APPENDIX A

THE PPSP/DSP LOAD FORECASTING PROGRAM

Since 1974 the Power Plant Siting Program, in conjunction with the Maryland Department of State Planning (DSP), has conducted an active load forecasting program. During this time period long-range forecast studies of each of the four major utility systems which operate in the State have been prepared (1), (2), (3), (4). These studies provide comprehensive and detailed projections of future electric energy use for each of the four systems. In each case, the forecasts were prepared for the entire multi-state system rather than just the Maryland portion because each of these utilities is planned on a systemwide basis. In addition to developing the annual peak demand forecasts, energy sales were forecast by major customer class, regulatory jurisdiction and season. The PPSP/DSP forecasts were obtained from a set of econometric equations which relate key explanatory variables to the demand for electricity. It is the purpose of this Appendix to describe the methodology and the forecasts it has produced.

PPSP has produced long-range forecast studies for Pepco (1975), BG&E (1979), APS (1980) and DP&L (1980). Revisions have been prepared for Pepco, BG&E and APS. The two most recent studies were the DP&L forecast completed in March 1980, and the APS forecast, completed in January 1980. Since those two studies were completed within a few months of one another, the methodologies employed are substantially similar. This Appendix uses the DP&L models to illustrate that methodology since it is the most recent of the four studies.

The BG&E and Pepco studies were prepared several years earlier, and thus are methodologically somewhat different from the DP&L and APS studies. The Pepco study was completed in 1974 using a data base which ran through 1972. The BG&E study was substantially completed in late 1977, although the report resulting from the study was published by PPSP in 1979. The terminal year of the BG&E data base was 1974.

PPSP has performed forecast updates of the Pepco and BG&E systems in 1978 and 1981, but those revisions are limited in scope. They involved alterations to the forecasting assumptions along with the use of a more recent base year. The updates provide revised energy and peak demand forecasts for Pepco (through 1991) and only peak demand forecasts for BG&E (through 1995).

Because the original studies were prepared so long ago and used little or no data from the post-Arab Oil Embargo period, completely new forecast studies of the two utiities are needed. The new studies will use the more complete data which are now available and will also use any methodological improvements which have taken place in the last few years. PPSP is currently in the process of performing a new Pepco load forecast. Completion is scheduled for September 1982. A revision of the BG&E forecast will also be prepared, scheduled for completion in March 1982. This revision will rely upon the models from the original study but will employ a more recent base year and updated assumptions.

A. Overview

The process of econometric forecasting consists of two principal stages. In the first stage, statistical models of the demand for electricity are estimated from historical data. These econometric models describe the relationship between the demand for electricity and various causative economic factors that govern it, such as population, income, employment, wage rates and energy prices. In the second stage, projections of future values for these causative factors are inserted into the econometric models in order to determine the likely future demand for electricity.

In order to construct a structural econometric model, it is first necessary to determine the important causative factors affecting the demand for electric power. After specifying a model which incorporates these factors, historical data on the dependent and independent variables are collected and processed. The precise quantitative relationships between the dependent variable, i.e., energy consumption, and the factors that govern it are estimated by the use of ordinary least squares regression. In the recent Delmarva study, such models were developed for summer and winter residential usage (per customer), summer and winter commercial usage (per nonmanufacturing employee) and industrial usage (per manufacturing employee). The study also included a statistical analysis of other, less important elements of electricity demand, as well as energy losses, and summer and winter system peak demands.

The econometric equations are derived from the behavioral relationships governing the demand for electricity, as they existed during the period from which the historical data were drawn, generally the mid-1960's to the mid- or late 1970's. The demand forecasts are then calculated by inserting into the estimated equations the expected future values of the driving (causative) variables. Most of these values have been developed from official state or federal projections, including those of the Department of State Planning. The remaining values were determined judgmentally. After the energy forecasts are calculated, these values are inserted into the equation which relates peak demand to energy usage, relative sector size and weather. In that manner projected peak demand is determined. Using values of the driving variables determined in this manner, the Most Likely Case forecast is produced.

It is critically important, however, that system planners and regulators realize that any forecast is uncertain, regardless of how skillfully the models are developed. In order to obtain alternative upper and lower bound growth paths, substantial but plausible alterations to the Most Likely Case assumptions are made and the forecasts recalculated. The difference between the upper and lower bounds represents the plausible long-run range of uncertainty. In addition to these alternative forecast scenarios, the PPSP/DSP studies include estimates of demand reductions (both total energy sales and peak demand) due to conservation programs and time-of-use electricity pricing.

B. The Econometric Models

The econometric models used to forecast energy usage have been formulated on the basis of a priori, theoretical judgment concerning the various economic and other factors which directly affect energy usage. Since the models in all cases are estimated from historical time-series data, the results reflect the behavioral relationships that prevailed during that historical period. It is assumed that these historical relationships will prevail in the future.

The development of the PPSP/DSP models has been guided by technical considerations normally encountered in the econometric analysis of electricity demand. These considerations relate to both the limitations of economic modeling, and to the statistical properties of ordinary least squares regression, the estimation method used to quantify the models.

- Specification -- Ideally, an econometric model should be fully specified. This means that all factors which significantly influence demand should be included in the model. Failure to do so will result in coefficients which may be biased, since the remaining variables will be forced to "explain" what the missing variables should explain. However, it is not practical to construct a model which includes the entire universe of possible considerations. Therefore, judgment is required to keep the models as simple as possible without excluding the truly important factors.

- Dynamic behavior -- The rubric of specification includes the "functional form" of the equation as well as the selection of variables included in the model. Since time-series data are being analyzed, there is an opportunity (as well as a necessity) of determining how rapidly households and businesses alter their power demands in response to changes in the causative variables. Since electricity is consumed only through stocks of electricity-using equipment, and since customers will only alter these stocks gradually, the electricity demand responses to changes in the causal variables will likewise be gradual. A model which fails to take this dynamic behavior into account is badly misspecified and will likely produce erroneous results.

- Multicollinearity -- A problem common to time-series regression analysis occurs when two or more independent variables are highly correlated with one another. It is very important that this situation be avoided since it may render the coefficient estimates of one or more of the correlated variables involved erroneous. If the problem is sufficiently serious, one or more of the correlated variables may have to be eliminated from the equation.

- Electricity price definition -- A key assumption in regression analysis is that causation runs solely from the independent to the dependent variable. If causation runs the other way or both ways then biased results are likely. Because electricity has historically been sold from declining block tariffs, this problem is familiar to analysts of electricity demand. With the declining block rates, a random factor, such as unusually hot weather, causes an increase in consumption and thus a decline in the average price paid per kilowatt hour for electricity. Thus, in this example, the increase in usage caused the reduction in price, not the other way around. This problem can be overcome by avoiding an average revenue definition of price.

- Aggregation -- The estimated equation should be derived from data which are not so aggregated as to camouflage important causal relationships. That is, the very act of aggregating can eliminate the variations in the dependent and independent variables needed for efficient econometric estimation. In the PPSP/DSP models this has been avoided by disaggregating by season, customer class and regulatory jurisdiction. How far disaggregation should go depends upon data quality (and availability) as well as theoretical or econometric considerations.

The PPSP/DSP econometric models were specifically designed to avoid these potential pitfalls to the extent possible. The way in which this was accomplished is described below, with special reference to the Delmarva study.

Residential Models

The important determinants of residential usage of electricity can be easily identified and would include:

- electricity prices
- alternative energy prices
- personal income
- population
- weather
- housing stocks
- household appliance stock ownership
- appliance vintages and energy efficiencies
- natural gas available
- household size
- inflation

However, it would be rather unwieldy to include all these items in a regression model, and moreover a reliable historical data series on many of these items is not available. Further, some of the variables (e.g., income and appliance stocks) are interdependent in a complicated manner and thus not truly independent of one another.

These problems can be largely avoided by the inclusion of a "lagged dependent variable" -- i.e., the value of the dependent variable the previous year. The lagged dependent variable serves as a proxy for appliance and housing stocks, lifestyle and other factors which are capable of changing very gradually. This specification also serves to introduce a dynamic adjustment process into the model in a convenient manner.

The residential equations in the Delmarva study were estimated from pooled time-series cross-section data. That data series consists of individual observations for each month 1966-1977 for each of the three states which comprise the Delmarva Peninsula. Separate equations were developed for the summer and winter seasons. Explanatory variables in the models include the number of customers, real (i.e. inflation adjusted) income, real electricity prices, weather, an air conditioning or space heating saturation measure, and a dummy variable for each region.[1] Logarithmic transformations were performed on the dependent variable (monthly sales per customer), real income and the price of electricity. The estimated summer and winter equations along with certain test statistics are presented in Table A-1.

