Electric Power Outlook for Pennsylvania 2010-15

July 2011

Pennsylvania Public Utility Commission

ELECTRIC POWER OUTLOOK FOR PENNSYLVANIA 2010–15

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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 foreseeable future.

Regional generation adequacy and reserve margins of the Mid-Atlantic will be satisfied through 2019, provided that planned generation and transmission projects will be forthcoming in a timely manner. Summer reserve margins are projected to range from 28 percent in 2010 to 25.8 percent in 2019.

In 2010, Pennsylvania retail sales increased 2.8 percent over the 2009 level, following a 4.2 percent decrease from 2008. The current average aggregate five-year projection of growth in energy demand is 0.9 percent per year. This includes a residential growth rate of 0.4 percent, a commercial rate of 1.2 percent and an industrial rate of 1.4 percent.

Over the past 15 years, the aggregate non-coincident peak load for the major EDCs increased at an average rate of 1.0 percent per year. The peak load is expected to increase at an average annual growth rate of 0.5 percent.

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

[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.
[5] Alternative Energy Portfolio Standards Act, effective Feb. 28, 2005; 73 P.S. §§ 1648.1—1648.8.

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.

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, and subsequently approved, with modifications.

[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 2010-15 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 that 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. 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 years to five 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 U.S. 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_2011.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 2006, the North American Electric Reliability Council (NERC), formerly operated as a voluntary organization, dependent on reciprocity and mutual self-interest, 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 334 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 entities. Members of these regional entities 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 entity operating in Pennsylvania is Reliability*First* Corporation, which is the successor organization to three former NERC Regional Reliability Councils: MAAC, ECAR and MAIN.

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 January 2011, NERC had 3,193 active violations, compared with 2006 the previous year. This increase is attributed to the implementation of NERC's critical infrastructure protection (CIP) standards. Compliance enforcement was greatly improved by focusing resources on risks deemed most significant to the reliability of the bulk power system. As of Nov. 19, 2010, NERC had 1,939 registered entities on the NERC Compliance Registry. 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]

[11] NERC, *2010 Annual Report*, May 2011.

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]

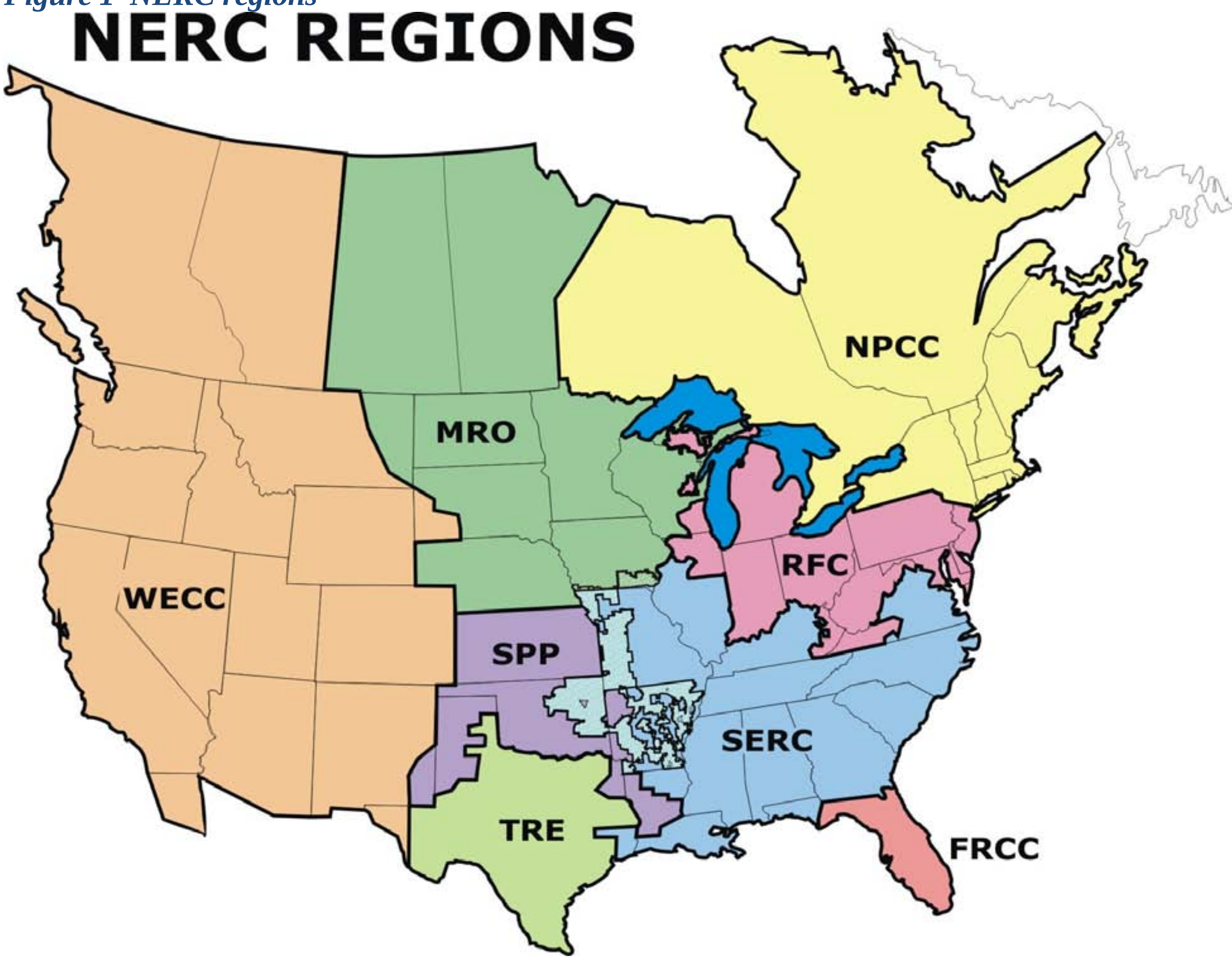
In an order issued Nov. 18, 2010, FERC directed NERC to revise the definition of the term "bulk electric system" through its Reliability Standards Development Process to address the FERC's policy and technical concerns and ensure that the definition encompasses all facilities necessary for operating an interconnected electric transmission network pursuant to Section 215 of the Federal Power Act. FERC believes the best way to accomplish these goals is to eliminate the regional discretion in the current definition, maintain a bright-line threshold that includes all facilities operated at or above 100 kV except defined radial facilities, and establish an exemption process and criteria for excluding facilities that are not necessary for operating the interconnected transmission network. However, FERC's Final Rule allowed NERC to develop an alternative proposal for addressing FERC's concerns with the present definition. Any such alternative must be as equally efficient and effective as FERC's suggested approach in addressing the identified technical and other concerns, and may not result in a reduction in reliability.[13] FERC noted 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.

NERC has requested public comments on a new procedure for facility-by-facility determinations of inclusions or exclusions to the bulk electric system not otherwise resolved through the application of the definition of "bulk electric system."

Figure 1 provides a map of the eight NERC Regional Entities.

[12] NERC, "Glossary of Terms Used in Reliability Standards."
[13] Docket No. RM09-18-000; Order No. 743.

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.*

FRCC

Florida Reliability Coordinating Council

MRO

Midwest Reliability Organization

NPCC

Northeast Power Coordinating Council Inc.

RFC

Reliability*First* Corporation

SERC

SERC Reliability Corporation

SPP

Southwest Power Pool Inc.

TRE

Texas Reliability Entity Inc.

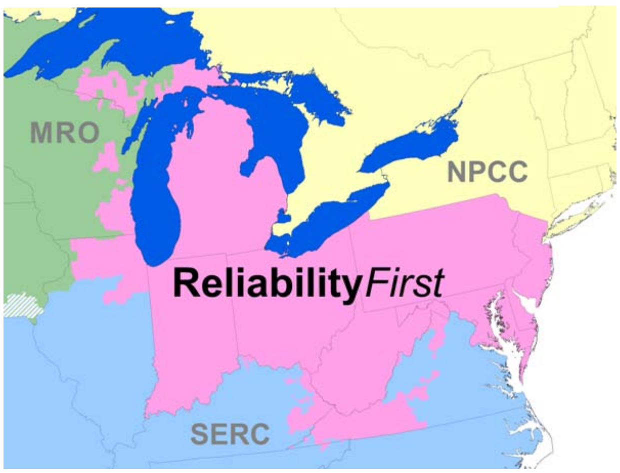
WECC

Western Electricity Coordinating Council

ReliabilityFirst Corporation

The regional reliability entity covering the state of 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 entities of NERC and serves the electrical requirements of more than 72 million people in a 238,000 square-mile area covering all of New Jersey, Delaware, Pennsylvania, Maryland, District of Columbia, West Virginia, Ohio, Indiana, Lower Michigan and portions of Upper Michigan, Wisconsin, Illinois, Kentucky, Tennessee and Virginia. 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 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.

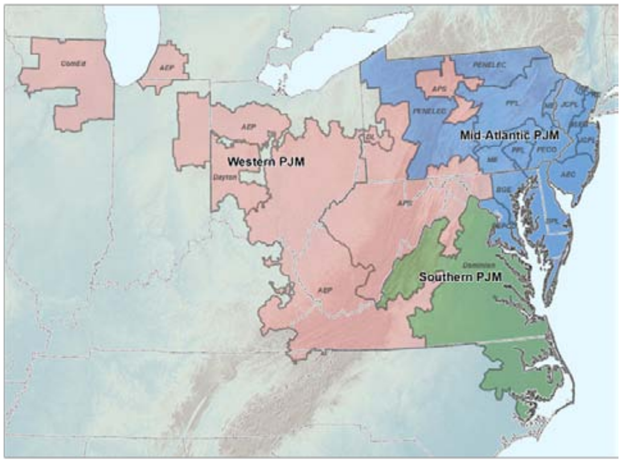
Regional Transmission Organizations

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, covering 168,500 square miles. PJM coordinates the operation of 167,362 MW of generating capacity and 56,750 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.

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) 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[14] 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, became 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.

[14] 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.

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 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. In 2010, PJM processed $34.8 billion in settlements among its 670 members, a 31 percent increase over 2009.[15] PJM's transmission usage in 2010 showed a 9 percent increase from 2009, rising to 745 million MWh.[16]

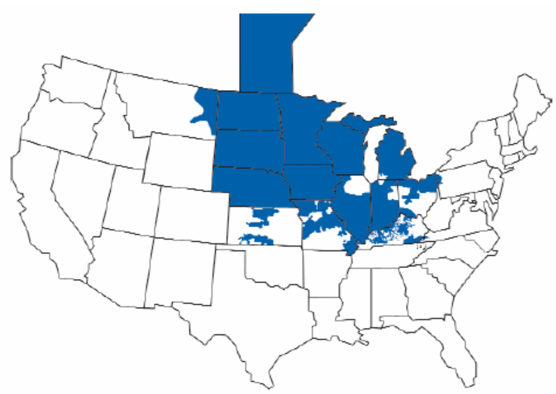
During 2010, PJM filed with FERC to create a new subsidiary to handle all of the credit, billing and settlement functions for PJM's members' transactions in the PJM markets and for transmission services. PJM received approval on Dec. 30, 2010, to begin operation of PJM Settlement Inc. on Jan. 1, 2011.

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



Midwest ISO Reliability Area

Utilities with 159,000 MW of generating capacity and 57,453 miles of transmission lines covering 750,000 square miles from Manitoba, Canada, to Kentucky have committed to participate in MISO. In 2010, gross market charges totaled $27.5 billion.[17]

[15] *PJM 2010 Financial Report.*
[16] *PJM 2010 Annual Report.*
[17] www.midwestiso.org.

As of June 2011, all FirstEnergy companies will be integrated into the PJM RTO. As indicated in *Section 3 – Regional Reliability*, both PJM and MISO analyses are used to determine the reliability of the RFC region. Although no Pennsylvania utility will remain within MISO, we will continue to provide information concerning both RTOs with regard to the RFC assessment of regional reliability.

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 (NIETC) under Section 1221 of the Energy Policy Act of 2005. The designation was to 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.[18] See Figure 5.

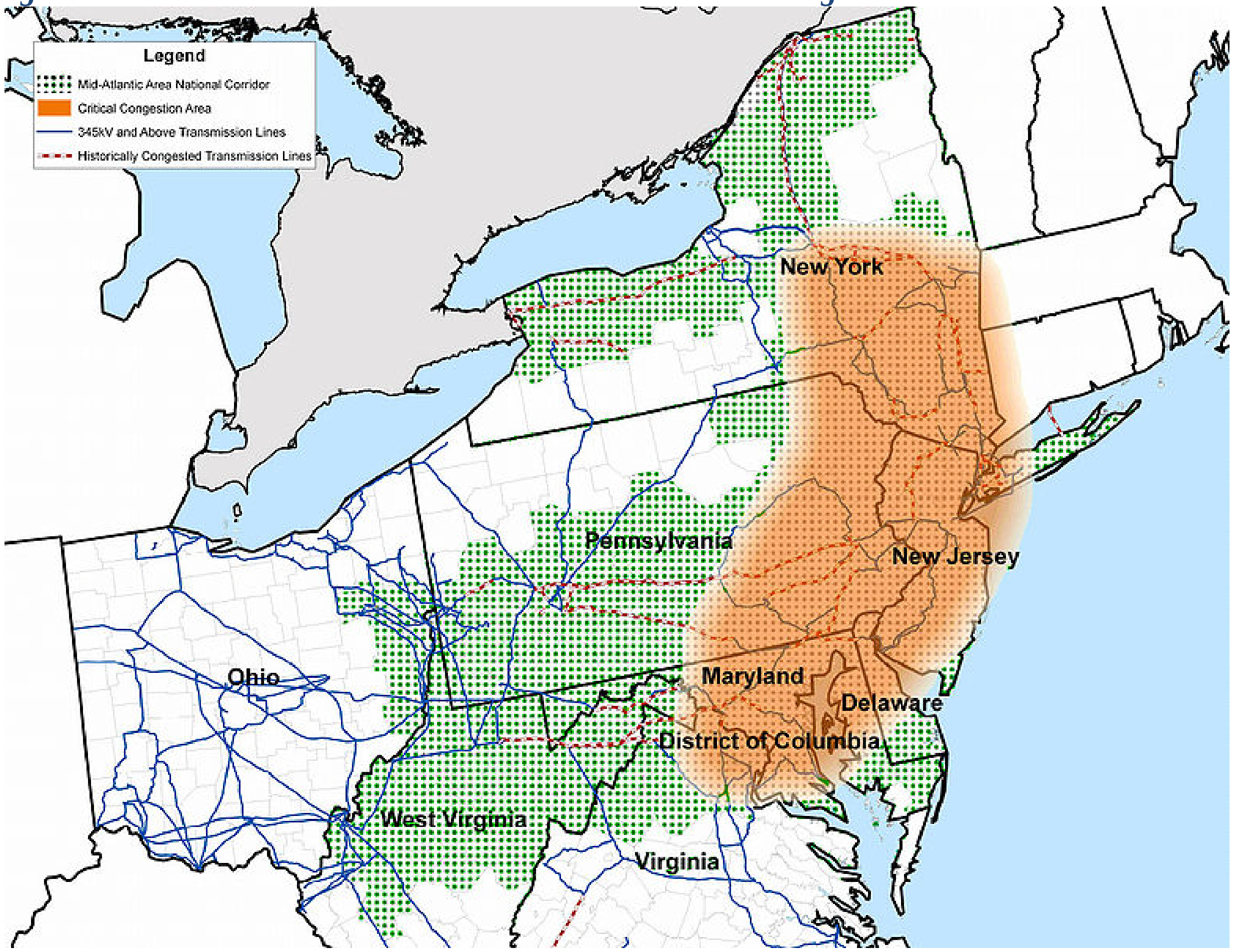
On April 27, 2010, DOE released its 2009 National Electric Transmission Congestion Study.[19] Congestion occurs on electric transmission facilities when actual or scheduled flows of electricity across a line or piece of equipment are restricted below desired levels. These restrictions may be imposed 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 that continues to experience high and costly levels of congestion that affect a significant portion of the nation's population, and should 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.

