CHAPTER II

POWER SUPPLY IN THE STATE OF MARYLAND

This chapter describes trends and issues relating to the supply of electric power by Maryland utilities. To place this subject in proper perspective, national and Maryland overall energy production trends are first examined. Next, the generation profiles and capacity expansion plans of each of the four major Maryland utility systems are presented in detail. The third section of this chapter concerns generating capacity expansion planning. An overview of the basic principles, methods and problems of generating planning is provided. The fourth section contains a discussion of some of the more important unconventional generation sources such as cogeneration, wind energy and small-scale hydroelectricity. This chapter concludes with a list of definitions of terms commonly used in the electric utility industry.

A. Nationwide Energy Production Trends

Primary energy supply in the U.S. grew steadily during the 1950's, 1960's and early 1970's. The increasing demand for energy was met principally by increases in natural gas and oil production and by higher levels of imports. As a consequence of the Arab oil embargo of 1973 and the subsequent increases in petroleum prices, the supply of primary energy shifted towards greater reliance on coal and nuclear energy. This shift represents an adjustment to the significantly higher price of petroleum, both absolutely and relative to other fuels, at the end of the 1970's compared to the pre-embargo years.

As shown in Table II-1, domestic production and net imports of oil and natural gas accounted for approximately 78 percent of total primary energy supply in 1973, while coal and nuclear energy combined represented 19 percent of supply. Hydro, solar and geothermal accounted for the remaining 3 percent. The most recent Department of Energy forecasts for 1985 indicate that the portion of total primary energy supply from coal and nuclear energy will rise to 33 percent, while domestic and net imports of oil and natural gas will decline to 62 percent.[1] This represents a substantial shift to coal and nuclear (1).

While higher prices for oil and natural gas have induced producers to increase exploration and to employ enhanced recovery techniques, physical returns to drilling are declining. Figure II-1 indicates a sharp increase in drilling activity throughout the forecast period, though less pronounced than the increase which occurred in the 1970's. The number of feet drilled is expected to approximately triple between 1971, a year of relatively low drilling activity, and 1995. In spite of the expected increase in drilling activity, the projected barrel-per-day of output over that period shows very little change (see Figure II-2).

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[1] Percentages are based on the Btu content of the primary energy sources.

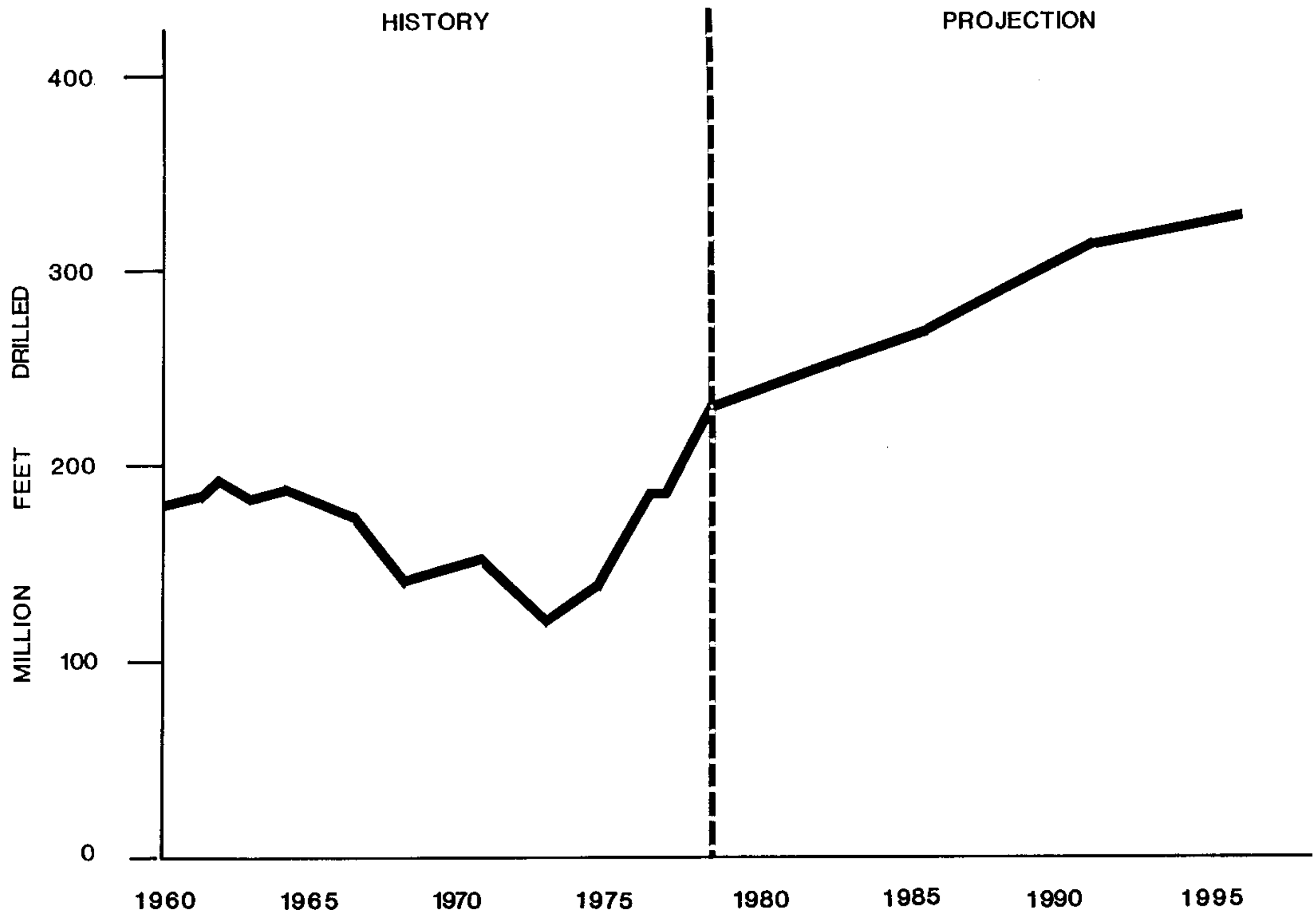

Fig. II-1. U.S. Oil and Gas Well Drilling, 1960-1995.

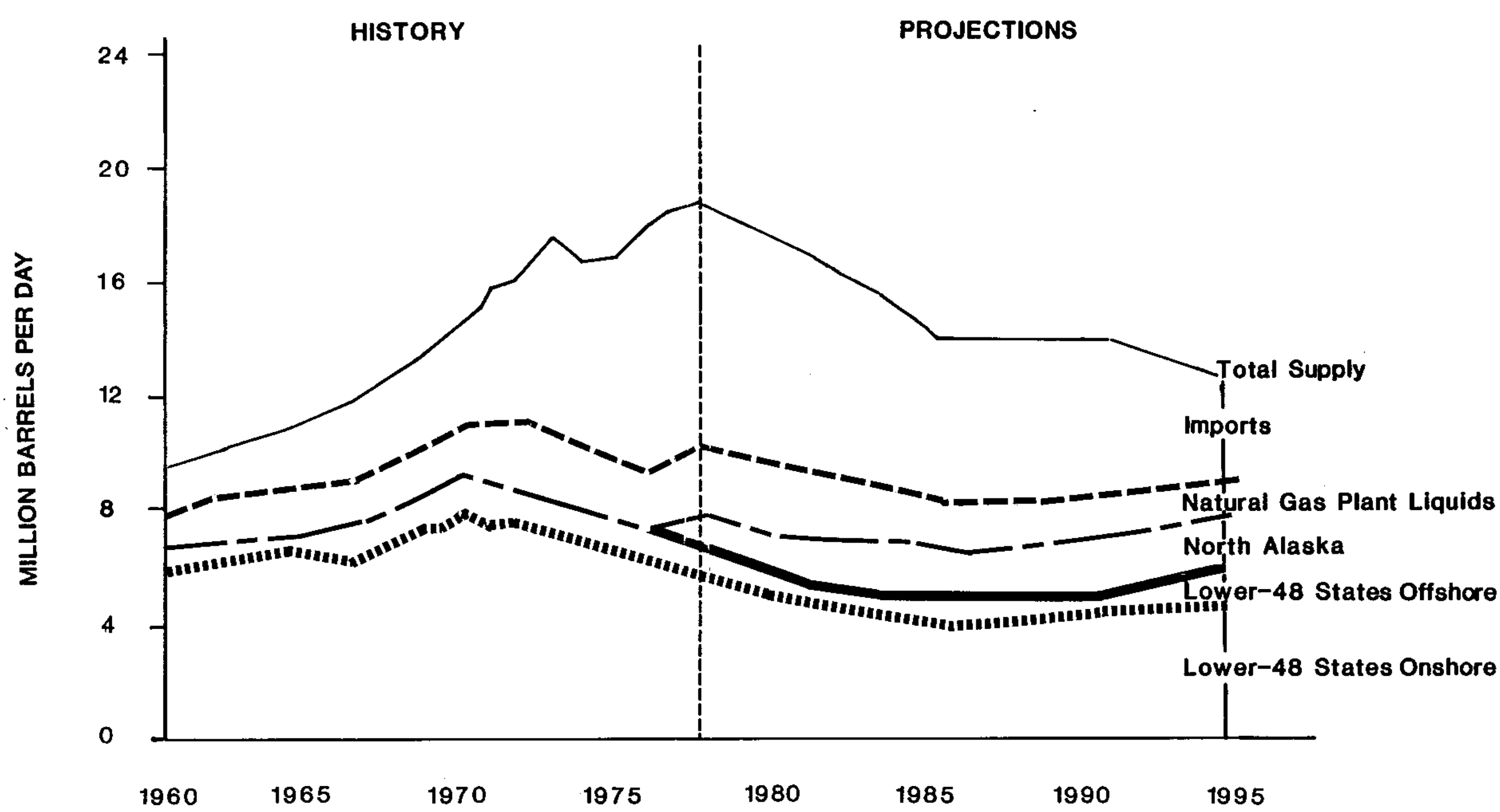

Fig. II-2. U.S. Petroleum Liquids Supply by Source, 1960-1995.

