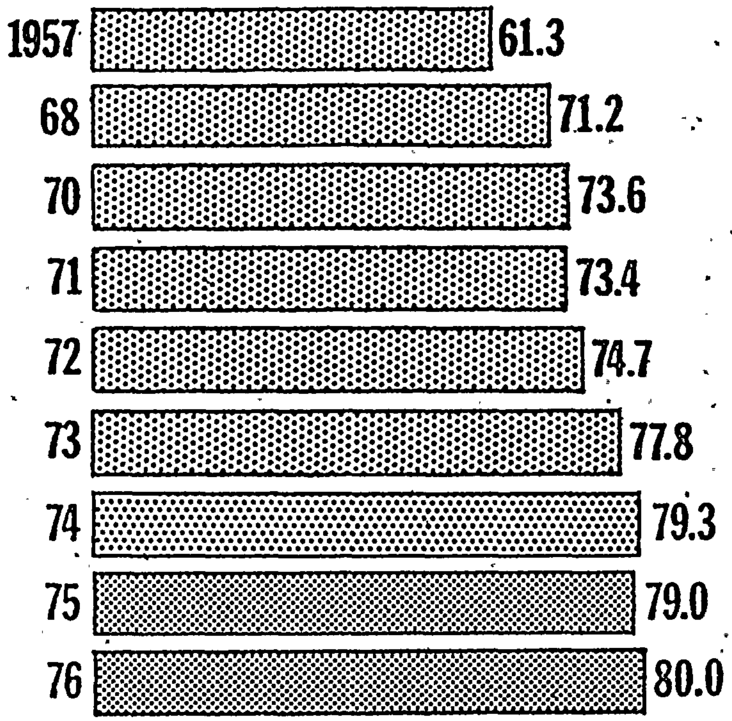


Home Food Freezer



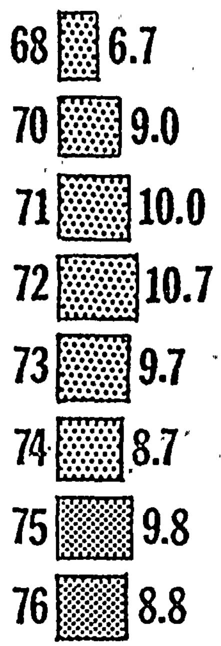
% OF SATURATION

Electric Water Heater



Gas Water Heater

1957 (Figures not available)



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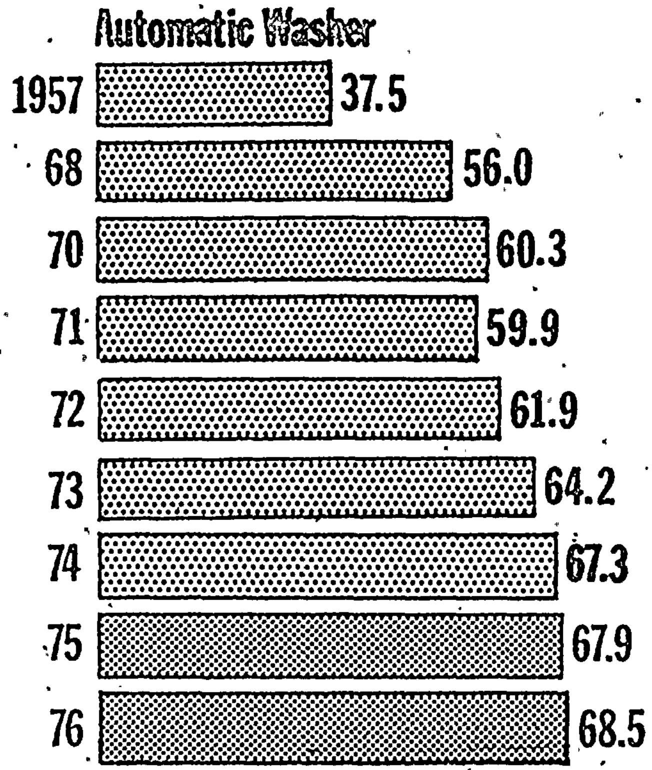
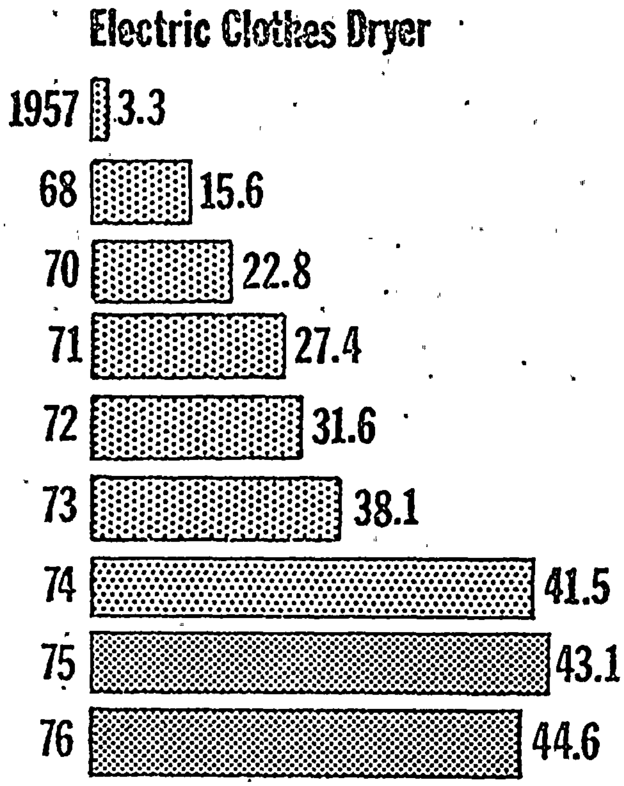
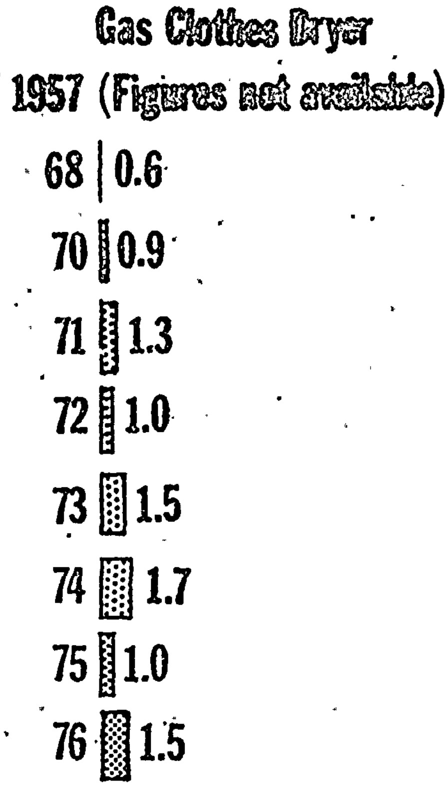
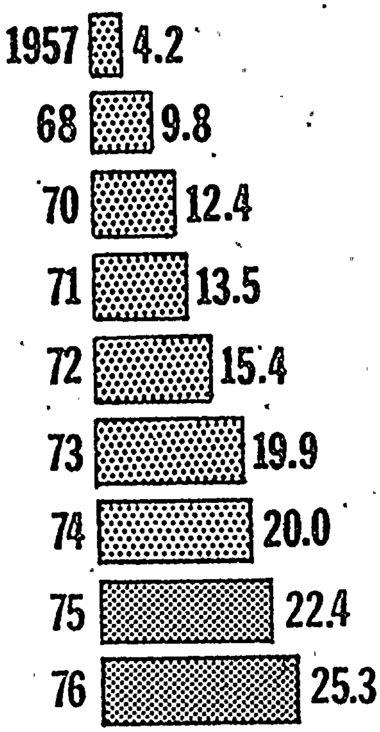






% OF SATURATION

Dishwasher



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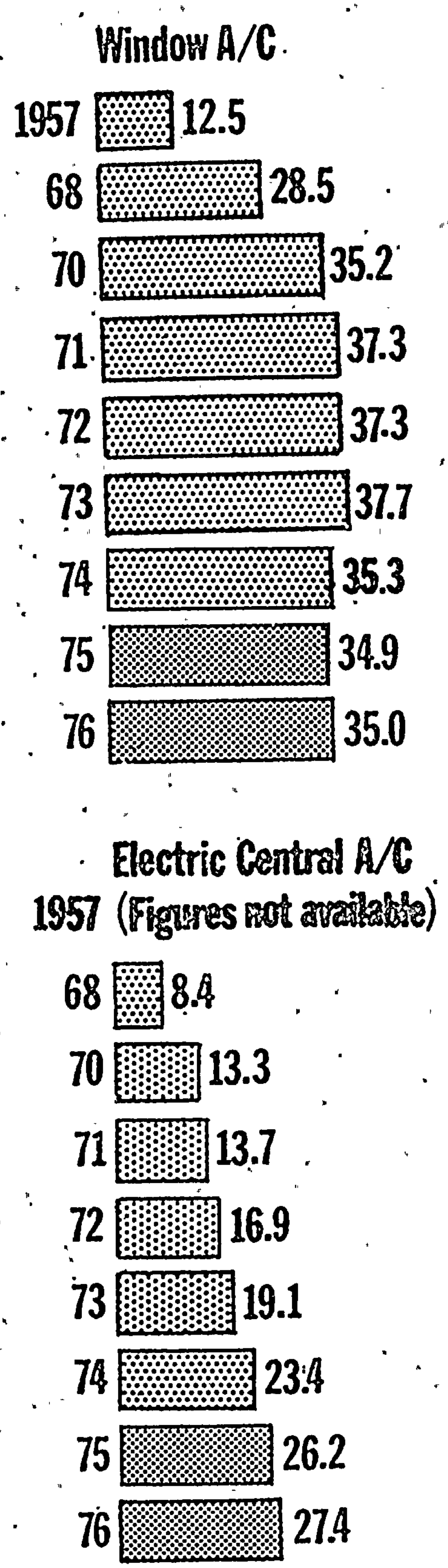
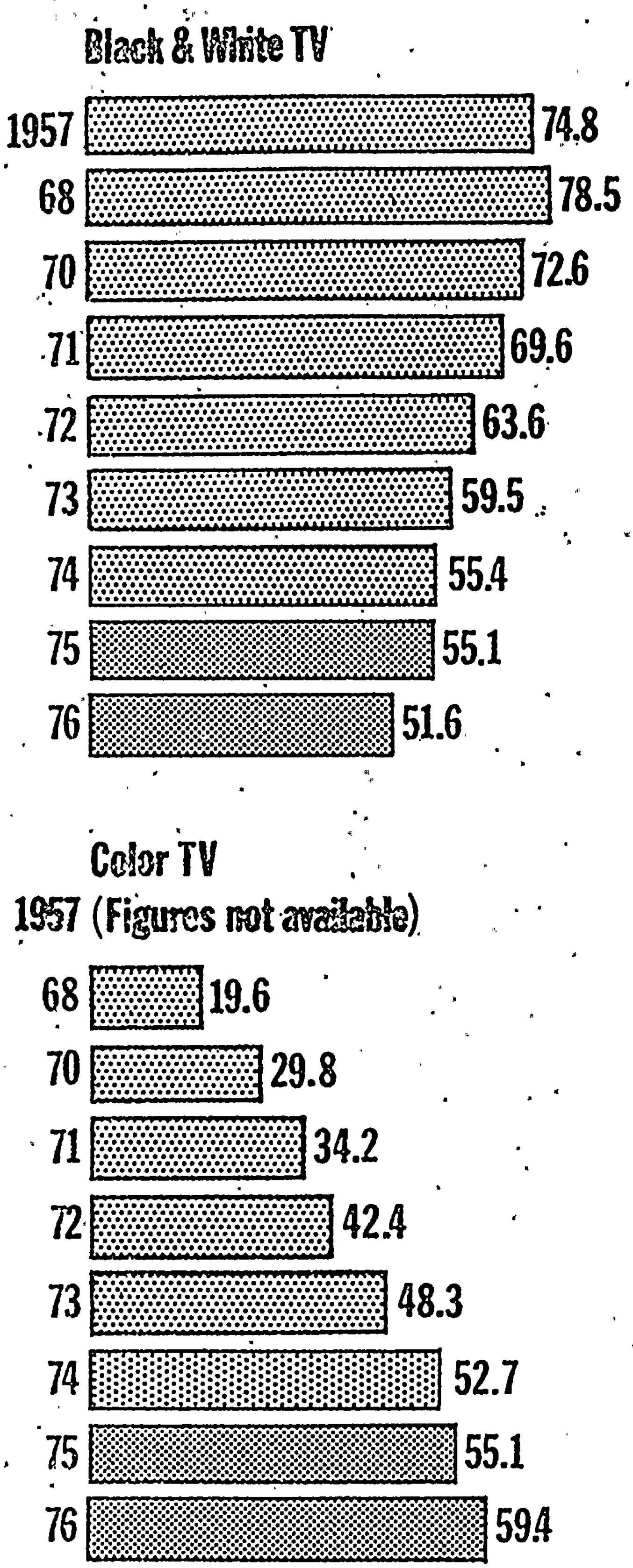
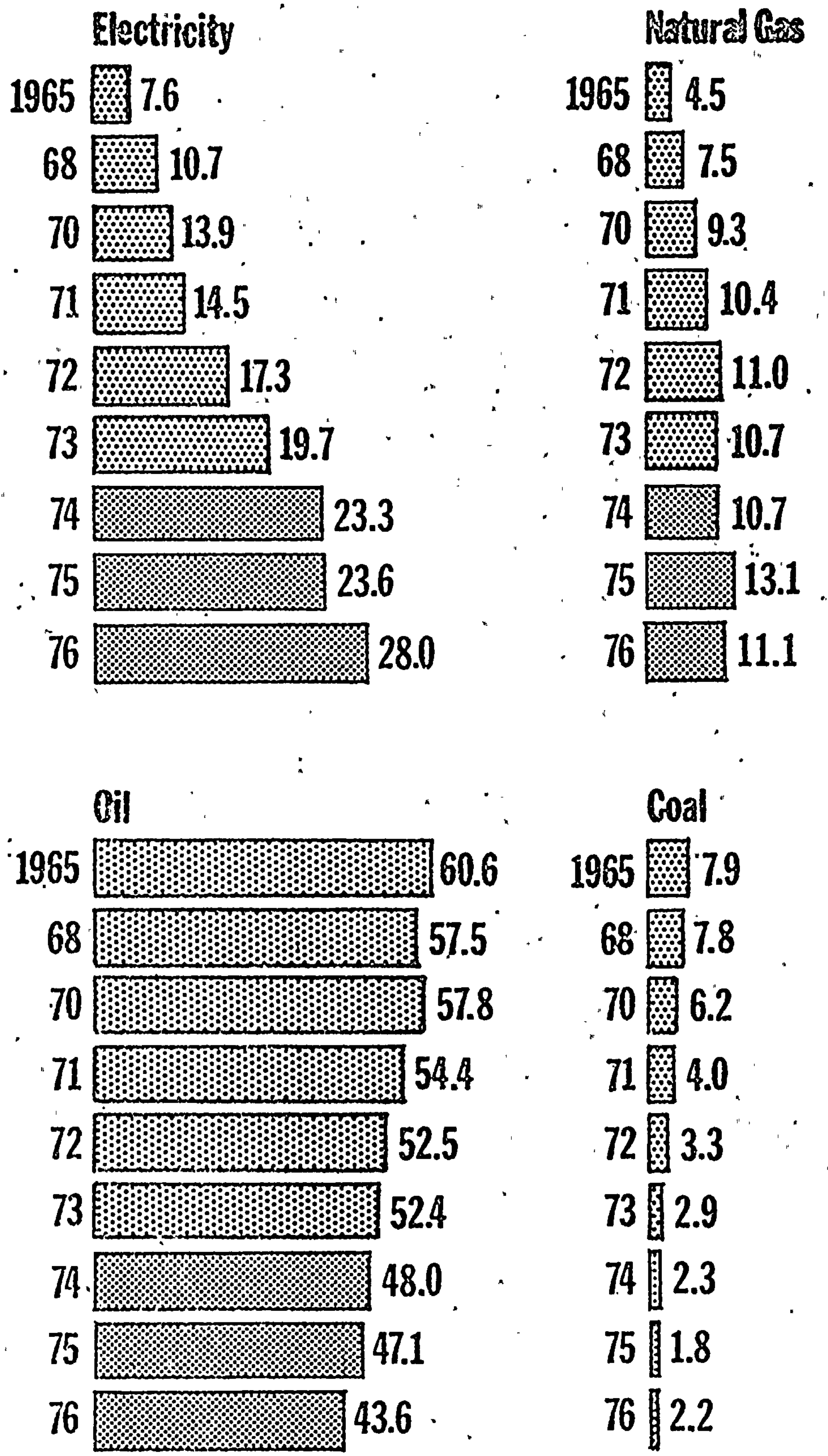