Several petitions for review were filed with the U.S. Court of Appeals for the Ninth District, offering three challenges to DOE's actions: (1) DOE failed to consult with the affected states; (2) DOE failed to properly consider the potential environmental consequences of its NIETC designations; and (3) DOE's corridor designations are arbitrary, capricious and not supported by the evidence. A Court Opinion, filed Feb. 1, 2011, vacated the DOE Congestion Study and the NIETC designation, and remanded the cases to DOE for further proceedings.

[18] 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 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).

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

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



On Jan. 28, 2010, the Commission issued a Tentative Order[20] 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 filed in March 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

[20] Docket No. M-2009-2141293; 40 Pa.B. 953.

and reliable interconnection of new generation and merchant transmission projects seeking interconnection within the PJM footprint. 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.

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 Mount Storm-Doubs 500-kV line.

In support of the TrAIL project, Trans-Allegheny Interstate Line Company (TrAILCo), an Allegheny Energy subsidiary, filed an application[21] 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. On Nov. 18, 2010, the Commission approved the Joint Petition for Settlement which maximizes the use of existing utility infrastructure with little impact on property owners near the site. The Settlement, which includes a series of interconnections of 138-kV transmission lines, is projected to resolve reliability concerns for Washington County for the next 10 years. The cost of the original Prexy Facilities was estimated to be $213 million. Under the settlement, the cost of these facilities was reduced to $11.6 million.[22]

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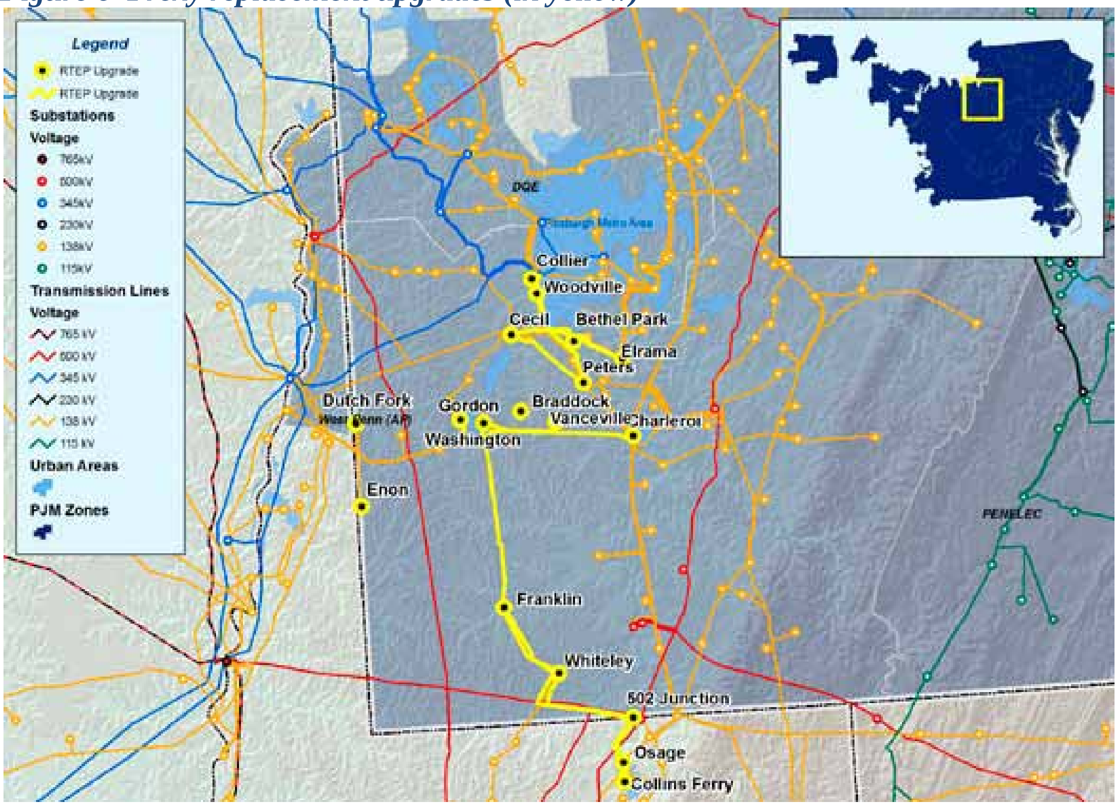
[21] Docket No. A-110172, *et al*.
[22] *PJM 2010 Regional Transmission Expansion Plan*.

The 2010 RTEP states that TrAIL project is expected to meet the required June 1, 2011, in-service date. 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. All TrAIL structures have been completed, and the conductors have been installed.

Figure 6 Prexy replacement upgrades (in yellow)



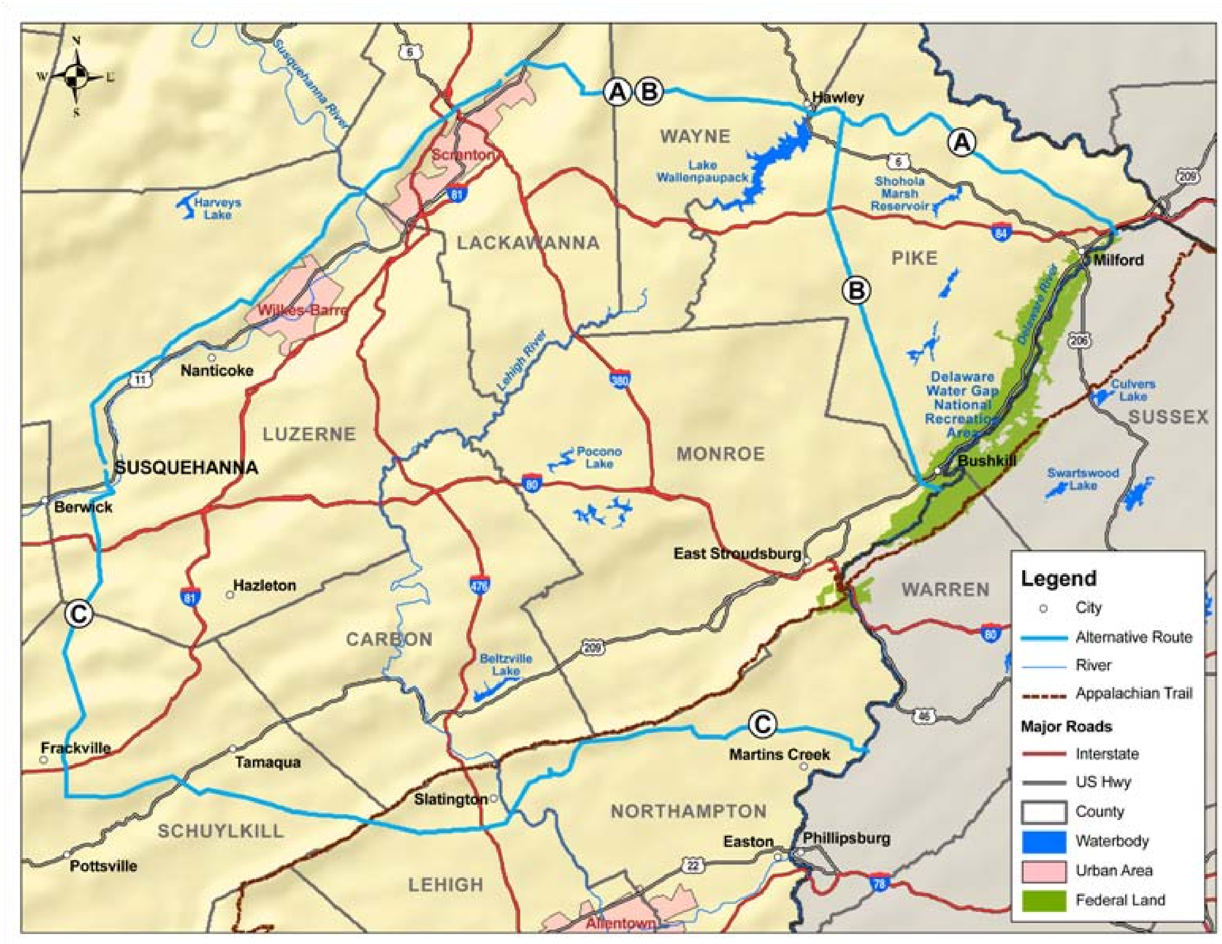
Susquehanna-Roseland 500-kV Line

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. A 2012 baseline retool study, conducted as part of PJM's 2010 RTEP process, identified 50 NERC reliability criteria violations, confirming the need for the project. According to PJM, incremental upgrades are not a practical solution. 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.

Figure 7 Susquehanna-Roseland 500- kV line alternatives



On Jan. 6, 2009, PPL filed its application for authorization to construct the line and a new substation in Blakely Borough, Lackawanna County.[23] Evidentiary hearings were held in 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.

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

Three public meetings were held in August 2010. The EIS, anticipated to be completed in fall 2011, 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 that 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, and construction of the project must commence within three years of the entry date of the Opinion and Order (Feb. 12, 2010). 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.

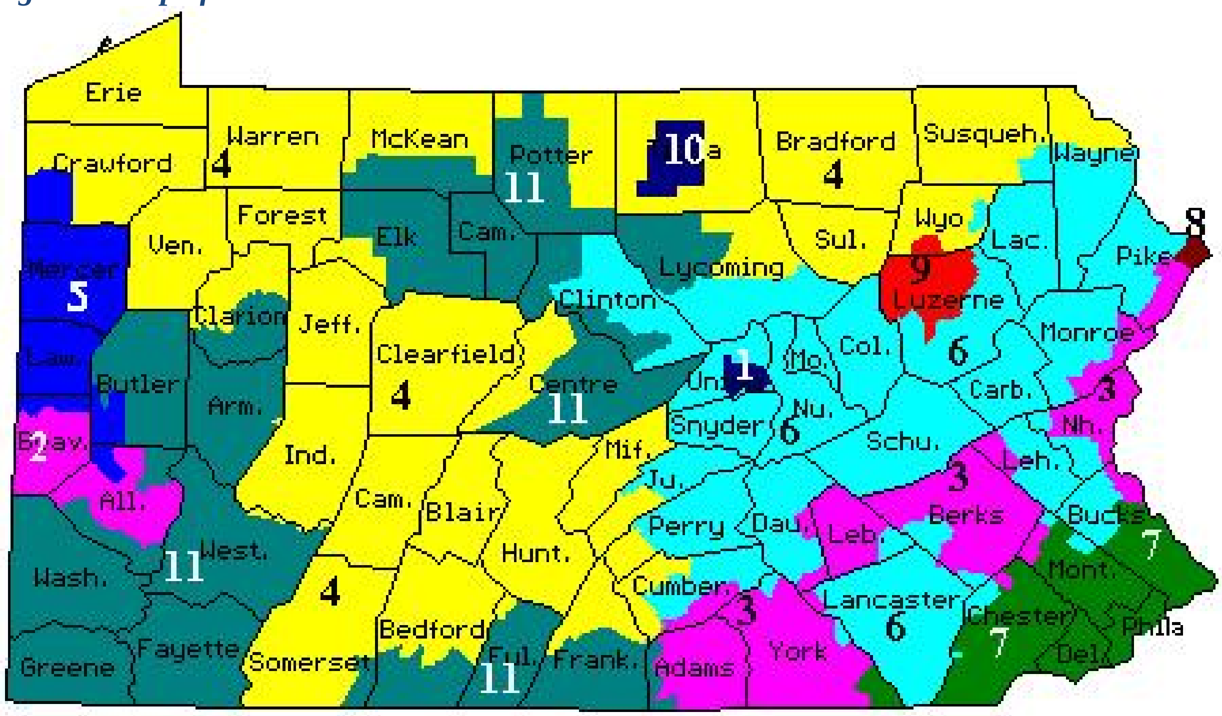
Transmission owners, PPL and PSEG, responsible for construction of the Susquehanna-Roseland line, have indicated that the line will not be in service until June 1, 2014, or later, primarily due to delays in obtaining the NPS permit. PJM has developed an operational solution to address the criteria violations that would otherwise be expected to occur in 2012 without the line.

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 (eight systems) are:

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

Figure 8 Map of EDC service territories



It is the responsibility of each load-serving entity to make provisions for adequate generating resources to serve its customers. 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]

The Commission's statewide default service rulemaking and policy statement provide 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 now expired for all 11 EDCs; Met-Ed. Penelec, PECO and West Penn Power are the last EDCs to end their recovery of stranded costs on Dec. 31, 2010.