The pattern of electric power supply in the U.S. reflects both the conditions in primary energy markets (including the slower growth in demand for electricity) and changes in the regulatory environment. The Power Plant and Industrial Fuel Use Act of 1978 (Public Law 95-620) prohibits the use of oil or natural gas as a primary fuel for new electric generating units and for existing units which can be converted from oil to coal.[1] The Act also restricts use of natural gas in existing power plants. Unless a utility submits a plan for reducing its consumption of natural gas by 1990 to 20 percent of the natural gas consumed in 1976, it is prohibited from using any natural gas after January 1990. Additionally, the proportion of natural gas consumed by an electric utility in any year prior to 1990 cannot exceed the average proportion consumed in the period from 1974 through 1976.

While exemptions from the Fuel Use Act guidelines may be granted for reasons of excessive cost of converting from oil to coal, fuel availability, or environmental considerations, the combined effects of the Fuel Use Act and higher oil and natural gas prices are clear: the future fuel mix of electric utilities will emphasize coal and nuclear more heavily than has been true in the past. The combined percentage of coal and nuclear fuel used by electric utilities is expected to rise from 48.2 percent in 1973 to 74.2 percent in 1985 and to 80.6 percent in 1990 according to EIA data (see Table II-2). National projections of electric utility generating capacity reveal a similar trend of increasing reliance on coal and nuclear and diminishing reliance on oil and natural gas (see Table II-3).

Projections for the composition of supply of electric power by Maryland utilities broadly follow the national trends though certain differences are apparent. As shown in Table II-5, 57 percent of the current generating capacity is coal-fired and 31 percent oil-fired. Current plans of the Maryland utilities will result in 61.6 percent of capacity being coal-fired by 1990, while oil-fired capacity falls to 23.7 percent.

While Maryland plans reflect national trends towards coal-fired capacity and away from oil-fired capacity, Maryland is currently more oil dependent than the nation as a whole and is expected to remain so through the end of this decade. Although Maryland's generation mix differs somewhat from the nationwide average, it is fairly typical of the Northeast region of the country. This region has neither the convenient access to coal nor the great hydroelectric resources found in other regions of the country. In addition, many units originally designed to burn coal were converted to oil for environmental reasons during the 1960's. For all of these reasons, the Northeast (including Maryland) became more oil dependent than the rest of the nation.

In addition to inducing a shift to coal, higher oil and gas prices will encourage the expansion of hydroelectric and nuclear capacity. At the national level, hydroelectric generating capacity is forecasted to increase approximately 35 percent between 1978 and 1990.[2] Hydroelectric capacity owned by Maryland utilities is expected to increase by over 600 percent during the 1980's and will account for 5.5 percent of 1990 generating capacity compared with 1.1 percent in 1980.

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[1] The Act also provides exemptions for peaking units, such as combustion turbines.

[2] Based upon EIA middle oil price scenario.

Table II-1

U.S. Primary Energy Supply 1965-1995[a]
Domestic Supply And Net Imports
(Quadrillion Btu's)

Year	Oil	Natural Gas	Coal	Nuclear	Other[b]	Total
1965	23.4	16.2	12.0	<0.1	2.1	53.7
1973	35.1	23.2	13.0	0.9	2.9	75.0
1978	37.8	20.4	14.1	3.0	3.0	78.4
1985	30.5	18.6	20.6	5.6	3.4	78.7
1990	30.8	17.0	27.6	8.0	3.6	87.0
1995	29.0	16.4	35.0	9.1	4.2	93.7

(a) Forecasts based on EIA middle price scenario.

(b) Other includes hydroelectric, solar, and geothermal.

Source: (1).

Table II-2

Electricity Fuel Consumption, 1965-1995
(Quadrillion Btu's)

Fuel	1965		1973		1978		1985		1990		1995	
	Quads	%	Quads	%	Quads	%	Quads	%	Quads	%	Quads	%
Fossil Fuels:												
Oil	0.8	7.2%	3.6	18.1%	3.8	16.3%	1.6	5.7%	2.1	6.4%	0.8	2.1%
Natural Gas	2.4	21.6	3.7	18.6	3.3	14.2	2.2	7.8	0.6	1.8	0	0
Coal	5.8	52.3	8.7	43.7	10.3	44.2	15.3	54.3	18.3	56.1	23.4	62.4
Subtotal	9.0	81.1	16.1	80.9	17.4	74.7	19.1	67.7	21.0	64.4	24.2	64.5
Nuclear	(a)		0.9	4.5	3.0	12.9	5.6	19.9	8.0	24.5	9.1	24.3
Hydroelectric	2.0	18.0	2.8	14.1	2.9	12.5	3.2	11.4	3.2	9.8	3.3	8.8
New Technologies (b)	(a)		(a)		0.1	0.4	0.3	1.1	0.4	1.2	0.8	2.1
Total Consumption	11.1		19.9		23.3		28.2		32.6		37.5	
Total Generation	3.6		6.4		7.5		9.0		10.6		12.5	

(a) Less than 0.05 quadrillion Btu.

(b) New technologies' historical data consist of geothermal and wood waste technologies. The projections include the following renewable resources: geothermal, wind, solar thermal, solar photovoltaics, biomass, and ocean thermal.

Source: (1).

Table II-3

Electric Utility Generation Capacity And Reserve Margins 1965-1995
(Millions Of Kilowatts)

	1965	1973	1978	1985[c]	1990[c]	1995[c]
Fossil Steam						
Oil	NA	NA	NA	77.0	92.0	82.0
Natural Gas	NA	NA	NA	69.0	48.0	56.0
Coal	NA	NA	NA	289.0	341.0	472.0
Subtotal	187.0	321.0	400.0	435.0	481.0	610.0
Nuclear	1.0	21.0	54.0	88.0	125.0	141.0
Hydroelectric	44.0	62.0	71.0	87.0	96.0	109.0
Combined Cycle	a	a	a	8.0	8.0	8.0
Combustion Turbine	5.0	38.0	55.0	64.0	73.0	80.0
New Technologies[b]	a	a	1.0	4.0	7.0	18.0
Total Capacity	236.0	442.0	579.0	686.0	790.0	966.0
Peak Demand	186.0	344.0	408.0	483.0	568.0	670.0
Reserve Margin (percent)	26.7%	28.5%	41.8%	41.9%	39.2%	44.2%

a Less than 0.5 million kilowatts.
b New technologies include the following renewable resources: geothermal, wind, solar thermal, solar photovoltaics, biomass, and ocean thermal. New coal conversion processes are reported with coal.
c Projections based on EIA middle price scenario.

Source: (1).

Table II-4

Production Of Electricity By The Electric Utility Industry
By Type Of Energy Source 1960-1980
(Billion Kilowatt Hours)

Energy Source	1960		1965		1970		1975		1980*	
	10^9 KWH	Percent	10^9 KWH	Percent	10^9 KWH	Percent	10^9 KWH	Percent	10^9 KWH	Percent
Coal	403	53.5%	571	54.1%	704	46.0%	853	44.5%	1161	50.8%
Petroleum	46	6.1	65	6.2	184	12.0	289	15.1	246	10.8
Natural Gas	158	21.0	222	21.0	373	24.3	300	15.6	346	15.1
Nuclear Power	1	0.1	4	0.4	22	1.4	173	9.0	251	11.0
Hydro Power	146	19.4	194	18.4	248	16.2	300	15.6	276	12.1
Other	-	-	-	-	0.1	0.1	3	0.2	0.6	0.3
Total	753		1055		1532		1918		2286	

* Estimate

Source: (2).

Table II-5

Electric Utility Generation
Capacity--Maryland Utility Systems
1980 AND 1990*
(Megawatts)

	1980		1990	
	MW/Percent		MW/Percent	
Oil	5,966	31.3%	5,799	23.7%
Coal	10,763	56.5	15,042	61.6
Natural Gas	246	1.3	246	1.0
Hydroelectric	211	1.1	1,339	5.5
Nuclear	1860	9.8	2,026	8.3
TOTAL	19,046		24,432	

* Based on Summer 1980 capacity; projections based on planned additions and retirements.