The specification of the weather variable, the lagged dependent variable and the electricity price measure warrant additional explanation. The lagged dependent variable is defined as the value of the dependent variable for that region exactly twelve months prior. The weather variable is specified in first difference form. In order to obtain an "effective" weather measure, the heating degree day values were multiplied by one plus the electric space heat saturation percentage, while the cooling degree day values were multiplied by one plus the air-conditioning saturation.

Finally, the price measures were specified so as to avoid the two-way causation problem described earlier. This requires avoiding the use of an average revenue measure. Therefore, the summer model uses a "marginal price" constructed by subtracting a 500 Kwh monthly bill from a 1000 Kwh monthly bill, and the winter model simply uses a 500 Kwh monthly bill.[2]

Both short and long-run elasticities can be calculated. The elasticities obtained, as shown below, are consistent with although somewhat below the results obtained in other studies. Both the price and income elasticities are slightly lower in the winter.

Summer Season

	Price	Income
Short-run:	-0.09	0.21
Long-run:	-0.40	0.95

Winter Season

	Price	Income
Short-run:	-0.05	0.09
Long-run:	-0.33	0.62

---

[1] A dummy variable operates in a binary fashion, taking on a value of 1 when operative and zero otherwise. This approach essentially allows for a separate intercept or constant term for each geographic region.

[2] The monthly bills were constructed from DP&L tariffs in each jurisdiction and fuel adjustment charges.

Table A-1

Delmarva Residential Energy Forecasting Models

Summer

$$\ln(RMWH/CUST) = \underset{(-2.4)}{-0.99} - 0.0004\ CDD + \underset{(19.3)}{0.78}\ LDEP$$

$$\underset{(-2.7)}{-0.09} \ln PRICE + \underset{(2.0)}{0.21} \ln INCOME + \underset{(0.7)}{0.04}\ DVA$$

$$+ \underset{(1.2)}{0.04}\ DSD + \underset{(1.0)}{0.03}\ DMD$$

$R^2 = .92$ Durbin-Watson = 1.94

Winter

$$\ln(RMWH/CUST) = \underset{(-1.2)}{-0.66} + \underset{(32.7)}{0.86}\ LDEP - \underset{(-1.2)}{0.05} \ln PRICE$$

$$+ \underset{(1.3)}{0.09} \ln INCOME + \underset{(9.0)}{0.0002}\ HDD + \underset{(2.4)}{0.06}\ DMD$$

$$+ \underset{(1.3)}{0.05}\ DVA + \underset{(2.0)}{0.05}\ DSD$$

R2 = .94 Durbin-Watson = 1.56

Variable Definitions

RMWH = Monthly Sales in Mwh
CUST = Number of residential customers
LDEP = Lagged dependent variable
PRICE = Electricity price measure in real terms
INCOME = Personal income in real terms
HDD = Heating degree day measure
CDD = Cooling degree day measure
DMD = Maryland region dummy variable
DVA = Virginia region dummy variable
DSD = Southern Delaware region dummy variable

Numbers in parentheses are t-statistics.

Commercial/Industrial Models

In contrast to the residential sector, the commercial and industrial classes are extremely heterogeneous. Although this heterogeneity warrants a highly disaggregated approach, lengthy time-series on energy usage are usually available only for broadly defined "commercial" and "industrial" customers. The Delmarva study developed separate equations from time-series data for commercial, industrial and other (mainly resale) customers for each of the three states on the Peninsula. Separate summer and winter equations were estimated for the commercial sector, but since seasonality is relatively unimportant in the industrial sector, only annual models were developed. Because of the relative month to month stability in industrial sales, those equations were estimated from quarterly rather than monthly observations.

The character and pattern of nonresidential electricity usage differs markedly from the residential, but the underlying determinants are analogous. Instead of household appliance stocks, power usage by firms tends to be governed by technology and the stock of capital goods which embodies that technology. Thus, it is convenient to specify a model with a lagged dependent variable to serve as both a surrogate for technology and to impart a dynamic response to changes in the values of the causative variables.

Nonresidential model specification is consistent with the standard economic theory of production. The demand for electricity is determined by the level of economic activity (represented by an appropriate measure of employment), and the technology utilized is ultimately determined by relative prices paid for the various production inputs. Thus, in addition to employment and a lagged dependent variable, key explanatory variables would include electricity price and the wage rate.[1]

Several short-run or transitory factors were also included in some of the equations. All commercial equations included a weather variable since commercial electric loads are weather sensitive. Two other variables were employed to account for short-run changes in labor productivity (and thus energy usage) which would normally be masked by an employment variable. A capacity utilization variable was used for that purpose in the industrial sector, reflecting the fact that employment tends to lag behind output over the course of the business cycle. In the commercial sector, an employment change variable was used since marginal or part-time workers are generally disproportionately discharged during a business downturn and hired during an upturn. Consistent with the model in the previous section, these short-run variables are specified in first difference form.

The estimated commercial/industrial models are shown in Table A-2 along with some key test statistics and variable definitions. Because of the marked difference in the nonresidential sector from state to state[2] the use of pooled data was avoided. All models were estimated from time-series data covering the period 1966-1977.

---

[1] Rapid increases in the wage rate encourage the use of more capital intensive production methods which, in turn, tend to be more energy intensive.

[2] For example, the industrial sector in Maryland is largely light industry, particularly food processing. By contrast, Delaware is dominated by heavy industry such as chemicals, metals and automobiles.

Table A-2

Delmarva Study
Commercial/Industrial Model

(1) Delaware Commercial Summer Model

$$\ln (MWH/CEMP) = \underset{(-0.27)}{-0.06} + 0.0004\ CDD + \underset{(19.6)}{0.77}\ LDEP$$

$$\underset{(0.97)}{0.11} \ln WAGE - \underset{(-1.21)}{0.06} \ln PRICE$$

R^2 = .88 Durbin-Watson = 1.84

(2) Delaware Commercial Winter Model

$$\ln (MWH-CEMP) = \underset{(20.5)}{0.80}\ LDEP + \underset{(1.13)}{0.07} \ln WAGE$$

$$\underset{(2.27)}{0.00004}\ HDD - \underset{(-2.43)}{0.06} \ln PRICE$$

R^2 = .88 Durbin-Watson = 1.40

(3) Maryland Commercial Winter Model

$$\ln (MWH/CEMP) = \underset{(30.55)}{0.89}\ LDEP - \underset{(-5.18)}{1.04}\ CH + \underset{(0.63)}{0.02}\ D\ 1969$$

$$+ \underset{(4.55)}{0.0002}\ HDD - \underset{(-0.83)}{0.03} \ln PRICE + \underset{(0.46)}{0.05} \ln WAGE$$

R^2 = .95 Durbin-Watson = 1.55

(4) Maryland Commercial Summer Model

$$\ln (MWH/CEMP) = \underset{(27.56)}{0.89}\ LDEP - \underset{(-0.85)}{0.03}\ PRICE$$

$$+ \underset{(0.63)}{0.06} \ln WAGE + \underset{(2.84)}{0.0002}\ CDD - \underset{(-3.94)}{0.74}\ CH$$

R^2 = .94 Durbin-Watson = 2.19

Table A-2 (Continued)

(5) Delaware Industrial Model

$$\ln(MWH/MEMP) = \underset{(3.47)}{1.97} + \underset{(6.07)}{0.49}\ LDEP - \underset{(-3.33)}{0.27}\ \ln PRICE$$

$$+ \underset{(1.81)}{0.56}\ \ln WAGE + \underset{(0.25)}{0.0009}\ CUL$$

$R^2 = .77$ Durbin-Watson = 0.80

(6) Maryland Industrial Model

$$\ln(MWH/MEMP) = \underset{(18.06)}{0.83}\ LDEP - \underset{(-1.03)}{0.05}\ \ln PRICE$$

$$\underset{(1.57)}{0.40}\ \ln WAGE + \underset{(2.24)}{0.06}\ D\ 1975$$

$R^2 = .94$. Durbin-Watson = 1.70

(7) Virginia Commercial/Industrial Model

$$\ln(MWH/TEMP) = \underset{(0.40)}{0.22} + \underset{(8.40)}{0.88}\ LDEP - \underset{(-1.23)}{0.08}\ \ln PRICE$$

$$\underset{(0.36)}{0.15}\ \ln WAGE + \underset{(4.51)}{0.0004}\ CDD + \underset{(1.01)}{0.00004}\ HDD$$

$R^2 = .87$ Durbin-Watson = 2.08

Variable Definitions

MWH	= Monthly or quarterly megawatt hour sales
CEMP, MEMP, TEMP	= Commercial, manufacturing and total employment
LDEP	= Lagged dependent variable
PRICE	= Electricity price defined as either marginal price or typical bill (inflation adjusted)
WAGE	= Manufacturing hourly wage rate (inflation adjusted)
CDD	= Cooling degree day measure
HDD	= Heating degree day measure
CUL	= Capacity utilization measure
CH	= Change in employment measure
D 1969, D 1975	= Dummy variables for 1969 and 1975

Numbers in parentheses are t-statistics.