As of May 11, 2011, the electric generation supplier (EGS) market share of total megawatthour (MWh) sales was 48.6 percent, varying greatly among the individual EDC service territories. EGSs supplied 19.3 percent of residential sales, 53.9 percent of commercial sales and 83.0 percent of industrial sales. The statewide total number of customers switching to an EGS was 1,101,351 or 19.5 percent of total customers served.[26] As of May 18, 2011, there were 205 licensed EGSs offering generation services to retail customers in Pennsylvania.

Alternative Energy Portfolio Standards

Act 213[27] requires that EDCs and EGSs 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.[28]

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

[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] www.PAPowerSwitch.com.
[27] Alternative Energy Portfolio Standards Act, effective Feb. 28, 2005; 73 P.S. §§ 1648.1–1648.8.
[28] See 52 Pa. Code §§ 75.61—75.70.

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%

EDCs were exempt from these requirements for the duration of their cost recovery periods. As of Jan. 1, 2011, all companies must comply. The 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	Dec. 31, 2006	Feb. 28, 2007
UGI Utilities Inc.	Dec. 31, 2006	Feb. 28, 2007
Citizens' Electric Company	Dec. 31, 2007	Jan. 1, 2008
Duquesne Light Company	Dec. 31, 2007	Jan. 1, 2008
Pike County Power and Light	Dec. 31, 2007	Jan. 1, 2008
Wellsboro Electric Company	Dec. 31, 2007	Jan. 1, 2008
PPL Electric Utilities Corporation	Dec. 31, 2009	Jan. 1, 2010
PECO Energy Company	Dec. 31, 2010	Jan. 1, 2011
Pennsylvania Electric Company	Dec. 31, 2010	Jan. 1, 2011
Metropolitan Edison Company	Dec. 31, 2010	Jan. 1, 2011
West Penn Power Company	Dec. 31, 2010	Jan. 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.

In 2006, the Commission adopted 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.[29]

The Commission also adopted regulations that 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.[30]

In 2008, the Commission adopted a Final Rulemaking Order pertaining to the AEPS obligations of the EDCs and EGSs.[31]

As of May 18, 2010, Pennsylvania had certified 5,312 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/.

The total cost for compliance with AEPS for all load-serving entities in Pennsylvania is estimated to be $30.2 million in 2011.[32]

Energy Efficiency and Conservation

Act 129

Act 129 of 2008[33] 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.[34] 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.

[29] Docket No. L-00050174; 52 Pa. Code §§ 75.11-75.15.
[30] Docket No. L-00050175; 52 Pa. Code §§ 75.21-75.40.
[31] Docket No. L-00060180; 52 Pa. Code §§ 75.61-75.70.
[32] http://www.puc.state.pa.us/electric/pdf/AEPS/AEPS_Ann_Rpt_2008-09.pdf.
[33] Energy Efficiency and Conservation Program, signed by Gov. Rendell on Oct. 15, 2008.
[34] 66 Pa.C.S. § 2806.1.

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 just under $1 billion.[35] 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**

In 2009, the Commission established standards each program must meet and provided guidance on the procedures to be followed for submittal, review and approval of all aspects of EDC plans. Programs are evaluated using a total resource cost test.[36] Each plan must include a proposed cost recovery tariff mechanism. Plans were filed on July 1, 2009.[37] The Commission approved the plans, with modifications, in late October 2009, requiring the filing of revised plans within 60 days, which were subsequently approved.[38]

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

[35] Program costs are from individual plans and generally represent 2 percent of revenues as of December 2006 multiplied by four to reflect the four-year duration of the plans.
[36] Docket No. M-2009-2108601.
[37] Docket No. M-2008-2069887.
[38] Docket Nos. M-2009-2093215, M-2009-2093216, M-2009-2093217, M-2009-2093218, M-2009-2092222, M-2009-2112952 and M-2009-2112956.
[39] 66 Pa. C.S. § 2807(f).
[40] Docket No. M-2009-209655.

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.

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.

PURPA

Section 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA)[43] 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 that would receive special rate and 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.[44]

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[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] Pub. L. 95-617, Title II, § 210, 92 Stat. 3144 (16 U.S.C.A. § 824a-3(a)—(j)).
[44] 52 Pa. Code §§ 57.31-57.39.

Under the provisions of purchase power agreements, utilities are required to purchase any energy which is made available from a qualifying facility.[45] In 2010, 5,962 GWh were purchased from independent power producers (IPPs) and QFs, representing 3.9 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 2010 Purchases from IPPs and QFs by Pennsylvania EDCs

Company	Purchased Energy (MWh)	Percent of Net Energy for Load	Contract Capacity (kW)	Total Capacity (kW)
Duquesne	0	0.00%	0	0
Met-Ed	1,935,785	13.08%	295,000	354,900
Penelec	3,034,903	20.13%	370,350	410,850
Penn Power	31	0.00%	0	10,600
PPL	62,969	0.16%	0	15,410
PECO	0	0.00%	0	0
West Penn	922,942	4.14%	125	135
UGI	0	0.00%	0	0
Citizens'	5,725	3.43%	0	6,000
Pike County	0	0.00%	0	0
Wellsboro	0	0.00%	0	0
Total	**5,962,355**	**3.87%**	**665,475**	**797,895**

[45] 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.

Section 2 – Historic and Forecast Data

Statewide Review

Pennsylvania's aggregate retail electricity sales in 2010 totaled 144,119 gigawatthours (GWh),[46] a 3.3 percent increase from that of 2009, while the number of customers increased by 0.3 percent. Residential sales represented 36.1 percent of the total sales, followed by industrial (35.1 percent) and commercial (26.9 percent). Aggregate non-coincident peak load[47] increased to 29,515 MW in 2010, an increase of 7.0 percent over 2009.

Tables 5 and 6 provide statistics for 2010 and 2009. It is noted that several EDCs have redefined their commercial and industrial (C&I) customers into small C&I and large C&I. Thus, comparisons with historical data are not valid for these sectors.

Table 5 PA EDCs' energy demand, peak load and customers served (2010)

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	578,094	4,326,761	6,712,326	2,987,278	63,598	19,998	14,109,961	701,201	29,199	14,840,361	2,889
Met-Ed	552,594	5,666,240	3,006,378	5,288,187	35,436	0	13,996,241	793,215	12,563	14,802,019	2,715
Penelec	590,712	4,655,812	3,670,566	5,748,044	41,969	0	14,116,391	955,381	4,141	15,075,913	2,659
Penn Power	160,116	1,696,442	1,311,186	1,488,033	6,434	0	4,502,095	191,470	1,947	4,695,512	903
PPL	1,401,274	14,205,788	10,667,407	12,045,496	0	0	36,918,691	2,662,968	66,975	39,648,634	7,365
PECO	1,566,873	13,895,996	8,472,056	15,823,964	924,797	808,446	39,925,259	2,225,117	53,184	42,203,560	8,864
West Penn	716,115	7,401,268	4,983,018	7,617,476	48,923	768,307	20,818,992	1,447,475	--	22,266,467	3,838
UGI	62,250	533,472	332,493	108,999	5,683	98	980,745	53,600	2,092	1,036,437	198
Citizens'	6,814	80,611	28,303	49,007	653	0	158,574	8,139	202	166,915	46
Pike County	4,661	29,110	44,743	0	419	0	74,272	4,112	16	78,400	18
Wellsboro	6,151	42,539	29,543	42,598	227	9	114,916	7,985	302	123,203	20
Total	**5,645,654**	**52,534,039**	**39,258,019**	**51,199,082**	**1,128,139**	**1,596,858**	**145,716,137**	**9,050,663**	**170,621**	**154,937,421**	**29,515**
% of Total		36.05%	26.94%	35.14%	0.77%	1.10%	100.00%				

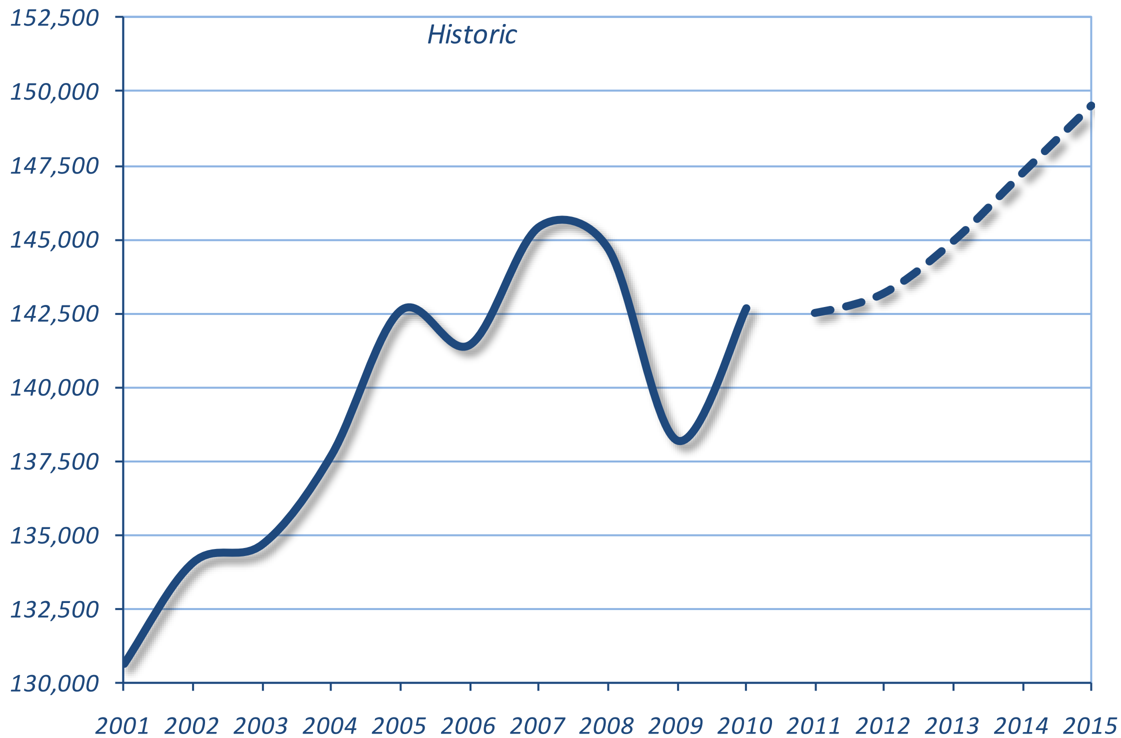
Table 6 PA EDCs' energy demand, peak load and customers served (2009)

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	**5,627,584**	**50,229,205**	**44,921,624**	**43,023,101**	**1,366,056**	**2,282,397**	**141,822,383**	**8,118,587**	**167,379**	**150,108,349**	**27,597**
% of Total		35.42%	31.67%	30.34%	0.96%	1.61%	100.00%				

[46] A GWh is equivalent to 1,000 MWh or 1,000,000 kWh.
[47] Non-coincident peak load is the sum of EDCs' annual peak loads regardless of their date or time of occurrence.

The current aggregate five-year projection of growth in energy demand is 0.9 percent. This includes a residential growth rate of 0.4 percent, a commercial rate of 1.2 percent and an industrial rate of 1.4 percent. See Figure 9, which depicts growth in total aggregate retail energy demand, in GWh.

Figure 9 Pennsylvania aggregate energy demand (GWh)



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.[48] Between 1970 and 2010, residential demand and cost increased at annual rates of 1.4 percent and 4.1 percent, respectively. Figure 10 compares the changes in residential cost and usage from 1940 to 2010.

Over the past 15 years, the average aggregate non-coincident peak load for the major EDCs increased 1.0 percent per year. The combined forecast of the EDCs' peak load shows the load increasing from 29,515 MW in 2010 to 30,250 MW in 2015 at an average annual growth rate of 0.5 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 11.

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

Figure 10 Average residential cost and use (cents per kWh or MWh per year)