Source: (3).

Most of the increase in hydroelectric capacity is represented by the Allegheny Power System's decision to purchase a large part of the Bath County pumped storage project. Increased ownership in the Safe Harbor Facility by BG&E and several small scale hydro projects will also add to the total. Although this represents a significant increase in total hydroelectric capacity, this 5.5 percentage is well below the 12.2 percent national figure projected for 1990.

Similarly, nuclear-powered units are projected to account for approximately 8 percent of the Maryland utilities' generating capacity in 1990, while nuclear plants nationwide are forecasted to represent 16 percent of capacity. The absence of additional nuclear capacity from the generation expansion plans of Maryland utilities is due in large part to the slowdown in both recent and projected growth in the demand for electricity, proximity to coal supplies, and the need for relatively small size generating units, as well as economic conditions which have reduced the relative desirability of nuclear power. In order for a nuclear-powered generating plant to be economically attractive, it needs to be large enough to capture the benefits of scale economies. Typically, nuclear units which have gone into service in recent years have name-plate capacity ratings of approximately 900 megawatts or more. (Calvert Cliffs in Maryland includes two 810 MW units.) Because electric power demand growth for Maryland utilities is expected to be relatively slow over the next ten to fifteen years, a utility bringing on-line a 900-1100 megawatt unit must either carry substantial excess capacity for several years (if the plant is put into operation as soon as any of its capacity is required) or it must purchase power to meet its load (if the utility waits until demand is sufficient to absorb the additional capacity).[1]

In addition to this "lumpiness" problem, several other factors have dampened interest in nuclear power. First, the lead time required in bringing on-line a nuclear facility is in excess of ten years, with wide variability, making generation planning difficult. In addition to the planning difficulties, the potential economic advantage to the utilities of using nuclear power rather than coal as a fuel is substantially lessened by the ability of Maryland utilities to pass through to the consumer any increase in fuel prices on a monthly basis. Finally, both operating problems and regulatory delay have served to lessen the economic attractiveness of nuclear units.

The rate of growth of capacity for Maryland utilities over the next ten years is projected to be comparable to that of the nation as a whole. By 1990, capacity is expected to increase by 27 percent nationally and by 28 percent in Maryland. Since 1973, however, the proportionate increase in generating capacity by Maryland utilities has been significantly lower than that for the nation: only 28 percent compared to 39 percent nationally. The main reasons for this difference are the relatively slow economic growth since 1973 in the service areas of Maryland utilities and the excess capacity which existed in the early part of this period and which was largely due to the dramatic decrease in the rate of growth in the demand for electricity since 1973 (see Chapter I).

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[1] Utilities have sometimes attempted to deal with this problem by either jointly owning the plant with other utilities or by short-term capacity sales, i.e., selling off some of the capacity of the plant during its early years of operation.

B. Generation Profiles Of Maryland Utilities

As described in Chapter I, almost all of the bulk power consumed in Maryland is provided by four major, privately-owned, integrated utilities: Potomac Electric Power Company, Baltimore Gas and Electric, Potomac Edison and Delmarva Power and Light. This section examines the present and future generating profiles of each of these four major utilities. The discussion describes the capacity expansion plans over the next ten years and evaluates the ability of each utility to meet its future loads by comparing forecasted loads with planned capacity additions. Trends in generating capacity mix are also discussed.

The discussion in this section is supplemented by data tables which summarize the capacity expansion plans and generating capacity profiles of the four major electric utilities. Table II-6 provides forecasted demands, capacity and reserve margins for each utility. Table II-7 presents a schedule of capacity changes on a unit by unit basis through the end of this century. The capacity profile (i.e., megawatts by fuel type) of each utility is shown for 1979 and for selected future years in Table II-8. Those figures are also presented in percentages in Table II-9. Finally, Table II-10 presents each Company's megawatt hour generation by fuel type for calendar 1980.

Baltimore Gas and Electric Company (BG&E)

BG&E, serving Baltimore City and all or portions of eight surrounding counties, had a total generating capacity of 5,010 megawatts in 1980 compared with a peak demand of 3,969 megawatts, leaving BG&E with a reserve margin of approximately 26 percent.[1] PPSP forecasts peak demand growth of 2.8 percent per year through 1990, and current plans call for an annual increase in generating capacity of 2.3 percent. On the basis of this forecast and expansion plan, BG&E will have adequate reserves through the end of this decade. Reserve margins exceed 25 percent in most years and never fall below 20 percent. (see Table II-6).

During the 1980's, BG&E plans to add two 620 mW coal-burning units at the Brandon Shores site, purchase power from a 40 megawatt municipal solid waste generating plant, and a 125 megawatt expansion of its Safe Harbor hydro capacity. The solid waste plant is scheduled to begin service in 1985, the Brandon Shores units are scheduled for 1984 and 1988, and the Safe Harbor addition is scheduled for Fall 1985. Five oil-fired units at the Westport Station which total 177 megawatts are scheduled for retirement during the 1984-1992 period. For the 1990's, BG&E plans to add 1400 megawatts of "baseload" capacity and 443 megawatts of pumped storage. One of the baseload plants will be an 800 megawatt coal-fired plant to begin service in 1992 at the Perryman site. The Company plans to retain 400 megawatts of the plant.

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[1] The industry usually accepts reserve margins of 15 to 25 percent as adequate for reliability purposes. Planned reserve margins differ for each utility.

Table II-6

Forecasted Peak Demand, Generating Capacity and Reserve Margins, 1980-1990[a] (megawatts)

	BG&E			DP&L			Pepco			APS [b]		
	Demand	Capacity	R.M.	Demand	Capacity	R.M.	Demand	Capacity	R.M.	Demand	Capacity	R.M.
1980	3,969	5,010	26.2%	1,529	2,008	31.3%	4,142	4,999	20.7%	5,564	7,568	36.0%
1981	3,897	5,025	29.0	1,506	2,219	47.3	4,242	4,999	17.9	5,552	7,587	36.7
1982	4,028	5,025	24.8	1,547	2,324	50.2	4,284	4,996	16.6	5,726	7,600	32.7
1983	4,162	5,025	20.7	1,594	2,167	36.0	4,322	5,322	23.1	5,910	7,600	28.6
1984	4,303	5,594	30.0	1,641	2,167	32.1	4,358	5,322	22.1	6,093	7,600	24.7
1985	4,447	5,634	26.7	1,694	2,217	30.9	4,393	5,322	21.2	6,264	8,020	27.4
1986	4,591	5,759	25.4	1,749	2,217	26.8	4,420	5,322	20.4	6,443	8,440	31.0
1987	4,741	5,701	20.3	1,808	2,177	20.4	4,453	5,322	19.5	6,626	8,440	27.4
1988	4,897	6,321	29.1	1,869	2,177	16.5	4,486	5,322	18.6	6,810	8,440	23.9
1989	5,091	6,321	24.2	1,934	2,177	12.6	4,520	5,322	17.7	7,000	9,070	29.6
1990	5,232	6,321	20.8	1,951	2,502	28.2	4,554	5,148	13.0	7,236	8,995	24.3

(a) Capacity figures are from the Company's latest generation plan. Peak demand figures are PPSP forecasts.

(b) Figures refer to peaks and installed capacity for winter beginning in designated year.

Source: Chapter I, Tables I-24 through I-35.

Table II - 7

Summary Of Capacity Changes Of Maryland Utilities[a] (Megawatts)

	Additions	Reductions
1981	+19 Miscellaneous Rerates (APS)	- 12 Kent (DP&L) - 4 Edge Moor 2, 3 & 4 (DP&L) - 2 Delaware City 3 (DP&L) -269 Benning 13 & Buzzard 1-6 Retirement (Pepco)
1982	+83 Salem 2 (DP&L) +22 Indian River Uprate (DP&L) +600 Chalk Point 4 (Pepco) +23 Pleasants 2 Uprate (APS)	- 10 Mitchell 3 Derate (APS) - 8 Chalk Point 1 & 2 Derate (Pepco)
1983	No additions	- 70 Edge Moor 1 Retirement (DP&L) - 15 Edge Moor 4 (DP&L) - 70 Edge Moor 2 Retirement (DP&L) - 2 Edge Moor 3 (DP&L) - 8 Chalk Point 1 & 2 Derate
1984	+620 Brandon Shores 1 (BG&E)	- 51 Westport 1, 13, 14 (BG&E)
1985	+50 Indian River 4 (DP&L) +420 Bath Project (APS) +40 Solid Waste (BG&E)	No reductions
1986	+125 Safe Harbor (BG&E) +420 Bath Project (APS)	- 40 Delaware City 3
1987	No additions	- 58 Westport 4 (BG&E)
1988	+620 Brandon Shores)2 (BG&E)	No reductions

Table II - 7 (Continued)

Summary of Capacity Plans Of
Maryland Utilities
(Megawatts)

	Additions	Reductions
1989	+630 Lower Armstrong 1 (APS)	
1990	+500 Vienna 9 (DP&L)[(a)] + 42 CT's (DP&L)	- 42 Edge Moor 10, Madison St (DP&L) - 75 Retirements (APS) -174 Potomac River 1, 2 (Pepco)
1991	+630 Lower Armstrong 2 (APS)	- 75 Retirements (APS)
1992	+800 Perryman (BG&E)[(c)] +630 Lower Armstrong 3 (APS) + 51 CT's (DP&L)	- 68 Westport 4 (BG&E) - 51 Delaware City 10, Indian River 10, Vienna 10 (DP&L) - 75 Retirements
1993	+300 Coal Plant (Pepco)	No reductions
1994	+148 Pumped Storage (BG&E)	No reductions
1995	+295 Pumped Storage (BG&E) +400 Coal Unit (DP&L)	No reductions
1996	No additions	-80 Edge Moor 3(DP&L)
1997	+400 Base Load (BG&E)	No reductions

Table II-7 (Continued)

Summary of Capacity Plans of
Maryland Utilities
(Megawatts)

	Additions	Reductions
1998	No additions +400 Coal Unit (DP&L)	-89 Indian River 1 (DP&L)
1999	+225 Pumped Storage (Pepco) +600 Base Load (BG&E)	No reductions
2000	No additions	No reductions

(a) APS plans only available through 1992.