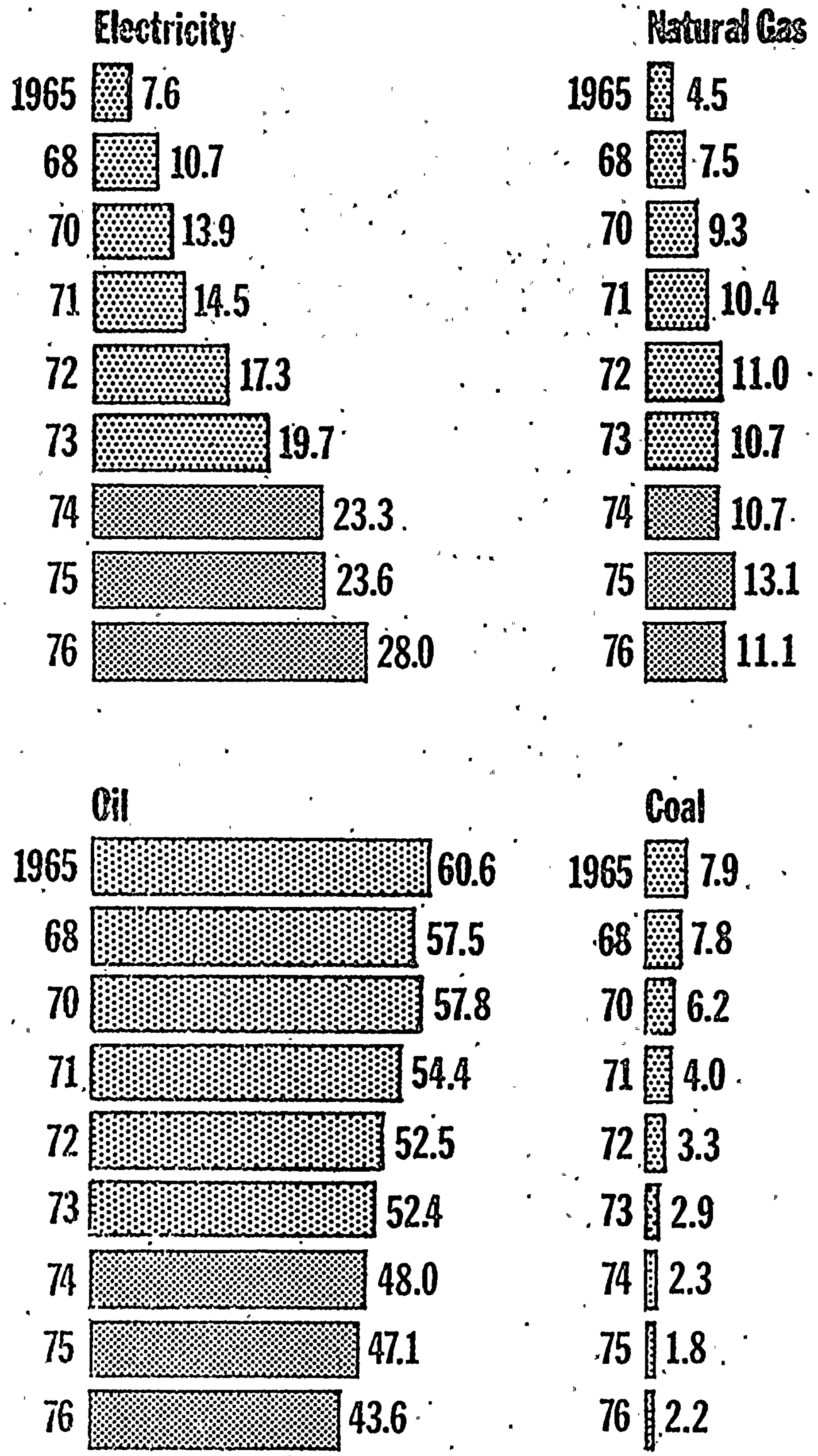
% OF SATURATION



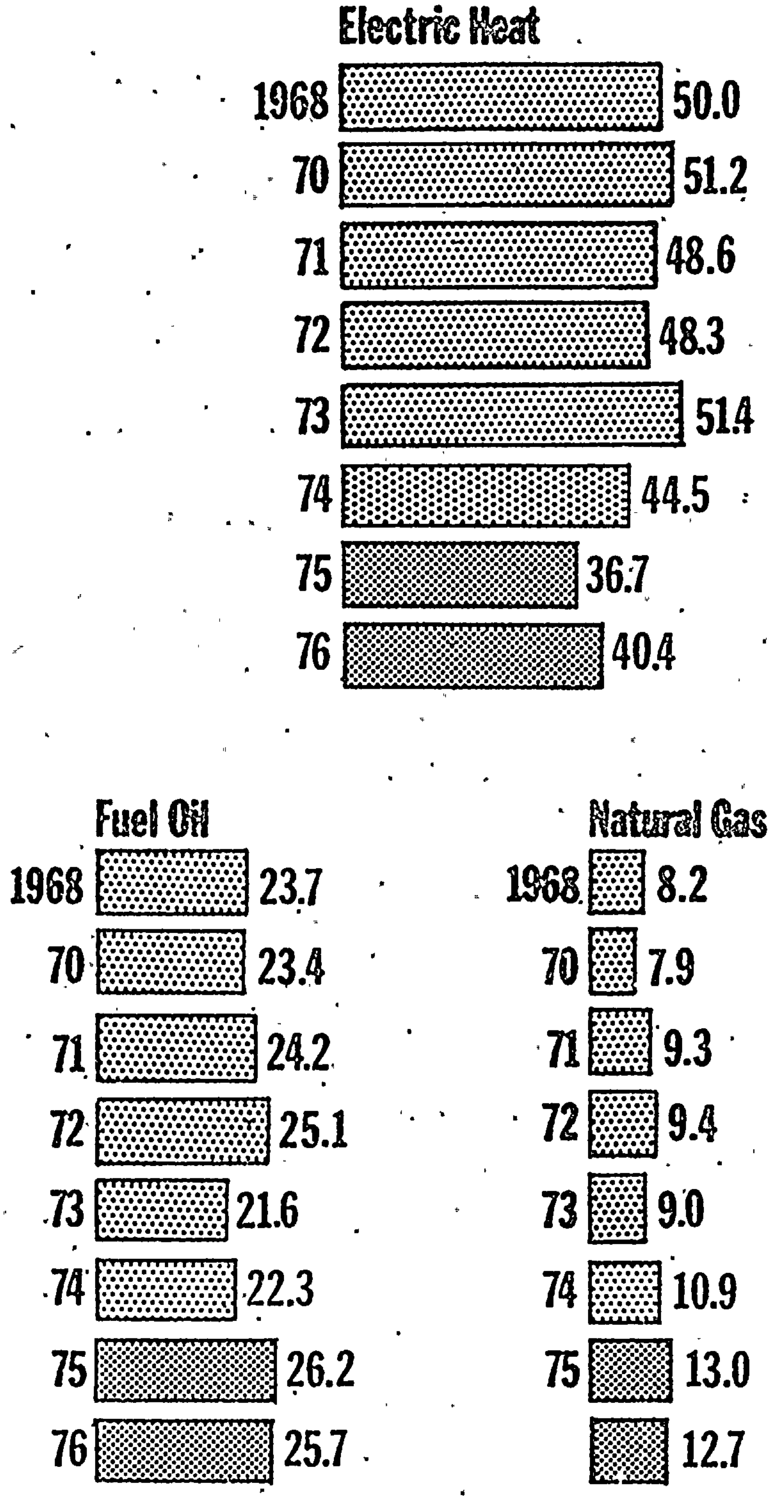
HEATING METHODS



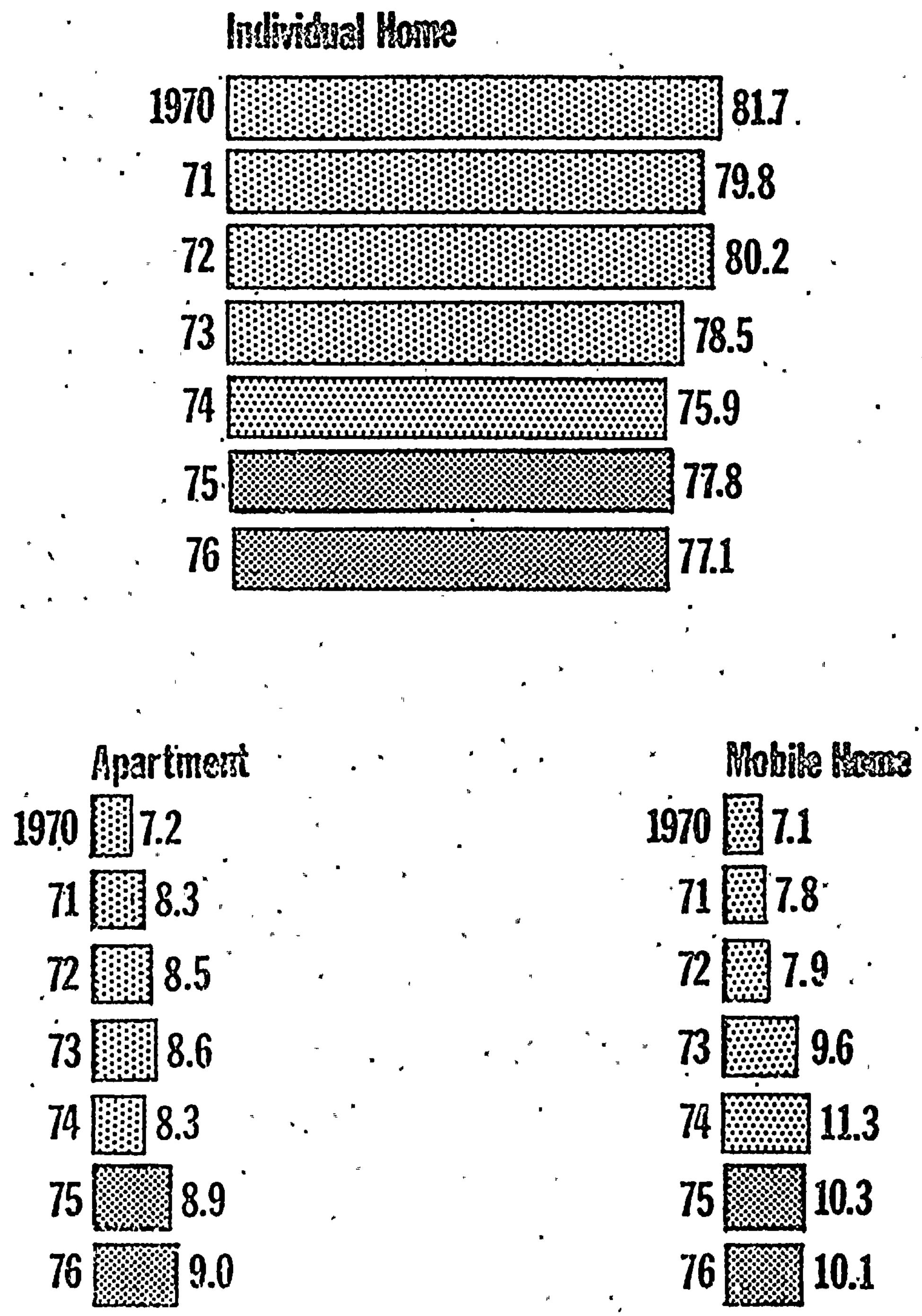
HEATING METHODS



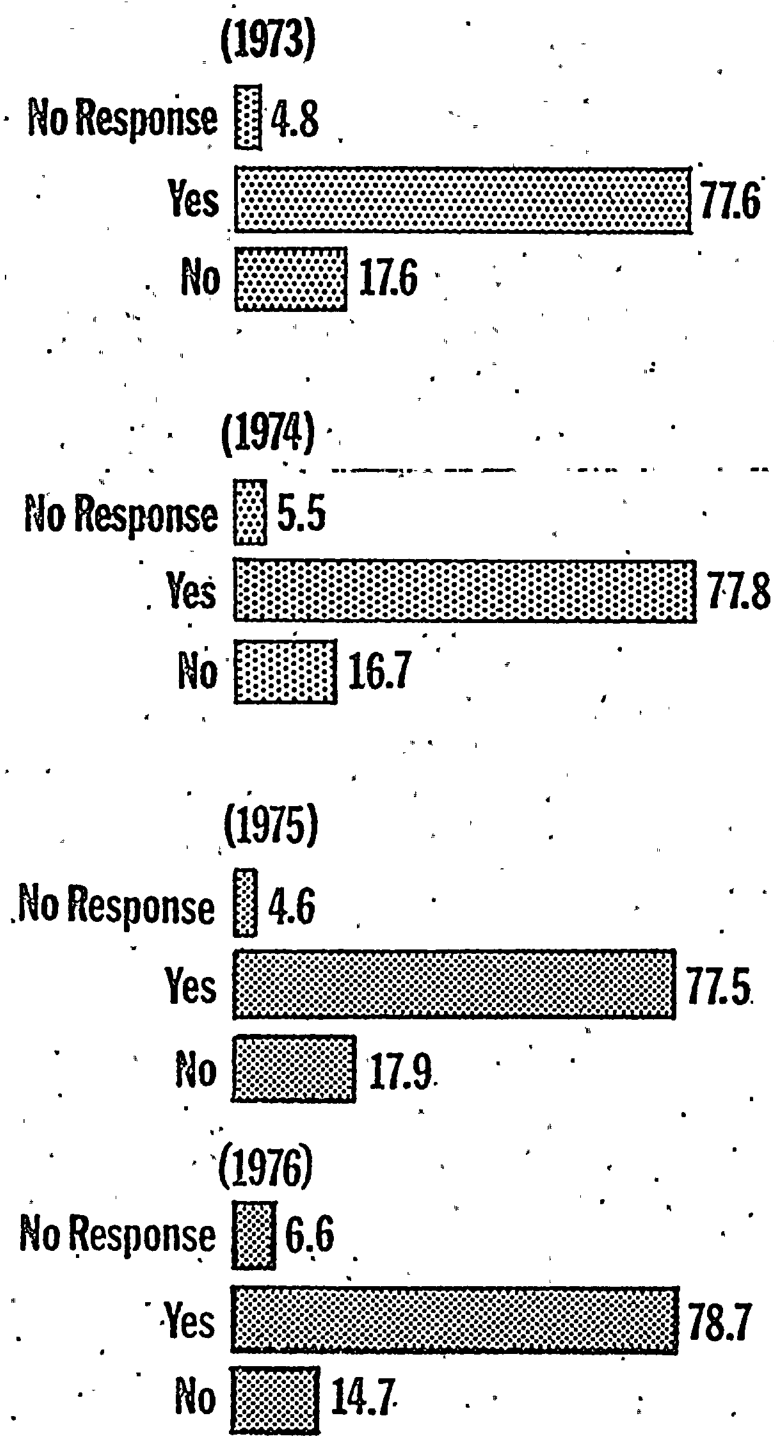
HEATING PREFERENCES



Type of Residence of Those Responding to Survey



FAMILIAR WITH TIPS TO SAVE ON ELECTRIC BILL



Question 15:

For period from present to 1993, present assumptions made regarding availability of oil and gas to ultimate customers. What assumptions, if any, are made regarding future substitution of electricity for oil and gas in the service area and what is resulting affect on energy forecasts?

Answer:

The situation with regard to the limited availability of natural gas is one that we feel will have some impact on our loads due to substitution of electricity. We have already had contact with several industrial customers regarding substitution of electricity for natural gas or propane. They are planning to convert or at least are looking at the economics involved in conversion to electricity. At this time, however, we are unable to quantify the effects of this shortage on our system. We feel that it is realistic to anticipate that due to cost and shortage of other fuels, substantially more industrial space will be heated electrically in the future. This trend can already be seen in the garment, plastic, textile, and electrical industries. Electric process heating is common in the plastic, glass, garment, and, to some extent, textile and metal industries. Substitution will increase more rapidly in metals, glass, electrical, and textiles, respectively, due to the practicality of electricity for such uses as induction heating, infrared heating, or glass furnace resistance heating. Clay, paper, chemicals, and some processes in textiles will utilize electric substitution only as a last resort due to the tremendous heating requirements. Some processes, such as finishing in textiles, have no practical electric alternative to natural gas or propane and during extreme shortages may be shutdown.

