Table I-9

Employment by Sector Washington, D.C. Area
(Thousands)

	1980*		1973*	
Sector	Number	Percent	Number	Percent
Manufacturing	56.0	3.6%	45.2	3.6%
Construction	75.4	4.8	77.9	6.2
Transportation/ Utilities	67.5	4.3	61.6	4.9
Trade	296.2	18.9	247.1	19.7
Services/Finance	512.2	32.7	348.9	27.7
Government	560.5	35.8	477.1	37.9
Total	1,567.8	100.0	1,257.8	100.0

* Figures are for April of indicated year.

Source: (7).

Table I-10 demonstrates the extent to which power demand growth rates on the Pepco system have fallen since 1973. Prior to that year, sales were growing by more than eight percent per year, and have since slowed to slightly over two percent per year. Peak demand growth has fallen even more dramatically, revealing a slight tendency for Pepco's very low annual load factor to improve over time. The pattern of growth in the residential and general service class is similar. Sales to SMECO continue to grow fairly rapidly as the Southern Maryland region continues to undergo a gradual suburbanization process.

Table I-10

Growth in Energy and Peak Demand on the Pepco System
(Thousands of MWh)

	1966	1973	1980	Annual Growth Rates 1966-1973	1973-1980
Residential	1,978	3,529	4,026	8.6%	1.9%
Nonresidential	5,661	9,704	11,425	8.0	2.4
Sales to SMECO	330	755	1,106	12.6	5.6
Total	7,969	13,988	16,557	8.4	2.4
Peak Demand (MW)	2,123	3,680	4,142	8.2	1.7

There are several identifiable factors accounting for the decline in demand growth. Although some economic development in the Washington area has occurred in recent years, it has done so at slower rate than in the past. Population growth, in particular, has slowed considerably. Moreover, much of the Washington area development which has occurred in recent years has been outside of the Pepco service area -- i.e., in Northern Virginia and the extremeties of Prince Georges and Montgomery Counties. The District's population, which is entirely served by Pepco, has been declining in absolute terms. Also, it has been hypothesized that Pepco residential and commercial customers have already achieved a very high level of air conditioning saturation (which represents a large percentage of the Company's load), and the growth opportunities from further saturation may be modest. Finally, it is likely that the combined effects of higher prices and conservation programs also have substantially contributed to this demand growth rate reduction.

Delmarva Power & Light Company

DP&L serves directly or indirectly the Delmarva Peninsula -- a geographic region which includes the entire State of Delaware, the Maryland Eastern Shore and two Virginia counties. This region contains about 5,700 square miles and a population of 860,000. Electric service is also furnished to households and businesses on the Peninsula by one other, very much smaller, privately owned utility (Lincoln & Ellendale); by eleven municipal electric utility systems;[1] and by three rural electric cooperatives. DP&L itself serves directly almost 80 percent of the retail electric load on the Peninsula; and it generates more than 90 percent of the bulk power consumed. DP&L has a larger role in generation than in retail sales, because it provides indirect service to much of the load served by the other distribution utilities. Dover, Delaware and Easton, Maryland are the only other systems generating significant quantities of power, and they buy (and sell) power on an interchange basis with DP&L. Thus, all utilities operating on the Peninsula are fully integrated with DP&L.

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[1] Until recently the Maryland towns of St. Michaels and Centreville operated their own municipal electric systems. Currently, those two towns are now served at retail by DP&L.

Some energy is also generated by industrial companies for their own use. Dupont's Seaford nylon plant generates most of the power it consumes and purchases back-up power from DP&L. A small amount of energy from the Getty Oil Company's joint steam-electricity facility is produced in excess of refinery requirements and is sold to DP&L.

Except for a major manufacturing and urban center in and around Wilmington, the Delmarva Peninsula is a largely rural region. An important food processing industry has developed in recent years as a natural complement to the region's agricultural activity. In addition, there are several popular ocean and Bay resorts, the largest being Ocean City, Maryland. Maryland comprises only about a quarter of DP&L's total load, and virtually all of the heavy manufacturing on the Peninsula is in Delaware. The Virginia service territory is very small and accounts for less than five percent of total Peninsula power demands.

The economy of the Peninsula, as well as the differences among the three states there, can best be understood by examining employment patterns as shown below for the year 1977. U.S. breakdowns are included on this table as a benchmark.

Table I-11

Employment Shares by Major Sector
on the Delmarva Peninsula, 1977

	Delaware	Maryland	Virginia	Total Peninsula	U.S.
Agriculture	2.3%	10.6%	12.0%	4.9%	3.6%
Manufacturing	26.2	21.5	26.8	25.1	21.7
Trade	19.4	21.4	13.4	19.6	20.4
Government	18.7	15.9	19.7	18.0	16.7
Other	33.4	30.6	28.1	32.4	37.6

Source: Bureau of Economic Analysis unpublished data.

This table suggests that the structure of the Delmarva economy is similar to the rest of the nation. However, these sector definitions are extremely broad and tend to hide important differences among the various portions of the Peninsula. For example the most important manufacturing industry in the Maryland service area is food processing, an activity which does not use large quantities of energy. By contrast, chemicals, an extremely energy intensive industry, dominates manufacturing in Delaware. Thus, within these employment categories are major differences in economic activity which are themselves expressed in electricity demand. This is shown below in Table I-12.

Table I-12

Customer Class Shares of Electricity Demand
On the Delmarva Peninsula, 1977

	Delaware	Maryland	Virginia	Total Peninsula	U.S.
Total Sales (thousands of megawatt-hours)					
	5,293	1,794	271	7,358	1,929,000
Percentage Distribution by Economic Sector					
Residential	30.3%	50.0%	47.1%	36.0%	33.2%
Commercial	29.5	32.8	41.5	30.8	23.1
Industrial	39.6	15.9	10.7	32.4	40.0
Other	0.6	1.3	0.7	0.8	3.7

The obvious, dramatic differences are in the industrial energy sales category. Delaware is typical of the U.S. (39.6 vs. 40.0), whereas in Maryland and Virginia the industrial sector accounts for merely ten to fifteen percent of total electricity usage. On the other hand, Maryland and Virginia have very large residential sectors.

Table I-13

Growth in Energy and Peak Demand on the Delmarva Peninsula
(Thousands of MWh)

				Average Annual Growth Rates	
	1966	1973	1980*	1966-1973	1973-1980
Residential	1,063	2,136	2,682	10.5%	3.3%
Commercial	1,025	1,969	2,387	9.8	2.8
Industrial	1,510	2,513	2,430	7.6	-0.5
Total	3,752	6,958	8,109	9.2	2.2
Peak Demand (MW)	752	1,540	1,698	10.8	1.4

* Estimates. 1980 peak demand is weather adjusted.

Clearly, a precipitous decline in energy sales and peak demand growth rates has taken place since 1973. This tendency can be explained by the various forces which have operated nationwide -- sluggish economic growth, responses to higher energy prices and so forth. But a prominent part of the explanation lies in the stagnant industrial power demands. (Note that 1980 industrial sales were actually below those in 1973.) The long-run outlook for heavy manufacturing industry in Delaware is one of virtually no growth. Because of the importance of this sector, overall system demand growth will be restrained.