(b) DP&L's share of Vienna 9 is 325 MW. The other shares are 125 MW to Atlantic City Electric and 50 MW to the Old Dominion Electric Cooperative.

(c) BG&E's share will be 400 MW.

Source: (4), (5), (6), (7).

Table II-8
Generating Capacity Of Maryland Utility Systems
By Fuel-Type 1979-1991
(Megawatts)

	Pepco	DP&L[a]	APS	BG&E	Other[b] Md.	Total[c]
1979						
Oil/Gas	1,986	1,285	486	2,371	31	6,159
Coal	3,013	793	6,449	852	-	11,107
Nuclear	-	237	-	1,635	-	1,872
Hydro	-	-	62	152	950	1,164
Total	4,999	2,315	6,997	5,010	981	20,302
1981						
Oil/Gas	1,986	1,189	446	2,371	31	6,023
Coal	3,013	815	7,079	852	-	11,759
Nuclear	-	320	-	1,650	-	1,970
Hydro	-	-	62	152	950	1,164
Total	4,999	2,324	7,587	5,025	981	20,916
1986						
Oil/Gas	2,317	760	446	1,936	31	5,490
Coal	3,005	1,097	7,092	1,856	-	13,050
Nuclear	-	320	-	1,650	-	1,970
Hydro	-	-	902	277	950	2,129
Total	5,322	2,177	8,440	5,719	981	22,639
1991						
Oil/Gas	2,317	760	296	1,878	31	5,282
Coal	2,831	1,422	8,352	2,476	-	15,081
Nuclear	-	320	-	1,650	-	1,970
Hydro	-	-	902	277	950	2,129
Total	5,148	2,502	9,550	6,281	981	24,462

(a) DP&L figures are for 1980, 1982, 1987 and 1992 rather than indicated years.

(b) Includes oil-burning units at Hagerstown, Md. and hydro units at Deep Creek Lake and Conowingo.

(c) Table excludes generating capacity of Easton, Maryland; Dover, Delaware; and a 40 megawatt municipal solid waste unit supplying the BG&E system.

Source: (4), (5), (6), (7).

Table II-9

Generating Capacity Of Maryland Utility Systems
By Fuel-type 1979-1991
(percent)

	Pepco	DP&L	APS	BG&E	Total
1979					
Oil/Gas	39.7%	55.5%	7.0%	47.3%	30.3%
Coal	60.3	34.3	92.2	17.0	54.7
Nuclear	-	10.2	-	32.6	9.2
Hydro	-	-	0.9	3.0	5.7
1981					
Oil/Gas	39.7	51.2	5.9	47.2	28.8
Coal	60.3	35.1	93.3	17.0	56.2
Nuclear	-	13.8	-	32.8	9.4
Hydro	-	-	0.8	3.0	5.6
1986					
Oil/Gas	43.5	34.9	5.3	33.9	24.3
Coal	56.5	50.4	84.0	32.5	57.6
Nuclear	-	14.7	-	28.9	8.7
Hydro	-	-	10.7	4.8	9.4
1991					
Oil/Gas	45.0	30.4	3.1	29.9	21.6
Coal	55.0	56.8	87.5	39.4	61.7
Nuclear	-	12.8	-	26.3	8.1
Hydro	-	-	9.5	4.4	8.7

Source: Table II-8.

Table II-10

1980 Generation Profile Of The Maryland Utilities

Generation (Thousands MWh)

	Pepco	BG&E	DP&L*	APS	Total
Oil/Gas	1,983	3,361	4,051	103	9,498
Coal	16,095	5,167	2,971	34,645	58,878
Hydro	-	436	-	193	629
Nuclear	-	10,947	1,286	-	12,233
Total	18,078	19,911	8,308	34,941	81,238

Percent

	Pepco	BG&E	DP&L*	APS	Total
Oil/Gas	11.0%	16.9%	48.8%	0.3%	11.7%
Coal	89.0	26.0	35.8	99.2	72.5
Hydro	-	2.2	-	0.5	0.8
Nuclear	-	55.0	15.4	-	15.1

* Generation from Delaware City 1, 2 and Atlantic City Electric's share of Indian River 4 have been subtracted from the totals.

Source: (4), (5), (6), (7).

Currently, BG&E's capacity profile is dominated by nuclear and oil. Coal comprises only 17 percent of the total compared to 33 percent for nuclear and 47 percent for gas and oil. Over the next ten years oil capacity will decline, nuclear will not change, and coal capacity will increase substantially. However, as shown in Table II-8 and II-9, oil and gas will still provide more than a third of BG&E's capacity in 1991.

In evaluating the power supply profile of an electric utility system, it is important to recognize generation by fuel type as well as capacity by fuel type. This is because not all generating units on a utility system run for the same amount of time. With some minor exceptions, all four utilities operate on an economy basis, meaning that the units which are most inexpensive to operate are run as much as possible, and the units which are more expensive to operate are run only when required to serve loads.[1] BG&E provides an excellent example of economy operation. The Calvert Cliffs nuclear units account for less than a third of BG&E's capacity, but they accounted for more than half of the Company's power generation in 1980. Oil and gas represented about 47 percent of BG&E's capacity in 1980, but less than 20 percent of the Company's power generation. Thus, BG&E is not nearly as oil dependent as the capacity figures might suggest.

Delmarva Power and Light Company (DP&L)

DP&L provides either directly or indirectly more than 90 percent of the electric power consumed on the Delmarva Peninsula.[2] For purposes of planning and operation, DP&L functions as a completely integrated system. The description which follows, therefore, examines the DP&L service area in its entirety rather than artificially isolating the Maryland portion, which accounts for only approximately one-fourth of DP&L's systemwide sales.

All of the municipal and rural electric cooperative utilities on the Delmarva Peninsula are integrated with DP&L. However, the data presented in Tables II-6 through II-10 exclude the Dover, Delaware and Easton, Maryland municipal systems (the only other systems on the Peninsula generating significant amounts of power) since DP&L does not routinely report Group figures to the Maryland Public Service Commission. Those tables also exclude the Getty refinery load and the generating units dedicated to those loads.

The DP&L Group, which includes the Dover and Easton systems, had a total generating capacity of 2,533 megawatts in 1981. DP&L plans to increase capacity by 8.7 percent by 1991. During the 1980's, DP&L will replace much of its oil-fired capacity with coal and a small amount of nuclear. The principal additions to capacity in the 1980's are two coal-fired plants -- Indian River 4, which began operation in late 1980, is a 400 megawatt power plant[3], and the

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[1] Utilities sometimes run their high cost plants to take advantage of opportunities to sell power to a power pool. The pool settlements procedure more than reimburses them for the cost of doing so.

[2] The Peninsula consists of the Maryland Eastern Shore counties, the State of Delaware, and the two Virginia counties on the Eastern Shore.

[3] Atlantic City Electric Company will lease 50 megawatts from the Indian River plant until 1985.

and the proposed Vienna 9, scheduled to come on-line in 1990, has a planned capacity of 500 megawatts.[1] DP&L will receive 83 megawatts of capacity in 1981 from the Salem 2 nuclear plant. Edge Moor 3 and 4 (combined capacity 249 megawatts) will be converted from oil-fired to coal-fired in 1982 and 1983. Edge Moor 1 and 2, oil-fired units with a combined generating capacity of 140 megawatts, will be retired during the 1980's.

Between 1980 and 1990, peak demand is forecasted to grow at an average annual compount rate of 2.5 percent, compared with a 2.2 percent rate of growth for capacity. While DP&L's peak demand is expected to grow more rapidly than capacity, DP&L is expected to face high reserve margins during the early portion of the 1980's. Reserve margins are expected to exceed 25 percent through the mid-1980's but will drop below 20 percent during the late 1980's until Vienna 9 comes on-line in 1990.[2]

DP&L has designed its generation plan to move very rapidly away from its very heavy oil dependence. In 1980, more than half of the DP&L Group capacity was oil-fired, with coal accounting for only about one-third. By 1990, oil capacity will fall to 30 percent, and coal capacity will rise to 57 percent. Thus, a dramatic reversal will take place within a decade if the Company's plan is implemented.