With residentail users, we assume for example, the competing fuel situations will manifest themselves in the mix of customers rather than the usage of each of the customer classes. For example, if natural gas is not available, dwelling units to be built during the forecast period are more likely to have electric heat. The price of fuel oil anticipated in the future will also influence the distribution of future customers between the classification with electric heat and the one with water heating. We are now forecasting that 1980, 84% of the net increase in residential customers will be all electric. This compares with 76% in 1973. As substitution of other energy forms for natural gas increases and trends develop, we will be in a much better position to accurately forecast this impact on electric energy requirements.

Question 16:

Provide current and projected rate structures for major customer classes.

Answer:

A copy of each of the Company's current rate schedule is provided herewith for your convenience. The Company does not project rate structures into the future.

Carolina Power & Light Company
(North Carolina Only)

RESIDENTIAL SERVICE

SCHEDULE RES-3

AVAILABILITY

This Schedule is available when electric service is used for domestic purposes in and about a residential dwelling unit, including electric service used on a farm and in the preparation of the farm's products for market. A residential house served under this Schedule may be used as a boarding house, fraternity house, tourist home, or like establishment, provided such residential house is one which ordinarily would be used as a private residence.

Service under this Schedule is not available for processing (or handling) for market of farm products produced by others, for separately metered farm operations, for individual motors in excess of 10 HP (except as provided below), for commercial or industrial purposes, or for other uses not specifically provided for by the provisions herein, or for breakdown, standby, supplementary, or resale service.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPES OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, either single phase 2 or 3 wires, or three phase 4 wires, at Company's standard voltages of 240 volts or less.

MONTHLY RATE

Single Phase Service

Summer (Billing Months July - October)	Winter (Billing Months November - June)
$6.00 Basic Customer Charge	$6.00 Basic Customer Charge
3.45¢ per kwh for all kwh	3.45¢ per kwh for the first 800 kwh 2.67¢ per kwh for the additional kwh

Where customer notifies Company that an approved water heater is in normal daily use, the kilowatt-hour rate stated above shall be 0.15¢ per kilowatt-hour less for up to 800 kilowatt-hours of monthly use.

Three Phase Service

The bill computed for single phase service plus $1.90.

Multiple Dwelling Units

When more than one residential housekeeping unit is served through the same meter, the kilowatt-hours in each of the energy blocks will be multipled by the number of individual dwelling units served.

INDIVIDUAL MOTORS

Service to individual motors rated for more than 10 HP will not normally be permitted under this Schedule. However, in exceptional cases, motors as large as 15 HP may be served upon approval by the Engineering Department.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

APPROVED WATER HEATER

An approved water heater is an insulated standard storage type water heater of not less than 15 gallons rated capacity equipped with either one self-contained heating element or two self-contained non-simultaneous operating heating elements. The wattage rating of each element shall not exceed 5500 watts.

PAYMENTS

Bills are due when rendered and are payable within 25 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedules R-2U, R-3U, and R-4S

Effective for service rendered on and after July 1, 1977

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

SMALL GENERAL SERVICE

SCHEDULE SGS-3

This Schedule is available for electric service (1) used by a commercial or industrial business and (2) for any other use not specifically excluded by the provisions hereof when Company does not own equipment, other than meters and metering equipment, on Customer's side of the point of delivery.

This Schedule is not available (1) for breakdown, standby, or supplementary service unless used in conjunction with the applicable Standby and Supplementary Service Rider for a continuous period of not less than one year, (2) for resale service, or (3) for service used only for domestic purposes in and about an individual dwelling unit.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, single phase 2 or 3 wires, or three phase 3 or 4 wires, at Company's standard voltages. When Customer desires two or more types of service, which types can be supplied from a single phase 3 wire type or a three phase 4 wire type, without voltage transformation, only the one of these two types necessary for Customer's requirements will be supplied.

CONTRACT DEMAND

The Contract Demand shall be the KW of demand specified in the Service Agreement.

MONTHLY RATE

$6.35 Customer Charge

4.78¢ per kwh for the first 600 kwh*
2.50¢ per kwh for the next 3000 kwh
1.72¢ per kwh for the additional kwh

*When the kw of Billing Demand exceeds 5 kw, add in this block 120 kwh for each additional kw of such excess.

Minimum: In all areas $6.35 plus $3.10 for each kw of Billing Demand in excess of 5 kw, but, for three phase service, not less than the smaller of (1) the bill computed in accordance with the preceding provisions plus $1.75 or (2) $16.00.

BILLING DEMAND

The Billing Demand shall be the maximum KW registered or computed, by or from Company's metering facilities, during a 15-minute interval within the current billing month. However, the Billing Demand shall not be less than the greater of (1) 80% of the maximum monthly 15-minute demand during the billing months of July through October of the preceding eleven billing months or (2) 60% of the maximum monthly 15-minute demand during the billing months of November through June of the preceding eleven billing months or (3) 75% of the Contract Demand until such time as the Billing Demand first equals or exceeds the effective Contract Demand.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year; except for short term or temporary service, the Contract Period may be for the period requested by Customer and in such event Customer agrees:

(1) That the service supplied shall be for a continuous period until discontinued, and

(2) That where it is necessary for Company to extend lines, erect transformers, or do any work necessary to supply service, except the installation of a self-contained meter, Customer shall pay in advance the estimated cost of such work, including the installation of the metering equipment; and that the estimated cost shall include labor, materials, transportation and supervision of furnishing, installing and removing, less salvage value of such facilities.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule C-1U

Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

GENERAL SERVICE

SCHEDULE GS-3

AVAILABILITY

This Schedule is available for electric service (1) used by a commercial or industrial business and (2) for any other use not specifically excluded by the provisions hereof when Company does not own equipment, other than meters and metering equipment, on Customer's side of the point of delivery and when Customer contracts for not less than 50 kw.

This Schedule is not available (1) for breakdown, standby, or supplementary service unless used in conjunction with the applicable Standby and Supplementary Service Rider for a continuous period of not less than one year, (2) for resale service, or (3) for short term or temporary service.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, single phase 3 wires, or three phase 3 or 4 wires, at Company's standard voltages. When Customer desires two or more types of service, which types can be supplied from a single phase 3 wire type or a three phase 4 wire type, without voltage transformation, only the one of these two types necessary for Customer's requirements will be supplied.

CONTRACT DEMAND

The Contract Demand shall be the KW of demand specified in the Service Agreement.

MONTHLY RATE

$213.65 for the first 50 kw of Billing Demand
$ 3.67 per kw for all additional kw of Billing Demand

1.72¢ per kwh for all kwh

BILLING DEMAND

The Billing Demand shall be the maximum KW registered or computed, by or from Company's metering facilities, during a 15-minute interval within the current billing month. However, the Billing Demand shall not be less than the greater of (1) 80% of the maximum monthly 15-minute demand during the billing months of July through October of the preceding eleven billing months or (2) 60% of the maximum monthly 15-minute demand during the billing months of November through June of the preceding eleven billing months or (3) 75% of the Contract Demand until such time as the Billing Demand first equals or exceeds the effective Contract Demand, or (4) 50 KW.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the sate regulatory commission.

Supersedes Schedule G-2R

Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

LARGE GENERAL SERVICE

SCHEDULE LGS-3

AVAILABILITY

This Schedule is available for electric service (1) used by a commercial or industrial business and (2) for any other use not specifically excluded by the provisions hereof when Company does not own equipment, other than meters and metering equipment, on Customer's side of the point of delivery and when Customer contracts for not less than 1000 kw.

This Schedule is not available (1) for breakdown, standby, or supplementary service unless used in conjunction with the applicable Standby and Supplementary Service Rider for a continuous period of not less than one year, (2) for resale service, or (3) for short term or temporary service.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, three phase 3 or 4 wires, at Company's standard voltages of 480 volts or higher. When Customer desires two or more types of service, which types can be supplied from a three phase 4 wire type, without voltage transformation, only the one of these two types necessary for Customer's requirements will be supplied.

CONTRACT DEMAND

The Contract Demand shall be the KW of demand specified in the Service Agreement.

MONTHLY RATE

$5,240.00 for the first 1000 kw of Billing Demand
$ 5.03 per kw for all additional kw of Billing Demand

1.35¢ per kwh for all kwh

BILLING DEMAND

The Billing Demand shall be the maximum KW registered or computed, by or from Company's metering facilities, during a 15-minute interval within the current billing month. However, the Billing Demand shall not be less than the greater of (1) 80% of the maximum monthly 15-minute demand during the billing months of July through October of the preceding eleven billing months or (2) 60% of the maximum monthly 15-minute demand during the billing months of November through June of the preceding eleven billing months or (3) 75% of the Contract Demand until such time as the Billing Demand first equals or exceeds the effective Contract Demand, or (4) 1,000 KW.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

POWER FACTOR ADJUSTMENT

When the power factor in the current billing month is less than 85%, the monthly bill will be increased by a sum equal to $0.25 multiplied by the difference between the maximum reactive kilovolt-amperes (kvar) registered by a demand meter suitable for measuring the demands used during a 15-minute interval and 62% of the maximum kw demand registered in the current billing month.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule G-3G

Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

GUARANTEED LOAD FACTOR SERVICE

SCHEDULE GLFS-3

AVAILABILITY

This Schedule is available for electric service used by a commercial or industrial business when Company does not own equipment, other than meters and metering equipment, on Customer's side of the point of delivery and when Customer contracts for not less than 10,000 KW.

This Schedule is not available (1) for breakdown, standby, or supplementary service unless used in conjunction with the applicable Standby and Supplementary Service Rider for a continuous period of not less than five years, (2) for resale service, or (3) for service to a Customer when any part of the service is metered by Customer and charged for in whole or in part or when its use is limited in any way even though not separately charged for.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, three phase 3 or 4 wires, at Company's standard voltages of 12,470 volts or higher.

CONTRACT DEMAND

The Contract Demand shall be the KW of demand specified in the Service Agreement.

MONTHLY RATE

Demand Charge

$130,114.00 for the first 10,000 kw of Billing Demand
$ 12.99 per kw for all additional kw of Billing Demand

Energy Charge

First 600 kwh per kw included in Demand Charge
1.00¢ per kwh for all additional kwh

BILLING DEMAND

The Billing Demand shall be the maximum KW registered or computed, by or from Company's metering facilities, during a 15-minute interval within the current billing month. However, the Billing Demand shall not be less than the greater of (1) 80% of the maximum monthly 15-minute demand during the billing months of July through October of the preceding eleven billing months or (2) 60% of the maximum monthly 15-minute demand during the billing months of November through June of the preceding eleven billing months or (3) 75% of the Contract Demand until such time as the Billing Demand first equals or exceeds the effective Contract Demand, or (4) 10,000 KW.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

POWER FACTOR ADJUSTMENT

When the power factor in the current billing month is less than 95%, the monthly bill will be increased by a sum equal to $0.25 multiplied by the difference between the maximum reactive kilovolt-amperes (kvar) registered by a demand meter suitable for measuring the demands used during a 15-minute interval and 33% of the maximum kw demand registered in the current billing month.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than five years.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule GLF-3L

Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

RURAL FARM SERVICE

SCHEDULE RFS-3

AVAILABILITY

This Schedule is available when electric service is used on a farm and in the preparation of the farm's products for market, provided such service is not metered in conjunction with a residence.

Service under this Schedule is not available for processing (or handling) for market of farm products produced by others, for separately metered seasonal farm operations of less than six months continuous and substantial use, for individual motors in excess of 10 HP (except as provided below), for highly seasonal heating load in excess of 10 KW connected, for commercial or industrial purposes, or for other uses not specifically provided for by the provisions herein, or for breakdown, standby, supplementary, or resale service.

This Schedule is not available for new applications after February 19, 1976.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPES OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, either single phase 2 or 3 wires, or three phase 4 wires, at Company's standard voltages of 240 volts or less.

MONTHLY RATE

Single Phase Service

$6.20 Customer Charge

3.70¢ per kwh for all kwh

Three Phase Service

The bill computed for single phase service plus $1.90.

INDIVIDUAL MOTORS

Service to individual motors rated for more than 10 HP will not normally be permitted under this Schedule. However, in exceptional cases, motors as large as 15 HP may be served upon approval by the Engineering Department.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule RF-1N
Effective for service rendered on and after July 1, 1977.
NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

CHURCH AND SCHOOL SERVICE

SCHEDULE CSG-3

AVAILABILITY

This Schedule is available for electric service used in a church plant contracting to pay for service for twelve months in each calendar year when Company does not own equipment, other than meters or metering equipment, on Customer's side of the point of delivery.

This Schedule is also available for electric service used in educational and recreational buildings operated as an educational institution of elementary or high school level provided that no part of the school is used for boarding facilities to accommodate students or faculty members.

This Schedule is not available for service to other types of schools, such as an industrial, vocational or training school, or for service to a building which is wholly or partially used for other purposes not specifically provided for by the provisions of this Schedule or for breakdown, standby or supplementary service.

This Schedule is not available for new applications after June 30, 1977.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, single phase 2 or 3 wires, or three phase 3 or 4 wires, at Company's standard voltages. When Customer desires two or more types of service, which types can be supplied from a single phase 3 wire type or a three phase 4 wire type, without voltage transformation, only the one of these two types necessary for Customer's requirements will be supplied.

MONTHLY RATE

$6.20 Customer Charge

4.74¢ per kwh for the first 600 kwh
3.63¢ per kwh for the additional kwh

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule CS-1F
Effective for service rendered on and after July 1, 1977.
NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

CHURCH AND SCHOOL SERVICE

SCHEDULE CSE-3

AVAILABILITY

This Schedule is available when permanently installed electric space heating equipment is the only type of space heating equipment installed in either (1) all parts of the church plant, (2) in the church sanctuary and pertinent rooms thereto, (3) in all parts of the church plant, except the parts contained in item (2), (4) in a newly constructed church educational building with not less than fifty percent of the floor area of the existing church plant, excluding the parts contained in item (2), or (5) any separately metered church building comprising a part of the church plant.

This Schedule is also available for electric service used in educational and recreational buildings operated as an educational institution of elementary or high school level, when permanently installed electric space heating equipment is the only type of equipment installed for space heating purposes and all installed cooking and water heating equipment is electrical provided that no part of the school is used for boarding facilities to accommodate students or faculty members.

This Schedule is not available for service to other types of schools, such as an industrial, vocational or training school, or for service to a building which is wholly or partially used for other purposes not specifically provided for by the provisions of this Schedule or for breakdown, standby or supplementary service.

This Schedule is not available for new applications after June 30, 1977.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, single phase 3 wires, or three phase 3 or 4 wires, at Company's standard voltages. When Customer desires two types of service, which types can be supplied from a three phase 4 wire type, without voltage transformation, only the three phase 4 wire type will be supplied.

MONTHLY RATE

$6.20 Customer Charge

4.74¢ per kwh for the first 600 kwh
2.94¢ per kwh for the additional kwh

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule CS-2F
Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

APARTMENT HOUSE SERVICE

SCHEDULE AHS-3

AVAILABILITY

This Schedule is available for electric service when (1) used for heating an entire building constructed primarily for apartment units, (2) each individual apartment is separately metered, and (3) each commercial establishment within the apartment building is either separately metered or metered in groups. Electric service used for water heating, cooling, domestic cooking, and general house usage (i.e., hall and exit lights, elevators, lobby lights) may be provided under this Schedule when metered in conjunction with the heating requirements. Only space heating, water heating and cooling service may be provided to commercial establishments through the meter serving the apartment building and then only when such services are provided for the entire building.

Service under this Schedule is available for separately metered laundry facilities installed solely for the use of the apartment occupants when total electric space heating service is provided under this or any other applicable schedule. In addition to the laundry equipment, only water heaters used exclusively for the laundry, space heating for the laundry area and incidental lighting may be served through the laundry meter.

Service under this Schedule is not available (1) when another source of commercial energy is used within any portion of the building, (2) for other than laundry facilities, when the heating requirements for one or more apartments are supplied through the individual apartment meter, (3) for other use not specifically provided for by the provisions herein, or (4) for breakdown, standby, supplementary or resale service.

This Schedule is not available for new applications after February 19, 1976.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPES OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, either single phase 3 wires, or three phase 4 wires, at Company's standard voltages of 240 volts or less.