The resultant econometric equations are noticeably different in the commercial and industrial sectors. The price and wage elasticities which are shown below as systemwide averages highlight the basic differences.

	Price		Wage Rate	
	Short-run	Long-run	Short-run	Long-run
Summer Commercial	-0.05	-0.24	0.10	0.50
Winter Commercial	-0.05	-0.29	0.06	0.37
Industrial	-0.23	-0.58	0.52	1.41

The industrial elasticities appear to be roughly in line with results obtained in other studies. The commercial elasticities are much lower, but since little econometric research has been performed in this sector it is difficult to compare these results with any sort of prevailing consensus.

Other Elements of Energy Demand

In addition to energy usage by commercial and industrial customers, there are some other elements of system energy use that must be forecasted. In the Delmarva study it was not possible to obtain customer class retail sales data from some of the municipal systems operating in Delaware. Consequently, the DP&L sales for resale to those systems and any generation by those systems were combined into one aggregated time series.

Since most of this energy is used by residential customers, it was modeled by constructing a regression model which relates this energy to Delaware residential sales and a series of monthly dummy variables. The dummies explain the extent to which this energy usage differs from DP&L residential usage with respect to seasonality and/or weather-relatedness.

The final element of energy considered in these studies is system energy losses, which on any utility system is an accounting residual measuring the difference between system output and system sales. The approach taken was first to construct a loss factor (defined as losses as a percentage of sales) and then to relate that loss factor to the industrial sector's share of total sales (ISHR) and the log of time. These relationships were estimated using annual time-series data with ordinary least squares regression. The results are shown below.

$$\underset{(5.66)}{\text{Losses/Sales} = 0.12} - \underset{(-2.38)}{0.12\ \text{ISHR}} - \underset{(-0.31)}{0.0008\ \ln \text{TIME}}$$

$R^2 = .56$ Durbin-Watson = 1.94

Increases in the industrial sector's share should lower the loss factor because industrial customers receive power at high voltages. Loss factors tend to be inversely related to the voltage level. Time is intended to serve as a proxy for technological change; over time loss factors should improve. The logarithmic transformation is intended to suggest "diminishing returns" to technological change and also to insure that any forecast of an improved loss factor is modest.[1]

Peak Demand Models

The PPSP studies have forecast peak demand at the system level only. No attempt has been made to do so at the class or jurisdiction level because accurate data series on such loads are not available. Moreover, system planning is governed by system peaks rather than class or jurisdictional peaks.

Peak demand in the long-run tends to be driven by virtually the same factors that determine energy usage -- economic activity, population, energy prices, weather and so forth. Rather than directly relate those factors to system peak demand, it is far easier to utilize a total energy output variable, which accounts for all of those factors implicitly. Thus, the basic approach involved constructing regression models, for the summer and winter seasons, which relate monthly peak demand to total system energy output (i.e. sales plus losses), the industrial sector's share of total system energy output and a peak day weather variable. For a given level of total energy output, an increase in the industrial sector's share should tend to lower peak demand since the industrial sector tends to exhibit flatter loads.

The estimation of such a model appears to be rather simple and straightforward, but it is in fact complicated by swings in monthly weather. Month to month changes in weather can rather drastically affect the magnitude of the total energy output variable. However, the weather sensitivity of peak demand is properly measured by a peak day weather variable, not a monthly weather variable. To complicate matters further, monthly weather and peak day weather (using a monthly series) are likely to be highly correlated causing a multicollinearity problem between the energy (which is strongly influenced by monthly weather) and peak day weather variables in the equation. The result is that the energy variable is likely to "overexplain" peak demand, and the weather variable would "underexplain" peak demand.

The solution to this problem is to first remove the weather component of the monthly energy usage variable. To do this a set of equations were econometrically estimated which related total monthly energy output to a trend measure and to monthly weather. Using the resultant coefficients and monthly weather values, the weather sensitive component was removed.

Thus, the peak demand estimating equations, which are shown in Table A-3, relate monthly peak demand to non-weather sensitive energy, the industrial sector's share of non-weather sensitive energy and peak day weather. These models were estimated from monthly time series covering the period 1966-1977. After examining residuals from initial regression results, it was found that the models produced some small but systematic error for August and January. To correct the problem, dummy variables were inserted for those months.

---

[1] Without such transformation the model might forecast unrealistic loss factor improvements a number of years into the future.

Table A-3

Delmarva Peak Demand Models

Summer

$$\ln(MW) = \underset{(-13.08)}{-9.94} + \underset{(30.89)}{1.04} \ln MWH - \underset{(-4.54)}{0.30} \ln ISHR$$

$$+ \underset{(7.84)}{1.03} \ln WEATHER - \underset{(-2.21)}{0.03}\ AUGUST$$

$R^2 = .98$ Durbin-Watson = 1.62

Winter

$$\ln(MW) = \underset{(-7.45)}{-4.37} + \underset{(30.59)}{0.95} \ln MWH - \underset{(-8.46)}{0.005}\ WEATHER$$

$$- \underset{(-3.83)}{0.25} \ln ISHR - \underset{(-2.67)}{0.04}\ JANUARY$$

$R^2 = .97$ Durbin-Watson = 2.36

Variable Definitions

MW	= Monthly system peak demand
MWH	= Monthly system nonweather sensitive outputs
ISHR	= Industrial sector's share of nonweather sensitive monthly system energy output
WEATHER	= Peak day weather variable.
AUGUST, JANUARY	= Dummy variables for those months.

Numbers in parentheses are t-statistics.

Backcast Checks

As judged by the R^2's, the Delmarva energy and peak demand regression equations were able to explain power demands rather accurately. This was further examined by the calculation of "backcasts." Backcasts are obtained by inserting actual values of each of the independent variables into the estimated model and then calculating the values of the dependent variable. The simulated or backcasted sales (or peak demand) figure can be obtained for each historical month or year and compared to actual experience in order to judge the accuracy of the model -- at least for that period.

A summary of backcast and actual comparisons is shown in Table A-4 for the Delmarva study. These errors are averaged over selected time periods on both a simple averaging basis and an absolute averaging basis. The purpose of the absolute average is to demonstrate the degree of accuracy in explaining the historical data. The percent error figures were converted to absolute values before taking the average so that the positive and negative values do not cancel each other out. These results indicate average errors of about one to two percent and almost no perceptible difference by time periods. The simple average measures permit positive and negative errors to cancel. This measure can be used to determine if models systematically underestimate demand during certain periods (e.g., 1967-1973) and overestimate demand during others (e.g., 1974-1977). All of the simple average figures in Table A-4 are extremely small (because of offsetting errors within time periods), and there appears to be no systematic tendency for differences in results by time period. Thus, Table A-4 indicates that the models appear to explain the early years of the data base as well as they do the later years.

Table A-4

Delmarva Peninsula

Average Differences Between Backcast and

Actual Power Demands (Percentages)

	Residential		Commercial		Industrial		Summer Peak	
Time Period	Absolute Average [a]	Simple Average [b]	Absolute Average [a]	Simple Average [b]	Absolute Average [a]	Simple Average [b]	Absolute Average [a]	Simple Average [b]
1967 - 1977	1.35%	0.22%	1.29%	-0.01%	2.56%	-0.03%	1.96%	-1.10%
1967 - 1973	0.93	0.57	0.54	-0.11	3.25	-0.32	2.46	-2.38
1974 - 1977	2.09	-0.40	2.60	0.17	1.35	0.46	1.56	1.14
1975 - 1977	1.61	0.64	1.85	1.85	1.42	1.00	1.04	0.48

(a) The absolute value of the percent backcast error for each year of the specified time period is first obtained, and the average of those figures for that time period is then computed.

(b) The percent backcast error for each year of the specified time period is first obtained, and the average of those figures for that time period is then computed. This differs from the "absolute average" in that positive and negative percent errors are permitted to cancel each other in in the averaging process.

Source: (4)

C. Forecast Assumption

In order to forecast demands using the models described in Section B, it is first necessary to formulate assumptions concerning future values of all right-hand-side variables in the models. For some variables, e.g., weather, dummy variables, capacity utilization, and so forth, future values are rather obvious and do not change over the forecast period. Most other variables can only be predicted with great difficulty and uncertainty. Since the variables in question tend to be causally interrelated, it is important to develop assumptions concerning these variables that are logically consistent with one another. A set of internally consistent assumptions is referred to as a "scenario." A Most Likely Case scenario is normally developed first based upon the best available information and judgment, and then alternative scenarios are constructed in order to bracket the range of uncertainty which surrounds the Most Likely Case growth path.