The Allegheny Power System

APS is a holding company whose principal operating subsidiaries are The Potomac Edison Company (PE), The Monongahela Power Company (MP) and The West Penn Power Company. These three companies serve a sprawling, largely rural service territory which extends over five states, approximately 86 counties and 29,000 squares miles. Approximately 2.6 million people live in this geographic region. The rural nature of the system is attested to by the fact that the largest city in the APS service territory, Parkersburg, West Virginia, has a population of about 44,000.

Potomac Edison operates in western Maryland, the eastern West Virginia panhandle, and the northwestern portion of Virginia. Monongahela Power serves the northern half of West Virginia and a small area in eastern Ohio along the Ohio River. West Penn serves the southwest and central areas of Pennsylvania. The relative sizes of the three companies and the various regulatory jurisdictions are shown in Table I-14 below.

Table I-14

1977 Energy Sales
(Thousands of MWh)

Company	Sales	%of APS	1965-1977 Annual Growth Rate
Potomac Edison	7,815.1	27.7%	10.7%
Maryland	5,628.8	19.9	11.9
Virginia	1,096.4	3.9	9.1
W. Virginia	1,089.9	3.9	6.9
Monongahela Power	7,198.0	25.5	6.0
W. Virginia	6,704.7	23.7	5.9
Ohio	493.3	1.7	7.4
West Penn	13,234.1	46.9	4.6
APS	28,247.3	100.0	6.3

On the basis of energy sales, West Penn is the single largest portion of the system; PE and MP are approximately equal in size. The Ohio and Virginia service areas of APS are quite small compared to those in Maryland, Pennsylvania and West Virginia. From the above table it is apparent that power demands in the various areas have been growing at different rates. Between 1965 and 1977, PE (Maryland) grew by nearly 12 percent per year compared to less than five percent for West Penn. The rather extraordinary growth in Maryland is partly explained by the establishment of the Eastalco Aluminum Company plant in 1970 near Frederick. As of 1977 that single customer represented nearly a third of the Maryland load and approximately a fifth of the total Potomac Edison load.

It should also be noted that APS serves several municipals and cooperatives in its service territory on a wholesale basis. In 1977 the APS companies sold 737 thousand MWh to 13 resale customers, the largest being Hagerstown, Maryland. However, those sales represented only about 2.6 percent of the System's energy sales.

APS serves a vast rural region containing small towns and a few small cities. Despite the absence of large cities in the service area, agriculture is relatively unimportant (less than six percent of total employment) compared to heavy manufacturing. APS serves a rather large industrial load due to the predominance of electricity intensive industries in the area such as steel, aluminum, chemicals, glass and coal mining. The employment shares shown below demonstrate that the structure of APS service area economy is not atypical of the rest of the nation.

Table I-15

Employment Shares by Major Sector, 1977

	Potomac Edison	Monongahela Power	West Penn	APS	US
Agriculture	7.2%	6.1%	4.8%	5.9%	3.6%
Mining	0.7	6.3	4.1	3.9	0.9
Manufacturing	23.9	15.6	24.4	21.8	21.7
Trade	19.2	21.8	16.8	18.6	20.4
Government	15.2	16.3	16.2	16.0	16.7
Other	33.7	33.9	33.7	33.8	36.7

Source: Bureau of Economic Analysis unpublished county level employment data.

These figures demonstrate that agriculture and coal mining are far more important activities in the APS service area than nationwide; but employment shares in the other major sectors compare rather closely with those of the U.S. Even though the manufacturing share is virtually identical to the U.S. average, manufacturing activity in this region has been disproportionately concentrated in the energy intensive industries. As of 1977 nearly 75 percent of the industrial electricity sales revenues came from a few, very energy intensive industries -- coal mining; stone, clay and glass; primary metals; paper and chemicals. Nationwide, these industries account for about 50 percent of industrial electricity sales revenues.

The pattern of electricity sales reflect the nature of the APS service territory economy. A breakdown of electricity sales by major customer class for APS and the U.S. shown below for 1977 reveal dramatic differences.

	APS	U.S.
Residential	28.7%	33.2%
Commercial	15.1	23.1
Industrial	53.3	40.0
Other	2.9	3.7

The combination of a concentration of heavy industry and the lack of any major commercial centers is largely responsible for the pattern of APS sales shown above. Also, the relatively mild summer climate and lower than average per capita incomes tend to hold down residential usage relative to the rest of the U. S.

Although the customer class distribution of electricity sales is quite different from the rest of the nation, historical sales growth experience for APS has been quite typical. Prior to 1973 sales and peak demand were growing rapidly. A slight decline in demand occurred during the 1974-1975 period, and demand since then has been growing sluggishly. The slowdown in demand experienced by APS has been for substantially the same reasons as for the rest of the electric utility industry. In addition, however, demand has reflected the poor performance of the steel industry, in recent years, upon which the service area economy is highly dependent. As the figures in Table I-16 demonstrate, the post-1973 decline in demand has been sharpest for industrial customers.

It is also interesting to note that peak demand has grown more rapidly than energy sales since 1973. The figure listed for 1973 is the peak demand for the winter of 1973-1974 -- in the midst of the Arab oil embargo. The 1973 energy sales figure is for the calendar year and therefore largely pre-embargo. This tends to exaggerate post-1973 peak demand growth somewhat. Further, it has been the nonindustrial sales which are the fastest growing part of the system. Since these customers tend to have lower load factors (and higher coincidence factors) than the system average, this has also caused peak to grow more rapidly than energy. Despite the deterioration which has occurred over the past few years, APS still maintains a relatively high system load factor, especially compared to the other Maryland utilities.

Table I-16

Growth of Energy and Peak Demand for the
Allegheny Power System
(Thousands of MWh)

	1966	1973	1980	Average Annual Growth Rates 1966-1973	1973-1980
Residential	3,711	6,614	8,633	8.6%	3.9%
Commercial	1,865	3,621	4,631	9.9	3.6
Industrial	8,822	13,760	15,808	6.6	2.0
Total	14,712	24,672	29,958	7.7	2.8
Peak Demand (MW)	2,661	4,230	5,564	6.2	4.0
Load Factor	68.7%	71.7%	66.8%		

Summary of Economic and Electricity Usage Trends

The historical power demand experience facing the four major utility systems is summarized in Table I-17. Detailed data tables for both historical and projected demands are presented in tables at the end of this chapter.

Table I-17 reveals important similarities in the patterns of demand growth for the four systems. From 1966 to 1973 energy sales and peak demand grew at annual average rates of 8.0 percent and 8.4 percent, respectively, for the four major systems combined. Demand fell in 1974 and 1975 and resumed its growth thereafter though at a slower pace than in earlier years. Between 1973 and 1980 demand growth averaged only 2.6 percent per year.