The Company is currently seeking a license from the Maryland Public Service Commission for a 500 megawatt plant to be located at its existing Vienna, Maryland site (Maryland PSC Case No. 7222). Although DP&L now intends to begin operation in 1990, the Company originally intended to bring Vienna 9 on-line in 1987. That date would have been in advance of when the capacity would have been needed for reliability purposes according to the PPSP load forecast. However, a PPSP study demonstrated that oil savings from the operation of the plant make the 1987 on-line date economically attractive (9). This result is due to the large disparity between the per Btu price of oil and coal.

Like BG&E, the DP&L Group is operated on an economy dispatch basis -- generating units are dispatched in merit order on the basis of their relative operating costs. Although nearly 65 percent of the Company's capacity in 1980 was oil, only 51 percent of its power was generated from burning oil in 1980.[3] The tendency to minimize the usage of oil by instead operating the cheaper to operate coal and nuclear facilities is illustrated in the detailed generation data provided in PPSP's annual report on the long run generation plans of Maryland utilities (10). As the data in that report show, the coal burning facilities have dramatically higher capacity factors[4] than do the oil burning plants.

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1 DP&L will maintain ownership of 325 megawatts, 50 megawatts will be owned by three rural co-ops that are presently wholesale customers of DP&L, and 125 megawatts will be owned by Atlantic City Electric.

2 DP&L considers 16 percent an adequate reserve margin.

3 The capacity percentage figure excludes Indian River 4 which did not begin service until October 1980.

4 A <u>capacity factor</u> is defined as total electric energy generated by a plant during some time interval as a percentage of the total amount of energy the unit is capable of generating. For purposes of comparison, 1980 capacity factors have been adjusted for planned and forced outages of each unit.

The Allegheny Power System (APS)

APS is a predominantly coal-fired utility. This is not surprising given the fact that its service territory is one of this nation's most important coal mining regions. Given the fact that transportation represents a very large percentage of the total cost of coal for most utilities, APS' proximity to that fuel has made coal-fired generation particularly attractive. Currently, more than 90 percent of the system's capacity is coal-fired. In addition, APS has about 450 megawatts of oil generation and a small amount of hydro capacity.

APS plans to add nearly 2,100 megawatts of generating capacity between now and 1991 from two large projects. APS has announced its intention to participate in a joint venture with Virginia Electric Power Company (VEPCO) to construct a hydroelectric pumped storage facility in Bath County, Virginia. When completed, this project will be the world's largest pumped storage facility.[1] APS intends to purchase (and/or lease), subject to regulatory approval, either 40 or 50 percent of the total 2,100 megawatts of the plant. APS' current generation plan indicates 420 megawatts in 1985 and an additional 420 megawatts in 1986, but it may ultimately add as much as 1,050 megawatts.

The other major facility which APS lists in its generation plan is the Lower Armstrong Station, which will consist of three 630 megawatt coal-fired units. The three units are scheduled to begin service in 1989, 1991, and 1992. Some initial design work and a draft environmental impact statement have been completed. However, APS suspended work in 1978 on the project, indicating that its financial condition and expectations concerning future rate treatment prevent it from undertaking the project (11). In order that the first Lower Armstrong unit meet its planned in-service date of 1989, work must resume within the next year. Thus, if the suspension continues much longer, the Company will be forced to alter its generation plan.

The APS decision to participate in the Bath Project was prompted by its inability to proceed with Davis, a proposed 1,000 megawatt pumped hydro plant which had been licensed several years ago by the Federal Energy Regulatory Commission (FERC). The FERC license has been challenged in Federal Courts. After receiving the FERC license, APS was refused a dredge and fill permit for Davis by the Army Corps of Engineers. The permit dispute is currently under litigation, but APS has eliminated Davis from its current ten year plan. However, should it succeed in obtaining needed approval, APS would consider constructing Davis in the 1990's after completion of Lower Armstrong.

APS has also included in its plans some unspecified retirements over the 1990 to 1992 periods which amount to 225 megawatts of capacity.

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[1] Pumped storage hydro involves pumping water from a lower reservoir to a higher reservoir during the off-peak period and allowing that water to flow back into the lower reservoir and generate power during the peak period. The facility creates no additional electricity because the energy required for pumping exceeds the energy generated. However, it is able to shift energy from the off-peak to the peak period, and thereby make energy available when most needed.

APS' current capacity plan, when compared to the PPSP load forecast, indicates a pattern similar to that of DP&L (see Table II-6). Reserve margins are rather high in the early part of the 1980's and gradually decline thereafter.[1] After the early 1980's reserves will range between approximately 25-30 percent. Because of its relatively high system load factor, APS believes that its optimal reserve margin should be approximately 23 to 27 percent. Thus, APS' generation plan appears to be adequate and only requires carrying excess reserves in the early part of the 1980's.

That evaluation assumes that APS' current generation plan is built as scheduled. The Lower Armstrong units cannot be built as scheduled unless progress is resumed in the very near future. On the basis of existing forecasts, significant further delays would lead to an unreliable system by the early 1990's.

The Potomac Electric Power Company (Pepco)

Pepco currently has 4,999 megawatts of generating capacity, approximately 40 percent of which burns oil and the remainder burns coal. It currently lacks, and has no plans to add, hydroelectric or nuclear capacity. Pepco capacity expansion plans are rather modest, largely because the Company's system load is growing so slowly: Pepco is predicting annual load growth of approximately one percent. The nearly completed Chalk Point 4 oil-fired plant is expected to begin service in 1982. The Company is currently planning for an unspecified 300 megawatt coal unit in 1993 and is considering an underground pumped storage facility for the late 1990's. Mixed in with these capacity additions are several retirements of some of the Company's older, oil-fired capacity.

Despite the planned retirements, Pepco's percentage of oil capacity will increase over time. Pepco is the only Maryland utility expected to experience such an increase. This situation will occur for two reasons. First, the Chalk Point 4 unit, which will add 600 megawatts of oil capacity in 1982, was planned and designed before the industry began to switch away from oil capacity so decidedly. Second, the next capacity addition is not scheduled to occur until 1993, and that addition is only half the size of Chalk Point 4. Thus, Pepco's generation plan after 1982 provides little opportunity to replace oil.

Like the other Maryland utilities, Pepco dispatches its generating units on an economy, cost-minimizing basis. The Company, therefore, attempts to maximize the operation of its coal plants and to minimize the operation of its oil plants. Consequently, although oil represents about 40 percent of the Company's capacity, it accounted for only 11 percent of total power production in 1980.

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[1] The reserve margins for the first half of the 1980's are actually greater than shown in Table II-6 (which includes only installed capacity) because APS maintains a diversity exchange arrangement with Vepco. Under this arrangement APS supplies 300 megawatts to Vepco in the summer in exchange for the same amount of power in the winter. This arrangement will run until 1985.

Pepco's level of reserves is barely adequate at the present time. However, with the imminent addition of Chalk Point 4, Pepco's reserves should be adequate until the early 1990's if the present forecasts are correct. To some extent the Company can modify the level of reserves by altering planned retirement dates of its older capacity. However, current forecasts call for load growth of roughly one percent per year. If loads were actually to grow at the rate of just under three percent forecast by APS and the DP&L systems, Pepco would experience deficient reserves several years in advance of its next planned capacity addition. For that reason, the Pepco load growth warrants careful scrutiny.

C. Generation Planning

A generation expansion plan is the means by which a utility proposes to serve its expected future loads. A franchise monopoly held by a regulated utility carries with it an obligation to provide adequate and reliable service to all its "firm" customers, and capacity must be planned accordingly. At the same time, it is desirable that the utility provide reliable service at minimum long run cost. As a result, reliability and long-run cost minimization are the twin goals of system generation planning.

With these goals in mind, the generation planner must address the following fundamental questions:

- When should new capacity additions be scheduled to begin service?
- How large should those capacity additions be?
- What kind of generating capacity (i.e., technology and fuel type) should be added?
- How can and should power demands be managed to avoid expensive energy and/or capacity additions?

The question relating to the timing of new capacity is determined by the projected growth in loads on the system in conjunction with judgments concerning the appropriate reserve margin for the utility. Load forecasting and the subject of demand-side approaches to generation planning are discussed in detail in Chapter I. This section focuses on the economic principles normally employed in the selection of the least cost generating technology. The discussion also gives recognition to the various dynamic factors which may complicate the planning process and often limit the options available to the planner. This section concludes with a discussion of the conversion of oil-fired plants to coal.