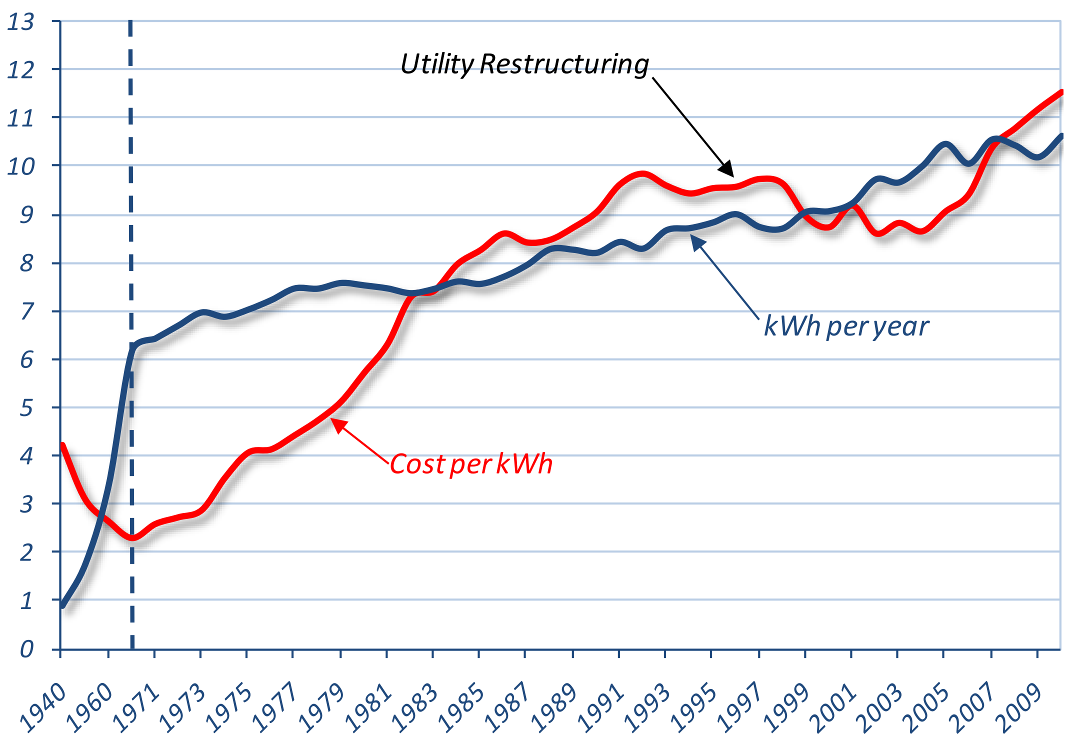
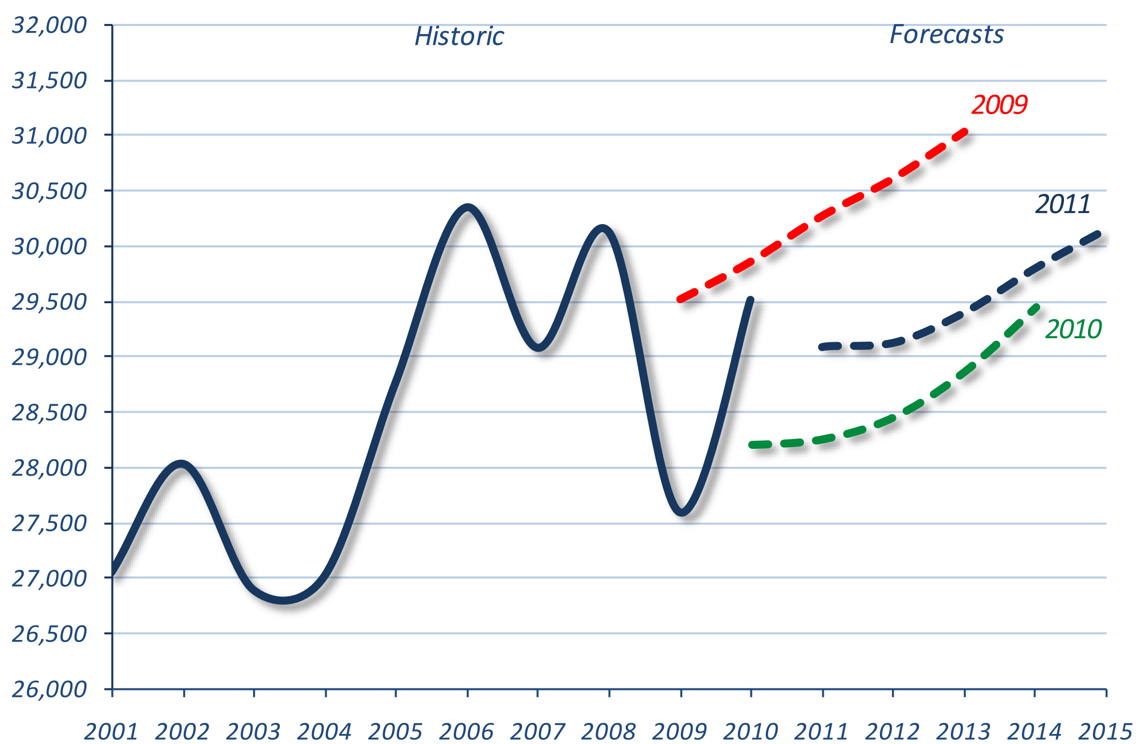


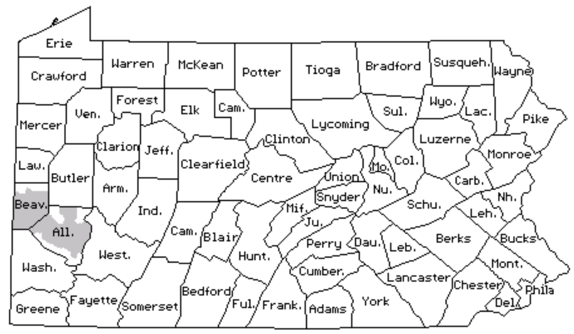
Figure 11 Pennsylvania aggregate non-coincident peak load (MW)



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.

Duquesne Light Company



Duquesne Light Company (Duquesne) is the principal subsidiary of DQE Holdings[49] and provides electric service to 578,094 electric utility customers in the City of Pittsburgh and portions of Allegheny and Beaver counties in Southwestern Pennsylvania. In 2010, Duquesne had energy sales totaling 14,110 GWh – up 1.7 percent from 2009. Commercial sales continued to dominate Duquesne's market with 47.6 percent of the total sales, followed by residential (30.7 percent) and industrial (21.2 percent). Average annual use per residential customer was 8,235 kWh at an average cost of 11.82 cents per kWh; operating revenues totaled $924 million.

The current five-year projection of average increase in total energy consumption is 0.3 percent per year. This includes a residential growth rate of 0.7 percent, a commercial rate of 1.0 percent and a major *decline* in industrial sales of 1.8 percent per year. See Figure 12.

Duquesne's summer peak load, occurring on July 23, 2010, was 2,889 MW, representing an increase of 5.7 percent from last year's peak of 2,732 MW. The 2010-11 winter peak load was 2,281 MW or 7.5 percent higher 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 2,889 MW in the summer of 2010 to 3,125 MW in 2015, or an average annual growth rate of 1.6 percent. The current forecast for 2011 is 2.8 percent above the previous forecast, filed in 2010. See Figure 13.

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 2001 through 2011.

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.

For Calendar Year 2010, 19 EGSs and one municipality sold a total of 8,789 GWh to retail customers in Duquesne's service territory, or 59.2 percent of net energy for load. Since joining PJM in 2005, PJM has provided energy imbalance service to all load-serving entities, which includes the EGSs.

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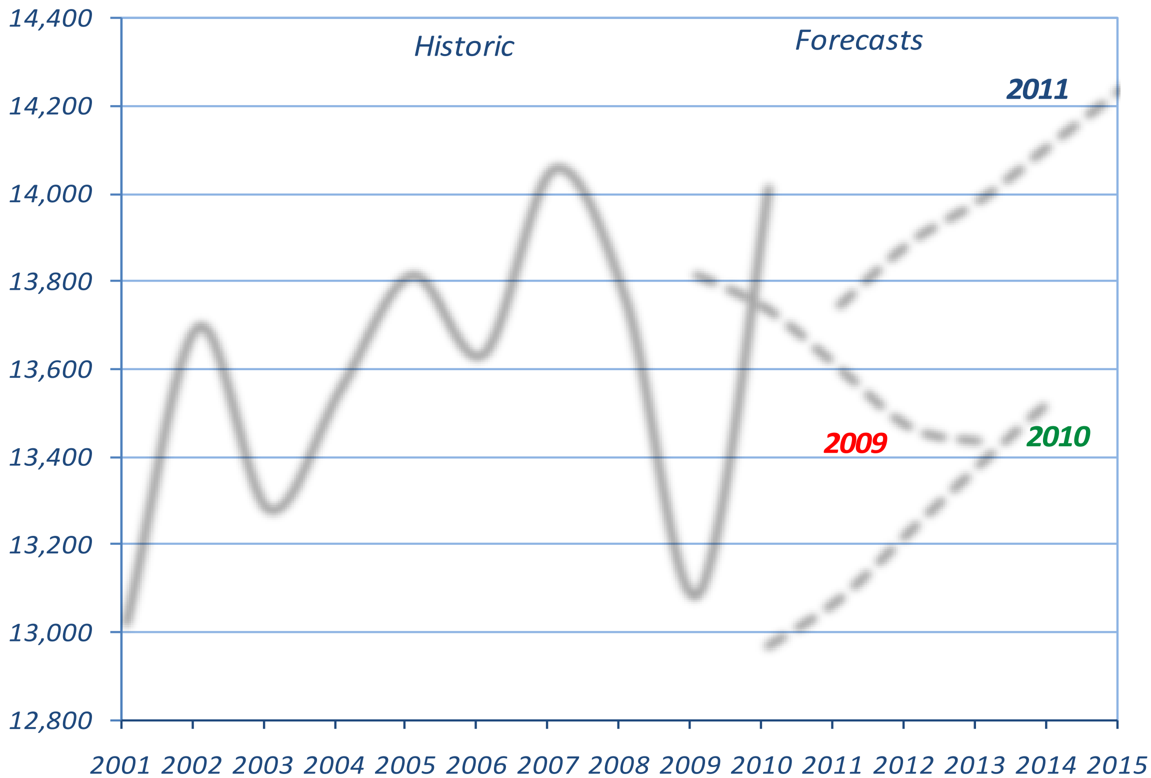
[49] On April 24, 2007, the Commission approved the acquisition of Duquesne Light Holdings Inc., by merger, with the Macquarie Consortium. Headquarters remain in Pittsburgh. See Docket No. A-110150F0035.

Duquesne has 121.6 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 2016. These projects are planned to mitigate anticipated NERC reliability criteria violations identified by both Duquesne and PJM.

Duquesne's Energy Efficiency and Conservation Plan[50] 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.

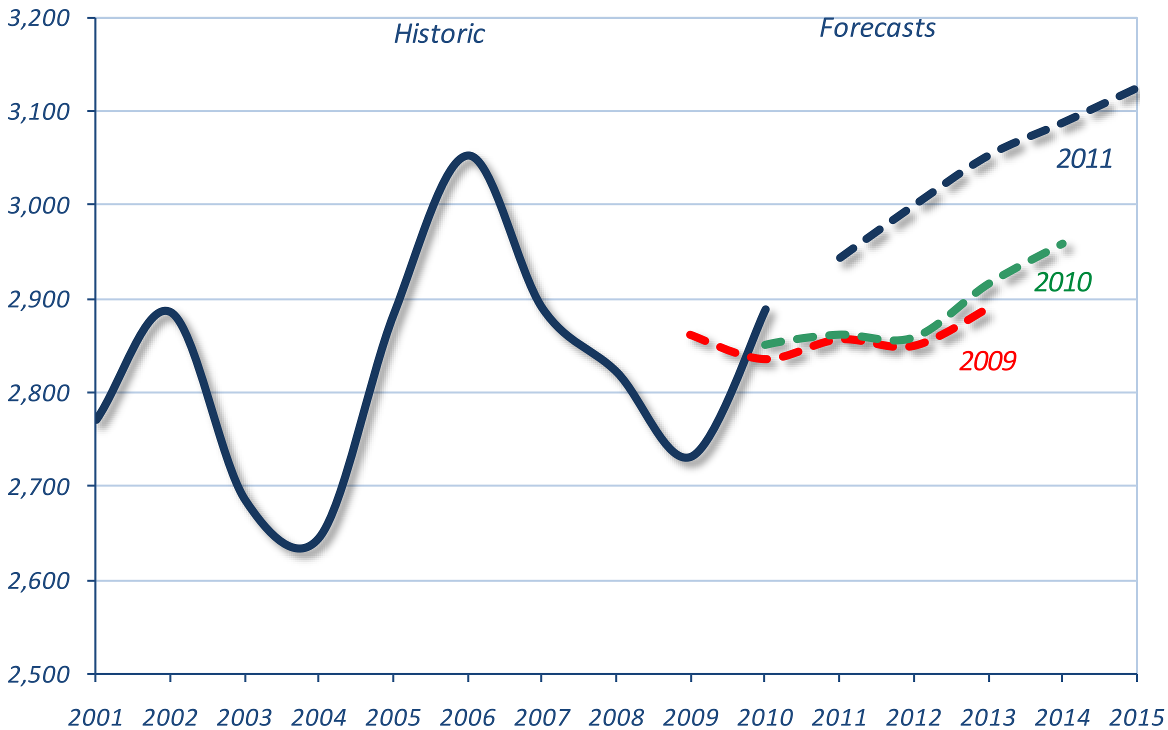
Duquesne is a member of PJM and RFC.

Figure 12 Duquesne Light Company energy demand (GWh)



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

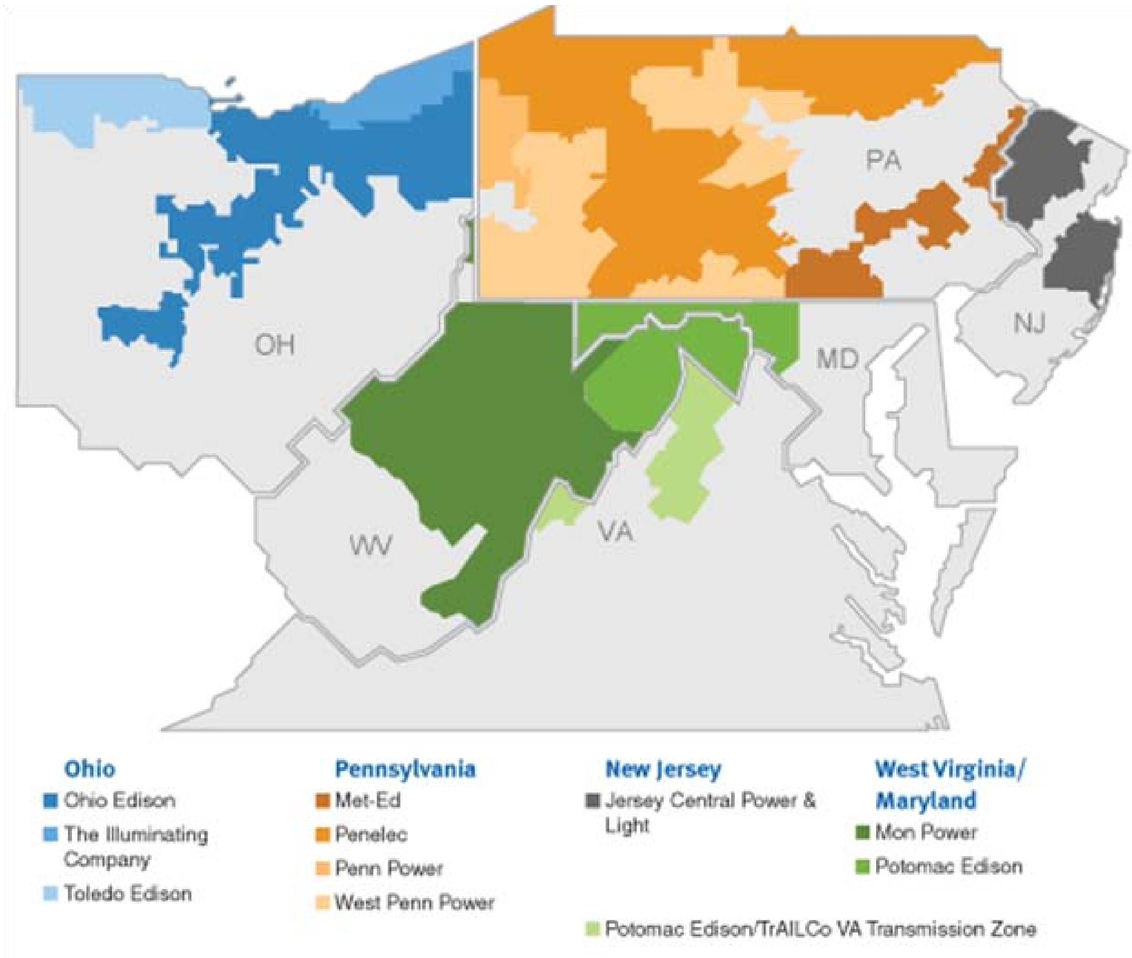
Figure 13 Duquesne Light Company peak load (MW)



FirstEnergy Corporation

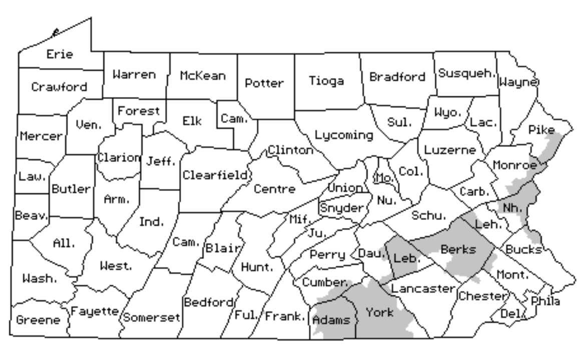
FirstEnergy Corporation (FirstEnergy) is a holding company with 10 electric utility operating companies, comprising the nation's largest investor-owned electric system, serving 6 million customers within 67,000 square miles of Ohio, Maryland, Pennsylvania, New Jersey, Virginia and West Virginia, with $16 billion in annual revenues. Its generation subsidiaries control approximately 24,000 MW of capacity (62 percent coal and 17 percent nuclear). The four operating companies in Pennsylvania include Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company and West Penn Power Company. See Figure 14.