Table I-17

Historic Energy Sales And Peak Demand Of
The Major Utility Systems
(MW and Thousands MWh)

	BG&E		PEPCO		DP&L		APS		TOTAL	
	Sales	Peak	Sales*	Peak	Sales	Peak	Sales	Peak	Sales	Peak
1966	8,653	1,817	7,639	2,123	3,638	661	14,712	2,661	34,642	7,262
1970	11,971	2,496	11,183	2,908	5,440	1,045	20,119	3,785	48,713	10,234
1973	14,341	3,334	13,645	3,680	6,756	1,489	24,672	4,230	59,414	12,733
1974	13,990	3,190	12,526	3,502	6,592	1,429	24,944	4,272	58,052	12,393
1975	13,857	3,256	13,064	3,623	6,393	1,443	23,962	4,650	57,276	12,972
1976	14,758	3,234	13,444	3,500	6,660	1,301	26,704	5,031	61,566	13,066
1977	15,462	3,588	14,020	3,857	6,906	1,499	28,247	5,174	64,635	14,118
1978	16,170	3,553	14,469	3,714	7,248	1,476	28,733	5,335	66,620	14,078
1979	16,823	3,621	14,651	3,804	7,492	1,501	30,377	5,272	69,343	14,198
1980	17,228	3,969	15,451	4,142	7,460	1,581	29,958	5,564	70,097	15,256

Annual Rates Of Growth

1966-1973	7.48%	9.06%	8.64%	8.18%	9.25%	12.30%	7.67%	6.85%	8.01%	8.35%
1973-1980	2.65	2.52	1.79	1.70	1.43	0.86	2.79	3.99	2.39	2.62
1966-1980	5.04	5.74	5.16	4.89	5.26	6.43	5.20	5.41	5.16	5.45

*Excludes sales to SMECO.

E. The Outlook for Growth in Power Demands

It is expected that future power demand growth will more closely resemble the post-embargo growth rates than those occurring in the decade before 1974. There are several reasons for this expectation. First, a continuation of the economic slowdown of the 1970's, in comparison to the more rapid economic expansion of the 1960's, is projected for the future. As Table I-18 indicates, population and employment growth rate projections for the 1980's are similar to or even below those experienced in the 1970's.[1] The Bureau of Economic Analysis (BEA) is projecting that real per capita income in Maryland will increase by only 2.3 percent annually over the next two decades (8). Finally, the tendency during the 1970's for manufacturing (particularly heavy, energy intensive manufacturing) to decline in absolute terms is expected to continue in the service territories of the major utilities.

Perhaps the most obvious and important reason for the decline in demand growth was the massive increases in energy prices during the mid and late 1970's. The historical price behavior and future outlook are shown in Table I-19. Even if future real price increases do not occur, the massive price increases which have already taken place will suppress future demand. This is because many years are required before consumers can fully adjust to price changes. Thus, during the 1980's consumers will still be adjusting their energy usage to the price shocks of the 1970's. It is also reasonable to expect that future real increases in electric rates for these systems will occur, and continued customer adjustment will follow.

Finally, attitudes and public policy concerning energy usage (and power usage) have changed. Toward the end of the 1970's several important legislative initiatives were enacted designed to require, fund or encourage conservation. Although less potent than the slow economic growth and rising energy prices, these numerous new conservation programs will help to slow the growth of power demands.

The Power Plant Siting Program (PPSP), in cooperation with the Department of the State Planning (DSP), has maintained a program of conducting independent long-range load forecasts. Such studies have been undertaken for each of the four major utilities (9), (10); (11), (12). The DP&L and APS studies were completed relatively recently; however the Pepco and BG&E studies were completed in 1974 and 1977 and were partially updated in 1978 and 1981, respectively. It is anticipated that both studies will be updated and substantially revised in 1982.

The PPSP/DSP load forecasts were developed through the application of econometric models (see Appendix A). This methodology involves 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 the various factors (i.e., the explanatory variables) that govern it, such as population, employment, climate, income and electricity rates. In the second stage, projected or assumed

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[1] The employment projections shown were prepared in 1978 and are therefore somewhat dated. The most recent BEA figures (November 1980) project employment in the State of Maryland to increase by only 1.2 percent annually.

Table I-18

Population and Employment Trends, 1970-1990
(Thousands)

Service Area	1970	1980	1990	Annual Rate of Growth 1970-1980	Annual Rate of Growth 1980-1990
Population					
Pepco	2,062	2,090	2,196		
(Md. only)	1,300	1,411	1,525	0.82%	0.81%
BG&E	2,071	2,174	2,296	0.49	0.55
Delmarva	800	879	959	0.94	0.87
(Md. only)	205	236	257	1.42	0.86
APS	2,495	2,636	2,797	0.55	0.59
(Md. only)	294	334	366	1.28	0.92
Maryland	3,924	4,216	4,510	0.72	0.67
Employment* (nonagricultural)					
Pepco	1,058.6	1,168.7	1,434.4	1.42%	1.59%
(Md. only)	411.6	514.7	728.4	3.24	2.71
BG&E	885.8	949.1	1,191.1	0.99	1.76
Delmarva	344.2	381.4	486.8	1.48	1.89
(Md. only)	92.8	105.9	127.8	1.90	1.46
APS	832.0	936.5	1040.0	1.70	0.81
(Md. only)	112.7	127.6	139.4	1.79	0.68
Maryland	1,519.0	1,709.0	2,216.1	1.70	2.02

* Employment figures in the 1980 column are 1977.

Source: (8), (9), (10), (11), (12)

Table I-19

Monthly Residential Electric Bills*

Service Area	1972	1980	1990	Annual Rate of Growth 1972-1980	Annual Rate of Growth 1980-1990
Pepco	$10.35	$29.62	--	14.1%	--
(CPI Adjusted)	10.35	15.92	18.28	5.5	1.4%
BG&E	15.30	28.11	--	7.9	--
(CPI Adjusted)	15.30	15.11	18.41	-0.2	2.0
DP&L	13.19	36.11	--	13.4	--
(CPI Adjusted)	13.19	19.40	20.80	4.9	0.7
Potomac Edison	10.62	27.12	--	12.4	--
(CPI Adjusted)	10.62	14.57	15.24	4.0	0.5
Maryland	13.82	28.57	--	9.5	--
(CPI Adjusted)	13.82	15.35	--	1.3	--

*Bills are based upon 500 kwh per month on January 1 of designated year. Bills are for Maryland portions of service area only.

Source: (13)

future values of the explanatory variables are inserted into the estimated model, and the forecast is then calculated for each year. Peak demand is forecasted in a similar manner except that total energy usage is used as an important explanatory factor in the peak demand equation. Thus, energy forecasts must first be developed in order to calculate the peak demand forecast.

In all of the PPSP/DSP forecast studies prepared to date, electricity sales models have been estimated separately for the residential and non-residential classes of customers. Moreover, models were separately estimated for the residential class, nonresidential class and system peak demand for the summer and winter seasons, since behavioral relationships and some of the underlying determinants differ between the two seasons. In all cases the models were estimated using ordinary least squares regression -- in some cases using quarterly or monthly time series data and in other cases using pooled time series/cross section data.

The resulting forecasts are heavily influenced by the projections of and assumptions on future values of the explanatory variables. To the extent possible, these values were obtained from official, published sources. Where official sources did not exist, future values were developed judgmentally (see Appendix A).

Table I-20 provides the energy and annual peak demand forecasts prepared by PPSP for the four major electric utility systems. Historical growth rates of power demands are included in this table for purposes of comparison. Forecasts for the Maryland portions of APS and DP&L are shown along with the aggregate totals both with and without the non-Maryland demands. The figures for the Maryland jurisdiction portions are not very meaningful to utility system planners since each of these utilities plans its generation investments strictly on a system-wide basis without regard to jurisdictional patterns of demand.

