Electric Power Outlook For Pennsylvania 2003 – 2008

August 2004

Pennsylvania Public Utility Commission

Bureau of Conservation, Economics & Energy Planning

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EXECUTIVE SUMMARY

Each public utility which produces, generates, distributes, or furnishes electricity must annually submit to the Commission information concerning its future plans to meet its customers' demands. 66 Pa.C.S. § 524. The law requires the Commission to prepare a report summarizing and discussing the data provided on or before September 1. The Commission is required to submit the report to the General Assembly, the Governor, the Office of Consumer Advocate and each affected public utility. The Commission adopted regulations at Title 52 §§ 57.141 – 57.154, Annual Resource Planning Report, in order to comply with the requirements of the public utility law.

This report concludes that there is sufficient generation, transmission and distribution capacity to meet the needs of Pennsylvania consumers for the foreseeable future.

Both generation adequacy and the reserve margins of the Pennsylvania-New Jersey-Maryland Interconnection, Inc. (PJM) and the East Central Area Reliability Council (ECAR) have been maintained. While sufficient generation capacity is expected for the next five years, the Pennsylvania Public Utility Commission will continue its current policy of encouraging generation adequacy within PJM.

With respect to transmission adequacy, the transmission system in the Mid-Atlantic region has sufficient capacity to meet demand. However, the system is often congested during periods of high demand. Both the Mid-Atlantic Area Council (MAAC) and ECAR are planning transmission expansions and upgrades over the next five years to relieve congestion. Current initiatives at the federal level may also help improve the overall reliability and efficiencies of the transmission system.

To summarize the relevant statistics in this report, electricity demand in Pennsylvania has grown at a rate of 1.5% annually in the past 15 years. This is an aggregate figure for all sectors, including industrial, commercial and residential. The current projections for 2003-2008 show electricity demand growth at 1.5% annually. This includes a residential growth rate of 1.3%, a commercial growth rate of 2.4% and an industrial growth rate of 0.8%.

Regionally, generating resources are projected to be adequate for the next several years. In MAAC, the 2008 reserve margin is expected to be 14.2%, with a net internal demand of 60,152 MW and generating resources totaling 68,703 MW. ECAR's 2008 reserve margin is projected to be 17.4%, with a net internal demand of 109,357 MW and 128,406 MW of committed resources.

As this report concludes, our electric system is adequate to meet the demand of Pennsylvania's consumers for the foreseeable future. Pennsylvania needs to maintain its commitment to the basics of energy production and to encourage new initiatives in demand side response, renewable energy, and other new technologies so we can continue as a national leader in these areas.

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Section 1

Purpose

Electric Power Outlook for Pennsylvania 2003-2008 is a statistical report summarizing and discussing the current and future electric power supply and demand situation for the eight major investor-owned jurisdictional electric distribution companies (EDCs) operating within the Commonwealth and the entities responsible for maintaining the reliability of the bulk electric supply system within the region. Any comments or conclusions contained in this report do not necessarily reflect the views or opinions of the Commission or individual Commissioners. Although this report has been issued by the Commission, it is not to be considered or construed as approval or acceptance by the Commission of any of the plans, assumptions or calculations made by the EDCs or regional reliability entities and reflected in the information submitted.

The Bureau of Conservation, Economics and Energy Planning prepares this report, pursuant to Title 66, Pennsylvania Consolidated Statutes, Section 524. This report is submitted annually to the General Assembly, the Governor, the Office of Consumer Advocate and each affected public utility. The report is also made available to the general public on the Commission's web site at http://puc.state.pa.us/general/publications_reports/publications_reports_yearly.aspx.

The information contained in this report includes a brief description of the existing generation, transmission and distribution system for each EDC, highlights of the past year, information on EDCs' projections of peak load and a discussion of historical trends in electric utility forecasting. Since the eight largest EDCs operating in Pennsylvania represent approximately 99% of jurisdictional electricity sales, the smaller companies have not been included in this report.

The report also provides a regional perspective with statistical information on the projected resources and aggregate peak loads for the regional reliability councils.

Informational sources include data submitted by jurisdictional investor-owned EDCs, which is filed annually pursuant to the Commission's regulations in Title 52 of the Pennsylvania Code, Sections 57.141-57.154. Sources also include data submitted by regional reliability councils to the North American Electric Reliability Council (NERC) which is subsequently forwarded to the federal Energy Information Agency (EIA).

Regional Reliability Councils & Regional Transmission Organization

In Pennsylvania, all major electric utilities are interconnected with neighboring systems extending beyond state boundaries. These systems are organized into regional entities – regional reliability councils – which are responsible for ensuring the reliability of the electric system. The regional reliability councils in Pennsylvania are the Mid-Atlantic Area Council (MAAC) and the East Central Area Reliability Council (ECAR).

MAAC and ECAR are members of the North American Electric Reliability Council (NERC), a national organization which oversees 10 regional reliability organizations. NERC establishes criteria, standards and requirements for its members and all control areas. All control areas must operate in a manner such that system instability, uncontrolled system separation and cascading outages will not occur as a result of the most severe single contingency.

For over 35 years, MAAC and ECAR have been instrumental in maintaining a high level of electric service reliability. Through the establishment of reliability standards and operational protocols (under NERC's guidance), these councils require their member companies to provide sufficient generating capacity and transmission facilities to ensure adequate system resources for efficient operation. MAAC and ECAR also are responsible for coordinating the planning of new generation and transmission facilities.

MAAC and ECAR set forth the criteria which individual utilities and systems must follow in planning adequate levels of generating capability. Among the factors which are considered in establishing these levels are load characteristics, load forecast error, scheduled maintenance requirements and the forced outage rates of generating units.

The MAAC reliability standards require that sufficient generating capacity be installed to ensure that the probability of system load exceeding available capacity is no greater than one day in ten years. Load serving entities that are members of MAAC have a capacity obligation determined by evaluating individual system load characteristics, unit size and operating characteristics.

MAAC member companies include Metropolitan Edison Company, Pennsylvania Electric Company, PPL Electric Utilities Corporation, PECO Energy Company and UGI Utilities, Inc.

ECAR's standard for evaluating the reliability of the generation component of the bulk power supply involves the computation of the number of days per year that the ECAR Region is expected to rely on (a) generating resources outside of ECAR and (b) reducing area load to the extent that such resources are not available. This measure of performance, the Dependence on Supplemental Capacity Resources (DSCR), is used to identify critical bulk power supply situations for appropriate response by the member companies.

ECAR members include Duquesne Light Company, Pennsylvania Power Company and West Penn Power Company.

The PJM Interconnection, L.L.C. (PJM) is a formal power pool, independent system operator and Regional Transmission Organization (RTO) in the Northeast Region of NERC. PJM is the largest centrally dispatched control area in North America. PJM coordinates the operation of about 800 generation sources with a combined capacity of 106,000 MW. On May 1, 2004, PJM began managing the flow of wholesale electricity over Commonwealth Edison's 5,000 miles of transmission lines, making PJM the world's largest grid operator, meeting a peak demand of 87,000 megawatts. The PJM control area coordinates the movement of electricity through all or parts of Delaware, Illinois, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia and the District of Columbia.

On April 1, 2002, PJM West became operational, broadening the regional scope of the electric grid operator for the Mid-Atlantic region, to include Allegheny Power (and West Penn Power Company) and marking the first time, nationally, that two separate control areas are operated under a single energy market and a single governance structure. The PJM West offices located at Greensburg, Pennsylvania, provide transmission and generation coordination for the PJM West area.

Although Allegheny is in PJM West, it continues to be a member of ECAR.

PJM has signed an agreement with Duquesne Light Company (also an ECAR member) to integrate the utility into the PJM RTO by January 1, 2005. Duquesne's inclusion in this RTO would put the region's transmission facilities under common control to enhance reliability to customers. PJM has been the reliability coordinator for Duquesne since February 2003.

On June 17, 2004, the FERC affirmed American Electric Power (AEP) and PJM's planned October 1, 2004, integration date, allowing PJM to assume functional control of AEP and Dayton Power and Light's transmission. This action will bring additional transmission and generation located in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia into PJM's integrated energy market.

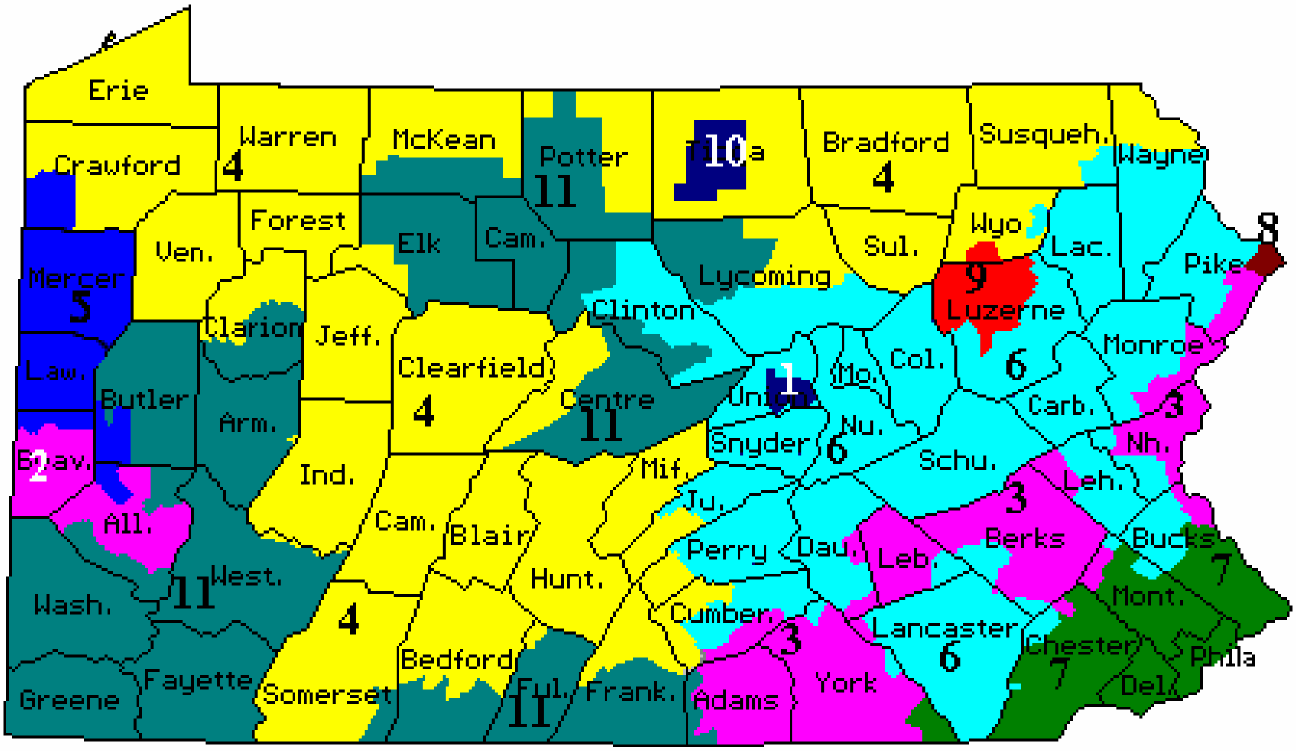
MAAC's capacity mix is 20.0% nuclear and 23.0% coal, whereas ECAR's mix is 6.2% nuclear and 66.0% coal. Natural gas is expected to be a major fuel source for new generating capacity additions, increasing to 13.3% of the total for MAAC and 27.9% for ECAR by 2008.

Regionally, generating resources are projected to be adequate for the next several years. In MAAC, the 2008 reserve margin is expected to be 14.2%, with a net internal demand of 60,152 MW and planned capacity resources totaling 68,703 MW. ECAR's 2008 reserve margin is projected to be 17.8%, with a net internal demand of 106,451 MW and 125,434 MW of committed resources.

Electric Distribution Companies

Eleven electric distribution companies (EDCs) currently serve the electrical energy needs of the majority of Pennsylvania's homes, businesses and industries. Cooperatives and municipal systems provide service to several rural and urban areas. The eleven jurisdictional EDCs (nine systems) are:

1. **Citizens' Electric Company**
2. **Duquesne Light Company**
3. **Metropolitan Edison Company (FirstEnergy)**
4. **Pennsylvania Electric Company (FirstEnergy)**
5. **Pennsylvania Power Company (FirstEnergy)**
6. **PPL Electric Utilities Corporation**
7. **PECO Energy Company (Exelon)**
8. **Pike County Light & Power Company (Orange & Rockland Utilities, Inc.)**
9. **UGI Utilities, Inc.**
10. **Wellsboro Electric Company**
11. **West Penn Power Company (Allegheny Energy, Inc.)**



Due to the deregulation of electric generation, local generating resources are now available to the competitive wholesale market. The EDCs have either entered into long-term contracts for power from traditional resources with affiliates or other generation suppliers or expect to purchase power from the wholesale market to fulfill their "provider-of-last-resort" obligations.

It is the responsibility of each load-serving entity to make provisions for adequate generating resources to serve its customers. Furthermore, section 2807(e)(3) of the Public Utility Code requires that, at the end of the transition period (the period in which the EDC recovers its stranded costs), the local EDC or Commission-approved alternate supplier must acquire electric energy at prevailing market prices for customers who contract for power which is not delivered, or for customers who do not choose an alternate supplier. EDCs must also assume the role of provider-of-last-resort for customers choosing to return to the EDC.

The Commission is in the process of developing regulations to address the EDCs' responsibilities concerning provider-of-last-resort service after the end of the transition period.

Demand Side Response Initiative

Through a collaborative process, the Commission, utility representatives and other interested parties are currently addressing ways to encourage customers to respond to peak period wholesale prices by reducing their demand for electricity. The working group is addressing existing and proposed demand side response programs, consumer education programs and appropriate methods to measure program results.

The Commission hosted a roundtable to discuss the issues related to decreasing electricity demand during peak periods. Many experts have called for developing such a demand-side response to benefit the performance of wholesale and retail electricity markets, electric reliability, and the environment.

The challenge that underlies this effort is extreme price volatility in the wholesale market during periods of peak consumption. When wholesale prices escalate during peak periods, there is a significant, lingering impact on retail prices. These price spikes and their aftermath dampen competition in retail markets because it becomes difficult for suppliers to obtain power at competitive prices.

Demand side response will increase the efficiency of the market. In other words, the price volatility in wholesale power markets has been greatly amplified by the lack of price-responsive retail demand.

Currently, most retail customers do not have a strong incentive to use less electricity during peak periods, even though wholesale prices are climbing. The reason for this is that the retail customer pays an average rate. A retail customer pays the same price for a kilowatthour of electricity on a high-demand day in the summer as the customer does on a low-demand day in the fall. During days when wholesale prices rise, inelastic retail demand exacerbates wholesale price increases.

PJM DSR Initiatives

In 2002, PJM received final approval from the FERC for an Emergency Load Response Program and for an Economic Load Response Program.

The Emergency Load Response Program is designed to provide a method by which end-use customers may be compensated by PJM for voluntarily reducing load during an emergency event. The Economic Load Response Program is designed to provide an incentive to customers or curtailment service providers to enhance the ability and opportunity for customers to reduce consumption when PJM Locational Marginal Prices (LMP) are high. Program participants have the choice of two options: a Day Ahead Option or Real Time Option. The Day Ahead Option will provide a mechanism by which any qualified market participant may offer customers the opportunity to reduce the load they draw from the PJM system in advance of real time operations and receive payments based on day ahead time LMP[1] for the reductions. The Real Time Option will provide a mechanism by which any qualified market participant may offer customers the opportunity to commit to a reduction of the load they draw from the PJM system during times of high prices and receive payments based on real time LMP for the reductions. These programs became effective on June 1, 2002, and will remain in effect until December 1, 2004.

According to PJM's State of the Market 2003 report, there was one locational emergency event during the summer of 2003 (August 15) when a total of 47 MWH were reduced over an 11-hour period with a maximum hourly load reduction of 6 MW. The maximum hourly load reduction attributable to the Economic Program was about 82 MW in 2003. It is estimated that a 1,000 MW reduction in the summer peak load would have resulted in a $10/MWH reduction in LMP and a 2,000 MW reduction would have resulted in a $15/MWH reduction in LMP.

Pennsylvania EDC Results

In the summer of 2003, the reported energy demand reduction attributable to EDCs' demand side response programs was 2,697 MWH and the aggregate peak load reduction was 528 MW.

In the short term, the purpose of Pennsylvania's demand side response initiative is to reduce peak demand and educate customers about peak price fluctuations. In the long term, the intention is to improve overall energy efficiency, maintain the integrity of the region's transmission system and mitigate the escalation of wholesale energy prices during times of peak demand.

The following is a summary of initiatives taken by the EDCs to implement demand-side response programs. Additional information is provided in individual company sections.

[1] LMP is the hourly integrated market clearing price for energy at the location the energy is delivered or received.

Sumary of EDC Demand Side Response Programs

EDC	*Program*	Description
Allegheny Power	**-- Voluntary Generation Buy-Back** **-- Real Time Pricing Pilot** **-- Distributed Generation Price Pilot Program**	**-- Allegheny Power buys-back or displaces firm load. (Large C&I)** **-- Allegheny Power calls curtailment events for temperature setbacks.(Res/Sm Comm)** **-- Customers run standby generation during peak hours. (R).**
Duquesne	**-- Voluntary Contract Load Reduction Program** **-- Direct Load Control**	**-- Customers make their generators or curtailable load available for peak load reductions. (Large C&I).** **-- Duquesne cycles A/C compressor off and on. (Res/Sm Comm)**
First Energy (Met-Ed, Penelec)	**-- Voluntary Load Reduction Programs** **-- Seasonal Savings Programs** **-- Time of Use Pilot** **-- Rider E / Rule 20** **-- Direct Load Control** **-- Distributed Generation**	**--Customers reduce specified level of hourly load. (C&I)** **--Customers contract to reduce specified level of hourly load. (C&I)** **--Residential customers shift usage from high-cost summer weekday periods.** **--Existing tariff provisions allow mandatory/semimandatory load reductions. (C&I)** **--Ongoing development for residential and small commercial customers.** **-- The companies will explore the use of distributed generation on an individualized basis.**
PECO	**-- Interruptible Rider-2** **-- "GoodWatts" Pilot**	**-- PECO notifies customer to reduce load at certain times to receive credits; or PECO compensates customer for reducing load. (Large C&I)** **-- PECO shifts air conditioning loads to off-peak periods.**
First Energy (PennPower)	**-- Real time Pricing (RTP)**	**-- Customers respond to day-ahead hourly signals. (C&I)**
PPL	**-- Demand Side Initiative Rider (DSI)** **-- Demand Side Response Rider** **-- Interruptible Service – Economic Provisions** **-- Interruptible Service – Emergency Provisions** **-- Price Response Service**	**-- Customers may respond to changes in the electric generation market by adjusting their load requirements. (C& I)** **-- Eligible residential customers may shift energy usage away from peak demand hours. (Res)** **-- Permits PPL to request customers to reduce load for economic conditions.** **-- Permits PPL to request customers to reduce load for emergency conditions.** **-- Permits customers to respond to market price signals with a portion of their load.**
UGI	**-- Voluntary Load Reduction Pilot Program** **-- Time-of-Use (Rate RTU)**	**-- Customers receive a monetary incentive to curtail load. (C&I)** **-- Time differentiated rate where residential customers pay higher prices during pre-defined on-peak hours. (Res)**

Section 2

2003: A Year in Review

The eight largest EDCs operating in Pennsylvania delivered approximately 99% of the jurisdictional companies' electrical energy needs. Aggregate sales in 2003 totaled approximately 137.9 billion kilowatthours (KWH), a 0.2% increase from that of 2002 and approximately 4.0% of the United States' total sales. Residential sales led the Pennsylvania market capturing 34.1% of the total sales, followed by industrial (33.4%) and commercial (30.2%). Aggregate non-coincident peak load dropped to 26,836 MW in 2003, down 4.1% from 2002. See Tables 2.1 and 2.2 below.

Table 2.1. Energy Demand, Peak Load and Customers Served (2003)

EDC	Total Customers Served	Residential (MWH)	Commercial (MWH)	Industrial (MWH)	Other (MWH)	Sales For Resale (MWH)	Total Consumption (MWH)	System Losses (MWH)	Company Use (MWH)	Net Energy For Load (MWH)	Peak Load (MW)
Duquesne	587,899	3,758,737	6,345,609	3,189,067	69,678	211,764	13,574,855	757,915	31,687	14,364,457	2,686
Met-Ed	516,559	4,894,672	4,017,843	3,985,660	35,604	633	12,934,412	1,074,482	n/a	14,008,894	2,438
Penelec	585,112	4,186,693	4,727,317	4,391,097	41,344	699	13,347,150	1,038,655	n/a	14,385,805	2,308
Penn Power	155,929	1,513,000	1,291,100	1,480,800	6,400	5,200	4,296,500	250,950	6,950	4,554,400	855
PECO	1,530,505	12,258,656	8,077,251	15,518,212	896,922	14,400	36,765,442	2,573,581	89,975	39,428,998	7,696
PPL	1,329,781	13,266,164	12,273,458	9,598,860	287,041	1,037,543	36,463,066	2,684,861	92,028	39,239,955	7,197
UGI	61,780	516,201	345,335	111,986	5,538	64	979,124	57,377	1,898	1,038,399	201
West Penn	696,855	6,640,582	4,529,422	7,747,364	52,213	641,890	19,611,471	1,202,523	n/a	20,813,994	3,455
Total	5,464,420	47,034,705	41,607,335	46,023,046	1,394,740	1,912,193	137,972,020	9,640,344	222,538	147,834,902	26,836
% of Total		34.09%	30.16%	33.36%	1.01%	1.39%	100.00%				
2003 v 2002	0.66%	1.64%	0.55%	-0.82%	-16.06%	-4.48%	0.18%	-3.18%	-11.01%	-0.06%	-4.07%

Table 2.2. Energy Demand, Peak Load and Customers Served (2002)

EDC	Total Customers Served	Residential (MWH)	Commercial (MWH)	Industrial (MWH)	Other (MWH)	Sales For Resale (MWH)	Total Consumption (MWH)	System Losses (MWH)	Company Use (MWH)	Net Energy For Load (MWH)	Peak Load (MW)
Duquesne	587,439	3,924,096	6,457,535	3,328,366	70,133	194,493	13,974,623	815,365	33,043	14,823,031	2,886
Met-Ed	510,093	4,720,617	3,984,966	4,012,022	34,844	607	12,753,056	1,204,631	n/a	13,957,687	2,616
Penelec	584,923	4,167,102	4,696,659	4,314,670	41,301	515	13,220,247	1,000,896	n/a	14,221,143	2,693
Penn Power	155,112	1,533,300	1,268,200	1,504,700	6,200	5,200	4,317,600	252,000	6,950	4,576,563	869
PECO	1,530,390	12,335,116	8,019,454	15,322,901	952,745	174,918	36,805,134	2,576,359	98,651	39,480,144	8,164
PPL	1,306,443	12,639,799	12,116,751	9,852,700	499,174	1,007,282	36,115,706	2,611,213	109,571	38,836,490	6,970
UGI	61,719	495,113	337,855	112,070	4,981	46	950,065	58,163	1,866	1,010,094	195
West Penn	692,644	6,458,857	4,496,820	7,957,010	52,133	618,825	19,583,645	1,438,860	n/a	21,022,505	3,582
Total	5,428,763	46,274,000	41,378,240	46,404,439	1,661,511	2,001,886	137,720,076	9,957,487	250,081	147,927,657	27,975
% of Total		33.60%	30.05%	33.69%	1.21%	1.45%	100.00%				

Between 1988 and 2003, the state's energy demand grew at an average rate of 1.5% annually. Residential sales grew at an annual rate of 1.8%, commercial at 3.0% and industrial at 0.03%.