Most Likely Case (MLC)

The major forecasting assumptions can be divided into four main categories:

- The size of the service area economy -- This would include such variables as employment (total and by sector), population, and number of households.
- The productivity of the service area economy -- The hourly wage rate and personal income largely reflect the productivity of the region.
- Energy prices -- This includes electricity price, and where fuel switching is relevant, price escalations for natural gas and/or oil.
- Other factors -- Assumptions must be made concerning weather, space heating and air-conditioning saturations, and capacity utilization. The treatment of dummy variables is self-explanatory.

The Delmarva study serves to illustrate the PPSP/DSP method of developing the Most Likely Case set of assumptions. For most variables, assumed growth rates were applied to the base year (i.e., 1977) values to obtain values of those variables for all future years of the forecast period. All dollar denominated variables (e.g., income, wage rate, energy prices) were escalated in inflation adjusted terms. In most cases, the economic and demographic assumptions could be obtained from official state or federal sources. In some instances official projections were only used to provide general guidance and additional analysis and judgment were applied. Finally, the methods used varied from state to state, depending upon the quality and quantity of projections data available from state governments.

Population and employment projections for Maryland counties were provided by DSP (5), and the growth rates implicit in these projections were applied in a straight-forward manner without any adjustment. The county level projections were simply aggregated to correspond to the Maryland portion of the service territory. The population growth rate was combined with the U.S. Census

Bureau's nationwide household formation rate projection to obtain a projection of the growth rate of households in the Maryland service area. The number of households is expected to grow more rapidly than population because of the tendency toward smaller size families.

The population and employment projections are also useful in obtaining projections on the service area's productivity variables -- i.e., wage rates and per capita income. Earnings per worker and the ratio of employment to population are the two main determinants of per capita income. That is, not only does per capita income depend upon earnings per worker, but it is also determined by the percentage of the population which is employed. Ignoring for the moment non labor income, the growth rate in per capita income is the sum of the growth rates of earnings per worker and the growth in the percentage of the population employed.

Over the very long term, real wage rates are governed by labor productivity advances, because real wages are the mechanism by which the economic benefit of increased productivity is reflected in labor incomes. However, neither regional wage rates nor productivity projections are available from any official source. Thus, it was assumed that the Maryland service area wage rates will grow by two percent annually based upon the U.S. Department of Labor's long-term outlook for the national economy. Finally, the income projection was obtained by adding to this two percent figure the growth in the employment/population percentage.

Undoubtedly, the most difficult variable to forecast is the price of electricity. To some extent, the U.S. Energy Information Administration's mid-term projections for electricity prices and the prices of fuels used to generate electricity -- coal and oil -- were relied upon for guidance. However, these figures are national and must be applied to any individual utility with caution. Thus, in formulating final assumptions on electricity price various factors were judgmentally considered, including expected growth in rate base resulting from scheduled capacity additions, changes in fuel mix, and past trends.

The final category of assumptions were dealt with very simply. All weather variables were assumed to equal their long-term average in all forecast years. The same assumption was made concerning capacity utilization. Assumptions concerning changes in space heat and air conditioning saturation were developed by specifying exponential "decay" rates for households not possessing those appliances. That is, households lacking those appliances are assumed to diminish by some fixed percentage each year until some theoretical maximum saturation level is achieved. These are relatively minor assumptions since the saturation variables only serve in the models to weight the weather values.

Alternative Scenarios

Alternatives to the Most Likely Case were developed to deal with the problem of assumption uncertainty and to produce a plausible range of results. In developing each scenario care was taken to ensure that the changes in assumptions were logically consistent with one another. Along with the scenarios, sensitivity tests were performed in which only one assumption change was made per forecast model run in order to determine the importance of each assumption.

The major alternative scenarios to the Most Likely Case include the following:

- High Electricity Prices -- Assume that the real price of electricity escalation rate is double the MLC for all customer classes and jurisdictions.
- Low Economic Growth -- Decrease all of the MLC projected growth rates of employment and in the number of residential customers by 0.5 percent annually, and decrease the real wage and per capita income MLC growth rates by 0.8 percent annually.
- High Electricity Prices and Low Economic Growth -- This scenario incorporates the changes to the MLC from the above two scenarios.
- High Economic Growth -- Increase MLC projected growth rates for employment and households by 0.5 percent per year and increase wage rates and per capita income by 0.8 percent per year.
- Energy Policy Scenario -- Includes anticipated effects of the National Energy Act conservation programs and the systemwide implementation of marginal cost, time-of-use rates. This scenario is discussed further in the next section.

In the Delmarva study, as in all the PPSP/DSP forecast studies, the results vary considerable from one scenario to another; the spread between the upper and lower bound results is quite large. Table A-5 presents the peak demand forecasts and annual average growth rates for each scenario in the Delmarva study. The high electricity price/low economic growth scenario serves as the lower bound, while the rapid economic growth scenario is the upper bound. The 1995 difference between the upper and lower bounds is about 1,100 megawatts, and both scenarios differ from the Most Likely Case in that year by about 500 megawatts.

Energy Policy Impacts

In October 1978 Congress passed five pieces of legislation known collectively as the National Energy Act. This legislation increased federal involvement in and regulation of the energy sector and mandated several major conservation programs. Some of the programs, such as the appliance efficiency standards, serve to regulate the way in which energy is used. Many others involve very substantial grants or tax incentives to encourage conservation and renewable resources. The Public Utilities Regulatory Policies Act requires state commissions to consider the appropriateness of marginal cost, time-of-use pricing of electricity.

None of the programs were considered in the Most Likely Case because the econometric models could not be directly structured to accommodate these programs. Thus, methods were employed to determine program impacts outside the framework of the Delmarva models.

Table A-5

Peak Demand Forecasts For The Most Likely Case And Alternative Scenarios

-- Delmarva Study (Megawatts)

	Most Likely	High Price	Low Economic Growth	High Price/ Low Growth	High Economic Growth	Energy Policy
1980	1,645	1,639	1,608	1,602	1,682	1,645
1985	1,979	1,872	1,788	1,745	2,060	1,871
1990	2,246	2,163	1,983	1,912	2,545	2,150
1995	2,632	2,504	2,198	2,096	3,156	2,504
Annual Rates of Growth						
1980-1995	3.19%	2.87%	2.11%	1.81%	4.29%	2.85%

Source: (4)

Because of the great uncertainty associated with both the future of these programs and their impacts, none of these results are included in the Most Likely Case forecasts. They are listed instead as a separate scenario.

Using the Oak Ridge National Laboratory integrated economic/engineering model of energy usage, the Energy Information Administration has made estimates of national electric energy savings from National Energy Act conservation programs. The Oak Ridge model is able to determine energy usage reductions net of what would have been induced by rising electric rates. Virtually all of the conservation programs included in their analysis relate to the residential and commercial sectors. By 1990, Oak Ridge estimates nonindustrial electric energy usage reductions of roughly seven percent as compared to their base case. For Delmarva, this translates into a 180 megawatt reduction in peak demand assuming that conservation programs are neutral with respect to time of use of electricity.

The Delmarva study also includes an analysis of the potential peak demand reductions from marginal cost, time-of-use pricing. It was assumed that these rates will have no effect on total energy consumption but only the time pattern of consumption. The impact on peak demand growth was determined by applying the price elasticities from the econometric models to differentials in peak/off-peak costs which were obtained from a recent marginal cost study of the Delmarva system. To obtain conservative impact estimates, it was assumed that the demand at the time of the system peak is less price elastic (i.e., price responsive) than overall energy use. Using this approach, it was estimated that systemwide implementation of time-of-use pricing might save as much as 130 megawatts of peak demand by 1995.

Monthly Adjustments to Energy Models

Since energy sales serve as an input to the forecast of peak demand, it is necessary that each of the various energy models be capable of producing a long-range forecast for each month of the year. The major concern in producing monthly forecasts is to ensure that the forecasted monthly pattern or allocation of annual sales is realistic. For the most part, the only right hand variable which is capable of generating monthly differences in energy usage is the weather. Other factors may also systematically influence the monthly energy sales pattern, but these factors were excluded from the models either because they could not be quantified, could not be identified, or would have introduced an unacceptable degree of multicollinearity.

A technique was utilized in the Delmarva study which assures that the monthly historical sales accurately reflects the historical pattern. For each of the energy forecasting models, residuals were computed from the econometric equations and regressed against a series of monthly (or quarterly in the industrial sector) dummy variables. The estimated coefficients on the dummies represent the average statistical error (after permitting positives and negatives to cancel) in the application of each of the models to the various months. The residual coefficients (or means) and dummy variables were then incorporated into the final forecasting models to obtain the monthly forecasts.

The results from this procedure indicate that for most equations and most months there is no significant tendency to over or underestimate energy usage. In a few instances the average error is as much as two to three percent; but in most cases it was less than one percent.

The analysis of residuals assures that the monthly pattern of usage per employee or per customer will be satisfactorily adjusted. However, to ensure that total energy sales reflect the proper monthly pattern, the patterns of employment and residential customers must be maintained. To this end, the projections on customers and employment were adjusted to fit the average monthly pattern in those variables which prevailed over the period 1972-1977.