There is significant variation among the forecasts for the four systems. Pepco's peak demand is projected (updated forecast) to grow by less than one percent annually compared to 3.3 percent for BG&E.[1] APS and DP&L, the two most recent studies prepared by PPSP, are between these two extremes. With the exception of the BG&E forecast of energy sales (which was completed in 1977), the forecasted growth rates are roughly comparable to those occurring between 1973 and 1980. This is not a surprising result. Future economic and population expansion in the service areas of the Maryland utilities is not expected to be any more rapid than in the 1970's. However, even though future energy prices are expected to rise in real terms, a 1970's type price explosion is assumed not to reoccur. Thus, growth rates slightly in excess of those occurring during the 1973-1980 period are plausible.

The PPSP/DSP forecasts in Table I-20 are each based upon a carefully formulated set of assumptions regarding the future behavior of the variables appearing in the demand equations. Those sets of assumptions are referred to as the Most Likely Case (MLC). In each case the MLC scenario is based upon official projections from federal and state agencies along with PPSP's best judgment

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[1] The BG&E peak demand forecast in Table I-20 is a revision of an original study prepared by PPSP. However, the energy projections shown in that table have not yet been revised. That accounts for the large discrepancy in the peak demand and energy sales growth rates.

Table I-20

Projected Energy Sales and Peak Demand
For Major Maryland Utilities[(a)]
(Thousands MWh and MW)

	1982		1985		1990		Annual Rates of Growth 1973-1980		Annual Rates of Growth 1982-1990	
	Sales	Peak	Sales	Peak	Sales	Peak	Sales	Peak	Sales	Peak
Pepco	15,828	4,284	16,824	4,393	18,599	4,554	2.22%	1.70%	2.04%	0.74%
BG&E	19,586	4,028	23,049	4,447	30,021	5,232	2.65	2.52	5.48	3.32
DP&L[(b)]	8,099	1,687	8,996	1,919	10,250	2,246	2.21	0.86	2.65	3.23
(MD Portion)	1,515	454	1,697	503	1,995	592	5.29	3.99	3.50	3.37
APS	31,394	5,726	33,997	6,294	38,251	7,236	2.79	3.99	2.50	2.96
(MD Portion)	6,014	1,063	6,488	1,181	7,384	1,405	5.59	5.01	2.60	3.55
MD Total[(c)]	42,943	9,829	48,058	10,524	57,999	11,783	2.96	2.44	3.83	2.29
Total	74,907	15,725	82,866	17,053	97,121	19,268	2.57	2.84	3.30	2.57

(a) PPSP/DSP forecasts.

(b) Includes entire Delmarva Peninsula.

(c) Includes non-Maryland portions of Pepco.

Source: Tables I-24 through I-35.

concerning those variables for which official projections are not available. Also, every effort is made to assure that the various assumptions in each case are logically consistent with one another.

Some of the sources of these projections have been referred to earlier. BEA has been relied upon for projections of real per capita income, and outside of Maryland, for employment projections. Population and household formation projections (utilized to determine residential customers) have been obtained from the U.S. Census Bureau. Within Maryland, the Department of State Planning projections of employment and population have been utilized. Finally, electric energy price projections have been determined on a largely judgmental basis, but taking into consideration national EIA fuel price projections along with the specific circumstances of the utility system under study.

The usage of the projections figures available from these sources introduces a large element of uncertainty into the load forecasts.[1] It is important that this uncertainty be recognized and explicitly incorporated into the planning process. In order to gauge the magnitude of forecast uncertainty, various alternative scenarios are constructed, including a "conservation case" scenario. Upper and lower bound load growth rates are obtained by determining the extreme, plausible modification to the MLC assumptions and recalculating the forecasts. For example, the DP&L MLC peak demand growth rate forecast is 3.2 percent per year, surrounded by upper bound of 4.3 percent and a lower bound of 1.8 percent. Clearly, the range of uncertainty is quite large.

Table I-21 provides a comparison between the PPSP and Company prepared peak demand forecasts through 1990. With some minor exceptions, the independent peak demand forecasts prepared by PPSP are quite similar to those prepared by the Companies. For all four major systems combined the difference is roughly 400 megawatts or less than one year's load growth. This discrepancy is well within any reasonable range of uncertainty.

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[1] Uncertainty over forecast assumptions is only one problem of many involved. For example, the models themselves may be in error to some degree. However, assumption error is probably the most serious problem in forecasting and the greatest source of uncertainty.

Table I-21

Comparisons Of PPSP/DSP And Company Prepared Peak Demand Forecasts
(MW)

	1982		1985		1990			Annual Rates of Growth(%)		
								1973-1980	1982-1990	
	PPSP	Company	PPSP	Company	PPSP	Company	Difference(%)		PPSP	Company
Pepco	4,284	3,956	4,393	4,105	4,544	4,355	4.2%	1.70%	0.74%	1.21%
BG&E	4,028	4,130	4,447	4,530	5,232	5,130	1.9	2.52	3.32	2.75
DP&L(a)	1,547	1,627	1,694	1,767	1,951	1,918	1.7	0.86	2.94	2.08
(MD Portion)	454	407	503	480	570	517	9.3	3.99	2.89	3.04
APS	5,726	5,689	6,294	6,202	7,236	7,182	0.8	3.99	2.97	2.96
(MD Portion)	1,063	1,050	1,181	1,195	1,405	1,460	-4.3	5.01	3.61	4.33
MD Total(b)	9,829	9,543	10,524	10,310	11,751	11,462	2.4	2.44	2.26	2.32
Total	15,585	15,402	16,828	16,604	18,963	18,585	2.0	2.84	2.48	2.38

(a) Figures exclude Dover and Easton load not served by DP&L and the Getty Oil Refinery load. The 1990 figures are lowered by 50 megawatts to reflect capacity purchase by The Old Dominion Electric Coop. (The Maryland portion load projections for 1990 are lowered by 22 megawatts for the acquisition of capacity by Old Dominion Electric Cooperative.)

(b) Includes non-Maryland portions of Pepco. Excludes Conowingo Power Company.

Source: Table I-20, (14), (15), (16), (17).

F. The Management of Demand

System planning has traditionally involved determining the optimal scheduling and mix of plant types (i.e. base load, cycling or peaker) and fuel types which will minimize the total costs of producing power, while at the same time providing reliable service. This is a complicated process and relies heavily upon the outlook for the growth of power demand. With the rapid increases in recent years in the cost of boiler fuel, generation facilities and financing, it is becoming increasingly obvious that the least-cost approach in planning will involve programs and measures to reduce energy demand (or at least the growth in energy demand) and flatten load curves.[1]

Many utility systems recognize and are pursuing the demand-side alternatives. The Duke Power Company has been pursuing an ambitious demand management program explicity in its generation plans. It has identified more than 25 such programs including new home insulation standards, direct load control and time-of-day rates, which could result in amazingly large benefits. The Company's Annual Report to Stockholders states:

> Over the next 14 years, Duke Power has the opportunity to avoid an investment of more that $10 billion.
> The Company's comprehensive Load Management Program is designed to do just that by reducing the incremental growth of peak demand 5,635,000 kilowatts by 1994 - nearly the equivalent of 5 generating units the size of McGuire 1. (18)

There are two basic approaches to managing power demands -- conservation and load management.[2] Conservation simply refers to the reduction in use of electricity that can be achieved by better weatherization, improved appliance efficiencies or by choosing a less energy intensive lifestyle. Load management is only concerned with when electricity is consumed and not total usage. Load management can achieve greater system efficiencies by shifting usage from times

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[1] There are other factors which also argue for seeking alternatives to construction of central station generating facilities -- environmental difficulties and financial distress. Environmental impacts of electric power generation (and industrial activity generally) has led to environmental legislation. This legislation has tended to increase power plant licensing time and has to some extent increased the length of the construction period. Both effects have contributed to lengthening the lead times necessary to bring new power plants on-line. Environmental litigation has also led to unanticipated delays in bringing facilities on-line (as in the case of APS's proposed Davis pumped storage hydro project) or even to out-right cancellations. High interest rates may make it difficult for utilities to carry large, expensive construction projects for long time periods.