The current aggregate 5-year projection of growth in energy demand is 1.5%. This includes a residential growth rate of 1.3%, a commercial rate of 2.4% and an industrial rate of 0.8%. See Figure 2.1 below. Gigawatthours are a measure of energy sales over time and megawatts are a measure of the instantaneous peak usage of electricity.

Figure 2.1
Historic & Forecast Energy Demand

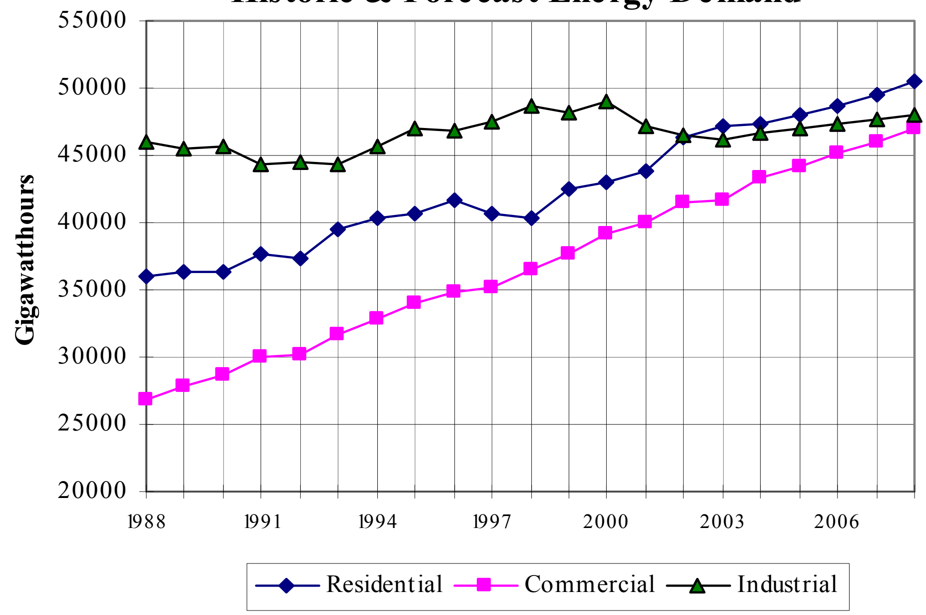
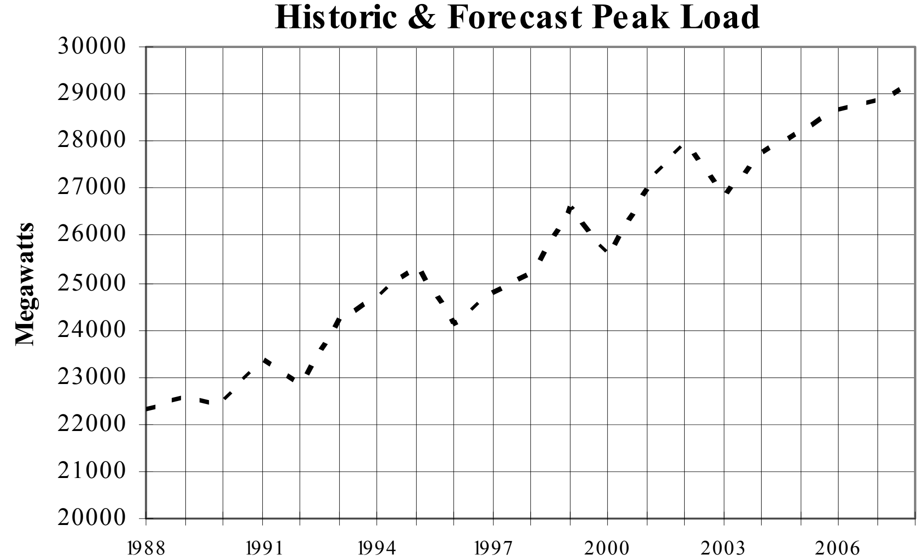


Figure 2.2
Historic & Forecast Peak Load



In 2003, Pennsylvania's EDCs purchased nearly 8.9 million MWH from independent power producers (IPPs). Table 2.3 below shows the amount of purchased energy by each EDC, the percentage of net energy for load represented by the purchases and contracted capacity, both online and future.

Table 2.3. Purchases from IPPs or QFs by Pennsylvania EDCs

Company	2003 Purchased Energy (MWH)	Percent of Net Energy For Load	On Line Contract Capacity (MW)	Future Contract Capacity (MW)
Duquesne	0	0.00%	0	0
Met-Ed	2,272,292	16.22%	295	295
Penelec	2,900,339	20.16%	399	399
Penn Power	183	0.00%	0	0
PPL	2,337,805	5.96%		
PECO	283,850	0.70%	223	223
West Penn	1,092,458	5.25%	136	136
Pennsylvania	8,886,927	6.05%	1,053	1,053

Also, in 2003, electric generation suppliers (EGSs) provided 12 million MWH to Pennsylvania customers, or about 8.2% of total resources. See Table 2.4 below.

Table 2.4. Summary of Resources (MWH)

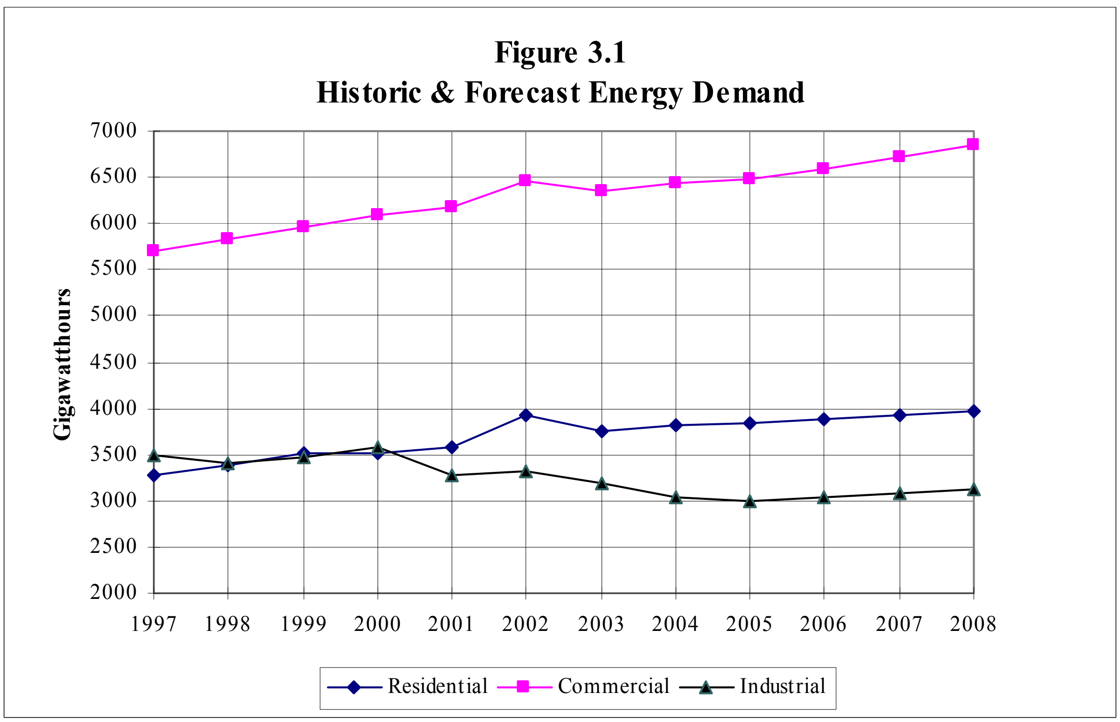
Company	EDC Purchases	IPP & QF Purchases	EGS Resources	Net Resources
Duquesne	10,384,901	0	3,917,846	14,302,747
Met-Ed	9,811,620	2,272,292	1,924,982	14,008,894
Penelec	9,222,855	2,900,339	1,885,611	14,008,805
Penn Power	4,547,135	183	7,082	4,554,400
PPL	36,028,241	2,337,805	873,909	39,239,955
PECO	35,677,824	283,850	3,467,324	39,428,998
West Penn	21,046,143	1,092,458	0	22,138,601
Pennsylvania	126,718,719	8,886,927	12,076,754	147,682,400

Summary of EDC Data

Duquesne Light Company

Duquesne Light Company (Duquesne) provides service to 587,899 electric utility customers in southwestern Pennsylvania. In 2003, Duquesne had energy sales totaling 13.6 billion kilowatthours (KWH) -- down 2.9% from 2002. Commercial sales continued to dominate Duquesne's market with 46.7% of the total sales, followed by residential (27.7%) and industrial (23.5%).

Between 1988 and 2003, Duquesne's total energy demand increased about 1.0% per year. Residential demand grew at an annual rate of 1.2% over the past 15 years, with an increase in commercial energy demand at an average of 1.5% per year. Industrial energy demand declined at an average rate of 0.2 percent for the period.



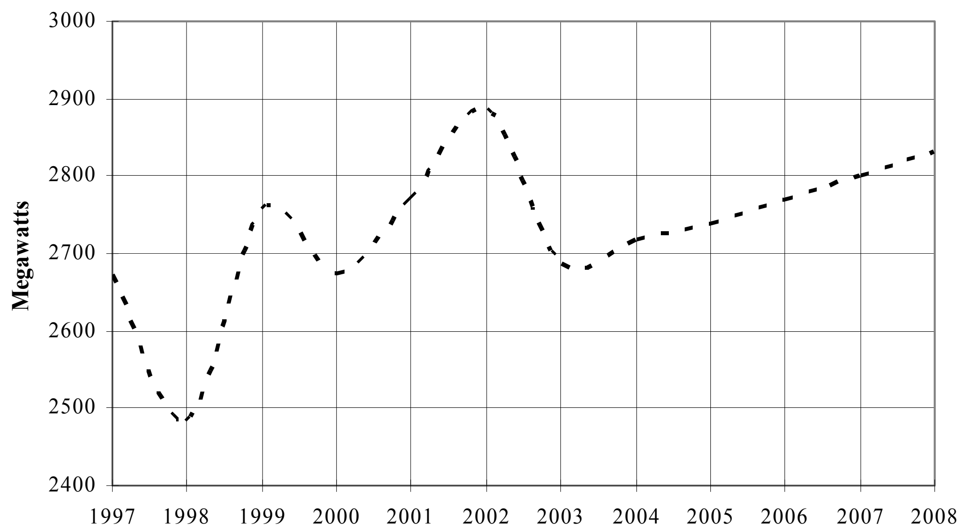
The current 5-year projection of average growth in total energy consumption is about 1.0% per year. This includes a residential growth rate of 1.1%, a commercial growth rate of 1.5% and an industrial decline in energy demand of 0.4% per year.

Duquesne's summer peak load, occurring on August 21, 2003, was 2,686 megawatts (MW), representing a decrease of 6.9% from last year's peak of 2,886

MW. The 2003/2004 winter peak load was 2,074 MW or 2.2% lower than that of the previous year.

The actual average annual peak load growth rate over the past fifteen years was 0.8%. Duquesne's forecast shows the peak load increasing from 2,686 MW in the summer of 2003 to 2,831 MW in 2008, or an average annual growth rate of 1.1%.

Figure 3.2
Historic & Forecast Peak Load



Tables 3.1-3.4 on pages 13 and 14 provide Duquesne's forecasts of peak load and residential, commercial and industrial energy demand from 1994 through 2004.

On January 1, 2005, Duquesne will join the PJM regional transmission organization, as part of its POLR III (Provider of Last Resort) proposal, to ensure a stable, plentiful supply of electricity for its customers.

For calendar year 2003, six electric generation suppliers sold a total of 3.9 billion KWH to retail customers in Duquesne's service territory, or about 28.9% of total consumption.

Duquesne reports that one EGS failed to deliver between 100 and 150 MW per hour to meet its customers' load for over 20 hours in 2003 during transmission load relief procedures. Also, during the August 14, 2003, blackout, between 100 and 550 MW per hour of energy supply schedules were curtailed for over 7 hours. During this period, generation and load were balanced through PJM energy purchases and the use of the ECAR Automatic Reserve Sharing system. No Duquesne customers were interrupted.

Duquesne has implemented a Pilot Voluntary Load Reduction Program available to commercial and industrial customers with the flexibility to curtail load or utilize on-site generating facilities during periods of peak market prices. A peak load reduction of 31.5 MW and 115.7 million KWH in energy savings are anticipated for 2004. This represents 1.2% of the 2003 peak load and 0.9% of annual sales. Also, a Pilot Direct Load Control Program is being implemented for residential and commercial customers in which air conditioning units will be shut off or cycled during periods of high temperature.

Table 3.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	2535	2324										
1995	2666	2352	2355									
1996	2463	2351	2346	2537								
1997	2671	2373	2390	2599	2583							
1998	2484	2392	2401	2634	2614	2614						
1999	2756	2412	2413	2652	2632	2632	2715					
2000	2673	2442	2433	2671	2653	2653	2736	2638				
2001	2771	2472	2452	2690	2677	2677	2757	2661	2661			
2002	2886	2501	2472	2709	2702	2702	2776	2682	2682	2850		
2003	2686	2533	2490	2728	2727	2727	2798	2702	2702	2884	2822	
2004			2511	2749	2754	2754		2723	2723	2912	2841	2719
2005				2769	2782	2782			2743	2934	2855	2740
2006					2810	2810				2953	2870	2771
2007						2839					2884	2801
2008												2831

Table 3.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	3219	3234										
1995	3379	3279	3190									
1996	3321	3303	3207	3175								
1997	3274	3324	3221	3167	3228							
1998	3382	3350	3237	3171	3234	3234						
1999	3526	3371	3254	3176	3240	3240	3366					
2000	3509	3396	3271	3181	3249	3249	3383	3610				
2001	3584	3425	3288	3187	3258	3258	3400	3643	3643			
2002	3924	3453	3305	3192	3267	3267	3415	3681	3681	3671		
2003	3759	3483	3322	3198	3276	3276	3432	3716	3716	3726	3697	
2004			3339	3204	3287	3287		3759	3759	3772	3721	3811
2005				3210	3297	3297			3780	3810	3744	3832
2006					3210	3307				3846	3767	3879
2007						3318					3791	3925
2008												3978

Table 3.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	5563	5570										
1995	5729	5748	5703									
1996	5737	5850	5818	5732								
1997	5703	5949	5908	5757	5858							
1998	5826	6033	6017	5824	5945	5945						
1999	5954	6117	6131	5910	6039	6039	5983					
2000	6092	6209	6247	6005	6159	6159	6073	6113				
2001	6170	6299	6359	6102	6301	6301	6157	6231	6231			
2002	6458	6385	6469	6198	6450	6450	6236	6336	6336	6324		
2003	6346	6477	6577	6295	6606	6606	6327	6438	6438	6467	6436	
2004			6693	6400	6773	6773		6540	6540	6570	6505	6428
2005				6505	6944	6944			6628	6653	6570	6479
2006					7118	7118				6729	6636	6597
2007						7296					6703	6713
2008												6841

Table 3.4

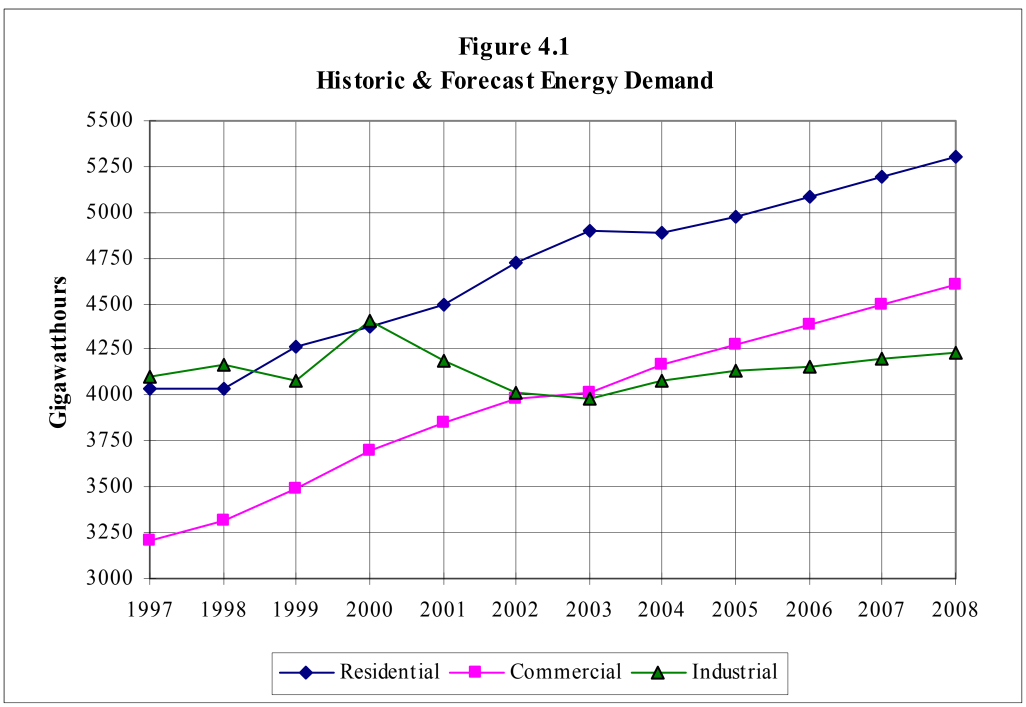
Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	3256	3149										
1995	3237	3293	3362									
1996	3285	3342	3423	3349								
1997	3501	3401	4367	3717	3431							
1998	3412	3451	4335	3941	3690	3690						
1999	3481	3484	4398	4013	3828	3828	3771					
2000	3581	3519	4461	4086	3919	3919	3836	3537				
2001	3283	3554	4526	4160	3988	3988	3901	3576	3576			
2002	3328	3591	4591	4236	4059	4059	3964	3615	3615	3315		
2003	3189	3631	4655	4313	4130	4130	4027	3651	3651	3382	3349	
2004			4717	4393	4202	4202		3695	3695	3445	3415	3031
2005				4474	4276	4276			3742	3491	3437	2990
2006					4351	4351				3530	3453	3033
2007						4427					3471	3075
2008												3123

Metropolitan Edison Company

Metropolitan Edison Company (Met-Ed) provides service to over 516,000 electric utility customers in eastern and south central Pennsylvania. In 2003, Met-Ed had total energy sales of 12.9 billion kilowatthours (KWH) - - up 1.4% from 2002. Residential sales dominated Met-Ed's market with 37.8% of the total sales, followed by commercial (31.1%) and industrial (30.8%).

Between 1988 and 2003, Met-Ed's energy demand grew at an average rate of 2.3% per year. Residential and commercial sales have maintained relatively steady growth over the period (2.8% for residential and 3.9% for commercial), while industrial sales have fluctuated considerably. Industrial sales grew at an average rate of about 0.5%.

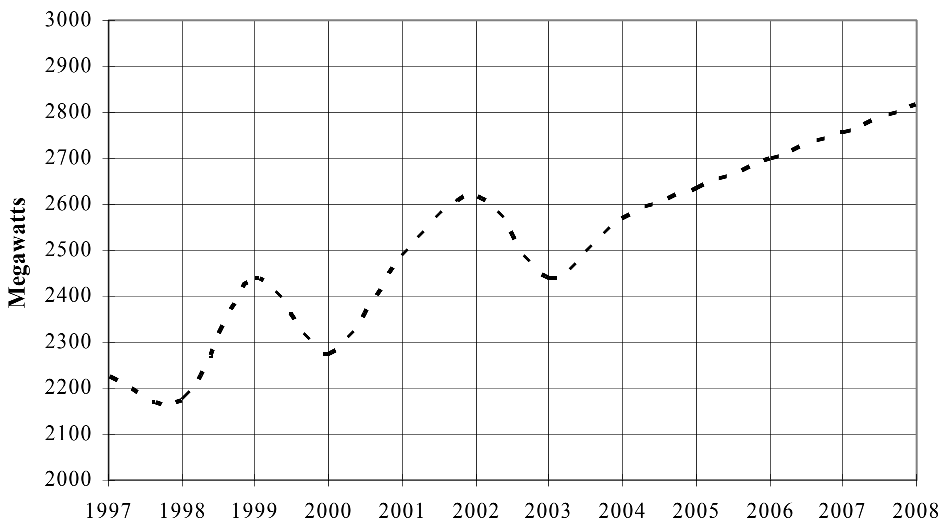
The current five-year projection of growth in total energy demand is 1.9%. This includes a residential growth rate of 1.6%, a commercial growth rate of 2.7% and an industrial rate of 1.2%.



Met-Ed's summer peak load, occurring on August 21, 2003, was 2,438 megawatts (MW), representing a decrease of 6.8% from last year's all time system peak of 2,616 MW. The 2003/04 winter peak load was 2,359 MW or 1.5% lower than the previous year's winter peak of 2,394 MW.

The actual average annual peak load growth rate over the past fifteen years was 2.0%. Met-Ed's forecast shows its peak load increasing from 2,438 MW to 2,817 MW by 2008, or an average annual growth rate of 2.9%.