MONTHLY RATE

Single Phase Service

$6.20 Customer Charge

3.22¢ per kwh for all kwh, plus*

*When the kwh used for cooking are billed under this Schedule, add $0.25 per dwelling unit.

Three Phase Service

The bill computed for single phase service plus $1.90.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

INDIVIDUAL METERS

Separately metered individual apartments, commercial establishments or other uses will be billed under the applicable rate schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule AH-1M

Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

SHOPPING CENTER SERVICE

SCHEDULE SCS-3

AVAILABILITY

This Schedule is available for electric service used only by electric space heating and cooling equipment when both are installed in a large shopping center where the operator furnishes both the heating and cooling requirements as a part of tenant's rent; provided such electric service is supplied for the shopping center at a central location(s) rather than at each tenant's premises. Electricity supplied under this Schedule may be used for the operation of air-handling equipment within the mall area when such air-handling equipment is an integral part of the heating and cooling equipment used specifically for the mall area. The shopping center shall consist of five or more stores with individual tenants, each metered separately.

When the shopping center meets the conditions stated above, Company will supply multiple points of delivery which, in its opinion, are necessary, and this Schedule will be available to each such point where (1) both space heating and space cooling are served or (2) either space heating or space cooling is served and at least 25% of the capacity of the transformer installation is required to serve loads other than those to which this Schedule is available.

This Schedule is not available to any portion of a shopping center where the space heating or cooling equipment uses an energy source other than electricity, for other uses not specifically provided for by the provisions herein or for breakdown, standby, supplementary, or resale service.

This Schedule is not available for new applications after February 19, 1976.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to customer's premises through one kilowatt-hour meter for each point of delivery.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, three phase 3 or 4 wires, at Company's standard voltages of 480 volts or less.

MONTHLY RATE

$6.20 Customer Charge

3.14c per kwh for all kwh

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

INDIVIDUAL METERS

Separately metered individual commercial establishments or other uses will be billed under the applicable rate schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule SC-1N
Effective on service rendered on and after July 1, 1977.
NCUC Docket No. E-2, Sub 297

(North Carolina Only)

SPORTS FIELD LIGHTING

SCHEDULE SFLS-3

AVAILABILITY

This Schedule is available for electric service used for lighting specifically designed outdoor fields which are normally used for football, baseball, softball, tennis, races and other organized competitve sports.

This Schedule is not available for breakdown, standby, supplementary or resale service.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, either single phase 2 wires, or three phase 3 or 4 wires, at Company's standard distribution voltage available for the area or the voltage at which an installation was served on December 1, 1973.

EXTENSION OF FACILITIES

Company will make the type of service agreed upon available to Customer, provided Customer will pay to Company the total estimated cost of extending, or increasing, the capacity of Company's facilities located on Company's side of the point of delivery, exclusive of the material cost of transformers and the entire cost of the meter installation.

MONTHLY RATE

$1.20 for the first 15 kwh or less per kw of demand
4.03¢ per kwh for all the additional kwh

BILLING DEMAND

The Billing Demand shall be the maximum kw registered or computed, by or from Company's metering facilities, during a 15-minute interval within the current billing month, but not less than the maximum kw previously registered during the current season (period of continuous connection).

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

BILLING

The billing to Customer will be continuous from the beginning to the end of each complete season, or period of special use, and service will not be disconnected until the end of each complete season or period of special use. If the season or period of use is for less than 30 consecutive days, Customer will be billed the estimated cost of connecting and disconnecting service, which estimated cost shall not be less than $10.00.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one month, unless Customer agrees to pay the estimated cost of connection and disconnection, which estimated cost shall not be less than $10.00.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule SFL-1P
Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

MUNICIPAL PUMPING SERVICE

SCHEDULE MPS-3

AVAILABILITY

This Schedule is available for electric service used in pumping plants owned and operated only by a municipality, incorporated sanitary district, or other governmental unit, for the purpose of supplying a retail water service or sewage disposal service, when Company does not own equipment, other than meters and metering equipment, on Customer's side of the point of delivery.

This Schedule is not available for breakdown, standby, supplementary or resale service.

This Schedule is not available for new applications after June 30, 1977.

APPLICABILITY

This Schedule is applicable to all electric service of the same available type supplied to Customer's premises at one point of delivery through one kilowatt-hour meter.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, single phase 2 or 3 wires, or three phase 3 or 4 wires, at Company's standard voltages. When Customer desires two or more types of service, which types can be supplied from a single phase 3 wire type or a three phase 4 wire type, without voltage transformation, only the one of these two types necessary for Customer's requirements will be supplied.

CONTRACT DEMAND

The Contract Demand shall be the KW of demand specified in the Service Agreement.

MONTHLY RATE

4.32¢ per kwh for the first 500 kwh*
2.70¢ per kwh for next 2000 kwh or 100 kwh/kw
1.91¢ per kwh for all additional kwh

*When the Billing Demand exceeds 5 kw, add 100 kwh for each kw of such excess.

Minimum: $6.20 plus $2.85 for each kw of Billing Demand in excess of 4.0 kw.

BILLING DEMAND

The Billing Demand shall be the maximum KW registered or computed, by or from Company's metering facilities, during a 15-minute interval within the current billing month. However, the Billing Demand shall not be less than the greater of (1) 80% of the maximum monthly 15-minute demand during the billing months of July through October of the preceding eleven billing months or (2) 60% of the maximum monthly 15-minute demand during the billing months of November through June of the preceding eleven billing months or (3) 75% of the Contract Demand until such time as the Billing Demand first equals or exceeds the effective Contract Demand.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

GENERAL

Service rendered under this Schedule is subject to the provisions of Company's Street Lighting Service Regulations filed with the state regulatory commission.

Supersedes Schedule SL-2J

Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

FIRE PUMPS

. Demand charges for equipment used exclusively for fire pumps or similar emergency service shall be waived for billing purposes provided Customer advises Company within 48 hours after the operation of such equipment for fire or other emergency service. Customer may operate such equipment for test purposes during prearranged periods satisfactory to Company, and the demands created by such prearranged test operations will be ignored for billing purposes.

Customer shall pay to Company cost of local facilities, including transformers, or the pro rata portion of total cost of facilities provided to supply service for emergency equipment.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than five years.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule MP-1M
Effective for service rendered on and after July 1, 1977

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

TRAFFIC SIGNAL SERVICE

SCHEDULE TSS-3

AVAILABILITY

This Schedule is available for electric service supplied for the operation and illumination of traffic signals installed along public and private highways where Company has an existing secondary distribution line.

INSTALLATION

The Company, for each signal or group of signals operating from one controller, will make its connection to Customer's service wire at a point one foot below the lowest support, carrying existing 120/240 volt conductors, or the equivalent, on the nearest pole. Customer will furnish, install, and maintain all service wires, fixtures, and other necessary equipment, including lamps and lamp renewals, for the installation and operation of all traffic signals.

TYPE OF SERVICE

Alternating current, 60 hertz, single phase, 2 wires, 120 volts nominal.

DEFINITIONS

A One-way Signal is a signal with only one face which can be seen from only one approach.
A Multi-Direction Signal is a signal with more than one face each of which can be seen from only one approach.

MONTHLY RATE

TYPE OF SIGNAL	MONTHLY RATE PER SIGNAL: With Lamps of 70 Watts or less(1) Operating for a Maximum Day of 16 Hours	24 Hours	With Lamps of 150 Watts or less Operating for a Maximum Day of 16 Hours	24 Hours
Blinker Signal with				
One Lamp	$0.85	$1.10	$1.65	$2.10
One-way Signal with				
One Lamp	$0.90	$1.10	$2.05	$2.85
Two Lamps	1.30	1.60	2.90	3.80
Three Lamps	1.40	1.80	3.00	4.00
Four Lamps	1.65	2.10	4.00	5.30

(1) When a customer elects to install a lamp of 120 watts or less, in lieu of 70 watts or less, in the red cycle of a One-way Signal with two or more lamps, then the rates for all One-way Signals with two, three or four lamps will be increased by $0.40 and $0.45, respectively, for 16 hours and 24 hours of operation.

Multi-Direction Signal

The rate for a Multi-Direction Signal is the sum of the applicable One-way Signal rate for each face of the Multi-Direction Signal.

Minimum: The amount computed under the above rates but not less than $6.50.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than one year.

GENERAL

Service rendered under this Schedule is subject to the provisions of the Service Regulations of the Company on file with the state regulatory commission.

Supersedes Schedule TS-1F
Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

AREA LIGHTING SERVICE
SCHEDULE ALS-3

AVAILABILITY

This Schedule is available for service supplied in the lighting of outdoor areas, private streets and private driveways by means of mercury vapor or sodium vapor lighting units. Lighting units will be bracket mounted on Company-owned poles and the mercury vapor lamps will be color corrected.

This Schedule is not available for the lighting of dedicated streets or highways.

SERVICE

Prior to installing area lighting facilities, customer and Company must execute Company's form entitled Application for Area Lighting Service. The service supplied by Company will include the installation and operation, according to Company standards and requirements, of the area lighting units and will include the furnishing of electricity required for the illumination of the lamps from dusk to dawn. Company will perform as soon as practicable, during regular working hours, the necessary maintenance to restore illumination after customer has notified Company that a lamp is not burning. The nominal lumen rating of the lighting units listed under the Monthly Rate indicates the class of lamp.

MONTHLY RATE PER LIGHTING UNIT

Basic Rate The basic rate does not include the monthly charges for additional facilities as set forth below or the contributions required under this Schedule.

Lighting Units	Overhead Service		Underground Service			
	Wood Pole		Wood Pole		Metal Pole	
	One Unit Per Pole	Two Units Per Pole	One Unit Per Pole	Two Units Per Pole	One Unit Per Pole	Two Units Per Pole
Mercury Vapor Units						
7000 lumen semi-enclosed	$ 5.25	$ 4.35	$ 9.85	$ 6.45	$ 12.70	$ 8.00
7000 lumen enclosed	6.45	4.90	11.10	7.35	13.95	8.95
7000 lumen post type	N/A	N/A	13.95	N/A	13.95	N/A
21000 lumen enclosed	8.45	6.95	13.75	9.70	17.20	11.25
21000 lumen flood	10.60	9.10	15.95	11.95	19.35	13.45
60000 lumen enclosed	14.30	12.45	20.20	15.55	23.65	17.15
60000 lumen flood	16.80	14.95	22.70	18.05	26.15	19.60
Sodium Vapor Units						
12000 lumen semi-enclosed	8.95	7.40	15.70	10.80	21.05	14.10
12000 lumen enclosed	9.40	7.85	16.05	11.15	21.35	14.45
12000 lumen post type	N/A	N/A	18.80	N/A	18.80	N/A
27000 lumen flood	13.05	11.05*	20.40	14.85*	25.25	17.60*
35000 lumen enclosed	10.85	9.10	16.05	11.70	19.40	13.55
50000 lumen enclosed	13.80	11.70	19.80	14.75	23.15	16.65
50000 lumen flood	15.40	13.05*	22.10	16.55*	26.95	19.30*

*Up to four (4) 21000 lumen, 27000 lumen, 50000 lumen, or 60000 lumen flood lighting units may be installed on one pole. The Monthly Rate per Lighting Unit will be as shown for the two units per pole.

Additional Required Facilities If the providing of lighting service requires the installation of poles other than those on which lighting units are installed, an extension of Company's primary conductors, the installation of a distribution transformer used only for the lighting service, or the installation of secondary underground conductors in excess of the footage stated below, the following monthly charges will be added to the basic charges.

(1) For each such wood pole $1.65

(2) For distribution transformer and/or primary conductors:

Agreements prior to March 1, 1973, 1.25 percent of the estimated installed cost.
Agreements on and after March 1, 1973, 2.0 percent of the estimated installed cost.

(3) For each span of underground secondary conductor in excess of the following:

7000 lumen unit	150 feet
21000 lumen unit	175 feet
60000 lumen unit	225 feet
27000 lumen unit	175 feet
35000 lumen unit	175 feet
50000 lumen unit	225 feet

Agreements on and after March 1, 1973, 2.0 percent of the estimated installed cost.

NONREFUNDABLE CONTRIBUTION

A customer receiving service from underground conductors will make a nonrefundable contribution for the following:

(1) Estimated additional cost of installing cable under paved areas.

(2) Estimated additional cost incurred due to encountering rock or other obstruction.

CONVERSION OF OVERHEAD CONDUCTORS

Service supplied under the Monthly Rate for Underground Service in this Schedule does not include the conversion of existing overhead secondary conductors to underground. Should the customer desire such a conversion under this Schedule, customer will contribute to Company, in addition to the applicable contributions above, the estimated net loss in salvage value of the overhead facilities being removed. The customer will thereafter pay the applicable rate for underground service.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall be not less than three years for overhead service and not less than five years for underground service and shall extend from year to year thereafter until terminated by the customer or Company. The customer may terminate the Agreement before the expiration of the initial Contract Period by paying to Company a sum of money equal to 40 percent of the bills which otherwise would have been rendered for the unexpired months of the initial Contract Period.

Company may require the customer to initially make a termination deposit which will not exceed the termination amount computed in accordance with the above paragraph. Such termination deposit will be refunded in equal amounts at the end of each full year service is rendered. This annual refund will be the termination deposit divided by the number of years in the Contract Period.

GENERAL

Service rendered under this Schedule is subject to the provisions of Company's Service Regulations filed with the state regulatory commission.

Supersedes Schedule AL-1H

Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

POLE TYPE STREET LIGHTING SERVICE

SCHEDULE SLP-3
(Overhead Conductors)

AVAILABILITY

This Schedule is available for service supplied in the lighting of dedicated public streets, highways, municipally owned and operated public parking lots, and municipally owned and operated public parks by means of incandescent, mercury vapor and sodium vapor lighting units mounted on Company owned poles. This Schedule is also available for continuous service to other installations which were being served on April 1, 1973 under the superseded Schedule SL-1G.

This Schedule is not available in areas where the primary and secondary distribution system is installed underground or in residential areas where the primary and secondary distribution system is installed overhead along rear property lines. This Schedule also is not available for the lighting of outdoor areas, private streets or private driveways, unless service was being furnished on April 1, 1973 under Company's superseded Schedule SL-1G.

SERVICE

The service supplied by Company will include the installation of a street lighting system, according to Company's standards and requirements, which will be owned, maintained and operated by Company, including the furnishing of the electricity required for the illumination of the lamps from dusk to dawn. When a metal pole is installed, the customer will make a nonrefundable contribution equal to the total installed cost of the metal pole in excess of $75.00 for each pole. The nominal lumen ratings of lighting units listed under the Monthly Rate indicate the class of lamp.

MONTHLY RATE PER LIGHTING UNIT

Basic Rate The basic rate does not include the monthly charges for additional facilities or for less than ten units or the contribution, if any, required under this Schedule and under the Street Lighting Service Regulations.

Incandescent Lighting Units	Monthly Charge
2500 lumen open unit - bracket mounted	$ 2.45
- on mast arm or center suspension	2.95
6000 lumen enclosed unit	4.45
10000 lumen enclosed unit	6.10
Mercury Vapor Lighting Units	
7000 lumen semi-enclosed unit	4.45
7000 lumen enclosed unit	4.95
21000 lumen enclosed unit	6.65
60000 lumen enclosed unit	12.65
Sodium Vapor Lighting Units	
12000 lumen semi-enclosed unit	6.25
12000 lumen enclosed unit	6.60
35000 lumen enclosed unit	8.80
50000 lumen enclosed unit	11.05

Additional Facilities If providing the lighting service requires an extension of Company's primary conductors, requires the installation of a distribution transformer used only for lighting service, requires the use of other than Company's standard brackets or mast arms, requires the installation of one or more poles, or if a metal pole is installed at Customer's request, the following monthly charges will be added to the basic charges.

(1)	For each special street lighting wood pole	$0.95
(2)	For each special street lighting metal pole (see SERVICE provision)	1.50
(3)	For each system street lighting metal pole (see SERVICE provision)	0.55

(4) For a distribution transformer and/or primary conductors - 2.0% of estimated installed cost of the required facilities.

(5) For a bracket or mast arm in excess of six feet on a metal pole or 16 feet on a wood pole - 2.0% of the estimated additional installed cost of all required facilities.

Less Than Ten Lighting Units When the total number of lighting units billed to a customer under a contract containing this and any other applicable street lighting schedule is less than ten units, a sum of money equal to twenty-five cents ($0.25) times the difference between ten and the number of lighting units billed under the contract will be added to customer's monthly billing.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than 10 years.

