Electric Power Outlook for Pennsylvania 2009-2014

July 2010

Pennsylvania Public Utility Commission

ELECTRIC POWER OUTLOOK FOR PENNSYLVANIA 2009–2014

July 2010

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Introduction

Section 524(a) of the Public Utility Code (Code) requires jurisdictional electric distribution companies to submit to the Commission information concerning plans and projections for meeting future customer demand.[1] The Commission's regulations set forth the form and content of such information, which is to be filed on or before May 1 of each year.[2] Section 524(b) of the Code requires that the Commission prepare an annual report summarizing and discussing the data provided, on or before Sept. 1. This report is to be submitted to the General Assembly, the Governor, the Office of Consumer Advocate and each affected public utility.[3]

Since the enactment of the *Electricity Generation Customer Choice and Competition Act*,[4] the Commission's regulations have been modified to reflect the competitive market. Thus, projections of generating capability and overall system reliability have been obtained from regional assessments.

Overview

This report concludes that there is sufficient generation, transmission and distribution capacity to reasonably meet the needs of Pennsylvania's electricity consumers for the near future. Additional generating capacity will likely be needed by 2015.

Regional generation adequacy and reserve margins of the Mid-Atlantic area have been maintained. While sufficient generation capacity is expected through 2014, the Commission will continue its current policy of encouraging generation adequacy within the region.

With respect to transmission adequacy, the transmission system in the Mid-Atlantic Region has sufficient capacity to meet demand. Transmission expansions and upgrades are being planned for the next five years to reinforce the bulk power grid.

To summarize the relevant statistics in this report, electricity demand in Pennsylvania has grown at an average annual rate of 1.0 percent over the past 15 years. This is an aggregate figure for all sectors, including industrial, commercial and residential. Average total sales growth from 2004 to 2009 was 0.1 percent. Aggregate sales in 2009 totaled 142,161 GWh, a 4.2 percent decrease from that of 2008. The current projections for 2009-14 show electricity demand growth at 1.4 percent annually. This includes a residential growth rate of 0.9 percent, a commercial growth rate of 1.9 percent and an industrial growth rate of 1.6 percent.

Regionally, generating resources are projected to be adequate for the next several years. Reliability*First* Corporation's net internal demand forecast shows it increasing from 169,900 MW in 2009 to 193,100 MW in 2018 at an average annual growth rate of 1.4 percent. The need for additional capacity resources ranges from 929 MW in 2015 to 7,160 MW in 2018 to maintain an

[1] 66 Pa. C.S. § 524(a).
[2] 52 Pa. Code §§ 57.141—57.154.
[3] 66 Pa.C.S. § 524(b).
[4] 66 Pa.C.S. §§ 2801—2812.

adequate reserve margin. Net capacity resources are projected to be 219,755 MW by 2018, resulting in a reserve margin of 13.8 percent, not including conceptual resources.

Pennsylvania must maintain its commitment to the basics of energy production and to encourage new initiatives in demand side response, energy efficiency, renewable energy, and other new technologies so we can continue as a national leader in these areas. We also need to continue providing assistance to low-income customers to reduce their energy consumption.

Alternative Energy Portfolio Standards (Act 213)

The Commission continues to implement procedures and guidelines necessary to carry out the requirements of Act 213.[5] Act 213 requires that an annually increasing percentage of electricity sold to retail customers be derived from alternative energy resources, including solar, wind, low-impact hydropower, geothermal, biologically derived methane gas, fuel cells, biomass, coal mine methane, waste coal, demand side management, distributed generation, large-scale hydropower, by-products of wood pulping and wood manufacturing, municipal solid waste, and integrated combined coal gasification technology. The amount of electricity to be supplied by alternative resources increases to a total of 18 percent by 2021. A subsequent amendment to Act 213 required the Commission to update its net-metering regulations. Among other things, this allows net-metered customer-generators to receive full retail value for all energy produced in excess of internal use.

The Commission issued a Final Order governing the participation of demand side management, energy efficiency and load management programs and technologies in the alternative energy market. The Commission also issued Final Orders governing net metering and interconnection for customer-generators using renewable resources, consistent with the goal of Act 213, and promoting onsite generation by eliminating barriers, which may have previously existed regarding net metering and interconnection.

Energy Efficiency and Conservation Program (Act 129)

Act 129 of 2008[6] added Section 2806.1 to the Public Utility Code which requires that the Commission adopt an energy efficiency and conservation program for the reduction of energy demand and consumption within the service territory of each electric distribution company with at least 100,000 customers.[7] Sales are to be reduced by 1 percent by May 31, 2011, and 3 percent by May 31, 2013. Peak demand is to be reduced by 4.5 percent by May 31, 2013. Based on forecast growth data, consumption reduction goals total 1,467 GWh in 2011 and 4,400 GWh in 2013. Peak demand reduction goals total 1,193 MW for 2013.[8] Plans were filed on July 1, 2009.

Act 129 also requires an increase in the percentage share of Tier I alternative energy resources to be sold under the provisions of Act 213.

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[5] Alternative Energy Portfolio Standards Act, effective Feb. 28, 2005; 73 P.S. §§ 1648.1—1648.8.
[6] Energy Efficiency and Conservation Program, signed by Gov. Rendell on Oct.15, 2008.
[7] 66 Pa.C.S. § 2806.1.
[8] Docket No. M-2008-2069887.

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Section 1 - Introduction

Purpose

Electric Power Outlook for Pennsylvania 2009-2014 summarizes and discusses the current and future electric power supply and demand situation for the 11 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 which encompasses the state.

The Bureau of Conservation, Economics and Energy Planning prepared this report, pursuant to Title 66, Pennsylvania Consolidated Statutes, Section 524(b). This report is submitted annually to the General Assembly, the Governor, the Office of Consumer Advocate and each affected public utility, and also is made available to the general public on the Commission's website.[9]

The information contained in this report includes highlights of the past year, EDCs' projections of energy demand and peak load, and a discussion of historical trends in electric utility forecasting. Since the eight largest EDCs operating in Pennsylvania represent 99.8 percent of jurisdictional electricity sales, information regarding the three smaller EDCs has been limited in this report. The report also provides a regional perspective with statistical information on the projected resources and aggregate peak loads for the region, which impacts Pennsylvania.

Under section 2809(e) of the Public Utility Code, the Commission has the authority to forbear from applying any requirements of the Code, including section 524 and existing regulations promulgated thereto, which it found no longer to be necessary due to competition among electric generation suppliers. Thus, the Commission adopted revised regulations reflecting a reduction in reporting requirements and a reduction in the reporting horizon for energy demand, connected peak load and number of customers from 20 to 5 years. Information regarding capital investments, energy costs, new generating facilities and expansions of existing facilities are no longer required. With the divestiture of generating facilities by the EDCs, the Commission relies on reports and analyses of regional entities, including the Reliability*First* Corporation and the PJM Interconnection, to obtain a more complete assessment of the current and future status of the electric power supply within the region.

Informational sources include data submitted by EDCs, which is filed annually pursuant to the Commission's regulations.[10] Sources also include data submitted by regional reliability councils to the North American Electric Reliability Corporation, which is subsequently forwarded to the federal Energy Information Administration.

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.

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[9] *See* http://www.puc.state.pa.us/general/publications_reports/pdf/EPO_2010.pdf.
[10] 52 Pa. Code §§ 57.141—57.154.

Regional Reliability Organizations

In Pennsylvania, all major electric distribution companies 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 bulk electric system.

North American Electric Reliability Corporation

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 had operated as a voluntary organization, dependent on reciprocity and mutual self-interest. Due to the restructuring of the electric utility industry, NERC was subsequently 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 organization is to develop, promote and enforce reliability standards for the bulk electric system.

On July 20, 2006, NERC was certified as the Electric Reliability Organization (ERO) in the United States, pursuant to Section 215 of the Federal Power Act of 2005. Included in this certification was a provision for the ERO to delegate authority for the purpose of proposing and enforcing reliability standards by entering into delegation agreements with regional entities.

Effective Jan. 1, 2007, NERC and the North American Electric Reliability Corporation merged, with the latter being the surviving entity (also referred to as NERC). As of June 18, 2007, the Federal Energy Regulatory Commission (FERC) granted NERC the legal authority to enforce reliability standards, and made compliance with those standards mandatory.

NERC oversees the reliability of a bulk power system that provides electricity to 350 million people, has a total demand of 830,000 megawatts (MW), has 211,000 miles of high-voltage transmission lines (230,000 volts and greater), and represents more than $1 trillion worth of assets.

NERC's members currently include eight regional reliability councils. Members of these regional councils include investor-owned utilities, federal and provincial entities, rural electric cooperatives, state/municipal and provincial utilities, independent power producers, independent system operators, merchant electricity generators, power marketers, and end-use electricity customers, and account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The regional council operating in Pennsylvania is Reliability*First* Corporation, which is the successor organization to three former NERC Regional Reliability Councils: MAAC, ECAR and MAIN.

NERC's North American Transmission Forum, formed in 2007 to improve the operations and reliability of the electric power systems in North America, has recently organized as an independent non-profit corporation. The Forum's membership has grown to 54 transmission owning utilities in the United States and Canada, representing 70 percent of the countries' total electricity demand. Members include Allegheny Power, Duquesne Light, Exelon, FirstEnergy, PJM Interconnection and PPL.

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.

As of Dec. 31, 2009, NERC had 1,950 active violations, the majority of which were being assessed and validated; others were in settlement negotiations, or were being addressed in a Notice of Penalty filing with FERC. During 2009, NERC filed 221 enforcement actions with FERC. Enforcement actions are designed to ensure and improve bulk power system reliability by mitigating risk; ensuring transparent, efficient and fair processing; and communicating lessons learned to the industry.[11]

NERC defines the bulk electric system as follows:

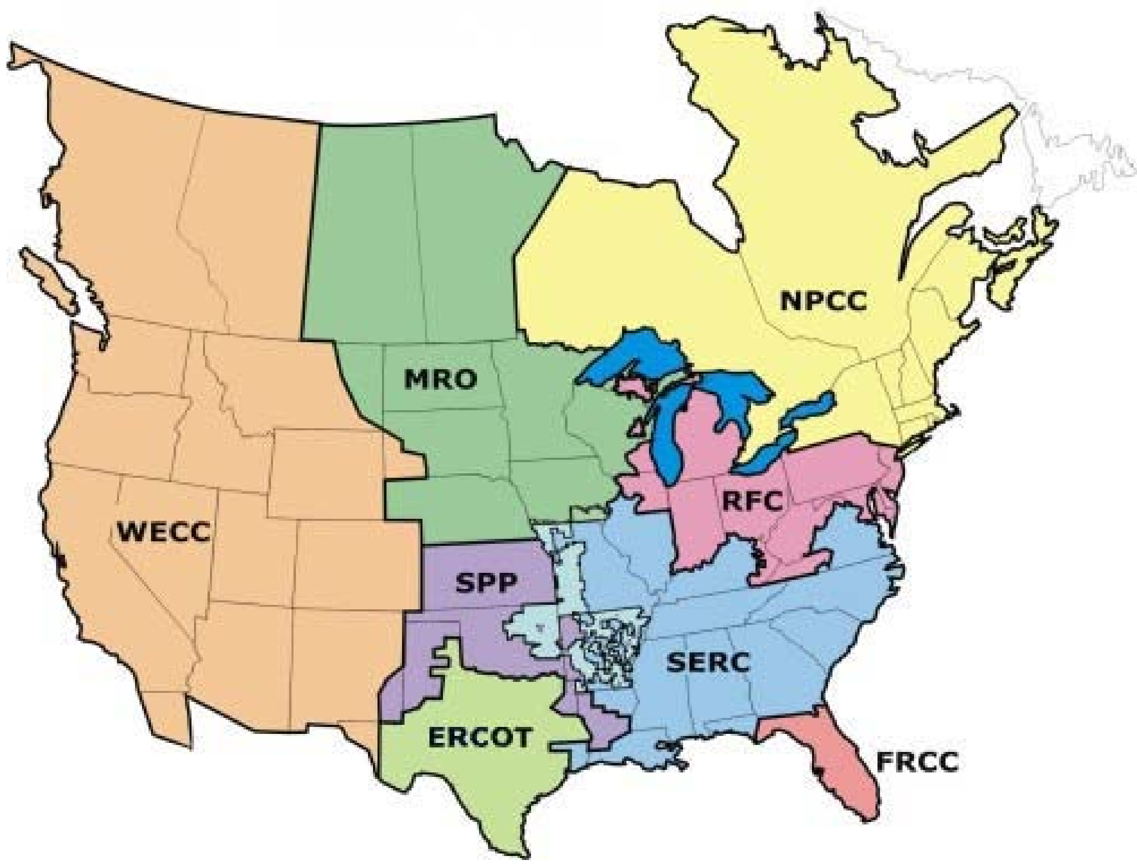
> As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition.[12]

On March 18, 2010, FERC issued a Notice of Proposed Rulemaking[13] directing NERC to include all electric transmission facilities of 100,000 volts (100 kV) or more in its definition of what constitutes the "bulk electric system" subject to mandatory reliability standards under the Energy Policy Act of 2005. The proposal is intended to eliminate the discretion that regional entities have to define the transmission facilities that comprise their "bulk electric systems," but allow regional councils to seek NERC and FERC approval if they wish to make variations from the 100 kV standard. FERC notes that there is a strong technical justification for a standard 100 kV threshold, pointing out that facilities rated at 115 kV and 138 kV have either caused or contributed to significant bulk electric system disturbances and cascading outages. FERC has determined that the definition needs to be modified in order to protect the reliability of the Nation's Bulk-Power System.

Figure 1 provides a map of the eight NERC Regions.

[11] NERC, *Annual Report 2009*, May 2010.
[12] "Glossary of Terms Used in Reliability Standards," adopted by NERC Board of Trustees: Feb. 12, 2008.
[13] Docket No. RM09-18-000.

Figure 1 NERC regions



Note: *The highlighted area between SPP and SERC denotes overlapping Regional area boundaries. For example, some load serving entities participate in one Region and their associated transmission owner/operators in another.*

ERCOT

Electric Reliability Council of Texas

FRCC

Florida Reliability Coordinating Council

MRO

Midwest Reliability Organization

NPCC

Northeast Power Coordinating Council

RFC

Reliability*First* Corporation

SERC

Southeastern Electric Reliability Council

SPP

Southwest Power Pool

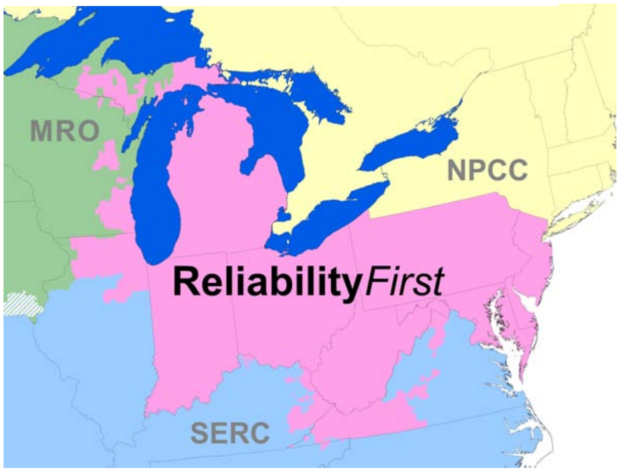
WECC

Western Electricity Coordinating Council

ReliabilityFirst Corporation

The regional reliability council covering Pennsylvania is the Reliability*First* Corporation (RFC), based in Akron, Ohio. RFC was formed by the merger of the Mid-Atlantic Area Council (MAAC), the East Central Area Reliability Coordination Agreement (ECAR) and the Mid-America Interconnected Network Inc. (MAIN). RFC is one of eight regional councils of NERC and serves the electrical requirements of more than 72 million people in a 238,000 square-mile area covering all of the states of Delaware, Indiana, Maryland, Ohio, Pennsylvania, New Jersey and West Virginia, plus the District of Columbia, and portions of Illinois, Kentucky, Michigan, Tennessee, Virginia and Wisconsin. RFC became operational on Jan. 1, 2006. Its membership includes load serving entities, regional transmission organizations (RTOs), suppliers and transmission companies. See Figure 2.

Figure 2 RFC footprint



RFC sets 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 RFC 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 RFC have a capacity obligation determined by evaluating individual system load characteristics, unit size and operating characteristics.

In addition to all NERC Standards, all heritage ECAR, MAAC, and MAIN standards that have not yet been replaced by vote of the RFC Board remain in effect.

There have been no enforcement actions against any Pennsylvania RFC members since the expansion of NERC's new authority.[14]

Regional Transmission Organizations

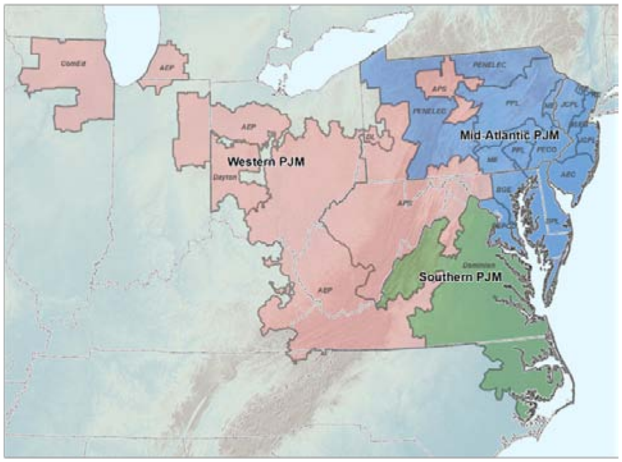
The two main control areas within the RFC footprint are the PJM Regional Transmission Organization (PJM RTO) and the Midwest Independent System Operator (MISO). Two-thirds of the RFC load is in the PJM RTO.

PJM Interconnection

The PJM Interconnection LLC (PJM) is a regional transmission organization that ensures the reliability of the largest centrally dispatched control area in North America. PJM coordinates the operation of 163,500 MW of generating capacity and 56,350 miles of transmission lines. The PJM RTO coordinates the movement of electricity through all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. See Figure 3.

[14] *See* http://www.nerc.com/filez/enforcement/index.html.

Figure 3 PJM RTO service territory



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 marking the first time, nationally, that two separate control areas were operated under a single energy market and a single governance structure.

On May 1, 2004, PJM began managing the flow of wholesale electricity over Commonwealth Edison's 5,000 miles of transmission lines in Illinois, making PJM the world's largest grid operator, meeting a peak demand of 87,000 MW. On Oct. 1, 2004, PJM began managing American Electric Power's (AEP's) eastern control area, including 22,300 miles of high-voltage transmission lines within a seven-state area and 23,800 MW of generating capacity. At the same time, Dayton Power and Light integrated into the PJM RTO with 1,000 miles of transmission lines and 4,450 MW of generation. Also, 20 municipal electric companies, cooperatives and generators in the AEP area joined PJM. On Jan. 1, 2005, PJM began managing the wholesale flow of electricity for Duquesne Light Company, with 3,400 MW of capacity and 620 miles of transmission lines. These entities, including Allegheny, comprise PJM West.

Virginia Electric and Power (Dominion) was integrated into the PJM RTO on May 1, 2005. Dominion's control area, covering parts of Virginia and North Carolina, operates separately under the single PJM energy market as PJM South, including an additional 6,100 miles of transmission lines and 26,500 MW of generating capacity.

On Aug. 17, 2009, FirstEnergy Service Company filed a request with FERC to consolidate all of its ATSI[15] transmission assets, currently operated by MISO, into the PJM RTO. ATSI has 32 interconnections with PJM, but only three with MISO. Moving ATSI into the PJM RTO is expected to reduce congestion and increase efficiency across both RTOs. The integration, which was approved by FERC on Dec. 17, 2009, will become effective June 1, 2011.

On May 20, 2010, Duke Energy Corporation announced its desire to move its Ohio and Kentucky utilities from MISO to the PJM RTO by Jan. 1, 2012, which would increase PJM's generating capacity by 2,379 MW. The subsidiaries would also add 5,800 MW to PJM's system peak load.

PJM manages a sophisticated regional planning process for generation and transmission expansion to ensure the continued reliability of the electric system. PJM is responsible for maintaining the integrity of the regional power grid and for managing changes and additions to the grid to accommodate new generating plants, substations and transmission lines. In addition, PJM analyzes and forecasts the future electricity needs of the region. Its planning process ensures that the growth of the electric system takes place efficiently, in an orderly fashion, and that reliability

[15] American Transmission Systems Inc., a subsidiary of FirstEnergy Corporation, has assets located within the footprint of FirstEnergy's Ohio and Pennsylvania (Penn Power) utilities, including 7,100 circuit miles of transmission lines with nominal voltages of 345 kV, 138 kV and 69 kV.

is maintained. PJM also develops innovative programs, such as demand response initiatives and efforts to support renewable energy, to help expand supply options and keep prices competitive.

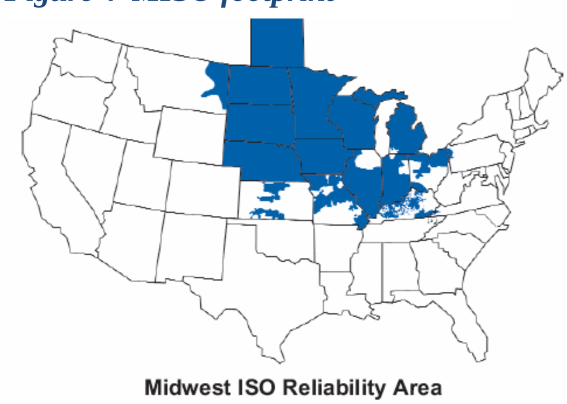
PJM coordinates the continuous buying, selling and delivery of wholesale electricity through robust, open and competitive spot markets. In operating the markets, PJM balances the needs of suppliers, wholesale customers and other market participants, and continuously monitors market behavior. PJM has administered more than $103 billion in energy and energy-service trades since the regional markets opened in 1997.

PJM exercises a broader reliability role than that of a local electric utility. PJM system operators conduct dispatch operations and monitor the status of the grid over a wide area, using telemetered data from 74,000 points on the grid. This gives PJM a big-picture view of regional conditions and reliability issues, including those in neighboring systems.

Midwest Independent System Operator

The Midwest Independent System Operator (MISO) is the nation's first RTO approved by FERC. MISO, with control centers in Carmel, Indiana, and St. Paul, Minnesota, is responsible for monitoring the electric transmission system, ensuring equal access to the transmission system and maintaining and improving electric system reliability in 13 Midwest states and the Canadian province of Manitoba. See Figure 4.

Figure 4 MISO footprint



Utilities with 93,600 miles of transmission lines covering 750,000 square miles from Manitoba, Canada, to Kentucky have committed to participate in MISO. Pennsylvania Power Company is currently the only Pennsylvania utility in MISO; however, as previously indicated, all FirstEnergy companies will be integrated into the PJM RTO by June 2011.

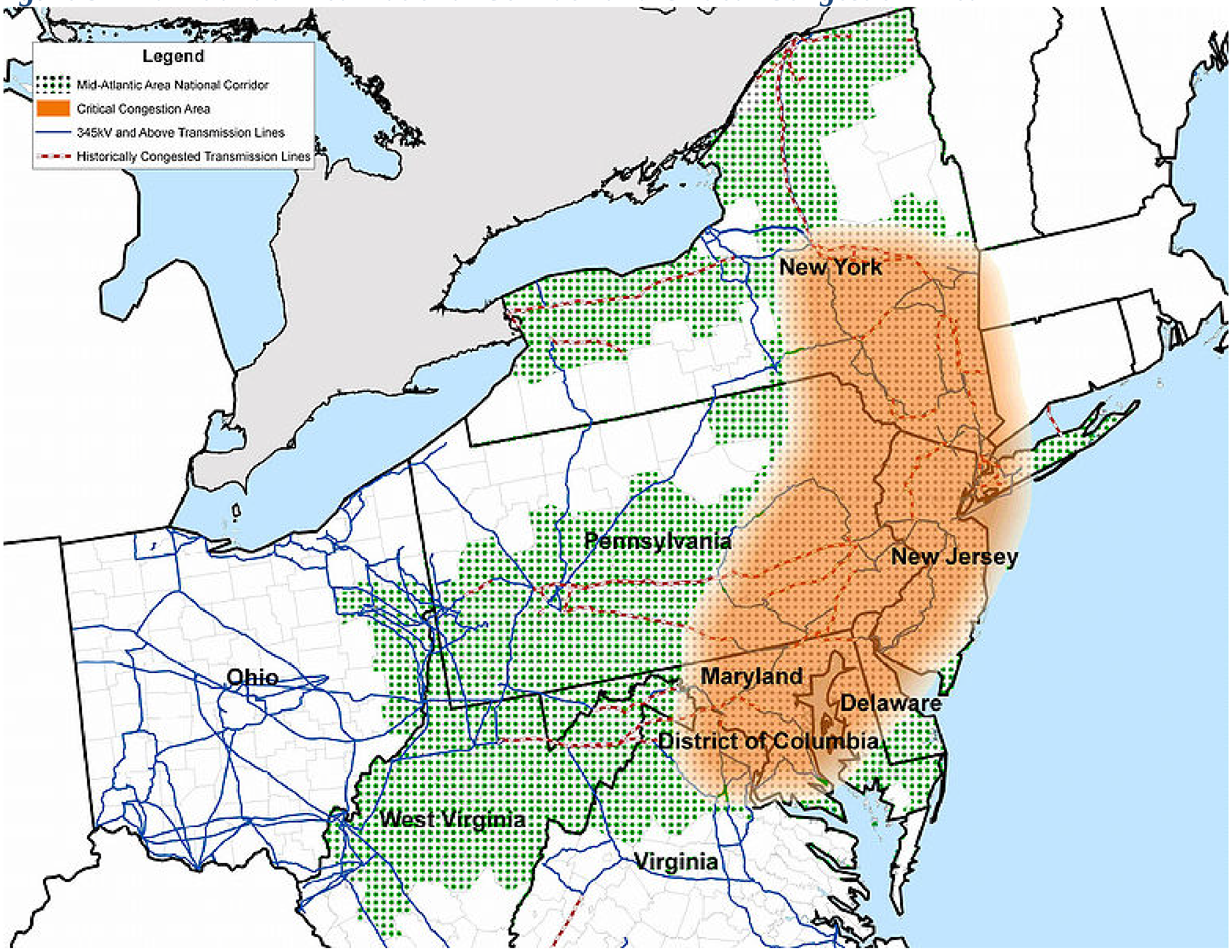
On Dec. 10, 2008, Duquesne Light Company announced that it will not transition to MISO, as indicated earlier. Duquesne has decided to remain with PJM, a decision which was approved by FERC on Jan. 29, 2009.

Transmission Line Expansion

Effective Oct. 5, 2007, the U.S. Department of Energy (DOE) designated all or major portions of West Virginia, Pennsylvania, Maryland, Delaware, the District of Columbia, New Jersey, New York and Virginia, as well as minor portions of Ohio, as the Mid-Atlantic Area National Interest Electric Transmission Corridor under Section 1221 of the Energy Policy Act of 2005. The designation will remain in effect until Oct. 7, 2019. The corridor includes 52 out of Pennsylvania's 67 counties. Section 1221 gives FERC authority to approve the construction or modification of electric transmission facilities within a designated corridor if the state does not approve an application within one year.[16] See Figure 5.

[16] On Feb. 18, 2009, the U.S. Court of Appeals for the Fourth Circuit issued a decision reversing, vacating and remanding key elements of FERC's final rule implementing its backstop siting authority under Section 216 of the

Figure 5 Mid-Atlantic Area National Corridor and Critical Congestion Area



On April 27, 2010, DOE released its 2009 National Electric Transmission Congestion Study.[17] Congestion occurs on electric transmission facilities when actual or scheduled flows of electricity across a line or piece of equipment are restricted below desired levels. These restrictions may be imposed either by the physical or electrical capacity of the line, or by operational restrictions created and enforced to protect the security and reliability of the grid. The study concludes that the Mid-Atlantic Critical Congestion Area is the only nationally significant congestion area in the Eastern Interconnection, which continues to experience high and costly levels of congestion that affect a significant portion of the nation's population, and should be continue to be identified as a Critical Congestion Area. DOE made this identification because of the area's importance as a population and economic center and because of the many known transmission constraints and challenges to building new transmission and managing load growth. The study also points out that slow development of new generation and new backbone transmission facilities could compromise continued reliability in the Washington, Baltimore, New Jersey and New York City areas.

Federal Power Act. In essence, the Court rejected FERC's interpretation that it may exercise its backstop authority when a state commission has affirmatively denied a permit application within one year. *Piedmont Environmental Council v. FERC*, No. 07-1651 (4th Cir. Feb. 18, 2009).

[17] U.S. DOE, *2009 National Electric Transmission Congestion Study*, December 2009.

According to a report issued by the National Council on Electricity Policy, Pennsylvania is one of 11 states whose statutes do not address the topic of interstate transmission siting and interstate coordination.[18] Participation in a regional organization, such as the PJM RTO, is one vehicle for addressing interstate coordination on transmission development, including siting. The report recommends that states determine whether language in their statutes creates opportunities for or impedes regional coordination, and consider reform, if necessary. States may also consider the environmental, economic, and health and safety benefits, in addition to the costs, that may result from interstate transmission siting for consumers in their state and more broadly in their respective region. Having a vehicle such as an RTO may provide the basis for a long-term strategy of equity in future decisions that share regional costs and benefits.

On Jan. 28, 2010, the Commission issued a Tentative Order[19] which sets forth specific Interim Guidelines to supplement the existing filing requirements, pending the conclusion of the rulemaking process. The additional information to be included in the initial filing is intended to streamline the application process by reducing the need for subsequent data requests, on a case-by-case basis, to more completely develop the record necessary to process the application. Comments to the Tentative Order were due March 30, 2010.

In recent transmission line siting proceedings, the Commission has given substantial weight to regional transmission studies conducted by PJM.

The PJM Regional Transmission Expansion Plan (RTEP) identifies transmission system upgrades and enhancements to preserve grid reliability within the region, the foundation of competitive wholesale power markets. The RTEP five-year planning process enables PJM to assess and recommend transmission upgrades to meet forecasted near-term load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects seeking interconnection within PJM. The 15-year planning horizon permits consideration of many transmission options with longer lead times.

PJM has addressed a number of critical issues in Pennsylvania having a bearing on reliability criteria violations, which drive the need for regional transmission expansion plans. The RTEP has identified two major transmission line projects, approved by the PJM Board, which have an impact on Pennsylvania.

[18] The National Council on Electricity Policy, *Coordinating Interstate Electric Transmission Siting: An Introduction to the Debate*, July 2008.
[19] Docket No. M-2009-2141293; 40 Pa.B. 953.

Trans-Allegheny Interstate Line

The RTEP recommended that Allegheny Power build facilities constituting the Trans-Allegheny Interstate Line (TrAIL). TrAIL was to extend from Southwestern Pennsylvania (37 miles) to West Virginia (114 miles) to Northern Virginia (28 miles). In-service dates ranged from 2009 to mid-2010. The 2008 RTEP retool analysis of 2011 system conditions confirmed the need for this line by June 1, 2011, to address reliability criteria violations on the Mt. Storm-Doubs 500 kV line.

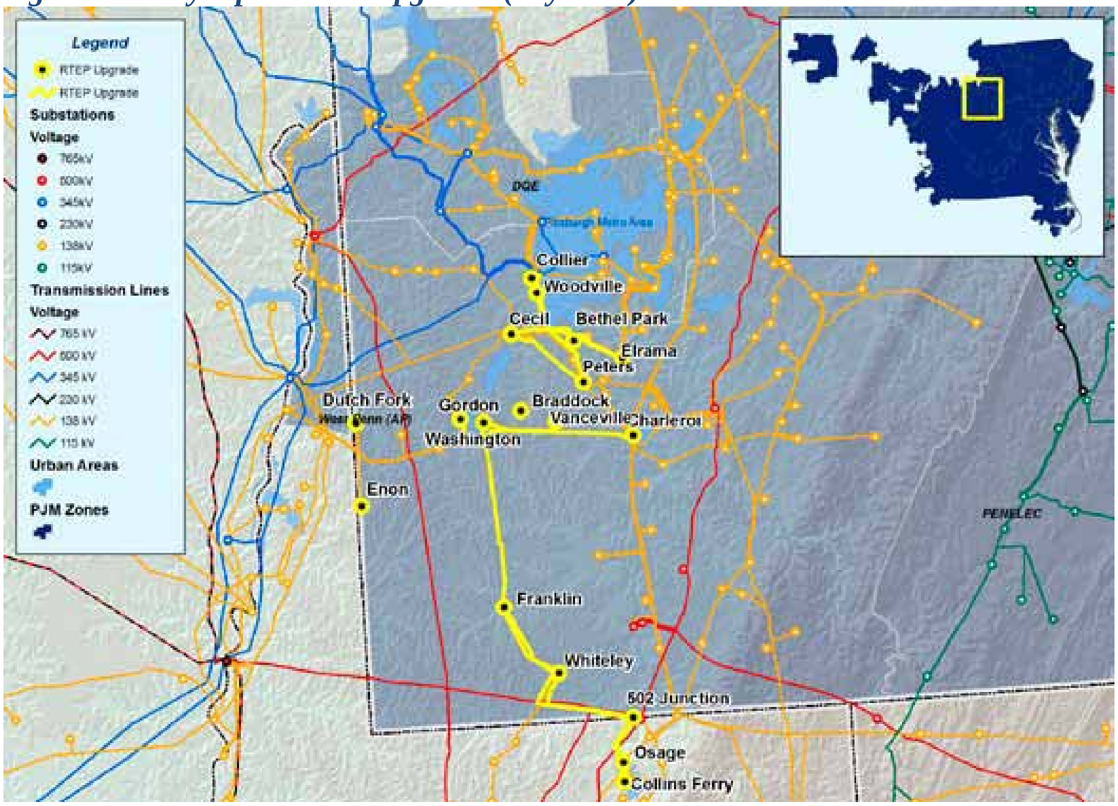
In support of the TrAIL project, Trans-Allegheny Interstate Line Company (TrAILCo), an Allegheny Energy subsidiary, filed an application[20] with the Commission on April 13, 2007, proposing the construction of one 500 kV and three 138 kV transmission lines in Washington and Greene counties. The project included a substation in Washington County (Prexy Substation), a substation in Greene County (502 Junction Substation), three 138 kV transmission lines and a 36-mile 500 kV transmission line.

Evidentiary hearings in all three states were concluded by April 2008. In a Recommended Decision issued Aug. 21, 2008, the Commission's ALJs recommended that the application be denied because TrAILCo had failed to prove a need for the facilities. A Partial Settlement Agreement was reached for the Pennsylvania portion of the TrAIL Project, involving approval of a 1.2-mile segment of the 500 kV line extending from a new substation in Greene County, Pennsylvania (the 502 Junction), to the West Virginia border. On Nov. 13, 2008, the Commission approved the Partial Settlement Agreement and stayed the application with regard to the Prexy facilities pending the outcome of a collaborative set forth in the Partial Settlement Agreement and the filing of a new or amended application. On July 13, 2009, a Joint Petition for Settlement was filed with the Commission, agreeing to an alternative, more cost-effective solution to NERC Reliability Standard violations, including a set of local 138 kV transmission upgrades. By Order of Aug. 25, 2009, the record was reopened for the purpose of amending the application and approving the Settlement. An Amendment to Application was filed on Oct. 13, 2009.

The 2009 RTEP stated that the alternative solution did not resolve several violations outside the contested area of the settlement, requiring additional upgrades that the Prexy-502 Junction would have otherwise resolved. The upgrades, including the construction of a new Osage-Whiteley 138 kV line and a new 138 kV Braddock substation, are shown in Figure 6.

[20] Docket No. A-110172, *et al*.

Figure 6 Prexy replacement upgrades (in yellow)



Susquehanna-Roseland 500 kV Line

The second major transmission project identified by the RTEP describes a new 500 kV circuit which is proposed to run 120 miles from the Susquehanna 500 kV substation in Salem Township, Luzerne County, near Berwick, through portions of Luzerne, Lackawanna, Wayne, Pike and Monroe counties to the Delaware River and then eastward to Roseland, New Jersey in the Public Service Electric & Gas Co. system.

According to the 2008 RTEP, the Susquehanna-Roseland 500 kV project would resolve 21 of 23 identified reliability criteria violations in Eastern Pennsylvania and New Jersey beginning in 2012. A March 2009 RTEP retool analysis included 13 potential overloads due to single contingencies, and 10 potential violations due to multiple contingencies. The 2009 RTEP, issued Feb. 26, 2010, re-validated the required June 1, 2012, in-service date for the line. The estimated cost to design and construct the Pennsylvania portion of the line (101 miles) is $510 million.

PPL conducted a multi-faceted analysis to determine the preferred route. Three alternative routes were selected for detailed examination. Following an analysis of comments from the public, societal concerns, environmental impacts, engineering considerations and cost, PPL selected Route B as the preferred route. See Figure 7.

On Jan. 6, 2009, PPL filed its Application for authorization to construct the line and a new substation in Blakely Borough, Lackawanna County.[21] Evidentiary hearings were held in

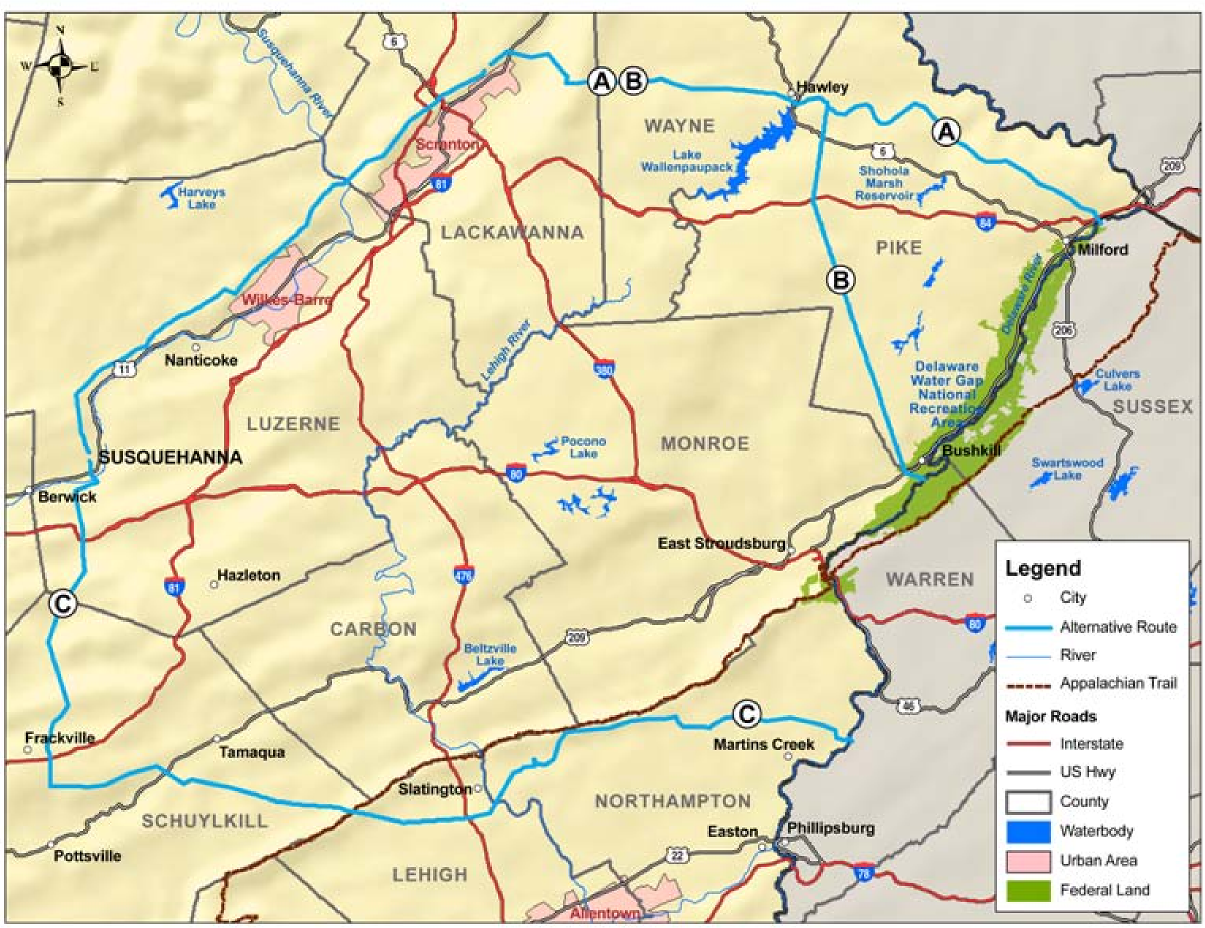
[21] Docket No. A-2009-2082652.

September 2009. A Recommended Decision, conditionally approving the application, was issued on Nov. 12, 2009, and adopted on Jan. 14, 2010. The New Jersey Board of Public Utilities approved the New Jersey portion of the line (45 miles) on Feb. 11, 2010.

The National Park Service (NPS) is preparing an Environmental Impact Statement (EIS) to analyze the potential impacts of the project on the Delaware Water Gap National Recreation Area, the Middle Delaware Scenic and Recreational River and the Appalachian National Scenic Trail. The EIS will compare the three alternative routes that had been originally considered to determine the alternative that would minimize impacts to the natural and human resources within the parks and surrounding areas. NPS is also developing other alternatives which may include relocation of the project partially outside of park boundaries, installation of portions of the entire upgraded line underground, installation of the line on the bottom of the Delaware River, an alternative that uses direct current, or a denial of the request for permits.