Figure 4.2
Historic & Forecast Peak Load



Tables 4.1-4.4 on pages 17 and 18 provide Met-Ed's forecasts of peak load and residential, commercial and industrial energy demand from 1994 through 2004.

Met-Ed is a wholly owned subsidiary of FirstEnergy Corporation. Met-Ed was formerly a subsidiary of GPU Corporation. Met-Ed is a member of the PJM Interconnection and the Mid-Atlantic Area Council.

Met-Ed retains Provider of Last Resort (PLR) responsibility for those customers who do not choose an alternate energy supplier.

Met-Ed divested most of its generation facilities in 1999. Met-Ed currently retains ownership of the York Haven generating station, which has a combined generating capacity of 19.4 MW.

In 2003, Met-Ed purchased approximately 2.3 billion KWH from cogeneration and small power production projects. Contract capacity (defined as PJM installed capacity credits) is 295 MW. For calendar year 2003, seven electric generation suppliers sold a total of over 1.9 billion KWH to retail customers in Met-Ed's service territory, or about 14.9% of total consumption.

Met-Ed’s only active conservation program is a low-income weatherization program (LIURP), which includes the installation of a variety of weatherization measures in the homes of customers with electric heat and/or electric water heating and/or high baseload use. In addition, 95 time-of-day conversions were made. Nearly $1.6 million was spent in 2003 for a peak load reduction of 56 KW, a load shift of 53 KW and energy savings totaling 447,922 KWH.

Table 4.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	2000	1999										
1995	2186	2041	2042									
1996	2017	2086	2080	2094								
1997	2224	2129	2113	2139	2139							
1998	2176	2170	2147	2176	2176	2194						
1999	2439	2216	2192	2205	2205	2233	2263					
2000	2274	2255	2229	2228	2228	2268	2318	2404				
2001	2486	2293	2263	2264	2264	2305	2373	2456	2455			
2002	2616	2331	2299	2303	2303	2343	2429	2508	2504	2503		
2003	2438	2367	2333	2345	2345	2386	2486	2559	2553	2554	2527	
2004			2369	2388	2388	2429		2612	2602	2611	2584	2570
2005				2432	2432	2472			2652	2668	2639	2634
2006					2475	2515				2725	2691	2702
2007						2559					2747	2756
2008												2817

Table 4.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	3921	3894										
1995	3925	4007	3892									
1996	4135	4114	3972	3961								
1997	4034	4203	4047	4028	4028							
1998	4040	4287	4121	4041	4041	4122						
1999	4266	4364	4203	4095	4095	4204	4264					
2000	4377	4446	4286	4152	4152	4264	4352	4344				
2001	4496	4522	4359	4222	4222	4328	4442	4430	4430			
2002	4721	4597	4438	4292	4292	4391	4533	4516	4501	4607		
2003	4895	4677	4508	4361	4361	4451	4624	4602	4577	4708	4846	
2004			4582	4430	4430	4513		4687	4651	4804	4860	4885
2005				4499	4499	4575			4724	4892	4980	4977
2006					4571	4636				4988	5094	5083
2007						4697					5211	5190
2008												5300

Table 4.3

	Actual	Projected Commercial Energy Demand (Gigawatthours)										
	Energy											
Year	**Demand**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
1994	2921	2878										
1995	3011	2961	2959									
1996	3144	3055	3037	3026								
1997	3209	3146	3117	3106	3106							
1998	3209	3237	3209	3179	3179	3224						
1999	3487	3328	3304	3258	3258	3306	3414					
2000	3699	3427	3397	3338	3338	3389	3518	3518				
2001	3855	3518	3497	3420	3420	3473	3622	3622	3751			
2002	3985	3608	3611	3512	3512	3567	3732	3732	3860	3976		
2003	4018	3700	3724	3607	3607	3663	3841	3837	3970	4096	4057	
2004			3835	3703	3703	3762		3947	4079	4216	4144	4170
2005				3805	3805	3864			4189	4336	4258	4281
2006					3912	3972				4456	4363	4388
2007						4083					4464	4498
2008												4601

Table 4.4

	Actual	Projected Industrial Energy Demand (Gigawatthours)										
	Energy											
Year	**Demand**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
1994	3861	3757										
1995	3957	3821	3888									
1996	4033	3891	3956	3985								
1997	4097	3974	4019	4064	4064							
1998	4173	4078	4110	4132	4132	4136						
1999	4085	4182	4205	4197	4197	4229	4239					
2000	4412	4277	4291	4294	4294	4305	4307	4313				
2001	4186	4367	4376	4389	4389	4370	4365	4352	4312			
2002	4012	4458	4463	4468	4468	4448	4435	4410	4409	4263		
2003	3986	4547	4552	4535	4535	4560	4506	4459	4490	4341	3954	
2004			4644	4627	4627	4664		4508	4567	4419	3989	4080
2005				4724	4724	4776			4645	4498	4010	4136
2006					4810	4876				4577	4030	4162
2007						4964					4050	4206
2008												4237

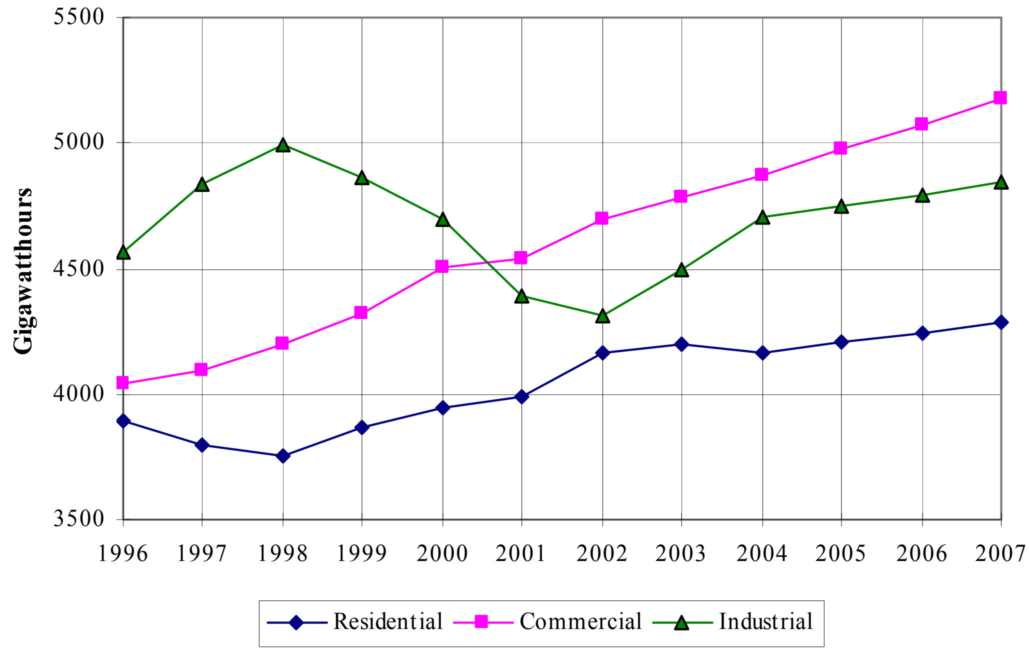
Pennsylvania Electric Company

Pennsylvania Electric Company (Penelec) provides service to over 585,000 electric utility customers in western and northern Pennsylvania. In 2003, Penelec had energy sales totaling 13.3 billion kilowatthours (KWH) - - up about 1.0% from 2002. Commercial sales dominated Penelec's market with 35.4% of the total sales, followed by industrial (32.9%) and residential (31.4%).

Between 1988 and 2003, Penelec's energy demand grew at an average rate of 0.9% per year. Residential and commercial sales have maintained relatively steady growth over the period (1.4% for residential and 3.1% for commercial), while industrial sales have fluctuated greatly. Industrial sales for 2003 were 14.8% less than the 1988 level, or an average annual decrease of 1.1%.

The current five-year projection of growth in total energy demand is 1.4%. This includes a residential growth rate of 0.7%, a commercial growth rate of 1.7% and an industrial growth rate of 1.9%.

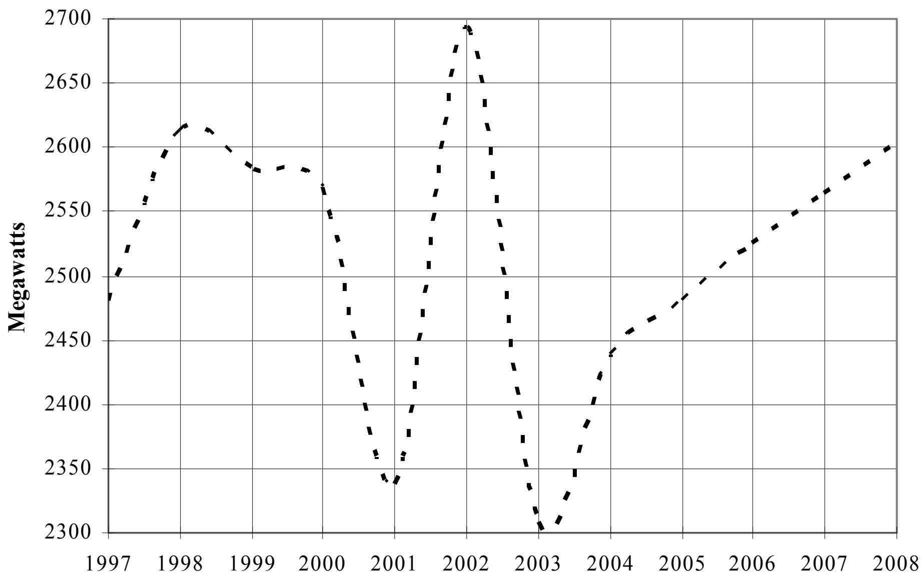
Figure 5.1
Historic & Forecast Energy Demand



Penelec's 2003 summer peak load, occurring on August 14, 2003, was 2,308 megawatts (MW), representing a decrease of 14.3% from last year's summer peak of 2,693 MW. The 2003/04 winter peak load was 2,290 MW or 14.0% lower than the previous year's winter peak of 2,663 MW.

The actual average annual peak load growth rate over the past fifteen years was 0.9%. Penelec's forecast shows its peak load increasing from 2,308 MW in 2003 to 2,604 MW in 2008, or an average increase of 1.4%.

Figure 5.2
Historic & Forecast Peak Load



Tables 5.1-5.4 on pages 21 and 22 provide Penelec's forecasts of peak load and residential, commercial and industrial energy demand from 1994 through 2004.

Penelec is a wholly owned subsidiary of FirstEnergy Corporation. Penelec was formerly a subsidiary of GPU Corporation. Penelec is a member of the PJM Interconnection and the Mid-Atlantic Area Council.

Penelec retains Provider of Last Resort (PLR) responsibility for those customers who do not choose an alternate energy supplier.

Penelec divested most of its generation facilities in 1999. Penelec owns no generation.

In 2003, Penelec purchased approximately 2.9 billion KWH from cogeneration and small power production projects. Contract capacity (defined as PJM installed capacity credits) is 399.4 MW.

For calendar year 2003, 22 electric generation suppliers sold a total of 1.9 billion KWH to retail customers in Penelec's service territory, or about 14.1% of total consumption, up from 6.5% in 2002.

Penelec's only active conservation program is a low-income weatherization program, which includes the installation of a variety of weatherization measures in the homes of customers with electric heat and/or electric water heating and/or high baseload use. In addition, 23 time-of-day conversions were made. Over $1.7 million was spent in 2003 for a peak load reduction of 179 KW and energy savings totaling 1.2 million KWH.

Table 5.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	2538	2519										
1995	2589	2578	2584									
1996	2652	2651	2641	2706								
1997	2481	2727	2758	2743	2751							
1998	2613	2717	2790	2728	2742	2688						
1999	2583	2775	2795	2769	2795	2730	2672					
2000	2569	2808	2893	2818	2855	2772	2704	2651				
2001	2337	2842	2916	2867	2904	2813	2737	2675	2321			
2002	2693	2875	2967	2914	2951	2853	2770	2700	2347	2337		
2003	2308	2507	3056	2527	2564	2472	2804	2737	2373	2375	2410	
2004			2526	2567	2604	2506		2760	2399	2405	2456	2438
2005				2606	2643	2540			2425	2437	2505	2481
2006					2682	2573				2465	2544	2525
2007						2606					2592	2565
2008												2604

Table 5.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	3773	3719										
1995	3765	3770	3772									
1996	3897	3817	3820	3813								
1997	3801	3859	3876	3853	3853							
1998	3756	3893	3920	3890	3890	3870						
1999	3864	3928	3961	3921	3921	3922	3894					
2000	3949	3961	3999	3948	3948	3950	3931	3881				
2001	3991	3986	4030	3982	3982	3979	3968	3915	3977			
2002	4167	4008	4064	4015	4015	4009	4007	3951	4021	4043		
2003	4187	4036	4084	4046	4046	4039	4045	3984	4065	4089	4194	
2004			4126	4077	4077	4069		4017	4109	4134	4162	4135
2005				4109	4109	4099			4154	4180	4203	4186
2006					4139	4129				4226	4245	4236
2007						4160					4287	4287
2008												4339

Table 5.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	3794	3713										
1995	3922	3809	3828									
1996	4044	3901	3934	4031								
1997	4098	3979	4041	4156	4156							
1998	4198	4054	4131	4282	4282	4283						
1999	4319	4122	4212	4388	4388	4408	4347					
2000	4509	4193	4292	4495	4495	4531	4459	4387				
2001	4538	4242	4389	4600	4600	4658	4571	4473	4472			
2002	4697	4291	4486	4695	4695	4784	4684	4558	4549	4613		
2003	4727	4333	4586	4795	4795	4908	4797	4643	4626	4730	4782	
2004			4682	4898	4898	5031		4728	4704	4846	4874	4825
2005				4995	4995	5152			4781	4962	4976	4912
2006					5099	5270				5078	5076	4986
2007						5386					5178	5060
2008												5136

Table 5.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	4449	4425										
1995	4463	4537	4538									
1996	4563	4678	4632	4809								
1997	4836	4783	4796	5054	5054							
1998	4996	4863	4854	5172	5172	4836						
1999	4866	4929	4912	5235	5235	4894	5047					
2000	4698	4989	4960	5309	5309	4948	5114	5004				
2001	4392	5037	5008	5363	5363	5002	5205	5093	4857			
2002	4315	5077	5057	5411	5411	5057	5293	5177	5144	4670		
2003	4391	5116	5107	5460	5460	5113	5383	5239	5214	4783	4492	
2004			5158	5515	5515	5169		5306	5244	4846	4708	4561
2005				5570	5570	5226			5274	4887	4749	4666
2006					5637	5284				4928	4797	4737
2007						5342					4845	4791
2008												4815

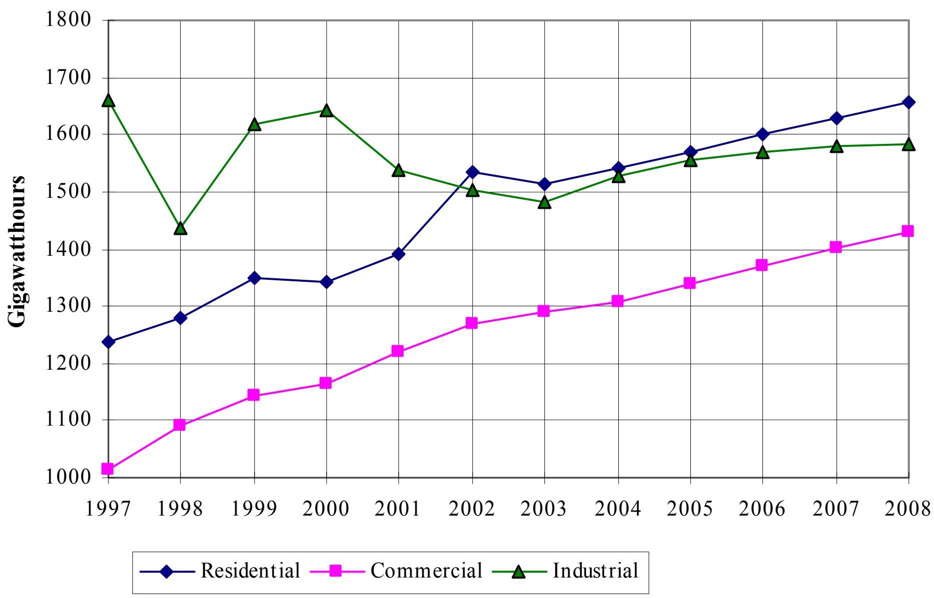
Pennsylvania Power Company

Pennsylvania Power Company (Penn Power) provides service to nearly 156,000 electric utility customers in western Pennsylvania. In 2003, Penn Power had energy sales totaling 4.3 billion kilowatthours (KWH) - - a decrease of 0.5% from the 2002 figure. Residential sales lead Penn Power's market with 35.2% of the total sales, followed by industrial (34.5%) and commercial (30.1%).

Between 1988 and 2003, Penn Power's energy demand grew at an average rate of 1.3% per year. Residential and commercial sales have maintained relatively steady growth over the period at rates of 2.7% and 4.5%, respectively. Industrial sales have fluctuated considerably and, in 2003, were only 78.9% of the 1988 level, or an average annual decline of 1.6%.

The current five-year projection of growth in total energy demand is 1.7%. This includes a residential growth rate of 1.8%, a commercial growth rate of 2.1% and an industrial rate of 1.3%.

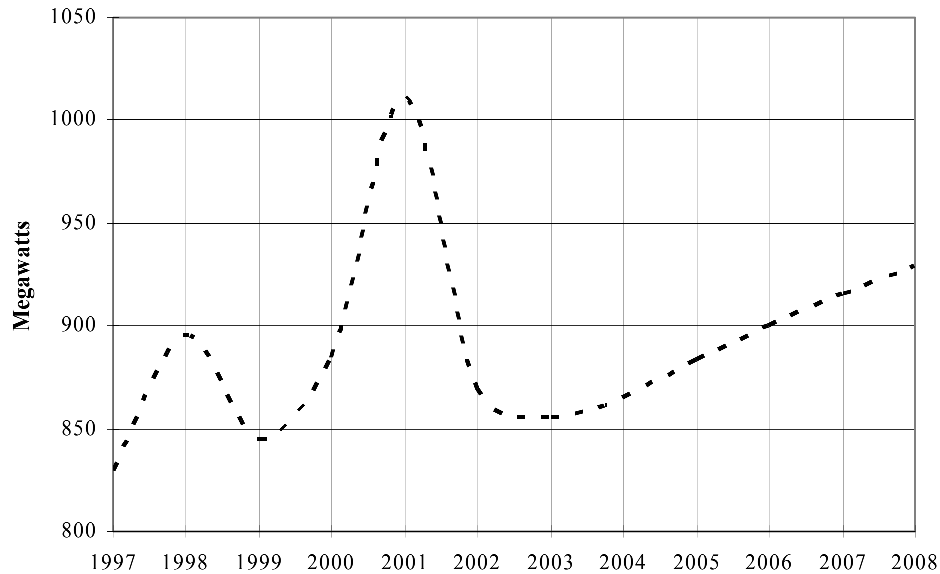
Figure 6.1
Historic & Forecast Energy Demand



Penn Power's 2003 summer peak load, occurring on August 14, 2003, was 855 megawatts (MW), representing a decrease of 1.6% from last year's peak of 869 MW. The 2003/04 winter peak load of 864 MW was 3.0% higher than the previous year's winter peak of 839 MW.

The actual average annual peak load growth rate over the past fifteen years was 1.7%. Penn Power's forecast shows its peak load increasing from 855 MW in the summer of 2003 to 929 MW by 2008, or an average annual growth rate of 1.7%. Penn Power's peak load represents about 7.6% of FirstEnergy's peak load.

Figure 6.2
Historic & Forecast Peak Load



Tables 6.1-6.4 on pages 25 and 26 provide Penn Power's forecasts of peak load and residential, commercial and industrial energy demand from 1994 through 2004.

The electrical systems of Penn Power and the other FirstEnergy operating companies are interconnected and fully integrated. As of January 1, 2004, Penn Power owned 1,237 MW of the First Energy system's generating capacity.

For calendar year 2003, two electric generation suppliers sold a total of nearly 7.1 million KWH to retail customers in Penn Power's service territory or about 0.2% of total consumption, down from 0.3% in 2002. Penn Power purchased 183 thousand KWH from an independent power producer in 2003.

Penn Power now offers a Real Time Pricing Program (RTP) which provides the customer the option to manage its load by reacting to market-driven day ahead prices on an hourly basis, where the customer can reduce its load during periods of high energy prices, increase load to take advantage of market conditions or shift loads to periods of lower prices.