Economic Principles of Generation Expansion Planning

Given forecasted loads and specified reliability standards (e.g., expressed as reserve margins), the planner determines when the system must add its next plant.[1] Having made the scheduling determination the planner must then select the least cost technology for the next unit. Conventional power plant technologies fall into three major categories -- baseload, cycling and peaking -- and five major fuel types -- nuclear, coal, hydro, oil and gas.[2]

The way in which a mix of these various plant types operate to serve a utility system's power demands can best be explained by reference to a typical daily load curve. That curve shows system demands at different times of the day. Load falls in the early morning hours and sharply rises throughout the day reaching a maximum in the late afternoon. Loads gradually subside during the evening. There is a certain minimum or "base" level of load which is exceeded at virtually every hour. This will be served by baseload units, which are large, very efficient generating units which run almost continuously. Because these units require long periods of time to be brought up to full throttle from a cold start, they can only run in a continuous mode. Typically, baseload units are coal or nuclear-fired and about 400 megawatts or larger.

Above the base or minimum load on the daily load curve, demand may change rapidly from hour to hour. There is a need for power plants on the system which can adjust their energy output to follow these changes in load. Cycling units have the capability of altering their output on short notice in response to expected load changes. The cost of this flexibility is some loss in energy efficiency as compared to the baseload units. Cycling units are usually steam plants, coal or oil-burning, and are somewhat smaller than baseload units. Hydro plants with reservoir storage can also be operated as cycling plants.

Finally, the very top of the load curve is served by peaking plants. Peaking plants are extremely expensive to operate, but are only run for short periods of time when power demands are near the maximum. Also, peaking plants are completely flexible and are capable of coming up to full load on very short notice (i.e., in minutes). Oil and gas burning combustion turbines are the most common type of peaking plant used in the industry. However, there

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[1] Because of the high cost of oil relative to other fuels, it is becoming increasingly common for utilities to schedule capacity additions in advance of load growth to displace oil-fired generation. Doing so reduces long-run system costs if the added fuel savings from accelerating the schedule more than offset the additional capital costs of carrying the "excess" capacity. A PPSP study concluded that this is likely to be the case for DP&L's proposed Vienna 9 plant (9).

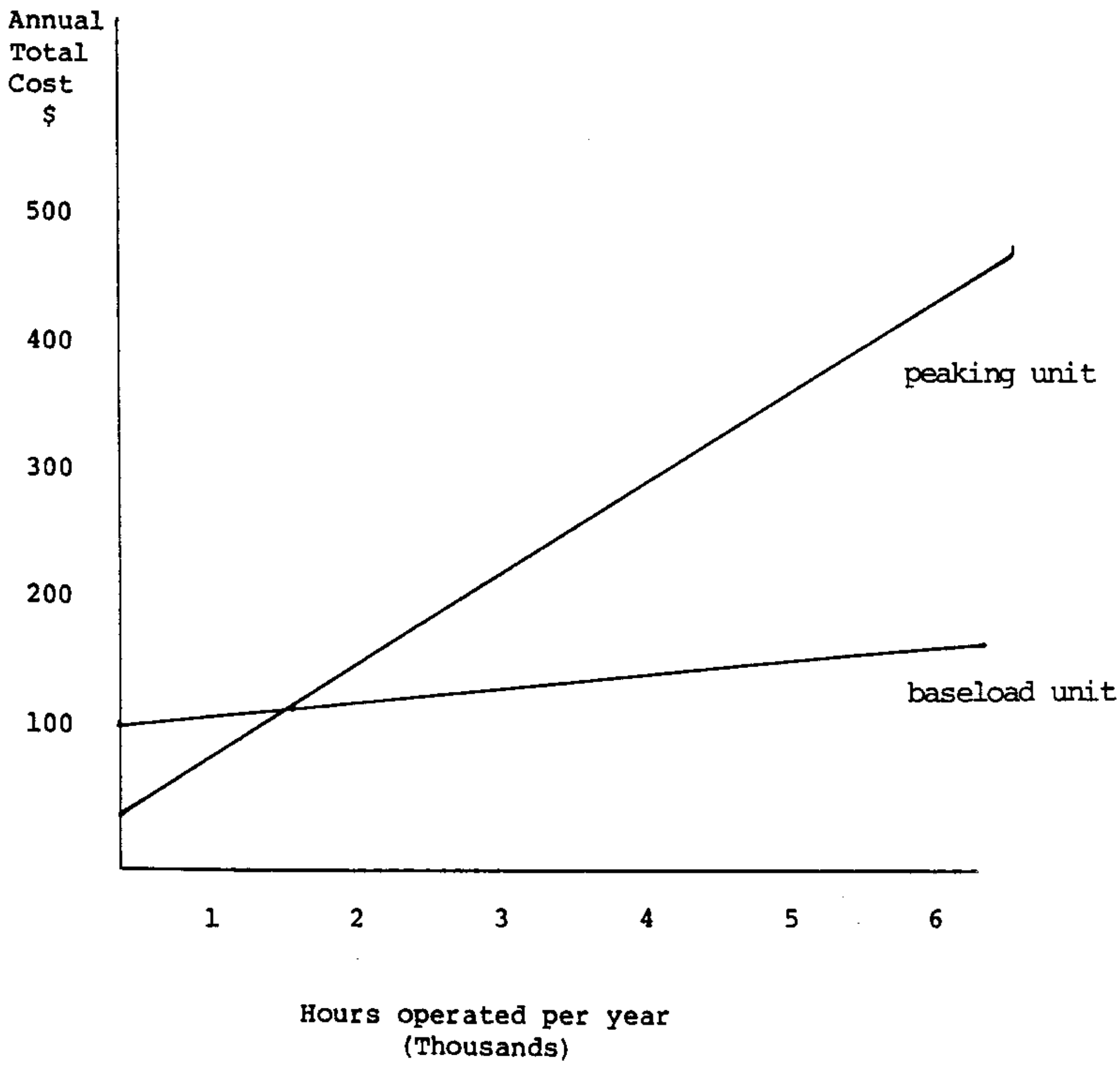
[2] The Fuel Use Act prohibits the use of gas or oil in new utility plants. However, it is possible to obtain exemptions for plants that will be operated as peaking units.

is also growing interest in pumped storage hydro both to serve peak loads and to function as cycling capacity.

Baseload, cycling and peaking plants have different operating characteristics, construction costs and lead time requirements. At one extreme, baseload plants are very expensive to construct and install on a per kW basis compared to smaller peaking plants. Offsetting that, baseload plants are capable of burning relatively inexpensive fuels (e.g., coal and uranium) and do so with relatively high efficiency. Thus, on a per kilowatt hour basis they are the most inexpensive plants to operate. At the other extreme peaking units are relatively inexpensive to construct per kW but are expensive to operate, largely because they typically burn oil or gas.

Thus, aside from operating characteristics, the choice of plant type is a matter of trading off capital and operating costs. For example, a typical baseload coal plant might cost $1,000 per kilowatt to construct and have an operating cost (i.e., fuel cost) of 1.5 cents per kilowatt hour. By comparison, a combustion turbine unit might cost roughly $200 per kilowatt to construct and 7 cents per kilowatt hour to operate. The selection of the type of capacity will ultimately depend upon the number of hours the plant must run. If the plant is expected to run a large number of hours, a baseload plant is clearly more economic. If the capacity is only required for a small number of hours, it is more economic to conserve capital costs and expend higher fuel costs.

The following diagram illustrates this trade-off on an annual basis for one kilowatt of capacity. A 10 percent annual carrying cost is assumed, translating the capital costs into $100 per kW per year for baseload and $20 per kW for a peaking unit.



The two lines indicate the total annual cost of carrying and operating both types of capacity at varying levels of usage. This diagram indicates that total costs are equal at roughly 1,500 hours of usage; for fewer hours of usage the peaking unit is less expensive, and for more hours of operation the baseload unit is less expensive. This simplified example, however, will overstate the attractiveness of the peaking unit if it is expected that oil will increase in price over time more rapidly than coal.

In order to select an optimal plant size and fuel type, it is necessary to compare generating costs in a manner which reasonably reflects the full range and complexity of relevant economic and engineering factors. The variable costs of bulk power supply over an appropriate time horizon (usually about 20 years) are often calculated by the use of a production costing simulation model. These models attempt to simulate the operation of a given power system by dispatching the utility's power plants to meet its forecasted loads. It is assumed (unless otherwise adjusted for) that plants will be dispatched on a merit basis so as to serve load in the most inexpensive way possible. The modeling takes into account numerous factors, including fuel costs over time, non-fuel operating and maintenance expenses, load growth, changes in load shape, unit maintenance requirements and forced outages.

After determining the variable costs of different generation capacity plans from the simulation model (and discounting those costs to the present), the fixed costs of the various generation plans must be considered. The fixed costs may be calculated as the additional revenue requirements over the time horizon of the alternative capacity addition plans (discounted to present value).[1] The sum of the variable and fixed cost revenue requirements is the total cost of a given plan. The plan providing the lowest total cost, assuming it satisfies the reliability criteria, is considered optimal.

The above discussion describes the straight-forward calculations used to determine the selection of the least-cost generation technology alternative. It is also important to recognize that the planner faces a multitude of complications and constraints. A partial list includes the following:

- Uncertainty -- The single most important planning decision relates to capacity addition timing. Unfortunately, the load forecasts which are relied upon tend to be highly uncertain. Similarly, the calculation of the cost-minimizing technology is based upon uncertain assumptions regarding future fuel prices, capital costs and so forth.