The Commission's approval of construction of a portion of the line is contingent upon the receipt of the necessary NPS permit. On March 1, 2010, the Office of Consumer Advocate (OCA) filed a Petition for Reconsideration or Clarification, which was granted on March 11, 2010, pending further review and consideration on the merits. On April 22, 2010, the Commission denied OCA's petition, thus reaffirming its previous approval of the application.

Figure 7 Susquehanna-Roseland 500 kV line alternatives

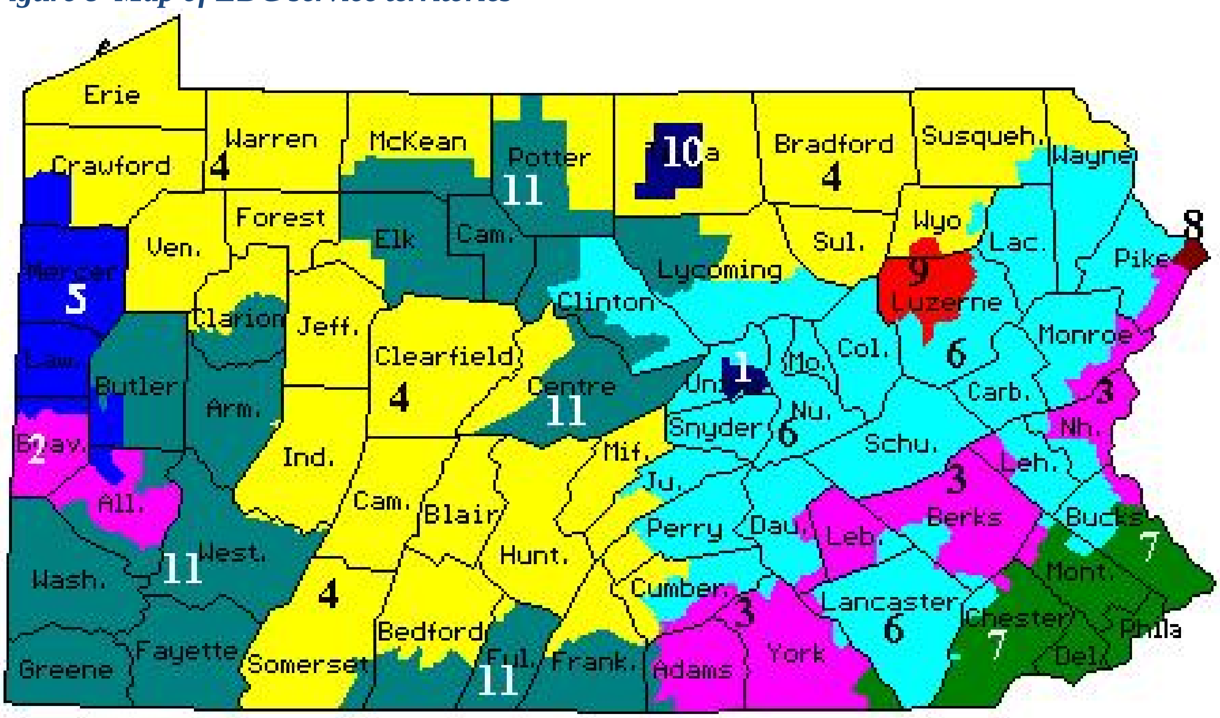


Electric Distribution Companies

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 11 jurisdictional EDCs (nine systems)[22] 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. – Electric Division
10. Wellsboro Electric Company
11. West Penn Power Company (Allegheny Energy Inc.)

Figure 8 Map of EDC service territories



Due to the deregulation of electric generation, local generating resources are now available to the competitive wholesale market. During their rate-cap or transition periods, the EDCs either entered into long-term contracts for power from traditional resources with affiliates or other generation

[22] On Feb. 11, 2010, FirstEnergy and Allegheny Energy Inc. announced a merger of the two companies, which is conditioned on, among other things, approvals by federal and state authorities. The combined company will retain the FirstEnergy name and be headquartered in Akron, Ohio.

suppliers or purchased power from the wholesale market to fulfill their provider of last resort (POLR) obligations.[23]

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, pursuant to a Commission-approved competitive procurement process, for customers who contract for power which is not delivered, or for customers who do not choose an alternate supplier. The acquired electric power must include a prudent mix of spot market purchases, short-term contracts and long-term purchase contracts, designed to ensure adequate and reliable service at the least cost to customers over time. EDCs must also assume the role of provider of last resort for customers choosing to return to the EDC.[24]

On May 10, 2007, the Commission finalized the statewide default service rulemaking and policy statement which provides guidelines to default service providers regarding the acquisition of electric generation supply, the recovery of associated costs and the integration of default service with competitive retail electric markets. The regulations establish the criteria on how electric generation service is provided to customers who choose to obtain generation service from an alternate supplier. In reviewing the comments and considering revisions to the proposed default service rules, the Commission recognized that some elements of the default service rules should be addressed in a policy statement that provides guidance to the industry rather than strict rules.[25]

The transition periods have expired for seven of the 11 EDCs, PPL being the latest EDC to end its recovery of stranded costs on Dec. 31, 2009.

The electric generation supplier (EGS) market share for the fourth quarter of 2009 may be considered indicative of the overall current status of customer choice in Pennsylvania. In the aggregate, the EGS share of total megawatthour (MWh) sales was 11.7 percent, varying greatly among the individual EDC service territories. EGSs supplied 3.3 percent of residential sales; EGS commercial and industrial sales were substantially higher at 16.1 percent of total sales. As of April 8, 2010, there were 99 licensed EGS offering generation services to retail customers in Pennsylvania.

Alternative Energy Portfolio Standards

Act 213[26] requires that EDCs and EGS acquire alternative energy credits (AECs) in quantities equal to an increasing percentage of electricity sold to retail customers. AECs are separate from the electricity that is sold to customers. An AEC represents one MWh of qualified alternative electric generation or conservation, whether self-generated, purchased along with the electric commodity or separately through a tradable instrument.[27]

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[23] Also referred to as “obligation to serve” and “default service.”
[24] 66 Pa.C.S. § 2807(e)(3).
[25] Docket Nos. L-00040169 and M-00072009; 52 Pa. Code §§ 54.4-54.6, 54.31-54.41, 54.123, 54.181-54.189, 57.178 and 69.1801-69.1817.
[26] Alternative Energy Portfolio Standards Act, effective Feb. 28, 2005; 73 P.S. §§ 1648.1–1648.8.
[27] See 52 Pa. Code §§ 75.61—75.70.

Alternative energy resources are categorized as Tier I and Tier II resources. Tier I resources include solar, wind, low-impact hydropower, geothermal, biologically derived methane gas, fuel cells, biomass and coal mine methane. Tier II resources include waste coal, demand side management, distributed generation, large-scale hydropower, by-products of wood pulping and wood manufacturing, municipal solid waste, and integrated combined coal gasification technology.

Act 213 requires that, within two years of the effective date, the Tier I requirement is 1.5 percent of all retail sales. The percentage of electric energy derived from Tier 1 resources (including solar) is to increase by at least 0.5 percent each year so that, by the 15th year, at least 8 percent of the electric energy in each service territory will come from these resources. Energy derived from Tier II resources is to increase to 10 percent (a total of 18 percent from both Tier I and Tier II). Act 213 sets forth a 15-year schedule for complying with its mandates, as shown in Table 1.

Table 1 Alternative Energy Portfolio Standards

Year	Period	Tier I (incl. Solar)	Tier II	Solar PV
1	June 1, 2006 through May 31, 2007	1.50%	4.20%	0.0013%
2	June 1, 2007 through May 31, 2008	1.50%	4.20%	0.0030%
3	June 1, 2008 through May 31, 2009	2.00%	4.20%	0.0063%
4	June 1, 2009 through May 31, 2010	2.50%	4.20%	0.0120%
5	June 1, 2010 through May 31, 2011	3.00%	6.20%	0.0203%
6	June 1, 2011 through May 31, 2012	3.50%	6.20%	0.0325%
7	June 1, 2012 through May 31, 2013	4.00%	6.20%	0.0510%
8	June 1, 2013 through May 31, 2014	4.50%	6.20%	0.0840%
9	June 1, 2014 through May 31, 2015	5.00%	6.20%	0.1440%
10	June 1, 2015 through May 31, 2016	5.50%	8.20%	0.2500%
11	June 1, 2016 through May 31, 2017	6.00%	8.20%	0.2933%
12	June 1, 2017 through May 31, 2018	6.50%	8.20%	0.3400%
13	June 1, 2018 through May 31, 2019	7.00%	8.20%	0.3900%
14	June 1, 2019 through May 31, 2020	7.50%	8.20%	0.4433%
15	June 1, 2020 through May 31, 2021	8.00%	10.00%	0.5000%

Companies are exempt from these requirements for the duration of their cost recovery periods. The current expiration dates for the cost recovery period in each EDC's service territory and the corresponding start dates for compliance are shown in Table 2.

Table 2 AEPS compliance schedule

Company	Exemption Expires	Compliance Begins
Pennsylvania Power Company	December 31, 2006	February 28, 2007
UGI Utilities Inc.	December 31, 2006	February 28, 2007
Citizens' Electric Company	December 31, 2007	January 1, 2008
Duquesne Light Company	December 31, 2007	January 1, 2008
Pike County Power and Light	December 31, 2007	January 1, 2008
Wellsboro Electric Company	December 31, 2007	January 1, 2008
PPL Electric Utilities Corporation	December 31, 2009	January 1, 2010
PECO Energy Company	December 31, 2010	January 1, 2011
Pennsylvania Electric Company	December 31, 2010	January 1, 2011
Metropolitan Edison Company	December 31, 2010	January 1, 2011
West Penn Power Company	December 31, 2010	January 1, 2011

AECs are earned when a qualified facility generates 1,000 kilowatthours (kWh) of electricity through either estimated or actual metered production. An AEC is a tradable certificate that represents all the clean energy benefits of electricity generated from a facility. An AEC can be sold or traded separately from the power. AECs are generally purchased by EDCs and EGSs in order to meet the percentages required under AEPS for any given energy year. The AECs can be traded multiple times until they are retired for compliance purposes.

On June 3, 2010, the Commission approved Clean Power Markets (CPM) to be the Alternative Energy Credit Program Administrator through 2013. CPM, which had been the administrator since 2007, verifies that EGSs and EDCs are complying with the minimum requirements of Act 213. The Commission also has chosen PJM's Generation Attribute Tracking System (GATS) to assist EDCs in their compliance with the requirements of Act 213, including registration of projects.

On June 22, 2006, the Commission approved Final Regulations promoting onsite generation by customer-generators using renewable resources and eliminating barriers which may have previously existed regarding net metering. The regulations also provide for metering capabilities that will be required and a compensation mechanism which reimburses customer-generators for surplus energy supplied to the electric grid.[28]

The Commission also approved Final Regulations, on Aug. 17, 2006, which govern interconnection for customer-generators. The regulations promote onsite generation by customer-generators using renewable resources, consistent with the goal of Act 213. The regulations strive to eliminate barriers which may have previously existed with regard to interconnection, while ensuring that interconnection by customer-generators will not pose unnecessary risks to the electric distribution systems in the Commonwealth.[29]

On Sept. 25, 2008, the Commission adopted a Final Rulemaking Order pertaining to the AEPS obligations of the EDCs and EGSs.[30]

Act 35 became effective on July 17, 2007, and amends provisions of Act 213, including definitions of customer-generators, the reconciliation mechanism for surplus energy supplied through net metering and the price to be paid for such surplus energy. Pursuant to Act 35, on Feb. 26, 2009, the Commission approved standard Interconnection Application Forms and a Policy Statement addressing Interconnection Application Fees. Act 35 also expanded the definition of Tier I alternative energy sources to include solar thermal energy.

As of May 18, 2010, Pennsylvania had certified 1,458 alternate energy facilities, many of which are located within the state. For additional information, visit the Commission's AEPS website at http://paaeps.com/credit/.

[28] Docket No. L-00050174; 52 Pa. Code §§ 75.11-75.15.
[29] Docket No. L-00050175; 52 Pa. Code §§ 75.21-75.40.
[30] Docket No. L-00060180; 52 Pa. Code §§ 75.61-75.70.

Energy Efficiency and Conservation

Act 129

Act 129 of 2008[31] added Section 2806.1 to the Public Utility Code requiring that the Commission adopt an energy efficiency and conservation program for the reduction of energy consumption and peak demand within the service territory of each EDC with at least 100,000 customers.[32] Sales are to be reduced 1 percent by May 31, 2011, and 3 percent by May 31, 2013. Peak demand is to be reduced 4.5 percent by May 31, 2013.

Based on forecast growth data, consumption reduction goals total 1.5 million MWh in 2011 and 4.4 million MWh in 2013. Peak demand reduction goals total 1,193 MW for 2013. These goals were adopted by the Commission on March 26, 2009. Total program costs are estimated at $1 billion.[33] See Table 3.

Table 3 Consumption and peak demand reduction goals and cost

Company	1% (MWh)	3% (MWh)	4.5% (MW)	Total Plan Cost
Duquesne	140,855	422,565	113	$78,183,806
Met-Ed	148,650	445,951	119	$99,467,568
Penelec	143,993	431,979	108	$91,898,976
Penn Power	47,729	143,188	44	$26,639,136
PPL	382,144	1,146,431	297	$246,005,504
PECO	393,860	1,181,580	355	$341,580,634
West Penn	209,387	628,160	157	$94,249,872
Total	**1,466,618**	**4,399,854**	**1,193**	**$978,025,496**

On Jan. 15, 2009, the Commission adopted an Implementation Order to establish the standards each program must meet and provide guidance on the procedures to be followed for submittal, review and approval of all aspects of EDC plans. Programs are to be evaluated using a total resource cost test, based on the *California Manual*, as modified by the Commission.[34] Each plan must include a proposed cost recovery tariff mechanism. Plans were filed on July 1, 2009.[35] The Commission approved the plans, with modifications, in late October 2009, requiring the filing of revised plans within 60 days, which were subsequently approved.[36]

Act 129 also requires an increase in the percentage share of Tier I alternative energy resources to be sold under the provisions of Act 213. The types of alternative energy resources that qualify as Tier I resources were expanded to include specific categories of low impact hydropower and biomass energy.[37] A Final Order was adopted on May 28, 2009.[38]

[31] Energy Efficiency and Conservation Program, signed by Gov. Rendell on Oct. 15, 2008.
[32] 66 Pa.C.S. § 2806.1.
[33] Program costs are from individual plans and generally represent two percent of revenues as of Dec. 2006 multiplied by four to reflect the four-year duration of the plans.
[34] Docket No. M-2009-2108601.
[35] Docket No. M-2008-2069887.
[36] Docket Nos. M-2009-2093215, M-2009-2093216, M-2009-2093217, M-2009-2093218, M-2009-2092222, M-2009-2112952 and M-2009-2112956.
[37] *See* Act 129 of 2008, Section 5, codified in the Pennsylvania consolidated statutes as 66 Pa. C.S. § 2814.
[38] Docket No. M-2009-2093383.

Smart Meters and Time-of-Use Rates

Section 2807(f) of the Public Utility Code[39] requires that EDCs, with greater than 100,000 customers, file a smart meter technology procurement and installation plan with the Commission for approval. Smart meters are to be furnished upon request from a customer that agrees to pay the cost of the meter, in new building construction, and in accordance with a depreciation schedule not to exceed 15 years.

A Smart Meter Procurement and Installation Implementation Order was adopted by the Commission on June 18, 2009.[40] Each smart meter plan must include a summary of the EDC's current deployment of smart meter technology, if any; a plan for future deployment, complete with dates for key milestones and measurable goals; and other pertinent information. The Commission granted a network development and installation grace period of up to 30 months following plan approval. The EDCs filed their Smart Meter Technology Procurement and Installation Plans on Aug. 14, 2009.[41] The plans were approved in April/May 2010.

Smart meter technology includes metering technology and network communications technology capable of bidirectional communication that records electricity usage on at least an hourly basis, including related electric distribution system upgrades to enable the technology. The technology must provide customers with direct access to and use of price and consumption information.

By Jan. 1, 2010, or at the end of the applicable generation rate cap period, whichever is later, default service providers with more than 100,000 customers[42] must submit at least one proposed time-of-use (TOU) rate and real-time pricing (RTP) plan. Commission approval is due within six months of submittal. These pricing options must be offered to all customers that have been provided with smart meter technology.

On Jan. 28, 2010, the Commission approved a voluntary program where PPL Electric Utilities Corporation would offer a new, optional TOU rate for residential and small commercial and industrial customers in order to satisfy a portion of the statutory obligation.[43] On June 16, 2010, the Commission approved Duquesne Light Company's TOU and RTP Plan, to be implemented in four phases over the 2010 to 2013 period.[44]

PURPA

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA)[45] was implemented to encourage the conservation of energy supplied by electric utilities, the optimization of the efficiency of use of facilities and resources by electric utilities, and equitable rates to electric consumers. One of the ways PURPA set out to accomplish its goals was through the establishment of a new class of generating facilities which would receive special rate and

[39] 66 Pa. C.S. § 2807(f).
[40] Docket No. M-2009-209655.
[41] Docket Nos. M-2009-2123944 (PECO), M-2009-2123945 (PPL), M-2009-2123948 (Duquesne Light), M-2009-2123950 (Met-Ed, Penelec and Penn Power) and M-2009-2123951 (West Penn Power).
[42] Duquesne, Met-Ed, Penelec, Penn Power, PPL, PECO and West Penn.
[43] Docket No. R-2009-2122718.
[44] Docket No. P-2009-2149807.
[45] Pub. L. 95-617, Title II, § 210, 92 Stat. 3144 (16 U.S.C.A. § 824a-3(a)—(j)).

regulatory treatment. Generating facilities in this group are known as qualifying facilities (QFs), and fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities.

A small power production facility is a generating facility of 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources. A cogeneration facility is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy. With some limited exceptions, these facilities are also limited in size to 80 MW.

Although enacted more than 30 years ago, PURPA continues to have an impact on Pennsylvania's EDCs. The Commission's regulations govern the purchases and sales of energy between QFs and electric utilities. It also governs the purchases and sales of capacity and associated energy between suppliers of electric generation and electric utilities.[46]

Under the provisions of purchase power agreements, utilities are required to purchase any energy which is made available from a qualifying facility.[47] In 2009, 8,400 GWh were purchased from independent power producers (IPPs) and QFs, representing 5.6 percent of net energy for load. See Table 4. Contract capacity refers to the amount of the facilities' total capacity that the EDC contracts for; some purchases are for energy only.

Table 4 2009 purchases from IPPs and QFs by Pennsylvania EDCs

Company	Purchased Energy (MWh)	Percent of Net Energy for Load	Contract Capacity (kW)	Total Capacity (kW)
Citizens'	3,296	1.97%	0	6,000
Duquesne	0	0.00%	0	0
Met-Ed	2,201,773	15.29%	295,000	354,900
Penelec	3,082,343	21.47%	370,350	410,850
Penn Power	2	0.00%	0	10,600
PPL	1,091,468	2.72%	0	152,517
PECO	1,033,939	2.54%	181,000	384,082
West Penn	987,023	4.66%	136	151
UGI	0	0.00%	0	0
Total	**8,399,843**	**5.59%**	**846,486**	**1,319,100**

[46] 52 Pa. Code §§ 57.31-57.39.

[47] Under PURPA Section 210(m)(1)(A), enacted in response to § 1253 of the Energy Policy Act of 2005, no electric utility shall be required to enter into a new contract or obligation to purchase electric energy from a QF under Section 210(m) if FERC finds that the QF has nondiscriminatory access to: "(i) independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and (ii) wholesale markets for long-term sales of capacity and electric energy." FERC Docket No. RM06-10-001.

2009: A Year in Review

Pennsylvania's aggregate electricity sales in 2009 totaled 142,161 gigawatthours (GWh),[48] a 4.2 percent *decrease* from that of 2008, while the number of customers increased by 0.35 percent. This decrease was evident in all retail customer groups except "other" and follows a 0.5 percent decrease in sales from 2007 to 2008. Industrial sales declined 9.2 percent. Residential sales represented 35.4 percent of the total sales, followed by commercial (31.7 percent) and industrial (30.3 percent). Aggregate non-coincident peak load[49] decreased to 27,597 MW in 2009, down 8.2 percent from 2008. Tables 5 and 6 provide statistics for 2009, and 2008 for comparison.

Table 5 PA EDCs' energy demand, peak load and customers served (2009)

Company	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	586,616	3,945,655	6,537,414	2,616,153	64,351	21,849	13,185,422	662,150	30,441	13,878,013	2,732
Met-Ed	551,283	5,448,240	4,568,227	3,438,601	34,487	0	13,489,555	895,908	13,633	14,399,096	2,739
Penelec	589,959	4,471,133	5,018,687	4,044,173	41,421	0	13,575,414	773,805	4,347	14,353,566	2,451
Penn Power	159,692	1,634,012	1,366,828	1,228,844	6,464	1,018	4,237,166	128,641	1,970	4,367,777	901
PPL	1,398,461	14,218,100	13,817,800	8,417,700	237,000	931,937	37,622,537	2,475,685	69,656	40,167,878	6,845
PECO	1,564,433	12,893,426	8,404,059	15,888,955	927,616	587,586	38,701,642	2,010,187	45,420	40,757,249	7,994
West Penn	714,974	7,100,611	4,880,026	7,285,694	49,114	739,915	20,055,360	1,118,642	--	21,174,002	3,667
UGI	62,166	518,028	328,583	102,981	5,603	92	955,287	53,569	1,912	1,010,768	193
Citizens'	6,814	79,818	27,487	52,237	667	0	160,209	7,205	190	167,604	39
Pike County	4,649	28,077	44,699	0	404	0	73,180	4,954	17	78,151	15
Wellsboro	6,133	40,171	31,051	33,600	229	130	105,182	9,106	300	114,587	21
Total	**5,645,180**	**50,377,271**	**45,024,861**	**43,108,938**	**1,367,356**	**2,282,527**	**142,160,954**	**8,139,852**	**167,886**	**150,468,691**	**27,597**
% of Total		35.44%	31.67%	30.32%	0.96%	1.61%	100.00%				
2009 v 2008	0.35%	-1.84%	-1.86%	-9.17%	1.82%	-1.76%	-4.16%	-8.73%	-2.76%	-4.42%	-8.16%

Table 6 PA EDCs' energy demand, peak load and customers served (2008)

Company	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	586,804	4,060,410	6,631,217	3,079,488	66,811	22,708	13,860,634	963,150	30,222	14,854,006	2,822
Met-Ed	549,486	5,597,600	4,776,548	3,831,118	35,467	0	14,240,733	961,231	13,270	15,215,234	3,045
Penelec	589,552	4,557,862	5,185,820	4,593,995	41,574	0	14,379,251	881,122	4,804	15,265,177	2,880
Penn Power	159,585	1,666,785	1,404,034	1,614,208	6,466	4,348	4,695,841	154,133	1,968	4,851,942	1,063
PPL	1,394,202	14,418,614	13,912,558	9,551,368	225,891	981,726	39,090,157	2,665,912	72,806	41,828,875	7,316
PECO	1,570,294	13,317,085	8,700,237	16,533,639	908,982	554,752	40,014,695	1,941,212	47,774	42,003,681	8,824
West Penn	713,409	7,172,183	4,925,027	8,134,755	52,001	759,876	21,043,842	1,300,129	--	22,343,971	3,823
UGI	62,262	530,174	344,039	122,861	5,658	91	1,002,823	52,016	1,809	1,056,648	197
Citizens'	6,791	82,710	29,015	55,820	713	0	168,258	4,411	190	172,859	41
Pike County	4,642	29,321	47,765	0	208	0	77,293	300	9	77,602	19
Wellsboro	6,014	41,382	33,377	35,304	231	152	110,446	7,726	277	118,449	21
Total	**5,625,594**	**51,320,713**	**45,879,480**	**47,461,432**	**1,342,850**	**2,323,501**	**148,327,976**	**8,918,905**	**172,653**	**157,419,534**	**30,050**
% of Total		34.60%	30.93%	32.00%	0.91%	1.57%	100.00%				

Between 1994 and 2009, the state's energy demand grew at an average rate of 1.0 percent annually. Residential sales grew at an annual rate of 1.5 percent and commercial at 2.1 percent;

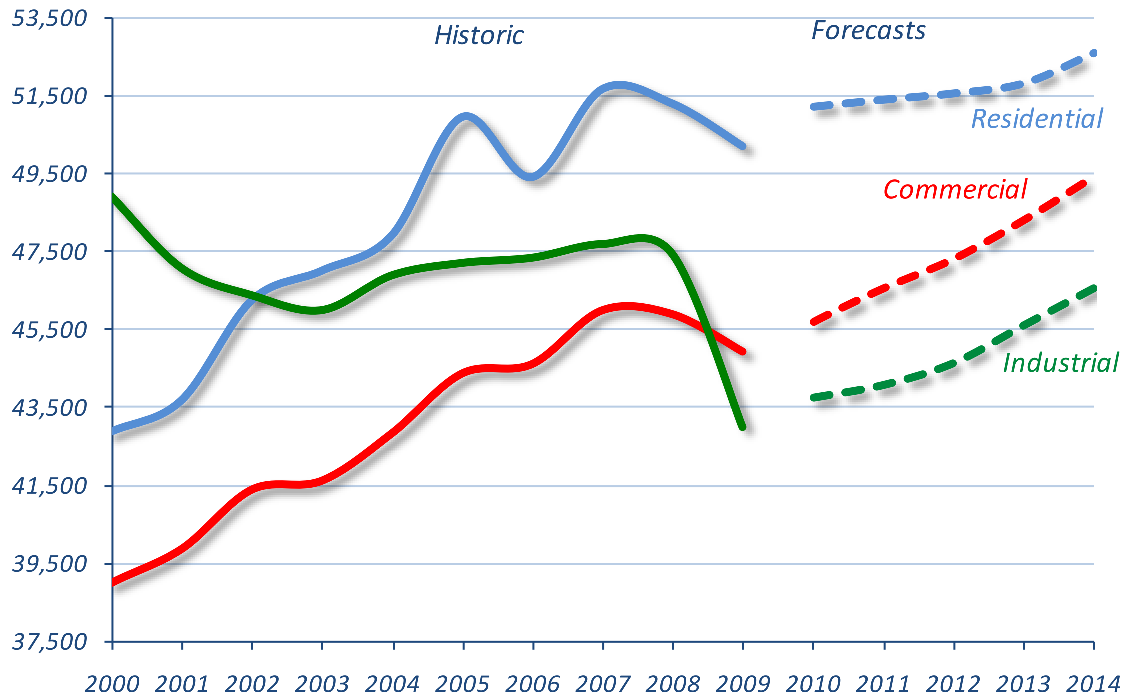
[48] A GWh is equivalent to 1,000 MWh or 1,000,000 kWh.

[49] Non-coincident peak load is the sum of EDCs' annual peak loads regardless of their date or time of occurrence.

industrial sales *declined* at an average rate of 0.4 percent per year, due mainly to a 9.4 percent drop in 2009. Over the past five years, residential demand increased an average of 0.9 percent per year and commercial at 1.0 percent; industrial sales *decreased* a total of 8.3 percent. Average annual total sales growth from 2004 to 2009 was 0.1 percent.

The current aggregate five-year projection of growth in energy demand is 1.4 percent. This includes a residential growth rate of 0.9 percent, a commercial rate of 1.9 percent and an industrial rate of 1.6 percent. See Figure 9, which depicts growth in retail energy demand by sector, in GWh.

Figure 9 Pennsylvania aggregate energy demand (GWh)

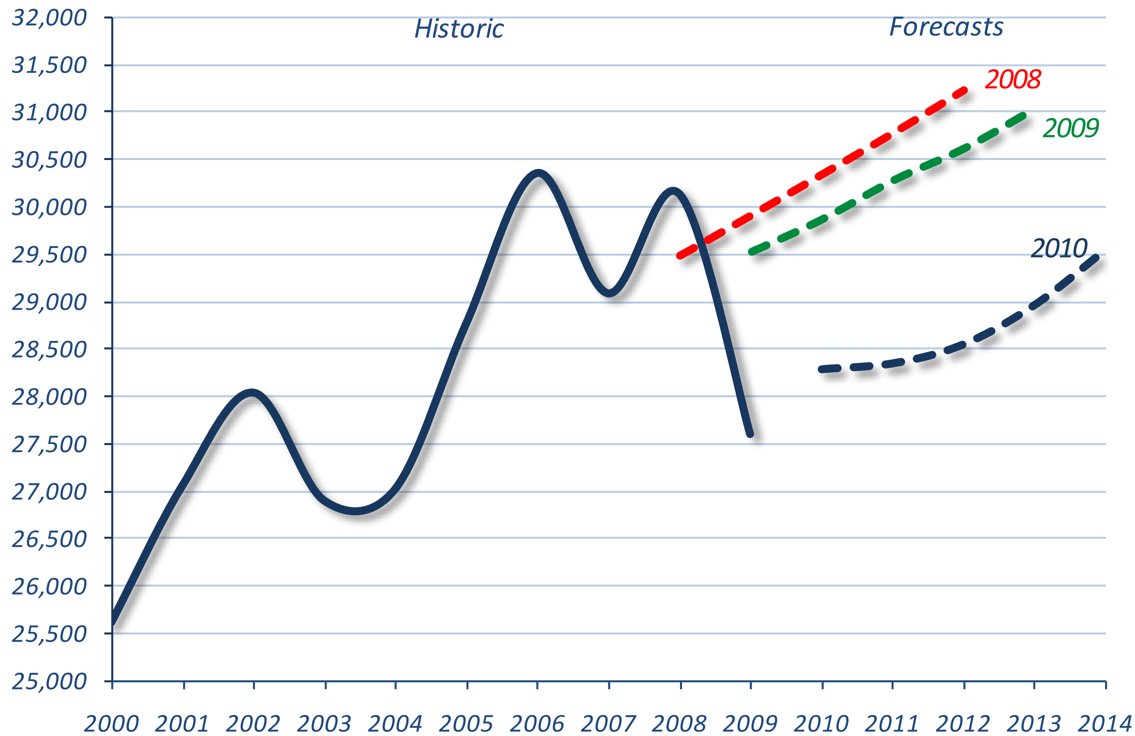


Over the past 15 years, the average aggregate non-coincident peak load for the major EDCs increased 0.7 percent per year. From 2004 to 2009, the peak load increased by an average of 0.4 percent per year. From 2008 to 2009, the aggregate peak load dropped 2,453 MW from 30,050 MW to 27,597 MW, or an 8.2 percent decrease. The 2009 summer peaks occurred in August.

The combined forecast of the EDCs' peak load shows the load increasing from 27,597 MW in 2009 to 29,550 MW in 2014 at an average annual growth rate of 1.4 percent. Actual peak loads are weather adjusted to reflect normal weather conditions prior to applying forecasting methodologies. Thus, the projected growth rates reflect the year-to-year fluctuations in energy sales and peak load.

Projections of energy demand and peak load reflect EDC compliance with the requirements of Act 129 relating to energy efficiency and demand response options available for each customer class. See Figure 10.

Figure 10 Pennsylvania aggregate non-coincident peak load (MW)



Forecasting Trends

Introduction

Load forecasting is an imprecise science affected by many unpredictable factors. These factors can amplify minor inaccuracies into substantial errors when they are relied upon for the planning of major construction projects, which take several years to design and build. During the 1960s and early 1970s, rapidly increasing demand for electricity drove the need for additions of large, base load generation facilities. The Commission's aggressive action taken after the 1965 Northeast Blackout during a period of electric power deficiency also contributed to the increase in generating resources. Subsequently, however, the interruption of this growth pattern by the Arab oil embargo, particularly in the industrial sector, distorted the historical capacity-load relationship, resulting in relatively large reserve margins. Several years of relatively moderate growth were required to lower margins to a more acceptable level.

While the overall growth rate has substantially declined and, although generation is no longer regulated by the Commission, utilities must continue to forecast future demand within a reasonable range of accuracy that insures a reliable future supply of electric energy. In a deregulated marketplace, forecasting is important for applications such as energy purchasing, generation and infrastructure development.

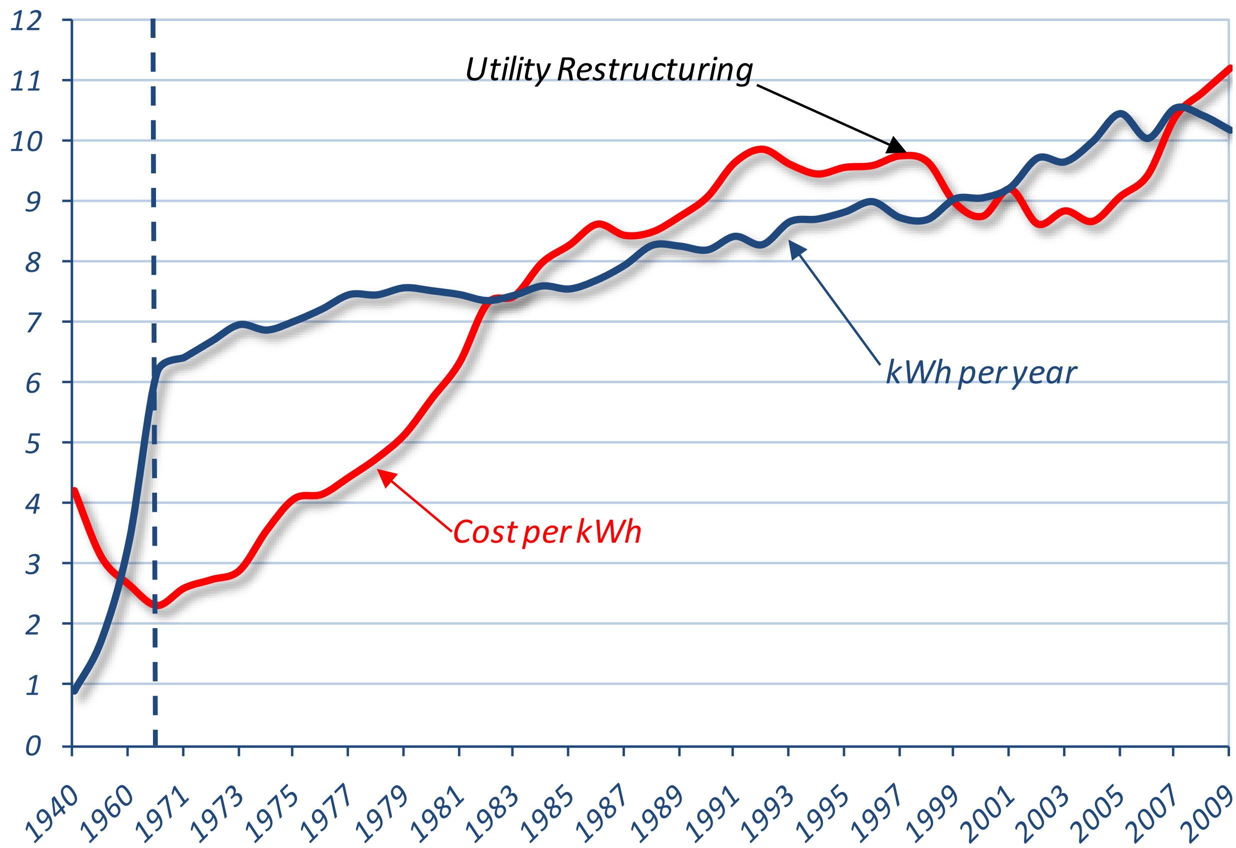
Forecasting Methodologies

In order to provide an adequate and reliable supply of electricity to the consuming public, EDCs must continue to forecast customer demands. Although EDCs are no longer the sole providers of energy within a competitive generation market, reasonably accurate projections are necessary to identify new capacity requirements and stimulate capital investment. Accurate forecasts are also needed to plan for future expansion of the transmission and distribution network.

Prior to 1973, customer load growth patterns remained relatively consistent, permitting utilities to forecast growth using a straightforward method such as linear regression analysis. This approach basically extrapolated future levels of demand from historical data. Although no one could foresee the 1973-74 Arab oil embargo and the 1979 energy crisis, or reasonably predict the effects of conservation and load management strategies and new technologies, the time trend approach failed to reflect the resultant dramatic changes in consumptive patterns, indicating a need for more sophisticated forecasting techniques.

Between 1940 and 1970, residential demand rose at a nominal levelized (average) rate of 6.6 percent per year, while the cost of electricity decreased at an annual average rate of 2.0 percent.[50] Between 1970 and 2009, residential demand and cost increased at annual rates of 1.3 percent and 4.1 percent, respectively. Between 1994 and 2009, the state's energy demand grew an average of 1.0 percent annually. Residential sales grew at an annual rate of 1.5 percent and commercial at 2.1 percent; industrial sales declined an average of 0.4 percent per year. During this same period, the average residential cost of electricity increased at an annual rate of 1.1 percent, going from an average of 9.46 cents to 11.21 cents per kWh. Figure 11 compares the changes in residential cost and usage from 1940 to 2009.

Figure 11 Average residential cost and use (cents per kWh or MWh per year)



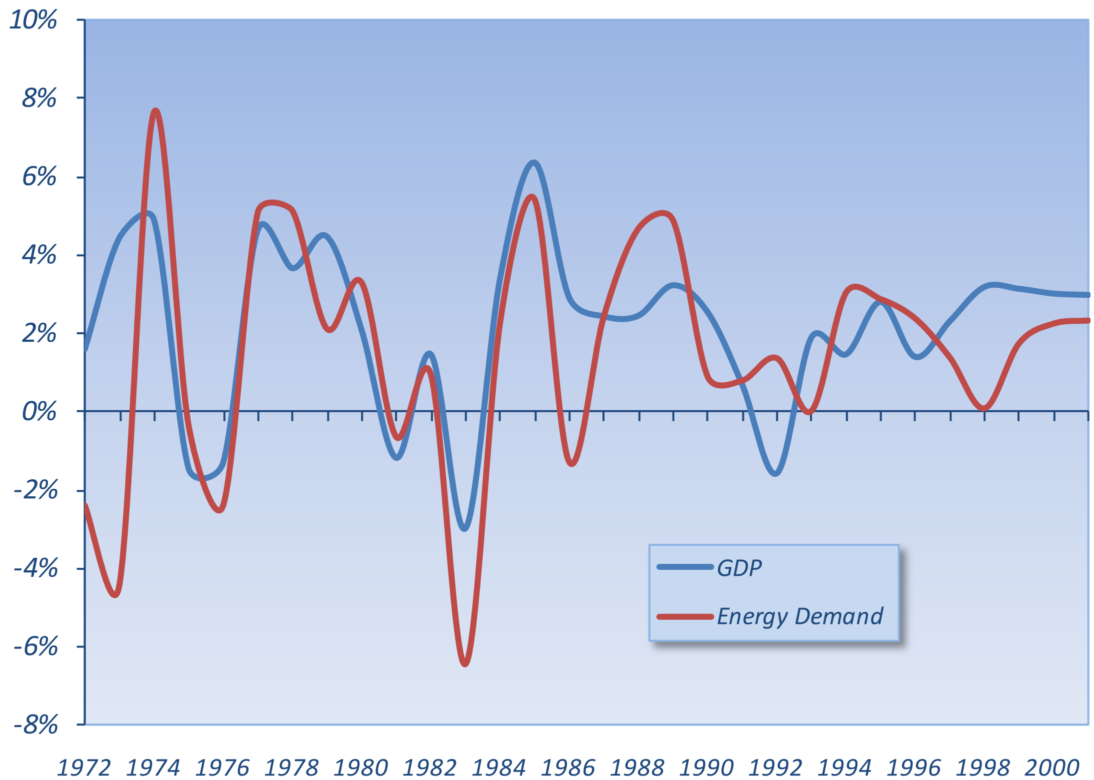
[50] Total Residential Account 440, FERC Form 1.

Most utilities have employed a combination of econometric and end-use forecasting methods which, although more sensitive to economic and engineering variables, were slow in adjusting to the overall decrease in load growth, since they are also based to a great extent on historical data. Econometrics is a statistical method combining the theories of economics and statistics for analysis of data, seasonal adjustment and model simulation. The end-use technique involves an explicit count of various energy consuming appliances or processes to which an energy use per unit is assigned.

Several factors affect the demand for electricity and among the most influential are economic growth, technological changes, energy supply, prices of electricity and other energy sources, and weather conditions. Industrial sales are more affected by economic conditions, whereas residential and commercial sales are most sensitive to weather conditions. Some of the key variables used by most large utilities in forecasting are: number of customers, appliance saturation, electricity price, population, per capita income, local employment, heating degree days, cooling degree days, appliance efficiencies, industrial output, natural gas prices and household size.

To illustrate the relationship between input variables and electrical usage, Figure 12 compares the yearly changes from U.S. Gross Domestic Product (GDP), in constant 1995 dollars, with energy demand.

Figure 12 Relationship between annual changes in GDP and energy demand



In addition to these key variables, the relatively unknown impacts of recently approved Energy Efficiency and Conservation Plans, pursuant to Act 129 of 2008, and the current economic downturn will make accurate forecasting a challenging pursuit. Although the Act 129 target reductions in energy consumption and peak demand are factored into the forecasts, the actual results of the EDCs' efforts will not be known for some time. The recession has already shown its effect on energy usage; forecasts generally reflect a recovery in 2010.

The EDCs' residential load growth scenarios typically reflect such variables as weather, personal income, electricity price (price elasticity), appliance saturation, consumer sentiment, mortgage rates and the number of new residential customers, based on population projections. Commercial sales forecasts relate historical sales to weather, non-manufacturing employment, personal income, real domestic product, the consumer price index and the number of residential customers. Industrial sales are primarily dependent on the level of economic activity within the service area and in the nation, and reflect specific information concerning large customer plans to expand or close their facilities. Forecasts of summer and winter peak demands are derived from econometric models which utilize the historic relationship of peak demand growth to the growth in the number of customers, and the effects of weather conditions.