[2] From the utilities point of view, production of power by the customer such as solar or wind energy also lessens demands, if that power replaces purchased power. However, since these technologies produce electricity they are discussed in Chapter II.

when additional energy is expensive to produce (or when demand is pressing against capacity) to times when additional energy is cheap (or when there is excess capacity). Approaches which would facilitate such load shifting include thermal storage technologies, appliance cycling controls, time-of-use pricing and interruptible rates.

There is mounting evidence that in many instances conservation is extremely cost-effective. However, there are numerous institutional barriers that tend to prevent economically justified conservation measures from being undertaken by consumers. These would include difficulty in obtaining information concerning costs and benefits of conservation; the setting of utility rates at historic costs rather than marginal costs (i.e. the costs of producing and providing additional power); rapid ownership turnover of homes; and the unwillingness of financial institutions to provide conservation loans at reasonable rates. These problems can be mitigated to some extent by utility and governmental programs.[1]

Weatherization

Improved weatherization of residential structures may be one of the most cost-effective methods of reducing expensive energy usage for homes which heat and/or cool with electricity. The following data from BG&E shown in Table I-22 illustrate this point.

Potential weatherization benefits were confirmed in a recent study of electricity usage in New York State. That study estimates that implementing weatherization measures, as compared to typical current practice, would reduce electricity used for space cooling by about 5 percent (20).

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[1] For a description of the many State and Federal programs operating in Maryland see: Energy in Maryland, Maryland Energy Administration, January 1981, pp.18-49.

Table I-22

Annual Electric Bill Savings for a "Typical Home" Served By BG&E

	Electric Resistance Heat	Heat Pumps	Electric A/C
Caulking & Weather-stripping	$33-$50	$25-$35	$3-$5
Wall Insulation	$65-$100	$36-$56	$10-$16
Floor Insulation	$66-$101	$36-$56	$0
Duct Insulation	NA	$29-$44	NA
Storm/Thermal Windows	$59-$91	$33-$50	$4-$6
Storm/Thermal Doors	$33-$51	$18-$28	$1-$2
Ceiling Insulation	$429-$600	$239-$367	$102-$157
Clock Thermostat	$42-$65	NA	$9-$14

Source: (19)

The California Energy Commission has estimated that a fairly modest investment in weatherization could save electric heat customers in California 1,800 to 3,000 kWh annually. The same study reports that The Pacific Power & Light Company (PP&L) estimates that a somewhat larger weatherization investment in a typical, electrically heated home in its Oregon service territory could save 5,000 kWh per year (21).

PP&L and Pacific Gas & Electric Company (PG&E) have implemented agressive programs to subsidize such investments. Under both programs, the utility, with the customer's consent, arranges and pays for the weatherization of a customer's home. There is no cost to the customer until the home is sold, at which point the original owner must repay the principal. The utility, however, absorbs all interest costs. PP&L and PG&E believe that these weatherization subsidies will have the effect of ultimately benefiting all customers since it will lead to large, long run reductions in system costs -- far larger than the amount of the subsidies.

The cost-effectiveness and practicality of such a program depend on a number of specific factors, such as the potential for further weatherization in the service area and the structure of costs of the utility in question. PPSP is conducting a study, jointly funded with the Office of People's Counsel, to determine the possible costs and energy savings impacts such a program might have on the BG&E system. If the results appear promising, the study will be extended to the other utilities in the State.

Even more cost-effective than retrofitting is the weatherization of new homes. In recognizing this fact, several utilities and state governments have proposed rate incentives, hook-up restrictions and information programs to encourage builders and prospective new home owners to build and purchase energy efficient homes. In Maryland, recent legislation has been enacted to ensure that new buildings will meet a minimum set of energy efficiency standards (HB 748).

Load Management

The demand for electricity on a given system varies significantly by season of the year, by day of the week, and by time-of-day. The major utilities in the State, with the exception of APS, have historically exhibited rather low annual load factors. Unless some deliberate efforts are made to change this situation, the low load factors are likely to persist and may even deteriorate further.

The setting of electric rates can play a useful and effective role in both reducing the large, time related variations in load and in encouraging conservation of electric power. This idea has been promoted by utility ratemaking experts and became embodied in Federal energy policy with the 1978 passage of the Public Utilities Regulatory Policies Act (PURPA).

This Act deals with numerous aspects of public utility regulation. It requires state commissions to hold evidentiary hearings and to determine the appropriateness of six principal ratemaking standards. These are:

> Cost of service standard -- Rates charged to each class of customers should reflect the costs of serving each class to the maximum extent practicable. Such determinations should include "marginal costs".
>
> Declining block rate standard -- Unless cost justified, the energy component of an electric rate shall not decrease as kilowatt hour consumption increases.
>
> Time-of-day rate standard -- To the extent practicable, rates should reflect time related variations in cost, unless such rates are determined not to be cost-effective.
>
> Seasonal rate standard -- Electric rates should reflect seasonal differences in cost.
>
> Interruptible rate standard -- Commercial and industrial customers shall be offered interruptible rates which reflect the costs of providing service on an interruptible basis to those customers.
>
> Load management techniques standards -- Utilities shall provide load management techniques found to be cost-effective, practical, and useful to reduce capacity requirements and/or fuel costs.

These rate design standards were established in order to promote the stated purposes of PURPA -- conservation, efficiency and equity. By and large, these goals can be achieved by providing the consumers of electricity with price signals that better reflect the costs of providing additional electric service to them.

Time-of-use (TOU) rates (based upon time-varying marginal costs) can help reduce the growth rate of peak demand, improve system annual load factors and generally flatten load curves. These results naturally occur as customers shift power usage from the peak to the off-peak period. If achieved, the existing generation system can function more efficiently, and capacity additions may be deferred. The fuel cost reduction occurs as the reduction in peak usage (in response to higher peak prices) permits the utility to reduce operation of its more energy inefficient generating units. In that manner TOU rates help to serve the purposes of PURPA.

TOU rate implementation requires a large front-end investment in expensive metering equipment needed to measure energy usage by time period. Consequently, PURPA requires that such rates pass a cost-effectiveness test. TOU rates will only lower system costs if the resulting increase in system efficiency outweigh the additional metering and administrative costs. This question was investigated by PPSP for the BG&E system (22). Benefits were measured as changes in "consumer surplus" when moving from current rates to those reflecting marginal costs by time period. TOU pricing was found to be cost-effective for the average size customer in each class though cost-ineffective for smaller residential customers. It was estimated that the present value of the gains over the lifetime of the metering equipment is roughly $85 million. Since this study relies upon data several years old, and since fuel prices have risen far more rapidly than metering costs, this may represent a substantial understatement of the benefits.