Table 6.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	706	655										
1995	835	670	717									
1996	784	680	752	759								
1997	829	689	792	781	781							
1998	895	703	807	804	804	902						
1999	845	717	825	831	830	919	880					
2000	885	732	844	858	858	937	897	935				
2001	1011	747	862	892	892	958	919	957	883			
2002	869	763	879	928	928	980	941	980	904	918		
2003	855	777	897	962	962	1003	963	1003	930	947	891	
2004			914	997	997	1026	983	1025	956	983	923	865
2005				1019	1019	1050			982	1022	958	884
2006					977	1012				1058	985	900
2007						1036					1020	916
2008												929

Table 6.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	1178	1103										
1995	1195	1126	1166									
1996	1254	1130	1179	1211								
1997	1238	1132	1189	1238	1238							
1998	1278	1142	1195	1265	1265	1300						
1999	1351	1152	1201	1292	1292	1318	1300					
2000	1341	1162	1220	1320	1320	1336	1319	1390				
2001	1391	1179	1235	1373	1373	1355	1339	1412	1360			
2002	1533	1196	1251	1430	1430	1374	1360	1434	1395	1447		
2003	1513	1207	1267	1459	1459	1398	1381	1457	1430	1483	1512	
2004			1283	1488	1488	1423	1403	1479	1451	1520	1523	1542
2005				1502	1502	1445			1473	1558	1552	1571
2006					1516	1467				1597	1579	1599
2007						1494					1607	1629
2008												1657

Table 6.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	891	850										
1995	938	881	893									
1996	996	897	903	936								
1997	1013	914	928	970	970							
1998	1090	934	953	1010	1010	1042						
1999	1143	955	976	1054	1054	1074	1110					
2000	1164	977	1008	1103	1103	1108	1145	1204				
2001	1220	999	1039	1167	1167	1143	1181	1242	1162			
2002	1268	1021	1070	1238	1238	1182	1221	1284	1206	1270		
2003	1291	1042	1101	1314	1314	1221	1262	1327	1251	1327	1279	
2004			1131	1395	1395	1262	1304	1372	1293	1387	1310	1309
2005				1436	1436	1304			1335	1449	1342	1339
2006					1478	1348				1514	1373	1370
2007						1392					1405	1402
2008												1429

Table 6.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	1293	1170										
1995	1558	1163	1499									
1996	1693	1187	1703	1894								
1997	1659	1208	1902	1967	1967							
1998	1436	1242	1935	2002	2002	1677						
1999	1619	1273	1966	2043	2043	1716	1483					
2000	1643	1305	2002	2082	2082	1759	1520	1563				
2001	1539	1337	2039	2138	2138	1803	1558	1596	1618			
2002	1505	1377	2077	2184	2184	1847	1596	1635	1644	1514		
2003	1481	1409	2114	2230	2230	1890	1633	1673	1677	1516	1521	
2004			2149	2273	2273	1933	1670	1711	1716	1517	1507	1529
2005				2314	2314	1981			1758	1519	1500	1555
2006					2357	2029				1520	1493	1570
2007						2076					1489	1580
2008												1583

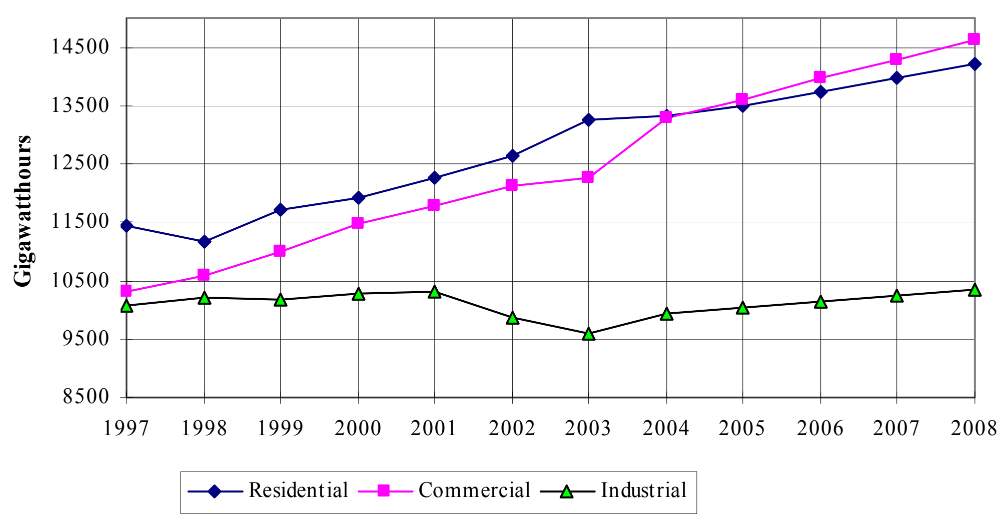
PPL Electric Utilities Corporation

PPL Electric Utilities Corporation (PPL) provides service to over 1.3 million homes and businesses over a 10,000 square mile area in 29 counties of central eastern Pennsylvania. In 2003, PPL had energy sales totaling 36.5 billion kilowatthours (KWH) -- up 1.0% from 2002. Residential sales continued to dominate PPL's market with 36.4% of the total sales, followed by commercial (33.7%) and industrial (26.3%).

Between 1988 and 2003, PPL's energy demand grew an average of 1.9% per year. Residential energy sales grew at an annual rate of 2.0%, commercial at a 3.0% rate and industrial at 0.6%.

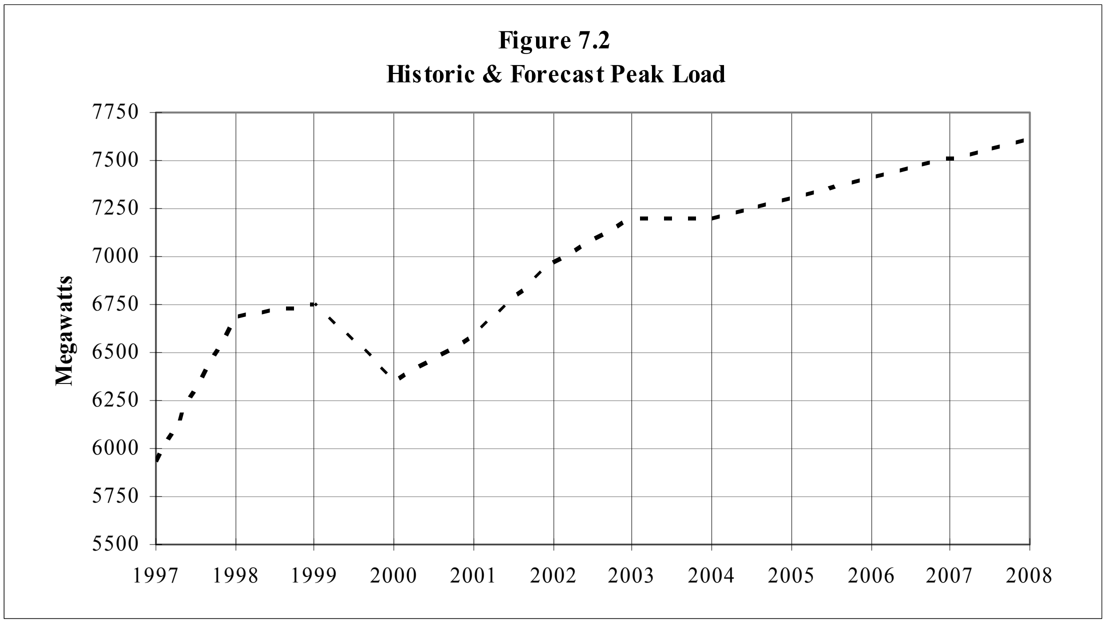
The current five-year projection of average growth in energy demand is 2.2%. This includes growth rates of 1.4% for residential, 3.6% for commercial and 1.5% for industrial.

Figure 7.1
Historic & Forecast Energy Demand



PPL's 2003/04 winter peak load, occurring on January 16, 2004, was 7,197 megawatts (MW), representing an increase of 3.3% from last year's peak of 6,970 MW. The 2003 summer peak load was 6,433 MW or 6.8% below the previous summer's peak of 6,906 MW.

The actual average annual peak load growth rate over the past fifteen years was 1.7%. PPL's five-year winter peak load forecast scenario shows the peak load increasing from 7,197 MW in 2003/04 to 7,610 MW in the winter of 2008/09 at an average annual rate of 1.1%. The summer peak load is projected to increase to 7,520 MW by 2008.



Tables 7.1-7.4 on pages 29 and 30 provide PPL's forecasts of peak load and residential, commercial and industrial energy demand from 1994 through 2004.

Net operable generating capacity of 8,020 MW (summer rating) includes 46.8% coal-fired capacity and 25.2% nuclear capacity. Independent power producers also provided 293 MW to the system. In 2003, PPL purchased over 2.3 billion KWH from cogeneration and independent power production facilities, or about 6.4% of total sales.

For calendar year 2003, ten electric generation suppliers sold a total of approximately 874 million KWH to retail customers in PPL's service territory, or about 2.4% of total consumption, down from 3.6% in 2002.

For 2003, PPL reported a peak load reduction of 246.5 MW and energy savings of 2.6 million KWH, resulting from its Interruptible Service – Economic Provisions tariff schedule. Customers reducing load for economic conditions receive significant rate discounts. The peak load reduction from this program represents approximately 3.8% of the 2003 summer peak load.

PPL's Price Response Service permits customers to respond to market price signals by reducing a portion of their load. In 2003, an estimated 1,100 KW peak load reduction was achieved, with energy savings totaling about 29,600 KWH. The Residential Demand Side Response Rider, which provides for the option of shifting load from on peak hours, reduced the peak by 104 KW and saved 60,435 KWH.

PPL is a member of PJM and MAAC.

Table 7.1

Year	Actual Peak Demand	Projected Peak Load Requirements (Megawatts)										
		1994	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
1994	6508	6406										
1995	6607	6531	6435									
1996	6506	6581	6500	6830								
1997	5925	6711	6625	6920	6910							
1998	6688	6846	6760	7055	6935	6910						
1999	6746	6991	6895	7190	7030	6935	6815					
2000	6355	7126	7040	7315	7120	7030	6905	6580				
2001	6583	7251	7175	7450	7130	7120	7006	6680	6850			
2002	6970	7396	7310	7590	7250	7130	7040	6770	6960	7000		
2003	7197	7526	7455	7725	7350	7250	7140	6860	7060	7070	6790	
2004			7585	7860	7470	7350		6960	7170	7040	6860	7200
2005				8040	7580	7470			7270	7120	7000	7300
2006					7690	7580				7200	7140	7410
2007						7690					7320	7510
2008												7610

Table 7.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)										
		1994	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
1994	11444	11220										
1995	11300	11420	11290									
1996	11848	11630	11450	11475								
1997	11434	11850	11620	11640	11690							
1998	11156	12070	11800	11815	11760	11690						
1999	11704	12290	11980	11980	11830	11760	11740					
2000	11923	12500	12160	12145	11910	11830	11850	12031				
2001	12269	12700	12330	12320	12020	11910	11980	12150	12176			
2002	12640	12910	12510	12495	12160	12020	12120	12280	12324	12391		
2003	13266	13110	12690	12680	12290	12160	12260	12421	12478	12514	12868	
2004			12870	12865	12430	12290		12562	12634	12650	13062	13308
2005				13040	12570	12430			12799	12803	13259	13505
2006					12710	12570				12955	13462	13728
2007						12710					13671	13962
2008												14198

Table 7.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	9715	9540										
1995	9948	9770	9830									
1996	10288	10010	10090	10100								
1997	10309	10260	10355	10350	10490							
1998	10597	10520	10625	10610	10740	10490						
1999	11002	10780	10910	10885	11000	10740	10740					
2000	11477	11045	11200	11165	11280	11000	10980	11090				
2001	11778	11315	11490	11445	11560	11280	11240	11275	11291			
2002	12117	11585	11780	11725	11870	11560	11500	11444	11431	11850		
2003	12273	11855	12065	11995	12140	11870	11760	11612	11561	12033	12212	
2004			12345	12265	12410	12140		11782	11699	12219	12507	13275
2005				12525	12680	12410			11848	12411	12757	13601
2006					12940	12680				12602	13101	13975
2007						12940					13418	14286
2008												14631

Table 7.4

Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	9536	9390										
1995	9845	9570	9685									
1996	10016	9565	9675	9900								
1997	10078	9695	9885	10150	10070							
1998	10220	9830	10070	10405	10110	10070						
1999	10179	9965	10260	10600	10270	10110	10190					
2000	10280	10100	10445	10795	10440	10270	10350	10543				
2001	10319	10240	10635	10990	10610	10440	10520	10836	10963			
2002	9853	10380	10830	11190	10790	10610	10690	11077	11255	10780		
2003	9599	10520	11040	11400	10960	10790	10860	11295	11521	11135	10355	
2004			11245	11615	11140	10960		11498	11777	11425	10503	9938
2005				11825	11320	11140			12010	11702	10641	10035
2006					11510	11320				11970	10795	10155
2007						11510					10924	10253
2008												10346

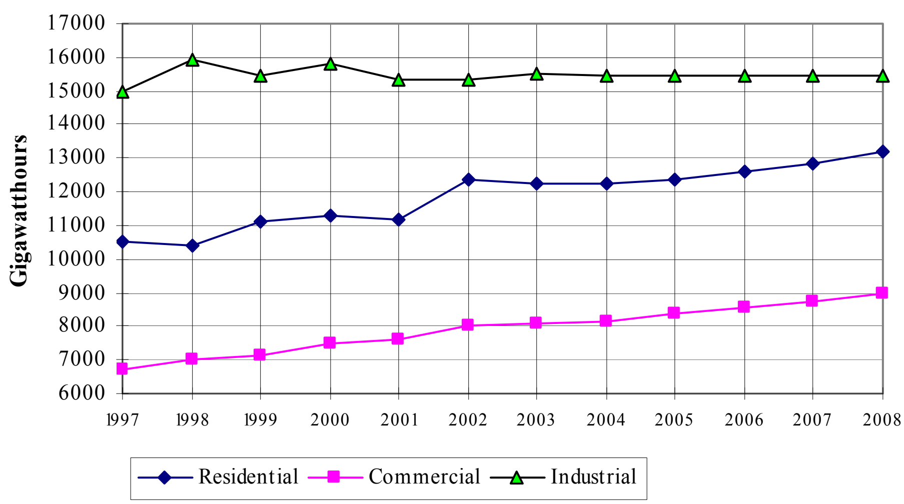
PECO Energy Company

PECO Energy Company (PECO) provides service to over 1.5 million electric utility customers in southeastern Pennsylvania. In 2003, PECO had total retail energy sales of nearly 36.8 billion kilowatthours (KWH) -- down 0.1% from 2002. Industrial sales continued to dominate PECO's market with 42.2% of the total sales, followed by residential (33.3%) and commercial (22.0%).

Between 1988 and 2003 PECO's energy demand grew an average of 1.1% per year. Residential energy sales grew at an annual rate of 1.6%, commercial at a 3.9% rate and industrial at -0.4%.

The current five-year projection of growth in energy demand is 1.0%. This includes an annual growth rate of 1.5% for residential, 2.1% for commercial and -0.1% for industrial.

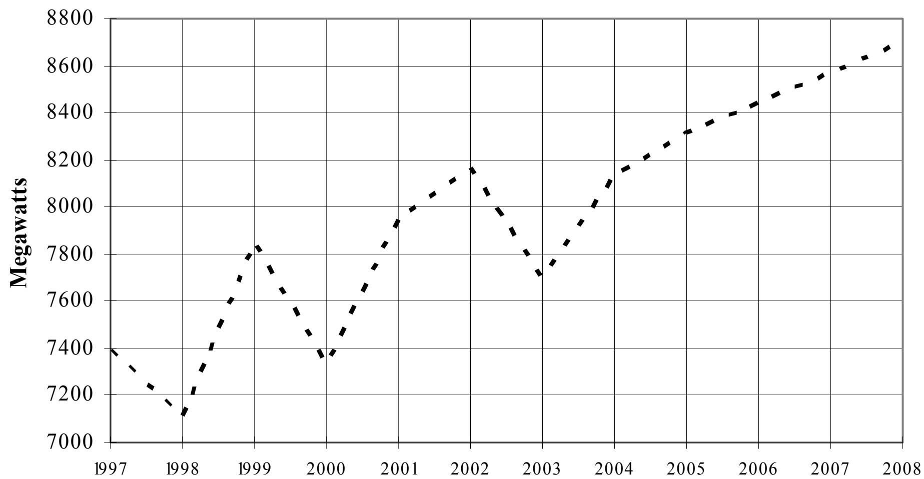
Figure 8.1
Historic & Forecast Energy Demand



PECO's 2003 summer peak load, occurring on June 26, 2003, was 7,696 megawatts (MW), representing a decrease of 5.7% from last year's peak of 8,164 MW. The 2003/04 winter peak demand was 6,396 MW or 0.8% above the previous winter's peak of 6,346 MW.

The actual average annual peak demand growth rate over the past fifteen years was 0.8%. PECO's current forecast shows the peak load increasing from the actual 2003 summer peak load of 7,696 MW to 8,700 MW in the summer of 2008, or an annual growth rate of 2.5%, due to a 468 MW drop in peak load from 2002 to 2003.

Figure 8.2
Historic & Forecast Peak Load



Tables 8.1-8.4 on pages 33 and 34 provide PECO's forecasts of peak load and residential, commercial and industrial energy demand from 1994 through 2004.

Net operable capacity of 9,463 MW includes 45.6% nuclear capacity and 15.2% coal-fired capacity. This capacity is owned by Exelon. PECO has entered into a Purchased Power Agreement with Exelon Generation to provide its provider-of-last-resort load throughout the forecast period.

In 2003, PECO purchased about 284 million KWH from cogeneration and independent power production facilities. Contract capacity totaled 223 MW.

For calendar year 2003, electric generation suppliers sold a total of 3.5 billion KWH to retail customers in PECO's service territory or about 9.4% of total consumption, up from 8.9% in 2002. On the summer peak day, electric generation suppliers represented a load of 873 MW.

PECO has developed commercial and industrial rate incentive programs to encourage customers to manage their energy demands and usage consistent with system capabilities. During 2003, the peak load reduction resulting from this rate option was 180 MW, with energy savings of 1.4 million KWH.

PECO is a member of the PJM Interconnection and MAAC.

Table 8.1

	Actual	Projections of Peak Load Requirements (Megawatts)										
	Peak											
Year	Demand	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	7227	6645										
1995	7246	6731	6671									
1996	6509	6815	6599	6811								
1997	7390	6897	6677	6868	6868							
1998	7108	6975	6751	6973	6973	6973						
1999	7850	7052	6825	7063	7063	7063	7063					
2000	7333	7135	6905	7135	7135	7135	7135	7339				
2001	7948	7226	6989	7233	7233	7233	7233	7398	7392			
2002	8164	7317	7077	7308	7308	7308	7308	7457	7451	8012		
2003	7696	7411	7166	7387	7387	7387	7387	7517	7510	8076	8229	
2004			7256	7466	7466	7466		7577	7570	8140	8295	8129
2005				7547	7547	7547			7631	8205	8362	8320
2006					7629	7629				8271	8428	8445
2007						7711					8496	8571
2008												8700

Table 8.2

	Actual	Projected Residential Energy Demand (Gigawatthours)										
	Energy											
Year	Demand	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	10412	10245										
1995	10660	10348	10423									
1996	10657	10457	10387	10576								
1997	10515	10570	10472	10653	10653							
1998	10376	10680	10581	10732	10732	10515						
1999	11132	10794	10696	10812	10812	10516	10516					
2000	11304	10909	10812	10894	10894	10600	10600	10600				
2001	11178	11024	10934	10976	10976	10685	10685	10685	11278			
2002	12335	11141	11055	11059	11059	10770	10770	10770	11385	11634		
2003	12259	11261	11177	11142	11142	10856	10856	10856	11488	11733	12020	
2004			11300	11225	11225	10943		10943	11592	11855	11905	12250
2005				11310	11310	11031			11697	11957	11981	12385
2006					11394	11119				12059	12054	12592
2007						11208					12128	12839
2008												13179

Table 8.3

Year	Actual Energy Demand	Projected Commercial* Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	5954	5678										
1995	6222	5820	6241									
1996	6410	5955	6403	6523								
1997	6689	6148	6593	6667	6667							
1998	7012	6342	6787	7044	7044	6643						
1999	7154	6538	6983	7346	7346	6597	6597					
2000	7481	6738	7182	7650	7650	6649	6649	6649				
2001	7604	6940	7385	7955	7955	6703	6703	6702	7315			
2002	8019	7146	7591	8262	8262	6756	6756	6756	7446	7732		
2003	8077	7354	7799	8572	8572	6810	6810	6810	7578	7963	8135	
2004			8011	8882	8882	6865		6864	7711	8099	8233	8140
2005				9195	9195	6920			7844	8265	8434	8349
2006					9510	6975				8436	8637	8550
2007						7031					8839	8755
2008												8965

* Small Commercial & Industrial

Table 8.4

Year	Actual Energy Demand	Projected Industrial* Energy Demand (Gigawatthours)										
		1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	15622	15819										
1995	15869	15899	15805									
1996	14976	16003	15766	15249								
1997	14992	16155	15791	15299	15299							
1998	15929	16270	15923	15259	15259	15456						
1999	15477	16402	16040	15271	15271	15919	15919					
2000	15828	16521	16145	15248	15248	16047	16047	16047				
2001	15312	16642	16253	15353	15353	16175	16175	16175	15405			
2002	15323	16766	16363	15333	15333	16304	16304	16305	15406	15324		
2003	15518	16893	16473	15314	15314	16435	16435	16435	15408	15417	15130	
2004			16588	15294	15294	16566		16567	15409	15429	14959	15477
2005				15278	15278	16699			15409	15442	14980	15448
2006					15262	16832				15458	15001	15448
2007						16967					15022	15448
2008												15448

* Large Commercial & Industrial

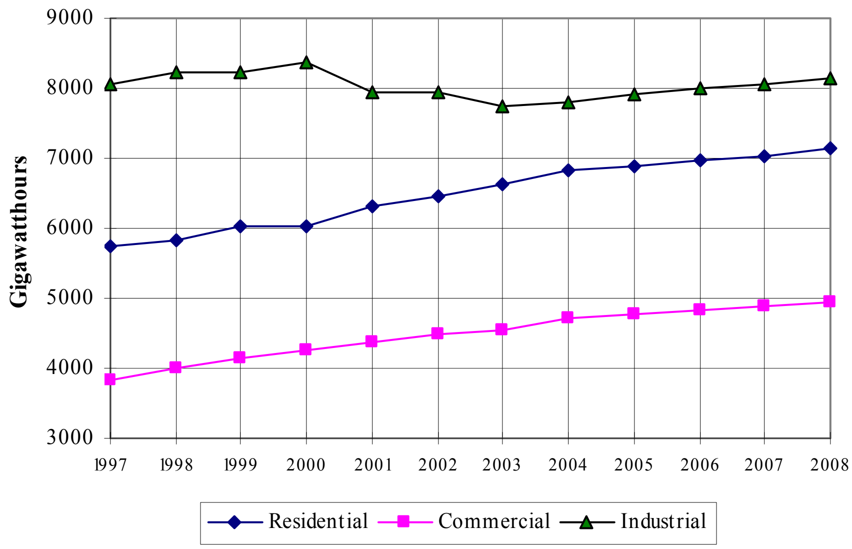
West Penn Power Company

West Penn Power Company (West Penn) provides service to nearly 697,000 electric utility customers in western, north and south central Pennsylvania. In 2003, West Penn had total retail energy sales of over 19.6 billion kilowatthours (KWH) – up 0.1% from 2002. Industrial sales continued to dominate West Penn's market with 39.5% of the total sales, followed by residential (33.9%) and commercial (23.1%).

Between 1988 and 2003, West Penn's energy demand grew an average of 1.7% per year. Sales for all sectors have maintained relatively steady growth during the period. Residential sales grew at an annual rate of 1.8%, commercial sales at 2.7% and industrial sales at 1.1% over the past 15 years.

The current five-year projection of growth in energy demand is 1.3%. This includes a residential growth rate of 1.4%, a commercial rate of 1.7% and an industrial rate of 1.0%.