PJM performs independent monthly and seasonal forecasts utilizing metered load data, load management, the PJM Load Forecast Model and Weather Normalization and Peak Allocation.[51] After-the-fact hourly load data, provided by the EDCs, is used by PJM for deriving seasonal load profiles, weather normalization factors and zonal load contributions. Monthly and seasonal load forecasts are prepared for each PJM zone, region, the RTO and selected combinations of zones. Weather normalization is employed to adjust historic loads for abnormal weather conditions. After each season, the model results are re-estimated, adding the most recent historical load, weather and economic data, to arrive at the weather normalized seasonal peak. Finally, zonal weather-normalized RTO-coincident summer peak loads are allocated to the wholesale and retail customers in the zones using EDC-specific methodologies that typically employ customer shares of RTO actual peaks.

Sectorial and Regional Trends

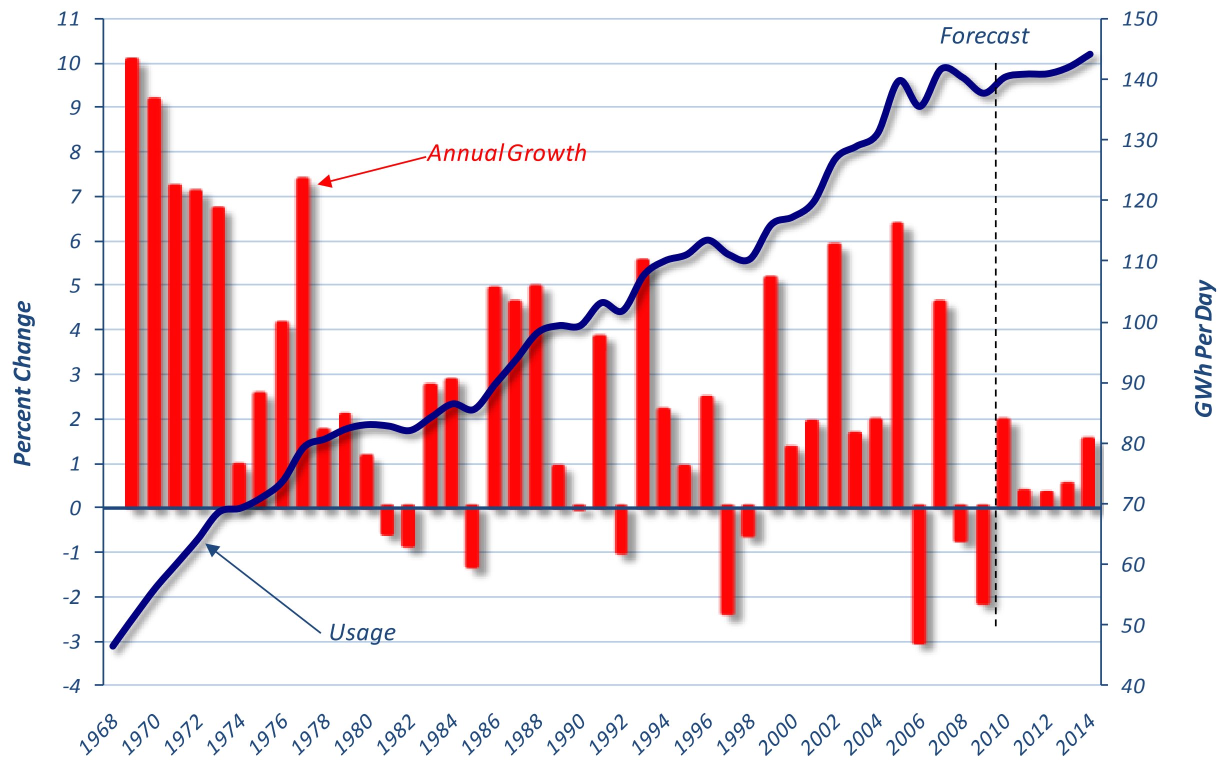
In the early 1970s, aggregate sales growth in the residential, commercial and industrial sectors ranged from 6 percent to 8 percent per year and rapidly declined thereafter. Industrial sales initially peaked in 1979 at 47,636 GWh, dropped to 39,994 GWh in 1982, climbed back to 48,941 GWh in 2000 and are currently 88.1 percent of the 2000 level. Over the past 40 years, total sales have grown an average of 1.8 percent annually: residential at 2.5 percent, commercial at 3.4 percent and industrial at 0.5 percent.

Statewide residential consumption has increased from 56 GWh per day in 1970 to 138 GWh per day in 2009. Growth in total residential usage has averaged 787 GWh per year. Over the same period, average annual usage per residential customer increased from 6,203 kWh to 10,217 kWh, a 65 percent increase. Average usage dropped 3.5 percent from the 2007 high of 10,583 kWh.

In 2009, residential usage dropped 1.8 percent, following a decrease of 0.7 percent the previous year. The five-year aggregate residential forecast shows a growth of 470 GWh per year or an average annual growth of 0.9 percent. See Figure 13.

[51] PJM Manual 19: Load Forecasting and Analysis, Oct. 1, 2009.

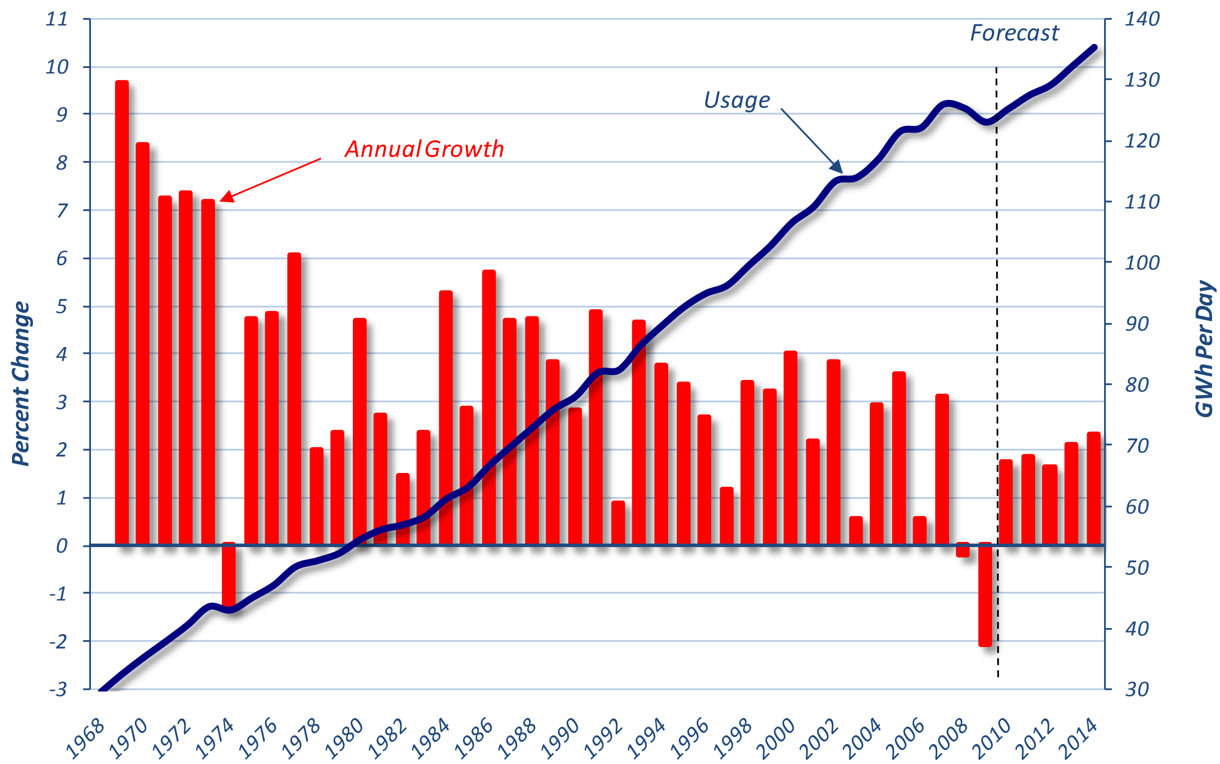
Figure 13 Pennsylvania residential usage and annual growth



Growth in commercial consumption has been relatively consistent, increasing at a levelized annual rate of 3.8 percent since 1970. Although year-to-year growth rates have been declining over the years, demand continues to grow an average of 825 GWh per year.

In 2009, commercial usage dropped 1.8 percent, following a decrease of 0.2 percent the previous year. The five-year forecast shows annual growth averaging 897 GWh, or an average annual growth rate of 1.9 percent. See Figure 14.

Figure 14 Pennsylvania commercial usage and annual growth



Industrial sales have fluctuated considerably, particularly during the 1970s and 1980s, as can be seen in Figure 15. Between 1970 and 2009, growth in aggregate industrial demand has averaged 177 GWh per year, or an average annual rate of 0.4 percent.

Since 2000, industrial sales have declined 12.1 percent. Last year's sales decreased 9.2 percent from 2008, and the forecast for 2010 is 7.8 percent below the 2008 level. From 2009 to 2014, industrial growth is projected to average 1.6 percent.

The recent drop in industrial sales has been, for the most part, the result of the economic recession. Prior to 2009, there were two other significant declines in the industrial energy market. A significant drop in sales (7.8 percent) followed the 1973 OPEC Oil Embargo, which quadrupled the price of oil.[52] The 1979 energy crisis occurred in the wake of the Iranian Revolution; at the same time, the Carter Administration began a phased deregulation of oil prices, and, within 12 months, the price of crude oil increased 150 percent.[53] Shortly after, a substantial drop in Iran's oil production, followed by a drop in Saudi Arabia's output occurred.[54] In 1982, the largest drop in industrial sales occurred (13.6 percent). Duquesne alone lost 40.7 percent of its industrial load that year.

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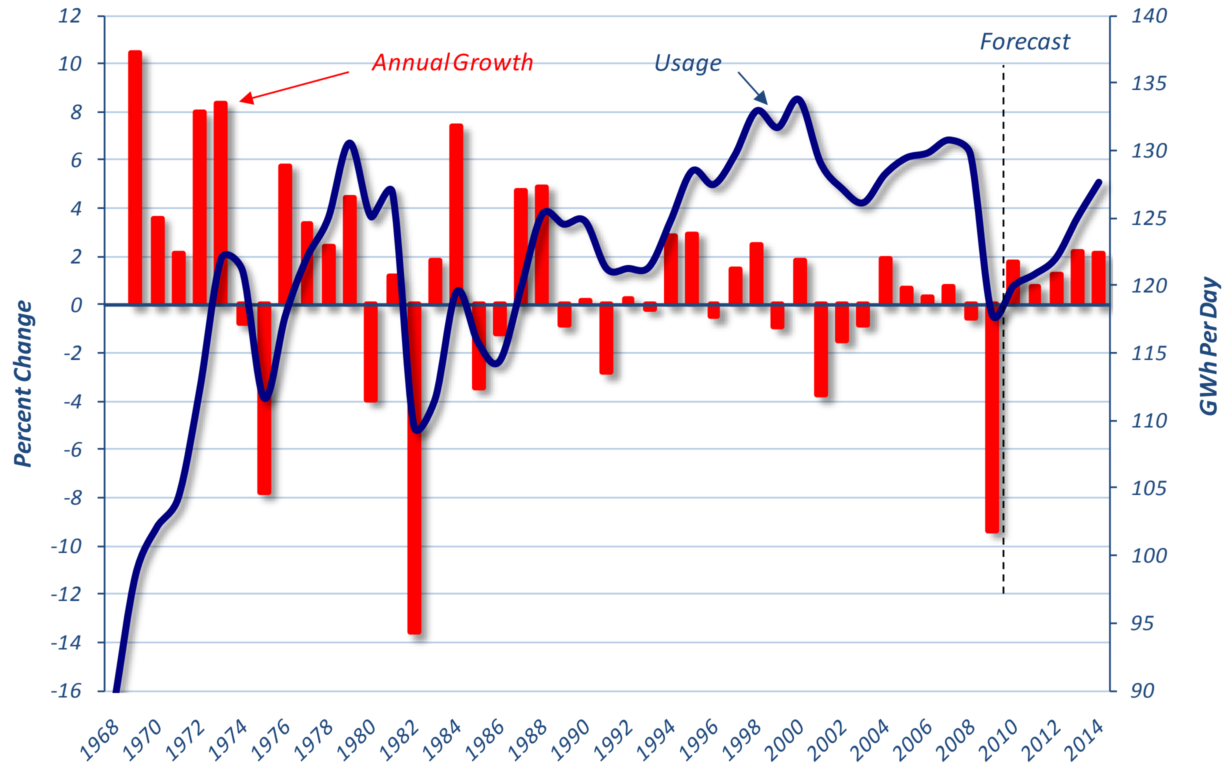
[52] U.S. Department of State, Office of the Historian, *OPEC Oil Embargo, 1973-1974*.
[53] *The New York Times*, March 3, 2008.
[54] Energy Information Administration, *Annual Energy Review 2008*, Fig. 11.5, p. 314.

Figure 15 Pennsylvania industrial usage and annual growth

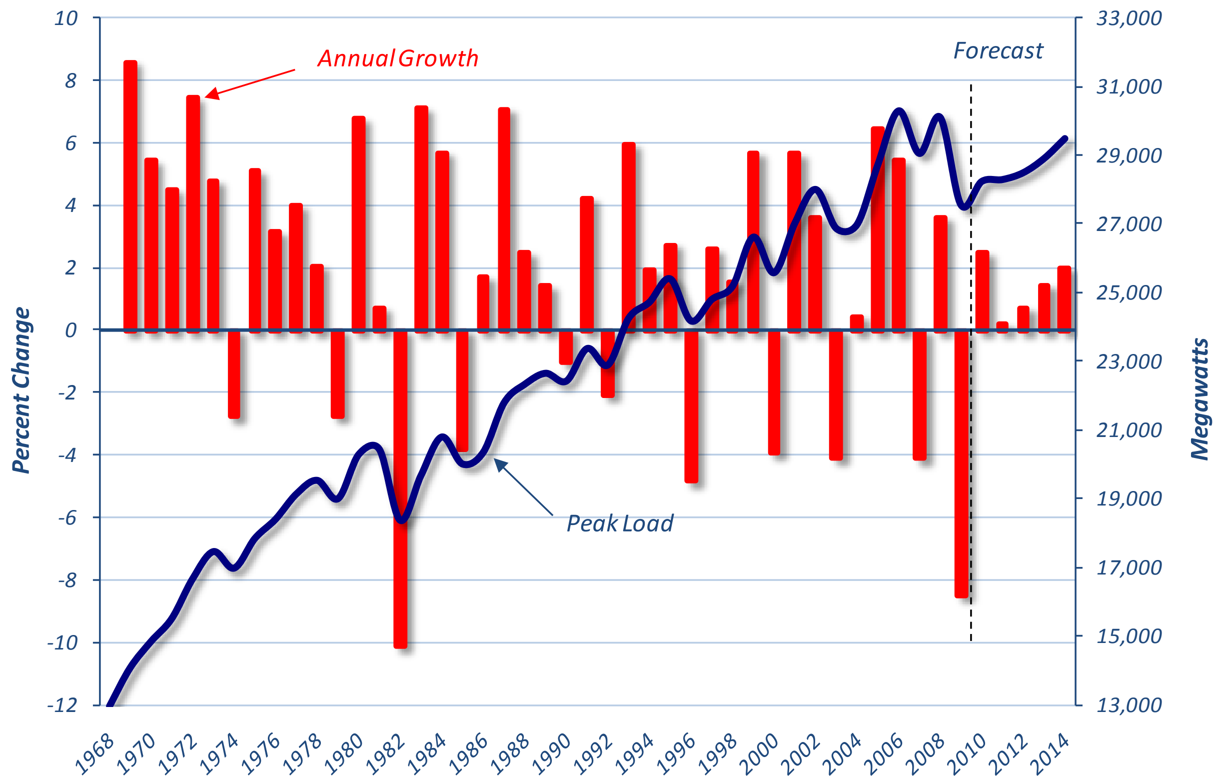


Growth in Pennsylvania's total electric consumption is expected to increase by 1.8 percent in 2010 and 1.0 percent in 2011. In comparison, total U.S. consumption is projected to increase by 3.0 percent in 2010 and grow by 1.2 percent in 2011.[55]

Aggregate non-coincident peak load increased from 14,812 MW in 1970 to 27,597 MW in 2009, at an annual average rate of 1.6 percent. Peak load is expected to increase to 29,550 MW by 2014, 500 MW less than the 2008 load, at an average annual rate of 1.4 percent. See Figure 16.

[55] *Short-Term Energy Outlook*, Energy Information Administration, April 2010.

Figure 16 Pennsylvania non-coincident peak load and annual growth



Trends in Forecast Accuracy

Since electricity use is a function of several forces outside the control of the utilities, forecasts of future electricity requirements cannot be any more certain than the forecasts of those external forces. Although all utilities have had some degree of difficulty in adjusting to the dramatic changes in electricity use, some utilities have fared better than others. This may, in part, be attributable to the stability (or volatility) of each utility's service territory.

During the 1970s and early 1980s, forecast deviations from actual figures quickly became excessive. Forecasts of peak load made three years in advance were, on average, 10 percent higher than actual demand. Forecasts made five years in advance were 20 percent higher. Over the last few years, however, forecast deviations have shown no appreciable difference as to whether forecasts are made one, two or even five years in advance. Peak load forecast deviations have varied only slightly, from 4.7 percent to 5.7 percent, based on the average of forecast deviations for each company. Deviation magnitudes have diminished over time. See Figure 17. (Available data points decrease from 10 for forecasts made one year in advance to six for forecasts made five years in advance.)

Energy demand forecast deviations have also diminished over time. Unlike the peak load forecasts, however, there is a definite pattern of increasing forecast deviation magnitudes as the forecasts advance into the future. Figures 18-20 show the absolute deviations from actual for the residential, commercial and industrial sectors, for forecasts made one to five years in advance.

Figure 17 Average deviation in peak load forecasts (%)

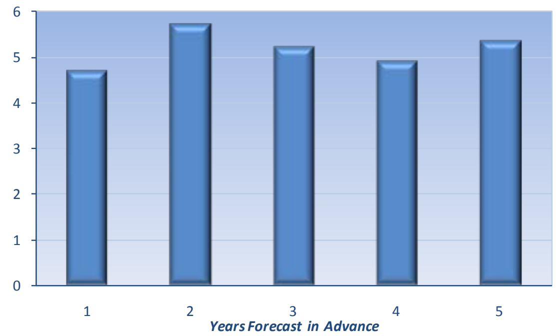


Figure 19 Average deviation in residential forecasts (%)

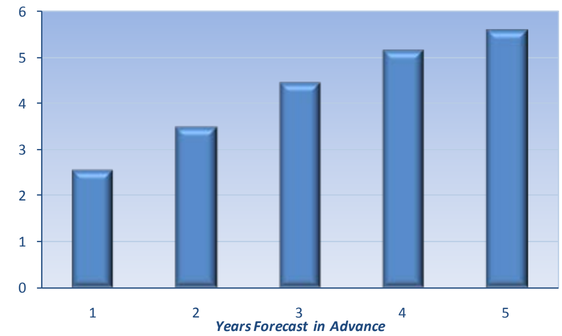


Figure 18 Average deviation in commercial forecasts (%)

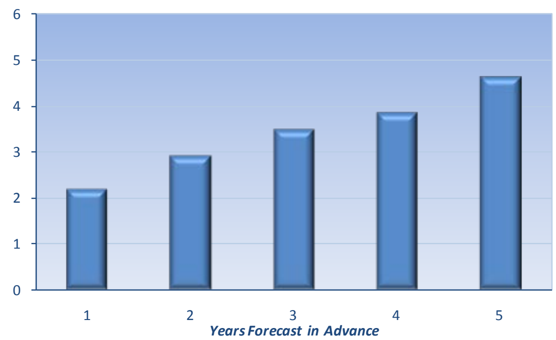
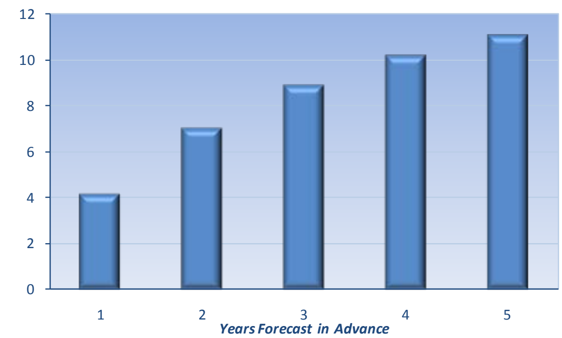


Figure 20 Average deviation in industrial forecasts (%)



Most utility forecasts have appreciably improved over time. There is, however, a significant range in the magnitude of forecast deviations from company to company. At the extremes, PPL's peak load forecast deviations have ranged from 2.6 percent to 4.7 percent, whereas Penn Power's deviations ranged from 7.6 percent to 9.2 percent. Figures 21-24 compare EDCs' absolute average forecast deviations from actual figures for peak load and residential, commercial and industrial energy demand for forecasts made one to five years in advance.

There has been little difference between the forecast accuracy of the residential and commercial sectors; however, forecasts for both of these sectors have, for the most part, been considerably more accurate than those made for the industrial sector.

Generally, residential and commercial energy demand has tended to be underestimated; whereas industrial energy demand has been overestimated. This can be seen in Figure 25 where the average short-term forecast error (deviation) is examined for peak load and for each major customer class.

Figure 21 Comparison of peak load forecast accuracy (%)

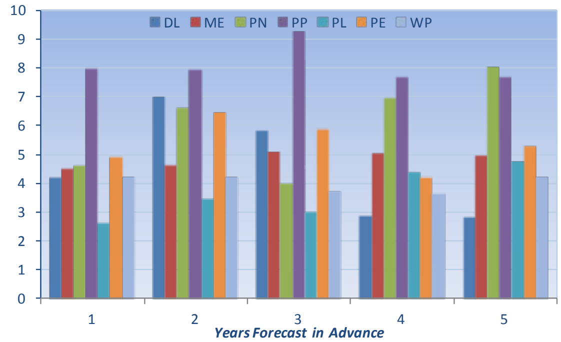


Figure 23 Comparison of commercial energy demand forecast accuracy (%)

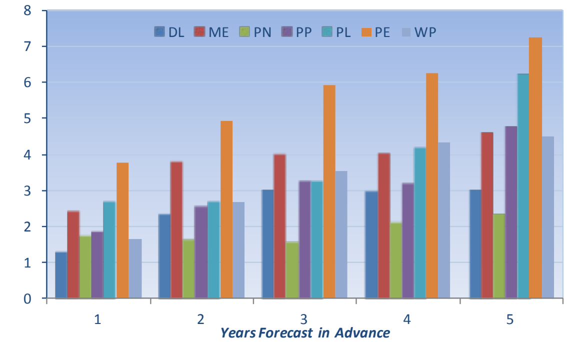


Figure 22 Comparison of residential energy demand forecast accuracy (%)

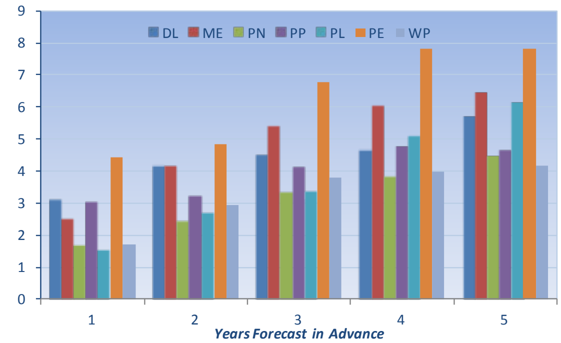


Figure 24 Comparison of industrial energy demand forecast accuracy (%)

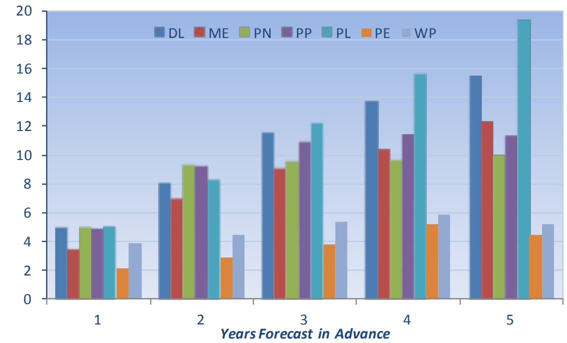
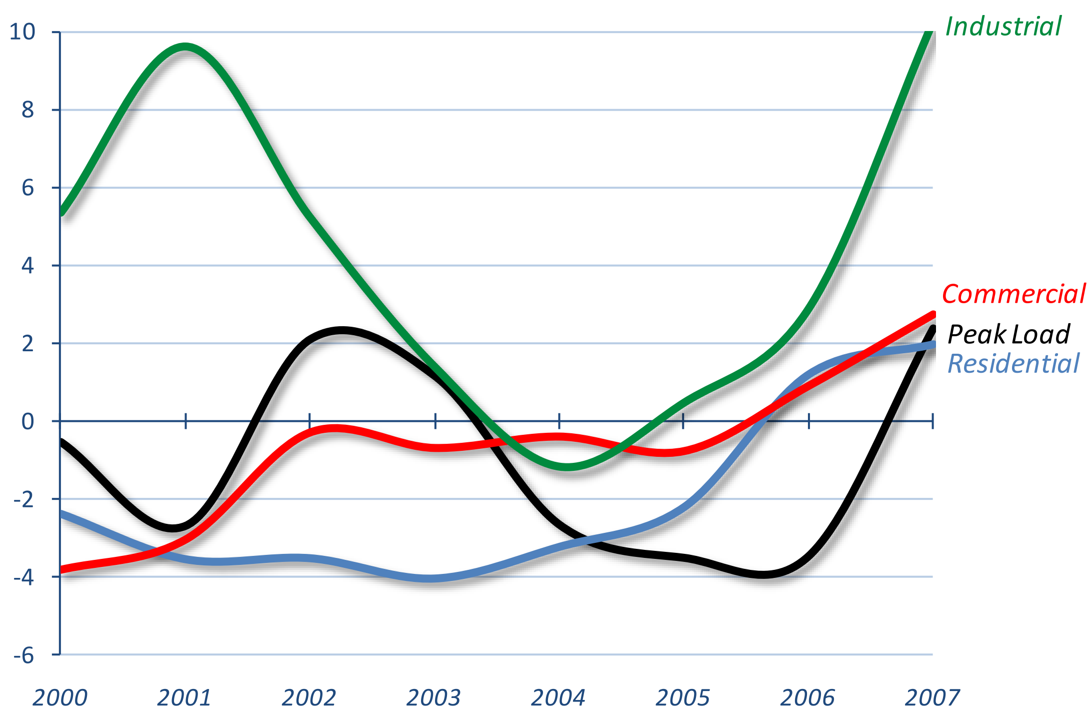


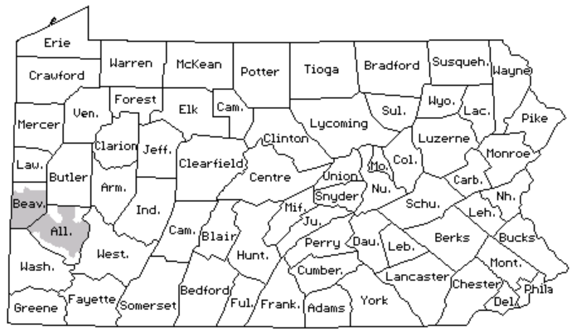
Figure 25 Average of deviations in forecasts made one to three years in advance (%)



Summary of EDC Data

The following sections provide, for each jurisdictional EDC, historic and projected energy sales and peak load; electric generation supplier sales statistics; purchases from cogeneration and small power production projects; planned transmission line additions; and conservation activities. Additional statistics on actual and forecast load and energy demand for the large EDCs are provided in Appendix A.

Duquesne Light Company



Duquesne Light Company (Duquesne) is the principal subsidiary of DQE Holdings[56] and provides electric service to 586,616 electric utility customers in the City of Pittsburgh and portions of Allegheny and Beaver counties in Southwestern Pennsylvania. In 2009, Duquesne had energy sales totaling 13,185 GWh -- down 4.9 percent from 2008. Commercial sales continued to dominate Duquesne's market with 49.6 percent of the total sales, followed by residential (29.9 percent) and industrial (19.8 percent). Average annual use per residential customer was 7,516 kWh at an average cost of 11.82 cents per kWh; operating revenues totaled $876.2 million.

Between 1994 and 2009, Duquesne's total energy demand increased 0.6 percent per year: residential demand grew at an annual rate of 1.4 percent; commercial demand grew at 1.1 percent; and industrial demand *decreased* at an average annual rate of 1.5 percent. The current five-year projection of average increase in total energy consumption is 0.7 percent per year. This includes a residential growth rate of 2.4 percent, a commercial rate of 0.6 percent and a major *decline* in industrial sales of 2.1 percent per year. See Figure 26.

Duquesne's summer peak load, occurring on Aug. 17, 2009, was 2,732 MW, representing a decrease of 3.2 percent from last year's peak of 2,822 MW. The 2009-10 winter peak load was 2,122 MW or 5.5 percent lower than that of the previous year. The actual average annual peak load growth rate over the past 15 years was 0.5 percent. Duquesne’s forecast shows the peak load increasing from 2,732 MW in the summer of 2009 to 2,960 MW in 2014, or an average annual growth rate of 1.6 percent. The current forecast for 2010 is 0.6 percent above the previous forecast, filed in 2009. See Figure 27.

Figure 28 depicts the average of deviations in forecasts made one to three years in advance. Tables A01-A04 in Appendix A provide Duquesne’s forecasts of peak load and residential, commercial and industrial energy demand, filed with the Commission in years 2000 through 2010.

Currently, PJM manages the flow of wholesale electricity for Duquesne. Duquesne’s integration into PJM involved transferring control of 670 miles of high-voltage transmission lines; however, ownership has remained with Duquesne. PJM is the regional reliability coordinator for Duquesne.

[56] On April 24, 2007, the Commission approved the acquisition of Duquesne Light Holdings Inc., by merger, with the Macquarie Consortium. Headquarters remain in Pittsburgh. See Docket No. A-110150F0035.

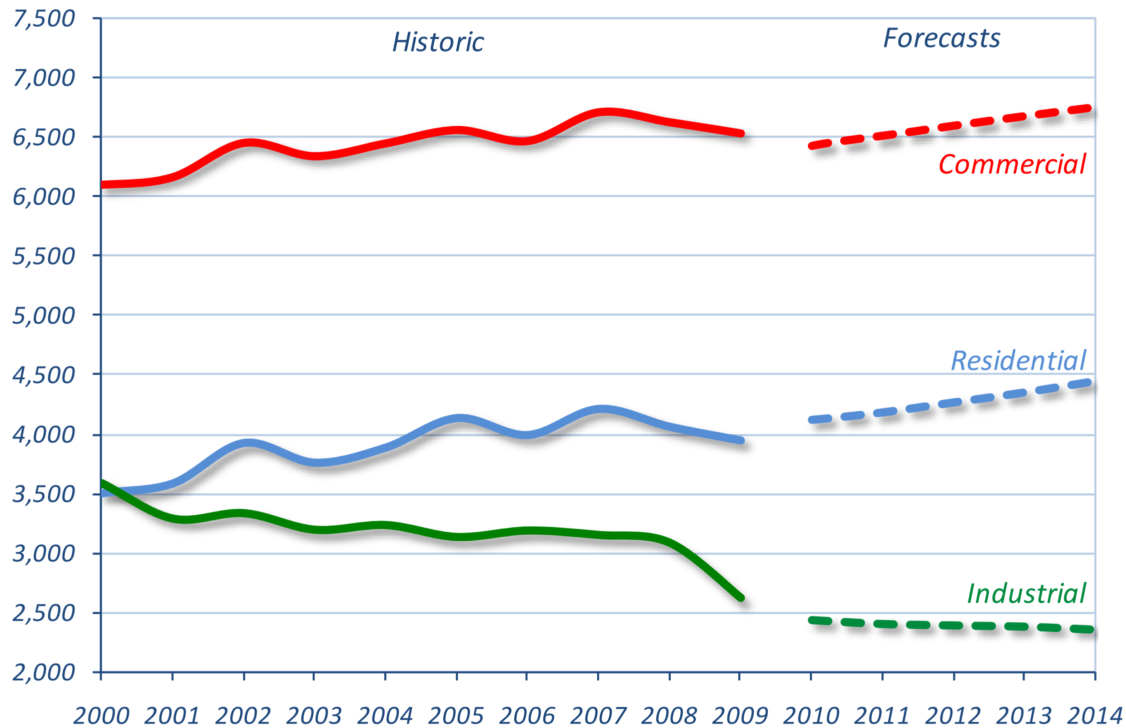
For Calendar Year 2009, 14 EGSs and one municipality sold a total of 7,956 GWh to retail customers in Duquesne's service territory, or 60.3 percent of total consumption. There were no instances in 2009 where EGSs failed to supply scheduled load. Since joining PJM in 2005, PJM has provided energy imbalance service to all load serving entities, which includes the EGSs. Duquesne does not own any generating facilities.

Duquesne has 120.7 miles of transmission line projects, including construction of new overhead and underground transmission, reconfiguration of existing transmission lines, and up-rates of existing lines, scheduled through 2013. These projects are planned to mitigate anticipated NERC reliability criteria violations identified by both Duquesne and PJM.

Duquesne's Energy Efficiency and Conservation Plan[57] includes 19 energy efficiency and three demand response programs to reach cumulative reduction targets of 423 GWh and 113 MW at a total cost of $78.2 million. The programs provide a full range of measures to assist residential, commercial and industrial customers of all sizes and in all key market segments. For further information, visit http://www.duquesnelight.com/wattchoices.

Duquesne is a member of PJM and RFC.

Figure 26 Duquesne Light Company energy demand (GWh)



[57] Docket No. M-2009-2093217.

Figure 27 Duquesne Light Company peak load (MW)

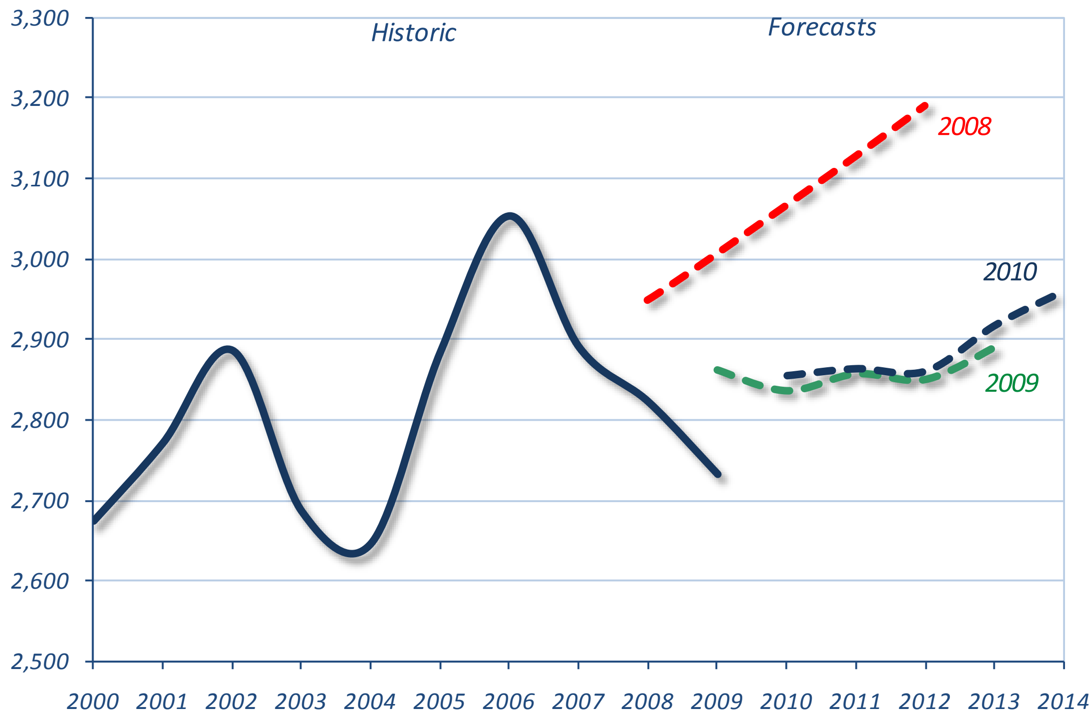
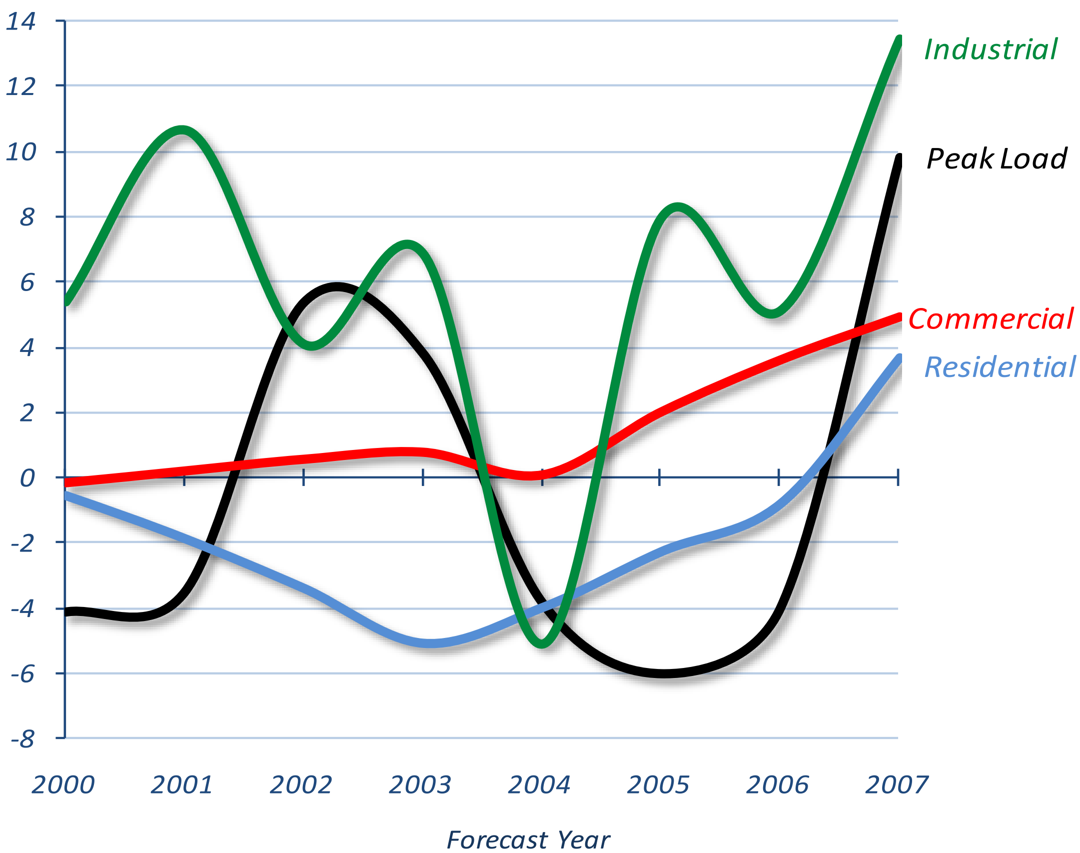


Figure 28 Duquesne Light Company average of deviations in forecasts (%)



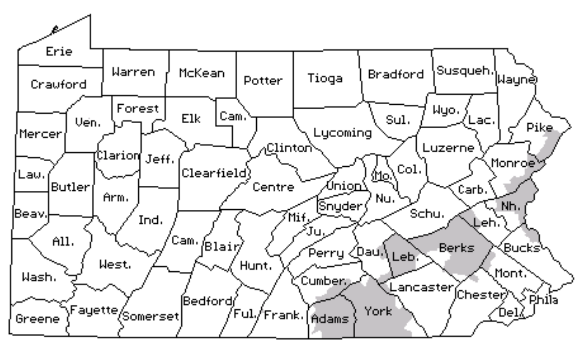
FirstEnergy Corporation

FirstEnergy Corporation (FirstEnergy) is a holding company with seven electric utility operating companies, comprising the nation's fifth largest investor-owned electric system, serving 4.5 million customers within 36,100 square miles of Ohio, Pennsylvania and New Jersey. Its generation subsidiaries control more than 14,200 MW of capacity (56 percent coal and 28 percent nuclear). The three operating companies in Pennsylvania include Metropolitan Edison Company, Pennsylvania Electric Company and Pennsylvania Power Company. See Figure 29.

Figure 29 FirstEnergy service territory

On May 14, 2010, FirstEnergy, West Penn Power Company and TrailCo filed a joint application with the Commission, at Docket No. A-2010-2176520, to obtain approval for the merger of Allegheny Energy, Inc. with a wholly-owned subsidiary of First Energy. The combined company will retain the FirstEnergy name and be headquartered in Akron, Ohio. If approved, the transaction, expected to be completed early in 2011, will result in an energy provider with $16 billion in annual revenues, 10 regulated EDCs operating in seven states, 20,000 miles of high-voltage transmission lines, 24,000 MW of generating capacity and more than 2,200 MW of renewable energy.