D. Forecast Results For The Other Companies

As a means of presenting the PPSP/DSP approach to load forecasting, this Appendix has used the Delmarva study as an example. This section provides a summary of the forecast results for the other three major utilities -- APS, Pepco and BG&E. Since updates have been performed for all three utilities, both the original and the latest PPSP forecasts are provided for comparison. Although the original studies all included several alternative scenarios, the udpates only provide a Most Likely Case forecast.

Table A-6 provides the results for the Most Likely Case and five alternative scenarios from the original forecast study for APS. Along with the various economic scenarios, the last column of the table incorporates the potential impact upon peak demand from time-of-use pricing. This table indicates that the upper and lower bounds have forecasted annual rates of growth which differ from the Most Likely Case by approximately a percentage point.

Table A-7 presents forecasted peak demand growth rates for BG&E, Pepco and APS from the original studies and updates for purposes of comparison. As this table indicates, the update results are substantially below the original forecasts in every case. There are two basic causes of the forecast reduction. First, late 1970's load growth was far less than anticipated, by both the Companies and PPSP. Second, the outlook for economic growth in the service areas of these utilities has become less optimistic. Although downward revisions to the orginal forecasts are clearly warranted, the new forecast studies which will be prepared by PPSP in the near future should provide more reliable results.

Table A-6

Peak Demand Forecasts For The Most Likely Case and Alternative Scenarios

-- The Allegheny Power System (Megawatts)

	Most Likely	Rapid Growth/ Low Price	Rapid Growth	Slow Growth	Slow Growth/ High Price	Time of Use Pricing
1980	5,648	5,902	5,775	5,521	5,340	5,648
1985	6,867	7,432	7,141	6,548	6,050	6,579
1990	8,156	9,386	8,732	7,565	7,015	7,592
1995	9,601	11,441	10,612	8,757	8,117	8,820
			Annual Rates of Growth			
1980-1995	3.60%	4.51%	4.14%	3.12%	2.83%	3.02%

Source: (3)

Table A-7

Original And Revised Peak Demand Forecasts For
APS, PEPCO And BG&E
(Megawatts)

	APS		Pepco		BG&E	
	Original	Revision	Original	Revision	Original	Revision
1980	5,648	5,272	4,452	4,142	3,510	3,770
1985	6,687	6,093	5,621	4,393	4,418	4,447
1990	8,156	7,000	--	4,554	5,543	5,232
1995	9,601	7,984	--	--	--	5,965
			Annual Rates of Growth			
1980 - 1995*	3.60%	2.81%	4.77%	0.95%	4.68%	3.11%

* Growth rates, based upon 1995 or last year of the forecast period.

Source: (3), (6), (1), (7), (8)

REFERENCES - APPENDIX A

(1) Wilson, John W., Douglas Point Site. Maryland Power Plant Siting Program, PPSE 4-2, Volume 3. July 1975.

(2) J.W. Wilson & Associates, Inc., Projected Electric Power Demands for the Baltimore Gas & Electric Company, Maryland Power Plant Siting Program, PPES-1. 1979.

(3) J.W. Wilson & Associates, Inc. Projected Electric Power Demands for the Allegheny Power System. Maryland Power Plant Siting Program, PPES-2. January 1980.

(4) J.W. Wilson & Associates, Inc., An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula. Maryland Power Plant Siting Program, PPES-3. March 1980.

(5) Maryland Department of State Planning, Population and Employment, 1975-1990. May 1978 Revisions.

(6) Kahal, Matthew I., Additional Direct Testimony of Matthew I. Kahal on behalf of the Maryland Power Plant Siting Program. November 12, 1981.

(7) Maryland Power Plant Siting Program, Ten Year Forecast of Energy and Peak Demand for Maryland Electric Utilities, 1981-1990. Maryland Department of Natural Resources (in conjunction with the Maryland Department of State Planning). November 1980.

(8) Kahal, Matthew I. (Exeter Associates, Inc.). Memorandum to Howard A. Mueller (PPSP). July 15, 1981.

APPENDIX B

STATUS OF POWER PLANTS UNDER THERMAL DISCHARGE REGULATIONS

APPENDIX B

STATUS OF POWER PLANTS UNDER THERMAL DISCHARGE REGULATIONS

Plant	Mixing Zone Criteria	Spawning and Nursery Area of Consequence	Status
Calvert Cliffs	Passes	PPSP recommends passage	Approved 12/81
Chalk Point	Fails	Under review	Draft impact report submitted by BG&E; undergoing review
Crane	Fails	Under review	Draft impact report submitted by BG&E; undergoing review
Dickerson	Fails (under some flow conditions)	PPSP recommends passage	PPSP recommendation of acceptable impact submitted 4/81; final hearing scheduled 2/82
Gould Street	Passes	Passes	PPSP recommendation submitted 10/81 to DHMH, awaiting EPA/OEP review
Morgantown	Passes	PPSP recommends passage	Approved 8/81
R.P. Smith	Fails (under some flow conditions)	PPSP recommends passage	PPSP recommendation submitted 5/81 to DHMH; awaiting hearing schedule
Wagner	Fails	Under review	Awaiting action for further studies

THE 1982 TEN YEAR PLAN

OF

MARYLAND ELECTRIC UTILITIES

PROPOSED AND PLANNED NEW POWER PLANTS

1982 THROUGH 1991

Prepared For:

POWER PLANT SITING PROGRAM
DEPARTMENT OF NATURAL RESOURCES

By:

ENGINEERING DIVISION
PUBLIC SERVICE COMMISSION OF MARYLAND
AMERICAN BUILDING
231 E. BALTIMORE STREET
BALTIMORE, MARYLAND 21202

NOVEMBER, 1981

TABLE OF CONTENTS

I. INTRODUCTION

This Report constitutes the 1982 Ten-Year Plan of the Public Service Commission of Maryland (referred herein as the Commission) regarding those planned and proposed sites, including associated transmission routes, of new electric power plants within the State of Maryland. This report is prepared in compliance with Section 54B(b) of Article 78 of the Annotated Code of Maryland. (See Attachment No. 1) The plans herein are based upon the long-range plans submitted annually by the individual electric utilities, with supporting analyses and information by the Engineering Division of the Commission.

Although the primary thrust of this Report is on new generating plants planned for just the State of Maryland, it should be recognized that three of the four major electric utilities operating in the State are multi-jurisdictional. Planning by these utilities is on a system-wide basis to provide generation capacity to meet the needs of their entire service area.

For this reason, this Report also provides data on projected system demands and new generation planned outside Maryland. Unit retirements are not listed although they are available in the individual utility plans.

II. UTILITIES IDENTIFIED

The 14 retail electric companies presently operating in Maryland and subject to the jurisdiction of the Commission are listed in Attachment No. 2, according to type of ownership: investor-owned, municipally-owned, and customer-owned (i.e., cooperatives).

In addition, 2 non-retail electric companies own generation property in Maryland. They are:

1. Pennsylvania Electric Company owns a hydro-electric plant on the Youghiogheny River, Garrett County (Deep Creek Lake Reservoir) and an associated transmission line into Pennsylvania.
2. Susquehanna Power Company, a wholly-owned subsidiary of Philadelphia Electric Company, owns the Conowingo hydro-electric plant on the Susquehanna River, Harford and Cecil Counties, and an associated transmission line. Operation of this plant is by the Susquehanna Electric Company under a long-term lease with Susquehanna Power Company.

Of these 14 companies, only the 7 utilities listed below have future power plant siting interests in Maryland:

Baltimore Gas and Electric Company
Conowingo Power Company
Delmarva Power and Light Company
Easton Utilities Commission
The Potomac Edison Company
Potomac Electric Power Company
Southern Maryland Electric Cooperative, Inc.

Of these 7 companies, 2 companies, Conowingo Power Company and Southern Maryland Electric Cooperative, own no generation plant at the present time. Some of the other Maryland utilities may have partial interests in generating plants outside the State.

III. 1982 TEN-YEAR SITING PLANS, BY COMPANY

General

These Plans reported herein reflect continued uncertainties by the electric utility industry in the demand for electricity, and in the amount and type of generation capacity required to reliably meet that demand. During the past 7 years, a number of events have occurred which have had and are having a significant influence on peak demand, such as the economic recession of 1974-75, the continued high rate of inflation, the escalating costs of all forms of energy, increased awareness for the need for energy conservation, and spiraling costs of new generation plant. Clouding the nuclear option has been the recent accident at Three Mile Island.

The estimates of peak demand contained herein have been provided by the individual utilities. It is anticipated that a review of the methodologies used will be undertaken at a later date.

A discussion of the individual company plans is provided below.