GENERAL

Service rendered under this Schedule is subject to the provisions of Company's Street Lighting Service Regulations filed with the state regulatory commission.

Supersedes Schedule SL-1N

Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

UNDERGROUND STREET LIGHTING SERVICE

SCHEDULE SLU-3

AVAILABILITY

This Schedule is available for service supplied in the lighting of dedicated public streets, highways, municipally owned and operated public parking lots, and municipally owned and operated public parks by means of mercury vapor and sodium vapor lighting units. This Schedule is also available for continuous service to other installations which were being served on April 1, 1973, under the superseded Schedule SL-2C. The lighting units normally will be bracket mounted on Company-owned standard metal poles; however, wood poles are available.

This Schedule is not available for the lighting of outdoor areas, private streets, or private driveways, unless service was being furnished on April 1, 1973, under Company's superseded Schedule SL-2C.

SERVICE

The service supplied by Company will include the installation of an underground street lighting system, according to Company's standards and requirements, which will be owned, maintained and operated by Company, including the furnishing of the electricity required for the illumination of the lamps from dusk to dawn. The nominal lumen ratings of lighting units listed under the Monthly Rate indicate the class of lamp.

MONTHLY RATE PER LIGHTING UNIT

Basic Rate The basic rate does not include the monthly credit for joint installation or the monthly charge for additional facilities or the monthly charge for less than ten units or the contribution, if any, required under this Schedule and the Street Lighting Service Regulations.

	Monthly Charge	
One Lighting Unit Per Pole	Wood Pole	Metal Pole
Mercury Vapor		
7000 lumen semi-enclosed unit	$ 7.15	$ 8.05
7000 lumen enclosed unit	7.60	8.50
7000 lumen post type unit	8.50	8.50
21000 lumen enclosed unit	9.90	11.60
60000 lumen enclosed unit	N/A	16.20
Sodium Vapor		
12000 lumen semi-enclosed unit	14.05	17.35
12000 lumen enclosed unit	14.40	17.70
12000 lumen post type unit	17.00	17.00
35000 lumen enclosed unit	18.85	21.65
50000 lumen enclosed unit	N/A	23.40
Two Lighting Units Per Pole		
Mercury Vapor		
7000 lumen semi-enclosed - per lighting unit	5.35	5.80
7000 lumen enclosed - per lighting unit	5.80	6.25
21000 lumen enclosed - per lighting unit	8.00	8.80
60000 lumen enclosed - per lighting unit	N/A	13.35
Sodium Vapor		
12000 lumen semi-enclosed - per lighting unit	10.00	13.30
12000 lumen enclosed - per lighting unit	10.35	13.65
35000 lumen enclosed - per lighting unit	13.40	14.80
50000 lumen enclosed - per lighting unit	N/A	16.75

Credit for Joint Installation The following credit will apply for each street lighting pole where seventy-five percent (75%) or more of the span of street lighting cable is installed at the same time and in the same trench as the underground distribution system:

7000 lumen mercury unit	$ 1.25 per pole
21000 lumen mercury unit	0.75 per pole
60000 lumen mercury unit	0.95 per pole
12000 lumen sodium unit	2.50 per pole
35000 lumen sodium unit	2.10 per pole
50000 lumen sodium unit	1.65 per pole

Additional Facilities If providing the lighting service requires an extension of Company's primary conductors, requires the use of other than Company's standard brackets or requires the installation of a span of street lighting cable in excess of the footage shown below, the following monthly charges will be added to the basic charge:

(1) For an extension of primary conductors - 2.0% of the estimated installed cost of the required facilities.

(2) For any mast arm - 2.0% of the estimated installed cost of all required facilities in excess of those required for a bracket mounted unit. A bracket is 6 feet or less and a mast arm is over 6 feet in length.

(3) For a span of street lighting cable in excess of the footage shown below - 2.0% of the estimated installed cost of such overages (1.5% for customers served prior to December 1, 1973). The cost of each overage will be computed individually by multiplying the number of feet of excess length of cable in the span by the average installed cost per foot of that span.

7000 lumen units	250 feet
21000 lumen units	225 feet
60000 lumen units	200 feet
12000 lumen units	250 feet
35000 lumen units	225 feet
50000 lumen units	200 feet

Less Than Ten Lighting Units When the total number of lighting units billed to a customer under a contract containing this and any other applicable street lighting schedule is less than ten units, a sum of money equal to twenty-five cents ($0.25) times the difference between ten and the number of lighting units billed under the contract will be added to customer's monthly billing.

NONREFUNDABLE CONTRIBUTION

A customer receiving service under this Schedule will make a contribution for the following:

(1) In the event that rock, unstable soil, or other conditions require the use of materials and methods of installation other than Company's normal materials and methods, customer will contribute the additional cost incurred thereby.

(2) The estimated cost of installing cables under paved areas; however, the customer may cut and replace the pavement in lieu of making the contribution.

CONVERSION OF OVERHEAD CONDUCTORS

Service supplied under the Monthly Rate in this Schedule does not include the conversion of existing overhead street lighting circuits to underground. Should the customer desire such a conversion under this Schedule, customer will pay to Company, in addition to the applicable contribution above, the estimated net investment depreciated, plus removal cost, less salvage value of the overhead conductor being removed.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this Schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than 10 years.

Carolina Power & Light Company
(North Carolina Only)

UNDERGROUND STREET LIGHTING SERVICE

SCHEDULE SLUC-3
(Customer Participation)

AVAILABILITY

This Schedule is available for service supplied in the lighting of dedicated public streets, municipally owned and operated public parking lots, and municipally owned and operated public parks by means of mercury vapor and sodium vapor lighting units. The lighting units normally will be bracket mounted on Company-owned standard metal poles; however, wood poles are available.

This Schedule is not available for the lighting of highways, outdoor areas, private streets, or private driveways.

SERVICE

The service supplied by Company will include the installation of an underground street lighting system, according to Company's standards and requirements, which will be owned, maintained and operated by Company, including the furnishing of the electricity required for the illumination of the lamps from dusk to dawn. The nominal lumen ratings of lighting units listed under the Monthly Rate indicate the class of lamp.

MONTHLY RATE PER LIGHTING UNIT

Basic Rate The basic rate does not include the monthly charges for additional facilities or for less than ten units or the contribution required under this Schedule and under the Street Lighting Service Regulations.

	Monthly Charge	
One Lighting Unit Per Pole	Wood Pole	Metal Pole
Mercury Vapor		
7000 lumen semi-enclosed unit	$ 5.40	$ 5.95
7000 lumen enclosed unit	5.85	6.40
7000 lumen post type unit	6.40	6.40
21000 lumen enclosed unit	7.60	8.15
60000 lumen enclosed unit	N/A	14.15
Sodium Vapor		
12000 lumen semi-enclosed unit	7.25	7.85
12000 lumen enclosed unit	7.60	8.20
12000 lumen post type unit	8.20	8.20
35000 lumen enclosed unit	9.75	10.30
50000 lumen enclosed unit	N/A	12.55
Two Lighting Units Per Pole		
Mercury Vapor		
7000 lumen semi-enclosed - per lighting unit	4.95	5.25
7000 lumen enclosed - per lighting unit	5.40	5.70
21000 lumen enclosed - per lighting unit	7.15	7.40
60000 lumen enclosed - per lighting unit	N/A	13.45
Sodium Vapor		
12000 lumen semi-enclosed - per lighting unit	6.75	7.05
12000 lumen enclosed - per lighting unit	7.10	7.40
35000 lumen enclosed - per lighting unit	9.30	9.60
50000 lumen enclosed - per lighting unit	N/A	11.85

Additional Facilities If providing the street lighting service requires an extension of primary conductors or requires the use of other than Company's standard brackets, the following monthly charge will be added to the basic charges:

(1) For an extension of primary conductors - 2.0% of the estimated installed cost of the required facilities.

(2) For any mast arm - 2.0% of the estimated installed cost of all required facilities in excess of those required for a bracket mounted unit. A bracket is 6 feet or less and a mast arm is over 6 feet in length.

Less Than Ten Lighting Units When the total number of lighting units billed to a customer under a contract containing this and any other applicable street lighting schedule is less than ten units, a sum of money equal to twenty-five cents ($0.25) times the difference between ten and the number of lighting units billed under the contract will be added to customer's monthly billing.

NONREFUNDABLE CONTRIBUTION

Installations under this Schedule are based on the customer making the following contributions:

(1) Base Contribution

The contributions stated under "Wood Pole" or "Metal Pole" provide for the installation of standard fixtures on the type wood or metal poles approved by the Company for use at the time of the installation.

(a) Separate Installation

The following applies for each street lighting pole where less than seventy-five percent (75%) of a span of street lighting cable is installed at the same time and in the same trench as the underground distribution system:

	Wood Pole	Metal Pole
7000 lumen bracket mounted unit	$ 108.50	$ 155.00
7000 lumen post type unit	155.00	155.00
21000 lumen mercury vapor unit	140.00	230.00
60000 lumen mercury vapor unit	N/A	175.00
12000 lumen bracket mounted sodium unit	270.00	395.00
12000 lumen post type sodium unit	350.00	350.00
35000 lumen sodium vapor unit	300.00	390.00
50000 lumen sodium vapor unit	N/A	375.00

(b) Joint Installation

The following applies for each street lighting pole where seventy-five percent (75%) or more of a span of street lighting cable is installed at the same time and in the same trench as the underground distribution system:

	Wood Pole	Metal Pole
7000 lumen bracket mounted unit	$ 18.50	$ 65.00
7000 lumen post type unit	65.00	65.00
21000 lumen mercury vapor unit	85.00	175.00
60000 lumen mercury vapor unit	N/A	120.00
12000 lumen bracket mounted sodium unit	150.00	280.00
12000 lumen post type sodium unit	235.00	235.00
35000 lumen sodium vapor unit	205.00	295.00
50000 lumen sodium vapor unit	N/A	300.00

(2) Excess Footage

When any street lighting pole is located so that a span of underground cable necessary to provide service exceeds the footage listed below, customer will contribute the sum of the estimated costs of all such overages within the project currently being installed. The cost of each overage will be computed individually by multiplying the number of feet of excess length of cable in the span by the average installed cost per foot of that span.

7000 lumen units	250 feet
21000 lumen units	225 feet
60000 lumen units	200 feet
12000 lumen units	250 feet
35000 lumen units	225 feet
50000 lumen units	200 feet

(3) Natural Conditions

In the event that rock, unstable soil, or other conditions require the use of materials and methods of installation other than Company's normal materials and methods, customer will contribute the additional cost incurred thereby.

(4) Existing Pavement

If the underground cable is to be installed under an existing paved area, customer will contribute the estimated additional cost of installing cables under paved areas, however, the customer may cut and replace the pavement in lieu of making the contribution.

(5) Conversion of Overhead Street Lighting

Service supplied under the Monthly Rate or the contributions set forth above do not include the conversion of existing overhead street lighting circuits to underground. Should the customer desire such a conversion under this Schedule, customer will pay to Company, in addition to the applicable contributions above, the estimated net investment depreciated, plus removal cost, less salvage value of the overhead conductors being removed.

APPROVED FUEL CHARGE

The Approved Fuel Charge applicable to retail service will apply to all service supplied under this schedule.

PAYMENTS

Bills are due when rendered and are payable within 15 days from the date of the bill. If any bill is not so paid, Company has the right to suspend service in accordance with its Service Regulations. In addition, any bill not paid on or before the expiration of twenty-five (25) days from the date of the bill is subject to an additional charge of 1% per month as provided in Rule R12-9 of the Rules and Regulations of the North Carolina Utilities Commission.

CONTRACT PERIOD

The Contract Period shall not be less than 10 years.

GENERAL

Service rendered under this Schedule is subject to the provisions of Company's Street Lighting Service Regulations filed with the state regulatory commission.

Supersedes Schedule SL-3J

Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

STREET LIGHTING SERVICE

SCHEDULE SLR-3
(Residential Subdivisions)

AVAILABILITY

This Schedule is available for service supplied in the lighting of residential dedicated public streets by means of mercury vapor lighting units installed within residential subdivisions, consisting of single or duplex dwelling units, located outside the corporate limits of a municipality at the time of the installation.

This Schedule is not available to supply service for the lighting of parking lots, shopping centers, other public or commercial areas within the residential subdivision, or areas not specifically provided for by the provisions herein.

SERVICE

The service supplied by Company will include the installation of a street lighting system, according to Company's standards and requirements, which will be owned, maintained and operated by Company including the furnishing of the electricity required for the illumination of the lamps from dusk to dawn. Lighting units will be located by Company to provide the most uniform lighting possible in the residential area. The nominal lumen ratings of the lighting units furnished under the Monthly Rate indicate the class of lamp.

MONTHLY RATE

The following amount will be added to each monthly bill rendered for residential electric service within the subdivision:

OVERHEAD DISTRIBUTION AREA:

7000 lumen, bracket mounted, enclosed luminaire on approved type wood pole - 1 street light per 10 customers or major fraction thereof - - - - - $0.65 per customer.

7000 lumen, bracket mounted, enclosed luminaire on approved type wood pole - 1 street light per 5 customers or major fraction thereof - - - - - $1.30 per customer.

UNDERGROUND DISTRIBUTION AREA:

7000 lumen, bracket mounted, enclosed luminaire on an approved type wood pole - 1 street light per 10 customers or major fraction thereof - - - - - $0.80 per customer.

7000 lumen, bracket mounted, enclosed luminaire on a standard metal pole - 1 street light per 10 customers or major fraction thereof - - - - - $0.90 per customer.

7000 lumen, bracket mounted, enclosed luminaire on an approved type wood pole - 1 street light per 5 customers or major fraction thereof - - - - - $1.60 per customer.

7000 lumen, bracket mounted, enclosed luminaire on standard metal pole - 1 street light per 6 customers or major fraction thereof - - - - - $1.55 per customer.

7000 lumen approved post mounted type luminaire - 1 street light per 6 customers or major fraction thereof - - - - - $1.55 per customer.

ANNEXATION CONSIDERATIONS

1. If any of the following conditions exist, the developer of the subdivision will be required to obtain from the municipal governing agency its written approval of the street lighting service being provided under this Schedule and the number and location of the lights to be installed:

   a. The subdivision abuts a boundary of the municipality.

   b. It is known that the subdivision will be annexed into the municipality.

c. The municipal governing agency has enacted a subdivision control ordinance which applies to the subdivision or any portion thereof.

2. If the subdivision is subsequently annexed, and the municipality accepts the street lighting under a street lighting service contract on the rate for the equivalent lighting unit, the following will apply:

OVERHEAD DISTRIBUTION - If the municipality accepts the street lighting service under Pole Type Street Lighting Service Schedule SLP-3, no monthly customer charge will be applied to the subdivision residents.

UNDERGROUND DISTRIBUTION - If the municipality accepts the street lighting service under Underground Street Lighting Service Schedule SLU-3, no monthly customer charge will be applied to the subdivision residents. If the municipality accepts the street lighting service under Underground Street Lighting Service Schedule SLUC-3 (Customer Participation), the monthly customer charges will be reduced according to the following schedule:

\$0.80 charge reduced to - - -	\$0.25
\$0.90 charge reduced to - - -	\$0.30
\$1.55 charge reduced to - - -	\$0.45
\$1.60 charge reduced to - - -	\$0.45

3. If the subdivision is subsequently annexed, and the municipality does not accept the installed street lighting under a street lighting service contract, the service will continue to be provided under this Schedule with the applicable monthly charges.

NONREFUNDABLE CONTRIBUTION

Normally a contribution will not be required for service under this Schedule. The Company will require a nonrefundable contribution from the developer under the following conditions:

1. Unusual Circumstances - In the event rock, unstable soil, or other conditions require the use of materials and methods of installation other than Company's normal materials and methods, the developer will contribute the additional cost incurred thereby.

2. Paved Areas - If Company has to install any portion of the street lighting system under existing paved areas, the developer will either cut and replace the pavement or contribute to Company the additional cost incurred to install its facilities under the paved area.

3. Excess Circuitry - When any lighting unit is located so that the span of underground cable necessary to serve such unit exceeds 250 feet, the developer will contribute the sum of the estimated installed costs of all such overages within the subdivision.