Metropolitan Edison Company



Metropolitan Edison Company (Met-Ed), a subsidiary of FirstEnergy, provides service to 551,283 electric utility customers in all or portions of 14 counties in Eastern and Southcentral Pennsylvania. In 2009, Met-Ed had total energy sales of 13,490 GWh—down 5.3 percent from 2008. Residential sales dominated Met-Ed's market with 40.4 percent of total sales, followed by commercial (33.9 percent) and industrial (25.5 percent). Declines in sales were seen in all customer segments, with the largest decline in the industrial sector at 10.2 percent. Industrial sales were 77.9 percent of the highest level occurring in

2000. Average annual use per residential customer was 1,218 kWh at an average cost of 11.38 cents per kWh; operating revenues totaled $1.32 billion.

Between 1994 and 2009, Met-Ed's energy demand grew at an average rate of 2.1 percent per year. Residential and commercial sales have maintained relatively steady growth over the period (2.2 percent for residential and 3.0 percent for commercial), while industrial sales have fluctuated considerably. Industrial sales *declined* at an average rate of 0.8 percent, attributable to the steep drop in 2009. The current five-year projection of growth in total energy demand is 1.9 percent. This includes a residential growth rate of 1.3 percent, a commercial growth rate of 1.7 percent and an industrial rate of 3.2 percent. See Figure 30.

Met-Ed's summer peak load, occurring on Aug. 10, 2009, was 2,739 MW, representing a decrease of 10.0 percent from last year's system peak of 3,045 MW. The 2009-10 winter peak load was 2,342 MW or 10.7 percent lower than the previous year's winter peak of 2,622 MW. The actual average annual peak load growth rate over the past 15 years was 2.1 percent. Met-Ed's forecast shows its peak load dropping from 2,739 MW in 2009 to 2,630 MW in 2012 and increasing thereafter to 2,731 MW by 2014. The current forecast for 2010 is 245 MW or 8.4 percent below the previous forecast. See Figure 31.

Figure 32 depicts the average of deviations in forecasts made one to three years in advance. Tables A05-A08 in Appendix A provide Met-Ed's forecasts of peak load and residential, commercial and industrial energy demand, filed with the Commission in years 2000 through 2010.

A restructuring settlement, approved by the Commission in 1998, provided for the transfer of 80 percent of Met-Ed's POLR responsibility to other generation suppliers by June 2003. Since this did not occur, Met-Ed retains POLR responsibility for those customers who do not choose an alternate energy supplier and currently supplies nearly all of its POLR customers. Met-Ed does not own any generating facilities.

In 2009, Met-Ed purchased 2,202 GWh from cogeneration and small power production projects, representing 15.3 percent of net energy for load. Contract capacity (defined as PJM installed capacity credits) is 295 MW of a total capacity of 355 MW. For Calendar Year 2009, two EGS sold a total of 21 GWh to retail customers in Met-Ed's service territory. There were no occurrences where EGSs were unable to supply scheduled loads during 2009.

Through 2013, Met-Ed's transmission line projects include construction of new lines and reconductoring of existing lines to improve local service at a combined cost of $4.1 million. Projects include 11.1 miles of 69 kV, 115 kV and 230 kV circuits.

Met-Ed's Energy Efficiency and Conservation Plan[58] offers a suite of programs for all customer segments designed to reach cumulative reduction targets of 446 GWh and 119 MW at a total cost of $99.5 million.

Met-Ed is a member of PJM and RFC.

[58] Docket No. M-2009-2092222.

Figure 30 Metropolitan Edison Company energy demand (GWh)

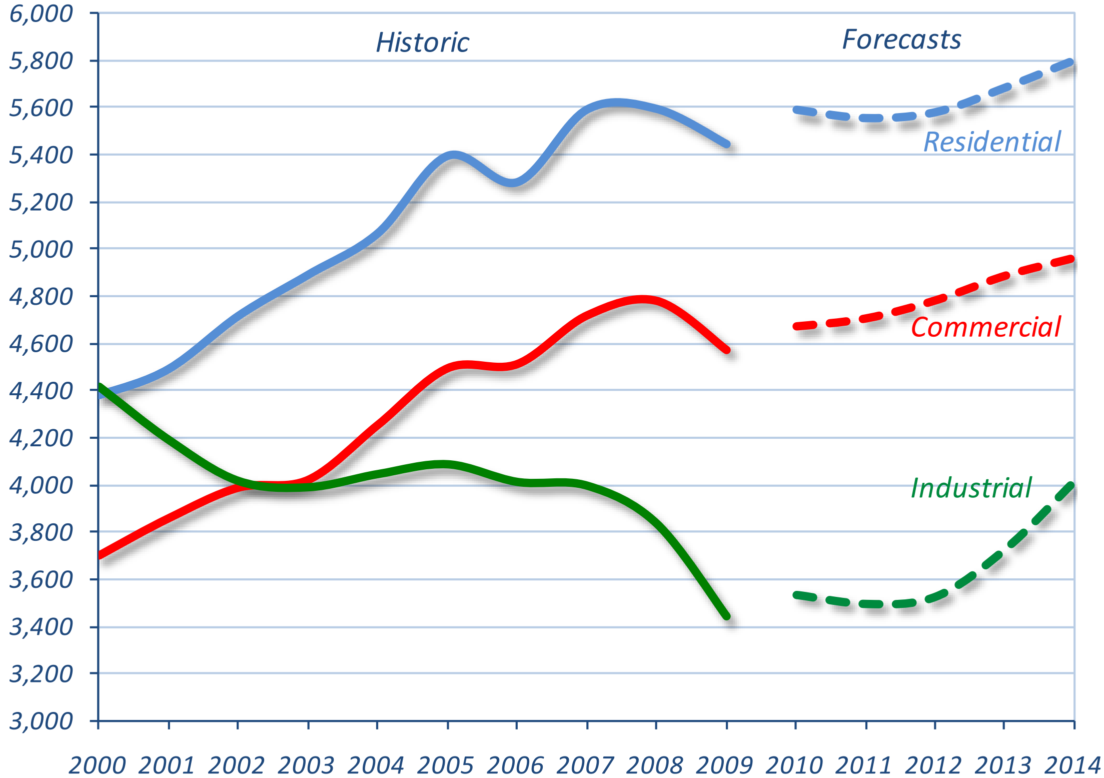


Figure 31 Metropolitan Edison Company peak load (MW)

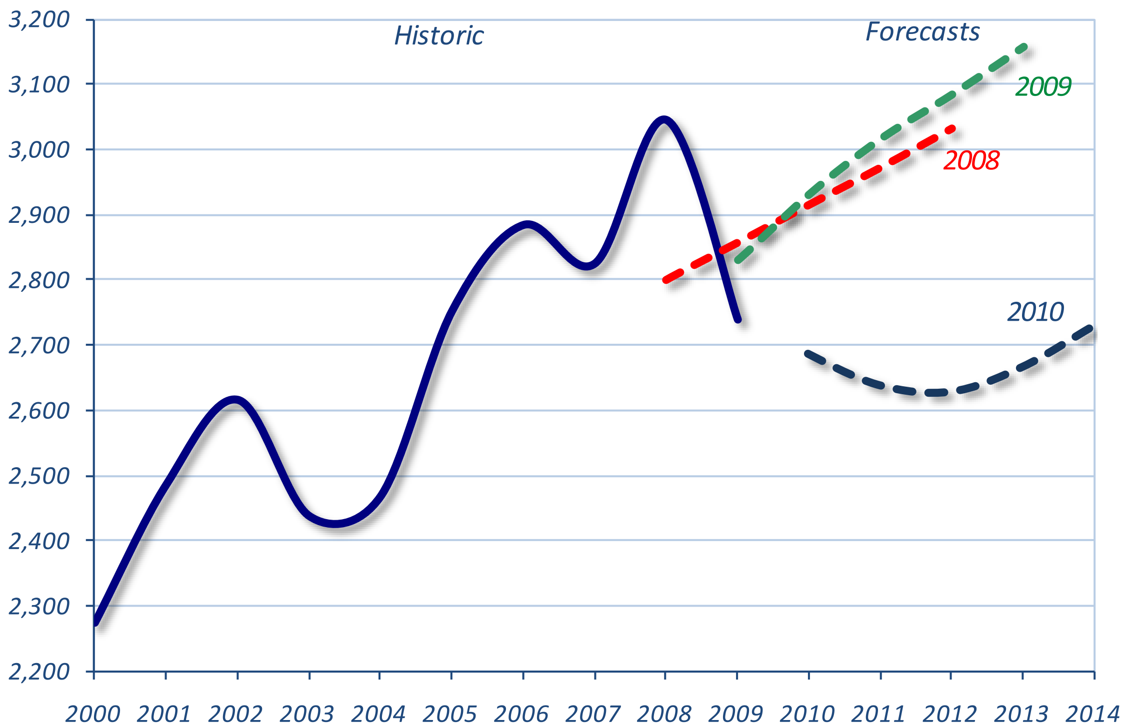
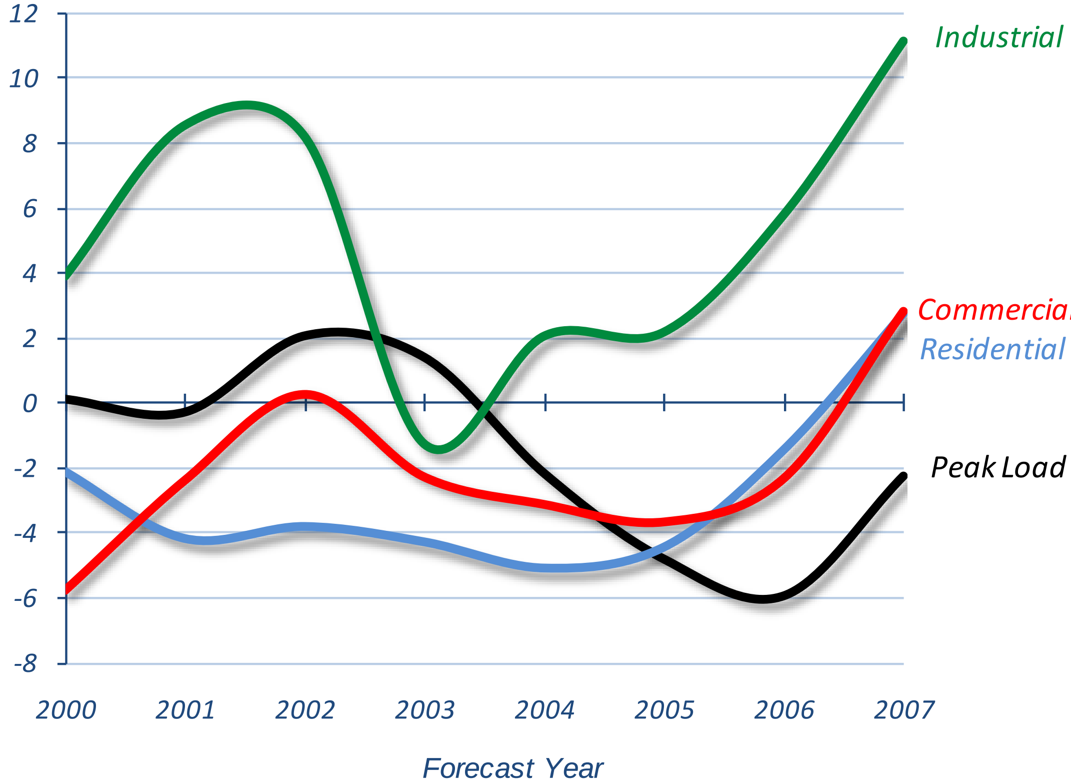
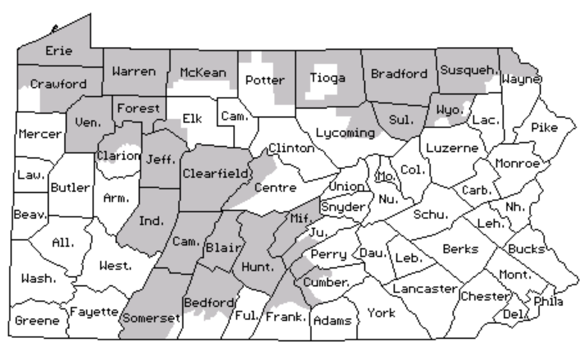


Figure 32 Metropolitan Edison Company average of deviations in forecasts (%)



Pennsylvania Electric Company



Pennsylvania Electric Company (Penelec), a subsidiary of FirstEnergy, provides service to 589,959 electric utility customers in all or portions of 29 counties in Western and Northern Pennsylvania. In 2009, Penelec had energy sales totaling 13,575 GWh—down 5.6 percent from 2008. Commercial sales led Penelec's market with 37.0 percent of the total sales, followed by residential (32.9 percent) and industrial (29.8 percent). Average annual use per residential customer was 8,844 kWh at an average cost of 10.46 cents per kWh; operating revenues totaled $1.08 billion.

Between 1994 and 2009, Penelec's energy demand grew at an average rate of 0.8 percent per year. Residential and commercial sales have maintained relatively steady growth over the period (1.1 percent for residential and 1.9 percent for commercial), while industrial sales have fluctuated greatly, with an average annual *decrease* of 0.6 percent, due mainly to the 12.0 percent drop in sales last year. The current five-year projection of growth in total energy demand is 1.5 percent.

This includes a residential growth rate of 0.1 percent, a commercial growth rate of 1.6 percent and an industrial growth rate of 2.9 percent. See Figure 33.

Penelec's 2009 summer peak load, occurring on Aug. 17, 2009, was 2,451 MW, representing a decrease of 14.9 percent from last year's summer peak of 2,880 MW. The 2009-10 winter peak load was 2,346 MW or 18.1 percent lower than the previous year's winter peak of 2,866 MW. The average change in the annual summer peak load over the past 15 years was -0.2 percent per year. Penelec's forecast shows its summer peak load increasing at an average annual rate of 0.6 percent, rising to 2,531 MW by 2014, or 349 MW less than the 2008 all-time peak of 2,880 MW. The current forecast for 2010 is 6.3 percent below the previous forecast. See Figure 34.

Figure 35 depicts the average of deviations in forecasts made one to three years in advance. Tables A09-A12 in Appendix A provide Penelec's forecasts of peak load and residential, commercial and industrial energy demand, filed with the Commission in years 2000 through 2010.

A restructuring settlement, approved by the Commission in 1998, provided for the transfer of 80 percent of Penelec's POLR responsibility to other generation suppliers by June 2003. Since this did not occur, Penelec retains POLR responsibility for those customers who do not choose an alternate energy supplier and currently supplies nearly all of its POLR customers.

Penelec divested all of its generation facilities in 1999.

In 2009, Penelec purchased 3,082 GWh from cogeneration and small power production projects, or 21.5 percent of net energy for load. Contract capacity (defined as PJM installed capacity credits) is 370 MW out of a total capacity of 411 MW.

For Calendar Year 2009, two licensed EGSs sold a total of 528 GWh to retail customers in Penelec's service territory, or 3.9 percent of total consumption, up from 3.0 percent in 2008.

Through 2012, Penelec's transmission line projects include construction of new lines and reconductoring of existing lines to improve local service at a combined cost of $11.7 million. Projects include 9.4 miles of 115 kV, 230 kV and 500 kV circuits.

Penelec's Energy Efficiency and Conservation Plan[59] offers a suite of programs for all customer segments designed to reach cumulative reduction targets of 432 GWh and 108 MW at a total cost of $91.9 million.

Penelec is a member of PJM and RFC.

[59] Docket No. M-2009-2112952.

Figure 33 Pennsylvania Electric Company energy demand (GWh)

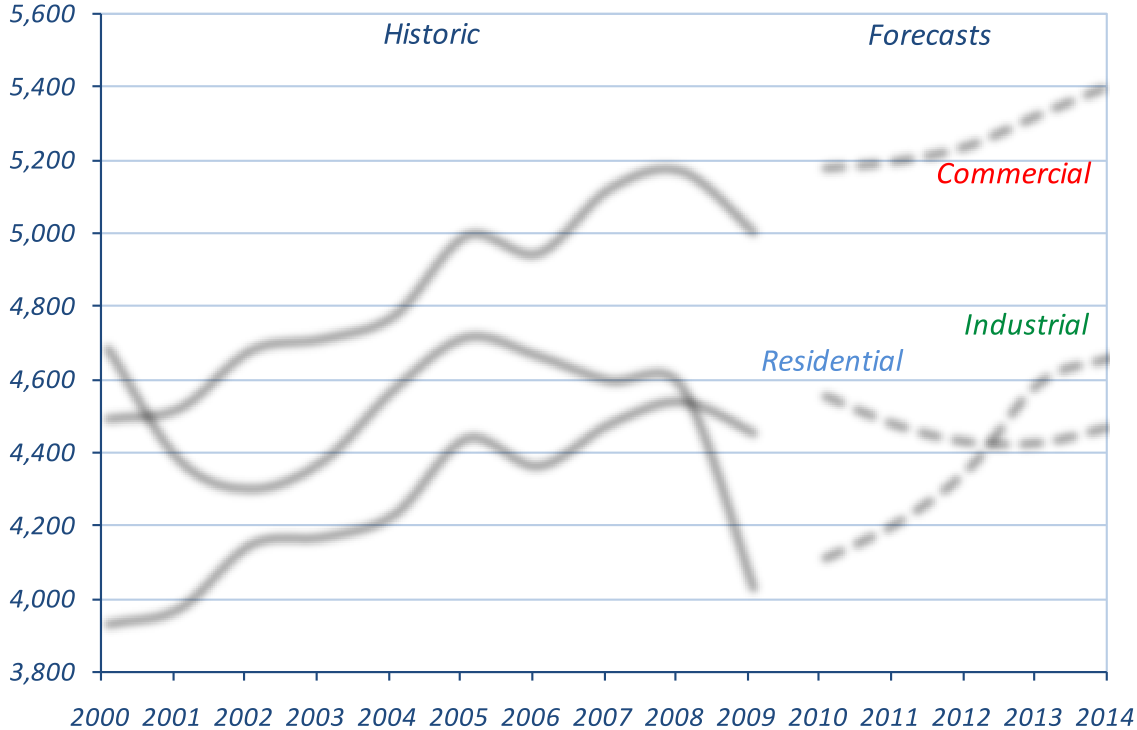


Figure 34 Pennsylvania Electric Company peak load (MW)

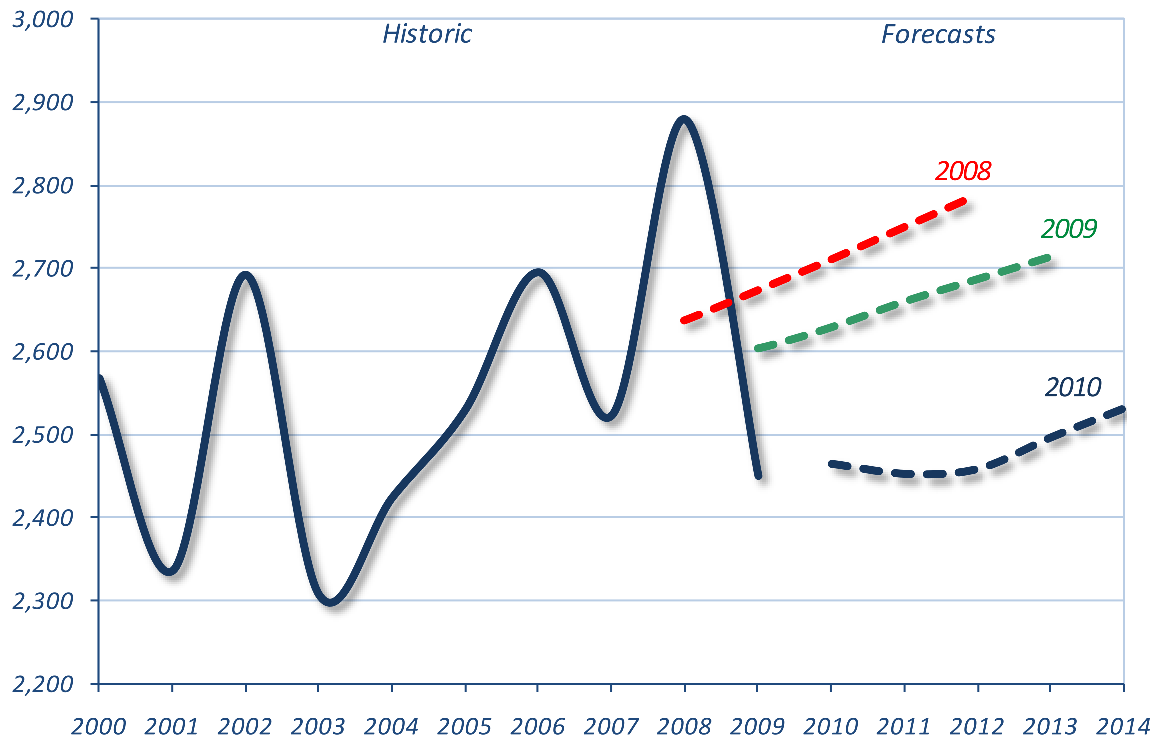
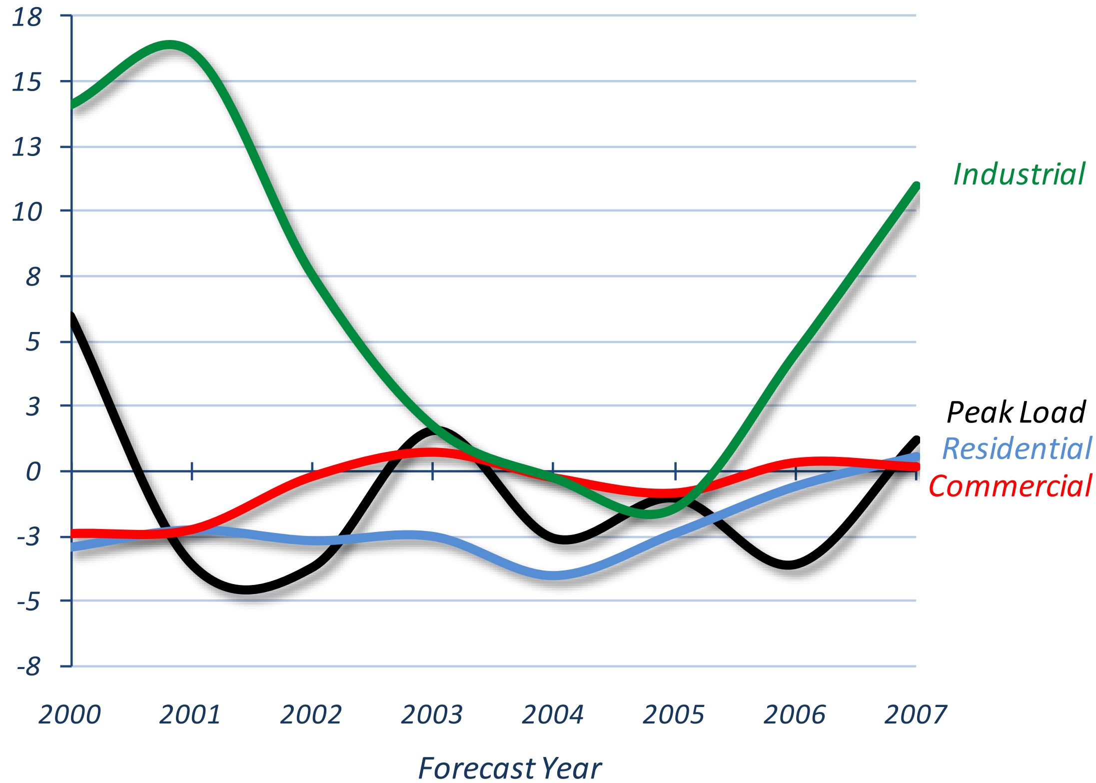
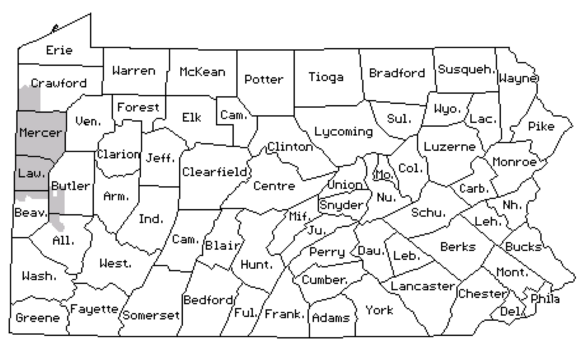


Figure 35 Pennsylvania Electric Company average of deviations in forecasts (%)



Pennsylvania Power Company



Pennsylvania Power Company (Penn Power), a subsidiary of FirstEnergy, provides service to 159,692 electric utility customers in all or portions of six counties in Western Pennsylvania. In 2009, Penn Power had energy sales totaling 4,237 GWh—a decrease of 9.8 percent from the 2008 figure. Residential sales lead Penn Power's market with 38.6 percent of the total sales, followed by commercial (32.3 percent) and industrial (29.0 percent). Average annual use per residential customer was 11,673 kWh at an average cost of 11.72 cents per kWh; operating revenues totaled $261.7 million.

Between 1994 and 2009, Penn Power's energy demand grew at an average rate of 1.5 percent per year. Residential and commercial sales have maintained relatively steady growth over the period at annual rates of 2.2 percent and 2.9 percent, respectively. Industrial sales have fluctuated considerably, with an overall average annual *decrease* of 0.3 percent, due mainly to a 23.9 percent drop in 2009 sales. The current five-year projection of growth in total energy demand is 2.9 percent. This includes a residential growth rate of 1.3 percent, a commercial growth rate of 2.3

percent and an industrial growth rate of 5.4 percent, expecting a return to the 2008 level by 2014. See Figure 36.

Penn Power's 2009 summer peak load, occurring on Aug. 10, 2009, was 901 MW, representing a decrease of 15.2 percent from last year's peak of 1,063 MW. The 2009-10 winter peak load of 878 MW was 1.5 percent lower than the previous year's winter peak of 891 MW. The actual average annual peak load growth rate over the past 15 years was 1.6 percent. Penn Power's forecast shows its summer peak load decreasing from 901 MW in the summer of 2009 to 890 MW in 2011, and then increasing to 977 MW by 2014, or an overall average annual growth rate of 1.6 percent. The current forecast for 2010 is 45 MW or 4.8 percent lower than the previous forecast. See Figure 37.

Figure 38 depicts the average of deviations in forecasts made one to three years in advance. Tables A13-A16 in Appendix A provide Penn Power's forecasts of peak load and residential, commercial and industrial energy demand, filed with the Commission in years 2000 through 2010.

The electrical systems of Penn Power and the Ohio FirstEnergy operating companies are interconnected and fully integrated, and for planning purposes are treated as a single electrical system. All of Penn Power's generating facility ownership (1,237 MW) was transferred in 2005. ATSI owns and operates the transmission assets of Penn Power and the Ohio FirstEnergy companies.

For Calendar Year 2009, seven EGSs sold 2,286 GWh to retail customers in Penn Power's service territory or 53.9 percent of total consumption. Penn Power purchased 2,002 kWh from an independent power producer in 2009.

Penn Power's Energy Efficiency and Conservation Plan[60] offers a suite of programs for all customer segments designed to reach cumulative reduction targets of 143 GWh and 44 MW at a total cost of $26.6 million.

Penn Power is a subsidiary of FirstEnergy, which is a member of RFC and MISO.

[60] Docket No. M-2009-2112956.

Figure 36 Pennsylvania Power Company energy demand (GWh)

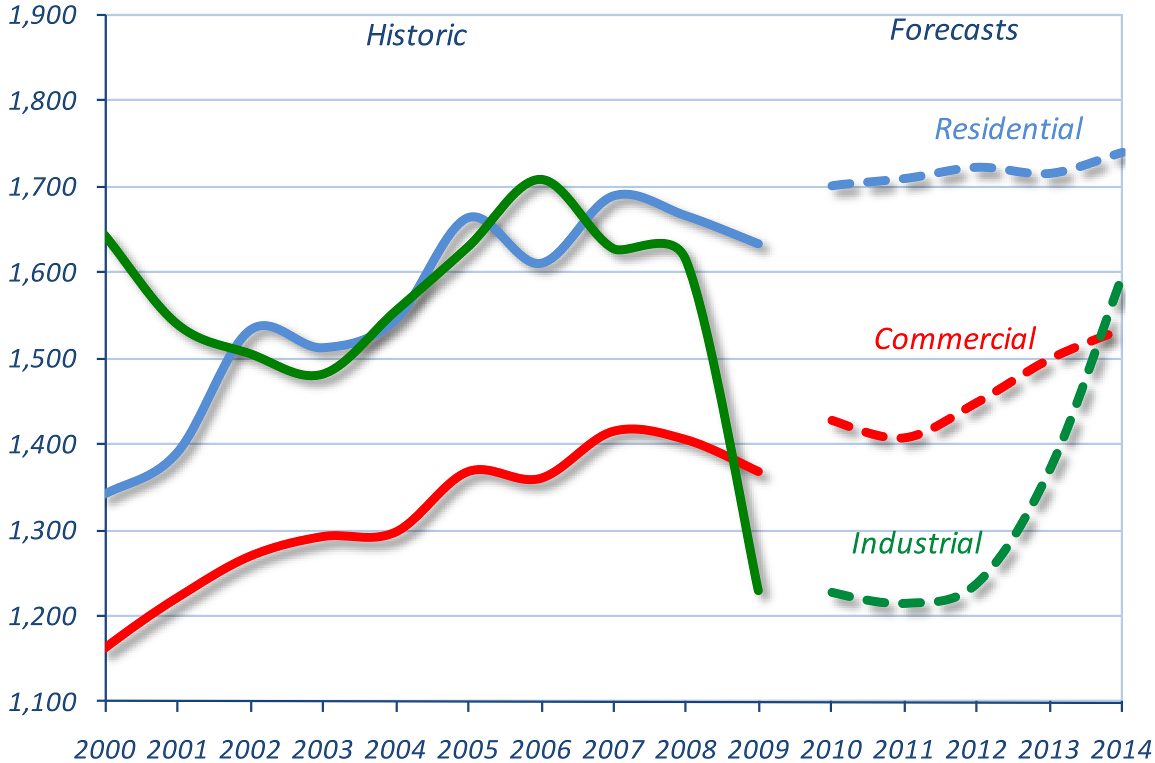


Figure 37 Pennsylvania Power Company peak load (MW)

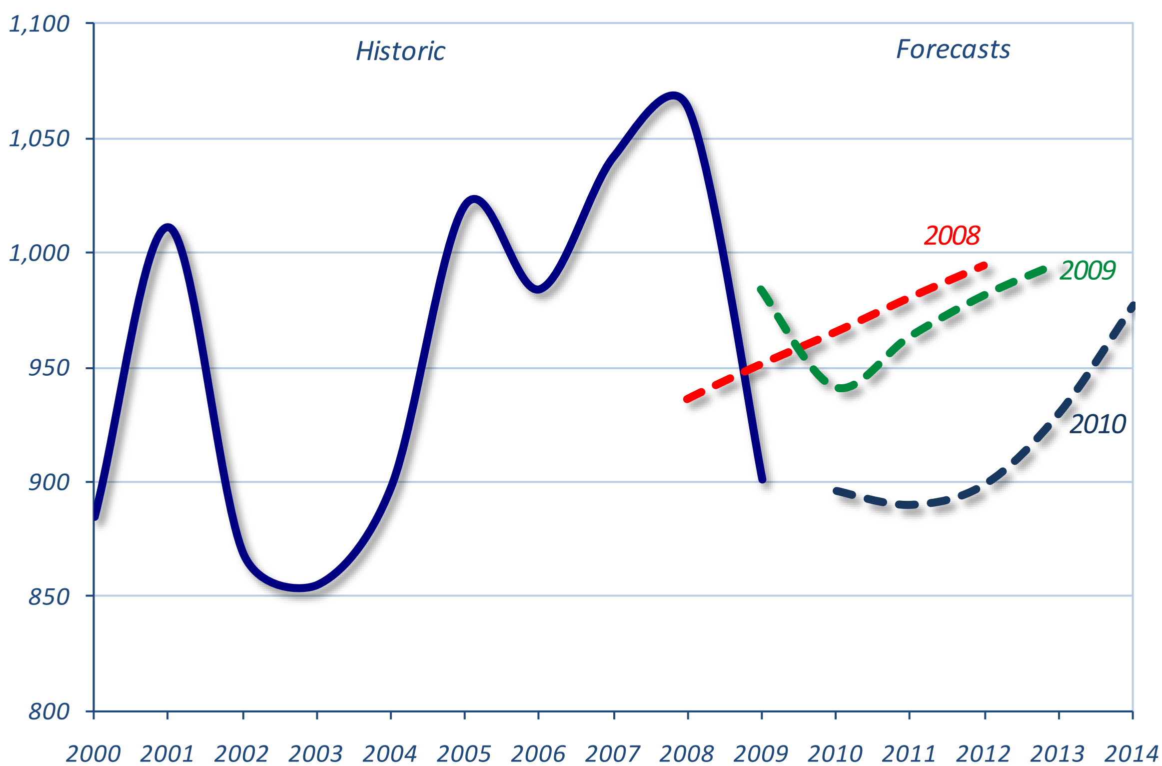
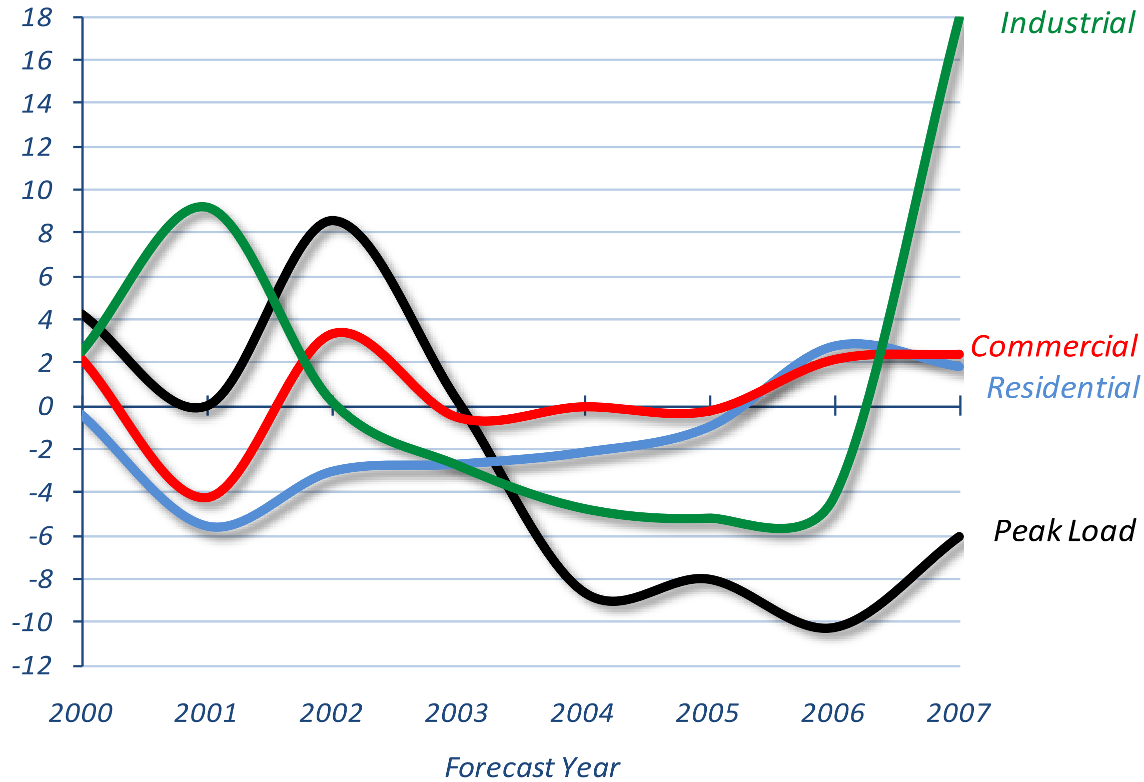
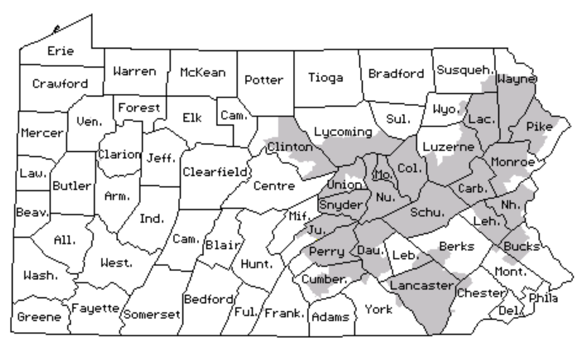


Figure 38 Pennsylvania Power Company average of deviations in forecasts (%)



PPL Electric Utilities Corporation



PPL Electric Utilities Corporation (PPL), a subsidiary of PPL Corporation, provides service to 1,398,461 homes and businesses over a 10,000-square-mile area in all or portions of 29 counties in Central Eastern Pennsylvania. In 2009, PPL had energy sales totaling 37,623 GWh—down 3.8 percent from 2008. Residential sales continued to dominate PPL's market with 37.8 percent of the total sales, followed by commercial (36.7 percent) and industrial (22.4 percent). Average annual use per residential customer was 11,641 kWh at an average cost of 10.33 cents per kWh; operating revenues totaled $3.43 billion.

Between 1994 and 2009, PPL's energy demand grew an average of 1.1 percent per year. Residential energy sales grew at an annual rate of 1.5 percent, and commercial sales grew at a 2.4 percent rate. Industrial sales *decreased* at a rate of 0.8 percent, due mainly to an 11.9 percent drop in 2009 sales. The current five-year projection of average growth in energy demand is 0.9 percent. This includes growth rates of 0.2 percent for residential and 2.8 percent for commercial. Industrial sales are expected to continue to fall at an average rate of 0.9 percent per year. See Figure 39.

PPL's 2009 summer peak load, occurring on Aug. 17, 2010, was 6,845 MW compared to the previous summer's peak of 7,316 MW, or a 6.4 percent decrease. The 2009-10 winter peak load was 6,800 MW, representing a decrease of 8.3 percent from last year's winter peak of 7,414 MW. The actual average annual peak load growth rate over the past 15 years was 0.3 percent. PPL's five-year winter peak load forecast scenario shows the peak load increasing from 6,845 MW in 2009 to 7,487 MW in 2014 at an overall average annual rate of 1.8 percent. The current forecast for 2010 is 43 MW or 0.6 percent lower than the previous forecast. It is noted that PPL is normally winter peaking, but in some years the summer peak has exceeded the previous winter peak; the current forecast represents the *annual* peak load. See Figure 40.

Figure 41 depicts the average of deviations in forecasts made one to three years in advance. Tables A17-A20 in Appendix A provide PPL's forecasts of peak load and residential, commercial and industrial energy demand, filed with the Commission in years 2000 through 2010.

Net operable generating capacity of 8,505 MW (summer rating) for 2009 included 40.6 percent coal-fired capacity and 25.1 percent nuclear capacity. Natural gas and dual fuel units account for 27.0 percent of the total. This capacity, previously owned by PPL, is now owned by a PPL affiliate, PPL Generation LLC. Independent power producers also provided 6 MW to the system. In 2009, PPL purchased 1,091 GWh from cogeneration and independent power production facilities, or 2.7 percent of net energy for load.

For Calendar Year 2009, no EGSs supplied energy to retail customers in PPL's service territory. However, with the removal of rate caps on Jan. 1, 2010, alternative suppliers were serving 47.5 percent of customer load as of April 1, 2010.[61]

PPL has identified several transmission projects, including new construction and rebuilding of existing lines, with in-service dates through 2020. The projects involve 562 circuit miles at a total cost of $937.2 million. The single largest project is the Susquehanna-Roseland Project, described in Section 1.

PPL reported a 2009 peak load reduction of 81.8 MW and energy savings of 3,048 MWh 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 1.2 percent of the 2009 summer peak load. PPL's Price Response Service permits customers to respond to market price signals by reducing a portion of their load. In 2009, a 14.6 MW peak load reduction was achieved, with energy savings totaling 396 MWh.

PPL's Energy Efficiency and Conservation Plan[62] includes a range of energy efficiency and demand response programs that include all customer segments, designed to reach cumulative reduction targets of 1,146 GWh and 297 MW at a total cost of $246 million.

PPL is a member of PJM and RFC.

[61] Pennsylvania Office of Consumer Advocate.
[62] Docket No. M-2009-2093216.