- Lead Time -- It now requires 10-12 years or longer to site, license and construct a new baseload power plant. Long lead times have the effect of reducing planning flexibility by limiting the feasible generation alternatives. For example, a firm may need new capacity sooner than it is capable of getting a new baseload unit on-line.

- Financial Capability -- Electric utilities do not have unlimited financial resources. The generation plan must therefore be consistent with the ability of the utility to raise the required investment capital. It is possible that financial limitations might force a utility to select a capacity expansion plan which does not minimize long-run costs.

- Regulatory Constraint -- Generation planning options are sometimes limited by regulatory constraints on power plant construction and operation. The inability of APS to obtain approval to construct the Davis pumped storage project is an example of such constraint. The restrictions in the Fuel Use Act represent a further restriction on the fuel type a power plant may be designed to burn.

Generation planning is clearly not a simple, straightforward exercise. It requires reconciling the economically most attractive plan with a long list of real world risks and problems which are beyond the direct control of the planner.

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[1] As in our simplified example, capital costs of alternative plants may be calculated by applying an appropriate annual carrying cost rate to the construction costs.

Coal Conversion

The price of oil in recent years has increased significantly and far more quickly than the price of coal. Prior to the 1973-74 Arab oil embargo, oil was viewed as an inexpensive, readily available and convenient fuel. Additionally, oil is a relatively clean fuel and does not require large investments in pollution abatement equipment. Consequently, the generation plans drawn up in the late 1950's, 1960's, and early 1970's relied heavily upon oil-fired power plants. It has been become evident since the embargo, however, that coal is generally more economical to use as a primary fuel in baseload generating units. Unfortunately, the replacement of oil-fired capacity with coal-fired capacity is complicated by the fact that the useful life of a generating unit is about 30 years. The long service life, coupled with the large initial capital investment associated with bringing on a new plant, tends to discourage replacement of oil-fired capacity far in advance of the originally envisaged retirement date.

A utility may, however, have the option of converting an oil-fired unit. Conversion of a generating unit specifically designed to burn oil into a coal-fired unit involves major alterations to the unit. However, many facilities were originally designed to burn coal and were later converted to oil. It is economically practical to reconvert many of these "coal-capable" units. Coal conversion is cost-effective only if the capital costs of conversion can be recovered over the remaining useful life of the generating unit by the savings (appropriately discounted) obtained by using coal as a primary fuel rather than the higher priced oil. This condition will be met if (1) the price of a unit of coal does not quickly increase to approach the price of an energy-equivalent amount of oil; and (2) if the useful life of the generating unit is sufficiently long. Clearly, if the cost of obtaining energy from coal is roughly equal to the cost of energy from oil, there is no compelling economic reason to convert to coal. Similarly, if the power plant under consideration can supply only a few remaining years of useful service, there will to be too few kilowatt hours generated in which to recoup the initial capital costs associated with the conversion.

The Energy Supply and Environmental Coordination Act of 1974 underscored the Federal Government's interest in shifting reliance from oil to coal and stipulated that coal-capable power plants must burn coal. In 1978, stricter standards were enacted and financial incentives were created to induce utilities to alter their fuel mix in favor of coal. The Power Plant and Industrial Fuel Use Act (1978) precludes the construction of large (baseload) oil and natural gas boilers by public utilities and industry[1], though certain exemptions may be granted by the U.S. Department of Energy if warranted by environmental or economic considerations, or site-specific limitations, such as insufficient space to achieve a coal-handling ability. The construction of oil-fired peaking units, however, may be permitted.

The Energy Tax Act (1978) provides financial incentives for coal conversion through a ten percent tax credit and accelerated depreciation. Not only are such tax credits unavailable for natural gas and oil-fired units, but they must be depreciated using the straight line method.

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[1] Boilers with a fuel heat input rate equal to or greater than 100 million Btu's per hour are considered large.

There are a number of technical and regulatory impediments to coal conversion. First, air quality regulations require desulfurization equipment to be installed if other than low sulfur coal is to be used.[1] The expense of desulfurization equipment may, in certain cases, be eliminated only by using more expensive low sulfur coal (see Chapter III). In non-attainment areas (where air quality standards are not met), pollution offsets may be required; that is, arrangements need to be made to reduce the emissions of the pollutant in question within the non-attainment area through reductions in emissions from other sources (see Chapter III).

Second, operation of a coal-fired unit requires more space than operation of an oil-fired unit of comparable capacity. Many stations lack the large area which is needed for coal storage. Also, waste material resulting from the burning of coal (e.g., fly ash), must be disposed (see Chapter VIII).

Third, when coal plants were originally converted to oil, many were replaced with boilers capable of burning only oil. Unless extensive alternations are undertaken, these units can only burn coal in the form of a coal/oil mixture -- a technology which is still in experimental stages. If the mix is more than 50 percent coal, it is considered by the U.S. Environmental Protection Agency (EPA) to be solid fuel, and federally mandated pollution control equipment for coal-burning stations must be installed. This creates a powerful disincentive to employ that fuel mix.

While the factors enumerated above serve to inhibit coal conversion, regulatory and economic considerations have made conversion an attractive option for several power plants owned by Maryland utilities. DP&L plans to convert the Edge Moor 3 and 4 facilities in 1982 and 1983 (249 megawatts), and BG&E is converting both its C.P. Crane facility (384 megawatts) and its two Brandon Shores plants (620 megawatts each) which are now under construction. No other utilities operating in the State currently have any coal conversion plans.

Coal conversion (to burn high sulfur coal) has been estimated at approximately $500 per kilowatt (1981 dollars). For example, at Delmarva's Edge Moor 3 and 4, the cost of conversion is estimated to be $74.6 million ($297/kW). DP&L plans to use expensive, low sulphur coal at the Edge Moor plants. The Company estimates that if it installs desulphurization equipment instead of using low sulphur coal at those plants, capital costs of coal conversion would be $175 to $200 per kW higher (12). Coal conversion often results in a slight reduction in generating capacity. In the case of Edge Moor 3 and 4, generating capacity is expected to decline by 5 megawatts for both units combined (2.0 percent), which is a cost that should be considered part of the coal conversion costs.

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[1] Western Maryland coal has a relatively high sulfur content.

D. Alternatives to Conventional Generation

Since 1973, the cost of generating electricity by conventional means has increased substantially. It has also become evident that much of our primary energy is supplied by unstable and unreliable sources. As a consequence of higher costs and an increased awareness of the need for a greater degree of energy independence, increased emphasis has been placed on the development and use of unconventional methods of electric generation to augment conventional sources. Both at the federal and state levels, financial incentives have been provided to induce residential, commercial, and industrial users to employ alternate sources of electricity.

Some of the more promising alternative generation sources are cogeneration, wind, solar, municipal solid waste, and small scale hydroelectric. Because of their current limitations, either due to technological considerations or their region-specific nature, this section does not examine such technologies as photovoltaics, ocean thermal energy conversion (OTEC), geothermal, or tidal power.

Legislation enacted 1981 by the Maryland General Assembly (Ch. 497) established the Maryland Energy Financing Administration (MEFA). MEFA was created to alleviate the problems of high initial cost and insufficient conventional financing of conservation and renewable resource equipment and installation in the industrial and commercial sectors. MEFA will be a self-supporting unit within the Department of Economic and Community Development, and is authorized to issue revenue bonds to finance low-interest loans for conservation, solar energy alcohol fuel production, geothermal, hydropower, cogeneration, synthetic fuel from coal, municipal solid waste, wood and wind projects (14).

In examining alternatives to conventional generation, special emphasis is given to their applicability in the State of Maryland and to the current Maryland experience and plans.

Municipal Solid Wastes

As an alternative to costly conventional fuels such as oil and coal, municipal solid wastes, which would otherwise be disposed of in landfills, are soon to be employed at several sites in Maryland. In addition to potential savings in fuel costs, generation using municipal solid wastes provides two other benefits. First, valuable landfill sites will be exhausted less quickly, thereby reducing the need for additional sites. Second, this technology provides a vehicle for the recycling of reusable wastes, such as glass and metals. The sorting of recyclable material is generally performed in conjunction with the sorting of usable energy-producing refuse.

The Northeast Maryland Waste Disposal Authority is currently in the final stages of replacing a large incineration unit in Baltimore with a waste-to-energy facility capable of burning 2,000 tons of solid waste per day. Electricity from the 40 megawatt unit will be sold to BG&E. Consideration is also being given to the future operation of two other units, one in Baltimore and the second in Harford County. The Harford County unit, which is to burn 750 tons of solid waste per day, would sell steam to Aberdeen Proving Grounds and a small amount of electricity to BG&E. The Baltimore unit will produce steam to be used in the drying of sewage sludge (13).

The Maryland Environmental Service Resource Recovery Facility at Baltimore produces refuse derived fuel (RDF), which has a higher Btu content than unprocessed waste. RDF, which can be used for combustion or as a sewage composting agent, was tested by BG&E at the Crane plant as a fuel supplement for high sulfur coal and was found to perform well (14).