EXISTING SUBDIVISIONS

Street lighting service under this Schedule will be available in existing residential subdivisions provided the Company receives a petition requesting this service signed by all the owners of residential lots within the subdivision. When the electrical distribution system within the subdivision is installed underground, the persons requesting the installation of the street lighting system will pay to Company, in addition to any contribution required above, a nonrefundable contribution equal to the cost of trenching and backfilling necessary for the installation of the street lighting system. If a contribution is required under Excess Circuitry, that portion of trenching and backfilling included in such contribution will be excluded from the preceding requirement. Relandscaping of the area necessary due to the installation of the street lighting system will be the responsibility of the residents within the subdivision. The appropriate monthly charge as set forth above will be applied to the monthly billings of all residents in the subdivision.

PAYMENTS

The monthly charges set forth under this Schedule will be billed in conjunction with the normal bill for residential service. The total of the bill so rendered shall be subject to the terms and conditions of the Service Regulations approved and on file with the state regulatory commission. Failure to pay the total bill rendered when due and payable shall constitute a failure to pay the bill for residential service.

CONTRACT PERIOD

The applicable monthly charge set forth in this Schedule shall be applied to the monthly billings of all residents in the subdivision as long as street lighting service is provided under any of the conditions as set out herein.

Supersedes Schedule SL-4C

Effective for service rendered on and after July 1, 1977.

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

CONSTRUCTION COST

RIDER NO. 15E

AVAILABILITY

This Rider is applicable to and becomes a part of all schedules for metered service under Service Agreements for one year or more when the construction cost exceeds the revenue credit, except that this Rider is not applicable to short term or temporary service, or to single phase residential or small commercial service.

CONSTRUCTION COST

The construction cost is the estimated cost of extending Company's facilities, exclusive of the cost of the transformers and the installed cost of meters and metering equipment, and Company and Customer shall each participate as follows:

1. Company will, at Customer's option, finance the construction cost up to an amount equal to 300 per cent of the revenue credit as hereinafter defined.

2. Customer shall finance any construction cost in excess of 300 per cent of the revenue credit and when Customer is taking service under a Service Agreement having an initial term of ten years, such excess shall be refundable in annual installments after Customer has taken service, under the original Service Agreement, for a period of 60 consecutive billing months. Each such annual installment shall be in an amount equal to 10 per cent of the bills paid (exclusive of Seasonal Service charges and the additional charges provided for by this Rider) for the twelve billing months of the current contract year, provided that the aggregate of such installments shall not exceed the excess costs financed by Customer, and that any portion of the excess costs not refunded at the expiration of the initial term of the original Service Agreement shall not thereafter be refunded.

REVENUE CREDIT

The revenue credit is the amount equal to 20 per cent multiplied by the number of years in the initial term of the Service Agreement, up to but not more than five years, times the difference between (a) the estimated annual revenue plus $100 and (b) the estimated annual kilowatt-hours multiplied by 0.68¢ per kwh. The estimated annual revenue shall be determined from the "Monthly Rate" set forth in the applicable rate schedule. In the case of a seasonal or intermittent Customer, the $100 will not be added to the estimated annual revenue.

BILLING

The monthly bill, for the initial term of the Service Agreement, but for not more than 60 consecutive monthly bills, shall be the amount computed under the applicable rate schedule and riders plus $________________, which is the sum of the following amounts, taken to the nearest dollar:

1. An amount equal to 1.0 per cent of the construction cost in excess of 200 per cent of the revenue credit or $______________ per month.

2. An amount equal to 0.5 per cent of the construction cost financed by Company in excess of 200 per cent of the revenue credit or $__________________ per month.

After 60 consecutive monthly bills Customer shall be billed in accordance with the applicable schedule and riders without giving effect to "Billing" under this Rider.

CONTRACT PERIOD

The contract period shall not be less than one year.

Supersedes Construction Cost Rider No. 15B
Effective for service rendered on and after July 1, 1977.
NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

TWO-PHASE SERVICE

RIDER NO. 41A

AVAILABILITY

This Rider is available in conjunction with the Small General Service Schedule for a Customer whose electric service requirements include two-phase electric service for equipment which will operate only on this type service.

This Rider will apply only to those customers presently receiving two-phase electric service and is not available to other customers. Should a customer served under this Rider terminate service, the Rider shall not be available thereafter.

The provisions of the Small General Service Schedule are modified only as shown herein.

TYPE OF SERVICE

The types of service to which this Schedule is applicable are alternating current, 60 hertz, single phase 2 or 3 wires, two-phase 4 wires (non-standard), or three phase 3 or 4 wires, at Company's standard voltages. When Customer desires two or more types of service, which types can be supplied from a single phase 3 wire type or a three phase 4 wire type, without voltage transformation, only the one of these two types necessary for Customer's requirements will be supplied.

Superseding Schedule TW-2
Effective on service rendered on and after July 1, 1977

NCUC Docket No. E-2, Sub 297

Carolina Power & Light Company
(North Carolina Only)

APPROVED FUEL CHARGE

RIDER NO. AFC-1

APPLICABILITY

This Rider is applicable to and becomes a part of all of Company's basic rate schedules and riders which provide for the supply of electric service.

MONTHLY BILLING

The monthly bill as computed under the applicable rate schedules and riders will include an amount computed below:

An amount equal to the result of multiplying (-$0.00055) times the kilowatt-hours used to reflect the current cost of fuels.

Effective on service rendered on and after July 1, 1977

NCUC Docket No. E-2, Sub 297

Any suspension of the delivery of electricity by Company or termination of the Agreement upon any authorized grounds shall in no wise operate to relieve Customer of his liability to pay for electricity supplied, nor shall it relieve Customer (1) of his liability for the payment of minimum monthly charges during the period of suspension, nor (2) of his liability for damages, if the Agreement has been terminated, in the amount of the minimum monthly charges which would have been payable during the unexpired term of the Agreement. Whenever the supply of electricity is suspended for any authorized reason, Company will make a charge of $5.00 for the restoration of service.

2. CONDITIONS OF SERVICE

(a) Company is not obligated to supply electricity to Customer unless and until: (1) Company's form of Application for Supply of Electricity is executed by Customer and accepted by Company; (2) in cases where it is necessary to cross private property to deliver electricity to Customer, the Customer conveys or causes to be conveyed to Company, without cost to Company, a right-of-way easement, satisfactory to Company, across such private property for the construction, maintenance, and operation of Company's lines and facilities, necessary to the delivery of electricity by Company to Customer: provided, however, in the absence of a formal conveyance, Company, nevertheless, shall be vested with an easement over Customer's premises authorizing it to do all things necessary to the construction, maintenance, and operation of its lines and facilities for such purpose; (3) any inspection certificates or permits that may be required by law in the local area are furnished to Company.

(b) If Company installs a substation or other facilities for service to Customer, any available capacity of such facilities not needed to supply Customer may be used by Company to supply others.

(c) Company may refuse to furnish electric service to any Applicant, or Customer, who at the time is indebted to Company for electric service previously supplied to such Applicant or Customer, or any other member of his household, or business, in any area served by Company, except that an applicant for residential service shall not be denied service for failure to pay such bills for classes of nonresidential service.

(d) If electricity is supplied by lines which cross the lands of the United States of America, a state, or any agency or subdivision of the United States of America or of a state, Company shall have the right, upon 30 days' written notice, to discontinue the supply of electricity to any Customer or Customers receiving electricity from such lines, if and when (1) Company is required by governmental authority to incur expense in the relocation or the reconstruction underground of any portion of said lines, unless Company is reimbursed for such expense by the Customer or Customers served therefrom, or (2) the right of Company to maintain and operate said lines shall be terminated, revoked, or denied by governmental authority for any reason.

3. SERVICE CHARGE

When Company first supplies electricity under any applicable Schedule to a Customer who has a load of 25 kw or less at a specified premises, the Customer shall pay the Company a service charge of $5.00, which shall be in addition to all other charges under the Service Agreement. This service charge shall become a part of the first bill rendered thereafter to Customer for electricity supplied at such premises unless it be paid in advance of the rendition of such bill.

4. RETURNED CHECK CHARGE

In conformity with an Order of the North Carolina Utilities Commission, Company will make a charge of $5.00 for checks tendered on a Customer's account and returned for insufficient funds. Such charge shall apply regardless of when the check is tendered.

5. DEPOSITS

The collection of Customer deposits shall be as provided in Chapter 12 of the Rules and Regulations of the North Carolina Utilities Commission establishing uniform rules for all public utilities for the collection of Customer deposits.

6. USE OF ELECTRICITY

Electricity shall be supplied directly to Customer by Company and shall be used by Customer only for the purposes specified in, and in accordance with, the Agreement. Electricity supplied by Company shall be for Customer's use only and may not be sold directly on a metered or unmetered basis by Customer to lessees, tenants or others and under no circumstances may Customer or other person or concern install or maintain any meter for the purpose of metering electricity supplied with the object of rendering a bill therefor unless authorized by the Company's Schedule attached to and made a part of the Agreement.

A Customer who desires electricity for more than one classification of use on the same premises shall execute a separate Agreement for each separate classification, Customer's wiring being so arranged that electricity for each separate classification can be metered separately. When a Customer conducts a business in his residence, for which business electricity is used, Company will supply all electricity through one meter under the Schedule applicable to the classification for his business use, unless Customer's wiring is so arranged that his residential use and his business use can be separately metered, in which event the appropriate Schedule will be applied to each such use.

In the event Customer utilizes a form of load control, such controls shall not cause a demand to be placed on Company's facilities which, in Company's opinion, unreasonably exceeds the integrated metered demand. Company reserves the right to determine the maximum fifteen-minute demand on a rolling time interval rather than the time interval of the metering facility in order to reflect the effect of any such controlled demand. The rolling time interval may or may not coincide with a time interval, if any, being supplied to Customer.

Customer shall not without the written assent of Company connect his installation to lines which cross over or under any public or semi-public space in order to supply electricity purchased through one meter to his adjacent properties. Such written assent may be given only in instances where such adjacent properties are operated as one integral unit under the same name and proprietorship and for carrying on parts of the same business, and where a separate type of business is not involved.

7. CONTRACT DEMAND

(a) The Contract Demand shall be the kw of demand specified in the Service Agreement. In cases where any change is required in Company's facilities due to the actual demand exceeding the Contract Demand or due to the Customer requesting an increase in available capacity, Company may require Customer to execute a new Agreement or amend an existing Agreement, thereby establishing a new Contract Demand. If Company is unable to supply such actual or requested increase, then upon written request, Customer will not exceed the existing Contract Demand or such amount in excess thereof as Company determines it is able to provide.

(b) If Customer desires to reduce the effective Contract Demand at any time prior to the time the Billing Demand of the applicable schedule first equals or exceeds the Contract Demand, Company may agree to reduce the Contract Demand to the number of kilowatts specified in writing by Customer provided Customer pays to Company a sum of money equal to the estimated cost (after deducting the then value of usable materials and facilities and the salvage value of nonusuable materials and facilities) of installing and removing the existing facilities in place for serving the customer, plus any money spent by Company which would not have been spent if Customer had originally requested the reduced Contract Demand. The agreed upon reduction shall be effective with the beginning of the next ensuing billing period.

The Company reserves the right to reduce its facilities to the capacity adequate to serve the Customer's maximum 15-minute demand of the preceding twelve billing months and to amend the Service Agreement to such maximum demand. If customer desires that Company not change its facilities, Company may agree to do so provided customer executes a Service Agreement for the amount such facilities were installed to serve.

(c) If Customer increases his load without adequate notice to Company, and without receiving Company's consent, and such unauthorized increase causes loss of or damage to Company's facilities, the cost of making good such loss or repairing such damage shall be paid by Customer.

8. LOW POWER FACTOR ADJUSTMENT

Customer shall at all times maintain a power factor at the point of delivery as nearly 100 per cent as practicable; however, if Customer's power factor determined at the time of maximum demand (determined in accordance with the applicable Schedule) is found to be less than 80 per cent lagging, Company will increase the demand used for billing purposes by the number of kilowatts equal to 20 per cent of the difference between (1) the maximum number of reactive kilovolt-amperes (kilovars) determined for the period of maximum demand and (2) 75 per cent of the demand as determined for the month in accordance with the provisions of the applicable Schedule.

9. BILLING

(a) Company's meters will be read as nearly as practicable at regular intervals of not less than 27 days and not more than 33 days. (By special order of the regulatory agencies bi-monthly reading is permitted under certain conditions.)

(b) If Company is unable to read Customer's meter for any reason, his use may be estimated by Company on the basis of his use during the next preceding billing period for which readings were obtained, unless some unusual condition is known to exist. A bill rendered on the basis of such estimate shall be as valid as if made from actual meter readings.

(c) The term "Month" or "Monthly" as used in Company's Schedules and Riders refers to the interval transpiring between the previous meter reading date and the current reading date and bills shall be rendered accordingly, except that if the period covered by an initial or final bill or due to rerouting of meter reading schedule is more or less than 27-33 days, the bill will be prorated based on a 30-day billing month.

10. METER STOPPAGE OR ERROR

In the event a meter fails to register accurately within the allowable limits established by the state regulatory body having jurisdiction, Company will adjust the measured usage for the period of time the meter was shown to be in error, not exceeding 60 days, just prior to the removal of such meter from service. Company shall refund or credit to Customer or Customer shall pay to Company the difference between the amount billed and the estimated amount which would have been billed had the meter not exceeded the allowable limits. No part of any minimum service charge shall be refunded.

11. POINT OF DELIVERY

The point of delivery is the point where Company's service conductors are, or are to be, connected to Customer's conductors. Customer shall do all things necessary to bring his service conductors to such point of delivery for connection to the Company's service conductors, and he shall maintain his said conductors in good order at all times. Unless otherwise stipulated in the Agreement, the point of delivery shall be located as follows:

(a) In cases of a connection of Company's overhead service conductors to Customer's overhead service conductors, such point of delivery shall be on the outside of the wall of Customer's building where Company's service conductors may be conveniently extended and anchored;

(b) In cases of connection of Company's overhead service conductors to Customer's underground service conductors, such point of delivery shall be at a place on Company's nearest pole approximately one foot below the Company's conductors from which Customer is to be supplied;

(c) In cases of connection of Company's underground service conductors to Customer's service conductors, such point of delivery shall be at a place on the outside wall of Customer's building to which Company's conductors may be conveniently extended and terminated;

(d) In cases where a ground type substation is installed by Company to supply electricity to Customer, the point of delivery shall be at a place to be designated by Company on its substation structure.

(e) In cases where a service entrance panel box is installed by Company on the exterior of the outside wall of Customer's dwelling for the purpose of supplying electricity under Company's All Electric Residential Service Schedule, the point of delivery shall be the point where Customer's conductors are connected to Company's conductors in such panel box.

(f) In cases where electric wiring is installed by Company in residences or apartment buildings with service entrances of 400 amperes or larger, by connection from Company's overhead service conductors, for the purpose of supplying electricity under Company's All Electric Residential Service Schedule, the point of delivery shall be the point where Company's conductors are connected to the main switch owned by Customer, or the point where Customer's conductors are connected to the meter trough provided for multiple dwelling units if there is not a main switch for all dwelling units.

Where special circumstances render it impracticable for the point of delivery to be located as above stated, then it shall be at a place selected or approved by Company and when so done the Customer shall bring his service conductors to and maintain them at such place.

12. INSTALLATIONS

(a) By Company: Company shall install, own, operate, and maintain all lines and equipment located on its side of the point of delivery. It shall also furnish and install the necessary meter, and meter transformers where necessary, for measuring the electricity used, though such meter will usually be located on Customer's side of the point of delivery.

When a Customer requests Company to supply electricity to a single premises in a special manner requiring facilities over and above those normally provided by Company, such additional facilities will be provided, if Company finds it practicable, under the following conditions:

(1) The facilities will be of a kind and type normally used by or acceptable to Company and will be installed at a place and in a manner satisfactory to Company.

(2) Customer will pay to Company a Monthly Facilities Charge equal to 2.0 per cent (1.5 percent for agreements prior to March 1, 1973) of the estimated installed cost of all facilities, including metering, required in addition to those Company would have provided, but not less than $25 per month for additional facilities not involving totalized metering or $100 per month for additional facilities involving totalized metering. The installed cost of all facilities will be based on current prices including new materials and equipment.

(3) If the Company increases its investment, other than replacement of existing equipment with equipment of equal capacity and kind, in facilities necessary to supply Customer's special electric requirements (including conversion of the primary voltage to a higher voltage), the monthly charge for providing the additional facilities will be adjusted at that time. The Customer may terminate the additional facilities in accordance with the applicable termination provisions or continue the additional facilities under the changed conditions.

(4) When an industrial Customer desires more than one point of delivery at one or more voltages with a meter installation, acceptable to Company, to obtain the total kilowatt hours and simultaneous kilowatts of demand, Company will furnish such service provided Customer will contract for:

(i) A total minimum Billing Demand of not less than 2000 kilowatts.