Figure 39 PPL Electric Utilities Corporation energy demand (GWh)

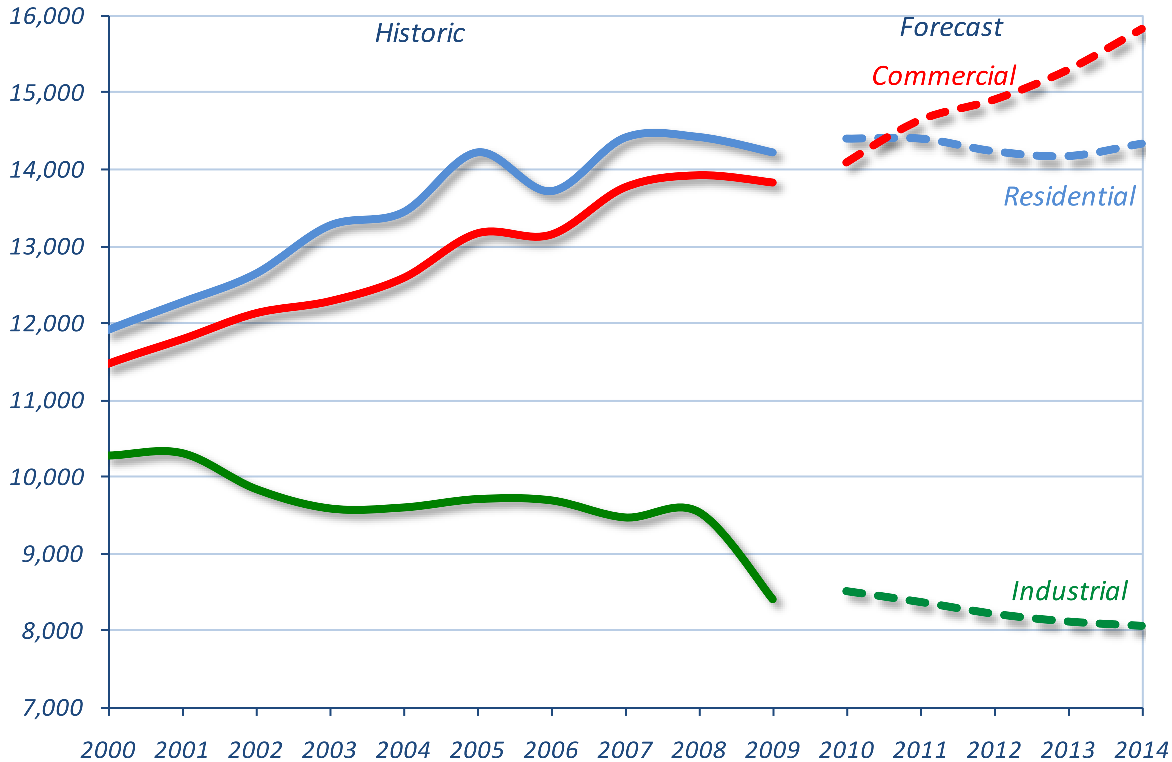


Figure 40 PPL Electric Utilities Corporation peak load (MW)

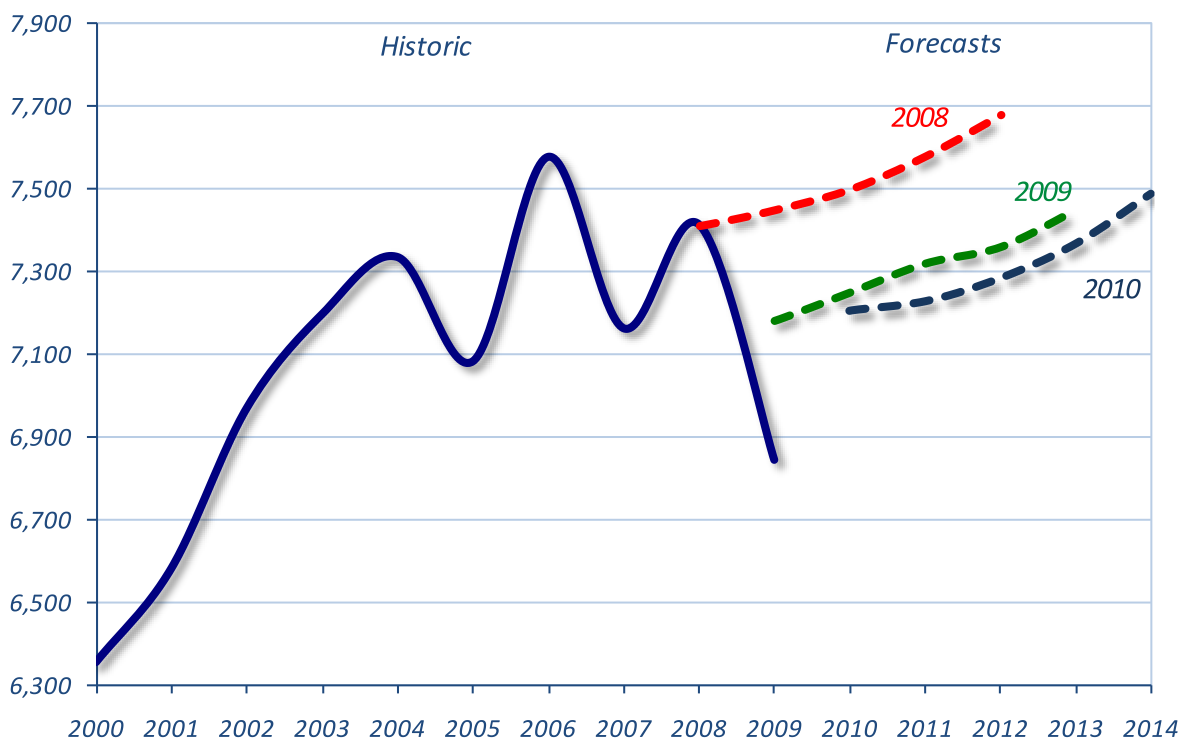
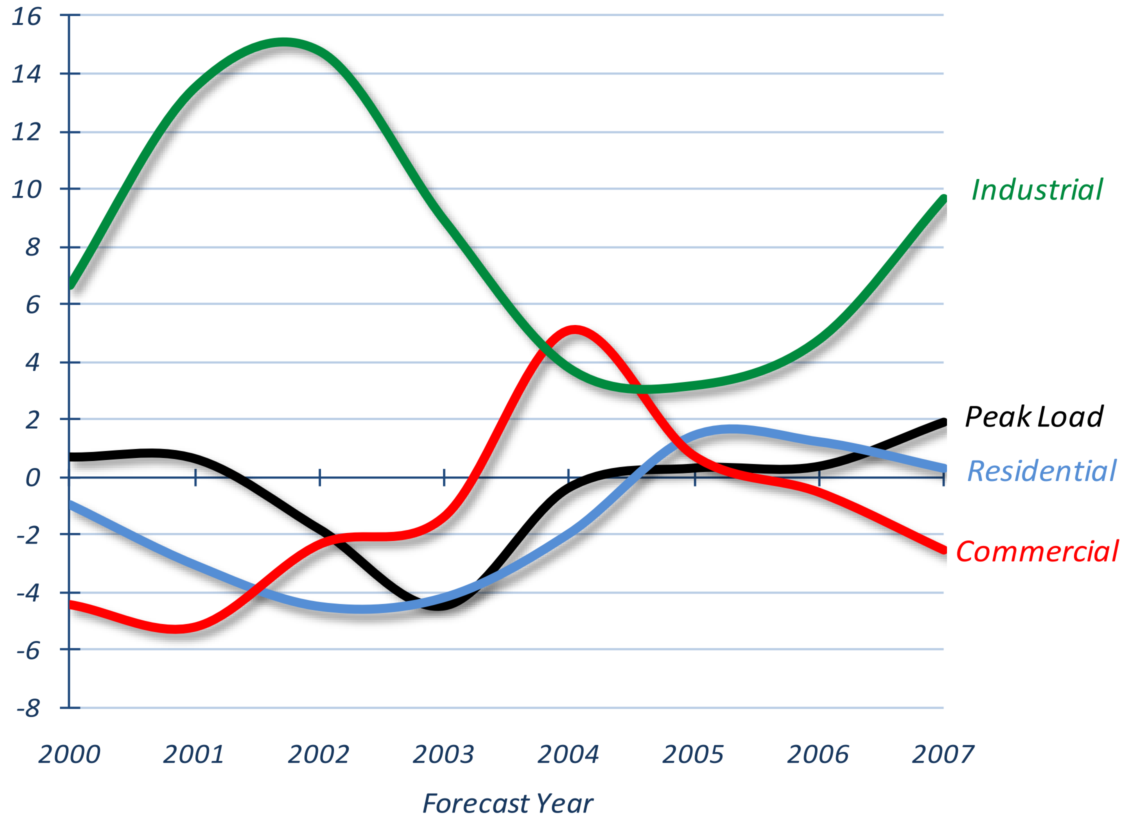
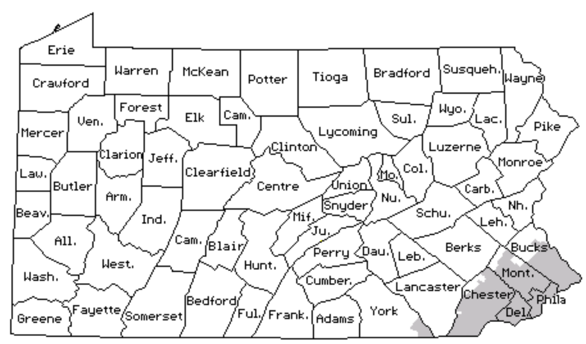


Figure 41 PPL Electric Utilities Corporation average of deviations in forecasts (%)



PECO Energy Company



PECO Energy Company (PECO), a subsidiary of Exelon Corporation, is the largest electric utility in Pennsylvania, providing service to 1,564,433 electric utility customers in the City of Philadelphia and all or portions of six counties in Southeastern Pennsylvania. In 2009, PECO had total energy sales of 38,702 GWh—down 3.3 percent from 2008. Industrial sales continued to dominate PECO's market with 41.1 percent of the total sales, followed by residential (33.3 percent) and commercial (21.7 percent). Average annual use per residential customer was 9,183 kWh at an average cost of 14.42 cents per kWh; operating revenues totaled $4.55 billion.

Between 1994 and 2009 PECO's energy demand grew an average of 1.0 percent per year. Residential energy sales grew at an annual rate of 1.4 percent, commercial at 2.3 percent and industrial at 0.1 percent. The current five-year projection of growth in energy demand is 2.0 percent. This includes an annual growth rate of 2.0 percent for the residential, commercial and industrial sectors. See Figure 42.

PECO's 2009 summer peak load, occurring on Aug. 10, 2009, was 7,994 MW, representing a decrease of 9.4 percent from last year's peak of 8,824 MW, and the lowest level since 2004. The 2009-10 winter peak demand was 6,728 MW or 0.7 percent below the previous winter's peak of 6,777 MW. The actual average annual peak demand growth rate over the past 15 years was 0.7 percent. PECO's current forecast shows the peak load increasing from the actual 2009 summer peak load of 7,994 MW to 8,612 MW in the summer of 2014, or an annual growth rate of 1.5 percent. The current forecast for 2010 is 977 MW or 10.7 percent lower than the previous forecast. See Figure 43.

Figure 44 depicts the average of deviations in forecasts made one to three years in advance. Tables A21-A24 in Appendix A provide PECO's forecasts of peak load and residential, commercial and industrial energy demand, filed with the Commission in years 2000 through 2010.

PECO has entered into a Purchased Power Agreement with Exelon Generation to provide energy and capacity for its POLR load throughout the forecast period. Other resources may be obtained through purchases from the wholesale markets.

In 2009, PECO purchased 1,034 GWh from cogeneration and independent power production facilities, or 2.5 percent of net energy for load. Contract capacity totaled 181 MW.

For Calendar Year 2009, EGSs sold a total of 391 GWh to retail customers in PECO's service territory or 1.0 percent of total consumption, down from 1.5 percent in 2008. On the summer peak day, EGSs represented a load of 80 MW, or 1.0 percent of the total.

PECO has identified 13 transmission projects involving reconductoring of existing lines, with in-service dates through 2013.

PECO has developed commercial and industrial rate incentive programs to encourage customers to manage their energy demands and usage consistent with system capabilities. In 2009, PECO contracted 409 MW of customer load for participation in its curtailment programs. Only 118 MW was called upon for a one-hour PJM mandatory testing event yielding 118 MWh of energy savings.

PECO's Energy Efficiency & Conservation Plan[63] includes 10 energy efficiency programs and eight demand reduction programs which are estimated to exceed the reduction targets of 1,186 GWh and 355 MW at a total cost of $341.6 million.

PECO is a member of PJM and RFC.

[63] Docket No. M-2009-2093215.

Figure 42 PECO Energy Company energy demand (GWh)

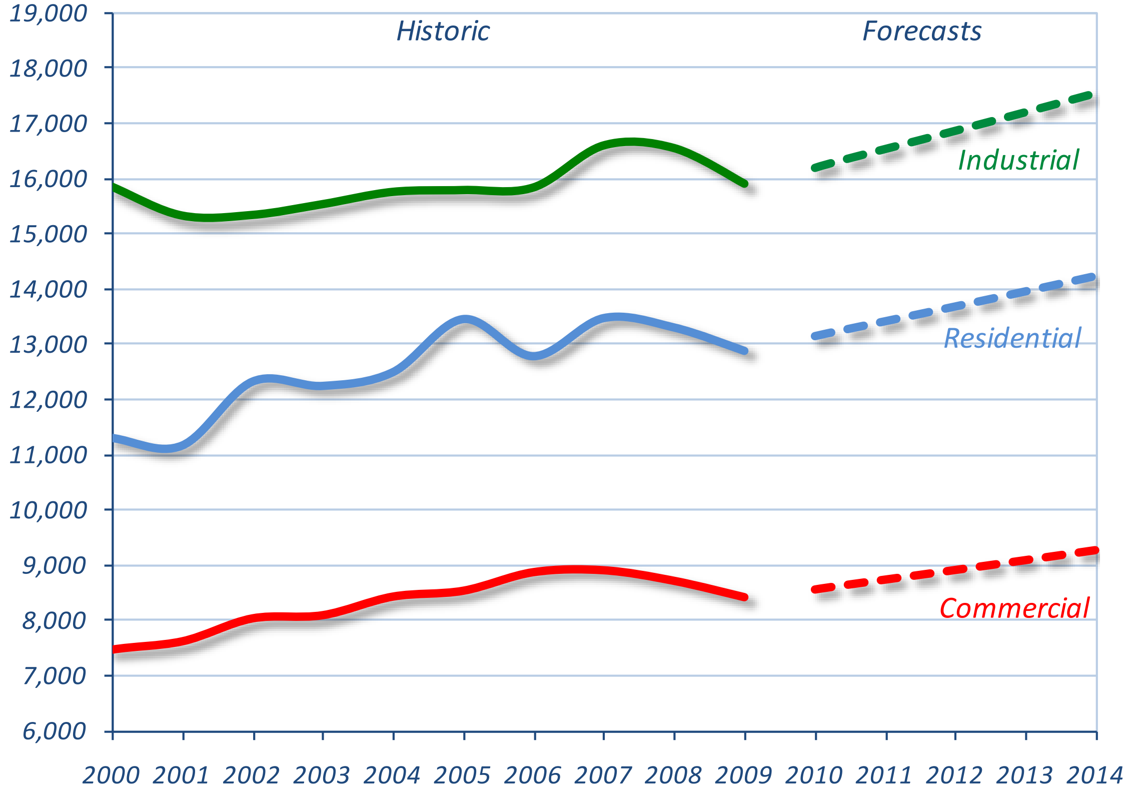


Figure 43 PECO Energy Company peak load (MW)

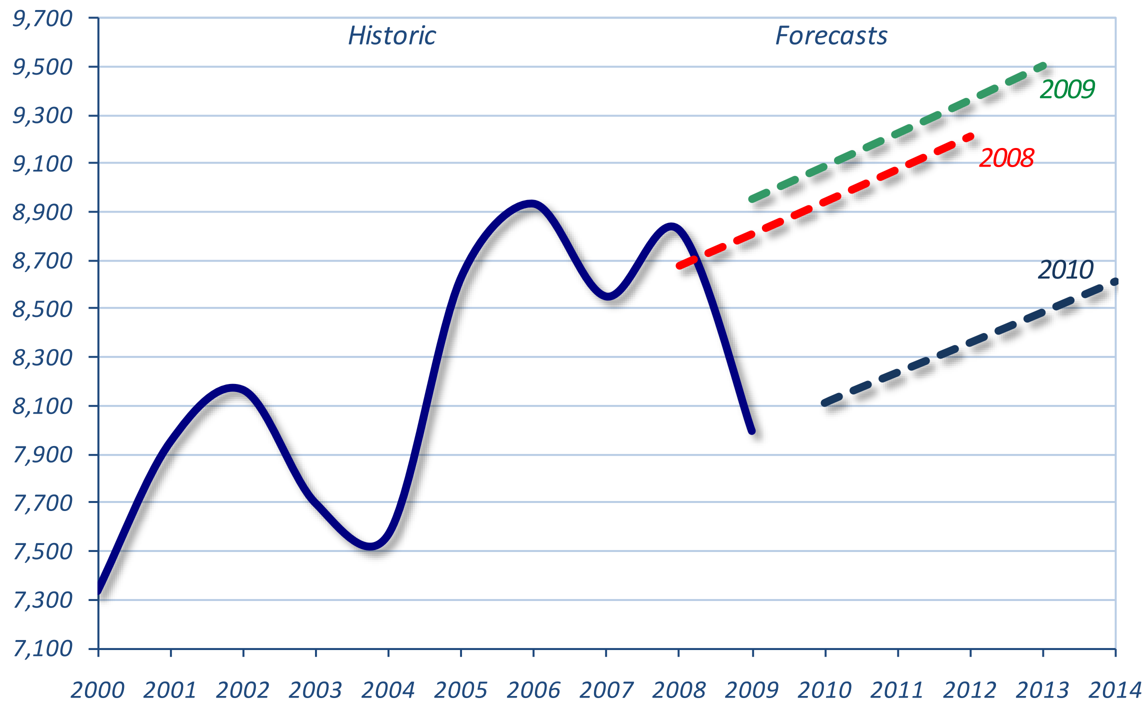
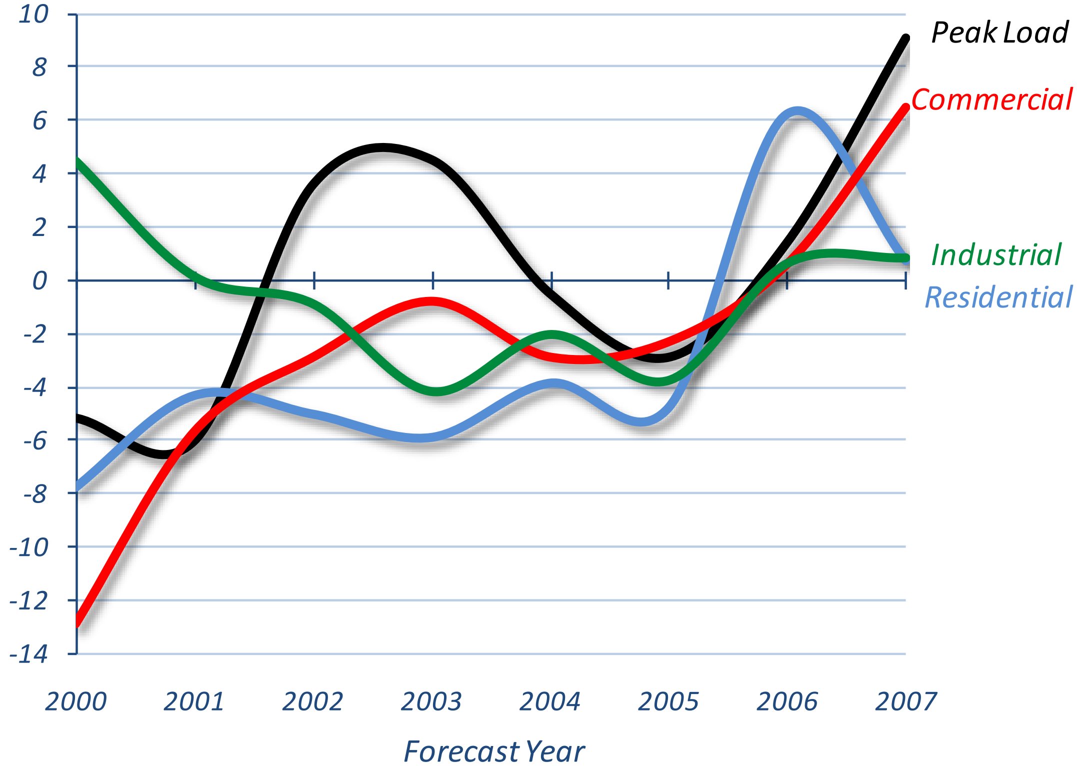


Figure 44 PECO Energy Company average of deviations in forecasts (%)



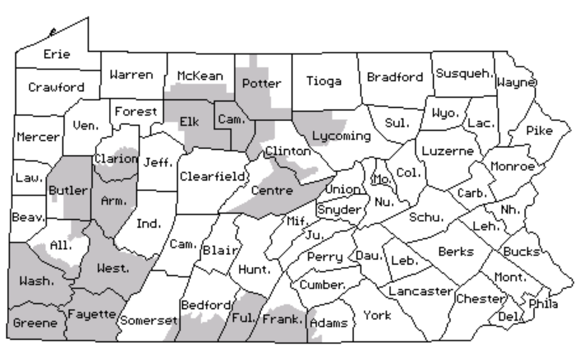
Allegheny Energy Inc.

Allegheny Energy Inc. is a holding company with three regulated electric utility operating companies, doing business as Allegheny Power, including West Penn Power Company (Pennsylvania), Monongahela Power Company (West Virginia) and The Potomac Edison Company (Maryland, Virginia and West Virginia), serving more than 1.5 million customers. The company owns 9,730 MW of generating capacity, 95 percent of which is coal fired. See Figure 45.

Figure 45 Allegheny Energy service territory

On May 14, 2010, FirstEnergy, West Penn Power Company and TrailCo filed a joint application with the Commission, at Docket No. A-2010-2176520, to obtain approval for the merger of Allegheny Energy, Inc. with a wholly-owned subsidiary of First Energy. The combined company will retain the FirstEnergy name and be headquartered in Akron, Ohio. If approved, the transaction, expected to be completed early in 2011, will result in an energy provider with $16 billion in annual revenues, 10 regulated EDCs operating in seven states, 20,000 miles of high-voltage transmission lines, 24,000 MW of generating capacity and more than 2,200 MW of renewable energy.

West Penn Power Company



West Penn Power Company (West Penn), doing business as Allegheny Power, a subsidiary of Allegheny Energy Inc., provides service to 714,974 electric utility customers in all or portions of 24 counties in Western, North and South Central Pennsylvania. In 2009, West Penn had total retail energy sales of 20,055 GWh—down 4.7 percent from 2008. Industrial sales continued to dominate West Penn's market with 36.3 percent of the total sales, followed by residential (35.4 percent) and commercial (24.3 percent). Average annual use per residential customer was 11,446 kWh at an average cost of 8.37 cents per kWh; operating revenues totaled $1.37 billion.

Between 1994 and 2009, West Penn's energy demand grew an average of 0.9 percent per year. Sales for all sectors have maintained relatively steady growth during the period, except for the last two years. Residential sales grew at an annual rate of 1.1 percent and commercial sales grew at a rate of 2.0 percent. Industrial sales *declined* at an average rate of 0.1 percent, due mainly to a 10.4 percent drop in sales for 2009. The current five-year projection of growth in energy demand is 1.3 percent. This includes a commercial rate of 1.7 percent and an industrial rate of 2.4 percent. Residential sales are expected to *decline* at an overall annual rate of 0.3 percent. See Figure 46.

West Penn's 2009 summer peak load, occurring on Aug. 10, 2009, was 3,667 MW, representing a decrease of 4.1 percent from last year's summer peak of 3,823 MW. The 2009-10 winter peak load was 3,513 MW or 4.3 percent lower than the previous year's winter peak of 3,671 MW. The actual average annual peak load growth rate over the past 15 years was 1.0 percent. West Penn's load forecast scenario shows the peak load increasing from 3,667 MW in the summer of 2009 to 3,951 MW in 2014, or an average annual growth rate of 1.5 percent. The current forecast for 2010 is 202 MW or 5.1 percent lower than the previous forecast. See Figure 47.

Figure 48 depicts the average of deviations in forecasts made one to three years in advance. Tables A25-A28 in Appendix A provide West Penn’s forecasts of peak load and residential, commercial and industrial energy demand, filed with the Commission in years 2000 through 2010.

In April 2002, Allegheny Power joined PJM Interconnection. As a PJM member, Allegheny Power is responsible for following the reliability standards of the PJM markets. The company has access to an increased amount of energy resources within the expanded PJM market. West Penn remains an EDC, providing transmission and distribution service to its customers and providing POLR service for those customers who do not choose an alternate supplier. Effective Nov. 18, 1999, West Penn transferred all of its remaining generation assets to its affiliate, Allegheny Energy Supply Company, LLC.

In 2009, West Penn purchased 987 GWh from cogeneration and independent power production facilities, or 4.7 percent of net energy for load. Contract capacity for these facilities was 136 MW.

West Penn and its affiliate, TrAILCo, have identified several transmission line projects under construction or planned from 2010 through 2015 totaling 190 miles of 138 kV and 500 kV circuits at an estimated cost of $140.8 million.

West Penn’s Energy Efficiency & Conservation Plan[64] includes 22 energy efficiency and demand response programs which are estimated to meet or exceed the reduction targets of 628 GWh and 157 MW at a total cost of $94.2 million.

West Penn is a member of PJM and RFC.

[64] Docket No. M-2009-2093218.

Figure 46 West Penn Power Company energy demand (GWh)

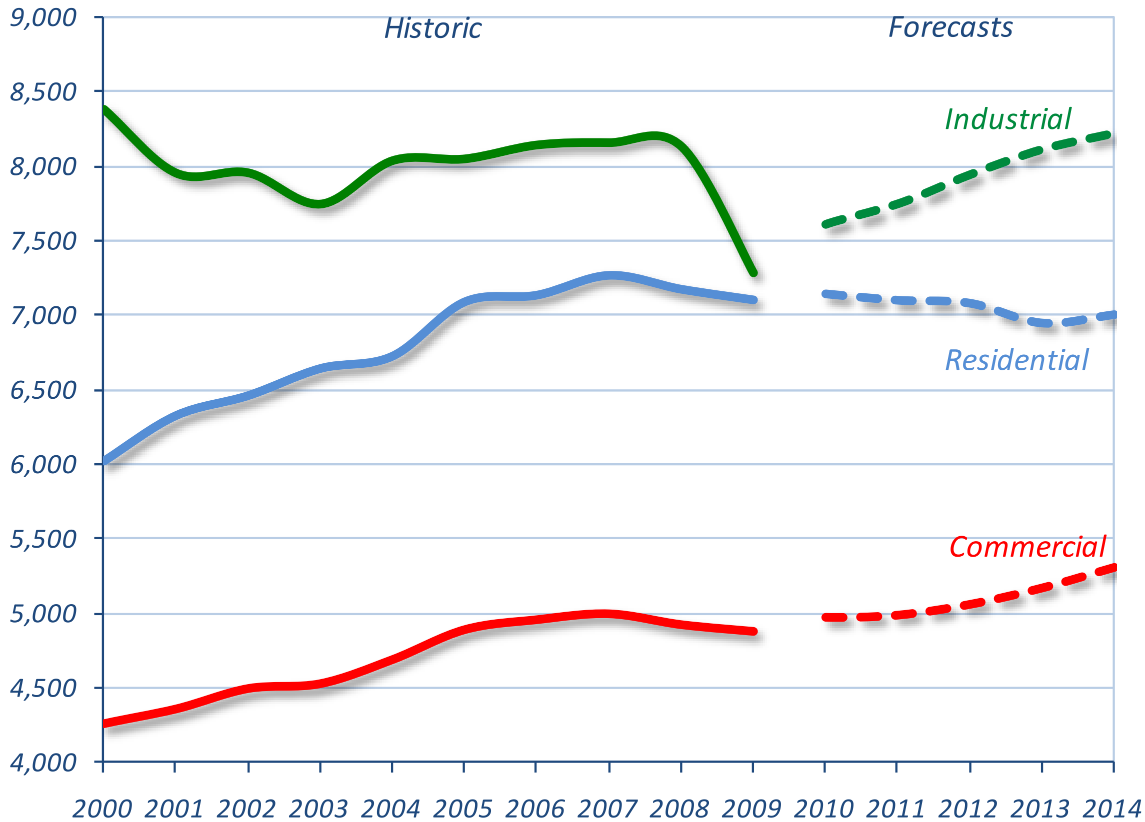


Figure 47 West Penn Power Company peak load (MW)

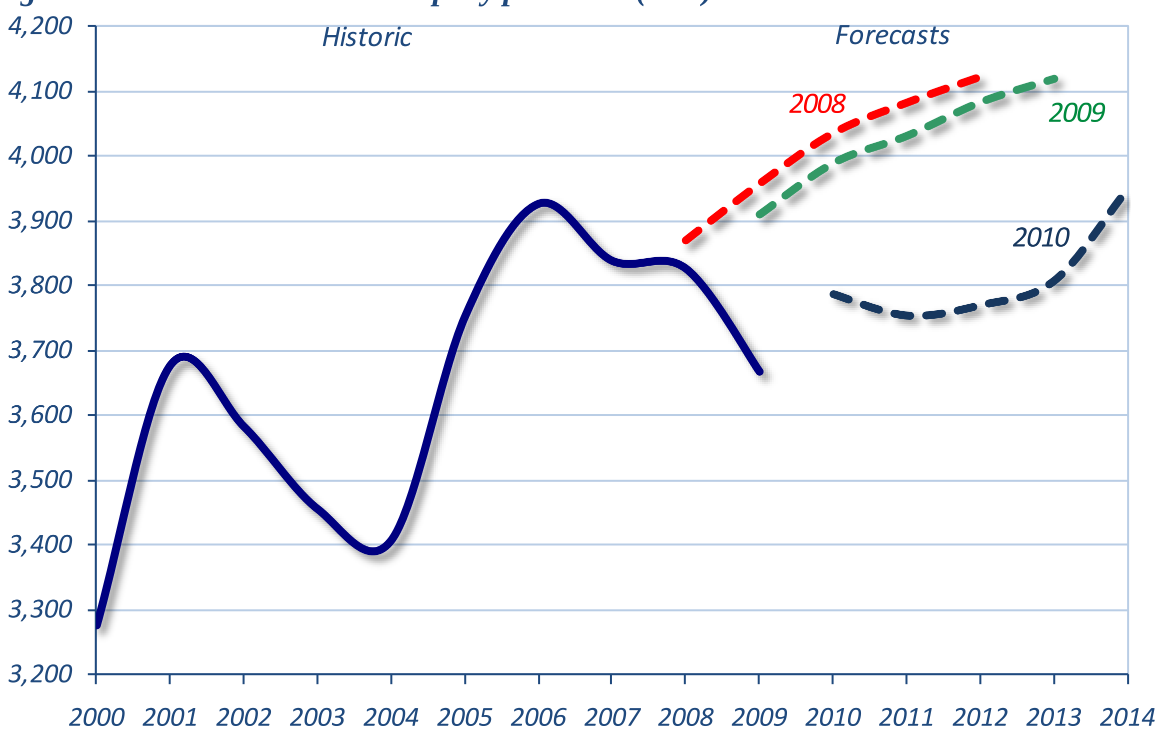
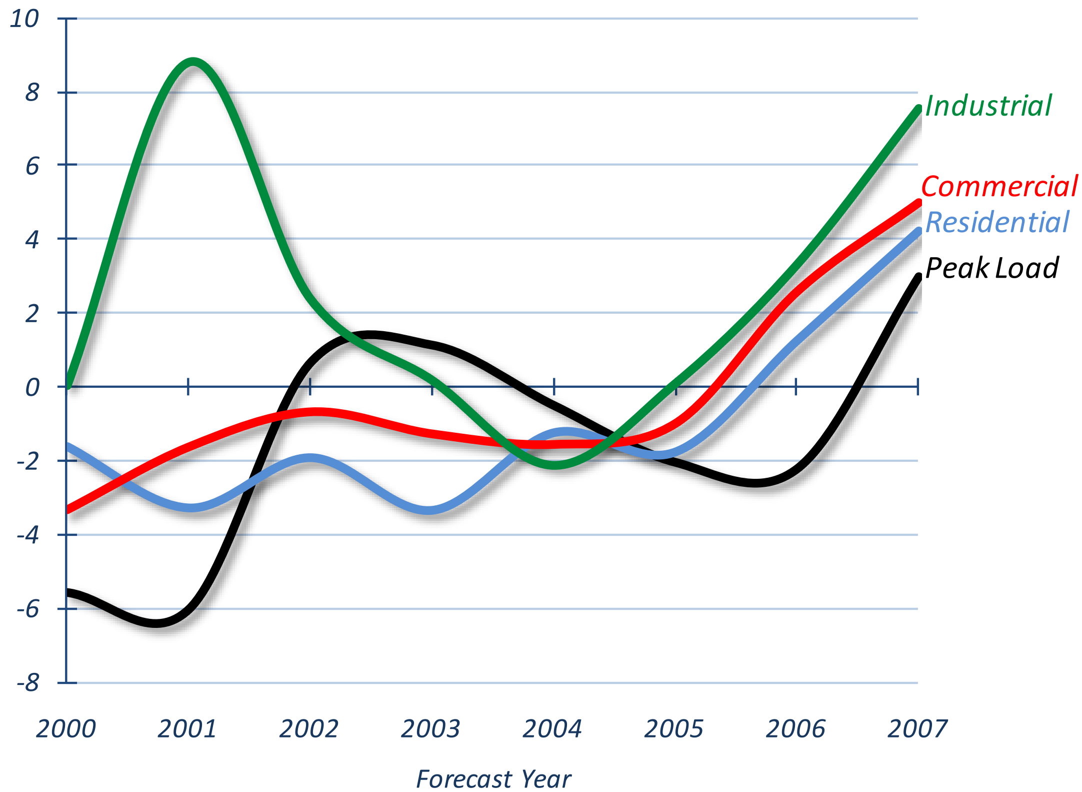
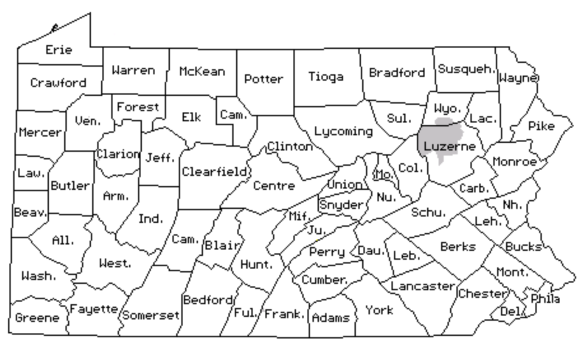


Figure 48 West Penn Power Company average of deviations in forecasts (%)



UGI Utilities Inc.—Electric Division



The Electric Division of UGI Utilities Inc. (UGI), a subsidiary of UGI Corporation, provides electric service to 62,166 customers in Northwestern Luzerne and Southern Wyoming counties in Pennsylvania. In 2009, UGI had energy sales totaling 955 GWh—down 4.7 percent from 2008. Residential sales continued to dominate UGI's market with 54.2 percent of the total sales, followed by commercial (34.4 percent) and industrial (10.8 percent). Average annual use per residential customer was 9,470 kWh at an average cost of 13.87 cents per kWh; operating revenues totaled $136.6 million.

Between 1994 and 2009, UGI experienced an average growth in total sales of 0.7 percent, which includes a residential growth rate of 0.7 percent, a commercial rate of 0.7 percent and an industrial rate of 0.4 percent. Over the five-year planning horizon, UGI expects energy demand to increase at an average rate of 0.7 percent. This includes an average annual increase in residential sales of 0.8 percent, and an average growth rate of 2.1 percent in industrial sales, following a 16.3 percent drop in 2009. Commercial sales are expected to increase after 2009 and then return to the 2009 level by 2014. See Figure 49.

UGI is basically a winter peaking utility, although the summer peak has exceeded the winter peak in some years. Peak load on the UGI system occurred on Dec. 29, 2009, and totaled 193 MW, or 2.0 percent below the 2008-09 winter peak load of 197 MW. The 2009 summer peak load of 181 MW was 7.2 percent lower than the peak load experienced during the summer of 2008. The actual average annual peak load growth rate over the past 10 years was 0.4 percent. The five-year forecast indicates an average increase in peak load of 1.4 percent. Peak load is projected to increase from 193 MW in 2009-10 to 207 MW in 2014-15. See Figure 50.

For Calendar Year 2009, there was one EGS serving 17 customers. UGI does not own electric generation supply and acquires supply for its customers through a series of competitive solicitations. Default service supply for customers with peak loads in excess of 500 kW is purchased in the spot market.

One transmission line project is scheduled to be completed in 2011 at a cost of $3.5 million.

UGI offered a Voluntary Load Reduction Program to commercial and industrial customers in 2009, and three customers enrolled. However, since no load reduction events were called, the program has been discontinued, in favor of PJM's economic and emergency demand response programs. If called upon, the 13 participating customers can provide six MW in total demand response reduction.

UGI is a member of PJM.

Figure 49 UGI Utilities Inc. energy demand (GWh)

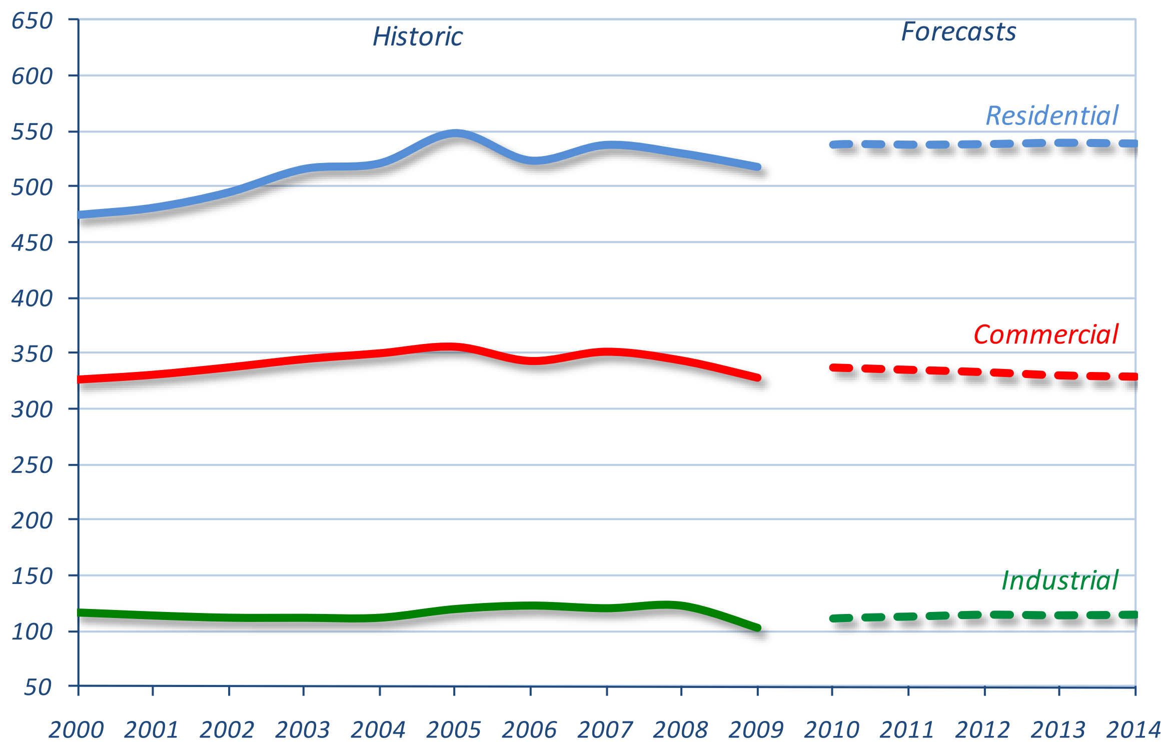
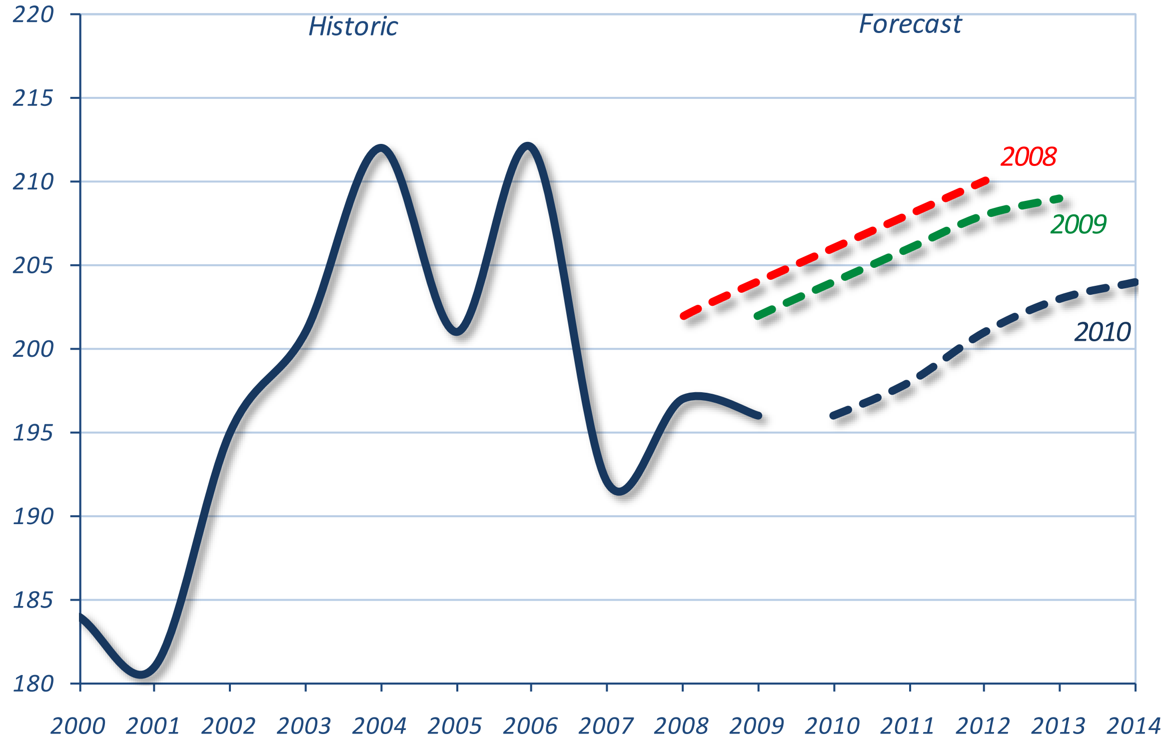
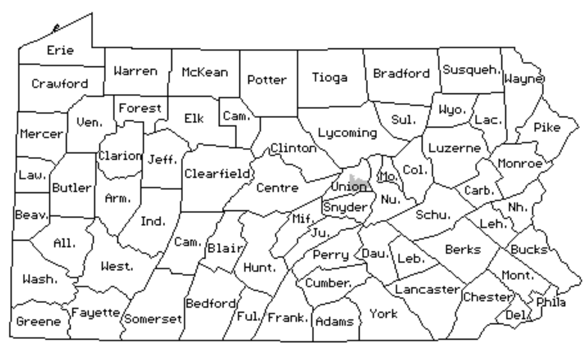


Figure 50 UGI Utilities Inc. peak load (MW)



Citizens' Electric Company



Citizens' Electric Company (Citizens') provides service to 6,814 customers in Union County, Pennsylvania. In 2009, Citizens' had retail energy sales totaling 160 GWh, down 4.8 percent from 2008. Residential sales accounted for 49.8 percent of Citizens' total sales, followed by industrial (32.6 percent) and commercial (17.2 percent). Average annual use per residential customer was 14,062 kWh at an average cost of 11.45 cents per kWh; operating revenues totaled $18.7 million.