Figure 14 FirstEnergy service territory



The merger between FirstEnergy and Allegheny Power was finalized when the Commission approved the merger on Feb. 24, 2011.[51]

Metropolitan Edison Company



Metropolitan Edison Company (Met-Ed), a subsidiary of FirstEnergy, provides service to 552,594 electric utility customers in all or portions of 14 counties in Eastern and Southcentral Pennsylvania. In 2010, Met-Ed had total energy sales of 13,996 GWh—up 3.8 percent from 2009. Residential sales dominated Met-Ed's market with 40.5 percent of total sales, followed by commercial (21.5 percent) and industrial (37.8 percent). These figures reflect a reclassification of commercial and industrial (C&I) customers based on rate

[51] Docket No. A-2010-2176520.

schedule; i.e., the commercial class now includes small C&I customers, and the industrial class includes large C&I customers. Average annual use per residential customer was 11,621 kWh at an average cost of 12.41 cents per kWh; operating revenues totaled $1.44 billion.

The current five-year projection of growth in total energy demand is 0.7 percent. This includes a slight *decline* in residential sales from the 2010 level at an average rate of 0.1 percent, a commercial growth rate of 1.0 percent and an industrial rate of 1.2 percent, based on the recent reclassifications. See Figure 15.

Met-Ed's summer peak load, occurring on Sept. 2, 2010, was 2,715 MW, representing a decrease of 0.9 percent from last year's system peak of 2,739 MW. The 2010-11 winter peak load was 2,413 MW or 3.0 percent higher than the previous year's winter peak of 2,342 MW. The actual average annual peak load growth rate over the past 15 years was 1.5 percent. Met-Ed's forecast shows its peak load increasing from 2,715 MW in 2010 to 2,952 MW in 2015, or an annual average growth rate of 1.7 percent. The current forecast for 2011 is 229 MW or 8.7 percent above the previous forecast. See Figure 16.

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 2001 through 2011.

Met-Ed retains Provider of Last Resort (POLR) responsibility for those customers who do not choose an alternate energy supplier and currently supplies nearly all of its POLR customers. Met-Ed conducted a competitive procurement process for its generation supply effective Jan. 1, 2011, after its generation rate cap expired at the end of 2010.

In 2010, Met-Ed purchased 1,936 GWh from cogeneration and small power production projects, representing 13.1 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 2010, 18 EGS sold a total of 435 GWh to retail customers in Met-Ed's service territory, representing 3.1 percent of total consumption.

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 $4.4 million. Projects include 8.02 miles of 69-kV, 115-kV and 230-kV circuits.

Met-Ed's Energy Efficiency and Conservation Plan[52] 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. Additionally, Met-Ed's WARM low-income weatherization program reduced peak load by 710 kW and saved 3,357 MWh at a cost of $2.5 million.

Met-Ed is a member of PJM and RFC.

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

Figure 15 Metropolitan Edison Company energy demand (GWh)

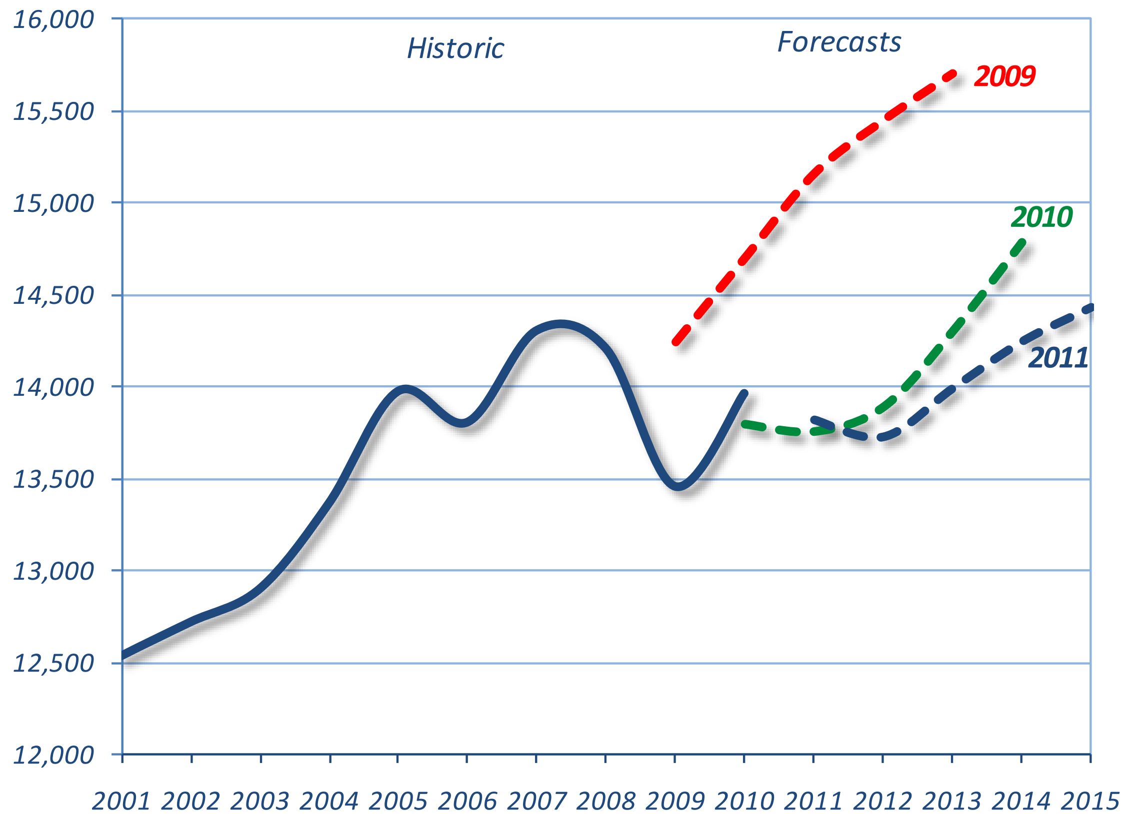
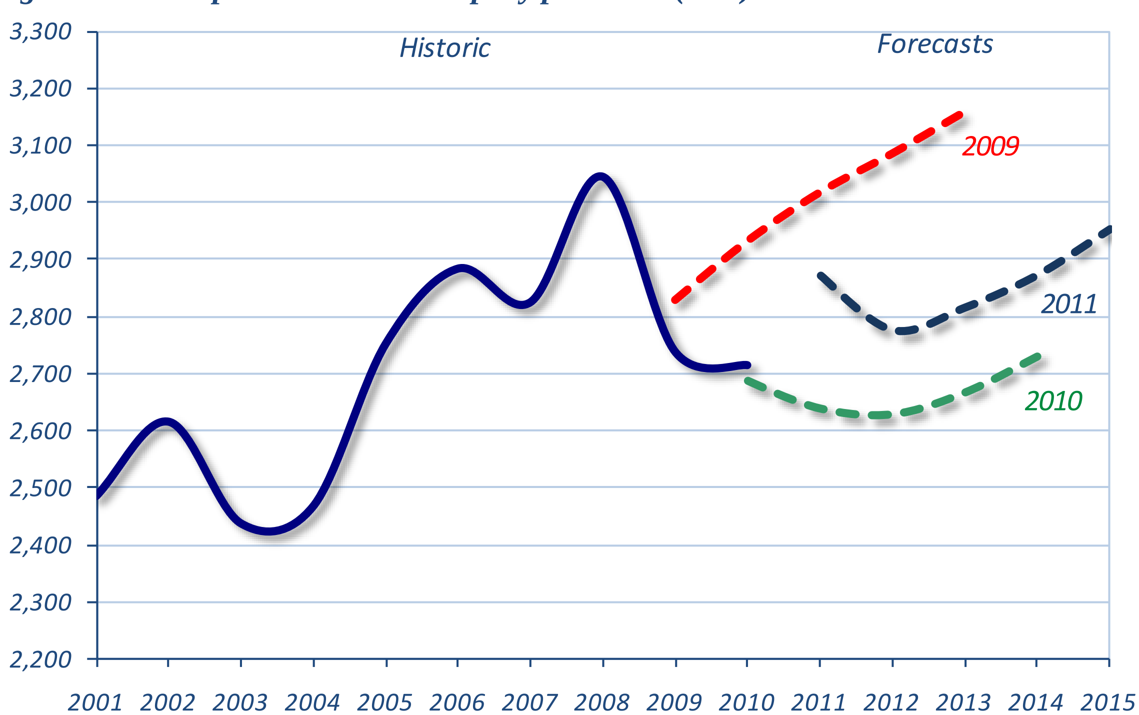
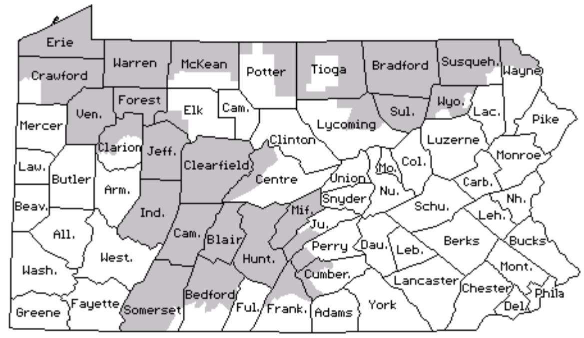


Figure 16 Metropolitan Edison Company peak load (MW)



Pennsylvania Electric Company



Pennsylvania Electric Company (Penelec), a subsidiary of FirstEnergy, provides service to 590,712 electric utility customers in all or portions of 29 counties in Western and Northern Pennsylvania. In 2010, Penelec had energy sales totaling 14,116 GWh—up 4.0 percent from 2009. Industrial sales led Penelec's market with 40.7 percent of the total sales, followed by residential (33.0 percent) and commercial (26.0 percent). These figures reflect a reclassification of commercial and industrial (C&I) customers based on rate schedule; i.e., the commercial class now includes small C&I customers, and the industrial class includes large C&I customers. Average annual use per residential customer was 9,181 kWh at an average cost of 11.12 cents per kWh; operating revenues totaled $1.16 billion.

The current five-year projection of growth in total energy demand is 0.8 percent. This includes a commercial growth rate of 0.2 percent and an industrial growth rate of 1.9 percent, based on the recent reclassifications. Residential sales are expected to decline and then increase to the 2010 level. See Figure 17.

Penelec's summer peak load, occurring on July 8, 2010, was 2,659 MW, representing an increase of 8.5 percent from last year's summer peak of 2,451 MW. The 2010-11 winter peak load was 2,534 MW or 8.0 percent higher than the previous year's winter peak of 2,346 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 dropping from 2,659 MW in 2010 to 2,515 MW in 2011 and then increasing to 2,662 MW by 2015. The current forecast for 2011 is 2.6 percent above the previous forecast. See Figure 18.

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.

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 conducted a competitive procurement process for its generation supply effective Jan. 1, 2011, after its generation rate cap expired at the end of 2010.

In 2010, Penelec purchased 3,035 GWh from cogeneration and small power production projects, or 20.1 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.

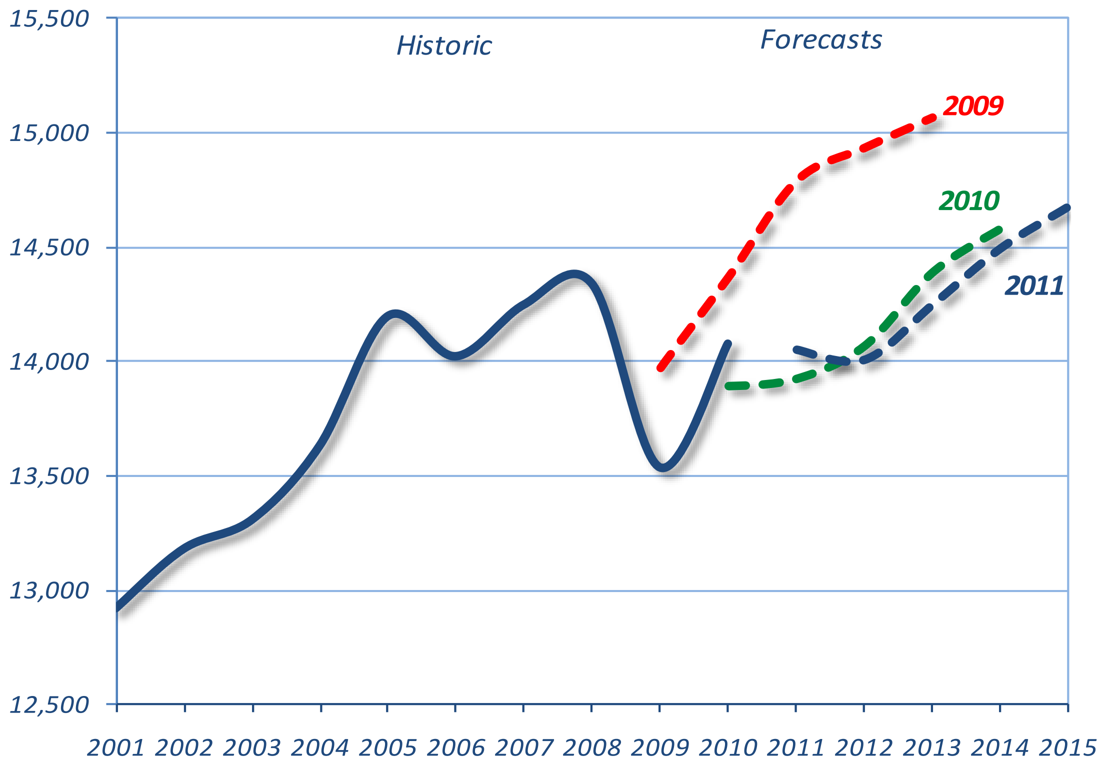
For Calendar Year 2010, 17 licensed EGSs sold a total of 532 GWh to retail customers in Penelec's service territory, or 3.8 percent of total consumption.