(ii) A minimum Billing Demand at each point of delivery of not less than 500 kilowatts.

(iii) Delivery voltages of not less than 480 volts.

Only those points of delivery located external to Customer's plant structure may be included in a totalized metering system arrangement. In case of a primary meter installation, the installed cost of metering equipment will not be included as additional facilities nor will the metering equipment be compensated for line or transformation losses.

(5) Company shall not be required to make such installation of facilities in addition to those normally provided until Customer has signed such agreements, including provisions for termination, as may be required by Company.

(b) By Customer: Customer shall install, own, operate, and maintain all lines, service conductors, and equipment, exclusive of Company's meter, meter transformers and meter base on Customer's side of the point of delivery, and Customer will be the owner and have exclusive control thereof as well also as of all electricity after it passes the point of delivery. Customer shall so arrange his wiring that all electricity for one type of use can be supplied at one point of delivery and measured by a single meter. Except under special circumstances, the Company's meter will be located on Customer's side of the point of delivery, and when it is to be so located the Customer must make suitable provision in his wiring for the convenient installation of the type of meter Company will use, and at a place suitable to Company. Customer's service entrance conductors shall not be installed within hollow walls unless the conductors are in conduit. Service entrance conductors not installed in conduit must be readily visible on the source side of Company's meter. And where a socket type meter is to be used, Company, upon application from Customer, will furnish to Customer (but retaining ownership) a meter base which will be installed by Customer at his expense in his wiring to accommodate the meter.

Customer shall not utilize any equipment, appliance, or device which tends to affect adversely Company's supply of service to, or the use of service by, Customer or others. Customer shall not install gaseous discharge lighting with a power factor of less than 90 per cent lagging. When polyphase service is supplied by Company, Customer shall control his use so that his load will be maintained in reasonable electrical balance between the phases at the point of delivery. Customer shall install and maintain devices adequate to protect his equipment against irregularities on Company's system, including devices to protect against single phasing.

(c) Access To Premises: The duly authorized agents of Company shall have the right of ingress and egress to the premises of Customer at all reasonable hours for the purpose of reading meters, inspecting Company's wiring and apparatus, changing, exchanging, or repairing its property on the premises of Customer and to remove such property at the time of or at any time after suspension of service or termination of Agreement.

(d) Protection: Customer shall protect Company's wiring and apparatus on Customer's premises and shall permit no one but Company's agents to handle same. In the event of any loss of or damage to such property of Company caused by or arising out of carelessness, neglect, or misuse by Customer, his employees or agents, the cost of making good such loss or repairing such damage shall be paid by Customer.

13. CONTINUANCE OF SERVICE AND LIABILITY THEREFOR

Company does not guarantee continuous service but shall use reasonable diligence at all times to provide an uninterrupted supply of electricity and having used reasonable diligence shall not be liable to Customer for damage, for failure in, or for interruptions or suspensions of, the same.

Company reserves the right to suspend service without liability on its part at such times and for such periods and in such manner as it may deem advisable (a) for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations, and facilities and (b) in cases where, in its opinion, the continuance of service to Customer's premises would endanger persons or property.

In the event of an adverse condition or disturbance on the system of the Company, or on any other system directly or indirectly interconnected with it, which requires automatic or manual interruption of the supply of electricity to some customers or areas in order to limit the extent or damage of the adverse condition or disturbance, or to prevent damage to generating or transmission facilities, or to expedite restoration of service, the Company may, without incurring liability, interrupt service to customers or areas and take such other action as appears reasonably necessary.

RESALE SERVICE

SCHEDULE RS-11

AVAILABILITY

Service hereunder is available throughout the Company's service area, from existing facilities of adequate type and capacity, for use and resale by a municipal utility, private distribution utility or an electric membership corporation.

This Schedule is not available for breakdown or standby service. Except as may be agreed to by the Company in writing, this Schedule is not available for supplementary service other than for "Excess Power and Energy" sold to a Government preference customer.

APPLICABILITY

This Schedule is applicable to all electric service of a single type delivered at one point through one metering installation at, or compensated to, the point of delivery. This Schedule shall apply to each delivery point separately, except metering will be electrically totalized for single rate application where customer takes delivery of all service at each point at a voltage of 115 KV or higher and accepts a minimum Billing Demand of 60,000 KW.

TYPE OF SERVICE

This Schedule is applicable to alternating current, 60 cycle, three phase electric service at the voltage set forth in Exhibit A for the point of delivery.

MONTHLY RATE

$210.00 plus

$ 4.90 per KW of Billing Demand

1.07¢ per KWH for all KWH

15¢ per KVAR for all Excess KVAR
(See POWER FACTOR ADJUSTMENT)

Adjustment: The bill computed under the above Monthly Rate will be increased or decreased by an amount calculated in accordance with the Company's applicable rider(s), which is incorporated as a part of the monthly billing under this Schedule.

DEMAND AND ENERGY DETERMINATION

The KW of metered demand shall be the kilowatts metered during the fifteen-minute period of greatest energy use during the current month, appropriately adjusted to preclude the the duplication of any demand caused by switching of load between delivery points. The Billing Demand shall be the metered demand, less the Government preference customer demand allotment if any, for any delivery point but not less than 95% of the greatest metered demand (less the Government preference customer demand allotment, if any) in the preceding months of June, July, August and September. Notwithstanding the foregoing, when a delivery point is added, the preceding June, July, August and September metered demands at each delivery point from which load is transferred shall be reduced, for the purpose of future determinations of the minimum Billing Demand hereunder, to reflect the estimated metered demand had such new delivery point been in existence during such period. The total by which the demand of the existing points of delivery is thereby reduced shall be considered as the preceding June, July, August and September maximum metered demand at the new point of delivery.

Prior to the billing date, customer will provide written notification to Company of each load transfer including the names of the points of delivery involved, the amount of load being transferred and the effect that such load had on the actual maximum demand in the previous months of June, July, August and September. A load transfer for forty-eight hours or less will not be considered for current or future billing at the point of delivery to which it was temporarily connected.

Monthly metered demand and energy quantities shall be reduced by the monthly kilowatts of allotted Contract Demand and kilowatt hours of a Government preference customer as determined in the Government-Company Contract.

A preference customer's monthly kilowatts of total allotted Contract Demand will be prorated among the customer's points of delivery in proportion to monthly delivery point maximum metered demands of the customer.

POWER FACTOR ADJUSTMENT

When the power factor in the current billing month is less than 85%, the monthly bill will be increased by a sum equal to $0.15 multiplied by the difference between the maximum reactive kilovolt amperes (KVAR) registered by a demand meter suitable for measuring the demands used during a 15-minute interval and 62% of the maximum KW demand registered in the current billing month.

PAYMENT

Bills are due when rendered and are payable within 15 days from the date of the bill.

CONTRACT PERIOD

The initial contract period for contracts entered into after the effective date of this schedule shall be seven years unless Company and customer agree to a longer period. Notwithstanding, a customer may terminate any such contract within such initial period, or at any time thereafter, upon three-years' written notice. If such termination occurs within the initial seven-year period, customer shall reimburse Company for the unamortized portion of its investment in transmission, distribution and transformation facilities installed by Company for such point of delivery to the extent devoted to customer's service. For purposes of this section, facilities owned by the Company shall be deemed to be fully amortized when such facilities have been in service for seven years and, upon contract termination, the investment will be prorated and the Company reimbursed for the remainder of the seven-year period.

When customer's load growth requires Company to increase the capacity of its facilities for a point of delivery, the contract period for the point of delivery will automatically be extended for seven years unless Company and customer agree, in writing, to a different extended contract period. Termination for the extended contract period shall be in accordance with the above paragraph.

The provisions set forth herein shall not apply with respect to any facilities installed as additional facilities, and the charges for any such additional facilities shall be in accordance with the contract between the parties.

GENERAL

Service under this Schedule is subject to the provisions contained in Company's FPC Electric Tariff filed with the Federal Power Commission. It is recognized that all the provisions of Company's FPC Electric Tariff, including this Rate Schedule and the rates and charges contained herein, are subject to changes or substitutions, either in whole or in part, made from time to time by a legally effective filing of Company with, or by order of, the Federal Power Commission, and both Company and customer shall have the right to seek unilaterally changes or substitutions from the Commission.

Qestion 17:

Describe in detail: a) analyses performed of effect to date of previous energy conservation efforts; b) assumption made regarding future effect of conservation and how introduced with forecast.

Answer:

See following pages.

17-a. As explained in answer to Question No. 6, we have been unable to separate the effects of conservation from those of price response. However, the combined effect--the net result of which is to reduce energy use--has been isolated and, as noted in the response to Question No. 6, the derived coefficients indicate how much consumption was reduced by both residential and commercial customers for each one cent rise in the price of electricity over the 1970-76 period.

17-b. We have assumed that the reduction in energy usage per every one cent increase in the real price of electricity experienced during the 1970-76 period--whether in response to price or out of a sense of civic duty and awareness of the value of conservation--will continue throughout the forecast period. We also have assumed that the real price of electricity will increase 1% per year. Thus for every one cent increase our energy forecast repeats the reduction experienced over the 1970-76 period, which includes the 1974-76 years of steep decline. While this forecasts a reduction in total energy consumption, we have not assumed a like reduction in peak demand. Logic dictates to the contrary, since at the time of the winter and summer peak, heating and cooling systems tend to operate full time within the range of thermostat settings known to be utilized by those trying to reduce their consumption.

Although we expect that as a result of more capital intensive conservation efforts, commercialization of non-central station energy substitutes, and similar developments, the future peak may be reduced somewhat, we have found that our attempts to quantify this results in considerable speculation. Thus these effects have not been reflected in our peak load forecast and could reduce it by some uncertain amount. However, within the limited period of the forecast we do not believe the reduction will be material or that there is any evidence which would confirm that it will not be offset by a likewise speculative increase in peak demand attributable to other energy substitution or other unknown uses which have not been factored into the forecast.

Question 18:

Load Management: in general, document all statements.
a) How ongoing programs have been effective and are taken into account in forecast; detailed description of participation in pricing experiments; b) anticipated effects of other load management schemes and how reflected in projected load factors.

Answer:

CP&L develops an energy forecast upon which the demand or load forecast is based, and since the effects of conservation and related assumptions are included in the energy forecast, they are inherently included in the demand forecast.

In the current load forecast, the total load of the City of Fayetteville, which previously had been included in the CP&L system demand forecast, was reduced 40 MW due to the installation of generating capacity with which they propose to trim their peaks.

CP&L is continuing to analyze and quantify the effects of load management programs. As a higher degree of confidence concerning load management effects on CP&L system demand develops, these effects will be included in the load forecast.

As discussed in the section on load management, CP&L is participating in two pricing experiments.

National Rate Design Study

CP&L is actively participating in the National Rate Design Study conducted by EPRI and EEI at the request of the National Association of Regulatory Utility Commissioners. The study, which is the most comprehensive ever attempted, includes an appraisal of various methods of controlling and peak-period uses of electricity as well as a study of the feasibility and cost of shifting various types of loads from peak to off-peak periods. During the first phase the study includes detailed analyses of the different methodologies. A preliminary report on this phase has been made. Experimentation will be conducted during the second phase of the study. In addition to the planned experimentation, a task force has identified and is currently monitoring some forty different experiments underway by other agencies and utilities.

To conduct the study, ten national task forces were organized and eleven consultants (firms) engaged. The task forces are composed of the best utility expertise in the nation. Leaders were drawn from every segment of the industry and included regulatory commissioners and staff; private, public, and municipal utility executives, and prominent consultants. Consultants fees totaled almost $1,000,000. The topics investigated by the different task forces and consultants included rate design formats, costing methodologies, metering equipment, the history of rate design, load control equipment, pricing/elasticities studies, methods of determining cost-benefit relationship, market research, and other aspects.

CP&L personnel have been actively participating in the planning and implementation of the study since early 1975. Additionally, CP&L is one of seven utilities selected for detailed work on costing and ratemaking. Ebasco worked with the Company to develop alternative costing methodologies were employed in developing peak load pricing rates which were filed for all customer classes in March, 1977. Additionally, one of the residential rates to be used in the FEA experiment was derived from data developed in this study.

Electric Utility Rate Demonstration Project

In cooperation with the North Carolina Utilities Commission, CP&L and Blue Ridge Electric Membership are conducting separate peak load pricing experiments which are partially funded by the Federal Energy Administration. The experiment, which will span a three-year period, began in July, 1976. The three-year CP&L project will cost approximately $850,000 of which CP&L will provide approximately $285,000 plus the use of 350 of its magentic tape recorders. The FEA funds will be used primarily to pay consultants and to provide an additional 250 magnetic tape recorders. The primary consultant is the Research Triangle Institute.

The primary purpose of the experiment is to determine the extent peak load prices will induce customers to shift their usage from the time our system is at or near its daily peak to the time our system is not at or near its peak and to determine what effects this will have on our capacity and fuel requirements. Other goals we hope to determine are the attitudes of our customers toward time-of-day pricing and what specific appliances they will delay using.

CP&L will test eleven different residential time-of-day rates. Additional meters will be placed on customers with our conventional rates for comparative purposes. Participating customers will be selected from throughout North Carolina on a random sampling basis to represent the different types and usage patterns of all our residential customers.

The peak load rates to be used in the experiment were derived from different costing methodologies including long-run incremental cost and embedded cost studies.

Activities during the first year include the preparation of the costing studies, determining the experimental rates, determining the customers to be tested, and training company and consultant personnel to be customer interviewers and customer inquiry representatives. A Commission hearing was held on the rates to be used in the experiment on May 3 and 4 and an order was issued approving such rates and the project plan on June 6, 1977. In July and August, 1977, meters will be installed on the first group; and after gathering three months of initial data, the test rates will be implemented in late October of 1977. Meters will be installed on a second group of 300 customers in November and December, 1977 with the rate to become effective in late February. The test rates will be in effect through May, 1977, on each group. Thereafter the customers will be interviewed again, the recorders removed, and the results analyzed.

In addition to the residential experiment, a group of about 25 commercial and 25 industrial customers will be surveyed to determine what changes they would make if peak load pricing rates were mandatory for all customers.

CP&L's Load Management Steering Committee has studied the potential effects of CP&L's load management program, in particular for 1982, the year of our lowest projected reserves.

	1982 Impact (MW)
1. Customer Owned Generation	63 (Excluding City of Fayetteville)
2. Industrial Load Shifting	19
3. Staggered Industrial Vacation Scheduling	11
4. Home Insulation	12
5. Rate Revision	75
6. Conservation Education	15
7. Wholesale Customer Load Management	30
Total 1982 Impact	225 MW

The above figures approximate the MW impact on the CP&L Load in 1982 that is not presently accounted for in the demand forecast.

The quantitative values placed on portions of CP&L's Load Management effort are at best imprecise because of the nationwide lack of adequate data or experience from which to quantify load reductions with a high degree of confidence.

The effects of these and other load management schemes have not been anticipated as it is felt that this action would be highly speculative. Therefore, the effects are not reflected in projected load factors.

Question 19:

Present planned generating capability at peakload period for each year 1991-1993.

Answer:

PLANNED GENERATING CAPABILITY AT PEAKLOAD

	Projected Load (MW)	Generating Capability (MW)
1991	13,248	15,555
1992	13,910	15,555
1993	14,606	16,705

Question 20:

Provide a listing of each generator 100 MWe or greater at present, plus planned and proposed additions each year thereafter to 1993. Include date of operation, retirements or deratings, redesignations and upratings. Categorize each generator as to type and function.