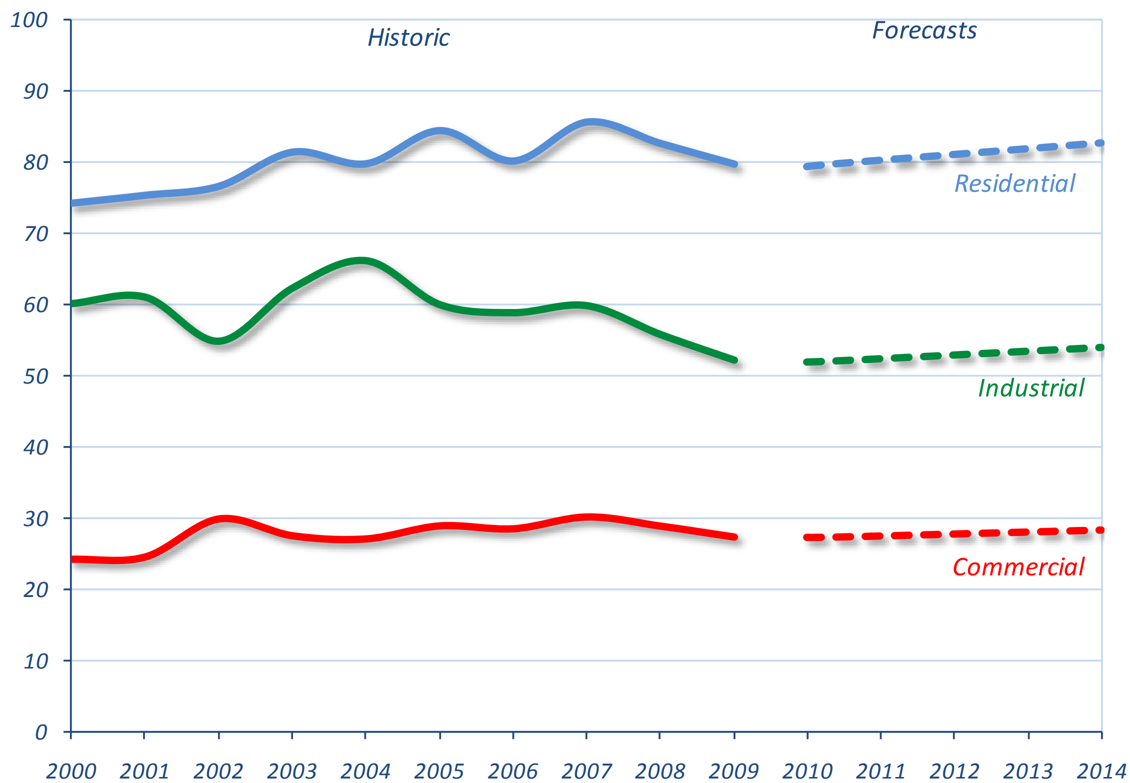
Between 1994 and 2009, Citizens' experienced a sales growth that has averaged 0.3 percent annually, due in part to a 4.8 percent drop in 2009. Residential and commercial sales have increased at annual rates of 1.0 percent and 2.7 percent, respectively. Industrial sales *decreased* at an average annual rate of 1.2 percent. Over the next five years, Citizens' expects total energy demand growth to average 0.7 percent, following a slight decrease in 2010. Growth rates are the same (0.7 percent) for all three sectors. See Figure 51.

Citizens' 2009-10 winter peak load, occurring on Jan. 11, 2010, was 38.7 MW, a 4.6 percent decrease from the winter peak of 2008. The 2009 summer peak load was 34.4 MW. Peak load growth is projected to average 5.2 percent over the next five years, with peak load going from 38.7 MW to 49.9 MW in the winter of 2014-15.

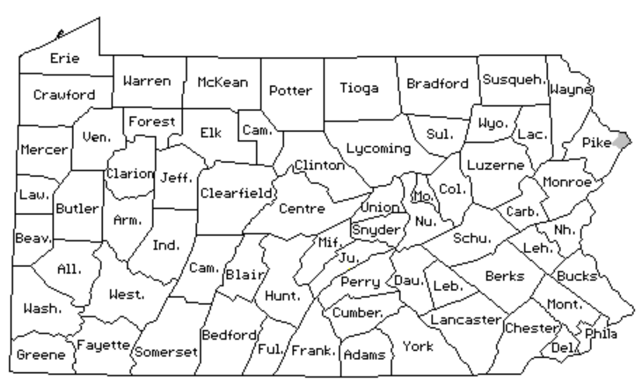
One of Citizens' largest customers, Bucknell University, generated 39 GWh of which Citizens' purchased three GWh, which represents 2.0 percent of Citizens' net energy for load.

The extent of the company's resource planning is to assure sufficient line and substation capacity to accommodate, in a reliable and economical manner, present requirements and future growth. Citizens' is a small distribution company and does not own any generation facilities.

Figure 51 Citizens' Electric Company energy demand (GWh)



Pike County Light & Power Company



Pike County Light & Power Company (Pike), a subsidiary of Orange & Rockland Utilities Inc. (O&R), provides service to 4,649 customers in Eastern Pike County, Northeastern Pennsylvania. In 2009, Pike's retail energy sales totaled 73 GWh, a decrease of 5.3 percent from 2008 sales. Commercial sales continued to dominate Pike's market with 61.1 percent of the total sales, followed by residential with 38.4 percent. Pike has no industrial customers. Average annual use per residential customer was 7,605 kWh at an average cost of 7.29 cents per kWh; operating revenues totaled $4.9 million.

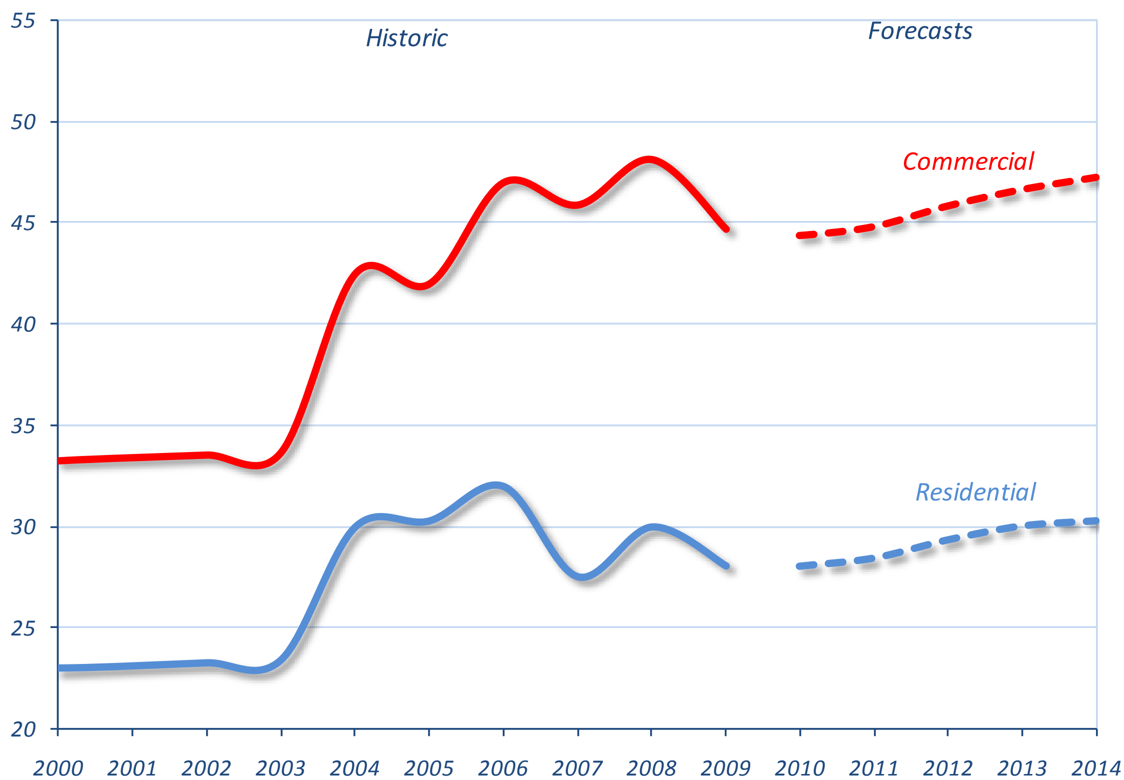
Between 1994 and 2009, Pike experienced an average increase of 2.2 percent in total sales. Residential sales grew at an average annual rate of 1.7 percent, and commercial sales increase at 2.6 percent per year. Over the next five years, total energy demand is projected to increase at an average annual rate of 1.3 percent, which includes a residential growth rate of 1.5 percent and a commercial growth rate of 1.1 percent. See Figure 52.

Over the next five years, Pike projects its system peak load to increase from 15.3 MW in the summer of 2009 to 20.7 MW in 2014, or an average annual increase of 6.2 percent.

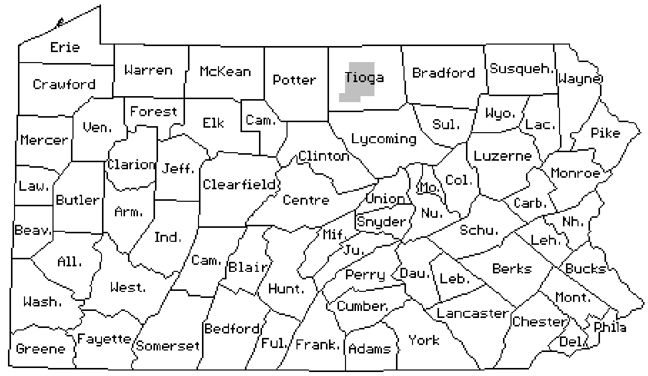
For the purpose of regulation, Pike is a small distribution company with no generating capability. O&R does not own any generating facilities.

O&R is a member of the Northeast Power Coordinating Council (NPCC).

Figure 52 Pike County Light & Power energy demand (GWh)



Wellsboro Electric Company



Wellsboro Electric Company (Wellsboro) provides electric service to 6,133 customers in Tioga County, Pennsylvania. In 2009, Wellsboro's energy sales totaled 105 GWh, down 4.8 percent from 2008. Residential sales dominated Wellsboro's market with 38.2 percent of the total sales, followed by industrial at 31.9 percent, and commercial at 29.5 percent. Average annual use per residential customer was 8,058 kWh at an average cost of 13.16 cents per kWh; operating revenues totaled $13.0 million.

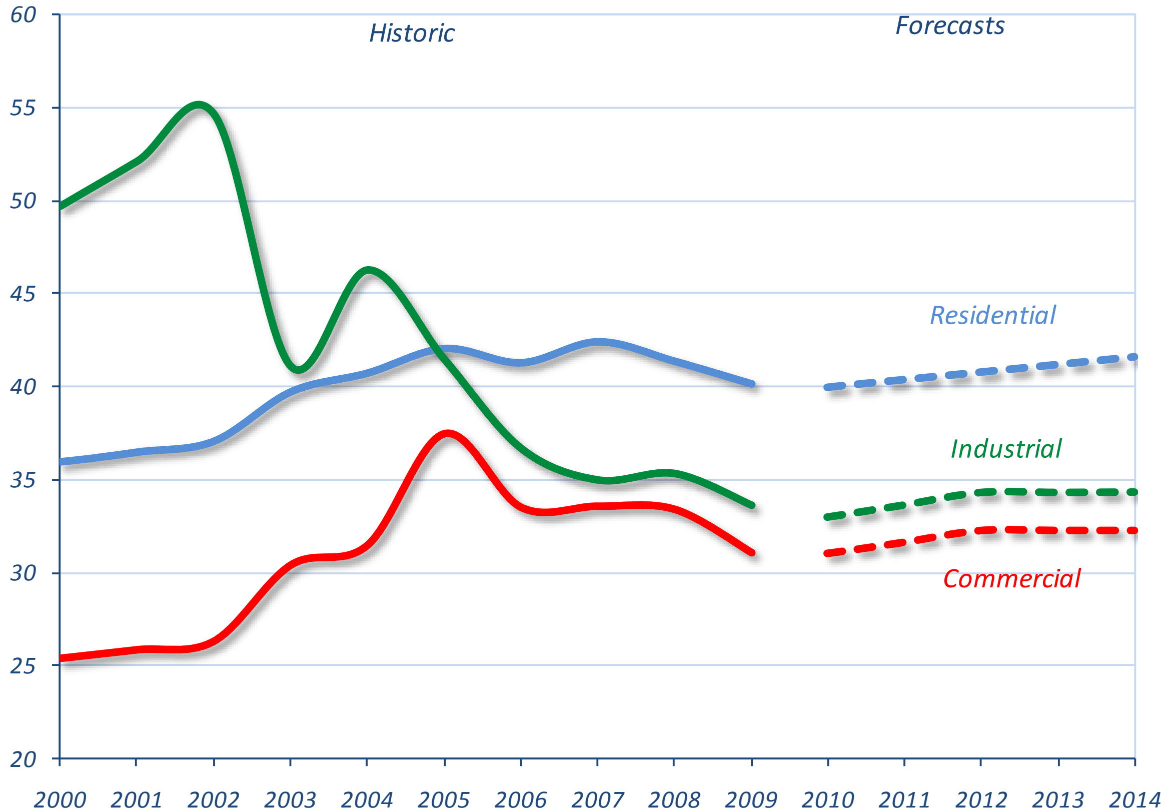
Over the past 15 years, Wellsboro has experienced an average annual sales growth of 0.8 percent, peaking in 2005 at 121 GWh. Industrial sector sales have *declined* substantially, at an average annual rate of 0.7 percent over the same period; industrial sales in 2009 were 61.5 percent of the peak 2002 sales level. Residential and commercial sales increased at an average annual rate of 1.4 percent and 2.1 percent, respectively. Over the next five years, Wellsboro expects total energy consumption to grow at an average annual rate of 0.6 percent. This includes a residential growth rate of 0.7 percent, a commercial rate of 0.8 percent, and an industrial rate of 0.4 percent. See Figure 53.

Wellsboro's summer peak load is projected to grow from 21.4 MW in 2009 to 23 MW by the year 2014, or a levelized annual growth rate of 1.5 percent.

Wellsboro is a small distribution company and does not own any generation facilities. Wellsboro has no shopping customers.

Wellsboro provides a detailed analysis of consumption patterns and load factors for its customers, and explains how energy usage affects the overall bill. In 2009, Wellsboro investigated stray voltage complaints, and conducted residential and commercial energy audits and billing analyses.

Figure 53 Wellsboro Electric Company energy demand (GWh)



Section 3 – Regional Reliability

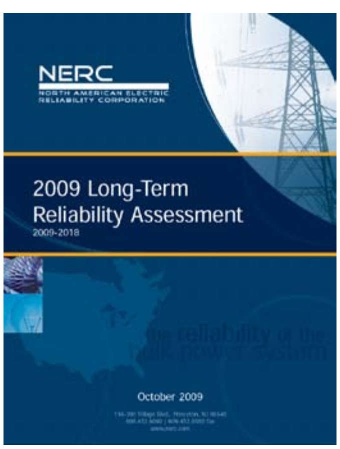
Regional Reliability Assessments

The passage of the Pennsylvania Electricity Generation Customer Choice and Competition Act substantially changed the Commission's jurisdiction as well as the Commission's ability to compile data from the generation sector. As a result, most information on generation and transmission capacity is regional. Therefore, this section summarizes the regional reliability assessments of NERC, RFC and PJM for generation and transmission capability.

The reliability of the interconnected bulk power system is defined in terms of two basic and functional aspects. *Adequacy* is the ability of the bulk power system to supply the aggregate electrical demand and energy requirements of the customer at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements. *Operating Reliability* is the ability of the bulk power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements from credible contingencies. 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 (total demand less dispatchable, controllable capacity demand response), expressed as a percentage of net internal demand. *Capacity margin* is the difference between available resources and net internal demand, expressed as a percentage of available resources.

North American Electric Reliability Corporation

The North American Electric Reliability Corporation's (NERC's) mission is to ensure the reliability of the bulk power system in North America. To achieve this objective, NERC develops and enforces reliability standards; monitors the bulk power system; assesses and reports on future transmission and generation adequacy; and offers education and certification programs to industry personnel. NERC is a non-profit, self-regulatory organization that relies on the diverse and collective expertise of industry participants that comprise its various committees and sub-groups. It is subject to oversight by governmental authorities in Canada and the United States. NERC assesses and reports on the reliability and adequacy of the North American bulk power system according to eight regional areas. The users, owners, and operators of the bulk power system within these areas account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico.



Reliability Assessment

The *2009 Long-Term Reliability Assessment*[65] represents NERC's independent judgment of the reliability and adequacy of the bulk power system in North America for the coming 10 years. NERC's primary purpose in preparing this assessment is to identify areas of concern regarding the reliability of the North American bulk power

[65] NERC, *2009 Long-Term Reliability Assessment*, October 2009.

system and to make recommendations for their remedy. Highlights of this recent assessment are summarized below (pages 1-6, emphasis added):

- ***Reduced economic activity and higher adoption of demand side management programs have led to decreased projected peak demand for electricity*** *and, as a result, higher reserve margins throughout North America for much of the 10-year period. The increase in demand side management contributes to 20 percent of the total reduction in summer peak demand for the 2017 forecast when compared to last year's forecast, while economic recession effects contribute 80 percent.*
- *Over the next 10 years, 260,000 MW of new renewable nameplate capacity (biomass, geothermal, hydro, solar and wind) is projected, 96 percent of which is wind (229,000 MW) and solar (20,000 MW). Wind power is projected to account for 18 percent of the total resource mix by 2018, but accounts for only 3 percent (or 38,000 MW) of the peak resource mix.* ***Industry, policymakers and regulators have significant work ahead of them to ensure that sufficient transmission is sited and built to enable the integration of projected renewable resources.***
- *By 2011, natural gas is projected to overtake coal as the dominant fuel source for peak capacity generation in North America. By 2018, natural gas is projected to account for 32 percent of the on-peak resource mix.* ***The projected growing reliance on natural gas increases the potential for adverse reliability impacts due to fuel supply and storage and delivery infrastructure adequacy issues.***
- *More than 11,000 miles, or 35 percent, of transmission (200 kV and above) proposed and projected in this report must be developed on time to ensure reliability over the next five years. Ranked as the No. 1 emerging issue in terms of likelihood and consequence, transmission siting remains a significant obstacle to meeting this goal.* ***State and provincial siting and permitting processes must be expedited to allow for the development of needed resources and ensure reliability.***
- ***Over the coming 10 years, the North American electric industry will face a number of significant emerging reliability issues.*** *The confluence of these issues will drive a transformational change for the industry, potentially resulting in a dramatically different resource mix, a new global market for emissions trading, a new model for customer interaction with their utility, and a new risk framework built to address growing cyber security concerns.*

NERC has also identified five emerging issues which could have a significant impact on reliability (pages 51-66):

- ***Economic Recession.*** *The economic recession has had an indelible impact on the electric power industry. While there is currently substantial uncertainty on the time, rate and breadth of an economic recovery in the coming years, it is certain that its eventual arrival may present risks and challenges to the bulk power system on several levels: (1) the recession has caused significant impacts in demand forecasts; (2) economic difficulties that drive new business opportunities and incent new resource programs may drive steep increases in these programs (and accompanying reliance upon them) but vigilance will be required to ensure they are available when needed for reliability; (3) an economic recovery will occur (eventually), but it is uncertain when it will happen and* *how fast it will occur—if the economy recovers quickly, the bulk power system must be ready to balance supply and demand while maintaining bulk power system reliability; (4) project financing uncertainty—in addition to reduced revenues—may thwart necessary infrastructure investments and impair long-term reliability.*

- ***Transmission Siting.*** *Province and State Renewable Portfolio Standards (RPS) will increase renewable resources located where wind power densities and solar development are favorable. Grid expansion is needed to support the dispersed nature of renewable resources. The limited timeframe provided to meet RPS mandates requires that the current siting and approval processes be expedited to ensure meeting mandated energy requirements. The inability to site and construct transmission can challenge bulk power system reliability in regions/subregions that are retiring generation or out-growing their existing generation, and are relying on new transmission to serve customers from remote generating resources.*
- ***Energy Storage.*** *Energy storage systems can benefit bulk power system reliability by storing energy capacity or to provide ancillary services. The introduction of significant amounts of variable generation resources, like wind and solar, can provide large amounts of energy, while not necessarily at the time it is most needed. Further, the variability and uncertainty of their fuel source (wind or sun), increases the need for more flexibility in the bulk power system to maintain reliability.*
- ***Workforce Issues.*** *Forty percent of senior electrical engineers and shift supervisors in the electricity industry would be eligible to retire in 2009, while the demand for engineers with a power background and other utility professionals has increased. At the same time, the number of students in the power engineering programs is dwindling in most universities. Further, the need for line workers, power plant operators, maintenance/repair workers, and pipefitters/pipelayers has also increased. The demand for power workers to plan, maintain and operate the bulk power system continued to increase with the growing need for new infrastructure investments in electric generation, delivery and the rising need for technology innovation driven by a world beset by new challenges.*
- ***Cyber Security.*** *With the new era of ever-increasing digital reliance and system complexity, there is an emergence of common vulnerabilities within the computational backbone of the power system that can result in credible, large-scale contingencies, due to common modal failures or coordinated cyber attacks. This may significantly challenge the ability to rebalance the system. More understanding of the cyber security issues and impacts that are possible on the electric grid is needed.*

In addition to these areas of concern, NERC has identified, in a separate 2008 report, some concerns regarding potential impacts of climate change initiatives on system reliability.[66] These include the following issues (page 4):

- *Broad-scale fuel switching from coal to natural gas and increased dependence on natural gas as a fuel for electric generation may impact reliability.*

[66] NERC, *Special Report: Electric Industry Concerns on the Reliability Impacts of Climate Change Initiatives*, November 2008.

- *Innovative resource planning and implementation mechanisms are needed to ensure the timely development, siting, construction, and operation of necessary and appropriate transmission infrastructure to facilitate achieving the goals and objectives of the various climate change initiatives.*
- *As demand side resources become an increasingly significant component of the resource mix, effective integration and verification of these resources will be vital to maintaining reliability.*

Reserve margins in many NERC regions have increased compared to 2008 projections due in large part to the economic recession, which has reduced demand projections. An increase in demand side management programs and the addition of new resources have also contributed to this trend. Demand is projected to grow within the next three years as the economy recovers. Demand is projected to increase 14.8 percent between 2009 and 2018, compared to 16.8 percent between 2008 and 2017, as forecast in last year's report. The projected compound annual growth rate over the 10-year period for peak demand has decreased from 1.6 percent in 2008 projections to 1.5 percent in 2009 projections. This projected growth rate reflects a continued decline from previous forecast periods and parallels a decline in the growth in projected energy use over similar forecast periods.

Net internal demand in the United States is expected to increase by 111,799 MW or an average of 1.6 percent per year for the next nine years, while deliverable capacity resources (existing-certain, resources, future-planned resources, and net firm and expected transactions) are projected to increase by 78,380 MW or 8.4 percent (0.9 percent annually). Reserve margins are expected to decline from 24.1 percent in summer 2009 to 17.4 percent in 2018.

If a region/subregion provides its own specific margin level based on load, generation and transmission characteristics, as well as regulatory requirements, that level is adopted as the NERC Reference Reserve Margin Level. If not, NERC assigns a 15 percent reserve margin for predominately thermal systems and 10 percent for predominately hydro systems. The NERC Reference Reserve Margin Level of 15 percent is used in the United States to identify when additional resources may be needed. The existing capacity sufficiently meets the NERC Reference Reserve Margin Level through 2018.

*Reliability*First *Corporation*

Reliability*First* Corporation (RFC) is one of eight regional reliability councils within NERC, and has replaced the reliability oversight functions of MAAC, ECAR and MAIN. The two main control areas within the RFC footprint are the PJM RTO and MISO. Two-thirds of the RFC load is in PJM.

From the perspective of the RTOs, 60 percent of the MISO load and 85 percent of the PJM load is within RFC. The reliability of these two RTOs determines the reliability of the RFC region. The reliability assessment summarized herein reflects the resource adequacy of each RTO based on their individual reserve margin requirements.[67]

Compliance Standards

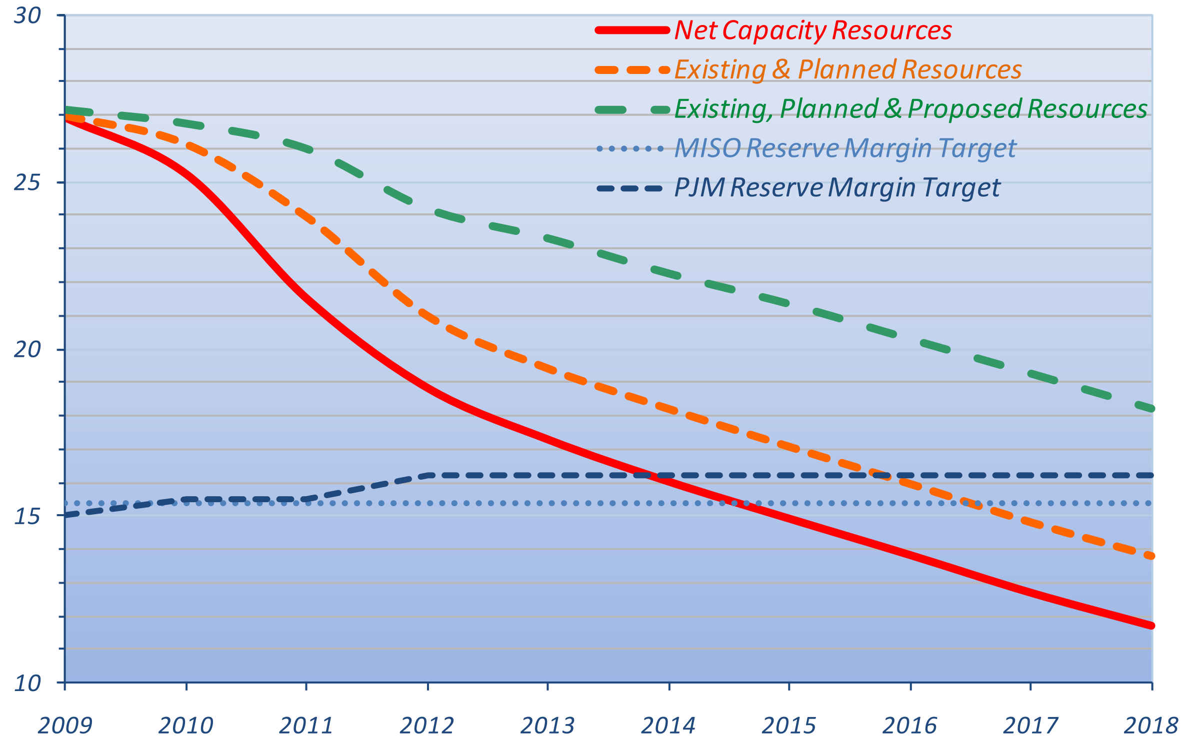
Analyses were conducted by PJM and MISO to determine the reserve margins that were equivalent to the RFC Loss of Load Expectation (LOLE) criterion of not exceeding one occurrence in 10 years (0.1 day/year) on an annual basis for their planning area. RFC's assessment of long-term PJM resource adequacy is based on the reserve margin target determined from the PJM Reliability Pricing Model analysis for the planning year 2009-10. This reserve margin target is 15.0 percent for 2009, 15.5 percent for 2010 and 2011, and 16.2 percent thereafter. The 2009 PJM Reserve Requirement Study, however, *recommends* a 15.3 percent margin beyond 2012.[68] The MISO reserve margin target for 2009 was 15.4 percent, and is used to assess each of the next 10 years. The reserve margin targets are used as a general indicator of the overall adequacy of resources in the RFC region.[69]

Reliability Assessment

RFC anticipates that sufficient resources will be available for PJM, MISO and the RFC regional area to have adequate reserves throughout the next 10 years. Summer reserve margins range from a high of 27.2 percent in 2009, declining to 18.2 percent in 2018. This assessment assumes that future planned and a portion of conceptual capacity is deliverable. Based only on existing resources, the reserve margins are projected to decline from 26.9 percent in 2009, to 11.7 percent in 2018, which is an improvement over the previous forecast, due mainly to current economic conditions. See Figure 54.

[67] NERC, *2009 Long-Term Reliability Assessment*, October 2009.
[68] PJM, *2009 PJM Reserve Requirement Study*, Nov. 4, 2009.
[69] RFC, *Long Term Resource Assessment 2009-2018*, October 2009.

Figure 54 RFC 2009-2018 reserve margin comparison (%)



The system peak load of the PJM RTO for summer 2009, occurring on Aug. 10, 2009, was 126,805 MW or 2.5 percent less than the 2008 peak load. This is the lowest annual peak load since the last transmission system integration. The weather normalized peak load was 133,780 MW. The all-time metered peak load was 144,644 MW, occurring on Aug. 2, 2006.

For summer 2018, the net internal demand is projected to be 149,800 MW, or an equivalent compound growth rate of 1.9 percent. PJM installed generating capacity totaled 167,326 MW at the end of 2009, a 1.5 percent increase from December 2008, which was dominated by coal (40.7 percent) and gas[70] (29.2 percent). A 2009 generation of 693,278 GWh included 50.5 percent coal and 36.0 percent nuclear. See Figures 55 and 56.[71]

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[70] Gas includes natural gas, landfill gas and biomass gas.
[71] *2009 State of the Market Report for PJM, Vol. 1*, March 11, 2010.

Figure 55 PJM 2009 installed capacity by fuel type

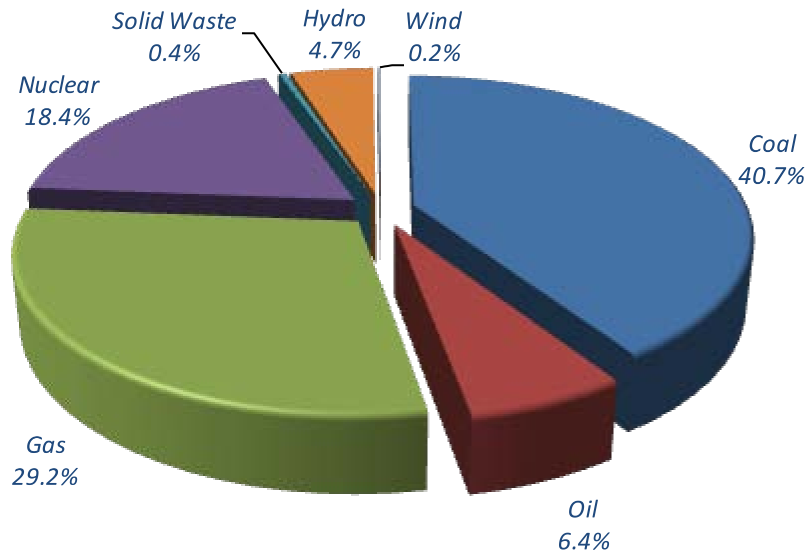
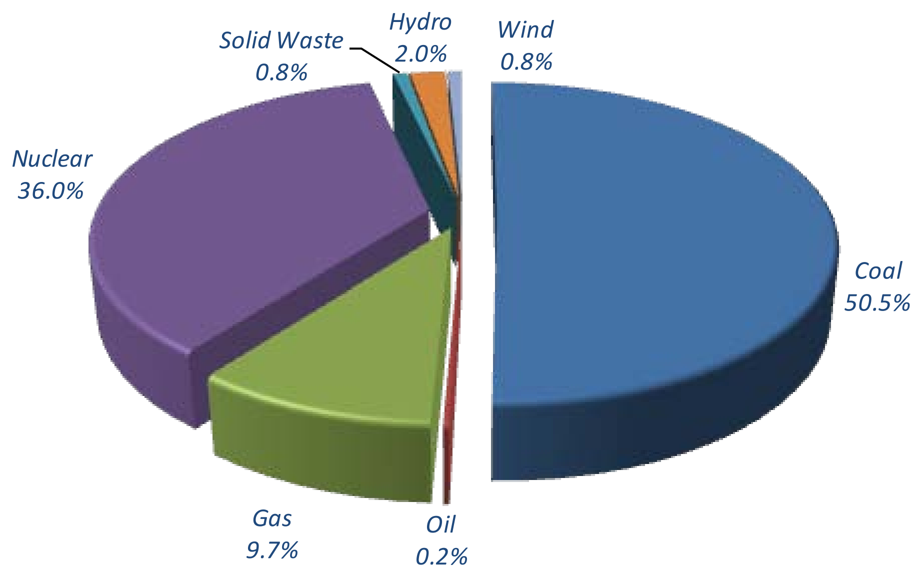


Figure 56 PJM 2009 generation by fuel type



At the time of PJM's 2009 summer peak load, the actual reserve margin for existing capacity resources was 39,981 MW, or 31.5 percent. With an additional 4,475 MW of planned new capacity, the reserve margins are expected to meet the PJM percent reserve margin target through 2016. If an additional 7,951 MW (18.4 percent) of conceptual seasonal capacity is included, the reserve margin remains adequate beyond the forecast period.

The MISO net internal peak demand for summer 2009 is projected to be 100,100 MW. For summer 2018, the net internal demand is projected to be 109,400 MW, or an equivalent compound growth rate of 1.0 percent. The MISO market has 121,769 MW of net capacity resources for the 2009 summer. The amount of proposed increase in capability for summer 2018, including 19.1 percent of conceptual seasonal capacity, is 4,542 MW.

The MISO reserve margin for existing capacity resources is 21,669 MW for 2009, which is 21.6 percent, based on net internal demand. With an additional 424 MW of planned new capacity, the reserve margins are expected to meet the 15.4 percent target through 2014. If the likely portion of proposed capacity additions is included, the reserve margin target is expected to be maintained through 2018.

Uncertain resources are not included when determining the reserve margin. Uncertain resources are the existing generation that represents wind/variable resource deratings, generating capacity that has not been studied for delivery within the RTOs, and capacity located within the region that is not part of PJM or MISO committed capacity. Conceptual capacity represents less certain future capacity additions and only a portion of the capacity is included when determining the expected reserve margins.

The amount of available wind power capability included in the reserve calculations is less than the nameplate rating of the wind resources. PJM has recently changed the default wind capability from 20 percent to 13 percent for new queue projects. MISO permits wind power providers to declare up to 20 percent of nameplate capability as a capacity resource.

The fuel mix of generating units in the RFC region is 15.0 percent nuclear, 3.0 percent conventional and pumped storage hydro, 47.0 percent coal, 6.0 percent oil, 28.0 percent gas, and 1.0 percent wind and other. Since there currently are no adverse conditions affecting the resources within the RFC region, the RFC assessment assumes that any future adverse weather or fuel supply issues would be temporary in duration and limited in impact on resource availability, and will not affect the long-term assessment.

Within the PJM footprint, the capacity mix is likely to shift to more natural gas-fired combined cycle and combustion turbine capacity. Continued reliance on steam (mainly coal) appears likely, although potential changes in environmental regulations may have an impact on coal units throughout the footprint.

Over the next seven years, there are plans within the RFC region for the addition of more than 1,700 miles of high-voltage transmission lines (100 kV and above), and numerous new substations and transformers expected to enhance and strengthen the bulk transmission system. PJM's RTEP has identified four major "backbone" projects, two of which were mentioned earlier.

The Trans-Allegheny Interstate Line, scheduled for operation in 2011, consists of a new 500 kV circuit from 502 Junction to Mt. Storm to Meadow Brook to Loudon. This project will relieve anticipated overloads and voltage problems in the Washington, D.C., area, including anticipated overloads expected in 2011 on the existing 500 kV network.

The planned 130-mile, 500 kV circuit from Susquehanna to Lackawanna to Roseland will tie into the existing 500 kV network and, with the addition of 500/230 kV transformers, will create a strong link from generation sources in Northeastern and North Central Pennsylvania into New Jersey. These facilities are expected to be in service by June 2012.

The Potomac-Appalachian Transmission Highline (PATH) transmission line consists of a 244-mile Amos to Bedington 765 kV line and a 92-mile, twin circuit 500 kV line from Bedington to Kemptown. This project will reduce the west-to-east power flow on the existing PJM 500 kV transmission paths and provide significant benefits to the constrained area of Washington and Baltimore. The Maryland Public Service Commission rejected the application of Allegheny affiliate, Potomac Edison Co., for a 20-mile segment of the line, and a new application has been filed. Also, the Virginia State Corporation Commission granted a motion of PATH Allegheny Virginia Transmission Corp. to withdraw its application for a 31-mile segment. A new application, based on the 2010 RTEP analysis, is not expected before the third quarter of 2010. The facilities were originally expected to be in service in 2012. Based on the findings of the latest analyses, PJM is directing that PATH be placed into service by June 1, 2015.

The fourth "backbone" project is the Mid-Atlantic Power Pathway (MAPP), consisting of a new 190-mile 500 kV line beginning at Possum Point, Virginia, and terminating at Salem, New Jersey.

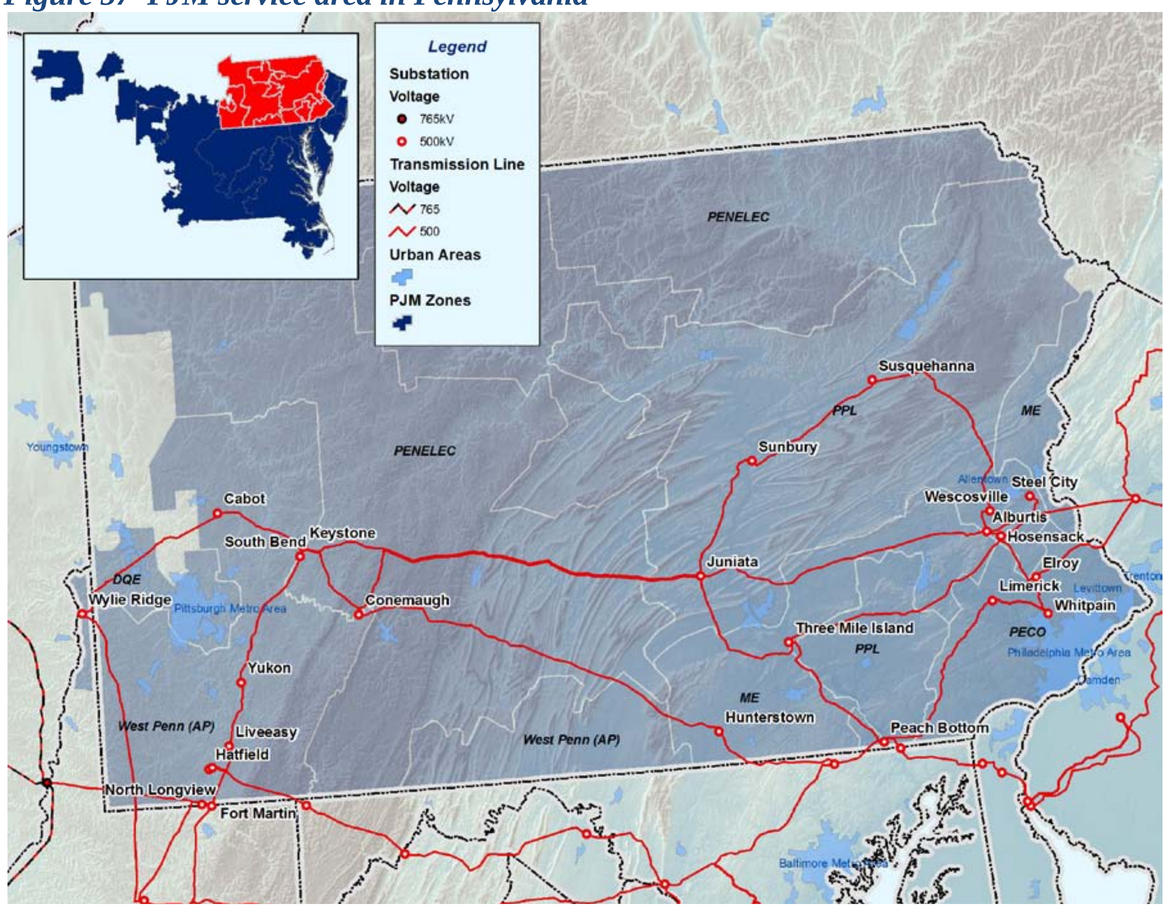
The transmission system is expected to perform well over a wide range of operating conditions, provided new facilities go into service as scheduled, and transmission operators take appropriate action, as needed, to control power flows, reactive reserves, and voltages.