Through 2014, Penelec's transmission line projects include construction of new lines and reconductoring of existing lines to improve local service at a combined cost of $16.6 million. Projects include 12 miles of 115-kV, 230-kV and 500-kV circuits.

Penelec's Energy Efficiency and Conservation Plan[53] 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. Additionally, Penelec's WARM low-income weatherization program reduced peak load by 763 kW and saved 2,809 MWh at a cost of $2.9 million.

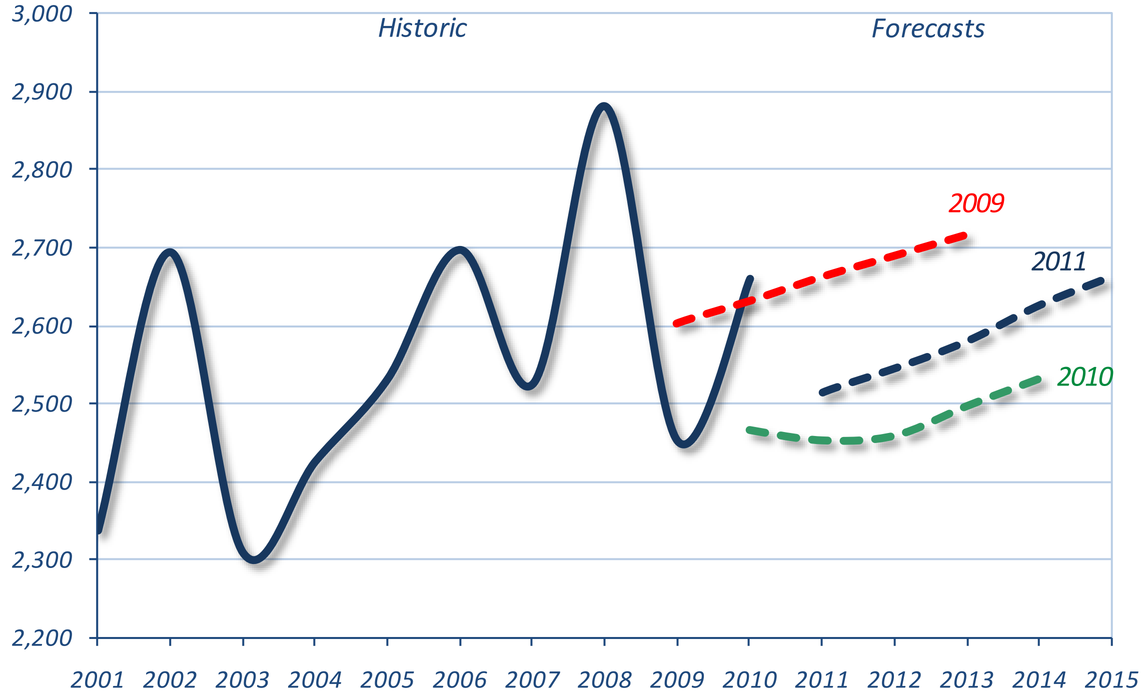
Penelec is a member of PJM and RFC.

Figure 17 Pennsylvania Electric Company energy demand (GWh)

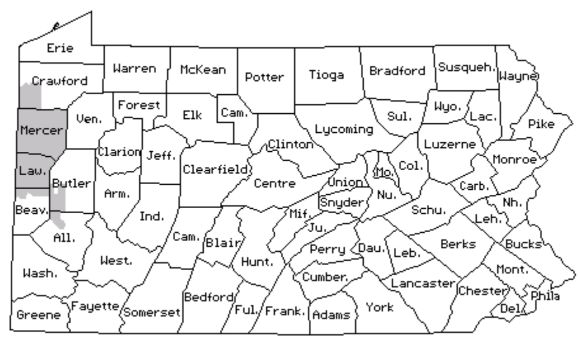


[53] Docket No. M-2009-2112952.

Figure 18 Pennsylvania Electric Company peak load (MW)



Pennsylvania Power Company



Pennsylvania Power Company (Penn Power), a subsidiary of FirstEnergy, provides service to 160,116 electric utility customers in all or portions of six counties in Western Pennsylvania. In 2010, Penn Power had energy sales totaling 4,502 GWh—an increase of 6.3 percent from the 2009 figure. Residential sales lead Penn Power's market with 37.7 percent of the total sales, followed by industrial (33.1 percent) and commercial (29.1 percent). These figures reflect a reclassification of commercial and industrial (C&I) customers based on rate schedule; i.e., the commercial class now includes small C&I customers, and the industrial class includes large C&I customers. Average annual use per residential customer was 12,095 kWh at an average cost of 11.23 cents per kWh; operating revenues totaled $255.2 million.

The current five-year projection of growth in total energy demand is 0.9 percent. This includes a residential *decline* rate of -0.1 percent, a commercial *decline* rate of -0.5 percent and an industrial growth rate of 3.2 percent, based on the recent reclassifications. See Figure 19.

Penn Power's summer peak load, occurring on Aug. 10, 2010, was 903 MW, representing an increase of 0.2 percent over last year's peak of 901 MW. The 2010-11 winter peak load of 831 MW was 5.4 percent lower than the previous year's winter peak of 878 MW. The actual average annual peak load growth rate over the past 15 years was 0.5 percent. Penn Power's forecast shows its summer peak load increasing from 903 MW in summer 2010 to 1,010 MW by summer 2015. The current forecast for 2011 is 54 MW or 6.1 percent higher than the previous forecast. See Figure 20.

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 2001 through 2011.

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. Effective June 1, 2011, Penn Power and the other FirstEnergy companies became a part of PJM, transferring from MISO. ATSI owns and operates the transmission assets of Penn Power and the Ohio FirstEnergy companies.

Beginning in January 2007, Penn Power has regularly conducted competitive procurements of its generation supply upon expiration of its generation rate cap at the end of 2006.

For Calendar Year 2010, seven EGSs sold 2,327 GWh to retail customers in Penn Power's service territory or 51.7 percent of total consumption. Penn Power purchased 31,056 kWh from an independent power producer in 2010.

Penn Power's Energy Efficiency and Conservation Plan[54] 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. Additionally, Penn Power's WARM low-income weatherization program reduced peak load by 201 kW and saved 976 MWh at a cost of $957,145.

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

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

Figure 19 Pennsylvania Power Company energy demand (GWh)

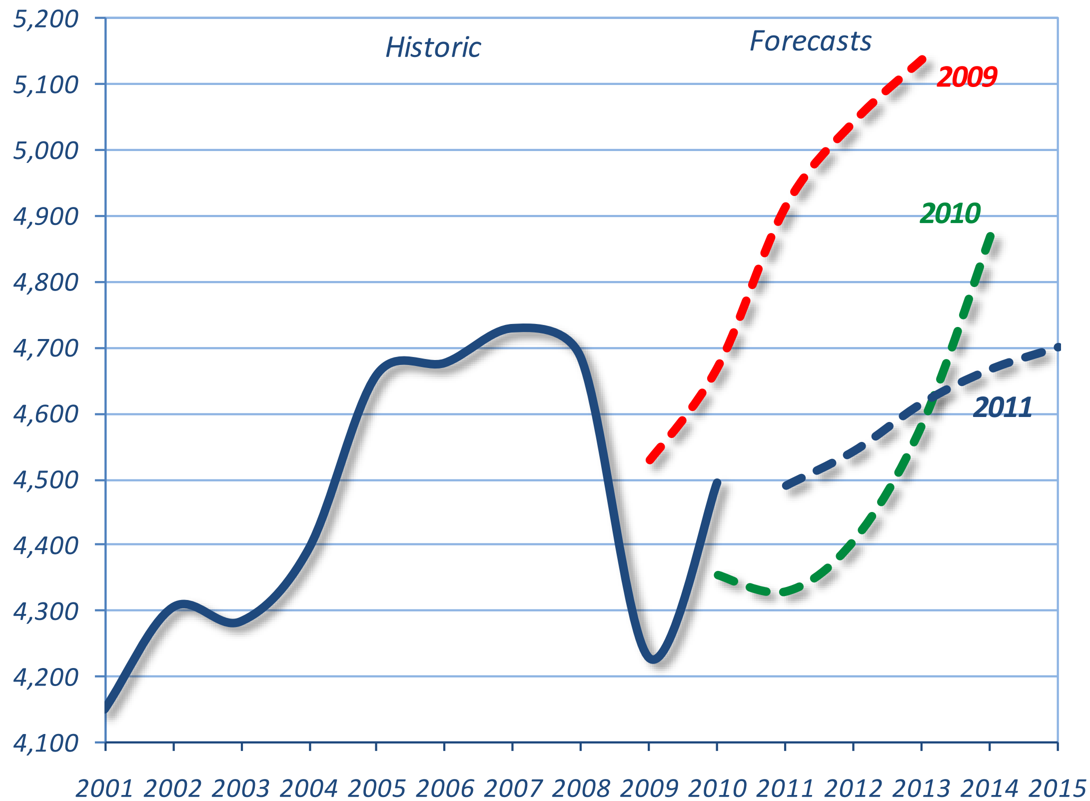
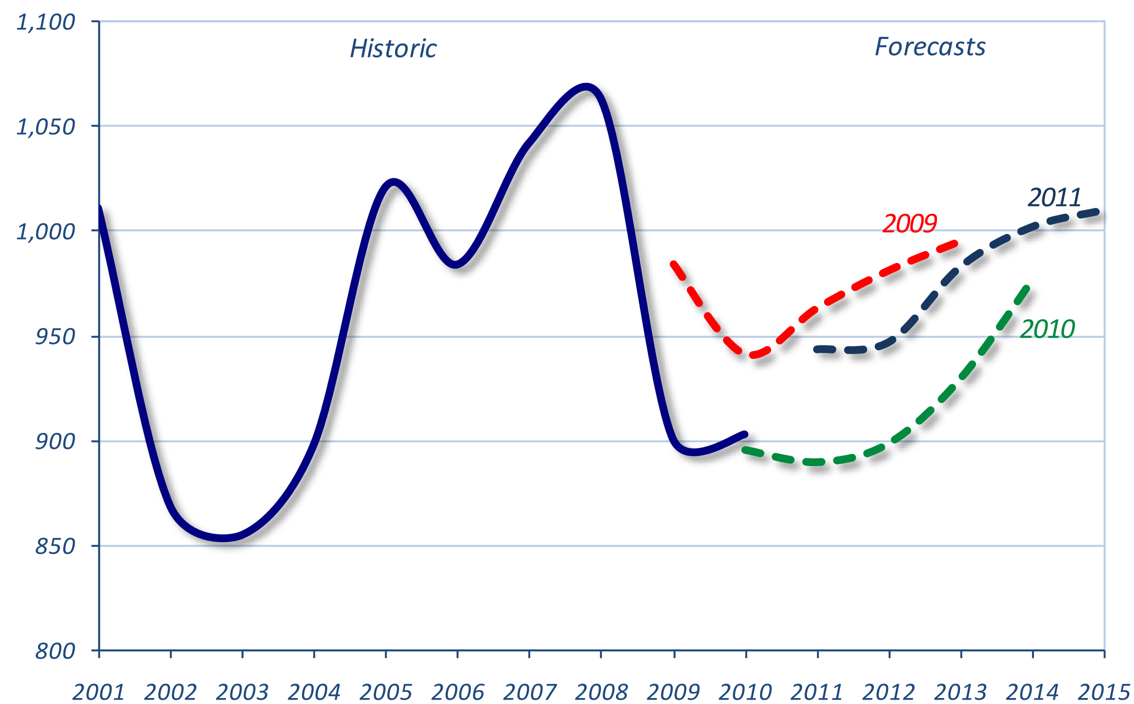
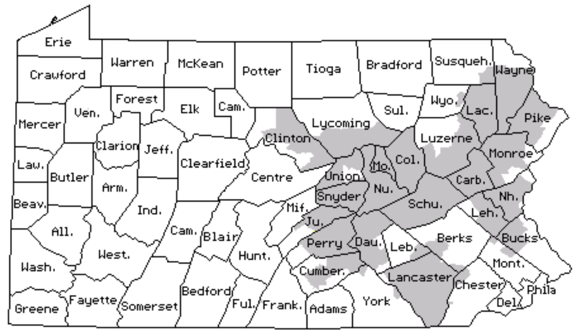


Figure 20 Pennsylvania Power Company peak load (MW)



PPL Electric Utilities Corporation



PPL Electric Utilities Corporation (PPL), a subsidiary of PPL Corporation, provides service to 1,401,274 homes and businesses over a 10,000-square-mile area in all or portions of 29 counties in Central Eastern Pennsylvania. In 2010, PPL had energy sales totaling 36,919 GWh—down 1.9 percent from 2009. Residential sales continued to dominate PPL's market with 38.5 percent of the total sales, followed by industrial (32.6 percent) and commercial (28.9 percent). These figures reflect a reclassification of commercial and industrial (C&I) customers; i.e., the commercial class now includes small C&I (non-residential secondary voltage), and the industrial class includes large C&I (primary and transmission voltage). Average annual use per residential customer was 11,666 kWh at an average cost of 10.27 cents per kWh; operating revenues totaled $2.5 billion.