The Federal government provides financial incentives for the use of municipal solid wastes in energy-producing activities through the Windfall Profit Tax Act (1980) and the Energy Security Act (1980). A ten percent tax credit is allowed for equipment designed to burn biomass fuel or used for converting biomass into synthetic solid fuel. Also, tax exempt Industrial Development Bonds may be used to finance facilities to produce electricity from solid wastes if the facility is owned and operated by a state or the Federal government. Subsidized loans, loan guarantees, and tax-exempt grants may also be obtained from the Federal government.

Solar

Solar energy systems are of two basic types: passive and active. Passive solar systems refer simply to devices used to permit sunshine to enter a structure or to exclude sunshine. Such devices include shutters, large window areas, southern exposures, window shades, etc. Active solar systems are based on the collection, storage, and use of solar energy. Typically, water (or air) is heated via solar collectors and circulated throughout the heating system of the building or used to heat domestic hot water.

Because sunshine is not available at night or during periods of inclement weather, active solar systems are generally equipped with thermal storage capability. While it is possible to construct an active solar system with sufficient storage to supply all the hot water or space heating requirements of a building, the cost is generally prohibitive and a back-up system is usually relied upon.

The primary application of active solar heating systems is for residential use. Nationally, in 1979, approximately 80 percent of solar collectors were delivered to residential end users and 60 percent of all collectors were used to heat swimming pools (14). Industrial and commercial application has not been widespread.

The costs and productivity of solar units vary widely and depend upon the geographic area, the type of solar system used, and the housing structure to which the system is affixed. A recent study conducted by Resources for the Future show that low-end estimates of solar costs make it competitive with electric resistance heat (15).

Purchase and installation costs for an active solar water heating system vary substantially. According to a recent survey, the average cost of purchase and installation in Maryland in 1979 was approximately $3,200, and repair and maintenance expenses for the solar facilities have been negligible. This study also estimates the pay back time of a solar water heating system to be approximately 6.5 years (16).

A number of different federal, state and local financial incentives make the installation of a solar system more attractive to the homeowner. The 1980 Windfall Profit Tax Act stipulates a 40 percent tax credit for investment in solar systems up to a maximum of $4,000 per household. The 1978 National Energy Conservation Act allows FHA to increase its limit on low interest loans by 20 percent. Additionally, the Energy Security Act (1980) allows for the establishment of a Solar Bank to administer loans for solar systems through HUD.

Maryland State solar legislation specifies that solar units cannot be used as a basis for increasing property assessments and allows local municipalities to grant tax credits for solar equipment. Harford and Anne Arundel Counties have established such property tax credits which appear to have stimulated considerable solar activity.

Small Scale Hydroelectricity

With the realization that the most economical of the large scale hydroelectric potential in the United States has already been fully exploited, interest in small scale hydro power has been increasing. Both large and small scale hydro (capacity less than 30 megawatts)[1] have been important components of the electric power industry since its inception.

There is considerable potential for expansion of small scale hydro in the State of Maryland. The Maryland Energy Administration estimates that the total underdeveloped hydroelectric potential in the State is 560 million kWh per year with an energy equivalence of 6.2 million Btu per year (14).

The construction of a small scale hydroelectric facility requires a license from the Federal Energy Regulatory Commission (FERC). Normally, the first step in this process is to obtain a preliminary permit which FERC routinely grants to the applicant for an 18-month to two-year period. This temporary permit allows the applicant the time to perform the necessary feasibility and environmental studies and during that time maintain exclusive rights to the site. Upon completion of the studies the permit holder may apply for the construction and operating license to be reviewed by FERC. Currently, five preliminary permits have been either applied for or obtained for small scale hydro facilities in Maryland.

Certain environmental and institutional impediments inhibit wide reliance on small scale hydro. Rights of access to the river, stream bed and stream banks need to be secured and permits for dam construction need to be acquired. Additionally, restrictions along certain reaches prohibit dam construction and initial capital costs are increased as a result of the required construction of fish ladders.

Federal initiatives aimed at using small scale hydro are contained in the Public Utilities Regulatory Policies Act of 1978, the Windfall Profit Tax Act of 1980, and the Energy Security Act of 1980. Incentives include tax credits, loans and loan guarantees, and grants for the development and construction of demonstration projects.

Wind Energy

The average wind speed in most areas of the State of Maryland ranges from 8 to 10 miles per hour, making wind an uneconomical energy source in most

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[1] U.S. Department of Energy definition from the Public Utilities Regulatory Policies Act of 1978.

parts of the State. An average wind speed of 12 miles per hour is generally required to make wind-powered energy an attractive alternative to conventional energy sources (14).

The Federal government has established financial incentives to foster increased investment in wind energy. A 40 percent tax credit is provided through 1985 for investment in wind energy equipment by the Windfall Profit Tax Act (1980).

Cogeneration

Cogeneration is a familiar though, to some extent, underexploited power source. Widespread use of cogeneration has been taking place in the industrialized European nations for many years, and it has enjoyed some limited success in this country. Because of its efficiencies, proponents believe that the potential exists to radically expand its usage.

The term cogeneration has been used by engineers to describe a process whereby electricity and process heat in some form (e.g., process steam) are simultaneously produced. It may arise from a situation where the primary purpose of consuming energy is to produce electricity, and waste heat is produced. The firm may then find a productive use for that waste heat. Alternatively, an industrial or commercial firm may use energy primarily to obtain process steam, and in doing so it finds it can also produce electricity relatively inexpensively. As a result of jointly producing both types of energy (e.g., steam and electricity), total energy requirements may be reduced by as much as 30 percent.[1] Although there is potential for exploiting cogeneration from commercial and residential heating systems, it is believed that the bulk of the cogeneration will come from industrial applications.

It is widely believed that cogeneration, particularly coal-fired steam, is capable of producing relatively inexpensive energy.[2] The cost tends to be competitive with both the short-run marginal costs of existing electric systems and the long-run marginal (and average) cost of a new baseload coal facility. Unfortunately, the contribution of cogenerators to system reliability is an unsettled issue and clouds a complete evaluation. On the basis of favorable cogeneration economics and the rather large industrial demand for process steam in the service areas of Maryland utilities, an opportunity exists to increase sharply the amount of electricity produced by cogeneration.

Maryland utilities have had some limited experience with industrial cogeneration in their service areas. The Getty Oil Company operates a large cogeneration project with DP&L near Wilmington, Delaware. The Delaware City 1 and 2 units simultaneously produce process steam and electric power for the refinery. Any excess power is sold back to DP&L. The Celanese Corporation in

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[1] Energy in America's Future, Resources for the Future, p. 160. The RFF study reports four additional benefits: (1) capital savings in generation equipment; (2) transmission and distribution savings; (3) reduced cooling water requirements; and (4) reduced siting and licensing lead times.

[2] Argonne National Laboratory estimates that the average total cost of cogenerated power may be as low as 2.5¢/kWh (in 1980 dollars) assuming a relatively large, efficient cogeneration facility. This is well below both the long-run and short-run marginal costs of power on most utilities (17).

Cumberland, Maryland has in the past operated a 10 megawatt facility with Potomac Edison, but that unit has been retired since 1978. The Westvaco Corporation in Luke, Maryland currently operates a large facility and sells a small amount of power to Potomac Edison. On the basis of Company surveys, there appears to be a significant potential to expand cogeneration and small power production in the Allegheny Power System service area.

E. A List of Electric Utility Industry Definitions

The final section of this chapter provides definitions of some of the terms commonly used by electric utility generation planners. Most of these terms are used extensively throughout this Report, and particularly in Chapters I and II.

- Cycling Plants are units designed to operate at relatively high efficiency, but which can be adjusted to meet changing loads and can operate well under relatively frequent on-off cycles.

- Peaking Plants are units designed to operate only for short periods of peak demand, usually for only a brief part of the day during a few months of the year.

- Demand is the amount of electric power required by customers at any given instant in time, usually stated in megawatts (MW) or kilowatts (kW). One kW is the amount of power needed to light ten 100 watt light bulbs, and a megawatt is 1,000 kilowatts.

- Peak Demand is a maximum demand experienced during some time interval, such as a day or year. Peak demand in the tables in this chapter is the average power used over the 60 minute period of heaviest demand during a given year.

- Load Factor is the ratio of the average load (MW) to the peak load during the time period being measured. An annual system load factor, SLFa, is defined as:

$$SLFa = \frac{SEa}{SPLA \times 8760}$$

where: SLFa = annual system load factor
SEa = annual system energy output (MWh) (energy sales plus losses)
SPLa = annual system peak load (MW), and
8760 is the number of hours in a year (8784 in a leap year)

- Capacity Factor is the ratio of the average load (MW) on a plant or entire system to the capacity rating (maximum rated output, MW) of the plant or system for the time period being measured.

- Reserve Margin is the difference between system maximum capacity (MW) and system peak load, divided by the system peak load, for any given moment in time. The most commonly used reserve margin is defined at the time of the system peak demand:

$$RMp = \frac{SCp - SDp}{SDp}$$

where: RMp = system reserve margin
SCp = system maximum capacity at time of peak
SDp = system peak demand

- Base Load Plants are generating units designed to be run at high efficiency on a continuous basis over long periods of time.

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