Pennsylvania

The Pennsylvania electric power outlook reflects the projections of RFC. Since transmission and generation are not regulated by this Commission, and since the bulk electric system is planned on a regional rather than a state basis, we must look to regional entities for data concerning the current and future condition of the bulk electric system. 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 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. PJM's service area in the state is shown in Figure 57. [72]

Figure 57 PJM service area in Pennsylvania



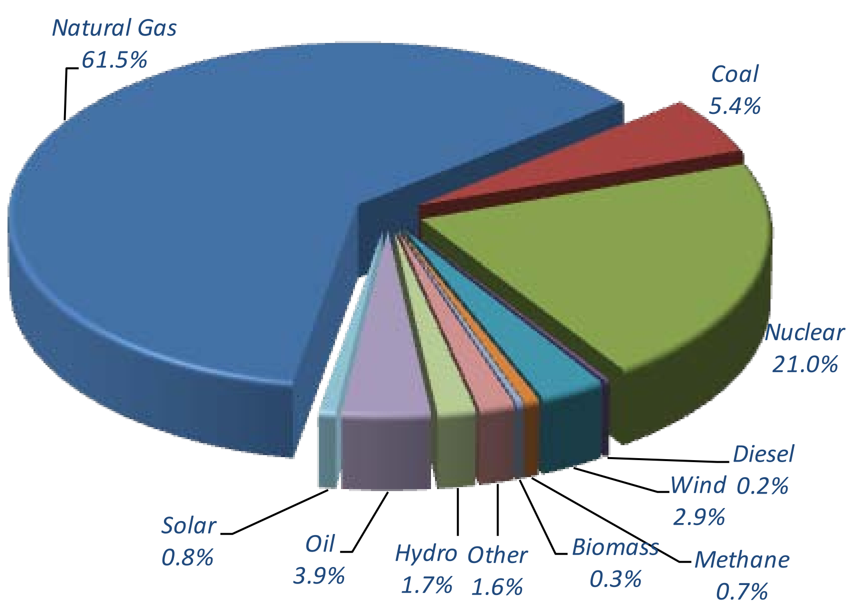
[72] *PJM 2009 Regional Transmission Expansion Plan*, Feb. 26, 2010.

Load-serving entities (LSEs) acquire capacity resources by entering into bilateral agreements, participating in the PJM-operated capacity market, owning generation, and/or pursuing load management options. The PJM generator interconnection process ensures that new capacity resources satisfy LSE requirements to reliably meet their obligations.

All new generation, which anticipates interconnecting and operating in parallel with the PJM transmission grid and participating 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 20,688 MW through 2015. These facilities are either under study (active), under construction, partially in-service or in-service. Natural gas projects make up 61.5 percent of queued capacity. This additional capacity may be used to serve Pennsylvania customers or out-of-state customers. See Figure 58. Appendix B provides the status of generator interconnection requests located in Pennsylvania.

Figure 58 PJM queued generating capacity in Pennsylvania by fuel type



The generating capacity located in Pennsylvania totals 46,568 MW.[73] As stated earlier, the output of some of these facilities may serve loads outside of Pennsylvania. See Figure 59.

The state's 2009 aggregate non-coincident summer peak demand was 27,580 MW. In 2009, Pennsylvania's net electric generation totaled 218,378 GWh, down 1.8 percent from 2008. Net generation from natural gas increased 55.7 percent from 2008. Pumped storage facilities used 560

[73] Electric Power Generation Association.

GWh more than they generated. Figure 60 shows the generation distribution by fuel type.[74] "Other" includes wind, solar and biomass sources. Appendix C lists the existing power plants located in Pennsylvania.

Figure 59 Existing generating capacity in Pennsylvania by fuel type

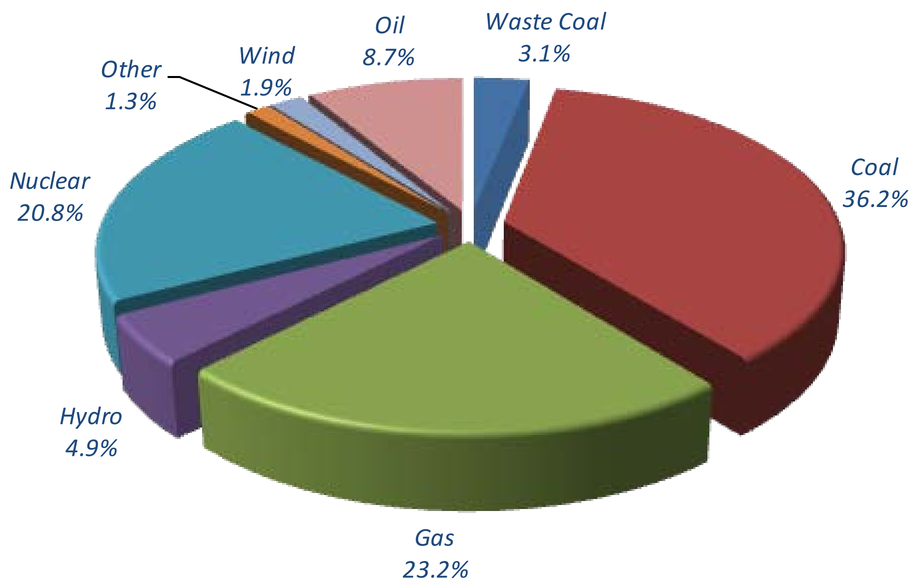
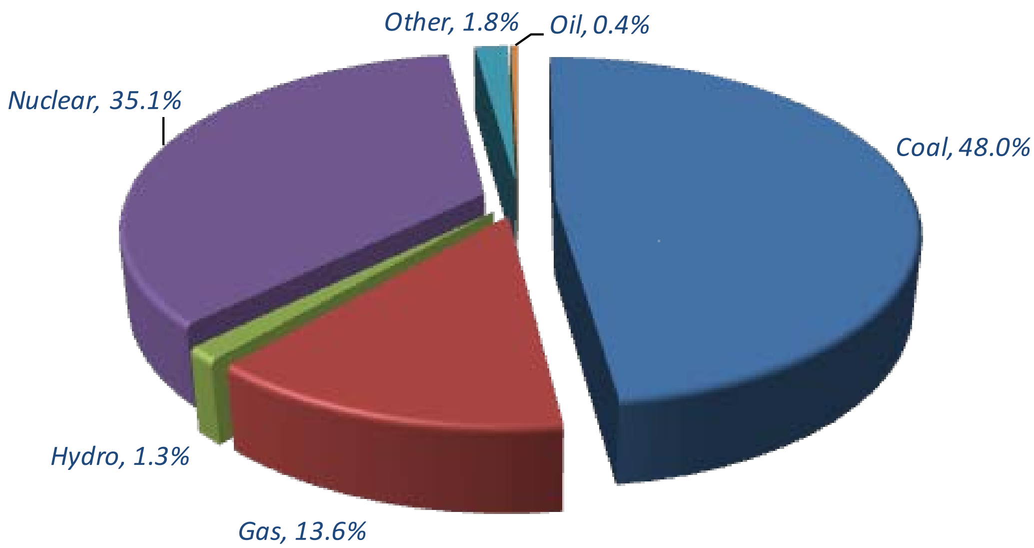


Figure 60 2009 generation in Pennsylvania by fuel type



[74] U.S. DOE Energy Information Administration.

Section 4 - Conclusions

Pennsylvania continues to benefit from a high level of electric service reliability. The Pennsylvania outlook reflects the regional assessment of RFC.

RFC reports that there is sufficient generation, transmission and distribution capacity in Pennsylvania to meet the needs of electric consumers for the foreseeable future. RFC anticipates that its reserve margin target will be satisfied through 2018, provided that proposed generation projects will be completed in a timely manner and enhancements to the transmission network will be capable of reliably delivering those resources. Summer reserve margins in RFC range from a high of 27.2 percent in 2009, declining to 18.2 percent in 2018. This assumes that 18.4 percent of conceptual seasonal capability will become available during the last five years of the forecast period.

The Commission continues to promote the development of alternative energy resources and pursue demand side management, energy efficiency, and load management programs and technologies to address ways to encourage customers to reduce their demand. These efforts include the implementation of the Alternative Energy Portfolio Standards and the Energy Efficiency and Conservation Program. In the long term, these initiatives will improve overall energy efficiency, expand energy markets and maintain system reliability. Through demand side measures and overall improvements in energy efficiency, EDCs and all customer classes will benefit.

To summarize the relevant statistics in this report, aggregate Pennsylvania retail sales in 2009 totaled 142,161 GWh, a 4.2 percent decrease from that of 2008. Residential sales accounted for 35.4 percent of the total sales, followed by commercial (31.7 percent) and industrial (30.3 percent).

Between 1994 and 2009, the state's energy demand grew at an average annual rate of 1.0 percent. Residential sales grew at an annual rate of 1.5 percent and commercial sales increased at 2.1 percent per year. Industrial sales *declined* at an annual rate of 0.4 percent, due mainly to a 9.4 percent drop in sales from 2008. Average total sales growth from 2004 to 2009 was 0.1 percent. The current aggregate five-year projection of growth in energy demand is 1.4 percent. This includes a residential growth rate of 0.9 percent, a commercial rate of 1.9 percent and an industrial rate of 1.6 percent.

Over the past 15 years, the non-coincident peak load for the major EDCs increased at an average rate of 0.7 percent per year. The peak load is expected to increase from 27,597 MW in 2009 to 29,550 MW in 2014 at an average annual growth rate of 1.4 percent.

* * * * *


Susquehanna Steam Electric Station, Luzerne County, Pennsylvania

Appendix A – Data Tables

The following tables provide actual and projected peak load and residential, commercial and industrial energy demand. Actual data covers years 2000 through 2009. Five-year projections are those filed with the Commission in years 2000 through 2010.

Table A01 Duquesne Light Company
Actual and Projected Peak Load (MW)

		Projected Peak Load Requirments (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	2673	2638										
2001	2771	2661	2661									
2002	2886	2682	2682	2850								
2003	2686	2702	2702	2884	2822							
2004	2646	2723	2723	2912	2841	2719						
2005	2884		2743	2934	2855	2740	2722					
2006	3053			2953	2870	2771	2765	2765				
2007	2890				2884	2801	2805	2805	3039			
2008	2822					2831	2835	2835	3086	2948		
2009	2732						2873	2873	3141	3007	2862	
2010								2910	3194	3067	2836	2854
2011									3242	3128	2857	2863
2012										3191	2850	2860
2013											2890	2917
2014												2960

Table A02 Duquesne Light Company
Actual and Projected Residential Energy Demand (GWh)

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	3509	3610										
2001	3584	3643	3643									
2002	3924	3681	3681	3671								
2003	3759	3716	3716	3726	3697							
2004	3886	3759	3759	3772	3721	3811						
2005	4134		3780	3810	3744	3832	3941					
2006	3991			3846	3767	3879	4018	3984				
2007	4211				3791	3925	4088	4054	4141			
2008	4060					3978	4125	4118	4214	4216		
2009	3946						4198	4181	4293	4293	4177	
2010								4243	4372	4371	4188	4117
2011									4453	4444	4181	4184
2012										4527	4171	4267
2013											4197	4352
2014												4448

Table A03 Duquesne Light Company
Actual and Projected Commercial Energy Demand (GWh)

		Projected Commercial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	6092	6113										
2001	6170	6231	6231									
2002	6458	6336	6336	6324								
2003	6346	6438	6438	6467	6436							
2004	6454	6540	6540	6570	6505	6428						
2005	6566		6628	6653	6570	6479	6568					
2006	6474			6729	6636	6597	6711	6693				
2007	6715				6703	6713	6870	6847	6784			
2008	6631					6841	6949	6991	6942	6731		
2009	6537						7076	7129	7127	6768	6648	
2010								7259	7302	6815	6627	6428
2011									7457	6878	6583	6501
2012										6952	6533	6585
2013											6527	6666
2014												6742

Table A04 Duquesne Light Company
Actual and Projected Industrial Energy Demand (GWh)

		Projected Industrial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	3581	3537										
2001	3283	3576	3576									
2002	3328	3615	3615	3315								
2003	3189	3651	3651	3382	3349							
2004	3229	3695	3695	3445	3415	3031						
2005	3128		3742	3491	3437	2990	3347					
2006	3182			3530	3453	3033	3407	3229				
2007	3145				3471	3075	3458	3299	3271			
2008	3079					3123	3501	3359	3315	3098		
2009	2616						3542	3411	3369	3102	3002	
2010								3464	3420	3084	2933	2440
2011									3467	3140	2851	2407
2012										3141	2777	2395
2013											2726	2385
2014												2359

Table A05 Metropolitan Edison Company
Actual and Projected Peak Load (MW)

		Projected Peak Load Requirements (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	2274	2404										
2001	2486	2456	2455									
2002	2616	2508	2504	2503								
2003	2438	2559	2553	2554	2527							
2004	2468	2612	2602	2611	2584	2570						
2005	2752		2652	2668	2639	2634	2625					
2006	2884			2725	2691	2702	2689	2689				
2007	2825				2747	2756	2740	2740	2740			
2008	3045					2817	2801	2801	2801	2801		
2009	2739						2857	2856	2857	2857	2829	
2010								2915	2915	2915	2932	2687
2011									2972	2972	3017	2640
2012										3032	3085	2630
2013											3158	2668
2014												2731

Table A06 Metropolitan Edison Company
Actual and Projected Residential Energy Demand (GWh)

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	4377	4344										
2001	4496	4430	4430									
2002	4721	4516	4501	4607								
2003	4895	4602	4577	4708	4846							
2004	5071	4687	4651	4804	4860	4885						
2005	5399		4724	4892	4980	4977	5097					
2006	5287			4988	5094	5083	5176	5325				
2007	5595				5211	5190	5276	5390	5516			
2008	5598					5300	5376	5515	5699	5699		
2009	5448						5472	5640	5872	5872	5771	
2010								5764	6037	6037	5836	5587
2011									6187	6187	5969	5552
2012										6341	6109	5577
2013											6232	5682
2014												5799

Table A07 Metropolitan Edison Company
Actual and Projected Commercial Energy Demand (GWh)

		Projected Commercial Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	3699	3518										
2001	3855	3622	3751									
2002	3985	3732	3860	3976								
2003	4018	3837	3970	4096	4057							
2004	4251	3947	4079	4216	4144	4170						
2005	4491		4189	4336	4258	4281	4310					
2006	4509			4456	4363	4388	4400	4462				
2007	4715				4464	4498	4506	4547	4664			
2008	4777					4601	4616	4668	4818	4818		
2009	4568						4721	4788	4969	4969	4853	
2010								4908	5108	5108	5020	4671
2011									5244	5244	5152	4706
2012										5375	5291	4783
2013											5421	4887
2014												4963

Table A08 Metropolitan Edison Company
Actual and Projected Industrial Energy Demand (GWh)

		Projected Industrial Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	4412	4313										
2001	4186	4352	4312									
2002	4012	4410	4409	4263								
2003	3986	4459	4490	4341	3954							
2004	4042	4508	4567	4419	3989	4080						
2005	4083		4645	4498	4010	4136	4077					
2006	4008			4577	4030	4162	4119	4176				
2007	3992				4050	4206	4145	4155	4123			
2008	3831					4237	4175	4177	4156	4156		
2009	3439						4195	4200	4181	4181	3620	
2010								4221	4193	4193	3842	3538
2011									4201	4201	4035	3497
2012										4209	4047	3528
2013											4048	3731
2014												4021

Table A09 Pennsylvania Electric Company
Actual and Projected Peak Load (MW)

		Projected Peak Load Requirements (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	2569	2651										
2001	2337	2675	2321									
2002	2693	2700	2347	2337								
2003	2308	2737	2373	2375	2410							
2004	2425	2760	2399	2405	2456	2438						
2005	2531		2425	2437	2505	2481	2511					
2006	2696			2465	2544	2525	2554	2554				
2007	2524				2592	2565	2598	2598	2598			
2008	2880					2604	2637	2637	2637	2637		
2009	2451						2674	2674	2674	2674	2603	
2010								2711	2711	2711	2630	2465
2011									2750	2750	2661	2452
2012										2789	2688	2458
2013											2715	2496
2014												2531

Table A10 Pennsylvania Electric Company
Actual and Projected Residential Energy Demand (GWh)

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	3949	3881										
2001	3991	3915	3977									
2002	4167	3951	4021	4043								
2003	4187	3984	4065	4089	4194							
2004	4249	4017	4109	4134	4162	4135						
2005	4457		4154	4180	4203	4186	4295					
2006	4381			4226	4245	4236	4333	4420				
2007	4497				4287	4287	4385	4438	4469			
2008	4558					4339	4438	4496	4533	4533		
2009	4471						4524	4554	4598	4598	4611	
2010								4614	4662	4662	4614	4569
2011									4727	4727	4662	4489
2012										4793	4721	4443
2013											4776	4442
2014												4486

Table A11 Pennsylvania Electric Company
Actual and Projected Commercial Energy Demand (GWh)

		Projected Commercial Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	4509	4387										
2001	4538	4473	4472									
2002	4697	4558	4549	4613								
2003	4727	4643	4626	4730	4782							
2004	4792	4728	4704	4846	4874	4825						
2005	5010		4781	4962	4976	4912	4928					
2006	4961			5078	5076	4986	4990	5049				
2007	5139				5178	5060	5064	5099	5045			
2008	5186					5136	5140	5188	5122	5122		
2009	5019						5213	5277	5199	5199	5159	
2010								5367	5277	5277	5213	5196
2011									5356	5356	5265	5215
2012										5436	5320	5257
2013											5364	5343
2014												5424

Table A12 Pennsylvania Electric Company
Actual and Projected Industrial Energy Demand (GWh)

		Projected Industrial Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	4698	5004										
2001	4392	5093	4857									
2002	4315	5177	5144	4670								
2003	4391	5239	5214	4783	4492							
2004	4589	5306	5244	4846	4708	4561						
2005	4729		5274	4887	4749	4666	4527					
2006	4678			4928	4797	4737	4612	4807				
2007	4610				4845	4791	4679	4828	4809			
2008	4594					4815	4708	4881	4881	4881		
2009	4044						4725	4905	4954	4954	4203	
2010								4930	4983	4983	4538	4126
2011									5013	5013	4859	4222
2012										5043	4889	4370
2013											4922	4607
2014												4674

Table A13 Pennsylvania Power Company
Actual and Projected Peak Load (MW)

		Projected Peak Load Requirements (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	885	935										
2001	1011	957	883									
2002	869	980	904	918								
2003	855	1003	930	947	891							
2004	898	1025	956	983	923	865						
2005	1021		982	1022	958	884	952					
2006	984			1058	985	900	921	904				
2007	1042				1020	916	930	930	921			
2008	1063					929	938	938	936	936		
2009	901						951	951	951	951	984	
2010								965	965	965	941	896
2011									980	980	963	890
2012										994	981	899
2013											995	930
2014												977

Table A14 Pennsylvania Power Company
Actual and Projected Residential Energy Demand (GWh)

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	1341	1390										
2001	1391	1412	1360									
2002	1533	1434	1395	1447								
2003	1513	1457	1430	1483	1512							
2004	1545	1479	1451	1520	1523	1542						
2005	1664		1473	1558	1552	1571	1612					
2006	1611			1597	1579	1599	1636	1659				
2007	1690				1607	1629	1665	1699	1659			
2008	1667					1657	1695	1744	1693	1693		
2009	1634						1723	1789	1724	1724	1780	
2010								1835	1758	1758	1761	1701
2011									1789	1789	1806	1708
2012										1821	1860	1721
2013											1904	1714
2014												1739

Table A15 Pennsylvania Power Company
Actual and Projected Commercial Energy Demand (GWh)

		Projected Commercial Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	1164	1204										
2001	1220	1242	1162									
2002	1268	1284	1206	1270								
2003	1291	1327	1251	1327	1279							
2004	1296	1372	1293	1387	1310	1309						
2005	1367		1335	1449	1342	1339	1353					
2006	1359			1514	1373	1370	1374	1384				
2007	1414				1405	1402	1400	1422	1394			
2008	1404					1429	1427	1460	1427	1427		
2009	1367						1453	1498	1461	1461	1401	
2010								1535	1496	1496	1394	1428
2011									1532	1532	1424	1408
2012										1569	1491	1449
2013											1535	1500
2014												1535

Table A16 Pennsylvania Power Company
Actual and Projected Industrial Energy Demand (GWh)

		Projected Industrial Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2000**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
2000	1643	1563										
2001	1539	1596	1618									
2002	1505	1635	1644	1514								
2003	1481	1673	1677	1516	1521							
2004	1554	1711	1716	1517	1507	1529						
2005	1629		1758	1519	1500	1555	1582					
2006	1708			1520	1493	1570	1558	1565				
2007	1627				1489	1580	1563	1578	1720			
2008	1614					1583	1568	1594	1727	1727		
2009	1229						1569	1610	1734	1734	1347	
2010								1626	1741	1741	1517	1226
2011									1748	1748	1687	1214
2012										1755	1694	1238
2013											1700	1370
2014												1596

Table A17 PPL Electric Utilities Corporation
Actual and Projected Peak Load (MW)

Year	Actual	Projected Peak Load Requirements (Year Forecast Was Filed)										
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	6355	6580										
2001	6583	6680	6850									
2002	6970	6770	6960	7000								
2003	7197	6860	7060	7070	6790							
2004	7335	6960	7170	7040	6860	7200						
2005	7083		7270	7120	7000	7300	7200					
2006	7577			7200	7140	7410	7290	7310				
2007	7163				7320	7510	7390	7410	7200			
2008	7414					7610	7490	7510	7270	7410		
2009	6845						7580	7610	7340	7450	7180	
2010								7710	7400	7500	7250	7207
2011									7480	7580	7320	7227
2012										7680	7360	7283
2013											7450	7366
2014												7487

Table A19 PPL Electric Utilities Corporation
Actual and Projected Commercial Energy Demand (GWh)

Year	Actual	Projected Commercial Energy Demand (Year Forecast Was Filed)										
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	11477	11090										
2001	11778	11275	11291									
2002	12117	11444	11431	11850								
2003	12273	11612	11561	12033	12212							
2004	12576	11782	11699	12219	12507	13275						
2005	13157		11848	12411	12757	13601	12967					
2006	13140			12602	13101	13975	13436	13188				
2007	13756				13418	14286	13946	13562	13184			
2008	13913					14631	14517	13836	13476	13676		
2009	13818						15068	14166	13777	14028	14258	
2010								14492	14045	14253	14486	14098
2011									14290	14596	14631	14642
2012										14907	14926	14907
2013											15228	15295
2014												15827

Table A18 PPL Electric Utilities Corporation
Actual and Projected Residential Energy Demand (GWh)

Year	Actual	Projected Residential Energy Demand (Year Forecast Was Filed)										
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	11923	12031										
2001	12269	12150	12176									
2002	12640	12280	12324	12391								
2003	13266	12421	12478	12514	12868							
2004	13441	12562	12634	12650	13062	13308						
2005	14218		12799	12803	13259	13505	13950					
2006	13714			12955	13462	13728	14311	14099				
2007	14411				13671	13962	14675	14392	14180			
2008	14419					14198	15019	14555	14422	14469		
2009	14218						15349	14794	14565	14584	14341	
2010								15036	14702	14562	14340	14384
2011									14828	14608	14246	14390
2012										14770	14350	14226
2013											14443	14164
2014												14325

Table A20 PPL Electric Utilities Corporation
Actual and Projected Industrial Energy Demand (GWh)

Year	Actual	Projected Industrial Energy Demand (Year Forecast Was Filed)										
		2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	10280	10543										
2001	10319	10836	10963									
2002	9853	11077	11255	10780								
2003	9599	11295	11521	11135	10355							
2004	9611	11498	11777	11425	10503	9938						
2005	9720		12010	11702	10641	10035	9750					
2006	9704			11970	10795	10155	9926	9968				
2007	9482				10924	10253	10136	10048	9965			
2008	9551					10346	10349	10084	9999	9625		
2009	8418						10577	10150	10032	9570	9401	
2010								10214	10059	9228	9141	8506
2011									10084	9005	8879	8365
2012										9009	8866	8211
2013											8864	8110
2014												8054

Table A21 PECO Energy Company
Actual and Projected Peak Load (MW)

		Projections of Peak Load Requirements (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	7333	7339										
2001	7948	7398	7392									
2002	8164	7457	7451	8012								
2003	7696	7517	7510	8076	8229							
2004	7567	7577	7570	8140	8295	8129						
2005	8626		7631	8205	8362	8320	8320					
2006	8932			8271	8428	8445	8445	8755				
2007	8549				8496	8571	8571	8887	9066			
2008	8824					8700	8700	9020	9202	8677		
2009	7994						8831	9155	9340	8807	8956	
2010								9293	9480	8940	9091	8114
2011									9622	9074	9227	8236
2012										9210	9365	8359
2013											9506	8485
2014												8612

Table A23 PECO Energy Company
Actual and Projected Commercial Energy Demand (GWh)

		Projected Commercial* Energy Demand (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	7481	6649										
2001	7604	6702	7315									
2002	8019	6756	7446	7732								
2003	8077	6810	7578	7963	8135							
2004	8414	6864	7711	8099	8233	8140						
2005	8520		7844	8265	8434	8349	8349					
2006	8857			8436	8637	8550	8550	8691				
2007	8892				8839	8755	8755	8864	9034			
2008	8700					8965	8965	9042	9215	9069		
2009	8404						9144	9223	9399	9251	8874	
2010								9407	9587	9436	9052	8572
2011									9779	9625	9233	8744
2012										9817	9417	8918
2013											9606	9097
2014												9279

* Small Commercial & Industrial

Table A22 PECO Energy Company
Actual and Projected Residential Energy Demand (GWh)

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	11304	10600										
2001	11178	10685	11278									
2002	12335	10770	11385	11634								
2003	12259	10856	11488	11733	12020							
2004	12507	10943	11592	11855	11905	12250						
2005	13469		11697	11957	11981	12385	12385					
2006	12797			12059	12054	12592	12592	13738				
2007	13487				12128	12839	12839	14013	13053			
2008	13317					13179	13179	14293	13314	13757		
2009	12893						13443	14579	13580	14032	13583	
2010								14870	13852	14313	13855	13151
2011									14129	14599	14132	13414
2012										14891	14415	13683
2013											14703	13956
2014												14235

Table A24 PECO Energy Company
Actual and Projected Industrial Energy Demand (GWh)

		Projected Industrial* Energy Demand (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	15828	16047										
2001	15312	16175	15405									
2002	15323	16305	15406	15324								
2003	15518	16435	15408	15417	15130							
2004	15741	16567	15409	15429	14959	15477						
2005	15774		15409	15442	14980	15448	15449					
2006	15821			15458	15001	15448	15448	16089				
2007	16582				15022	15448	15448	16411	16137			
2008	16534					15448	15448	16739	16460	16914		
2009	15889						15757	17074	16789	17252	16864	
2010								17415	17125	17597	17202	16207
2011									17467	17949	17546	16531
2012										18308	17897	16861
2013											18254	17199
2014												17543

* Large Commercial & Industrial

Table A25 West Penn Power Company
Actual and Projected Peak Load (MW)

		Projections of Peak Load Requirements (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	3277	3284										
2001	3677	3304	3141									
2002	3582	3341	3445	3458								
2003	3455	3380	3465	3505	3535							
2004	3407	3415	3501	3542	3572	3621						
2005	3752		3536	3586	3610	3670	3702					
2006	3926			3622	3639	3705	3763	3723				
2007	3838				3674	3738	3812	3782	3813			
2008	3826					3766	3845	3824	3882	3871		
2009	3667						3866	3864	3965	3958	3910	
2010								3895	4028	4036	3990	3788
2011									4078	4083	4032	3755
2012										4123	4084	3771
2013											4120	3809
2014												3951

Table A27 West Penn Power Company
Actual and Projected Commercial Energy Demand (GWh)

		Projected Commercial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	4265	4182										
2001	4360	4225	4326									
2002	4497	4275	4395	4458								
2003	4529	4329	4449	4543	4577							
2004	4691	4397	4517	4624	4653	4701						
2005	4892		4571	4684	4695	4780	4791					
2006	4959			4749	4739	4832	4907	4996				
2007	4998				4776	4878	5006	5092	5083			
2008	4925					4936	5098	5179	5179	5115		
2009	4880						5135	5249	5279	5235	5048	
2010								5318	5365	5327	5160	4966
2011									5452	5387	5275	4987
2012										5462	5353	5059
2013											5450	5169
2014												5307

Table A26 West Penn Power Company
Actual and Projected Residential Energy Demand (GWh)

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	6022	6061										
2001	6325	6172	6192									
2002	6459	6256	6260	6374								
2003	6641	6339	6329	6471	6486							
2004	6724	6445	6436	6596	6599	6818						
2005	7088		6521	6680	6671	6890	6923					
2006	7133			6775	6744	6965	7047	7164				
2007	7266				6821	7041	7136	7289	7319			
2008	7172					7132	7194	7387	7484	7481		
2009	7101						7189	7417	7639	7654	7206	
2010								7447	7761	7774	7264	7147
2011									7869	7892	7233	7104
2012										7965	7248	7085
2013											7102	6952
2014												7008

Table A28 West Penn Power Company
Actual and Projected Industrial Energy Demand (GWh)

		Projected Industrial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
2000	8383	7942										
2001	7955	8120	8481									
2002	7957	8230	8597	8006								
2003	7747	8353	8663	8116	7885							
2004	8039	8477	8729	8188	7973	7814						
2005	8051		8799	8230	8023	7913	8027					
2006	8144			8290	8087	7998	8137	8283				
2007	8160				8187	8069	8220	8429	8282			
2008	8135					8140	8311	8543	8411	8311		
2009	7286						8313	8615	8584	8476	8440	
2010								8634	8728	8699	8711	7612
2011									8766	8799	8906	7740
2012										8844	9093	7936
2013											9246	8105
2014												8214

Appendix B – Plant Additions and Upgrades

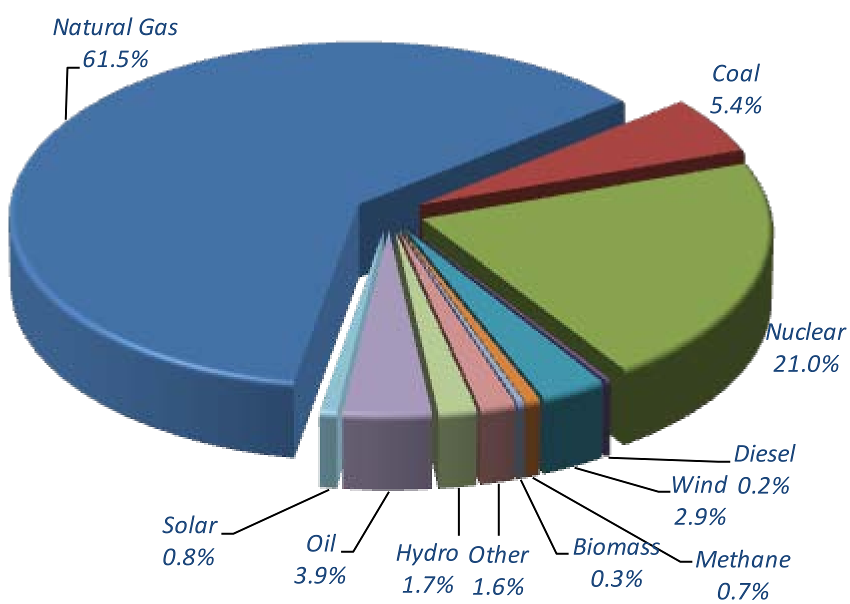
The following data represents PJM interconnection requests for new generating resources located in Pennsylvania. As of Jan. 31, 2010, 13,167 MW or 13 percent of all PJM queued requests for new generating resources or incremental additions to existing resources in Pennsylvania, received since 1999, were placed in service. Projects withdrawn totaled 79,129 MW or 78 percent, representing 261 out of 464 projects. New capacity under construction amounts to 1,811 MW.

Note: Some project requests may be duplicative, in that the same project may be considered for more than one point of injection into the system; however, in those cases, only one project is being considered for construction.

For addition information, see: http://www.pjm.com/planning/generation-interconnection.aspx.

Source: PJM

PJM queued generating capacity in Pennsylvania



Status of Pennsylvania's Plant Additions and Upgrades

Queue	PJM Substation	MW	MWC	Status	In Service	Fuel	Transmission Owner
A01	South Lebanon 230 KV	720	655	In-Service	2002 Q2	Natural Gas	ME
A08	Susquehanna 230kV	1140	15	In-Service	2002 Q3	Nuclear	PPL
A09	Susquehanna 230kV	1140	35	In-Service	2003 Q2	Nuclear	PPL
A10	Glory 115kV	6	6	In-Service	2000 Q1	Coal	PENELEC
A11	Harwood 230 kV	356	201	In-Service	2002 Q2	Natural Gas	PPL
A12	Martins Creek 230 kV	600	600	In-Service	2004 Q2	Natural Gas	PPL
A18	North Temple 230 kV	557	557	In-Service	2002 Q4	Natural Gas	ME
A19	Eddystone 230 kV	521	521	In-Service	2002 Q1	Natural Gas	PECO
A21	Chichester 230 kV	725	725	In-Service	2004 Q4	Natural Gas	PECO
A31	Peckville/Varden 69kV	46	44	In-Service	2001 Q4	Natural Gas	PPL
A32	Montour #1	759	14	In-Service	2001 Q2	Coal	PPL
A33	Montour #2	14	14	In-Service	2000 Q4	Coal	PPL
A34	Brunner 230kV	749	14	In-Service	2002 Q2	Coal	PPL
A35	North Bangor 34.5kV	10	10	In-Service	2001 Q2	Methane	ME
A36	Hunterstown 500 kV	830	830	In-Service	2003 Q3	Natural Gas	ME
A59	Emilie	1145	540	In-Service	2004 Q2	Natural Gas	PECO
A59_W00	Springdale 138 kV	88	88	In-Service	2000 Q4	Natural Gas	APS
B03	Hosensack 500kV	750	750	In-Service	2003 Q1	Natural Gas	PPL
B05	Wayne-Homer City 345kV	265	250	In-Service	2002 Q1	Natural Gas	PENELEC
B12_W01	South Bend 500 kV	600	600	In-Service	2002 Q1	Natural Gas	APS
B14	Arnold 115kV	10		In-Service	1999 Q1	Wind	PENELEC
B18_W03	Springdale 138 kV	525	525	In-Service	2003 Q3	Natural Gas	APS
B23	Siegfried/Allentown 138kV	115	5	In-Service	2001 Q2	Coal	PPL
B23_W04	Gans 138 kV	88	88	In-Service	2001 Q4	Natural Gas	APS
B26	Hunlock Creek 66kV	50	50	In-Service	2002 Q2	Natural Gas	PPL
B28	Muddy Run 230kV	160	160	In-Service	2003 Q3	Hydro	PECO
B28_W08	Mill Run 25 kV	15		In-Service	2002 Q2	Wind	APS
B30	Emilie 230kV	605	605	In-Service	2004 Q2	Natural Gas	PECO
B34	Seward 230kV	550	304	In-Service	2006 Q2	Other	PENELEC
D01	Engleside 69kV	2	1.6	In-Service	2000 Q2	Natural Gas	PPL
D03	Harwood 69kV	99	99	In-Service	2002 Q2	Natural Gas	PPL
D04	Peckville 69kV	20	1	In-Service	2000 Q2	Natural Gas	PPL
D05	East Carbondale 69kV	70		In-Service	2003 Q4	Wind	PPL
D06	Eclipse 115kV	85	5	In-Service	2000 Q3	Natural Gas	PPL
D07	Blueball 69kV	53	8	In-Service	2000 Q3	Natural Gas	PECO
D18	Hosensack 230kV	350	350	In-Service	2004 Q2	Natural Gas	PPL
E02	N. Lebanon 69kV	1	1.2	In-Service	2000 Q4	Methane	ME
E04_W20	Guilford 138 kV	88	88	In-Service	2002 Q4	Natural Gas	APS
E07	Montour 230kV	750	7	In-Service	1999 Q1	Coal	PPL
E13	Somerset 22.86kV	10		In-Service	1999 Q1	Wind	PENELEC
E17_W27	Ronco	620	620	In-Service	2003 Q2	Natural Gas	APS
E20	Croydon 230kV	387	6.5	In-Service	2002 Q4	Oil	PECO
F03	Martins Creek 230kV	850	30	In-Service	2001 Q2	Coal	PPL
G04	Brunner Island #2	749	14	In-Service	2002 Q1	Coal	PPL
G05	Brunner Island #1	14	14	In-Service	2002 Q1	Coal	PPL
G06	Martins Creek #4	850	30	Under Construction	2012 Q1	Coal	PPL
G21	Meyersdale North	48		In-Service	2003 Q4	Wind	PSEG
G22	North Wales 34.5 kV	38	38	In-Service	2002 Q3	Natural Gas	PECO
G30_W53	South Bend 500 kV	704	104	Partially In-Service	2003 Q2	Natural Gas	APS
G36	Holtwood	152	5	In-Service	2002 Q2	Hydro	PPL
G46	Peach Bottom 500kV	2256	70	Partially In-Service	2007 Q4	Nuclear	PECO
G51_W60	Hatfield Ferry 500 kV	525	525	Suspended	2011 Q3	Coal	APS
G51_W63	Upton 34.5 kV	10	9.9	In-Service	2003 Q2	Methane	APS

Status of Pennsylvania's Plant Additions and Upgrades

Queue	PJM Substation	MW	MWC	Status	In Service	Fuel	Transmission Owner
H02	Susquehanna 230kV	9	9	In-Service	2007 Q2	Nuclear	PPL
H03	Susquehanna 500kV	1153	9	In-Service	2003 Q4	Nuclear	PPL
H06	Chichester 230kV	750	25	In-Service	2004 Q4	Natural Gas	PECO
I12	Grand Point 69kV	31	23.3	In-Service	2004 Q1	Diesel	APS
I13	Hooversville 115kV	29	0	In-Service	2008 Q1	Wind	PENELEC
I14	Upton 34.5kV	14	4.1	In-Service	2004 Q2	Methane	APS
J09	Harrisburg Authority	26	26	In-Service	2006 Q2	Methane	PPL
K02	East Towanda-Moshannon 230kV	70	0	Suspended	2010 Q4	Wind	PENELEC
K13	Hooversville 115kV	29	5.88	In-Service	2008 Q1	Wind	PENELEC
K18	Arnold (Green Mountain) 115kV	10	2.08	In-Service		Wind	PENELEC
K20	Mill Run 25 kV	15	3	In-Service	2002 Q2	Wind	APS
K21	East Carbondale 69kV	69	13	In-Service	2004 Q3	Wind	PPL
K22	Somerset 22.86kV	9	1.8	In-Service	1999 Q1	Wind	PENELEC
K23	Meyersdale North	48	6	In-Service	2004 Q3	Wind	PENELEC
L08	Holtwood 69kV	109	2	In-Service	2003 Q4	Hydro	PPL
L09	Montour #1 230kV	761	2	In-Service	2003 Q4	Coal	PPL
L13	Rockwood	40	8	In-Service	2008 Q1	Wind	PENELEC
L17	Rolling Hills	6		In-Service	2005 Q2	Methane	ME
L18	Bear Creek	26	5.2	In-Service	2006 Q1	Wind	PPL
M07	Peckville (Archbald)	50	6.3	In-Service	2004 Q1	Natural Gas	PPL
M11	Susquehanna #1	2520	111	Partially In-Service	2008 Q2	Nuclear	PPL
M12	Susquehanna #2	2520	107	Partially In-Service	2010 Q2	Nuclear	PPL
M26	Champion	272	272	Suspended	2013 Q4	Coal	APS
M27	Eddystone 138kV	1408	7	In-Service	2004 Q2	Coal	PECO
N06	Hamilton 12kV	0		In-Service	2005 Q1	Methane	PPL
N13	Beaver Valley	1652	1630	In-Service	2005 Q1	Nuclear	DL
N14	Frackville-Hauto #3 69kV	27	5.4	In-Service	2006 Q2	Wind	PPL
N26	Daleville	2	1.7	Partially In-Service	2006 Q4	Methane	PECO
N31	Freemansburg 69kV	5		In-Service	2008 Q2	Methane	PPL
N32	Gans 138kV	50	10.1	Under Construction	2010 Q3	Wind	APS
N36	Gold-Sabinsville 115kV	50	10	Under Construction	2010 Q4	Wind	PENELEC
N39	Johnstown-Altoona 230kV	80	16	In-Service	2007 Q1	Wind	PENELEC
O01	Letort 12kV	3	3.2	In-Service	2006 Q1	Methane	PPL
O18	Salix-Claysburg (Krayn) 115kV	65	13	Partially In-Service	2008 Q4	Wind	PENELEC
O19	Somerset 115kV	33	6.6	Under Construction	2012 Q2	Wind	PENELEC
O26	Pine Grove 69kV	8	8	Partially In-Service	2008 Q2	Diesel	PPL
O28	Jenkins-Harwood #2 69kV	51	10.2	Suspended	2011 Q4	Wind	PPL
O36	Honey Brook 12kV	2		Under Construction	2008 Q4	Methane	PPL
O38	Johnstown-Altoona 230kV	50	10	In-Service	2009 Q3	Wind	PENELEC
O39	Sunbury - Dauphin 69kV	56	11.2	Suspended	2010 Q2	Wind	PPL
O40	Pine Grove - Frailey 69kV	28	5.6	Suspended	2012 Q3	Wind	PPL
O46	Frackville-Hauto #3 69kV	27	0.4	In-Service	2007 Q4	Wind	PPL
O48	Hays Mill - Lookout 115kV	38	7.2	In-Service	2008 Q2	Wind	PENELEC
O52	Gold-Potter Co 115kV	50	10	Suspended	2011 Q2	Wind	PENELEC
O53	Beaver Valley #1	902	81	In-Service	2007 Q2	Nuclear	DL
O54	Beaver Valley #2	908	77	In-Service	2008 Q3	Nuclear	DL
O56	Osterburg East 115kV	76	15.2	Suspended	2013 Q1	Wind	PENELEC
O60	Berlin 23 kV	5	1.08	Under Construction	2012 Q1	Wind	PENELEC
O70	Susquehanna - Harwood 230kV	124	24.8	Suspended	2011 Q4	Wind	PPL
O72	Hooversville-Central City	60	12	Suspended	2009 Q4	Wind	PENELEC
P01	Westover-Madera 115kV	65	13	Suspended	2010 Q4	Wind	PENELEC
P03	Frackville-Hauto #3	27	1.3	In-Service	2007 Q4	Wind	PPL
P04	Peach Bottom 500kV	557	550	Under Construction	2011 Q3	Natural Gas	PECO