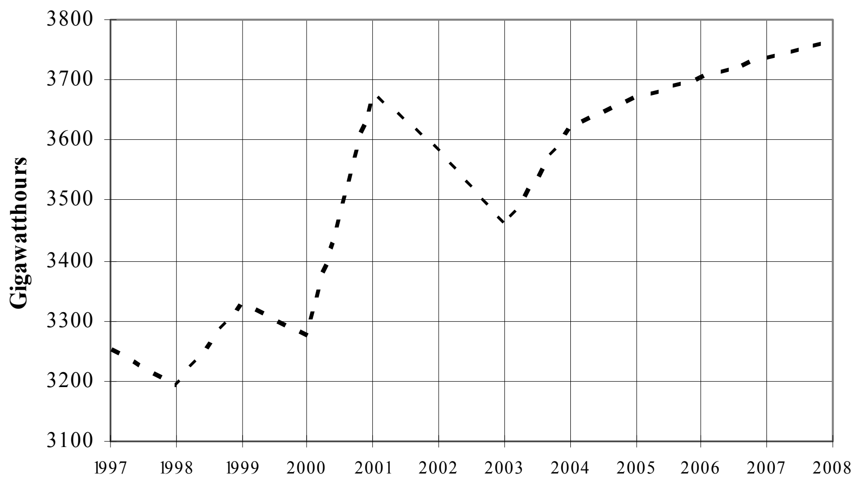
Figure 9.1
Historic & Forecast Energy Demand



West Penn's 2003 summer peak load, occurring on August 14, 2003, was 3,455 megawatts (MW), representing a decrease of 3.5% from last year's summer peak of 3,582 MW. The 2003/04 winter peak load was 3,424 MW or 1.3% below the previous year's winter peak of 3,470 MW.

The actual average annual peak load growth rate over the past fifteen years was about 1.5%. West Penn's load forecast scenario shows the annual peak load increasing from 3,455 MW in the summer of 2003 to 3,766 MW in 2008, or an average annual growth rate of 1.7%.

Figure 9.2
Historic & Forecast Peak Load



Tables 9.1-9.4 on pages 37 and 38 provide West Penn's forecasts of peak load and residential, commercial and industrial energy demand from 1994 through 2004.

Effective January, 2000, all of West Penn's generation assets were transferred to its affiliate, Allegheny Energy Supply Company, LLC (AESC). West Penn subsequently entered into a Power Sales Agreement with AESC for providing default service load requirements. The power provided by AESC will come from owned generation and market purchases. West Penn will remain an electric distribution company, providing transmission and distribution service to its customers and providing default service, or Provider of Last Resort service, for those customers who do not choose an alternate supplier.

In 2003, West Penn purchased nearly 1.1 billion KWH from cogeneration and independent power production facilities. Contract capacity for these facilities was 136 MW.

West Penn implemented a Generation Buy-Back program in 2001, intended as a way for West Penn to buy back or displace firm load from large commercial and industrial customers that have on-site generation or operational flexibility. A total of 15 West Penn customers signed up with a potential load reduction of 36.9 MW.

In April 2002, Allegheny Power joined PJM Interconnection, LLC (PJM) through the creation of PJM West. As a PJM member, Allegheny Power is responsible for following the reliability standards of the PJM markets as are defined in the PJM Tariffs and PJM West Reliability Assurance Agreement.

Table 9.1

Year	Actual Peak Demand	Projections of Peak Load Requirements (Megawatts)										
		1994	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
1994	3179	3075										
1995	3242	3147	3117									
1996	3215	3214	3207	3235								
1997	3251	3270	3279	3315	3315							
1998	3192	3335	3329	3371	3371	3379						
1999	3328	3396	3372	3417	3417	3442	3279					
2000	3277	3440	3410	3462	3462	3496	3360	3284				
2001	3677	3503	3454	3506	3506	3545	3425	3304	3141			
2002	3311	3560	3500	3547	3547	3578	3484	3341	3445	3458		
2003	3455	3624	3554	3586	3586	3617	3519	3380	3465	3505	3535	
2004			3609	3630	3630	3668		3415	3501	3542	3572	3621
2005				3679	3679	3723			3536	3586	3610	3670
2006					3722	3769				3622	3639	3705
2007						3812					3674	3738
2008												3766

Table 9.2

Year	Actual Energy Demand	Projected Residential Energy Demand (Gigawatthours)										
		1994	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**	**2003**	**2004**
1994	5740	5697										
1995	5819	5763	5826									
1996	5913	5843	5897	5844								
1997	5757	5932	5979	5923	5923							
1998	5823	6016	6081	6020	6020	6127						
1999	6020	6096	6166	6118	6118	6250	5873					
2000	6022	6163	6260	6223	6223	6381	6013	6061				
2001	6325	6238	6313	6282	6282	6446	6077	6172	6192			
2002	6459	6317	6391	6371	6371	6518	6165	6256	6260	6374		
2003	6641	6405	6460	6445	6445	6604	6165	6339	6329	6471	6486	
2004			6567	6546	6546	6699	6231	6445	6436	6596	6599	6818
2005				6624	6624	6763			6521	6680	6671	6890
2006					6722	6864				6775	6744	6965
2007						6976					6821	7041
2008												7132

Table 9.3

Year	Actual Energy Demand	Projected Commercial Energy Demand (Gigawatthours) 1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	3624	3640										
1995	3782	3706	3741									
1996	3836	3826	3834	3856								
1997	3833	3935	3942	3950	3950							
1998	3993	4034	4049	4055	4055	4080						
1999	4137	4128	4147	4161	4161	4163	4039					
2000	4265	4199	4223	4271	4271	4270	4215	4182				
2001	4360	4256	4272	4347	4347	4339	4313	4225	4326			
2002	4497	4340	4350	4430	4430	4393	4401	4275	4395	4458		
2003	4529	4450	4434	4501	4501	4457	4443	4329	4449	4543	4577	
2004			4556	4588	4588	4557		4397	4517	4624	4653	4701
2005				4664	4664	4630			4571	4684	4695	4780
2006					4756	4707				4749	4739	4832
2007						4779					4776	4878
2008												4936

Table 9.4

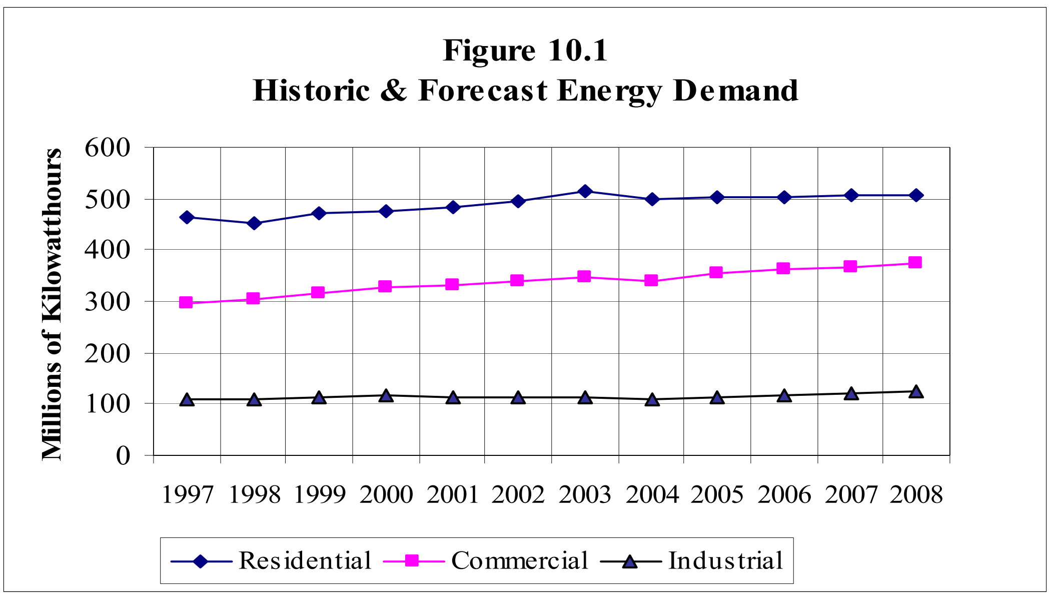
Year	Actual Energy Demand	Projected Industrial Energy Demand (Gigawatthours) 1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1994	7426	7604										
1995	7858	7854	7659									
1996	7974	7985	7981	8204								
1997	8046	8235	8232	8427	8427							
1998	8226	8426	8429	8755	8755	8608						
1999	8237	8618	8502	8855	8855	8808	8575					
2000	8383	8781	8609	8976	8976	8997	8830	7942				
2001	7955	8934	8664	9052	9052	9070	8975	8120	8481			
2002	7957	9191	8767	9156	9156	9136	9167	8230	8597	8006		
2003	7747	9322	8874	9241	9241	9264	9161	8353	8663	8116	7885	
2004			9010	9367	9367	9448		8477	8729	8188	7973	7814
2005				9450	9450	9561			8799	8230	8023	7913
2006					9566	9660				8290	8087	7998
2007						9768					8187	8069
2008												8140

UGI Utilities, Inc.

The Electric Division of UGI Utilities, Inc. (UGI) provides electric service to nearly 62,000 customers in northwestern Luzerne and southern Wyoming counties, Pennsylvania. In 2003, UGI had energy sales totaling 979.1 million kilowatthours (KWH) -- up 3.1% from 2002. Residential sales continued to dominate UGI's market with 52.7% of the total sales, followed by commercial (35.3%) and industrial (11.4%).

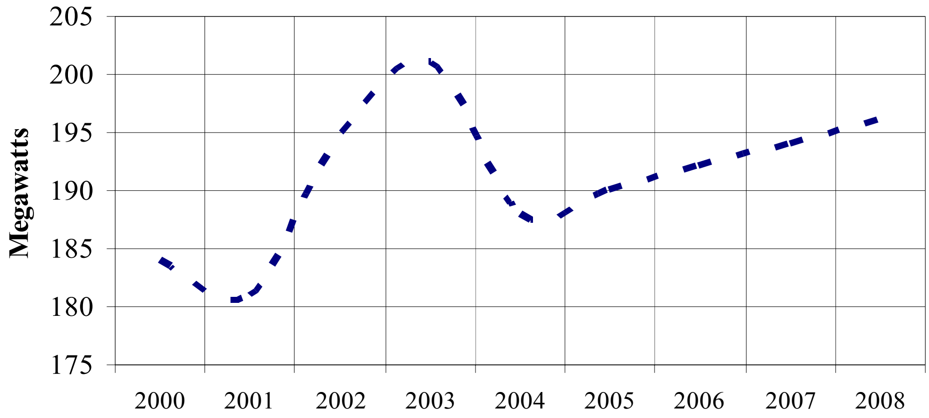
Between 1988 and 2003, UGI experienced an average growth in total sales of 1.6%, which includes a residential growth rate of 1.3%, a commercial rate of 2.1% and an industrial rate of 1.9%.

Over the five-year planning horizon, UGI expects growth in energy demand to average 0.7%. This includes an average decline in residential sales of 0.4%, a commercial growth rate of 1.7% and an industrial growth rate of 2.2%. The five-year peak load forecast indicates an average annual decline of 0.5%. Peak load is projected to decrease from 201 MW in 2003 to 196 MW by the winter of 2008/09.



Peak demand on the UGI system occurred on January 15, 2004, and totaled 201 megawatts (MW), or 3.1% above the January 23, 2003, winter peak load of 195 MW and 15.5% above the 2003 summer peak load of 174 MW, occurring on June 26, 2003.

Figure 10.2
Historic & Forecast Peak Load



In 2003, one electric generation supplier provided 509,000 KWH to UGI's retail customers who chose an alternate supplier. This represents about 0.05% of total sales, down from 1.0% in 2002. UGI does not own electric generation supply and will meet its customers' energy requirements by making wholesale purchases in various markets.

As of December 31, 2003, 56 UGI customers were taking generation service from an alternate generation supplier, comprising an aggregate load of 0.13 MW. Of those, approximately 95% were residential customers, with the remaining 5% commercial.

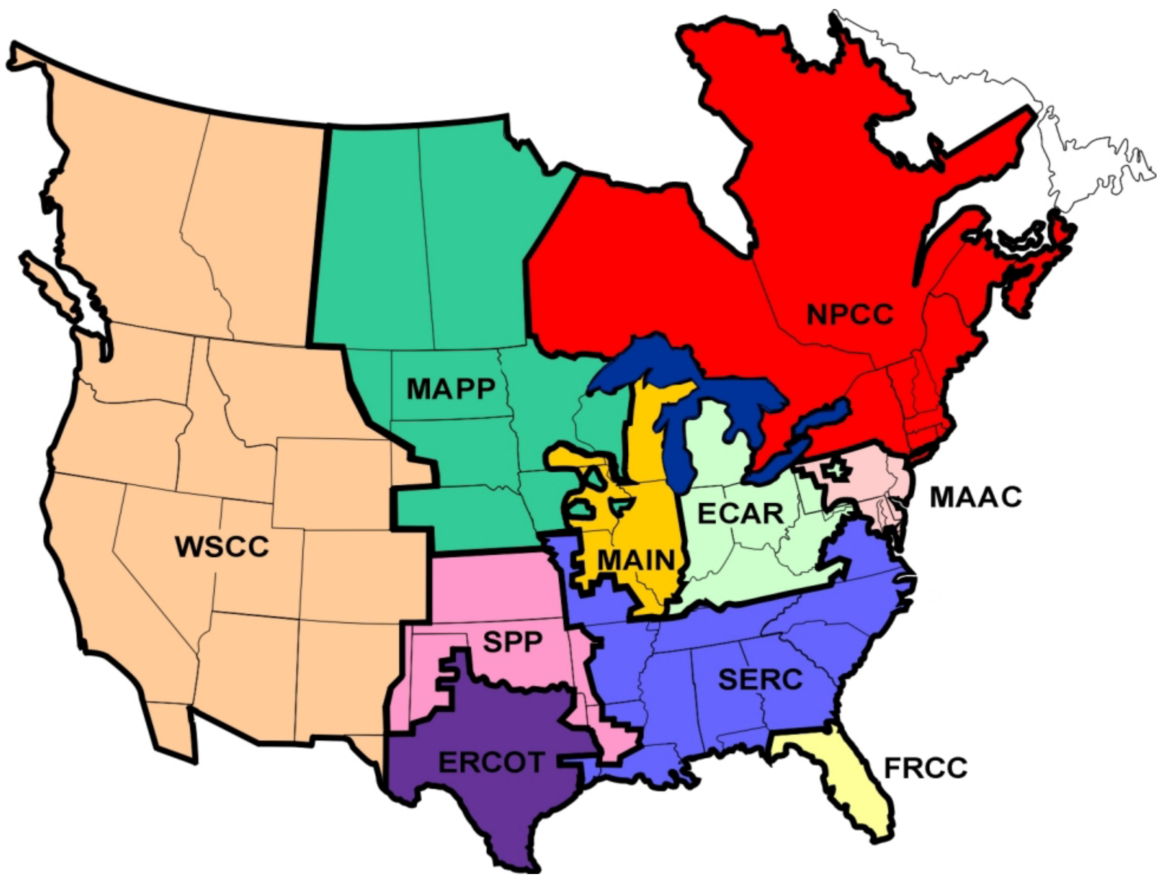
During the summer of 2003, UGI offered a modified version of its Voluntary Load Reduction program to all of its commercial and industrial customers. The program centers on a customer's ability to reduce its demand during peak periods, thereby enhancing system reliability and increasing the economic efficiency of the wholesale and retail markets. Each of the program participants had a PJM Locational Marginal Price (LMP) threshold of $200/MWH. Since the real-time LMP's in UGI's zone never reached or surpassed this level, the program was never utilized.

Section 3

Regional Reliability Assessments

The passage of the Pennsylvania Electricity Generation Customer Choice and Competition Act substantially changed the Commission's jurisdiction as well as our ability to compile data from the generation sector. At this time, all information on generation and transmission capacity is regional. Therefore, this section summarizes the regional reliability assessments of MAAC, ECAR and PJM for generation and transmission capability. The regional reports find that there is sufficient generation and transmission capacity in PA to meet the needs of electric consumers for the foreseeable future.

NERC



Source: http://www.nerc.com

In 1968, electric utilities formed the North American Electric Reliability Council (NERC) to promote the reliability of the electricity supply for North America. Since its formation, NERC has operated as a voluntary organization, dependent on reciprocity and mutual self-interest. Due to the restructuring of the electric utility industry, NERC is being transformed from a voluntary system of reliability management to one that is mandatory, with the backing of U.S. and Canadian governments. The mission of the new North American Electric Reliability Organization (NAERO) will be to develop, promote and enforce reliability standards.

NERC's members are the ten regional reliability councils. Members of these regional councils include investor-owned utilities, federal, rural electric cooperatives, state/municipal and provincial utilities, independent power producers and power marketers. The regional councils operating in Pennsylvania are the Mid-Atlantic Area Council (MAAC) and the East Central Area Reliability Council (ECAR).

Electric system reliability is addressed by considering two basic and functional aspects of the electric system: adequacy and security. *Adequacy* is the ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. *Security* is the ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Resource adequacy can be expressed in terms of either reserve margin or capacity margin. *Reserve margin* is the difference between available resources and net internal demand, expressed as a percent of net internal demand. *Capacity margin* is the difference between available resources and net internal demand, expressed as a percent of available resources.

Compliance Standards

On March 30, 2001, NERC changed its governance to a new, ten-member independent Board of Trustees, replacing a 47-member Board, which comprised both stakeholders and independent members. Additionally, NERC has initiated an Agreement for Regional Compliance and Enforcement Programs under which the Regional Councils will monitor and enforce certain NERC reliability standards, including the imposition of financial penalties.

NERC believes that compliance with reliability standards must be mandatory. The number and complexity of transactions are increasing, due to an increase in the expanse of competitive markets. Compliance with NERC standards is necessary to maintain system reliability to protect the public welfare and ensure a robust competitive market.

Reliability Assessment

According to NERC's *Reliability Assessment 2003-2012* report, the average annual peak demand growth rate over the next ten years is projected to be 1.9% in the United States, compared to 2.0% for last year's forecast. Over the next 10 years, capacity adequacy in North America will be highly dependent upon the timely construction of new generating facilities by merchant power plant developers. Investor-owned utilities, public power entities, rural electric cooperatives and developers have announced plans for more than 117,000 MW of new capacity during the 10-year period, a potential 14% increase over that existing in 2002. Recent new power plant delays and cancellations amount to a 35.2% decrease from 2001 to 2003. These delays and cancellations are a result of changing business conditions, such as fuel prices and load growth.

Projected 2005 U.S. capacity margins are about 12.7% lower this year. The projected margin continues to decline to about 14.1% as projected demand continues to grow while the number of proposed and/or announced new generating units decline. However, near term generation adequacy is deemed by NERC to be satisfactory throughout most of North America, provided new generating facilities are constructed as planned.

About 11,109 new circuit miles of transmission facilities (230 kV and Higher) are planned for construction throughout North America over the next 10 years. Most of these additions are intended to address local transmission concerns or to connect proposed new generators to the transmission grid. Transmission systems are expected to perform reliably in the near term; however, portions of the transmission systems are reaching their limits as customer demand increases and the systems are subjected to new loading patterns resulting from increased electricity transfers.

Coal remains the predominant fuel for electric generation; however, nearly all recently built power plants and those proposed use natural gas as their primary fuel. With a majority of the new generation fueled by natural gas, there is the question of whether the availability of natural gas and the infrastructure to move it to the generating stations will be adequate. Also, there is a concern about the potential reliability impacts associated with environmental policies and compliance implementation.

August 14, 2003 Blackout

On August 14, 2003, large portions of the Midwest and Northeast U.S. experienced an electric power blackout, affecting an estimated 50 million people – the largest in North America's history. NERC had participated in the investigation conducted by the U.S./Canada Power System Outage Task Force and, on October 15, 2003, issued a letter requesting that each control area and reliability coordinator review existing reliability practices to ensure compliance. The Task Force report, issued on November 19, 2003, which describes the major events leading up to the blackout and identifies the causes of the blackout, can be found at https://reports.energy.gov/BlackoutFinal-Web.pdf.

MAAC

The Mid-Atlantic Area Council (MAAC) is one of ten regional reliability councils comprised of investor-owned electric utilities, power marketers and independent power producers. MAAC serves over 22 million people in a nearly 50,000 square mile area, which includes all of Delaware and the District of Columbia, major portions of Pennsylvania, New Jersey and Maryland, and a small part of Virginia. MAAC comprises less than 2% of the land area of the contiguous United States but serves about 8% of the electrical load.

MAAC was established in December 1967 to augment the reliability of the bulk electric supply systems of its members through coordinated planning of generation and transmission facilities. PJM Interconnection, L.L.C., (PJM) is the only control area in MAAC. The MAAC signatory systems operate on a "free flowing ties" basis under the PJM Operating Agreement and in accordance with the PJM Open Access Transmission Tariff filed at FERC.

MAAC signatories participate in the PJM energy and capacity market, obtain transmission service through the PJM OASIS, enter into bilateral transactions coordinated between PJM and other control areas and participate in PJM emergency procedures. Under the MAAC Agreement and the PJM Operating Agreement, MAAC and PJM members are obligated to comply with MAAC and NERC operating and planning principles and standards.

A new MAAC Agreement went into effect on January 1, 2001, whereby all members of the PJM Interconnection became members of MAAC. As of June 17, 2004, MAAC had 291 members. Funding for MAAC and NERC will now be collected under a new schedule of the PJM Open Access Transmission Tariff. Full members include Allegheny Electric Cooperative, Inc., Baltimore Gas and Electric Company, Citizens Power Sales, Conectiv, Dynegy Power Marketing, Inc., Metropolitan Edison Company, Pennsylvania Electric Company, PECO Energy Company, Potomac Electric Power Company, PPL Electric Utilities Corporation, Public Service Electric and Gas Company, UGI Utilities, Inc., U.S. Generating Company and Vineland Municipal Electric Utility. Operation of the MAAC region is coordinated from the PJM Interconnection Control Center located near Valley Forge, Pennsylvania.

The 2003 MAAC aggregate coincident system summer peak load of 53,566 MW was 3.6% lower than the MAAC all-time peak of 55,569 MW, occurring in 2002. Net energy for load in 2003 increased 2,694 GWH (1.0%) from 2002. The regional total internal summer peak demand (including direct control load management and interruptible demand) is projected to increase to 60,152 MW by 2008 at an average annual growth rate of about 2.5%.