Currently, none of the four utility systems provides time-of-use pricing to its Maryland customers. The PURPA compliance hearings have been held or are currently underway for each utility, but the Public Service Commission has ruled on the ratemaking standards only for BG&E. In the other state jurisdictions in which the Maryland utilities operate time-of-use rates have also been considered, and they have been adopted to a limited extent. The District of Columbia has implemented the rates for the Pepco's approximately 250 largest High Tension customers. The State of Delaware has also moved forward to implement such rates for many of the large industrial concerns. For many years now West Penn Power and Monongahela Power have sold power on a time-of-use basis to some of their industrial customers. However, there appears to be a very large potential to expand time-of-use pricing, on a cost-effective basis, for both the Maryland and non-Maryland portions of the service areas.

Direct load control devices are intended to serve the same purpose as time-of-use rates, but they are generally controlled by the utility rather than the individual customer. There are two basic approaches to direct load control -- heat (or cooling) storage and appliance cycling. With the former, electricity heats water or some other thermal storage medium during the off-peak period. Through the use of a communication device of some sort, the utility shuts off the customer's electric space and/or water heater during the peak period. The other approach, appliance cycling, involves interrupting the service of major appliances -- air conditioners, electric space or water heaters -- for only a few minutes at a time during the periods of maximum demand on a system. Whereas thermal storage systems can save capacity and energy costs, appliance cycling saves little energy cost and is primarily designed to save capacity costs.

Like time-of-use pricing, load control devices can improve system efficiency but require a major investment in facilities to communicate with and control customer appliances. A recent Tennessee Valley Authority (TVA) staff study estimated the costs and benefits of several different proposed load management methods. These results are summarized below on a present value basis through the year 2000.

Table I-23

TVA System Savings From Load Management
(Millions $)

Method	Costs	System Benefits	MW Reduction
Water Heat Cycling	$71-$96	$130	458
Water Heat Storage	11-47	267	627
Space Heat Storage	35-127	335	578
Space Heat Cycling	48-55	129	311

Source: (23)

Several observations concerning direct load control need to be be made. First, interrupting service may involve a certain amount of customer inconvenience. Second, it also appears that heat storage economics is more favorable than cooling storage, thus making it more advantageous for winter peaking systems (such as TVA) but less so for summer peaking systems. Third, since appliance cycling does not save a great deal of energy, it is probably only worthwhile on systems that are capacity constrained. Many systems, such as Pepco, will have excess capacity for many years to come. On excess capacity systems, there appears to be little that direct load control can accomplish that cannot be accomplished by TOU pricing. The latter method allows customers to respond to price signals that follow the time pattern of costs, and is therefore a preferable method of managing system loads. However, there may be an important role for both approaches to load management.

None of the major Maryland utilities currently have direct load control programs of any significance in any jurisdiction. Each of the four utilities plans to examine or has examined the feasibility and impacts from such programs. Pepco, for example, is currently attempting to intitiate a load management experiment in Maryland. However, a preliminary analysis suggests to the Company that implementation is not cost-effective at this time (24). DP&L is currently conducting a two-year experiment of load management techniques and innovative rate structures with 1,000 of its Delaware residential customers. The purpose of the study is to determine customer attitudes and responses to these programs.

Outside of their Maryland service area two utilities, DP&L and APS, have a modest program of curtailable rates (i.e., rates that permit service interruptions) for their large industrial customers. DP&L currently sells power to three customers on interruptible rates, whose potential interruptible loads represent roughly five percent of the Company's system peak demand. APS has roughly 50 megawatts of interruptible load which is less than 1 percent of total system peak demand.

G. Historical and Projected Company Load Data

The last section of this chapter presents detailed statistical data on historical and projected power demands for the four major electric utilities serving Mayland. The historical tables provide annual residential and nonresidential sales, summer and winter peak demand, generating capacity and the reserve margin. Reserve margin is defined as generating capacity minus annual peak demand divided by annual peak demand.

The tables of projected demands provide the same information through 1990. The projections of energy sales and peak demand were prepared by PPSP, and the capacity figures are based upon Companies' latest generation plans. The table also provides the Companies' load forecasts (and thus reserve margin forecasts) for purposes of comparison.

For Delmarva Power & Light Company and the Allegheny Power System, the historical and projected data are provided for both the total system and for the Maryland portions of those systems. The reserve margins have no meaning for the Maryland portions and are therefore not provided.

Table I-24

Historic Energy Sales, Peak Demand
And Generating Capacity For The Allegheny Power System

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity	Reserve Margin(%)
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	3,711	11,001	14,712	2,425	2,661	2,536	-4.7%
1970	5,319	14,800	20,119	3,206	3,785	4,254	12.4
1971	5,694	15,585	21,279	3,274	3,769	4,731	25.5
1972	6,137	16,678	22,815	3,622	4,039	5,208	28.9
1973	6,614	18,058	24,672	4,040	4,230	5,742	35.7
1974	6,809	18,135	24,944	3,916	4,272	6,388	49.5
1975	7,229	16,733	23,962	3,959	4,650	6,428	38.2
1976	7,524	19,181	26,704	4,284	5,031	6,428	27.8
1977	8,096	20,152	28,247	4,539	5,174	6,428	24.2
1978	8,351	20,382	28,733	4,632	5,335	6,417	20.3
1979	8,466	21,911	30,377	4,676	5,272	6,997	32.7
1980	8,633	21,274	29,958	4,903	5,564	7,568	36.0
			Annual Average Rates of Growth				
1966-1970	9.42%	7.70%	8.14%	7.23%	9.21%	13.81%	
1970-1975	6.33	2.48	3.56	4.31	4.20	8.61	
1975-1980	3.61	4.92	4.57	4.37	3.65	3.32	
1966-1980	6.22	4.82	5.21	5.16	5.41	7.56	

Peak demand figures are for winter beginning in designated year.

Table I-25

Projected Energy Sales, Peak Demand And
Generating Capacity For The Allegheny Power System

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)	Margin(%)	Winter Peak (MW)	R.M.(%)
1981	8,793	21,718	30,511		5,552	7,587	36.7%	5,445	39.3%
1982	9,194	22,200	31,394		5,726	7,600	32.7	5,689	33.6
1983	9,602	22,657	32,259		5,910	7,600	28.6	5,798	31.1
1984	10,022	23,106	33,128		6,093	7,600	24.7	6,024	26.2
1985	10,447	23,550	33,997		6,294	8,020	27.4	6,202	29.3
1986	10,853	23,975	34,828		6,443	8,446	31.0	6,448	30.9
1987	11,260	24,401	35,661		6,626	8,440	27.4	6,628	27.3
1988	11,676	24,836	36,512		6,810	8,440	23.9	6,806	24.0
1989	12,099	25,271	37,370		7,000	9,070	29.6	6,933	30.8
1990	12,526	25,725	38,251		7,236	8,995	24.3	7,182	25.2
Annual Average Rates of Growth									
1980-1985	3.88%	2.05%	2.56%		2.50%	1.17%		2.19%	
1985-1990	3.70	1.78	2.39		2.83	2.32		2.98	
1980-1990	3.79	1.92	2.47		2.66	1.74		2.59	

* Projections prepared by PPSP.
Peak demand figures are for winter beginning in designated year.