1. Baltimore Gas and Electric Company

In 1973, the Company was granted approval by the Commission to begin construction of two 620-MW coal-fueled steam units at Brandon Shores, near Hawkins Point, Anne Arundel County. Unit One is scheduled to begin operational service in May, 1984. The second unit will become operational in January, 1988. These same operational dates were reported in last year's Plans.

Additional generation capacity is being planned as an extension to the Safe Harbor Water Power Corporation hydro-electric plant in Pennsylvania. This plant has a present capacity of 228-MW. It is located on the Susquehanna River, Lancaster County, Pennsylvania, approximately 20 miles upstream from the Pennsylvania-Maryland border.

The Safe Harbor Water Power Corporation is wholly owned by the Baltimore Gas and Electric Company and the Pennsylvania Power and Light Company. The entitlement to the present plant's capacity and energy is:

Baltimore Gas and Electric Company	152-MW	(66.67%)
Pennsylvania Power and Light Company	76-MW	(33.33%)
TOTAL	228-MW	(100.00%)

The expansion already approved by the Federal Energy Regulatory Commission will consist of 4 additional turbine units, each of 37.5-MW, for a total added capacity of 150-MW. Of this, Baltimore Gas and Electric Company will receive 100-MW.

Approval of a fifth turbine unit (37.5-MW) by the Federal Energy Regulatory Commission is being awaited, pending completion of minimum flow studies of the Susquehanna River.

This approved expansion, as well as the fifth new unit, will have an in-service date of Fall, 1985. Construction is scheduled to start in the Fall of 1982. Baltimore Gas and Electric Company will not require any reinforcements of the existing transmission line from this plant.

Projects which will go on-line in the years following the 1982-1991 decade require planning, site work, regulatory approval and licensing within this ten-year period. The Company is considering new generation subsequent to 1991 to include the construction of a large fossil-fueled unit at its Perryman site in Harford County, Maryland. It would become operational in the early to mid-1990's. The technology choice, including the kind of fuel and unit size, are currently under study. There may be joint ownership with a neighboring utility.

Also being studied for the mid to late 1990's is a hydro pumped storage plant. Studies by the Company have shown this technology to be an attractive way to generate power during times of peak demand. The Company is looking for another utility for joint participation. There is no indication as to its location.

2. Conowingo Power Company

The Conowingo Power Company is a wholly-owned subsidiary of The Philadelphia Electric Company. Conowingo Power Company is operated as an integral part of the Philadelphia Electric system, and so enjoys the benefits of being part of the larger system and of the PJM Interconnection, of which Philadelphia Electric is a member.

Almost all of the Philadelphia Electric system generation plant is located in Pennsylvania. The Conowingo hydro-electric plant on the Susquehanna River in Maryland has 474-MW installed capacity. It represents about 7% of the Philadelphia Electric's total installed capacity.

Philadelphia Electric Company owns two sites in Maryland for future power plant development. The 680 acre Canal site is located on the Chesapeake and Delaware Canal approximately one mile west of the town of Chesapeake City, Cecil County, Maryland.

The other site, known as Seneca Point, contains approximately 560 acres which Philadelphia Electric Company owns for future power plant development. It is located on the west bank of the Northeast River, approximately one mile southwest of Charlestown, Cecil County, Maryland.

There are no plans for Philadelphia Electric Company to start construction on either of the above sites within the next ten years.

3. Delmarva Power and Light Company

In April, 1978, Delmarva filed an Application with the Commission for the construction of a new 400-MW coal-fired steam generation unit as an extension to its existing generation plant at Vienna, Dorchester County, Maryland. By a letter to the Commission in July, 1979, Delmarva modified its original Application to increase the size of the unit to 500-600-MW nominal. Its exact size will depend on ultimate ownership and each owner's degree of participation.

Delmarva anticipates shared ownership of this unit, known as Vienna #9, as follows:

Delmarva	325-MW	(65%)
Atlantic City Electric Co.	125-MW	(25%)
Old Dominion Electric Co.	50-MW	(10%)
Total	500-MW	(100%)

Delmarva will be responsible for the licensing, construction and operation of this unit. It is expected to be operational in 1990. Actual construction start is presently planned for 1986.

No new transmission lines associated with this new unit will be required. However, several existing bulk power lines will be upgraded to 230-KV operation.

The Commission's Hearing Examiners Division issued a Proposed Order granting a Certificate of Public Convenience and Necessity to Delmarva for the construction of this unit on October 30, 1981. Additional details concerning this unit will be found in Commission Case No. 7222 which dockets this proceeding.

Two sites on the eastern shore, identified and evaluated by the Maryland Power Plant Siting Program in a recent study* appear suitable for use by Delmarva as possible sites. The Church Creek site, in Dorchester County, is just east of Church Creek and approximately 5 miles southwest of Cambridge along Maryland Route 16. The Deep Branch site is in southwestern Wicomico County about 3 miles west of the Nanticoke River at the Bivalve community, and north of the Wicomico River at its junction with Wicomico Creek.

---

*Eastern Shore Power Plant Siting Study, Vol. 2, Maryland Major Facilities Studies, October, 1977 PPSA-4

4. <u>Easton Utilities Commission</u>

In 1975, the Public Service Commission granted Easton Utilities Commission a Certificate of Public Convenience and Necessity for the construction of a new generating plant, to be known as Plant #2. This plant is located on a Town-owned 7 acre site within the city limits of Easton. The first two units of this Plant, having a total capacity of 12.5-MW, are in commercial operation.

Additional generation of 12.5-MW is planned for Plant #2 with commercial start-up in 1990. Prime mover of all units will be diesel engines, fueled by either No. 2 fuel oil or natural gas.

5. <u>The Potomac Edison Company</u>

The Potomac Edison Company is one of three operating subsidiaries of the Allegheny Power System. Potomac Edison together with its sister utilities Monongahela Power Company and West Penn Power Company are operated as one integrated facility. Most of the generation facilities of the Allegheny Power System are in Pennsylvania and West Virginia.

The Potomac Edison Company owns one site in Maryland for possible future power generation. This site, containing 829 acres, is approximately 2 miles downstream from the town of Point of Rocks, Frederick County, Maryland on the north side of the Potomac River. This site is one of several sites which are being evaluated for a coal-fired station with an in-service date in the mid-1990's.

Several other potential power generating sites in Maryland have been identified in an Allegheny Power System Siting study. A list of favorable candidate areas has been given to the Power Plant Siting Program which is currently performing a Western Maryland Power Plant Siting study. The site selected would be coal-fired with an initial in-service date in the mid-1990's.

In October, 1980, the Virginia Electric and Power Company signed an $800 million preliminary agreement to share its 2,100-MW pumped storage hydro-electric facility in Bath County, Virginia with the Allegheny Power System. Expected APS participation in this facility may be as much as 50% through either outright purchase or lease. Scheduled for completion in 1985, this facility is the largest pumped hydro plant ever built in the United States. The Potomac Edison Company's entitlement would be 280-MW. This matter is currently in proceedings before the Commission and before the Pennsylvania Public Utilities Commission.

6. Potomac Electric Power Company

Potomac Electric Power Company expects its 600-MW Chalk Point Unit #4 to begin commercial service in 1982, the same date identified in last year's Plan.

Plans by the Company show a possible 300-MW coal-fired unit for construction at its Dickerson site. In-service date has been tentatively identified as 1993. Preliminary engineering site studies, etc. were begun in 1981 with start-up as early as 1990, if needed.

The Company's Ten-Year Plan lists a possible 2,000-MW pumped-storage hydro-electric plant at an undetermined site in Maryland. The plant would likely be a joint venture with one or more other utilities. The in-service date is not specified.

7. Southern Maryland Electric Cooperative, Inc.

The Cooperative owns a 300 acre site on the Patuxent River, St. Mary's County. This site, known as the De La Brooke Farm, is considered for possible future generation. However, no plans have been made for such use.

IV. PROJECTED GROWTH IN PEAK DEMAND IN MARYLAND

The peak demand for electricity in Maryland as projected by the major utilities is listed on a yearly basis for the next decade on Attachments No. 3 through No. 6. Also shown on these Attachments are peak demands, system-wise, for the three multi-jurisdictional utilities. Total installed capacity reflecting both the additions of new or upgraded plant and retirements of older units is also indicated.

Data on the smaller utilities, Southern Maryland Electric Cooperative, Conowingo Power Company, Easton Utilities Commission and Thurmont Municipal are shown on Attachments No. 7 and No. 8.

A summary of the average annual growth rates in peak demand by utility is provided by Attachment No. 9. Corresponding data for the 1980 and 1981 Ten-Year Plans are also shown. Attachment No. 10 is a bar chart of the peak demand growth rates.