Compliance Standards

The MAAC reliability standards require that sufficient generating capacity be installed to ensure that the probability of system load exceeding available capacity is no greater than one day in 10 years. Load serving entities that are members of MAAC have a capacity obligation determined by evaluating individual system load characteristics and unit size and operating characteristics. These obligation reserves must be met by all load-serving entities in PJM as signatories to the Reliability Assurance Agreement.

Net capacity resources are projected to increase from 65,902 MW in 2003 to 68,703 MW in 2008, an increase of 2,801 MW or 4.3%. The reserve margin is expected to be 19.3% in 2004. (These figures do not include PJM West, which is a part of ECAR.) The majority of the capacity additions are expected to be natural gas-fueled combined-cycle units. It must be noted that some of this capacity is speculative and may never be built.

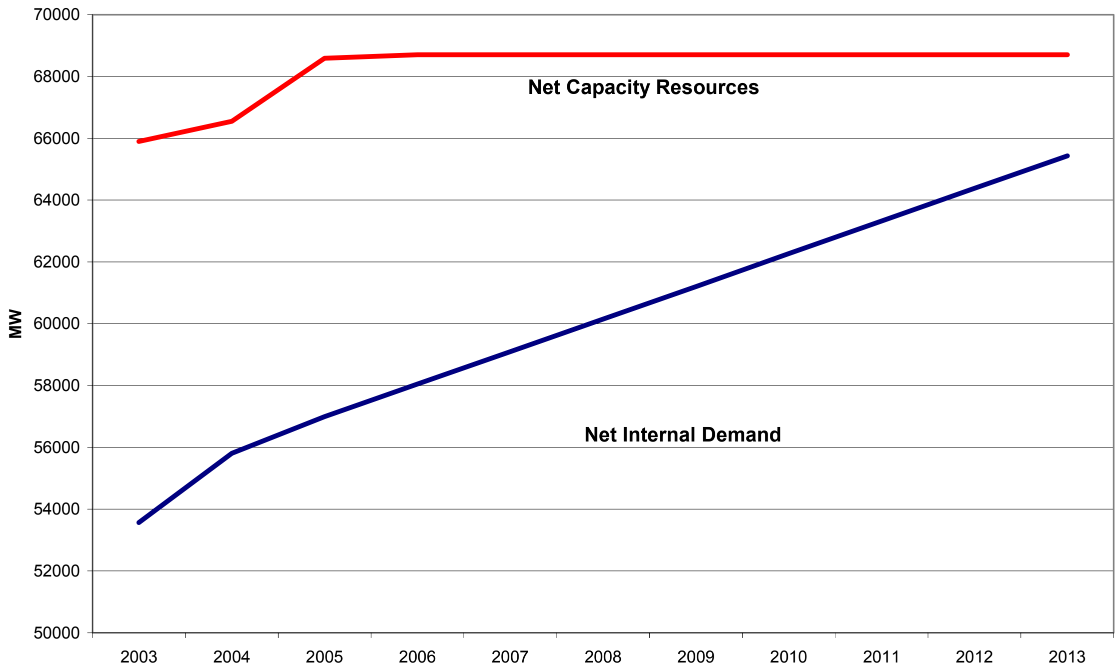
Table 11.1 provides a five-year forecast of loads, resources and reserve margins for MAAC, based on MAAC's Response to the 2004 NERC Data Request (formerly the MAAC EIA-411).

Table 11.1. MAAC 5-Year Load, Resource & Reserve Margin Forecast

		2003	2004	2005	2006	2007	2008
MAAC	Demand (MW)	53566	55809	56989	58054	59098	60152
	Capacity (MW)	65902	66555	68596	68703	68703	68703
	Reserve (%)	23.0	19.3	20.4	18.3	16.3	14.2

Figure 11.1 graphically shows the projected generating capacity and demand for the summer of 2003 through the summer of 2013.

Figure 11.1 -- MAAC Projected Capacity and Demand - Summer



In 2003, the MAAC region's mix of generating capacity was as follows: 23.0% coal, 20.0% nuclear, 10.1% oil, 4.8% hydroelectric (including pumped storage) and 8.2% natural gas. Dual fueled units represent 32.3% of the total. Natural gas generation is expected to increase significantly, rising to 13.3% of the total by 2008.

Reliability Assessment

MAAC's self assessment contained in NERC's *Reliability Assessment 2003-2012 Report* states that generation resources are expected to be adequate to maintain regional reliability over the next ten years. PJM is currently evaluating generator interconnection requests for over 18,000 MW of new generating capacity through 2010. Although not all of this capacity will be built, MAAC believes that sufficient generating capacity will be added to meet the MAAC adequacy objective.

Over the next five years, MAAC expects there will be adequate transmission capability to meet MAAC's criteria requirements. Several transmission reinforcement projects are expected to be in service by 2007.

See Appendix A for additional data on MAAC capacity and demand projections.

PJM Interconnection L.L.C.

PJM coordinates with its member companies to meet the load requirements of the region. PJM's members also use bilateral contracts and the spot energy market to secure power to meet the electric load of nearly 35 million people. In order to reliably meet its load requirement, PJM must monitor and assess 25,000 miles of transmission lines for congestion concerns or physical capability problems. As of June 17, 2004, there were 291 members of PJM.

On April 1, 2002, PJM West (Allegheny Energy) became operational as part of the PJM Regional Transmission Organization (RTO). PJM West will continue to be a separate control area, within the ECAR Region, but will operate under the direction of the PJM Board of Managers. This has expanded the scope of PJM's operations in Pennsylvania, Maryland and Virginia and extended PJM's operations into West Virginia and Ohio. This expansion of PJM's operations provides greater resources to maintain both short-term and long-term reliability at a lower overall cost and environmental impact.

On May 1, 2004, PJM began managing the flow of wholesale electricity over Commonwealth Edison's (ComEd's) 5,000 miles of transmission lines and administering open, competitive wholesale electricity trading markets. The integration of ComEd into PJM makes PJM the world's largest grid operator, meeting a peak demand of about 87,000 MW with a combined generating capacity of about 106,000 MW.

On May 6, 2004, PJM signed an implementation agreement with Duquesne Light Company to integrate into the PJM RTO by January 1, 2005. Duquesne will become part of PJM West. PJM has been the reliability coordinator for Duquesne since February 2003.

The eastern transmission system of American Electric Power and the transmission system of The Dayton Power & Light Company are scheduled to join PJM on October 1, 2004. On November 1, 2004, Virginia-based Dominion's transmission lines are to be integrated into PJM. This integration will bring transmission and generation in AEP and Dayton's territory in Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia and West Virginia into PJM's integrated energy market and congestion management system.

On May 24, 2004, the Midwest Independent Transmission System Operator (Midwest ISO), PJM and the Tennessee Valley Authority (TVA) announced that they signed a data exchange agreement to pursue the development of a multi-regional approach to strengthen coordination of transmission, operations and related transactions. The agreement establishes protocols and procedures to allow the three organizations to exchange grid operational data on an ongoing basis. The ultimate goal is to improve the reliability, congestion management and adequacy of the transmission grid while providing broad, seamless, nondiscriminatory transmission service and energy markets across a large portion of the Eastern Interconnection. The area comprised by the three entities represents 270,000 MW or 43% of the Eastern Interconnection.

In addition to the direct connect transmission facilities associated with new generating capacity, several transmission reinforcement projects are expected to be in service by 2007. These projects were evaluated by PJM through the PJM Regional Transmission Expansion Planning Process. PJM conducted a comprehensive load flow analysis of the ability of the PJM system as planned for 2007 to meet single contingency, second contingency and multiple facility outage contingency tests.

According to the PJM State of the Market Report – 2003, PJM's Demand-Side Response (DSR) program resulted in a maximum hourly reduction in load of 14,678 MWH during 2003. In 2003, the total resources in the Economic Program were 724 MW; the total resources in the Emergency Program were 659 MW; and the total resources in the ALM Program were 1,207 MW.

PJM Generation Adequacy

Four activities conducted by PJM decide the future construction or expansion of an existing power plant in the region:

- Proposals are submitted to PJM and entered in a calendar-based queue.
- Feasibility studies are conducted by queue to estimate interconnection costs and construction time, and provide feedback to project owners.
- Impact studies are conducted next to develop specific recommendations for system additions and costs. Permitting of plants begins at this stage.
- The Board of Managers grants approvals after public review with PJM committee members.

The projected 2004 aggregate load for PJM Mid-Atlantic and APS (PJM West) is 64,109 MW. Existing installed capacity as of June 30, 2004, is 76,929 MW. The forecasted reserve margin is 20%. The summer load is projected to increase to 68,854 MW by 2008, with a capacity of 79,871 MW, or a reserve margin of 18.3%.

Figure 11.1 shows the forecasted summer peak net internal demand and existing generating capacity plus the expected new generation additions for PJM Mid-Atlantic (PJM East) and APS (PJM West). Figure 11.2 shows the projected reserve margin for the combined PJM East and PJM West.

Figure 11.1 PJM Mid-Atlantic and APS Capacity and Demand

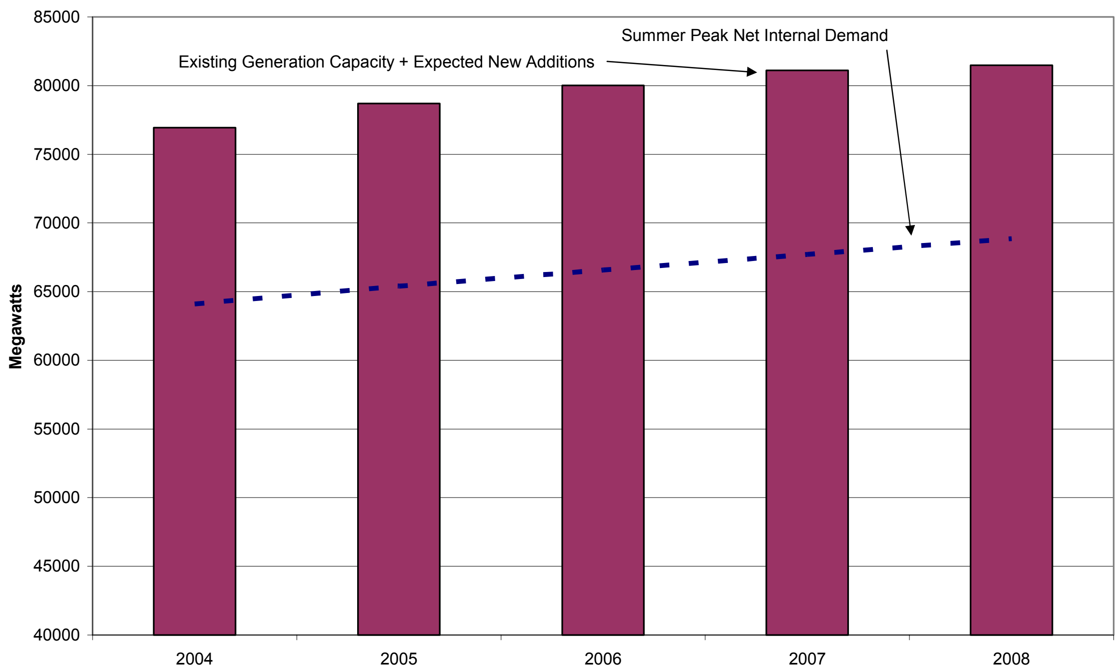
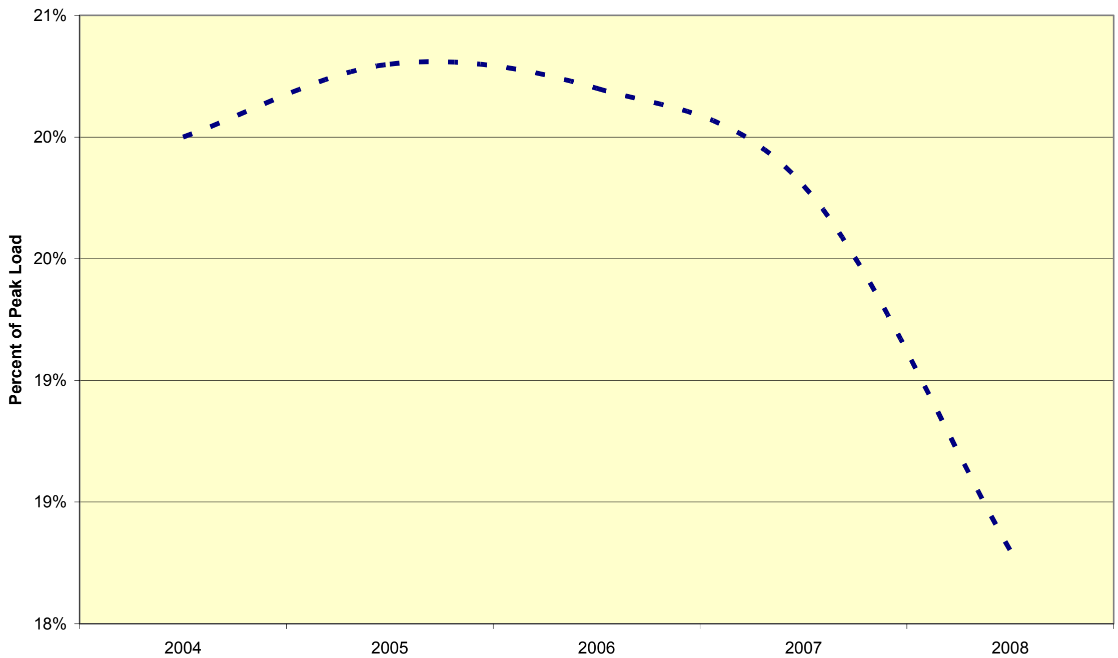


Figure 11.2. PJM Mid-Atlantic and APS Reserve Margin



ECAR

The East Central Area Reliability Council (ECAR) augments bulk power supply reliability through coordination of planning and operation of member companies' generation and transmission facilities. Full members currently includes 20 systems serving either all or parts of the states of Indiana, Kentucky, Maryland, Michigan, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia, serving more than 36 million people.

Control of the generating units and the bulk power transmission networks within the ECAR region is directed by 19 Power Control Centers which include Allegheny Power (of which West Penn Power Company is a subsidiary), Duquesne Light Company and FirstEnergy (of which Pennsylvania Power Company is a subsidiary).

The 2003 aggregate (non-coincident) summer peak load of 98,487 MW was 4,509 MW or 4.4% lower than the summer peak of 2002. This load was also 2,227 MW or 2.2% lower than the forecast. Net generating capacity resources at the time of the peak were 123,755 MW. Net energy for load in 2003 was 545.1 billion KWH or 4.0% lower than that of the previous year.

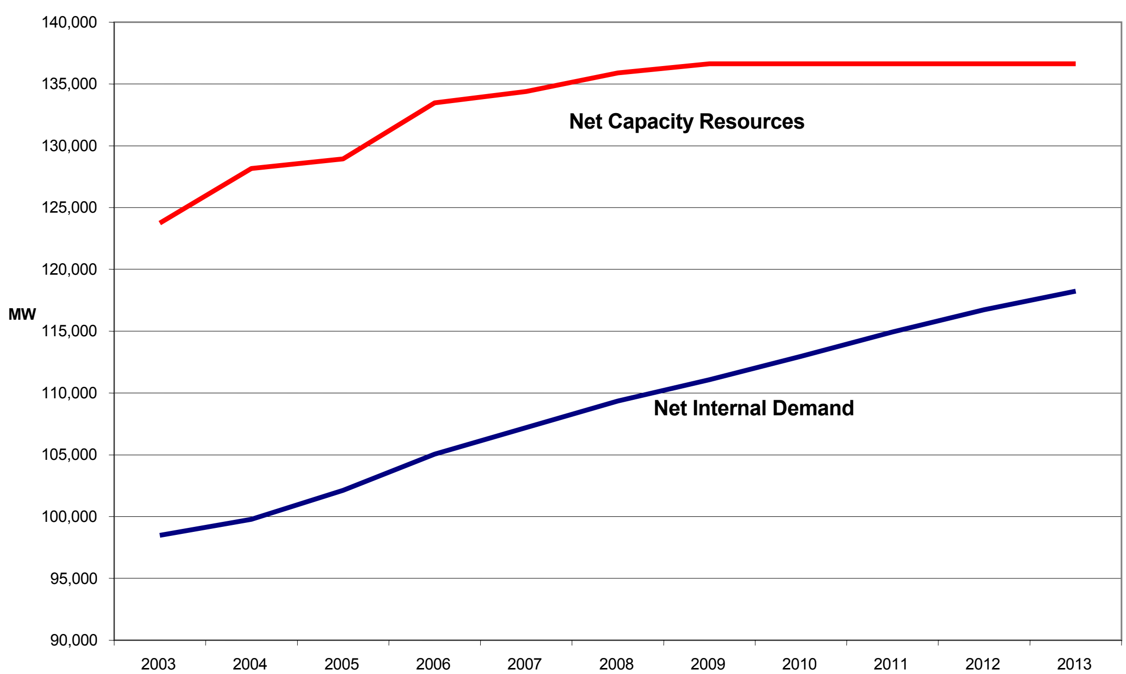
The regional non-coincident internal peak load is projected to increase to 112,007 MW by the summer of 2008 at an average annual growth rate of 2.7%. Peak load reductions from direct load control programs and interruptible customers are expected to reach 2,650 MW by 2008. Energy demand is expected to grow at an average rate of 2.0% per year.

ECAR's members project additions of 12,226 MW of new generating capacity by 2008, which includes 9,435 MW of uncommitted resources. A majority of this new capacity is projected to be short lead-time, gas-fired combustion turbine and combined cycle units (65.9%). Capacity margins for net internal demand are expected to range between 22.1% in 2003 to 19.5% in 2008. See Figure 11.3.

August 14, 2003, Blackout

ECAR has completed its investigation of the August 14, 2003, blackout. The results of the investigation are documented in two reports, available on the ECAR web site: http://www.ecar.org. The ECAR Executive Board has accepted the findings of the U.S. – Canada Power System Outage Task Force and the NERC investigations and expects to fully implement the NERC recommendations.

Figure 11.3. ECAR Capacity and Demand - Summer



Compliance Standards

ECAR's standard for evaluating the reliability of the generation component of the bulk power supply involves the computation of the number of days per year that the ECAR Region is expected to rely on (a) generating resources outside of ECAR and (b) reducing area load to the extent that such resources are not available. The member companies use this measure of performance, the Dependence on Supplemental Capacity Resources (DSCR), to identify critical bulk power supply situations for appropriate response.

Reliability Assessment

ECAR's self assessment contained in NERC's *Reliability Assessment 2003-2012* report states that resources planned for the ECAR Region should be adequate. The system is expected to meet the forecasted demand obligations, assuming proposed projects are completed as planned.

See Appendix A for additional data on capacity and demand projections.

Pennsylvania

The Pennsylvania outlook reflects the projections of both ECAR and MAAC/PJM. Since transmission and generation are not regulated by the Commission, we must look to these two entities for data concerning the status of the electric system on a regional basis. While we can determine the aggregate load for the State's consumers, we do not know, with complete certainty, what generating facilities will be available to serve these consumers.

Planning the enhancement and expansion of transmission capability on a regional basis is one of the primary functions of regional transmission organizations. PJM implements this function pursuant to the Regional Transmission Expansion Planning Protocol (RTEPP) set forth in Schedule 6 of the PJM Operating Agreement. A key part of this regional planning protocol is the evaluation of both generation interconnection and merchant transmission interconnection requests, the procedures for which are codified under Part IV of the PJM Open Access Transmission Tariff.

Although transmission planning is performed on a regional basis, most transmission additions and upgrades in Pennsylvania are planned to support the local delivery system and new generating facilities. Appendix C lists planned transmission line additions and upgrades for Pennsylvania's EDCs. Included are projects with a design voltage of over 100 kV with an in-service date of 2003 or beyond. Estimated project costs are also provided.

All new generation, anticipated to interconnect and operate in parallel with the PJM Transmission Grid and participate in the PJM capacity and/or energy markets, must submit an Interconnection Request to PJM. These requests are placed in queues, or waiting lists, for the performance of feasibility studies and other technical reviews.

Proposed new generating plants and increased capacity of existing plants located in Pennsylvania total 9,566 MW. These facilities are either under study, under construction, partially in-service or in-service. This additional capacity may be used to serve Pennsylvania customers or out-of-state customers. Appendix D provides the status of new power plant queues for Pennsylvania.

Appendix E lists the existing power plants located in Pennsylvania, along with the operating companies' names and fuel types. The generating capacity of these plants total 46,092 MW. As stated earlier, the output of some of these facilities may serve loads outside of Pennsylvania.

Section 4

Conclusions

For many years, Pennsylvania has benefited from a high level of electric service reliability.

The Mid-Atlantic Area Council (MAAC) and the East Central Area Reliability Council (ECAR) regions covering Pennsylvania continue to have sufficient generating resources to maintain a high level of reliability during the summer of 2004 and beyond. Load growth in the mid-Atlantic is expected to be moderate. Thousands of megawatts of new capacity are proposed to be in service between 2004 and 2008, and it is anticipated that total generating capacity will exceed demand by a reliable margin. New capacity will help to ensure the reliability of electric service in the state and will increase the robustness of the competitive energy markets.

Thus, the regional reliability councils report that there is sufficient generation, transmission and distribution capacity in Pennsylvania to meet the needs of electric consumers for the foreseeable future. The Commission also continues to pursue demand side response initiatives to address ways to encourage customers to respond to peak period wholesale prices by reducing their demand. In the long term, this initiative will improve overall energy efficiency.

* * *

To summarize the relevant statistics in this report, aggregate Pennsylvania sales in 2003 totaled 137.9 billion kilowatthours (KWH), a 0.2% increase from that of 2002 and represents 3.9% of the United States' total. Residential sales accounted for 34.1% of the total sales, followed by industrial (33.4%) and commercial (30.2%).

Between 1988 and 2003, the state’s energy demand grew an average annual rate of 1.5%. Residential sales grew at an annual rate of 1.8%, commercial at 3.0% and industrial at 0.03%. The current aggregate 5-year projection of growth in energy demand is 1.5%. This includes a residential growth rate of 1.3%, a commercial rate of 2.4% and an industrial rate of 0.8%.