Table I-26

Historic Energy Sales, Peak Demand And
Generating Capacity For The Potomac Edison Company (Maryland Portion)

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity*	Reserve Margin(%)
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	489	932	1,421		336	227	
1970	731	2,104	2,835		550	143	
1971	788	2,775	3,563		601	142	
1972	851	2,908	3,759		656	142	
1973	930	3,080	4,010		682	139	
1974	985	3,004	3,990		693	139	
1975	1,065	2,889	3,954		802	139	
1976	1,142	4,164	5,306		916	139	
1977	1,235	4,394	5,629		1,018	139	
1978	1,267	4,231	5,498		981	129	
1979	1,276	4,554	5,830		961	129	
1980	1,289	4,580	5,869		960	117	
			Annual Average Rates of Growth				
1966-1970	10.58%	22.58%	17.24%		13.11%	-10.9%	
1970-1975	7.82	6.55	6.88		7.84	-0.6	
1975-1980	3.89	9.65	8.22		3.66	-3.4	
1966-1980	7.14	12.04	10.66		7.79	-4.6	

Peak demand figures are for winter beginning in designated year.

* Does not include the Potomac Edison Company share of jointly-owned stations located in Pennsylvania and West Virginia, or the wholly-owned stations in Virginia.

Table I-27

Projected Energy Sales, Peak Demand And
Generating Capacity For The Potomac Edison Company (Maryland Portion)

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)	Margin(%)	Winter Peak (MW)	R.M.(%)
1981	1,355	4,517	5,872		1,021	117		1,015	
1982	1,452	4,562	6,014		1,063	117		1,050	
1983	1,555	4,610	6,165		1,098	117		1,085	
1984	1,665	4,658	6,323		1,141	117		1,140	
1985	1,781	4,707	6,488		1,181	117		1,195	
1986	1,897	4,757	6,654		1,225	117		1,255	
1987	2,018	4,807	6,825		1,269	117		1,295	
1988	2,146	4,858	7,004		1,309	117		1,350	
1989	2,280	4,910	7,190		1,355	117		1,405	
1990	2,421	4,963	7,384		1,405	117		1,460	
Annual Average Rates of Growth									
1980-1985	6.69%	0.55%	2.03%		4.23%	0.0%		4.48%	
1985-1990	6.33	1.06	2.62		3.53	0.0		4.09	
1980-1990	6.51	0.81	2.33		3.88	0.0		4.28	

*Projections prepared by PPSP.

Peak demand figures are for the winter beginning in designated year.

Capacity data does not include the Potomac Edison Company share of jointly-owned stations located in Pennsylvania and West Virginia or the wholly-owned stations in Virginia.

Table I-28

Historic Energy Sales, Peak Demand And
Generating Capacity For The Baltimore Gas And Electric Company

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity	Reserve Margin(%)
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	2,347	6,306	8,653	1,817	1,422	1,866	2.7%
1970	3,665	8,306	11,971	2,496	1,954	2,791	11.8
1971	3,864	8,620	12,485	2,605	2,053	3,303	26.8
1972	4,102	8,889	12,991	2,960	2,059	3,748	26.6
1973	4,618	9,723	14,341	3,334	2,302	3,541	6.2
1974	4,469	9,251	13,990	3,190	2,177	3,410	6.9
1975	4,664	9,194	13,857	3,256	2,301	4,046	24.3
1976	4,888	9,870	14,758	3,234	2,418	4,241	31.1
1977	5,231	10,230	15,462	3,588	2,640	4,995	39.2
1978	5,435	10,735	16,170	3,553	2,850	4,995	40.6
1979	5,497	11,327	16,823	3,621	2,900	4,995	37.9
1980	6,005	11,223	17,228	3,969	3,046	5,010	26.2
			Annual Average Rates of Growth				
1966-1970	11.79%	7.14%	8.46%	8.26%	8.28%	10.59%	
1970-1975	4.94	2.05	2.97	5.46	3.32	7.71	
1975-1980	5.18	4.07	4.45	4.04	5.77	4.37	
1966-1980	6.94	4.20	5.04	5.74	5.59	7.31	

Table I-29

Projected Energy Sales, Peak Demand And
Generating Capacity For The Baltimore Gas And Electric Company

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)	Margin(%)	Summer Peak	R.M.(%)
1981	5,824	12,719	18,543	3,897		5,025	29.0%	3,970	26.6%
1982	6,122	13,464	19,586	4,028		5,025	24.8	4,130	21.7
1983	6,446	14,234	20,681	4,162		5,025	20.7	4,260	18.0
1984	6,797	15,036	21,833	4,303		5,594	30.0	4,390	27.4
1985	7,175	15,874	23,049	4,447		5,634	26.7	4,530	24.4
1986	7,577	16,713	24,290	4,591		5,759	25.4	4,640	24.1
1987	8,008	17,596	25,604	4,741		5,701	20.3	4,740	20.3
1988	8,469	18,525	26,994	4,897		6,321	29.1	4,870	29.8
1989	8,961	19,503	28,464	5,031		6,321	25.6	5,000	26.4
1990	9,486	20,535	30,021	5,232		6,321	20.8	5,130	23.2
Annual Average Rates of Growth									
1980-1985	3.62%	7.18%	6.00%	2.30%		2.38%		2.68%	
1985-1990	5.74	5.28	5.43	3.30		2.33		2.52	
1980-1990	4.68	6.23	5.71	2.80		2.35		2.60	

* Projections prepared by PPSP.

Table I-30

Historic Energy Sales, Peak Demand And
Generating Capacity For The Delmarva Power And Light Company (Total System)

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity	Reserve Margin(%)
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	839	2,799	3,638	661	639	799	12.5%
1970	1,280	4,610	5,440	1,014	943	1,151	13.5
1971	1,381	4,367	5,748	1,090	1,002	1,184	8.6
1972	1,464	4,777	6,241	1,262	1,150	1,364	8.1
1973	1,630	5,126	6,756	1,434	1,076	1,552	8.2
1974	1,597	4,995	6,592	1,375	1,140	1,624	18.2
1975	1,672	4,721	6,393	1,397	1,155	1,905	36.4
1976	1,788	4,872	6,660	1,301	1,278	1,917	47.4
1977	1,925	4,981	6,906	1,450	1,352	1,998	37.8
1978	1,980	5,268	7,248	1,428	1,339	1,993	39.6
1979	1,968	5,524	7,492	1,452	1,322	1,993	37.3
1980	2,047	5,413	7,460	1,529	1,444	2,008	31.3
			Annual Average Rates of Growth				
1966-1970	11.14%	10.41%	10.58%	9.32%	10.22%	7.57%	
1970-1975	5.49	2.56	3.28	6.62	4.14	10.60	
1975-1980	4.13	2.77	3.14	1.82	4.57	1.06	
1966-1980	6.58	4.82	5.26	5.63	6.00	6.80	

Data represent the entire DP&L System and exclude energy sales to Easton and includes portions of Dover and Easton peak demand provided by DP&L generation. Data exclude capacity from and loads served by Delaware City 1 and 2 (dedicated to Getty Refinery).