Several observations concerning the data of Attachment No. 9 are noteworthy:

1. Baltimore Gas and Electric Company, the largest utility in Maryland, has revised downward the growth in peak demand to 2.7%. Last year it projected a 3.0% growth per year.
2. At the low end of the range of growth rates is Potomac Electric Power Company. This utility is now estimating an average growth of 1% per year in Maryland, somewhat more (1.2%) system-wise.
3. The Potomac Edison Company, the only major winter-peaking utility in the state, is estimating that its Maryland customers will be requiring a 2.6% increase in peak demand,

off sharply from its figure of 4.3% in its last year's Ten-Year Plan.

4. Delmarva Power and Light Company, also, for Maryland, has revised its projected demand significantly downward, from 3.8% per year in the 1981 Plan to 2.2% this year.

5. For the entire State, the peak demand estimate has dropped from 2.8% per year last year to this year's figure of 2.3%. As a matter of interest, a growth rate of 2.3% per year corresponds to a doubling in demand in 30 years, that is by the year 2011.

V. ASSOCIATED TRANSMISSION LINES

The transmission lines associated with the construction of new generating stations will generally operate at 115-KV and higher voltages. They will require rights-of-way widths of 150 to 300 feet. An "associated transmission line", with respect to Section 54B of Article 78, refers to the means of transporting electric power from a power plant to one or more points on an existing transmission system. Such lines are often called "generation leads". There are also "transmission lines", with respect to Section 54A of Article 78, which are not "generation leads" but rather they provide substation-to-substation bulk power transmission for increased capacity or reliability purposes. In any of these instances, the long-range need and probable capacity of a future transmission line can be determined from extensive system studies. However, the actual route and often the actual terminal location(s) of a line can be established only after subsequent years of planning and surveys.

Lines planned for possible construction at later dates and in particular the "associated transmission lines" for new power plants cannot be defined as to specific siting. However, general planning information regarding terminal points, voltage levels and dates to the extent possible is contained in the individual plans submitted by the major companies.

VI. POWER PLANT SITING PROGRAM PROJECTIONS OF UTILITY PEAK DEMAND

The Power Plant Siting Program of the Department of Natural Resources has prepared its own forecasts of annual peak demand for the four major utilities in Maryland out through 1992.

These projections, forwarded to the Public Service Commission in a letter dated November 20, 1981, are listed in Attachment No. 11. Additional details concerning the methodologies and assumptions used as a basis for these data may be obtained from Dr. Howard Mueller of the Power Plant Siting Program.

VII. FURTHER INQUIRY

In the event further inquiry is indicated, such as by other state agencies, the request should be directed to the Commission by writing to Mrs. Gloria Jimenez, Executive Director. Specific information requests of an engineering nature and comments on this Plan should be directed to Mr. John W. Dorsey, Chief Engineer, or to its author, Mr. Richard M. Hollis, Senior Engineer.

ATTACHMENT NO. 1

SECTION 54B(b), ARTICLE 78 OF THE ANNOTATED CODE OF MARYLAND

"§ 54B. Consolidated public hearing, long-range plans and establishing an environmental surcharge on generated electric energy; notice to landowners over whose property company intends to run line, etc.; purchase of power plant site by State.

(b) In cooperation with the Secretary of Natural Resources as set forth in §3-304 of the Natural Resources Article of the Code, the Commission shall be responsible for assembling and evaluating annually the long-range plans of Maryland's public electric utilities regarding generating needs and means for meeting those needs. The chairman of the Public Service Commission shall, on an annual basis, forward to the Secretary of Natural Resources a ten-year (10) plan listing possible and proposed sites, including associated transmission routes, for the construction of electric power plants within the State of Maryland. Sites which are identified as unsuitable by the Secretary of Natural Resources in accordance with the requirements of §3-304 of the Natural Resources Article of the Code shall be deleted from the plan, provided, however, nothing in this subsection shall prevent the inclusion of such site in subsequent ten-year (10) plans. The first ten-year (10) plan shall be submitted on or about January 1, 1972."

ATTACHMENT NO. 2

RETAIL ELECTRIC COMPANIES OPERATING IN MARYLAND

NAME	ADDRESS	TELEPHONE NO.
Investor-Owned		
Baltimore Gas and Electric Company	Gas and Electric Building Baltimore, MD 21203	234-5000
Conowingo Power Company	211 North Street Elkton, MD 21921	398-1400
Delmarva Power and Light Company	P. O. Box 1739 Salisbury, MD 21801	749-6111
Potomac Edison Company, The	Downsville Pike Hagerstown, MD 21740	731-3400
Potomac Electric Power Company	1900 Pennsylvania Ave., N.W. Washington, D. C. 20006	(202)872-2449
Municipally-Owned		
Berlin, Mayor and Council of	P. O. Box 235 Berlin, MD 21811	641-2770
Easton Utilities Commission, The	11 S. Harrison Street Easton, MD 21601	822-6110
Hagerstown Municipal Electric Light Plant	Hagerstown, MD 21740	731-2600
Thurmont Municipal Light Co.	P. O. Box 385 Thurmont, MD 21788	271-7313
Williamsport, Mayor and Council of	Williamsport, MD 21795	223-7711
Customer-Owned		
A and N Electric Cooperative	Parksley, Virginia 23421	(804)665-5116
Choptank Electric Cooperative, Inc.	P. O. Box 430 Denton, MD 21629	479-0380
Somerset Rural Electric Coop., Inc.	P. O. Box 270 Industrial Park Somerset, Pennsylvania 15501	(814)445-4106
Southern Maryland Electric Coop., Inc.	Hughesville, MD 20637	274-3111

ATTACHMENT NO. 3

PROJECTED PEAK LOAD, CAPACITY, AND RESERVE ESTIMATES

BALTIMORE GAS AND ELECTRIC COMPANY

YEAR	PROJECTED CONTRACT LOAD (MW)*	TOTAL INSTALLED CAPACITY, (MW)	INSTALLED RESERVE MARGIN (PERCENT)
1982	4130	5025	21.7
1983	4260	5025	18.0
1984	4390	5634	28.3
1985	4530	5634	24.4
1986	4640	5759	24.1
1987	4740	5701	20.3
1988	4870	6321	29.8
1989	5000	6321	26.4
1990	5130	6321	23.2
1991	5260	6321	20.2

Average Annual Compound Growth, Percent, 2.7 in Peak Load

*Contract load represents the total demand on the Company including only that part to Bethlehem Steel which cannot be supplied by the Bethlehem generating capacity itself. The Company also reports a Group Load which represents the total electrical requirements of the Company and of Bethlehem Steel.

ATTACHMENT NO. 4

PROJECTED PEAK LOAD, CAPACITY, AND RESERVE ESTIMATES

POTOMAC ELECTRIC POWER COMPANY

	SYSTEM			MARYLAND COMPONENT*
YEAR	PROJECTED PEAK LOAD (MW)	TOTAL INSTALLED CAPACITY (MW)	INSTALLED RESERVE MARGIN (PERCENT)	PROJECTED PEAK DEMAND (MW)
1981	3912	4999	27.8	2152
1982	3956	4996	26.3	2167
1983	4000	5322	33.0	2182
1984	4058	5322	31.1	2214
1985	4105	5322	29.6	2235
1986	4153	5322	28.1	2254
1987	4208	5322	26.5	2280
1988	4259	5322	25.0	2309
1989	4302	5322	23.7	2326
1990	4355	5148	18.2	2344
1991**	Not Available (N.A.)	N.A.	N.A.	N.A.
Average Annual Compound Growth, Percent (1981-1990 Period)	1.2			1.0

*These data include Southern Maryland Electric Cooperative projected peak demand.

**PEPCO estimates for 1991 were not available at the time this report was prepared. It is anticipated that approved figures through 1991 will be made available in early 1982, and distribution of revised figures made at that time to recipients of the Commission's 1982 Plan.

ATTACHMENT NO. 5

PROJECTED PEAK LOAD, CAPACITY AND RESERVE ESTIMATES

THE POTOMAC EDISON COMPANY

	SYSTEM			MARYLAND COMPONENT
YEAR WINTER OF	PEAK LOAD (MW)	INSTALLED CAPACITY (MW)	INSTALLED RESERVE MARGIN (Percent)	PEAK LOAD (MW)
1982/83	1585	1882	18.7	1024
1983/84	1630	1882	15.5	1046
1984/85	1694	1882	11.1	1081
1985/86	1741	1999	14.8	1116
1986/87	1822	2117	16.2	1147
1987/88	1881	2117	12.5	1174
1988/89	1932	2117	9.6	1199
1989/90	1968	2281	15.9	1226
1990/91	2050	2242	9.4	1260
1991/92	2113	2405	13.8	1295
Average Annual Compound Growth, Percent in Peak Loads	3.2			2.6

ATTACHMENT NO. 6

PROJECTED PEAK LOAD, CAPACITY AND RESERVE ESTIMATES

DELMARVA POWER AND LIGHT COMPANY

	SYSTEM			MARYLAND COMPONENT
YEAR	PROJECTED PEAK LOAD (MW)	TOTAL INSTALLED CAPACITY (MW)	INSTALLED RESERVE MARTIN (PERCENT)	PROJECTED PEAK DEMAND (MW)
1982	1,627	2,324	42.8	452
1983	1,667	2,167	30.0	457
1984	1,711	2,167	26.6	467
1985	1,767	2,217	25.5	480
1986	1,808	2,217	22.6	490
1987	1,818	2,177	19.7	503
1988	1,870	2,177	16.4	516
1989	1,919	2,177	13.4	528
1990	1,918*	2,460	28.3	517**
1991	1.964*	2,560	29.7	528**

Average Annual 2.4 2.2
Compound Growth (Percent), 1982-1989 Period in Peak Loads

*These figures reflect a 50-MW reduction in peak REA Cooperative load due to the proposed assumption of responsibility as a result of participation in Vienna #9 by Old Dominion.