Status of Pennsylvania's Plant Additions and Upgrades

Queue	PJM Substation	MW	MWC	Status	In Service	Fuel	Transmission Owner
P22	Johnstown Altoona 230kV	20	4	In-Service	2009 Q3	Wind	PENELEC
P28	Mehoopany 115kV	150	30	Under Construction	2011 Q4	Wind	PENELEC
P34	Washington Landfill	6	6.4	In-Service	2009 Q1	Biomass	APS
P47	Mansfield-S. Troy 115kV	100	20	In-Service	2009 Q4	Wind	PENELEC
P60	New Baltimore 115kV (Stony Creek)	53	10.5	In-Service	2010 Q1	Wind	PENELEC
Q18	Moser 34.5kV	5	5	In-Service	2007 Q4	Methane	PECO
Q20	Holtwood	249	140	Under Construction	2013 Q3	Hydro	PPL
Q25	Donegal-Iron City 138kV	80	16	Under Construction	2013 Q1	Wind	APS
Q27	Frackville-Shennandoah 69kV	100	20	In-Service	2009 Q2	Wind	PPL
Q28	Eldred-Frackville 230kV	170	34	Suspended	2011 Q3	Wind	PPL
Q34	Garrett 115kV	100	20	Under Construction	2011 Q2	Wind	PENELEC
Q36	Philipsburg - Tyrone North 115kV	50	10	Under Construction	2010 Q4	Wind	PENELEC
Q44	Elizabethtown	0	0	In-Service	2006 Q3	Natural Gas	PECO
Q45	North Lebanon 13.2kV	3	3.2	In-Service	2007 Q3	Methane	ME
Q46	Curwensville 34.5 kV	10	10	Under Construction	2009 Q1	Coal	PENELEC
Q47	Peach Bottom	2532	140	Under Construction	2013 Q2	Nuclear	PECO
Q53	Summit-West Fall 115kV	38	7.6	Under Construction	2010 Q4	Wind	PENELEC
Q59	S. Reading-Birdsboro 64kV	6	6.4	In-Service	2008 Q2	Biomass	ME
Q63	Seneca 230kV	16	16	Active	2008 Q1	Hydro	PENELEC
Q73	South Reading 69kV	30	16	In-Service	2008 Q4	Biomass	ME
R01	Susquehanna	800	800	Active	2013 Q1	Nuclear	PPL
R02	Susquehanna	800	800	Active	2013 Q1	Nuclear	PPL
R32	Salix - Claysburg 115kV	75	15	Active	2009 Q4	Wind	PENELEC
R40	Rockwood - Meyersdale 115kV	38	0.36	Under Construction	2008 Q2	Wind	PENELEC
R43	Frackville - Hauto #3	20	4	Under Construction	2012 Q2	Wind	PPL
R57	South Reading 69kV	30	9	In-Service	2008 Q4	Biomass	ME
R81	Emilie 230kV	1195	101	In-Service	2010 Q1	Natural Gas	PECO
R92	DuBois 115kV	70	14	Active	2009 Q2	Wind	PENELEC
S05	Seneca #2 230kV	16	16	Active	2008 Q1	Hydro	PENELEC
S103	Warren 115kV	57	57	Active	2008 Q2	Natural Gas	PENELEC
S20	Pine Grove-Fishbach 69kV	50	10	Suspended	2013 Q2	Wind	PPL
S29B	Somerset 23kV	6	5.7	Active	2009 Q2	Methane	PENELEC
S34	Handsome Lake Energy 345kV	270	20	In-Service	2007 Q2	Natural Gas	PENELEC
S40	Hegins	11	10.5	In-Service	2009 Q1	Methane	PPL
S41	Eldred-Reed 69kV	13	12.5	Suspended	2010 Q2	Biomass	PPL
S42	Eldred-Fairview	18	3.6	Suspended	2010 Q2	Wind	PPL
S49	Bedford 115kV	203	18	Active	2009 Q4	Wind	PENELEC
S64	York Inc. 115kV	18	18	Active	2011 Q1	Biomass	ME
T102	Sunbury 69kV	160	10	In-Service	2007 Q4	Coal	PPL
T103	Sunbury 69kV	160	10	In-Service	2007 Q4	Coal	PPL
T108	Archbald 69kV	9	9.2	In-Service	2010 Q1	Methane	PPL
T109	Keystone 500kV	918	20	Active	2009 Q2	Coal	PENELEC
T110	Keystone 500kV	916	20	Active	2009 Q4	Coal	PENELEC
T117	Hunlock Creek 69kV	126	126	Under Construction	2012 Q2	Natural Gas	UGI
T118	Linwood 230kV	840	10	Under Construction	2010 Q2	Natural Gas	PECO
T121	Potter 115kV	75	15	Active	2009 Q4	Wind	PENELEC
T129	Printz 230kV	541	20	Under Construction	2010 Q2	Natural Gas	PECO
T155	Belknap 25kV	6	6	Active	2010 Q2	Hydro	APS
T156	Champion	292	20	Active	2011 Q1	Coal	APS
T174	Yukon-Browns Run 500kV	930	900	Active	2011 Q2	Natural Gas	APS
T182	TMI 230kV	845	24	Active	2008 Q1	Nuclear	ME
T20	Falls	3	3	In-Service	2008 Q4	Solar	PECO
T39	Coudersport 46kV	18	3.6	Active	2011 Q1	Wind	APS

Status of Pennsylvania's Plant Additions and Upgrades

Queue	PJM Substation	MW	MWC	Status	In Service	Fuel	Transmission Owner
T49	Steel City	1134	42	In-Service	2009 Q2	Natural Gas	PPL
T85	Roxbury-Blain 23kV	6	6	Under Construction	2008 Q4	Methane	PENELEC
T86	Bradford 34.5kV	2	1.5	Under Construction	2008 Q3	Methane	PENELEC
U1-010	Peach Bottom	575	18	Under Construction	2011 Q3	Natural Gas	PECO
U1-051	Clearfield	130	16.9	Active	2011 Q4	Wind	PENELEC
U1-067	Honey Brook	3	1.6	Under Construction	2009 Q4	Methane	PPL
U1-068	York 115kV	51	10	Active	2008 Q2	Natural Gas	ME
U1-089	Paper Tap 69kV	20	20	In-Service	2008 Q4	Other	PECO
U2-015	Harwood-E. Palmerton 230kV	100	13	Active	2010 Q4	Wind	PPL
U2-016	Grover 230kV	85	11.05	Active	2011 Q4	Wind	PENELEC
U2-029	Passyunk	1	0	Active	2015 Q4	Solar	PECO
U2-054	Weissport	3	2.6	Under Construction	2011 Q3	Hydro	PPL
U2-055	Karthaus-Milesburg 230kV	89	11.5	Active	2012 Q3	Wind	APS
U2-063	Croydon 230kV	391	5	Under Construction	2008 Q3	Natural Gas	PECO
U2-067	Eldred-Pine Grove 69kV	33	2.5	Under Construction	2008 Q3	Other	PPL
U2-069	Frackville	56	7.3	Under Construction	2014 Q2	Wind	PPL
U2-073	Frostburg 138kV II	200	26	Active	2010 Q4	Wind	APS
U2-074	Peach Bottom-Rock Springs 500kV	650	650	Active	2012 Q4	Natural Gas	PECO
U2-076	Falls	10	10	Suspended	2011 Q1	Methane	PECO
U3-001	Barbadoes 34kV	1	0	In-Service	2008 Q3	Other	PECO
U3-008	Mt. Bethel 230kV	200	200	Active	2012 Q1	Oil	ME
U3-009	Mt. Bethel 230kV	595	595	Active	2014 Q1	Oil	ME
U3-029	Beaver Valley #1	950	37	Active	2013 Q4	Nuclear	DL
U3-030	Beaver Valley #2	951	38	Active	2012 Q4	Nuclear	DL
U4-014	Siegfried-Hauto 69kV	10	3.8	Active	2009 Q2	Solar	PPL
U4-040	Lincoln 13.2kV	2	2	Under Construction	2011 Q1	Natural Gas	ME
U4-041	Valley 13.2kV	2	2	Under Construction	2011 Q1	Diesel	ME
U4-042	Hanover 13.2kV	2	2	Under Construction	2011 Q1	Diesel	ME
U4-043	Tolna 13.2kV	2	2	Under Construction	2011 Q1	Diesel	ME
U4-044	Stoverstown 13.2kV	2	2	Under Construction	2011 Q1	Diesel	ME
U4-045	Oil Creek 34.kV	2	2	Under Construction	2011 Q1	Diesel	PENELEC
U4-046	Teepleville 34.5kV	2	2	Under Construction	2011 Q1	Diesel	PENELEC
U4-047	Mill Village 34.5kV	2	2	Under Construction	2011 Q1	Diesel	PENELEC
U4-048	Saegertown 34.5kV	2	2	Under Construction	2011 Q1	Diesel	PENELEC
V1-026	Limerick	1213	20	Active	2010 Q4	Nuclear	PECO
V1-027	Limerick	1213	20	Active	2011 Q2	Nuclear	PECO
V1-028	North Wales	10	2	Under Construction	2009 Q2	Diesel	PECO
V2-019	Mansfield-S. Troy 115kV	101	0	Active	2009 Q4	Wind	PENELEC
V2-027	South Milton	2	1.62	Under Construction	2011 Q1	Methane	PPL
V3-004	Siegfried	83	83	Active	2012 Q4	Coal	PPL
V3-006	Linglestown	1	0.38	Active	2009 Q4	Solar	PPL
V3-018	Towanda 115kV	75	9.75	Active	2012 Q4	Wind	PENELEC
V3-019	Edinboro 13.8kV	2	2	Active	2011 Q1	Natural Gas	PENELEC
V3-030	St. Benedict-Patton 46kV	32	4	Active	2012 Q4	Wind	PENELEC
V3-031	Germantown	20	7.6	Active	2010 Q4	Solar	ME
V3-040	Siegfried-Hauto 69kV	10	3.8	Active	2011 Q2	Solar	PPL
V3-041	Daleville	4	4	Active	2010 Q1	Methane	PECO
V3-042	Thompson 115kV	84	10.9	Active	2012 Q4	Wind	PENELEC
V3-044	Glendon 34.5kV	5	4.8	Active	2010 Q3	Methane	ME
V3-051	Letort	3	0.4	Active	2010 Q4	Wind	PPL
V3-057	Ironwood 230kV	20	0	Active	2011 Q1	Other	ME
V3-062	McConnellsburg-Guilford 138kV	20	7.6	Active	2011 Q4	Solar	APS
V4-002	Graceton 230kV	575	575	Active	2014 Q3	Natural Gas	PECO

Status of Pennsylvania's Plant Additions and Upgrades

Queue	PJM Substation	MW	MWC	Status	In Service	Fuel	Transmission Owner
V4-012	Morgantown	5	4.8	Active	2010 Q4	Methane	PPL
V4-014	Greenridge Landfill	7	0	Active	2010 Q4	Methane	APS
V4-020	North Temple 230kV	650	650	Active	2014 Q2	Natural Gas	ME
V4-027	Quarryville	5	1.9	Active	2010 Q4	Solar	DPL
V4-045	Peach Bottom	320	320	Active	2015 Q4	Nuclear	PECO
V4-052	West Reading	6	6	Active	2011 Q1	Natural Gas	ME
V4-072	Blue Ridge Landfill	13	12.8	Active	2011 Q1	Methane	APS
V4-075	Warwick 12kV	2	0.76	Active	2010 Q4	Solar	PPL
V4-076	Carlisle Pike 23kV	5	2	Active	2011 Q2	Solar	PENELEC
V4-077	Montgomery Avenue 12.47kV	13	4.9	Active	2011 Q3	Solar	PENELEC
W1-010	Cooper	20	7.6	Active	2011 Q4	Solar	PECO
W1-012	Millheim-Brush Jct 46kV	50	6.5	Active	2013 Q4	Wind	APS
W1-013	Saint Thomas 34kV I	20	7.6	Active	2011 Q3	Solar	APS
W1-014	Saint Thomas 34kV II	20	7.6	Active	2011 Q3	Solar	APS
W1-015	Shade Gap 115kV	70	9.1	Active	2013 Q4	Wind	PENELEC
W1-042	Hubar Road 1	20	7.6	Active	2011 Q3	Solar	APS
W1-043	Hubar Road 2	20	7.6	Active	2011 Q3	Solar	APS
W1-044	Mont Alto	20	7.6	Active	2011 Q3	Solar	APS
W1-045	Roxbury 34.5kV	20	7.6	Active	2011 Q3	Solar	ME
W1-046	Face Rock 69kV	15	5.7	Active	2011 Q2	Solar	PPL
W1-050	Keller & Valle Camp Roads I	20	7.6	Active	2011 Q4	Solar	APS
W1-051	St. Thomas 34kV III	130	49.4	Active	2012 Q3	Solar	APS
W1-052	Keller & Valley Camp Roads II	20	7.6	Active	2011 Q4	Solar	APS

MW - Maximum facility output after interconnection request
MWC - Capacity interconnection request for the queue position (summer net)

Source: PJM.com (as of March 12, 2010)

Generation Deactivations in Pennsylvania

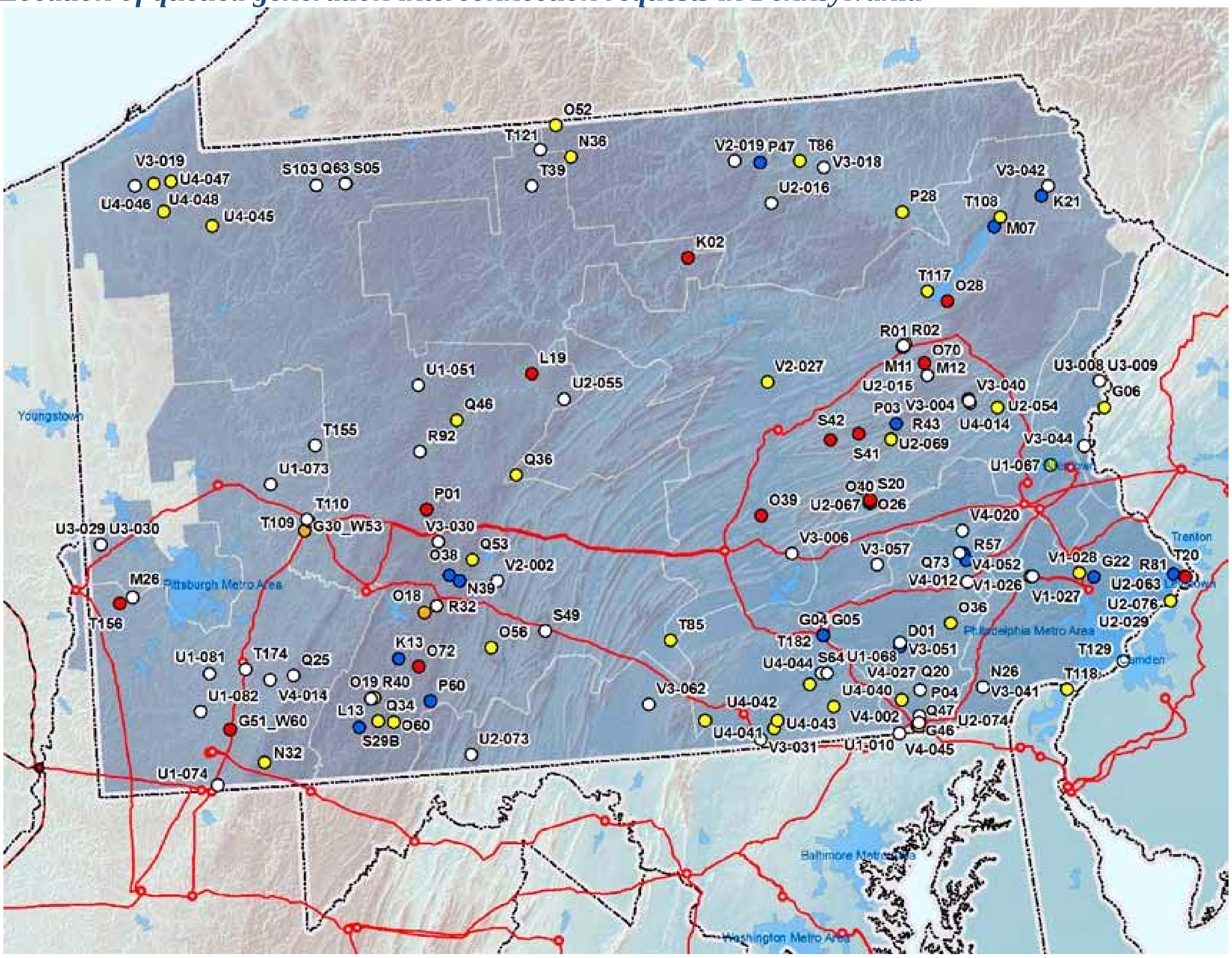
Unit	Capacity (MW)	Transmission Zone	Age (Years)	Requested Deactivation Date	Projected Deactivation Date	Status
Hunlock 3	45	UGI	48	Jun-10	Jun-10	No reliability issues
Cromby 1	144	PE	55	May-11	May-11	Reliability impacts identified
Cromby 2	201	PE	54	May-11	May-12	Reliability impacts identified
Eddystone 1	279	PE	49	May-11	May-11	Reliability impacts identified
Eddystone 2	309	PE	49	May-11	Dec-13	Reliability impacts identified

Source: PJM.com (as of March 16, 2010)

Note 1: The NRC has approved a 20-year extension of the operating license for both reactors at PPL's Susquehanna nuclear power plant in Luzerne County. The license for unit 1 has been extended to 2042; the license for Unit 2 has been extended to 2044. Unit 2 ended a PPL record of 723 days of continuous generation when it shut down for refueling and maintenance in April 2009. The combined facility output is 2,465 MW. PPL owns 90 percent.

Note 2: PJM has notified Exelon that with the completion of scheduled transmission system upgrades, Cromby Unit 1 and Eddystone Unit 1 will not be needed for reliability and can be deactivated on the proposed date of May 31, 2011. The retirement of Cromby Unit 2 and Eddystone Unit 2 could, however, result in reliability impacts. Although they are no longer economical to operate, Exelon plans to continue operating the units beyond their deactivation dates, during the completion of additional transmission system upgrades.

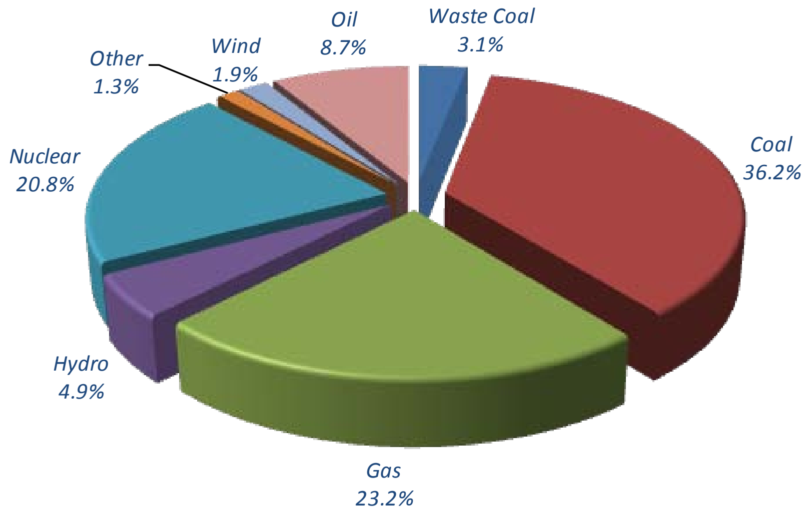
Location of queued generation interconnection requests in Pennsylvania



Source: PJM 2009 Regional Transmission Expansion Plan

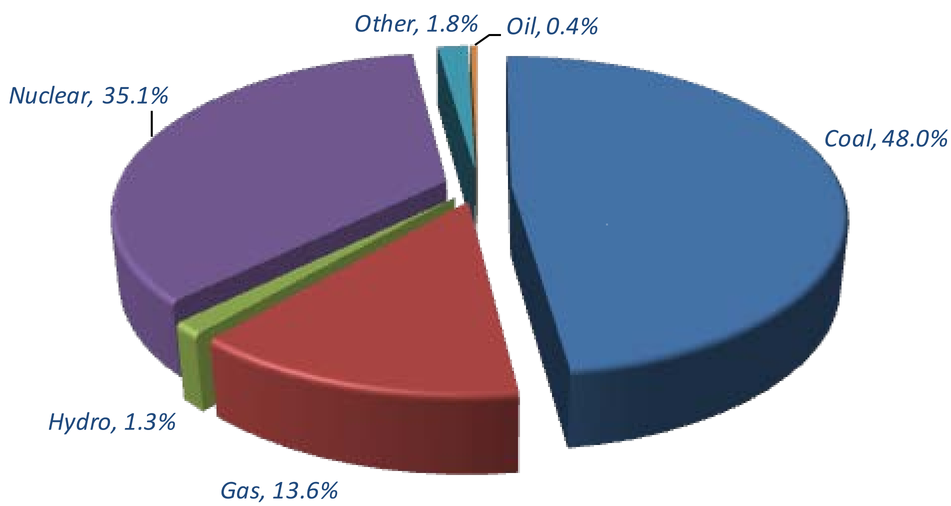
The following represents the most recently available data on existing generating facilities located in Pennsylvania. Below is a summary of generating capacity by fuel type, and the distribution of electric generation by fuel type for 2009.

Existing generating capacity in Pennsylvania



Source: Electric Power Generation Association

2009 generation in Pennsylvania



Source: Energy Information Administration

Pennsylvania's Existing Electric Generating Facilities

Company Name	Plant Name	Fuel Type	Alternate Fuel Type	Technical Type	MW
A/C Power-Colver Operations	Colver Power Project	Waste Coal		ST-S	102.00
AES Corporation*	Beaver Valley	Coal		ST	125.00
AES Corporation*	AES Ironwood LLC	Gas		CC	710.00
AES Wind Generation*	Armenia Mountain	Wind		WTG	100.50
Allegheny Electric Cooperative*	William F Matson Hydroelectric Plant	Water		HY	21.70
Allegheny Electric Cooperative*	PPL Susquehanna Power Plant	Nuclear		ST	245.50
Allegheny Energy Supply*	Allegheny Lock & Dam 5 & 6	Water		HY	13.00
Allegheny Energy Supply*	Armstrong Generating Station	Coal		ST	356.00
Allegheny Energy Supply*	Chambersburg Gen. Facility, AE Units 12 & 13	Gas		SC	88.00
Allegheny Energy Supply*	Gans Gen. Facility, AE Units 8 & 9	Gas		GT	88.00
Allegheny Energy Supply*	Hatfield's Ferry Power Station	Coal		ST	1710.00
Allegheny Energy Supply*	Hunlock Creek Power Station	Gas		GT	44.00
Allegheny Energy Supply*	Lake Lynn Hydroelectric Project	Water		HY	52.00
Allegheny Energy Supply*	Mitchell Generating Station	Coal	Oil	ST	370.00
Allegheny Energy Supply*	Springdale, Units 1,2,3,4 & 5	Gas		CC/GT	628.00
American Consumer Industries Inc (ACI)	Colmac Clarion Inc	Waste Coal		ST	32.00
Babcock & Brown Wind Partners	Allegheny Ridge Wind Farm	Wind		WTG	80.00
Babcock & Brown Wind Partners	Bear Creek	Wind		WTG	24.00
Bio-Energy Partners	Lake View Landfill	Other		IC	6.10
Brookfield Renewable Power, Inc.	Piney Dam (PA) Hydroelectric Plant	Water		HY	28.80
Chambersburg Borough Electric Dept	Chambersburg Power Plant	Gas	Oil	IC	30.47
Cogentrix*	Northhampton Generating Station	Waste Coal		ST-S	112.00
Cogentrix*	Scrubgrass Generating Plant	Waste Coal		ST	85.00
Community Energy, Inc.*	Locust Ridge Wind Farm	Wind		WTG	128.00
Conectiv Energy*	Bethlehem Commerce Plant	Gas		CC	1092.00
Consolidated Rail Corporation	Juniata Locomotive Shop	Coal		ST-H	10.00
Constellation Generation Group*	Colver Power Plant	Waste Coal		ST-S	26.00
Constellation Generation Group*	Conemaugh Power Plant	Coal		IC/ST	179.00
Constellation Generation Group*	Keystone Generating Station (20.99%)	Coal		ST	357.00
Constellation Generation Group*	Keystone Peaking Plant (20.99%)	Oil		IC/Diesel	2.00
Constellation Generation Group*	Safe Harbor Hydroelectric Plant (66 2/3%)	Water		HY	277.00
Constellation Power Inc*	Handsome Lake Plant	Gas		SC	267.00
Constellation Power Inc.*	Panther Creek Energy Facility (50.00%)	Waste Coal		ST-S	40.00
Corona Power LLC	Sunbury Generating Station	Coal	Oil	ST/GT/IC	462.50
Covanta Energy Corporation	Covanta Plymouth Renewable Energy LP	Other		ST	32.13
Covanta Energy Corporation	Delaware Valley Resource Recovery Facility	Other		ST-S	90.00
Covanta Energy Corporation	Lancaster County Resource Recovery Facility	Other		ST	35.70
Covanta Energy Corporation	York County Resource Recovery Plant	Other		ST	36.50
Covanta Energy for Harrisburg Authority	Harrisburg WTE Plant	Other	Gas	ST-S	24.10
Dominion Generation	Fairless Energy	Gas		CC	1200.00
Duke Energy	North Allegheny Wind Farm	Wind		WTG	70.00
Duke Energy Wholesale Power Generation	Fayette County Energy Facility	Gas		CC	677.00
Duquesne Conemaugh LLC	Conemaugh Power Plant (3.83%)	Coal		IC/ST	65.60
Duquesne Keystone LLC	Keystone Generating Station (2.47%)	Gas	Oil	IC/ST	42.30
Dynegy Midwest Generation	Ontelaunee Energy Center	Gas		CCGT	545.00
E.On Climate and Renewables	Stony Creek Wind Farm	Wind		WTG	52.50
Ebensburg Power Co.	Ebensburg Power Co	Coal		ST-S	48.50
Edison Mission Group	Forward Wind Farm	Wind		WTG	29.40
Edison Mission Group	Lookout Windpower Wind Farm	Wind		WTG	37.80
EverPower Renewables	Highland Wind Project	Wind		WTG	62.50
Exelon Nuclear*	Limerick Nuclear Gen. Station, Units 1 & 2	Nuclear		ST-BWR	2293.00
Exelon Nuclear*	Three Mile Island	Nuclear		ST-PWR	837.00
Exelon Nuclear*	Peach Bottom Atomic Power St., Units 2 & 3 (50%)	Nuclear		ST-BWR	1145.00
Exelon Power Generation Co. LLC*	Chester Peaking Plant	Oil		GT	39.00
Exelon Power Generation Co. LLC*	Conemaugh (20.72%)	Coal		ST	352.00
Exelon Power Generation Co. LLC*	Conemaugh Peaking Plant	Oil		IC/Diesel	2.00
Exelon Power Generation Co. LLC*	Cromby Generating Station 1	Coal		ST	144.00
Exelon Power Generation Co. LLC*	Cromby Generating Station 2	Oil	Natural Gas	ST	201.00
Exelon Power Generation Co. LLC*	Cromby Peaking Plant (20.72%)	Oil		IC/Diesel	3.00
Exelon Power Generation Co. LLC*	Croydon Peaking Plant	Oil		GT	391.00

Pennsylvania's Existing Electric Generating Facilities

Company Name	Plant Name	Fuel Type	Alternate Fuel Type	Technical Type	MW
Exelon Power Generation Co. LLC*	Delaware Peaking Plant	Oil		GT	56.00
Exelon Power Generation Co. LLC*	Delaware Peaking Plant	Oil		IC/Diesel	3.00
Exelon Power Generation Co. LLC*	Eddystone Generating Station 1 & 2	Coal		ST	588.00
Exelon Power Generation Co. LLC*	Eddystone Generating Station 3 & 4	Oil	Natural Gas	ST	760.00
Exelon Power Generation Co. LLC*	Exelon-Conergy Solar Energy Center	Other		PV	3.00
Exelon Power Generation Co. LLC*	Fairless Hills Generating	Other		ST-S	60.00
Exelon Power Generation Co. LLC*	Falls Twp Peaking Station	Oil		GT	51.00
Exelon Power Generation Co. LLC*	Keystone Gen. Station (20.99%)	Coal		ST	357.00
Exelon Power Generation Co. LLC*	Keystone Peaking Plant (20.99%)	Oil		IC/Diesel	2.00
Exelon Power Generation Co. LLC*	Moser Peaking Station	Oil		GT	51.00
Exelon Power Generation Co. LLC*	Muddy Run HydroElectric Plant	Water		HY	1070.00
Exelon Power Generation Co. LLC*	Pennsbury Peaking Station	Other		GT	51.00
Exelon Power Generation Co. LLC*	Richmond Peaking Station	Oil		GT	96.00
Exelon Power Generation Co. LLC*	Schuylkill Generating Station	Oil		GT-S	166.00
Exelon Power Generation Co. LLC*	Schuylkill Peaking Station	Oil		GT	30.00
Exelon Power Generation Co. LLC*	Schuylkill Peaking Station	Oil		IC/Diesel	3.00
Exelon Power Generation Co. LLC*	Southwark Peaking Station	Oil		GT	52.00
FirstEnergy Generation Corp.*	Bruce Mansfield Plant	Coal		ST	2490.00
FirstEnergy Generation Corp.*	Seneca Pumped Storage Plant	Water		HY	451.00
FirstEnergy Generation Corp.*	York Haven	Water		HY	19.00
FirstEnergy Nuclear Operating Co.*	Beaver Valley Power Station	Nuclear		ST-PWR	1815.00
Gamesa	Locust Ridge II	Wind		WTG	102.00
Gas Recovery Services, Inc.	Modern Landfill (PA) Production Plant	Other		GT	9.00
GDF Suez Energy Generation NA, Inc.*	NEPCO-Northeastern Power Co.	Waste Coal		ST	59.00
GDF Suez Energy Generation NA, Inc.*	Northumberland Cogeneration Facility	Other	NG	GT	18.00
General Electric Co.	Erie Works Plant	Coal		ST	36.00
General Electric Co.	Grove City Plant	Oil		GT	10.60
Gilberton Power Co*.	John B Rich Memorial Power Station	Waste Coal		ST-S	80.00
Iberdrola Renewables	Casselman Wind Project	Wind		WTG	34.50
Indiana University of Pennsylvania*	SW Jack Cogeneration Plant	Gas	Oil	IC-H	24.40
Ingenco	Mountain View Landfill	Other	Oil	IC	16.00
Integrys Energy Services, Inc.*	WPS Westwood Generation	Waste Coal		ST	30.00
International Power America, Inc. (ANP)*	Armstrong Energy LLC	Gas		GT	625.00
Kimberly Clark Corp	Chester Cogeneration Plant	Coal	Coke	ST-S	60.00
Koppers, Inc.	Koppers Montgomery Cogeneration Plant	Other		ST-S	10.00
Liberty Electric Power LLC	Liberty Electric Power LLC	Gas		CC	610.00
Merck & Co., Inc.	West Point (PA) Merck Plant	Gas		GT/ST	30.25
Midwest Generation LLC	Homer City (EME) Generation	Coal		ST	1884.00
Morris Energy Group LLC (MEG)	York Solar Plant	Other	Gas	CC	52.20
Mount Carmel Cogeneration, Inc.	Mount Carmel Cogeneration, Inc.	Waste Coal		ST-S	46.50
NAES Corp	North East Cogeneration Plant	Gas		CC	81.80
NextEra Energy Resources (formerly FPL)*	Marcus Hook Cogen Power Plant	Other		GT-S	50.00
NextEra Energy Resources (formerly FPL)*	Marcus Hook Cogeneration Plant	Gas		CC	744.00
NextEra Energy Resources (formerly FPL)*	Green Mountain Wind Energy Center	Wind		WTG	10.40
NextEra Energy Resources (formerly FPL)*	Meyersdale Wind Power Project	Wind		WTG	30.00
NextEra Energy Resources (formerly FPL)*	Mill Run Wind	Wind		WTG	15.00
NextEra Energy Resources (formerly FPL)*	Somerset Wind Farm	Wind		WTG	9.00
NextEra Energy Resources (formerly FPL)*	Waymart Wind Farm	Wind		WTG	64.50
Noble Environmental Power	Locust Ridge Wind Farm	Wind		WTG	26.00
Northern Star Generation Services Co.	Cambria County Cogen	Waste Coal		ST-S	98.00
NRG Energy - Conemaugh Power LLC	Conemaugh Power Plant	Coal	Oil	IC/ST	65.00
NRG Energy - Keystone Power LLC	Keystone Generating Station (3.70%)	Coal	Oil	IC/ST	65.00
NRG Thermal, LLC*	NRG Energy Paxton LLC	Gas	Oil	ST-S	10.00
PEI Power Corp.	Archbald Cogenereation Power Station	Other		GT/ST	25.00
PEI Power Corp.	Archbald PEI II LLC Archbald	Gas		CT	50.00
Pennsylvania Renewable Resources Assoc.	Conemaugh Saltsburg	Water		HY	15.00
Pennsylvania Wind Energy	Humboldt Industrial Park	Wind		WTG	0.13
PH Glatfelter Co.	Spring Grove Glatfelter Cogeneration Plant	Coal		ST-S	67.25
Power Systems Operations	Ebensburg Power Co	Waste Coal		ST-S	48.50
PPL Corp.*	Lebanon County Landfill (2007)	Other		IC	3.20

Pennsylvania's Existing Electric Generating Facilities

Company Name	Plant Name	Fuel Type	Alternate Fuel Type	Technical Type	MW
PPL Montour LLC*	Conemaugh Power Plant (16.25%)	Coal	Oil	IC/ST	278.00
PPL Generation LLC*	Allentown Generating Station	Oil		CT	64.00
PPL Generation LLC*	Fishbach Generating Station	Oil		CT	37.20
PPL Generation LLC*	Harrisburg Generating Station	Oil		CT	64.00
PPL Generation LLC*	Harwood (PA) Generation Station	Oil		CT	32.00
PPL Generation LLC*	Jenkins Generating Station	Oil	Coke	CT	32.00
PPL Generation LLC*	Keystone Steam Electric Station (12.34%)	Coal		CT	211.00
PPL Generation LLC*	Lock Haven Generating Station	Oil		CT	18.60
PPL Generation LLC*	Lower Mt. Bethel Energy LLC	Gas		CC	623.00
PPL Generation LLC*	PPL Brunner Island	Coal		ST	1483.00
PPL Generation LLC*	PPL Holtwood, LLC	Water		HY	108.00
PPL Generation LLC*	PPL Martins Creek	Oil	Natural Gas	GT/ST	1664.00
PPL Generation LLC*	PPL Montour LLC	Coal		ST	1552.00
PPL Generation LLC*	PPL Susquehanna LLC	Nuclear		ST	2218.50
PPL Generation LLC*	PPL Wallenpaupack LLC	Water		HY	44.00
PPL Generation LLC* (PPL Holtwood LLC)	Safe Harbor Hydroelectric Plant (33 1/3%)	Water		HY	140.50
PPL Generation LLC*	Suburban Generation Station c/o Martins Creek	Oil		CT	29.00
PPL Generation LLC*	West Shore Generating Station	Oil		CT	37.20
PPL Generation LLC*	Williamsport Generating Station	Oil		CT	32.00
Procter & Gamble	Mehoopany Plant	Gas		GT-S	53.00
PSEG Power	Peach Bottom Atomic Power St., Units 2&3 (50%)	Nuclear		ST-BWR	1145.00
PSEG Power	Keystone Generating Station (22.84%)	Gas	Oil	IC/ST	391.00
PSEG Power	Conemaugh Power Plant (22.50%)	Gas	Oil	IC/ST	385.00
Rohm and Haas Co.	Bristol	Oil		ST	1.50
RRI Energy, Inc.*	Blossburg Plant (Mothball Pending)	Gas		CT	19.00
RRI Energy, Inc.*	Brunot Island Generating Station	Gas	Oil	CC/GT	289.00
RRI Energy, Inc.*	Cheswick Generating Station	Coal	Diesel	ST	560.00
RRI Energy, Inc.*	Conemaugh Power Plant (16.45%)	Coal	Oil	IC/ST	281.00
RRI Energy, Inc.*	Elrama Generating Station	Coal		ST	460.00
RRI Energy, Inc.*	Hamilton Generating Station	Oil		CT	20.00
RRI Energy, Inc.*	Hunterstown Generating Station	Gas	Diesel	CC	870.00
RRI Energy, Inc.*	Keystone Generating Station (16.67%)	Coal	Oil	IC/ST	284.00
RRI Energy, Inc.*	Mountain Generating Station	Gas	Oil	GT	40.00
RRI Energy, Inc.*	New Castle Generating Station	Coal	Oil	ST/IC	333.00
RRI Energy, Inc.*	Orrtanna Generating Station	Oil		GT	20.00
RRI Energy, Inc.*	Portland Generating Station	Coal	Gas	GT/ST	570.00
RRI Energy, Inc.*	Seward Generating Station	Waste Coal		ST	525.00
RRI Energy, Inc.*	Shawnee Generating Station	Oil		GT	20.00
RRI Energy, Inc.*	Shawville Generating Station	Coal	Oil	ST	603.00
RRI Energy, Inc.*	Titus Generating Station	Coal	Gas	ST/GT	274.00
RRI Energy, Inc.*	Tolna Station	Oil		GT	39.00
RRI Energy, Inc.*	Warren Generating Station	Gas	Oil	GT	68.00
Schuylkill Energy Resources	St Nicholas Cogeneration Plant	Waste Coal		ST-S	100.00
Sithe Energies Inc.	Allegheny Lock & Dam No. 8	Water		HY	13.00
Sithe Energies Inc.	Allegheny Lock & Dam No. 9	Water		HY	17.40
Smurfit-Stone Container Corp.	Philadelphia Container Plant	Oil		ST-S	10.00
Solar Turbines Inc.	York Solar Plant	Gas		CC	70.00
Sunoco, Inc.	Philadelphia Refinery Power Plant	Other		ST-S	30.00
Temple University	Temple Univ. Standby Electric Gen. Facility	Gas		IC-H	16.00
UGI Energy Services Inc.*	Conemaugh Generation Station (5.97%)	Coal		ST	102.00
United States Steel Corp. (US Steel)	Clairton USX B Plant	Gas		ST	219.75
Veolia Energy North America, Inc.	Grays Ferry Power Plant	Gas		CC	174.60
Weyerhaeuser Co (WEYCO)	Bradford (PA) Plant	Coal	Liq	ST	52.00
Wheelabrator Technologies Inc. (WTI)	Wheelabrator Falls, Inc.	Other		ST	53.00
Wheelabrator Technologies Inc. (WTI)	Wheelabrator Frackville Energy Co.	Waste Coal		ST-S	48.00
WM Renewable Energy	Pottstown Plant	Other		GT	6.40
Total MW in PA					46568.48

*=verified data

Revised 6/10

Source: Electric Power Generation Association

Nuclear Power Plants in Pennsylvania

Net Generation and Capacity (2008)

Plant Name	Unit	Net Capacity (MW)	Net Generation (GWh)	Capacity Factor (%)	Operator/Owner
Beaver Valley	1	892	7,945	101	FirstEnergy Corp./FirstEnergy Nuclear Operating Company
Beaver Valley	2	846	6,726	92	
Total		**1,738**	**14,671**	**96**	
Limerick	1	1,134	9,345	94	Exelon Generation/Exelon Nuclear
Limerick	2	1,134	9,702	97	
Total		**2,268**	**19,047**	**96**	
Peach Bottom	2	1,112	8,717	89	Exelon Generation/Dual Ownership (1)
Peach Bottom	3	1,112	9,818	101	
Total		**2,224**	**18,535**	**95**	
Susquehanna	1	1,149	8,984	89	PPL Susquehanna, LLC/Dual Ownership (2)
Susquehanna	2	1,140	10,056	100	
Total		**2,289**	**19,040**	**95**	
Three Mile	1	786	7,365	107	Exelon Generation/Exelon Nuclear

(1) Plant Owners, Peach Bottom, both Units: Exelon Nuclear (50%) and PSEG Power (50%).

(2) Plant Owners, Susquehanna, both Units: PPL Susquehanna, LLC (90%) and Allegheny Electric Cooperative (10%)

Source: Form EIA-860, "Annual Electric Generator Report," and Form EIA-906, "Power Plant Report."