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, 1.5 percent for commercial and 1.0 percent for industrial, based on the redefined rate groups. See Figure 21.

PPL's summer peak load, occurring on July 7, 2010, was 7,214 MW compared to the previous summer's peak of 6,845 MW, or a 5.4 percent increase. The 2010-11 winter peak load was 7,365 MW, representing an increase of 8.3 percent from last year's winter peak of 6,800 MW. The actual average annual peak load growth rate over the past 15 years was 0.7 percent. PPL's five-year winter peak load forecast scenario shows the peak load decreasing from 7,365 MW in 2010 to 7,101 MW in 2011 and then increasing to 7,282 MW in 2015 at an average annual rate of 0.5 percent. The current forecast for 2011 is 126 MW or 1.7 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 22.

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 2001 through 2011.

In 2010, PPL purchased 63 GWh from cogeneration and independent power production facilities, or 0.2 percent of net energy for load.

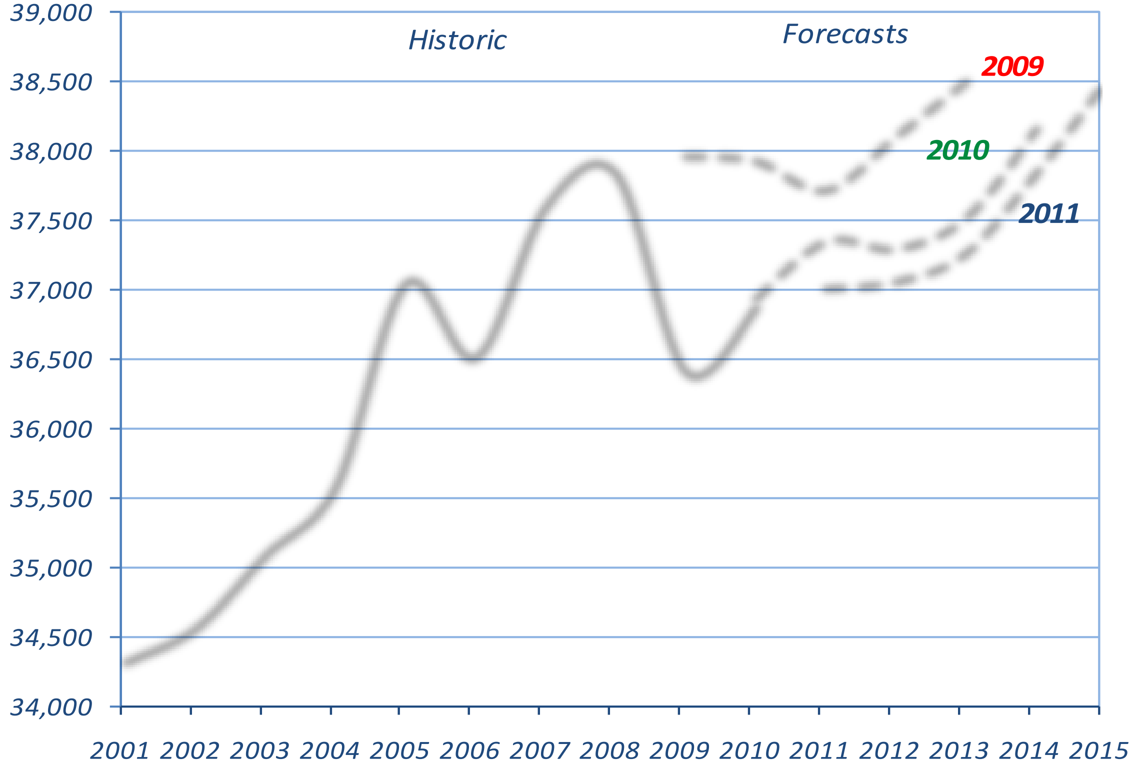
For Calendar Year 2010, 45 EGSs supplied 23.7 GWh to retail customers in PPL's service territory, representing 64.3 percent of total consumption.

PPL has identified several transmission projects, including new construction and rebuilding of existing lines, with in-service dates through 2020. The projects involve 796 circuit miles at a total cost of $1.14 billion. The single largest project is the Susquehanna-Roseland Project, described in Section 1.

PPL's Energy Efficiency and Conservation Plan[55] 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.

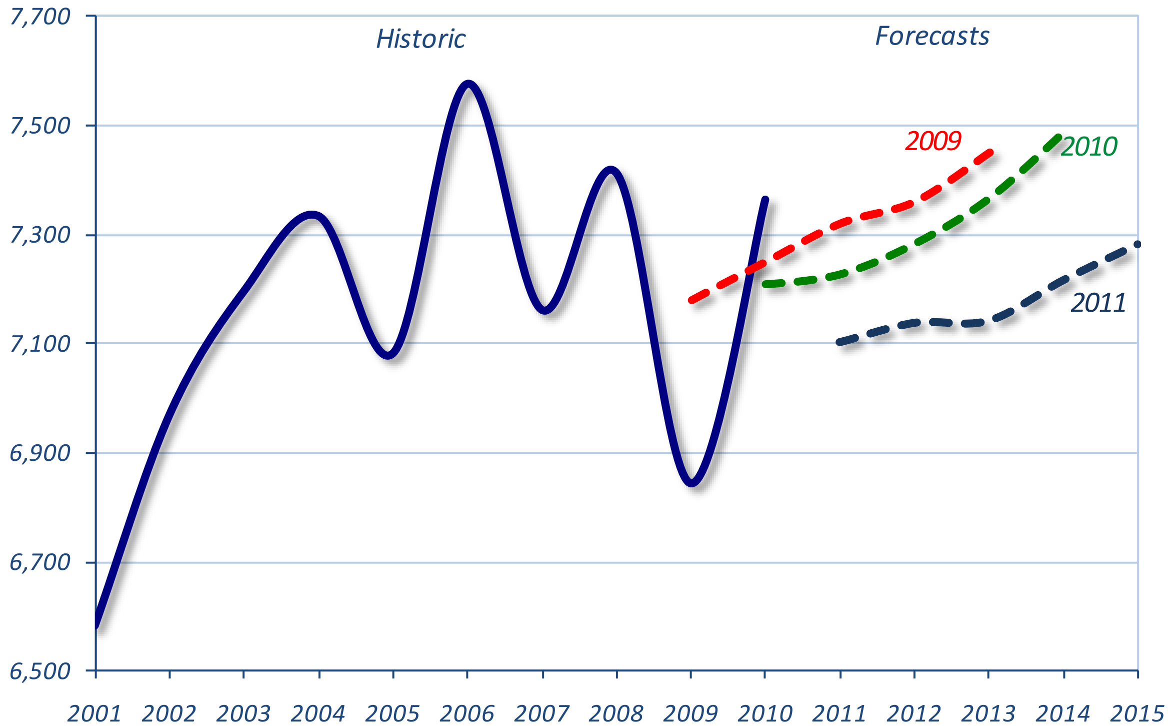
PPL is a member of PJM and RFC.

Figure 21 PPL Electric Utilities Corporation energy demand (GWh)

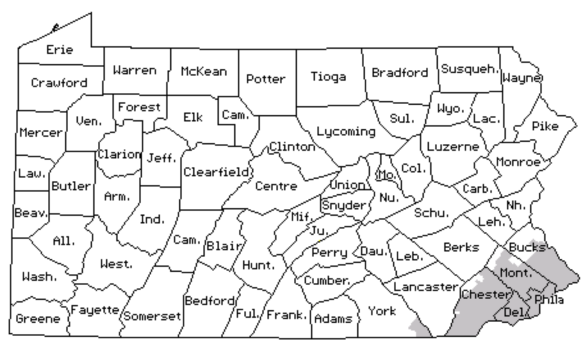


[55] Docket No. M-2009-2093216.

Figure 22 PPL Electric Utilities Corporation peak load (MW)



PECO Energy Company



PECO Energy Company (PECO), a subsidiary of Exelon Corporation, is the largest electric utility in Pennsylvania, providing service to 1,566,873 electric utility customers in the City of Philadelphia and all or portions of six counties in Southeastern Pennsylvania. In 2010, PECO had total energy sales of 39,925 GWh—up 3.2 percent from 2010. Industrial sales continued to dominate PECO's market with 39.6 percent of the total sales, followed by residential (34.8 percent) and commercial (21.2 percent). Average annual use per residential customer was 9,867 kWh at an average cost of 14.87 cents per kWh; operating revenues totaled $4.83 billion.

The current five-year projection of growth in energy demand is 1.5 percent. This includes an annual growth rate of 1.4 percent for residential, 1.7 percent for commercial and 1.6 percent for industrial. See Figure 23.

PECO's summer peak load, occurring on July 6, 2010, was 8,864 MW, representing an increase of 10.9 percent from last year's peak of 7,994 MW. The 2010-11 winter peak demand was 6,333 MW or 5.9 percent below the previous winter's peak of 6,728 MW. The actual average annual peak demand growth rate over the past 15 years was 1.4 percent. PECO's current forecast shows the peak load increasing from the 2010 summer peak load of 8,864 MW to 8,991 MW in summer

2015, or an annual growth rate of 0.3 percent. The current forecast for 2011 is 550 MW or 6.7 percent higher than the previous forecast. See Figure 24.

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 2001 through 2011.

As of Jan. 1, 2011, PECO will acquire electricity for default service customers using the process detailed in PECO's Default Service Plan.[56]

For Calendar Year 2010, EGSs sold a total of 414 GWh to retail customers in PECO's service territory or 1.0 percent of total consumption. On the summer peak day, EGSs represented a load of 107 MW, or 1.2 percent of the total.

PECO has identified three 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 2010, PECO contracted 392 MW of customer load for participation in its curtailment programs. There were a total of four separate curtailment events called.

PECO's Energy Efficiency & Conservation Plan[57] includes 10 energy efficiency programs and eight demand reduction programs 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.

[56] Docket No. P-2008-2062739.
[57] Docket No. M-2009-2093215.

Figure 23 PECO Energy Company energy demand (GWh)

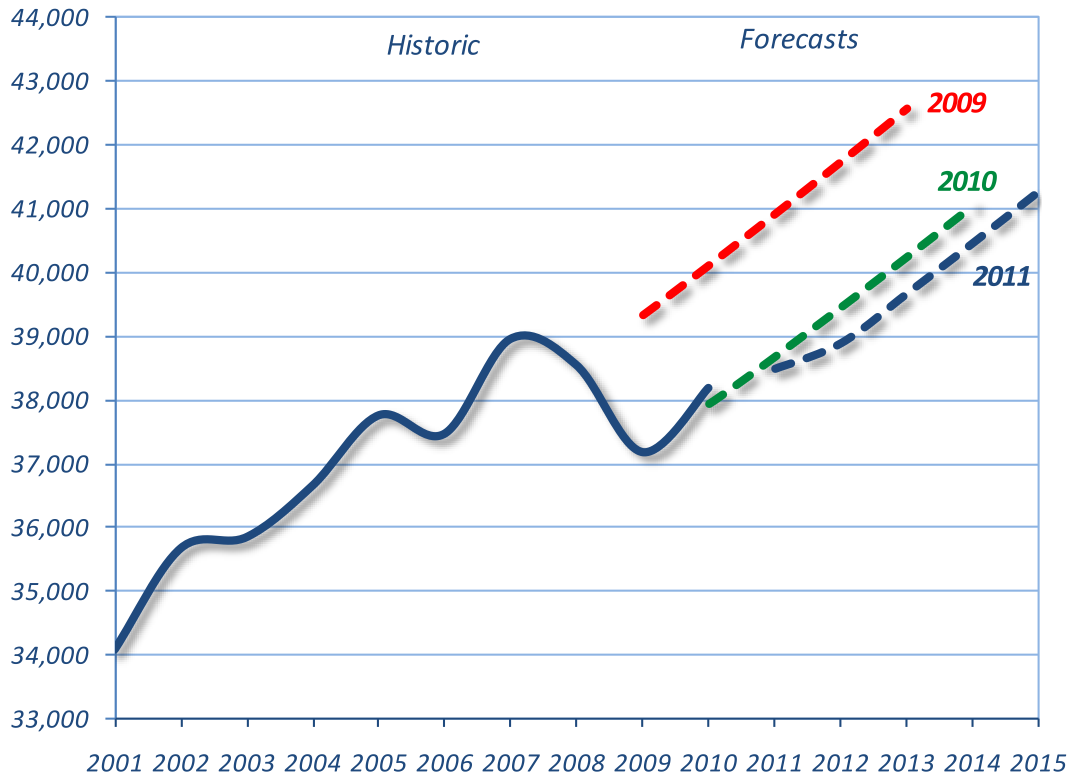
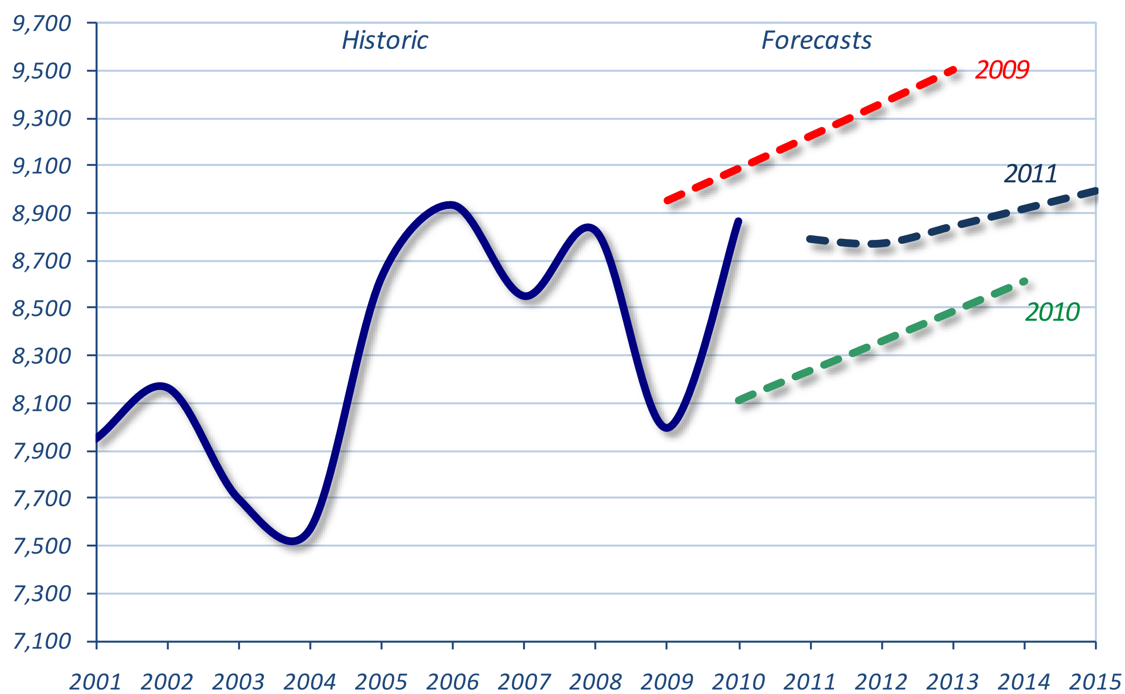
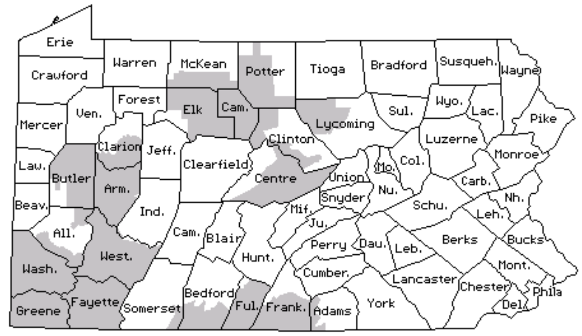