The 2003 MAAC aggregate coincident system summer peak load of 53,566 MW was 3.6% lower than the MAAC all-time peak of 55,560 MW, occurring in 2002. Energy consumption in 2003 increased 1.0% from 2002. The regional total internal summer peak demand (including direct control load management and interruptible demand) is projected to increase to 60,152 MW by 2008 at an average annual growth rate of about 2.5%.

Net capacity resources are projected to grow from 65,902 MW in 2003 to 68,703 MW in 2008, an increase of 2,801 MW or 4.3%. The reserve margin is expected to peak at 23.0% in 2003, declining to 14.2% by 2008. (These figures do not include PJM West, which is a part of ECAR.) The majority of the capacity additions are expected to be natural gas-fueled combined-cycle units.

ECAR's non-coincident internal peak demand is projected to increase to 109,357 MW by the summer of 2008 at an average annual growth rate of 2.2%. Peak load reductions from direct load control programs and interruptible customers are expected to reach 2,650 MW by 2008. Energy demand is expected to grow at a rate of 2.0% per year.

ECAR's members project additions of 12,226 MW of new generating capacity by 2008, which includes 9,435 MW of uncommitted resources. A majority of this new capacity is projected to be short lead-time, gas-fired combustion turbine and combined cycle units (65.9%). Capacity margins for net internal demand are expected to range between 22.1% in 2003 to 19.5% in 2008.

Appendix A

Capacity and Demand Projections
Of ECAR and MAAC

Source: ECAR and MAAC Responses to the 2004 NERC Data Request
(formerly the EIA-411)

ECAR Actual and Projected Energy and Peak Demand

Actual Data:	**2003**	**Jan.**	**Feb.**	**March**	**April**	**May**	**June**	**July**	**Aug.**	**Sept.**	**Oct.**	**Nov.**	**Dec.**
Peak Hour Demand - MW		86,339	80,792	77,618	70,007	69,116	95,520	90,385	98,487	79,510	69,179	75,525	80,945
Net Energy - GWH		51,098	45,390	45,191	40,889	41,542	43,785	49,352	50,904	43,335	42,659	42,612	48,352

Reporting Year:	**2004**	**Jan.**	**Feb.**	**March**	**April**	**May**	**June**	**July**	**Aug.**	**Sept.**	**Oct.**	**Nov.**	**Dec.**
Peak Hour Demand - MW		86,332	82,343	77,533	69,759	81,027	96,523	102,423	102,087	91,222	72,811	77,448	84,196
Net Energy - GWH		50,685	45,060	45,819	41,454	43,406	47,639	52,396	51,486	44,714	44,153	44,044	48,932

Next Year:	**2005**	**Jan.**	**Feb.**	**March**	**April**	**May**	**June**	**July**	**Aug.**	**Sept.**	**Oct.**	**Nov.**	**Dec.**
Peak Hour Demand - MW		87,972	84,353	79,217	71,274	82,788	98,650	104,765	104,216	93,341	74,468	79,096	85,893
Net Energy - GWH		51,728	45,313	46,843	42,285	44,392	48,721	53,400	52,594	45,497	45,034	44,941	49,919

Actual Previous Year and	**Actual**	**Projected**									
10 Year Projection:	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Peak Hour Demand - MW - Summer	98,487	102,423	104,765	107,689	109,852	112,007	113,674	115,579	117,442	119,254	120,769

Actual Previous Year and	**Actual**	**Projected**									
10 Year Projection:	**03/04**	**04/05**	**05/06**	**06/07**	**07/08**	**08/09**	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**
Peak Hour Demand - MW - Winter	86,332	87,972	89,268	91,131	93,128	95,558	97,073	98,558	98,904	100,526	102,108

Actual Previous Year and	**Actual**	**Projected**									
10 Year Projection:	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Net Energy - GWH	545,109	559,788	570,667	582,651	591,555	600,407	608,905	618,599	628,156	638,269	646,707

Peak demands are sum of monthly company peaks (non-coincicent).

MAAC Actual and Projected Energy and Peak Demand

Actual Data: 2003	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	46,239	42,024	41,312	36,722	34,072	53,444	51,356	53,566	40,346	34,966	36,848	41,328
Net Energy - GWH	25,939	22,777	22,392	20,278	20,164	22,634	26,978	27,541	21,927	20,828	20,747	24,393

Reporting Year: 2004	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	44,646	43,044	41,107	37,732	43,378	54,046	56,886	55,564	49,081	38,109	39,576	43,365
Net Energy - GWH	25,280	22,810	22,678	20,448	20,943	23,654	27,276	26,766	22,274	21,252	21,707	24,445

Next Year: 2005	Jan.	Feb.	March	April	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Peak Hour Demand - MW	45,466	43,868	41,886	38,512	44,311	55,178	58,056	56,688	50,077	38,871	40,313	44,170
Net Energy - GWH	25,701	22,978	23,009	20,788	21,289	24,058	27,692	27,225	22,631	21,582	22,043	24,848

Actual Previous Year and	Actual	Projected									
10 Year Projection:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Peak Hour Demand - MW - Summer	53,566	56,886	58,056	59,126	60,170	61,224	62,276	63,339	64,403	65,455	66,508

Actual Previous Year and	Actual	Projected									
10 Year Projection:	03/04	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Peak Hour Demand - MW - Winter	45,625	45,471	46,215	46,955	47,690	48,420	49,160	49,899	50,638	51,360	52,100

Actual Previous Year and	Actual	Projected									
10 Year Projection:	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Net Energy - GWH	276,600	279,533	283,844	288,461	293,018	297,832	302,192	306,853	311,420	316,088	320,538

ECAR Projected Capacity and Demand - Summer

	Actual	Projected									
Demand in Megawatts	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Internal Demand	98,487	102,423	104,765	107,689	109,852	112,007	113,674	115,579	117,442	119,254	120,769
Standby Demand											
Total Internal Demand	98,487	102,423	104,765	107,689	109,852	112,007	113,674	115,579	117,442	119,254	120,769
Direct Control Load Management		172	207	240	274	289	290	291	291	293	294
Interruptible Demand		2,471	2,426	2,395	2,385	2,361	2,302	2,308	2,216	2,232	2,240
Net Internal Demand	98,487	99,780	102,132	105,054	107,193	109,357	111,082	112,980	114,935	116,729	118,235

	Actual	Projected									
Capacity in Megawatts	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Committed Resources	125,615	128,406	128,406	128,406	128,406	128,406	128,406	128,406	128,406	128,406	128,406
Distributed Generator Capacity											
Other Capacity >= 1 MW	125,579	128,370	128,370	128,370	128,370	128,370	128,370	128,370	128,370	128,370	128,370
Distributed Generator Capacity											
Other Capacity < I MW	36	36	36	36	36	36	36	36	36	36	36
Uncommitted Resources			2,480	7,008	7,935	9,435	10,167	10,167	10,167	10,167	10,167
Total Capacity	125,615	128,406	130,886	135,414	136,341	137,841	138,573	138,573	138,573	138,573	138,573
Nuclear	7,739	7,733	8,001	10,561	10,561	12,061	12,793	12,793	12,793	12,793	12,793
Hydro	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052	1,052
Pumped Storage	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138
Geothermal											
Steam	86,786	86,642	86,642	86,642	86,642	86,642	86,642	86,642	86,642	86,642	86,642
Coal	82,862	82,715	82,715	82,715	82,715	82,715	82,715	82,715	82,715	82,715	82,715
Oil	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570	1,570
Gas	2,354	2,357	2,357	2,357	2,357	2,357	2,357	2,357	2,357	2,357	2,357
Dual Fuel											
Combustion Turbine	20,410	21,137	21,365	21,893	21,893	21,893	21,893	21,893	21,893	21,893	21,893
Oil	1,799	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796	1,796
Gas	18,611	19,341	19,569	20,097	20,097	20,097	20,097	20,097	20,097	20,097	20,097
Dual Fuel											
Combined Cycle	6,774	8,988	10,972	12,412	13,339	13,339	13,339	13,339	13,339	13,339	13,339
Oil											
Gas	6,774	8,988	10,972	12,412	13,339	13,339	13,339	13,339	13,339	13,339	13,339
Dual Fuel											
Other	716	716	716	716	716	716	716	716	716	716	716
Inoperable Capacity	1,860	1,943	1,943	1,943	1,943	1,943	1,943	1,943	1,943	1,943	1,943
Net Operable Capacity	123,755	126,463	128,943	133,471	134,398	135,898	136,630	136,630	136,630	136,630	136,630
Capacity Purchases - Total		2,902									
Full Responsibility Purchases											
Capacity Sales - Total		1,200									
Full Responsibility Sales											
Adjustment to Purchases and Sales											
Net Capacity Resources	123,755	128,165	128,943	133,471	134,398	135,898	136,630	136,630	136,630	136,630	136,630

ECAR Projected Capacity and Demand - Winter

Demand in Megawatts	Actual 03/04	Projected 04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Internal Demand	86,332	87,972	89,268	91,131	93,128	95,558	97,073	98,558	98,904	100,526	102,108
Standby Demand											
Total Internal Demand	86,332	87,972	89,268	91,131	93,128	95,558	97,073	98,558	98,904	100,526	102,108
Direct Control Load Management		170	173	174	176	178	180	182	184	186	188
Interruptible Demand		1,990	1,994	1,937	1,920	1,860	1,864	1,870	1,875	1,887	1,864
Net Internal Demand	86,332	85,812	87,101	89,020	91,032	93,520	95,029	96,506	96,845	98,453	100,056

Capacity in Megawatts	Actual 03/04	Projected 04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14
Committed Resources	131,296	133,387	133,387	133,387	133,387	133,387	133,387	133,387	133,387	133,387	133,387
Distributed Generator Capacity											
Other Capacity >= 1 MW	131,257	133,632	133,632	133,632	133,632	133,632	133,632	133,632	133,632	133,632	133,632
Distributed Generator Capacity											
Other Capacity < 1 MW	39	39	39	39	39	39	39	39	39	39	39
Uncommitted Resources			2,710	7,470	8,500	10,000	10,732	10,732	10,732	10,732	10,732
Total Capacity	131,296	133,387	136,097	140,857	141,887	143,387	144,119	144,119	144,119	144,119	144,119
Nuclear	7,872	7,872	7,872	7,872	7,872	7,872	7,872	7,872	7,872	7,872	7,872
Hydro	1,091	1,091	1,091	1,091	1,091	1,091	1,091	1,091	1,091	1,091	1,091
Pumped Storage	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138	2,138
Geothermal											
Steam	87,321	87,311	87,579	90,139	90,139	91,639	92,371	92,371	92,371	92,371	92,371
Coal	83,512	83,512	83,780	86,340	86,340	87,840	88,572	88,572	88,572	88,572	88,572
Oil	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585	1,585
Gas	2,224	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214	2,214
Dual Fuel											
Combustion Turbine	23,804	24,792	25,050	25,650	25,650	25,650	25,650	25,650	25,650	25,650	25,650
Oil	2,098	2,098	2,098	2,098	2,098	2,098	2,098	2,098	2,098	2,098	2,098
Gas	21,706	22,694	22,952	23,552	23,552	23,552	23,552	23,552	23,552	23,552	23,552
Dual Fuel											
Combined Cycle	8,355	9,459	11,643	13,243	14,273	14,273	14,273	14,273	14,273	14,273	14,273
Oil											
Gas	8,355	9,459	11,643	13,243	14,273	14,273	14,273	14,273	14,273	14,273	14,273
Dual Fuel											
Other	715	724	724	724	724	724	724	724	724	724	724
Inoperable Capacity	1,945	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678	1,678
Net Operable Capacity	129,351	131,709	134,419	139,179	140,209	141,709	142,441	142,441	142,441	142,441	142,441
Capacity Purchases - Total		2,813									
Full Responsibility Purchases											
Capacity Sales - Total		1,165									
Full Responsibility Sales											
Adjustment to Purchases and Sales											
Net Capacity Resources	129,351	133,357	134,419	139,179	140,209	141,709	142,441	142,441	142,441	142,441	142,441

MAAC Projected Capacity and Demand - Summer

	Actual	Projected									
Demand in Megawatts	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Internal Demand	53,566	56,891	58,061	59,126	60,170	61,224	62,276	63,339	64,403	65,455	66,508
Standby Demand	0	0	0	0	0	0	0	0	0	0	0
Total Internal Demand	53,566	56,891	58,061	59,126	60,170	61,224	62,276	63,339	64,403	65,455	66,508
Direct Control Load Management	0	619	619	619	619	619	619	619	619	619	619
Interruptible Demand	0	463	453	453	453	453	453	453	453	453	453
Net Internal Demand	53,566	55,809	56,989	58,054	59,098	60,152	61,204	62,267	63,331	64,383	65,436

	Actual	Projected									
Capacity in Megawatts	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Committed Resources	65,409	66,062	68,103	68,660	68,660	68,660	68,660	68,660	68,660	68,660	68,660
Distributed Generator Capacity	5	5	5	5	5	5	5	5	5	5	5
Other Capacity >= 1 MW	0	0	0	0	0	0	0	0	0	0	0
Distributed Generator Capacity	0	0	0	0	0	0	0	0	0	0	0
Other Capacity < 1 MW	0	0	0	0	0	0	0	0	0	0	0
Uncommitted Resources	0	0	0	0	0	0	0	0	0	0	0
Total Capacity	65,414	66,067	68,108	68,665	68,665	68,665	68,665	68,665	68,665	68,665	68,665
Nuclear	13,097	13,232	13,232	13,232	13,232	13,232	13,232	13,232	13,232	13,232	13,232
Hydro	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205	1,205
Pumped Storage	1,905	1,905	1,905	1,905	1,905	1,905	1,905	1,905	1,905	1,905	1,905
Geothermal	0	0	0	0	0	0	0	0	0	0	0
Steam	28,354	28,417	28,417	28,417	28,417	28,417	28,417	28,417	28,417	28,417	28,417
Coal	15,032	15,549	15,549	15,549	15,549	15,549	15,549	15,549	15,549	15,549	15,549
Oil	2,516	2,541	2,541	2,541	2,541	2,541	2,541	2,541	2,541	2,541	2,541
Gas	78	78	78	78	78	78	78	78	78	78	78
Dual Fuel	10,728	10,249	10,249	10,249	10,249	10,249	10,249	10,249	10,249	10,249	10,249
Combustion Turbine	10,773	10,354	11,644	12,201	12,201	12,201	12,201	12,201	12,201	12,201	12,201
Oil	4,096	3,837	3,837	3,837	3,837	3,837	3,837	3,837	3,837	3,837	3,837
Gas	1,826	1,836	3,126	3,683	3,683	3,683	3,683	3,683	3,683	3,683	3,683
Dual Fuel	4,851	4,681	4,681	4,681	4,681	4,681	4,681	4,681	4,681	4,681	4,681
Combined Cycle	10,075	9,869	10,619	10,619	10,619	10,619	10,619	10,619	10,619	10,619	10,619
Oil	0	0	0	0	0	0	0	0	0	0	0
Gas	3,447	4,639	5,389	5,389	5,389	5,389	5,389	5,389	5,389	5,389	5,389
Dual Fuel	5,548	5,230	5,230	5,230	5,230	5,230	5,230	5,230	5,230	5,230	5,230
Other	1,080	1,080	1,081	1,081	1,081	1,081	1,081	1,081	1,081	1,081	1,081
Inoperable Capacity	0	0	0	0	0	0	0	0	0	0	0
Net Operable Capacity	65,414	66,067	68,108	68,665	68,665	68,665	68,665	68,665	68,665	68,665	68,665
Capacity Purchases - Total	488	488	488	38	38	38	38	38	38	38	38
Full Responsibility Purchases	0	0	0	0	0	0	0	0	0	0	0
Capacity Sales - Total	0	0	0	0	0	0	0	0	0	0	0
Full Responsibility Sales	0	0	0	0	0	0	0	0	0	0	0
Adjustment to Purchases and Sales	0	0	0	0	0	0	0	0	0	0	0
Net Capacity Resources	65,902	66,555	68,596	68,703	68,703	68,703	68,703	68,703	68,703	68,703	68,703

MAAC Projected Capacity and Demand - Winter

	Actual	Projected									
Demand in Megawatts	**03/04**	**04/05**	**05/06**	**06/07**	**07/08**	**08/09**	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**
Internal Demand	45,625	45,471	46,215	46,955	47,690	48,420	49,160	49,899	50,638	51,360	51,245
Standby Demand	0	0	0	0	0	0	0	0	0	0	0
Total Internal Demand	45,625	45,471	46,215	46,955	47,690	48,420	49,160	49,899	50,638	51,360	51,245
Direct Control Load Management	0	55	55	55	55	55	55	55	55	55	55
Interruptible Demand	0	344	344	344	344	344	344	344	344	344	303
Net Internal Demand	45,625	45,072	45,816	46,556	47,291	48,021	48,761	49,500	50,239	50,961	50,887

	Actual	Projected									
Capacity in Megawatts	**03/04**	**04/05**	**05/06**	**06/07**	**07/08**	**08/09**	**09/10**	**10/11**	**11/12**	**12/13**	**13/14**
Committed Resources	67,646	69,624	70,717	70,717	70,717	70,717	70,717	70,717	70,717	70,717	70,717
Distributed Generator Capacity	5	5	5	5	5	5	5	5	5	5	5
Other Capacity >= 1 MW	0	0	0	0	0	0	0	0	0	0	0
Distributed Generator Capacity	0	0	0	0	0	0	0	0	0	0	0
Other Capacity < 1 MW	0	0	0	0	0	0	0	0	0	0	0
Uncommitted Resources	0	0	0	0	0	0	0	0	0	0	0
Total Capacity	67,651	69,629	70,722	70,722	70,722	70,722	70,722	70,722	70,722	70,722	70,722
Nuclear	13,174	13,309	13,309	13,309	13,309	13,309	13,309	13,309	13,309	13,309	13,309
Hydro	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179	1,179
Pumped Storage	1,749	1,749	1,749	1,749	1,749	1,749	1,749	1,749	1,749	1,749	1,749
Geothermal	0	0	0	0	0	0	0	0	0	0	0
Steam	28,724	28,776	28,776	28,776	28,776	28,776	28,776	28,776	28,776	28,776	28,776
Coal	15,110	15,627	15,627	15,627	15,627	15,627	15,627	15,627	15,627	15,627	15,627
Oil	2,609	2,634	2,634	2,634	2,634	2,634	2,634	2,634	2,634	2,634	2,634
Gas	79	79	79	79	79	79	79	79	79	79	79
Dual Fuel	10,926	10,436	10,436	10,436	10,436	10,436	10,436	10,436	10,436	10,436	10,436
Combustion Turbine	12,519	11,956	11,956	11,956	11,956	11,956	11,956	11,956	11,956	11,956	11,956
Oil	4,947	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588	4,588
Gas	1,931	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944	1,944
Dual Fuel	5,641	5,423	5,423	5,423	5,423	5,423	5,423	5,423	5,423	5,423	5,423
Combined Cycle	9,232	11,585	12,678	12,678	12,678	12,678	12,678	12,678	12,678	12,678	12,678
Oil	0	0	0	0	0	0	0	0	0	0	0
Gas	3,543	6,234	7,327	7,327	7,327	7,327	7,327	7,327	7,327	7,327	7,327
Dual Fuel	5,689	5,350	5,350	5,350	5,350	5,350	5,350	5,350	5,350	5,350	5,350
Other	1,069	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071
Inoperable Capacity	0	0	0	0	0	0	0	0	0	0	0
Net Operable Capacity	67,651	69,629	70,722	70,722	70,722	70,722	70,722	70,722	70,722	70,722	70,722
Capacity Purchases - Total	488	488	488	38	38	38	38	38	38	38	38
Full Responsibility Purchases	0	0	0	0	0	0	0	0	0	0	0
Capacity Sales - Total	0	0	0	0	0	0	0	0	0	0	0
Full Responsibility Sales	0	0	0	0	0	0	0	0	0	0	0
Adjustment to Purchases and Sales	0	0	0	0	0	0	0	0	0	0	0
Net Capacity Resources	68,139	70,117	71,210	70,760	70,760	70,760	70,760	70,760	70,760	70,760	70,760

ECAR Transmission Line Circuit Miles

		Voltage Class (kV)				Total
		230	345	500	765	
Existing	**12/31/2003**	1,274	12,089	852	2,224	16,439
Under Construction	**First 5 Years**	7	11	0	91	109
Committed or Planned	**Second 5 Years**	0	0	0	0	0
		======	======	======	======	======
Total	**12/31/2013**	1,281	12,100	852	2,315	16,548