**These figures reflect a 22-MW reduction in the peak load of the Maryland Component due to participation by Old Dominion in Vienna #9, (*) above.

ATTACHMENT NO. 7

PROJECTED PEAK LOAD

SOUTHERN MARYLAND ELECTRIC COOPERATIVE, INC.

YEAR	PEAK LOAD (MW)
1982	282
1983	300
1984	316
1985	333
1986	348
1987	366
1988	383
1989	398
1990	414
1991	428

Average Annual Compound Growth, Percent - 4.7

ATTACHMENT NO. 8

PROJECTED PEAK LOADS

CONOWINGO POWER COMPANY
EASTON UTILITIES COMMISSION
THURMONT MUNICIPAL LIGHT COMPANY

YEAR	PEAK LOAD (MW) CONOWINGO	EASTON	THURMONT
1982	95	26.3	7.5
1983	97	27.1	7.9
1984	100	28.0	8.3
1985	102	28.9	8.7
1986	105	29.8	9.1
1987	107	30.7	9.5
1988	110	31.7	9.9
1989	113	32.7	10.3
1990	116	33.7	10.7
1991	119	34.8	11.1
Average Annual Compound Growth, Percent -	2.5	3.2	4.5

ATTACHMENT NO. 9

COMPARISON OF PROJECTED AVERAGE ANNUAL
COMPOUND GROWTH RATES IN PEAK DEMAND FOR ELECTRICITY
(PERCENT PER YEAR)

	1980 PLAN (1980-1989)	1981 PLAN (1981-1990)	1982 PLAN (1982-1991)
Baltimore Metro			
Baltimore Gas and Electric Company	3.5	3.0	2.7
Washington Metro			
Potomac Electric Power Company			
(Maryland Only)	N/A	1.2	1.0
(System)	1.9	1.2	1.2
Western Maryland			
Potomac Edison Company			
(Maryland Only)	4.4	4.3	2.6**
(System)	N/A	4.8	3.2**
Southern Maryland			
Southern Maryland Electric Coop., Inc.	4.0	4.8	4.7
Eastern Shore			
Conowingo Power Company	4.0	3.0	2.5
Delmarva Power and Light Company			
(Maryland Only)	4.1	3.8	2.2*
(System)	N/A	2.4	2.4*
Easton Utilities Commission	5.4	5.5	3.2
Entire State	3.0	2.8	2.3*

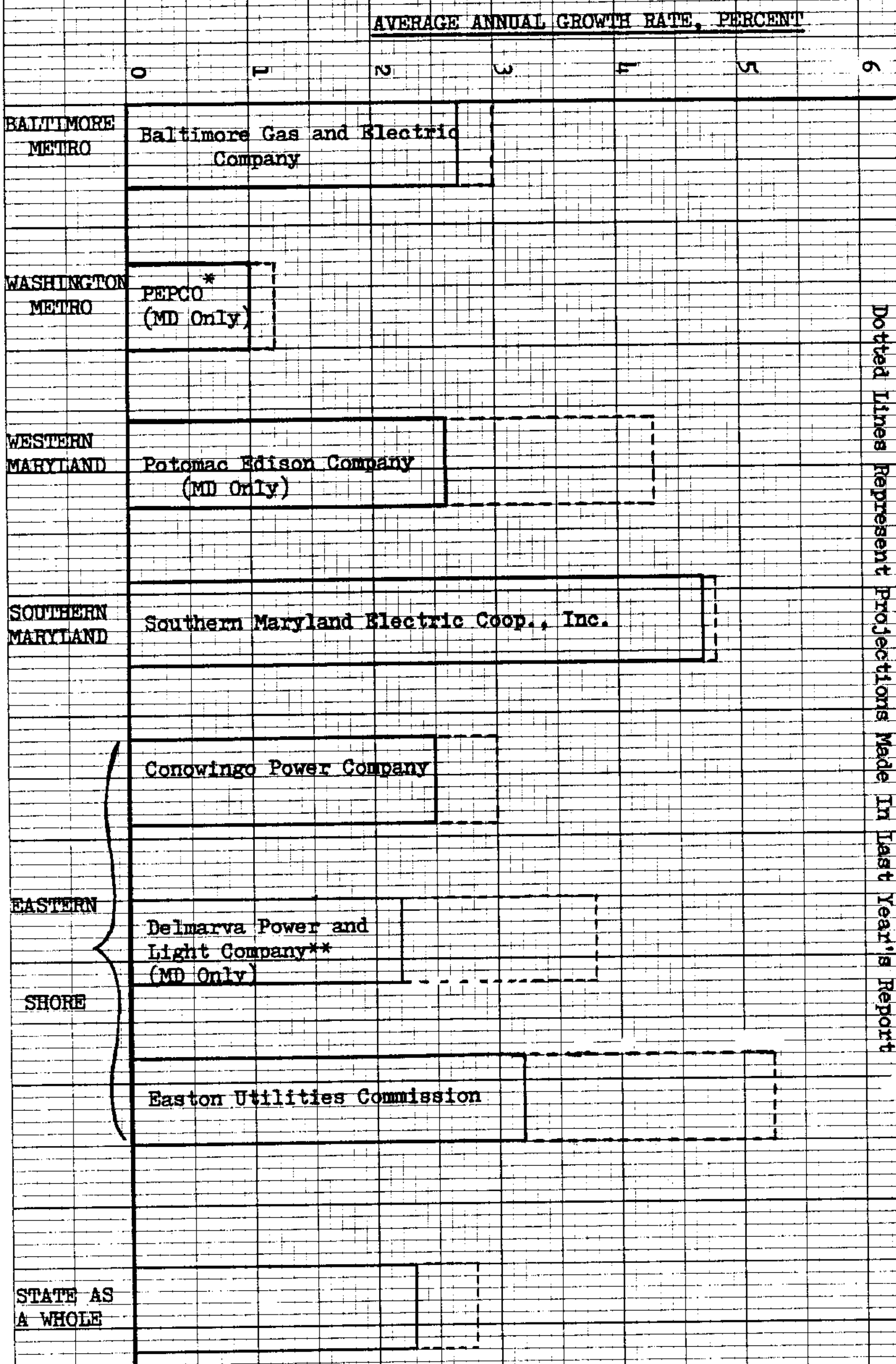
*Average Over 1982-1989 Time Period

**Average Over 1981-1990 Time Period

ATTACHMENT NO. 10

PROJECTED AVERAGE ANNUAL GROWTH RATES IN PEAK DEMAND BY UTILITIES AND IN STATE

1982-1991 PERIOD



*Data For The Period 1981-1990

**Data For The Period 1982-1989

ATTACHMENT NO. 11

POWER PLANT SITING PROGRAM PROJECTIONS
OF
UTILITY PEAK DEMAND, 1982-1992 PERIOD
(MW)

	POTOMAC EDISON*		DELMARVA P. & L.**		PEPCO	BG & E
YEAR	TOTAL SYSTEM	MD. ONLY	TOTAL SYSTEM	MD. ONLY	TOTAL SYSTEM	
1982	1,544	988	1,619	454	4,284	4,028
1983	1,600	1,024	1,671	468	4,322	4,162
1984	1,657	1,061	1,728	485	4,358	4,303
1985	1,717	1,099	1,790	503	4,393	4,447
1986	1,775	1,136	1,844	518	4,420	4,591
1987	1,834	1,174	1,902	535	4,453	4,741
1988	1,895	1,213	1,963	553	4,486	4,897
1989	1,958	1,253	2,027	572	4,520	5,091
1990	2,023	1,295	2,094	592	4,554	5,232
1991	2,088	1,337	2,160	612	4,580	5,372
1992	Not Available	Not Available	2,229	634	4,623	5,513
Average Annual Compound Growth Rate (Percent)	3.4	3.4	3.2	3.4	0.8	3.2

*Potomac Edison is a winter peaking utility. The peak indicated for, say 1982, is that projected for the winter of 1981/1982.

**Data includes portions of the Dover, Delaware and Easton, Maryland loads served by Delmarva at the time of the annual peak.