Answer:

CP&L GENERATING UNITS 100 MWs OR GREATER

Date	Plant	Unit	Type	Capability - MW	Function
Present	Brunswick	1	Nuclear	790	Base Load
Present	Brunswick	2	Nuclear	790	Base Load
Present	Robinson	2	Nuclear	665	Base Load
Pending	Roxboro	3	Fossil	720	Base/Intermediate Load[1]
Present	Roxboro	2	Fossil	670	Base/Intermediate Load
Present	Roxboro	1	Fossil	385	Intermediate Load
Present	Lee	3	Fossil	252	Intermediate Load
Present	Asheville	1	Fossil	198	Intermediate Load
Present	Asheville	2	Fossil	194	Intermediate Load
Present	Cape Fear	5	Fossil	143	Intermediate Load
Present	Cape Fear	6	Fossil	173	Intermediate Load
Present	Sutton	2	Fossil	106	Intermediate Load
Present	Sutton	3	Fossil	420	Intermediate Load
Present	Robinson	1	Fossil	174	Intermediate Load
Pending	Brunswick	1	Nuclear	821	Base Load[1]
Pending	Brunswick	2	Nuclear	821	Base Load[1]
March 1983	Mayo	1	Fossil	720	Base/Intermediate Load
March 1984	Harris	1	Nuclear	900	Base Load
March 1985	Mayo	2	Fossil	720	Base/Intermediate Load
March 1986	Harris	2	Nuclear	900	Base Load
March 1988	Harris	4	Nuclear	900	Base Load
March 1989	SR	1	Nuclear	1150	Base Load
March 1990	Harris	3	Nuclear	900	Base Load
March 1991	SR	2	Nuclear	1150	Base Load
March 1993	Undesignated	1	Fossil	1150	Base/Intermediate Load[2]
March 1993	Roxboro	2	Fossil	670	Intermediate Load[2]

[1] Uprating

[2] Redesignation

CP&L distinguishes between base load, intermediate load, and peaking capacity based on the amount of time the unit is expected to be used. As an economic dispatch procedure is used whereby available units are loaded in order of increasing generation costs to meet customers' demands and then retired in reverse order, we are assured of meeting our customers' needs in the most economical manner possible. When this method is used, however, the amount of generation that is required from any given unit is tied directly to its cost of operation, load characteristics, and system conditions. With delivered fuel costs varying monthly, load characteristics changing seasonally, and system conditions changing daily, except for nuclear (base load) and IC turbine or hydroelectric units which are energy limited (peaking capacity), it becomes difficult to state categorically that a given unit will always be base loaded or will be cycled as intermediate or peaking capacity. When a new unit becomes commercial, it will be used in accordance with economic dispatch procedures and its effect on the use of other units on the system will be determined by the variables mentioned above.

Qestion 21:

Provide CP&L's definitions of the following terms: baseload, intermediate, peaking, firm and non-firm sales and purchases.

Answer:

See following page.

Base Load, Intermediate, Peaking - As stated in the response to Q - 20, CP&L distinguishes between base load, intermediate load, and peaking capacity based on the amount of time the unit is expected to be used. As an economic dispatch procedure is used whereby available units are loaded in order of increasing generation costs to meet customers' demands and then retired in reverse order, we are assured of meeting our customers' needs in the most economical manner possible. When this method is used, however, the amount of generation that is required from any given unit is tied directly to its cost of operation, load characteristics, and system conditions. With delivered fuel costs varying monthly, load characteristics changing seasonally, and system conditions changing daily, except for nuclear (base load) and IC turbine or hydroelectric units which are energy limited (peaking capacity), it becomes difficult to state categorically that a given unit will always be base loaded or will be cycled as intermediate or peaking capacity. When a new unit becomes commercial, it will be used in accordance with economic dispatch procedures and its effect on the use of other units on the system will be determined by the variables mentioned above.

Firm Sales & Purchases - CP&L considers firm sales & purchases to be those that are contracted for when the terms of the contract are such that the energy or capacity involved can be used as if it were from an owned source.

Non-firm Sales & Purchases - CP&L considers non-firm sales & purchases to be those resulting from day-to-day operations of the system. They can result from economic considerations or unforeseen system conditions and can be cancelled on call from the supplying party. Generally these transactions will net out to approximately zero on an annual basis.

Question 22:

Present the ratio of baseload capacity to total capacity for each year in the period 1966 through 1993.

Answer:

1966 - 1993 BASELOAD TO TOTAL CAPACITY RATIOS*

Year	Nuclear Baseload	Capacity (MW) Total:Baseload Nuclear & Base/Intermediate Load (Coal)	Total Capacity (MW)	Nuclear Baseload Ratio	Total Ratio
1966	0	1008	2219	.00	.45
1967	0	1008	2229	.00	.45
1968	0	1353	2994	.00	.45
1969	0	1353	3111	.00	.43
1970	0	1353	3181	.00	.43
1971	665	2018	4202	.16	.48
1972	665	2369	4631	.14	.51
1973	665	2370	5281	.13	.45
1974	665	2370	5506	.12	.43
1975	665	2370	5714	.12	.41
1976	1455	3160	6538	.22	.48
1977	2245	3635	7433	.30	.49
1978	2307	3697	7495	.31	.49
1979	2307	3697	7495	.31	.49
1980	2307	4417	8215	.28	.54
1981	2307	4417	8215	.28	.54
1982	2307	4417	8215	.28	.54
1983	2307	5137	8935	.26	.57
1984	3207	6037	9835	.33	.61
1985	3207	6757	10555	.30	.64
1986	4107	7657	11455	.36	.67
1987	4107	7657	11455	.36	.67
1988	5007	8557	12355	.41	.69
1989	6157	9707	13505	.46	.72
1990	7057	10607	14405	.49	.74
1991	8207	11757	15555	.53	.76
1992	8207	11757	15555	.53	.76
1993	8207	12237	16705	.49	.73

* Based on unit Summer Ratings

Question 23:

For 1990, estimate energy to be generated by function and type of all generators.

Answer:

1990 ENERGY GENERATION ESTIMATE

Function	Energy (MWHR)	Percent (%)
Base Load		
Type		
Nuclear	42,281,917	63.23
Subtotal	42,281,917	63.23
Base/Intermediate Load		
Type		
Fossil (Coal)	15,060,582	22.53
Subtotal	15,060,582	22.53
Intermediate		
Type		
Fossil (Coal)	9,057,321	13.55
Subtotal	9,057,321	13.55
Peaking		
Type		
IC Turbine	362,717	.54
Combined Cycle	11,417	.02
Hydro	83,890	.13
Subtotal	458,024	.69
TOTAL	66,857,844	100.00

Question 24:

Provide estimates of <u>net</u> firm and non-firm power sales and purchases or interchange agreements for each year of the period 1976 to 1993.

Answer:

1976-1993 CP&L Net Sales and Purchases*

	1976	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993
Firm Sales																		
None																		
Firm Purchases (Long Term)																		
AEP	100	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
SEPA (Kerr Project)	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75	75
SCE&G (Saluda)	53	53	53	53	53	—	—	—	—	—	—	—	—	—	—	—	—	—
Non-Firm Sales (Limited Term)																		
Sutton #3-(SCE&G)	(128)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Asheville #2	(17)	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Non-Firm Purchases																		
None																		
Net Sales & Purchases	83	108	108	108	108	75	75	75	75	75	75	75	75	75	75	75	75	75

* After 1976 Non-Firm Sales and Purchases are estimated to net to zero.

NOTE: Sales (XX), Purchases XX

Question 25:

Provide projected base load demand for each year 1976 to 1993.

Answer:

1976-1993 Estimated CP&L Base Load Demand

Year	Peak Load (MW)	Base Load (MW)*	Avg. Load (MW)**
Actual			
1976	5121	2714	2992
Forecast			
1977	5548	2940	3126
1978	5975	3167	3355
1979	6411	3398	3599
1980	6878	3645	3860
1981	7367	3905	4134
1982	7897	4185	4434
1983	8441	4474	4728
1984	9019	4780	5051
1985	9590	5083	5353
1986	10190	5401	5687
1987	10801	5725	6027
1988	11444	6065	6396
1989	12016	6368	7269
1990	12617	6687	7680
1991	13248	7021	8111
1992	13910	7372	8560
1993	14606	7741	9027

* That load which must be served 6000 hrs. a year (68% of the time) with a system load factor of .6. With these assumptions, base load is approximately 53% of peak load.

**Avg. Load (MW) = Annual Energy (MWH)/8760 hr.

Question 26:

Provide copies of the following reports:

a) CP&L Annual Report, last 2 years.

b) Annual Report of VACAR and/or SERC to FPC in response to Order No. 383-3.

c) FPC Forms 3, 5, and 12.

d) Uniform Statistical Report to American Gas Assoc, EEI, and Financial Analysts.

e) Consultant energy forecasts for past two years.

Answer:

See following pages.

Reports a), b), c), d) and e) in response to the preceding Question 26 have not been included in this copy of Amendment 64. Copies have been provided to the Nuclear Regulatory Commission, Mr. Thomas S. Erwin and the Olivia Raney Library, Raleigh, North Carolina.

ALTERNATIVES

Question 1:

Document any conclusions that new technologies are not currently viable, i.e., references used, internal studies undertaken, etc. What specific technologies were reviewed?

Answer:

See following pages:

Carolina Power & Light Company (CP&L) has followed various proposals and experiments to develop new energy technology and has supported related studies and experiments through participation in the Electric Power Research Institute. At present, these new technologies do not offer firm prospects of providing base load generation in the amounts and at the cost which would make them competitive with the more proven types of generation normally used for this purpose. This view is in agreement with studies by EPRI (1, 2, 3, 4, 5), by ERDA (6), and other independent assessments of new energy technologies (7, 8).

In the ERDA document (6), the broad conclusion for technologies, such as, solar electric, fusion and breeder reactor is that, "Even if these technologies should prove successful in satisfying the technical, economic, institutional and environmental requirements for implementation, their major energy supply contributions will occur in the twenty-first century." For each of the future energy options, long lead times and a series of essential steps, many of which have not been started, are necessary; for example, prospects for the extensive use of solar energy for other than space heating are not good. The first commercial availability of solar electric generation is estimated to be after 1990 and then only for intermediate load applications (9).

While coal gasification is technically feasible and nearer term, demonstrations for power generation applications are just getting under way and a commercial application of the technology is not expected until the late 1980's (10).

New energy storage technologies such as compressed air and battery were also considered and while these technologies can theoretically improve system load factor, they are not yet available and/or economically vaible alternatives (11, 12, 13, 14). Furthermore, these storage systems provide an alternative for peak power generation not base load generation. In fact, adequate base load generation is required for off-peak "pumping" of these storage systems.

On the basis of the above observations and references, CP&L has concluded that power generation alternatives based on new technology will not be commercially available in significant quantity during the 1980's.

REFERENCES

1. Economic Assessment of the Utilization of Fuel Cells in Electric Utility System; EPRI EM-336; November, 1976.

2. Advanced Steam Cycles Using Fluidized Bed Steam Generation and Heating; EPRI FP-317; December, 1976.

3. Clean Coal: What Does it Cost at the Busbar? EPRI Journal; November, 1976.

4. Alternatives to Oil and Gas; EPRI Journal; May, 1976.

5. Nuclear Power, Coal and Energy Conservation; EPRI (SR-34).

6. ERDA, A National Plan for Energy Research, Development and Demonstration: Quoting Energy Choices for the Future; ERDA-48; June, 1975; p. 5-3.

7. Bolzhiser, R. E., "Energy Options to the Year 2000," Chemical Engineering; January, 1977.

8. Rose, D. J., et al, "Nuclear Power-Compared to What," American Scientist, May-June, 1976.

9. Spencer, D. F., "Solar Energy: A View from an Electric Utility Standpoint," American Power Conference; April, 1975.

10. Economics of Current and Advanced Gasification Processes for Fuel Gas Production; EPRI AF-244; July, 1976.

11. Near-Term Energy Storage Technologies: The Lead Acid Battery. A Compilation of Workshop Papers; EPRI SR-33 Special Report; March, 1976.

12. An Assessment of Energy Storage Systems Suitable for Use by Electric Utilities; Volumes I, II, and III; EPRI EM-264; July, 1976.

13. Development of Sodium-Sulfur Batteries for Utility Application; EPRI EM-266; December, 1976.

14. Underground Pumped Storage Research Priorities; EPRI AF-182; April, 1976.

Question 2:

Provide detailed results of studies performed evaluating coal, oil, and nuclear alternatives demonstrating the economic advantage of nuclear units.

Answer:

CP&L performed a study in 1970 to determine what type of generating units to be installed on the system for the years 1977 and 1978 (originally scheduled in-service dates for the first two units at the SHNPP). The General Electric Company was engaged to work with the Company's System Planning Section to make this study using their production cost and investment programs. All input data for the programs was supplied by the Company. The analysis showed that nuclear units provided the lowest overall cost and, consequently, were the type that should be added. The study was later updated in 1971 to determine if the results of the earlier study were still valid. The results showed that the conclusions reached in the 1970 study were still valid and that from an economic standpoint, nuclear generating units should still be installed.

Since making the commitment to use nuclear generation, CP&L has not made any further detailed studies with regard to this plant. We have, however, followed very closely those studies made by Ebasco Services, Incorporated, architect engineers for the plant.

Provided herewith are two studies by Ebasco personnel. The first, "Dramatic Changes in Nuclear and Fossil Cost," compares estimates of coal-fired and nuclear plants estimated in 1969 for 1976-1978 operation with estimates made in 1976 for operating dates of 1986-1988. The second, "The Economics of Nuclear Power," is an update of an earlier study with nuclear fuel costs modified to reflect the effects of no reprocessing and no recycling.

The reports referenced in the preceding Question 2 have not been included in this copy of Amendment 64. Copies have been provided to the Nuclear Regulatory Commission, Mr. Thomas S. ERwin and the Olivia Raney Library, Raleigh, North Carolina.

Question 3:

If not provided in response to question 2 above, provide the following information both for nuclear and for coal-fired units using a) low sulfur coal and b) high sulfur coal with stack gas cleaning:

a) information requested in Table 2 attached.

b) estimated costs of generating electric energy in mills per kilowatt-hour in the detail shown in Table 3 attached. State whether the costs of fuel and of operation and maintenance are initial costs or levelized costs over some period of operation and, in the latter case, what assumptions are made about escalation.

c) In responding to a and b above, carefully document sources of information and assumptions employed. Provide supporting studies if available.

Answer:

See response to preceding Question 2.

TABLE 2

COST INFORMATION FOR NUCLEAR AND ALTERNATIVE POWER GENERATION METHODS

1. Interest during construction ________ %/year, ________ compound rate

2. Length of construction workweek ________ hours/week

3. Estimated site labor requirement ________ man-hours/kWe

4. Average site labor pay rate (including fringe benefits) effective at month and year of NSSS order ________ $/hour

5. Escalation rates
   - Site labor ________ %/year
   - Materials ________ %/year
   - Composite escalation rate ________ %/year

6. Power Station Cost[a]

Direct Costs	Unit 1	Unit 2
a. Land and land rights	________	________
b. Structures and site facilities	________	________
c. Reactor (boiler) plant equipment	________	________
d. Turbine plant equipment not including heat rejection systems	________	________
e. Heat rejection system	________	________
f. Electric plant equipment	________	________
g. Miscellaneous equipment	________	________
h. Spare parts allowance	________	________
i. Contingency allowance	________	________
Subtotal	________	________

Indirect Costs	Unit 1	Unit 2
a. Construction facilities, equipment, and services	________	________
b. Engineering and construction management services	________	________
c. Other costs	________	________
d. Interest during construction (@________ %/year)	________	________
Escalation		
Escalation during construction @________ %/year	________	________
Total Cost		
Total Station Cost, @ Start of Commercial Operation	________	________

[a]Cost components of nuclear stations to be included in each cost category listed under direct and indirect costs in Part 6 above are described in "Guide for Economic Evaluation of Nuclear Reactor Plant Designs," U.S. Atomic Energy Commission, NUS-531, Appendix B, available from National Technical Information Service, Springfield, Virginia 22161.

TABLE 3

ESTIMATED COSTS OF ELECTRICAL ENERGY GENERATION

	Mills/Kilowatt-Hour
Fixed Charges[a]	
Cost of money	________
Depreciation	________
Interim replacements	________
Taxes	________
Fuel Cycle Costs[b]	
For fossil-fueled plants, costs of high-sulfur coal, low-sulfur coal, or oil	________
For nuclear stations:	
Cost of U_3O_8 (yellowcake)	________
Cost of conversion and enrichment	________
Cost of conversion and fabrication of fuel elements	________
Cost of processing spent fuel	________
Carrying charge on fuel inventory	________
Cost of waste disposal[c]	________
Costs of Operation and Maintenance[d]	
Fixed component	________
Variable component	________
Costs of Insurance	
Property insurance	________
Liability insurance	________

[a]Give the capacity factor assumed in computing these charges, and give the total fixed-charge rate as a percentage of station investment.

[b]Include shipping charges as appropriate. Give the heat rate in Btu/kilowatt-hour.

[c]If no costs are available, the applicant may use the cost assumptions as listed in the most recent publication of *Nuclear Industry*.

[d]Give separately the fixed component that in dollars per year does not depend on capacity factor and the variable component that in dollars per year is proportional to capacity factor.