Table I-31

Projected Energy Sales, Peak Demand And
Generating Capacity For The Delmarva Power And Light Company (Total System)

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)	Margin(%)	Summer Peak(MW)	R.M.(%)
1981	2,022	5,028	7,059	1,506	1,406	2,219	47.3%	1,531	44.9%
1982	2,100	5,107	7,226	1,547	1,453	2,234	44.4	1,627	37.3
1983	2,183	5,212	7,423	1,594	1,504	2,167	40.0	1,667	30.0
1984	2,270	5,333	7,641	1,641	1,557	2,167	32.1	1,711	26.7
1985	2,363	5,464	7,874	1,694	1,594	2,217	30.9	1,767	25.5
1986	2,437	5,584	8,075	1,749	1,640	2,217	26.8	1,808	22.6
1987	2,515	5,711	8,286	1,808	1,688	2,177	20.4	1,818	19.8
1988	2,597	5,841	8,505	1,869	1,757	2,177	16.5	1,870	16.4
1989	2,682	5,978	8,734	1,934	1,808	2,177	12.6	1,919	13.4
1990	2,770	6,118	8,970	1,951	1,819	2,502	28.2	1,918	30.5
			Annual Average Rates of Growth						
1980-1985	2.91%	0.19%	1.09%	2.07%	1.37%	2.00%		2.94%	
1985-1990	3.23	2.29	2.64	2.87	2.68	2.45		1.65	
1980-1990	3.07	1.23	1.86	2.47	2.02	2.22		2.29	

* Projections prepared by PPSP.
Peak demand figures are for the winter beginning in designated year.
Energy sales figures exclude sales to Easton and Dover. Peak figures include the portion of Easton and Dover load provided by DP&L generation. Peak load and capacity figures exclude the Getty Refinery loads and the Delaware City 1 and 2 capacity, respectively. The 1990 peak loads are reduced by 50 megawatts to reflect the sale of capacity from the Vienna 9 plant to the Old Dominion Electric Cooperative.

Table I-32

Historic Energy Sales, Peak Demand And
Generating Capacity For The Delmarva Power And Light Company (Maryland Portion)

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity	Reserve Margin %
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	199	299	498	141	116	105	
1970	322	451	773	210	206	132	
1971	355	480	835	227	227	282	
1972	389	511	900	278	233	282	
1973	441	564	1,005	327	290	252	
1974	458	569	1,027	319	275	252	
1975	483	593	1,076	342	294	252	
1976	543	648	1,190	315	347	252	
1977	624	733	1,357	384	400	252	
1978	654	776	1,430	377	400	252	
1979	650	778	1,428	402	388	252	
1980	669	773	1,442	430	-	252	
Annual Average Rates of Growth							
1966-1970	12.78%	10.80%	11.62%	10.47%	15.44%	4.68%	
1970-1975	8.45	5.62	6.85	10.25	7.37	13.81	
1975-1980	6.73	5.44	6.03	4.69	-	0.0	
1966-1980	9.05	7.02	7.89	8.29	-	6.45	

* Peak demand figures are for winter beginning in designated year.
Energy sales figures exclude sales for resale and sales to Easton. Peak demand figures include the portion of Easton peak served by DP&L generation.

Table I-33

Projected Energy Sales, Peak Demand And
Generating Capacity For The Delmarva Power And Light Company (Maryland Portion)

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve	Company Projections	
	Residential	NonResidential	Total	Summer	Winter	(MW)	Margin(%)	Summer Peak(MW)	R.M.(%)
1981	661	800	1,461	443		252		391	
1982	688	826	1,515	454		177		452	
1983	717	854	1,573	468		177		457	
1984	749	882	1,633	485		177		467	
1985	782	913	1,697	503		177		480	
1986	804	945	1,751	518		177		490	
1987	829	978	1,809	535		177		503	
1988	854	1,013	1,868	553		177		516	
1989	880	1,048	1,930	572		177		528	
1990	908	1,086	1,995	570		502		517	
			Annual Average Rates of Growth						
1980-1985	3.18%	3.38%	3.31%	3.18%		-6.82%		2.22%	
1985-1990	3.03	3.53	3.29	2.53		23.18		1.50	
1980-1990	3.10	3.46	3.30	2.86		7.13		1.86	

* Projections prepared by PPSP.
Peak demand figures are for the winter beginning in designated year.
Energy sales figures exclude sales for resale and sales to Easton. Peak demand figures include the portion of Easton peak served by DP&L generation. The 1990 peak load projection is reduced by 22 megawatts to account for acquisition of capacity by the Old Dominion Electric Cooperative.

Table I-34

Historic Energy Sales, Peak Demand And
Generating Capacity For The Potomac Electric Power Company (Total System)

	Energy Sales (Thousands MWh)			Peak Load (MW)		Capacity	Reserve Margin %
	Residential	NonResidential	Total	Summer	Winter	(MW)	
1966	1,978	5,661	7,639	2,123	1,249	2,363	11.3%
1970	2,932	8,251	11,183	2,908	1,813	3,708	27.5
1971	3,038	8,696	11,734	3,045	1,919	4,529	39.9
1972	3,122	9,069	12,190	3,479	1,990	4,454	28.0
1973	3,529	9,704	13,233	3,680	2,159	4,721	28.3
1974	3,304	8,885	12,189	3,502	2,012	4,933	40.9
1975	3,399	9,322	12,722	3,623	2,145	5,190	43.3
1976	3,485	4,603	13,088	3,500	2,334	5,010	43.1
1977	3,617	10,030	13,647	3,857	2,508	5,013	30.0
1978	3,761	10,473	14,234	3,714	2,682	5,003	34.7
1979	3,907	10,821	14,729	3,804	2,691	4,990	31.2
1980	4,026	11,425	15,451	4,142	--	4,999	20.7
			Annual Average Rates of Growth				
1966-1970	10.34%	9.88%	10.01%	8.18%	9.78%	11.92%	
1970-1975	3.00	2.47	2.61	4.49	3.42	6.96	
1975-1980	3.44	4.16	3.96	2.71	-	-0.74	
1966-1980	5.21	5.14	5.16	4.89	-	5.50	

Peak demand figures are for the winter beginning in designated year.
Data exclude energy retail sales in Virginia and sales to SMECO, but include Virginia and SMECO loads at the time of system peak.

Table I-35

Projected Energy Sales, Peak Demand And
Generating Capacity For The Potomac Electric Power Company (Total System)

	Energy Sales (Thousands MWh)*			Peak Load (MW)*		Capacity	Reserve	Company Projections	
								Summer	
	Residential	NonResidential	Total	Summer	Winter	(MW)	Margin(%)	Peak (MW)	R.M.(%)
1981	4,232	11,276	15,508	4,242		4,999	17.9%	4,152	20.4%
1982	4,404	11,424	15,828	4,284		4,996	16.6	3,956	26.3
1983	4,590	11,572	16,162	4,322		5,322	23.1	4,000	33.1
1984	4,790	11,704	16,494	4,358		5,322	22.1	4,058	31.2
1985	5,000	11,824	16,824	4,393		5,322	21.2	4,105	29.7
1986	5,235	11,853	17,088	4,420		5,322	20.4	4,153	28.2
1987	5,484	11,962	17,446	4,453		5,322	19.5	4,208	26.5
1988	5,746	12,072	17,818	4,486		5,322	18.6	4,259	25.0
1989	6,020	12,184	18,204	4,520		5,322	17.7	4,302	23.7
1990	6,308	12,297	18,599	4,554		5,148	13.0	4,355	18.2
Annual Average Rates of Growth									
1980-1985	4.43%	0.70%	1.72%	1.18%		1.26%		-0.18%	
1985-1990	4.76	0.79	2.03	0.72		-0.65		1.19	
1980-1990	4.60	0.74	1.87	0.95		0.29		0.50	

* Projections prepared by PPSP.
Energy sales exclude retail sales in Virginia and sales to SMECO, but include Virginia and SMECO loads at the time of the system peak.

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