MAAC Transmission Line Circuit Miles

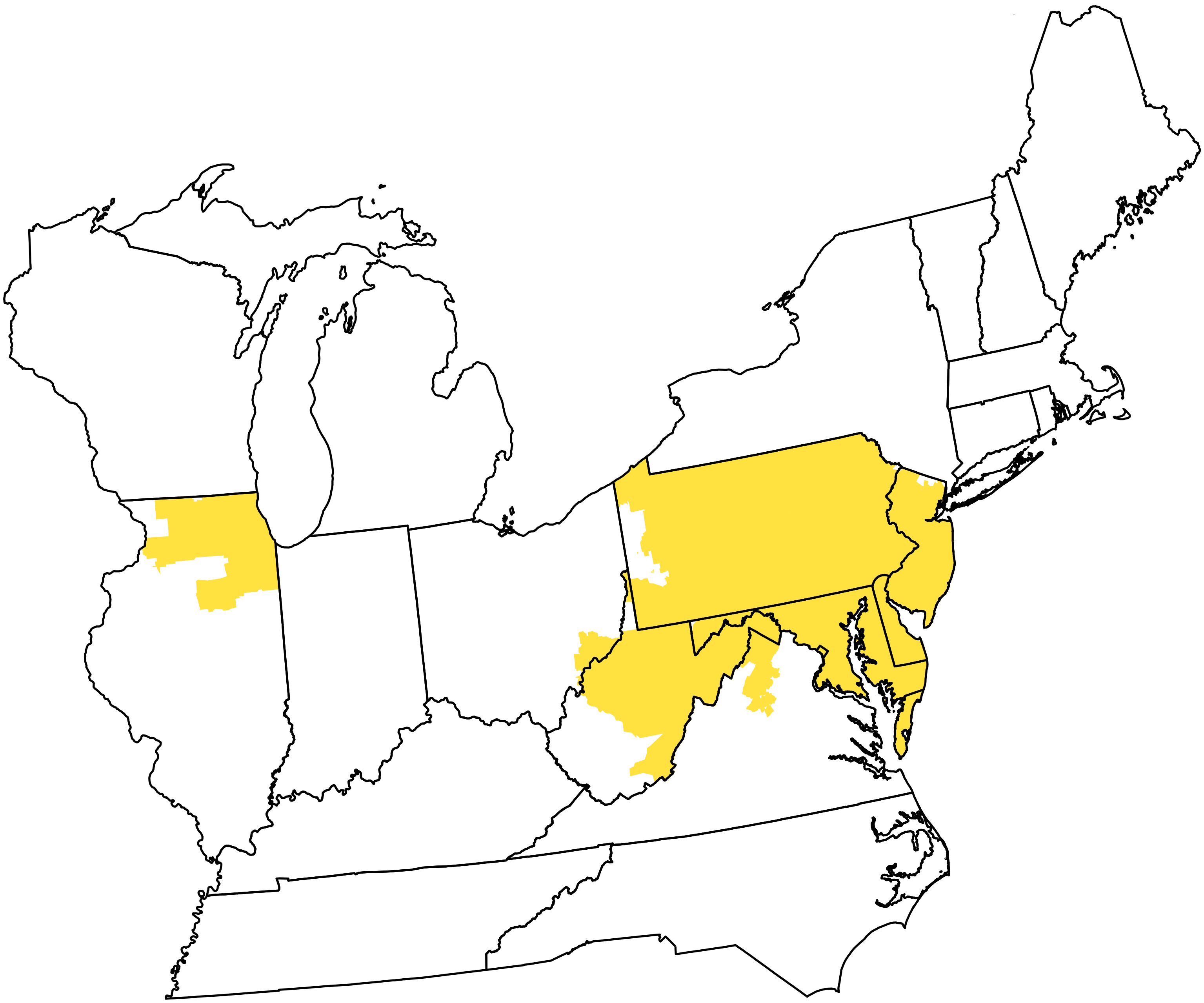
		Voltage Class (kV)				Total
		230	345	500	765	
Existing	**12/31/2003**	5,216	165	1,676	0	7,057
Under Construction	**First 5 Years**	134	0	0	0	134
Committed or Planned	**Second 5 Years**	0	0	0	0	0
		======	======	======	======	======
Total	**12/31/2013**	5,350	165	1,676	0	7,191

Appendix B

PJM Control Area

Source: http://www.pjm.com

PJM Control Area



Appendix C

Transmission Line Projections

Source: http://www.pjm.com

Transmission Line Projections (over 100 kV)

Company	Transmission Line	County	Design Voltage	Length	Construction Start Date	In-Service Date	Line Cost
Duquesne	Cheswick - North	Allegheny	138 kV	3.5 mi.	Jun-04	Jun-05	$1,750,000
Duquesne	Dravosburg - Wilmerding	Allegheny	138 kV	0.1 mi.	Apr-04	Jun-04	$150,000
Duquesne	Cheswick - North	Allegheny	138 kV	2.2 mi.	Jun-05	Jun-06	$750,000
Duquesne	Dravosburg - Oakland	Pittsburgh	138 KV	0.9 mi.	Mar-05	Jun-05	$450,000
Duquesne	BI-North	Pittsburgh	138 KV	10.0 mi.	Jan-06	Jun-07	$5,000,000
Met-Ed	Middletown Jct.	Lanc/York	115 kV	8.8 mi.	2004	2004	n/a
Met-Ed	Glendon - Gilbert	Northampton	115 kV	11.7 mi.	2005	2005	n/a
Penelec	North Meshoppen	Susquehanna	230 kV	0.4 mi.	2002	2003	$771,000
PPL	Otter Creek - Yorkana	York	230 kV	12.0 mi.	Jun-03	May-04	$11,673,000
PPL	Dauphin-Hummelstown	Dauphin	230 kV	1.5 mi.	Mar-09	Nov-09	$5,300,000
PPL	Martins Creek - Gilbert	Northampton	230 kV	0.3 mi.	Oct-03	Nov-03	$703,000
PPL	Jenkins	Luzerne	230 kV	0.6 mi.	Jan-06	Nov-06	$300,000
PPL	Susquehanna	Luzerne	230 kV	0.6 mi.	Jan-06	Nov-06	$300,000
PPL	Lackawanna	Lackawanna	138 kV	8.0 mi.	Jan-06	Nov-07	$6,605,000
PPL	Hauto-Frack	Carbon	138 kV	0.7 mi.	Jan-07	Nov-07	$276,000
PPL	W. Hempfield	Lancaster	138 kV	1.6 mi.	Oct-02	May-05	$2,079,000
PPL	Horseshoe	Lancaster	138 kV	3.0 mi.	Nov-03	May-05	$226,000
PPL	North Shamokin	Northumberland	138 kV	0.2 mi.	Jun-09	Nov-09	$497,000
PPL	Eldred-Pine Grove Rebuild	Schuylkill	138 kV	5.8 mi.	Dec-07	May-08	$4,891,000
PPL	Springfield	Bucks	230 kV	1.2 mi.	Aug-10	Sep-11	$3,586,000
PPL	Replace Sumner-Central	Lehigh	138 kV	1.3 mi.	Sep-07	Nov-07	$2,949,000
PPL	Seidersville-Quakertown	Northampton	138 kV	13.5 mi.	Sep-07	Nov-09	$33,898,000
PPL	Devonshire	Dauphin	138 kV	0.1 mi.	Feb-03	May-04	$78,000
PPL	Linglestown	Dauphin	138 kV	3.9 mi.	Apr-03	Nov-03	$929,000
PPL	Steel City-Quarry	Northampton	230 KV	2.0 mi.	May-02	May-03	$1,925,000
PECO	Richmond-Holmesburg	Philadelphia	230 kV	6.25 mi.	Feb-04	Apr-04	n/a
West Penn	South Fayette Substation	Allegheny	138 kV	0.5 mi.	Sep-04	Nov-04	$117,000
West Penn	Springdale - Butler	Allegheny	138 kV	0.4 mi.	Apr-03	Nov-03	$336,000
West Penn	Glade Run Loop	Armstrong	138 kV	6.6 mi.	Oct-04	Jun-05	$3,448,000
West Penn	Saxonburg Substation	Butler	138 kV	3.5 mi.	Sep-03	May-05	$3,230,000
West Penn	Saxonburg - Silverville	Butler	138 kV	8.0 mi.	Sep-07	May-08	$4,365,000
West Penn	Dale Substation Loop	Centre	230 kV	0.02 mi.	Sep-01	Jul-03	$141,000
West Penn	Carbon Center Jct.	Elk/McKean	138 kV	14.4 mi.	Jan-08	Nov-08	$2,719,000
West Penn	Elko - Carbon Center	Elk	230 kV	5.7 mi.	Nov-11	Jun-12	$7,091,000
West Penn	Manifold Loop	Washington	138 kV	1.5 mi.	Oct-04	May-05	$2,000,000
West Penn	Gordon - Van Kirk Jct.	Washington	138 kV	2.7 mi.	Sep-04	Dec-04	$1,453,000
West Penn	Vanceville	Washington	138 kV	0.1 mi.	Sep-08	Nov-08	$45,000
West Penn	Ethel Springs	Westmoreland	138 kV	2.5 mi.	Jan-05	Jun-05	$1,022,000
West Penn	Unity Substation Loop	Westmoreland	138 kV	0.1 mi.	May-06	Nov-06	$29,000

Appendix D

Status of Pennsylvania's New Power Plants

Source: http://www.pjm.com

Status of Pennsylvania's New Power Plants

Queue	Project	MW	In-Service	Status	Fuel
A09	Susquehanna	50	2003	In-Service	Nuclear
A12	Martins Creek	600	2004	Partially In-Service	Natural Gas
A18	North Temple	557	2003	In-Service	Natural Gas
A21	Chichester	725	2004	Under Construction	Natural Gas
A36	Hunterstown	830	2003	Partially In-Service	Natural Gas
A59	Emilie	540	2004	In-Service	Natural Gas
B03	Hosensack	750	2003	In-Service	Natural Gas
B18_W03	Springdale	582	2003	In-Service	Natural Gas
B28	Muddy Run	160	2003	In-Service	Natural Gas
B30	Emilie	605	2004	In-Service	Natural Gas
B34	Seward	304	2004	Under Construction	Coal
C02	South Lebanon	47	2004	Under Study	Natural Gas
C10	Erie East	100	2005	Under Construction	Natural Gas
D05	East Carbondale	70	2003	In-Service	Wind
D18	Hosensack	350	2003	Partially In-Service	Natural Gas
E17_W27	Ronco	620	2003	In-Service	Natural Gas
F04	Somerset	30	2004	Under Study	Wind
G05	Brunner Island #1	14	2004	In-Service	Coal
G06	Martins Creek #4	30	2005	Under Study	Coal
G21	Myersdale North	48	2003	In-Service	Wind
G30_W53	South Bend	104	2003	In-Service	Natural Gas
G46	Peach Bottom	70	2004	Under Construction	Nuclear
G51_W60	Hatfield Ferry	525	2006	Under Study	Coal
G51_W63	Upton	10	2003	In-Service	Methane
H02	Susquehanna	9	2004	Under Construction	Nuclear
H03	Susquehanna	9	2003	In-Service	Nuclear
H06	Chichester	25	2004	Under Study	Natural Gas
I04	Somerset-Allegheny	45	2004	Under Study	Wind
I12	Grand Point	31	2004	In-Service	Diesel
I13	Hooversville	30	2004	Under Study	Wind
I14	Upton	4	2004	In-Service	Methane
J09	Harrisburg	26	2006	Under Study	Methane
K02	East Towanda-Moshannon	70	2005	Under Study	Wind
K10	Somerset	6	2004	Under Study	Wind
K12	Somerset-Allegheny	14	2004	Under Study	Wind
K13	Hooversville	7	2004	Under Study	Wind
K18	Arnold	2	2004	Under Study	Wind
K20	Mill Run	3	2004	Under Study	Wind
K21	East Carbondale	13	2004	Under Study	Wind
K22	Somerset	2	2004	Under Study	Wind
K23	Meyersdale North	6	2004	Under Study	Wind

Status of Pennsylvania's New Power Plants

Queue	Project	MW	In-Service	Status	Fuel
L03	Morgantown	1	2004	Under Study	Methane
L07	Jenkins-Harwood #2	43	2005	Under Study	Wind
L08	Holtwood	2	2003	In-Service	Natural Gas
L09	Montour #1	2	2003	In-Service	Coal
L10	Hatfield	520	2006	Under Study	Coal
L11	Rockwood	10	2005	Under Study	Wind
L13	Rockwood	40	2005	Under Study	Wind
L17	Rolling Hills	6	2004	Under Study	Natural Gas
L18	Bear Creek	34	2004	Under Study	Wind
L19	Karthaus	290	2008	Under Study	Coal
L20	Birdsboro	10	2005	Under Study	Methane
M02	Jenkins-Harwood #2	8	2004	Under Study	Wind
M06	Grand Point	31	2004	Under Study	Diesel
M07	Peckville	6	2004	In-Service	Natural Gas
M08	Somerset-Allegheny	20	2004	Under Study	Wind
M11	Susquehanna #1	111	2008	Under Study	Natural Gas
M12	Susquehanna #2	107	2007	Under Study	Natural Gas
M15	Union City	302	2006	Under Study	Natural Gas
	Total MW	**9,566**			

Source: PJM

PJM Mid-Atlantic + APS
Megawatt Summary by Queue Letter
As of June 30, 2004

Queue	Active	In-Service	Under Construction	Withdrawn	Total MW Requests
A	105	6,883	1,475	18,085	**26,548**
B	0	3,686	304	15,882	**19,872**
C	47	27	536	3,954	**4,564**
D	0	744	0	7,603	**8,347**
E	727	795	0	16,910	**18,432**
F	30	52	0	3,063	**3,145**
G	1,795	402	70	21,293	**23,560**
H	612	147	9	8,422	**9,190**
I	150	31	10	4,818	**5,009**
J	233	8	6	655	**902**
K	295	35	23	1,902	**2,255**
L	1,061	0	0	2,375	**3,436**
M	2,932	6	100	0	**3,038**
Total MW	**7,987**	**12,816**	**2,533**	**104,962**	**128,298**

Source: PJM

Appendix E

Pennsylvania's Existing Electric Generating Facilities

Source: http://www.epga.org/GeneratingFacilities.html

COMPANY NAME	ST.	PLANT NAME	FUEL TYPE	ALT. FUEL TYPE	TECH. TYPE	MW
A/C Power-Colver Operations	PA	Colver Power Project	Waste Coal			102
AES Corporation	PA	Ironwood	Gas		CC	705
AES Corporation	PA	Beaver Valley	Coal			120
Allegheny Electric Cooperative*	PA	Raystown Hydroelectric Project (Matsen)	Water			21.7
Allegheny Energy Supply*	PA	Armstrong Generating Station	Coal			356
Allegheny Energy Supply*	PA	Chambersburg Generating Facility	Gas		SC	88
Allegheny Energy Supply*	PA	Gans Generating Facility	Gas			88
Allegheny Energy Supply*	PA	Hatfield's Ferry Power Station	Coal			1710
Allegheny Energy Supply*	PA	Lake Lynn Hydroelectric Project	Water			52
Allegheny Energy Supply*	PA	Mitchell Generating Station	Coal	Oil		370
Allegheny Energy Supply*	PA	Springdale, Units 1,2,3,4 & 5	Gas		CC	628
AmerGen Energy Co. LLC	PA	Three Mile Island	Nuclear			850
American Ref-Fuel Co.	PA	Delaware Valley Resource Recovery Facility	Other			90
BioEnergy Partners	PA	Pottstown Plant	Other			6.4
Calpine Corporation	PA	Ontelaunee Energy Center	Gas		CC	545
Calpine Corporation	PA	Philadelphia Water Project	Gas			23
Cambria Cogen Co.	PA	Cambria County Cogen	Waste Coal			85
Chambersburg Borough Electric Dept	PA	Chambersburg Power Plant	Gas		IC	7.27
City of Harrisburg	PA	Harrisburg WTE Plant	Other			8.2
Conectiv Energy	PA	North East Cogeneration Plant	Gas		CC	81.8
Conectiv Energy	PA	Bethlehem Plant	Gas		CC	1,100
Constellation Power Inc.	PA	Panther Creek Energy Facility	Waste Coal			80
Constellation Power Inc.	PA	Handsome Lake Plant	Gas		SC	250
Covanta Energy Corporation	PA	Lancaster County Resource Recovery Facility	Other			35.7
Dominion Generation	PA	Armstrong County	Gas	Oil	CT	600
Dominion Generation	PA	Bucks County	Gas		SC	1100
Duke Energy	PA	Fayette County	Gas		CC	620
Exelon Generation Co. LLC*	PA	Clairton USX (Fairless Hills)	Other		ST/S	60
Exelon Generation Co. LLC*	PA	Cromby Generating Station	Coal	Oil/Nat. Gas		388
Exelon Generation Co. LLC*	PA	Croydon Plant	Gas			370
Exelon Generation Co. LLC*	PA	Eddystone Generating Station	Coal	Oil/Nat. Gas		1340
Exelon Generation Co. LLC*	PA	Falls Plant	Gas			50
Exelon Generation Co. LLC*	PA	Delaware Generating Station (Retiring)	Oil			250
Exelon Generation Co. LLC*	PA	Exelon Power Dist. Gen. Group (47 Units)	Oil	Gas		795
Exelon Generation Co. LLC*	PA	Grows Landfill	Other			6.6
Exelon Generation Co. LLC*	PA	Limerick Nuclear Generating Station	Nuclear			2286
Exelon Generation Co. LLC*	PA	Moser Plant	Oil			48
Exelon Generation Co. LLC*	PA	Muddy Run Hydroelectric Plant	Water			1072
Exelon Generation Co. LLC*	PA	Peach Bottom Atomic Power Station	Nuclear			2186
Exelon Generation Co. LLC*	PA	Pennsbury Plant	Oil			48
Exelon Generation Co. LLC*	PA	Schuylkill Generating Station	Oil			166
Exelon Generation Co. LLC*	PA	Southwark Plant	Oil			54
FirstEnergy Generation Corp.*	PA	Bruce Mansfield Plant	Coal			2360
FirstEnergy Generation Corp.*	PA	York Haven	Water			19
FirstEnergy Generation Corp.*	PA	Seneca Pumped Storage Plant	Water			435
FirstEnergy Nuclear Operating Co.*	PA	Beaver Valley Power Station	Nuclear			1630
FPL Energy	PA	Marcus Hook Plant	Gas		CC	750
FPL Energy	PA	Mill Run Wind (FPL)	Wind			15
FPL Energy	PA	Somerset Wind Farm (FPL)	Wind			9
FPL Energy	PA	Moosic Mountain Wind Farm (FPL)	Wind			50
General Chemical Corp.	PA	Marcus Hook Cogen	Oil			4.5
General Electric Co.	PA	Erie Works Plant	Coal			36
General Electric Co.	PA	Grove City Plant	Oil			10.6
Gilberton Power Co.	PA	John B Rich Power Station	Waste Coal			80
Indiana University of Pennsylvania	PA	S.W. Jack Cogeneration Plant	Gas			24
Kimberly Clark	PA	Chester Operations	Waste Coal			60
Merck & Co., Inc.	PA	West Point (PA) Merck Plant	Gas			30.25
Mid-Atlantic Energy Co.	PA	Piney Creek LP	Waste Coal			32
Midwest Generation LLC	PA	Homer City (EME) Generation	Coal			2012
Montenay Power Corp.	PA	Montgomery County	Other			31
Montenay Power Corp.	PA	Yourk County WTE	Other			35
Mount Carmel Power	PA	Mount Carmel	Waste Coal			40
National Renewable Resources Assoc.	PA	Conemaugh Saltsburg	Water			15
PEI Power Corp.	PA	Archbald Power Station	Gas		CT	70
Penntech Paper Inc.	PA	Bradford (PA) Plant	Coal			52
PG&E National Energy Group	PA	Northhampton Generating Station	Waste Coal			107
PG&E National Energy Group	PA	Scrubgrass Generating Plant	Waste Coal			83
Power Systems Operations	PA	Ebensburg Plant	Waste Coal			50
PPL Generation LLC*	PA	PPL Bruner Island	Coal			1434

COMPANY NAME	ST.	PLANT NAME	FUEL TYPE	ALT. FUEL TYPE	TECH. TYPE	MW
PPL Generation LLC*	PA	PPL Martins Creek	Coal	Oil		1920
PPL Generation LLC*	PA	PPL Montour LLC	Coal			1526
PPL Generation LLC*	PA	PPL Holtwood	Water			109
PPL Generation LLC*	PA	PPL Lower Mt. Bethel	Gas		CC	575
PPL Generation LLC*	PA	PPL Susquehanna LLC	Nuclear			2352
PPL Generation LLC*	PA	PPL Wallenpaupack	Water			44
Procter & Gamble	PA	Mehoopany Plant	Gas			45
Reliant Energy Wholesale Group*	PA	Blossburg Plant (Mothball Pending)	Gas			19
Reliant Energy Wholesale Group*	PA	Cheswick Generating Station	Coal			577
Reliant Energy Wholesale Group*	PA	Conemaugh Power Plant	Coal	Gas		1883
Reliant Energy Wholesale Group*	PA	Elrama Generating Station	Coal			474
Reliant Energy Wholesale Group*	PA	Hamilton CT	Oil			20
Reliant Energy Wholesale Group*	PA	FR Philips Generating Station	Coal			411.3
Reliant Energy Wholesale Group*	PA	Keystone Generating Station	Coal	Oil		1883
Reliant Energy Wholesale Group*	PA	Mountain Plant	Gas	Oil		40
Reliant Energy Wholesale Group*	PA	New Castle Generating Station	Coal	Oil		303
Reliant Energy Wholesale Group*	PA	Orrtanna Plant	Oil			20
Reliant Energy Wholesale Group*	PA	Piney	Water			27
Reliant Energy Wholesale Group*	PA	Portland Generating Station	Coal	Gas		570
Reliant Energy Wholesale Group*	PA	Seward Generating Station	Waste Coal			521
Reliant Energy Wholesale Group*	PA	Shawville Generating Station	Coal	Oil		603
Reliant Energy Wholesale Group*	PA	Titus Generating Station	Coal	Gas		274
Reliant Energy Wholesale Group*	PA	Tolna Station	Oil			40
Reliant Energy Wholesale Group*	PA	*Warren Power Plant*	Gas	Oil		
Reliant Energy Wholesale Group*	PA	Brunot Island Generating Station	Gas	Oil		343
Reliant Energy Wholesale Group*	PA	Liberty Plant	Gas		CC	578
Reliant Energy Wholesale Group*	PA	Hunterstown Plant	Gas		CC	795
Reliant Energy Wholesale Group*	PA	*Wayne*	Oil			
Reliant Energy Wholesale Group*	PA	Shawnee CT	Oil			20
Rohm and Haas Co.	PA	Bristol	Oil			1.5
Safe Harbor Water Power Corp.	PA	Safe Harbor Hydroelectric Plant	Water			417.5
Schuylkill Energy Resources	PA	Shenandoah Plant	Waste Coal			80
Sithe Energies Inc.	PA	Allegheny Lock & Dam No. 8	Water			13
Sithe Energies Inc.	PA	Allegheny Lock & Dam No. 9	Water			17.4
Smurfit-Stone Corp.	PA	Philadelphia Container Plant	Oil			10
Solar Turbines Inc.	PA	York Solar Plant	Gas			70
Temple University	PA	Temple Univ. Standby Electric Gen. Facility	Gas			16
Tractebel Power Inc.	PA	NEPCO	Waste Coal			50
Tractebel Power Inc.	PA	Northumberland Cogeneration Facility	Other			16.2
Trigen Energy Corp.	PA	Grays Ferry Power Plant	Gas		CC	173.6
Trigen Energy Corp.	PA	Pennsylvania House Power Plant	Other			0.1
UGI Development Co.*	PA	Hunlock Creek Power Station	Coal	Oil		50
UGI Development Co.*	PA	Hunlock Creek Power Station	Gas		CT	50
Wheelabrator Technologies Inc.	PA	Frackville Energy Co.	Waste Coal			42
Wheelabrator Technologies Inc.	PA	Wheelabrator Falls WTE	Other			53
Wind Developers	PA		Wind			250
WPS Power Development	PA	Sunbury Generating Station	Coal	Oil		462.5
WPS Power Development	PA	WPS Westwood Generation	Waste Coal			30
Total MW in PA						**46092**