Figure 24 PECO Energy Company peak load (MW)



West Penn Power Company



West Penn Power Company (West Penn), a subsidiary of FirstEnergy, provides service to 716,115 electric utility customers in all or portions of 24 counties in Western, North and South Central Pennsylvania. In 2010, West Penn had total retail energy sales of 20,819 GWh—up 3.8 percent from 2009. Industrial sales continued to dominate West Penn's market with 36.6 percent of the total sales, followed by residential (35.6 percent) and commercial (23.9 percent). Average annual use per residential customer was 11,947 kWh at an average cost of 9.22 cents per kWh; operating revenues totaled $1.57 billion.

The current five-year projection of growth in energy demand is 0.7 percent. This includes a commercial rate of 1.0 percent and an industrial rate of 1.8 percent. Residential sales are expected to drop 3.5 percent in 2011 and remain relatively flat through 2015. See Figure 25.

West Penn's summer peak load, occurring on July 23, 2010, was 3,838 MW, representing an increase of 4.7 percent from last year's summer peak of 3,667 MW. The 2010-11 winter peak load was 3,988 MW or 13.5 percent higher than the previous year's winter peak of 3,513 MW. The actual average annual peak load growth rate over the past 15 years was 1.1 percent. West Penn's load forecast scenario shows the peak load increasing from 3,838 MW in summer 2010 to 3,928 MW in 2015, or an average annual growth rate of 0.5 percent. The current forecast for 2011 is 2 MW higher than the previous forecast. See Figure 26.

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 2001 through 2011.

In 2010, West Penn purchased 923 GWh from cogeneration and independent power production facilities, or 4.1 percent of net energy for load. Contract capacity for these facilities was 125 MW.

For Calendar Year 2010, 17 EGSs sold a total of 517 GWh to retail customers in West Penn's service territory or 2.5 percent of total consumption. On the summer peak day, EGSs represented a load of 63 MW, or 1.6 percent of the total.

West Penn and its affiliate, TrAILCo, have identified several transmission line projects under construction or planned from 2011 through 2016 totaling 132 miles of 138-kV and 500-kV circuits at an estimated cost of $117 million.

West Penn's Energy Efficiency & Conservation Plan[58] includes 22 energy efficiency and demand response programs estimated to meet or exceed the reduction targets of 628 GWh and 157 MW at a total cost of $94.2 million.

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58 Docket No. M-2009-2093218.

West Penn is a member of PJM and RFC.

Figure 25 West Penn Power Company energy demand (GWh)

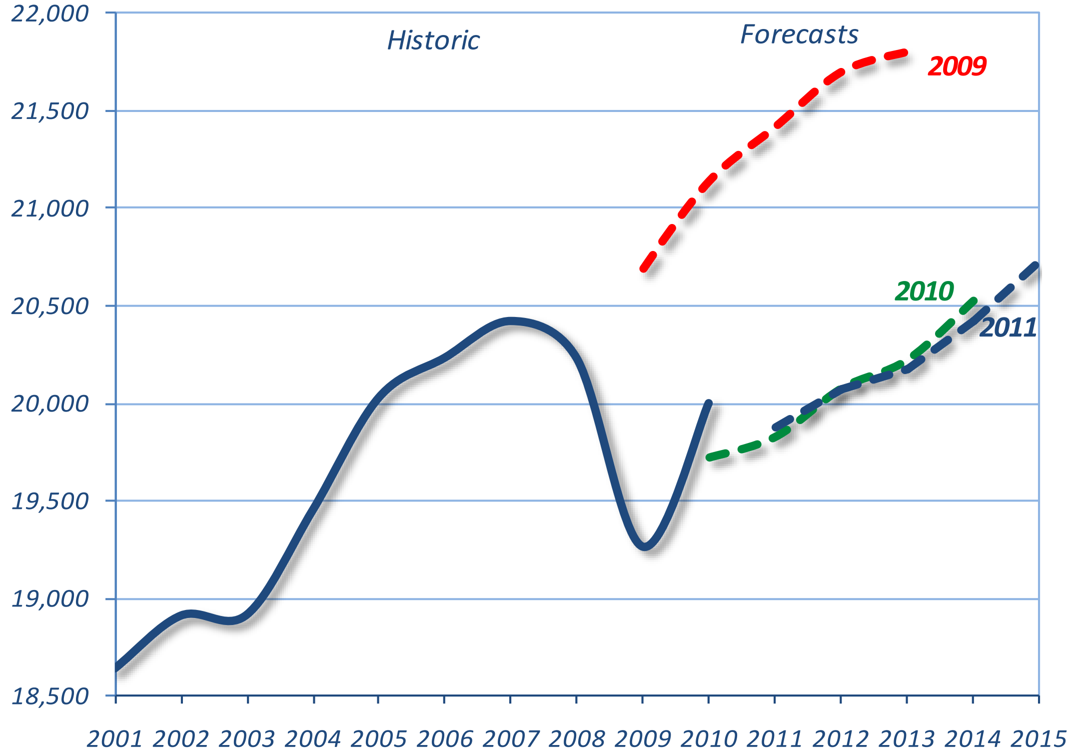
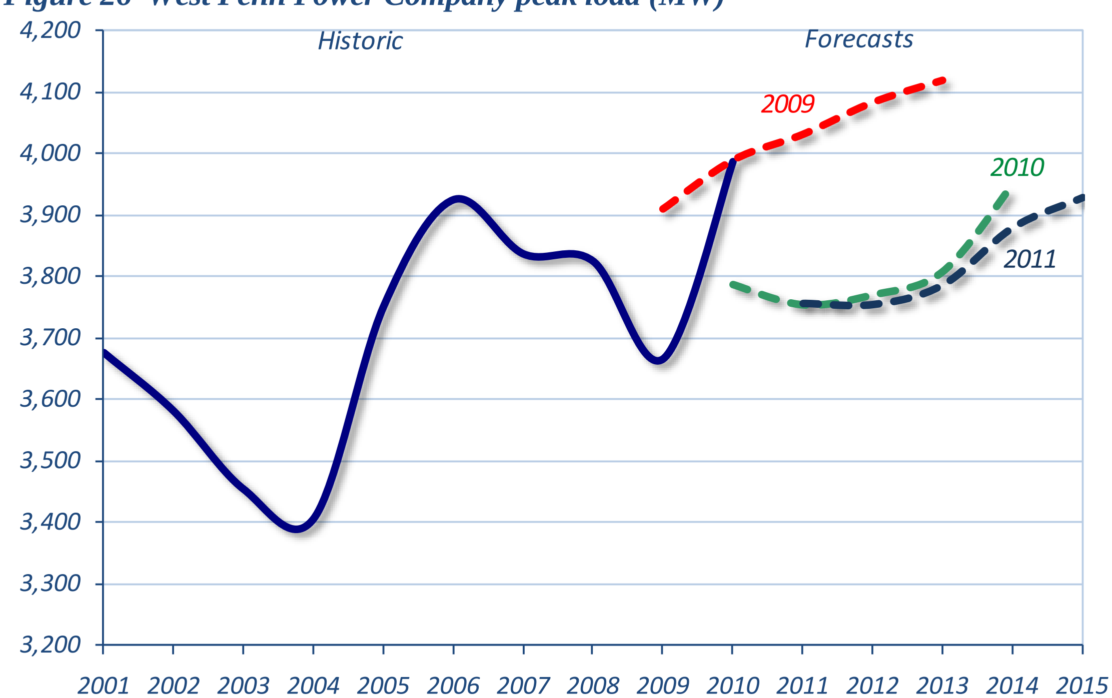
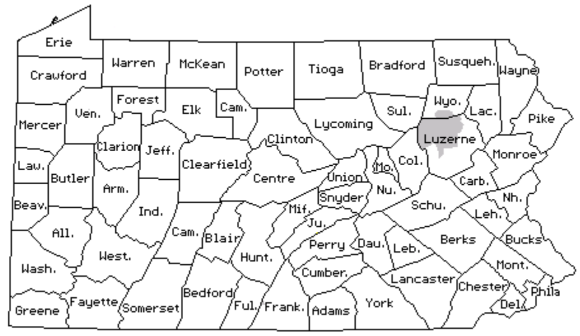


Figure 26 West Penn Power Company peak load (MW)



UGI Utilities Inc.—Electric Division



The Electric Division of UGI Utilities Inc. (UGI), a subsidiary of UGI Corporation, provides electric service to 62,250 customers in Northwestern Luzerne and Southern Wyoming counties in Pennsylvania. In 2010, UGI had energy sales totaling 981 GWh—up 2.7 percent from 2009. Residential sales continued to dominate UGI's market with 54.4 percent of the total sales, followed by commercial (33.9 percent) and industrial (11.1 percent). Average annual use per residential customer was 9,742 kWh at an average cost of 13.58 cents per kWh; operating revenues totaled $115.2 million.

Over the five-year planning horizon, UGI expects total energy demand to drop in 2011 and then increase at an average annual rate of 0.2 percent. This includes an average annual increase in residential sales of 0.1 percent and an annual increase in commercial sales of 0.4 percent. Industrial sales are expected to remain flat. See Figure 27.

UGI is basically a winter peaking utility, although the differential is inconsequential. One or 2 MW separates the two peaks. Peak load on the UGI system occurred on Jan. 24, 2011, and totaled 198 MW, or 2.6 percent above the 2009-10 winter peak load of 193 MW. The 2010 summer peak load of 197 MW was 8.8 percent higher than the peak load experienced during summer 2009. The actual average annual peak load growth rate over the past 10 years was 1.5 percent. The five-year forecast indicates an average increase in peak load of 0.8 percent. Peak load is projected to increase from 198 MW in 2010-11 to 206 MW in 2015-16. See Figure 28.

For Calendar Year 2010, there were five EGSs serving UGI's customers, providing 185 GWh, or 18.8 percent of total consumption. 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.

At the end of 2010, EGSs were serving 400 customers, or 18 percent of total sales volumes.

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 27 UGI Utilities Inc. energy demand (GWh)

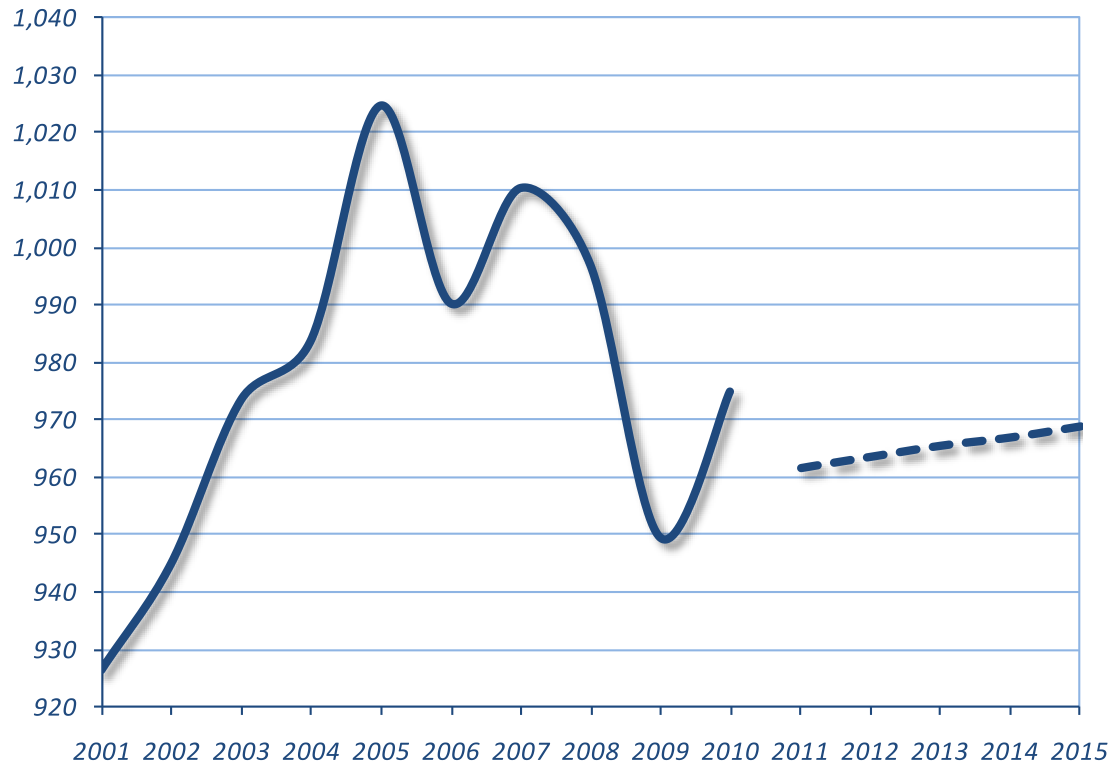
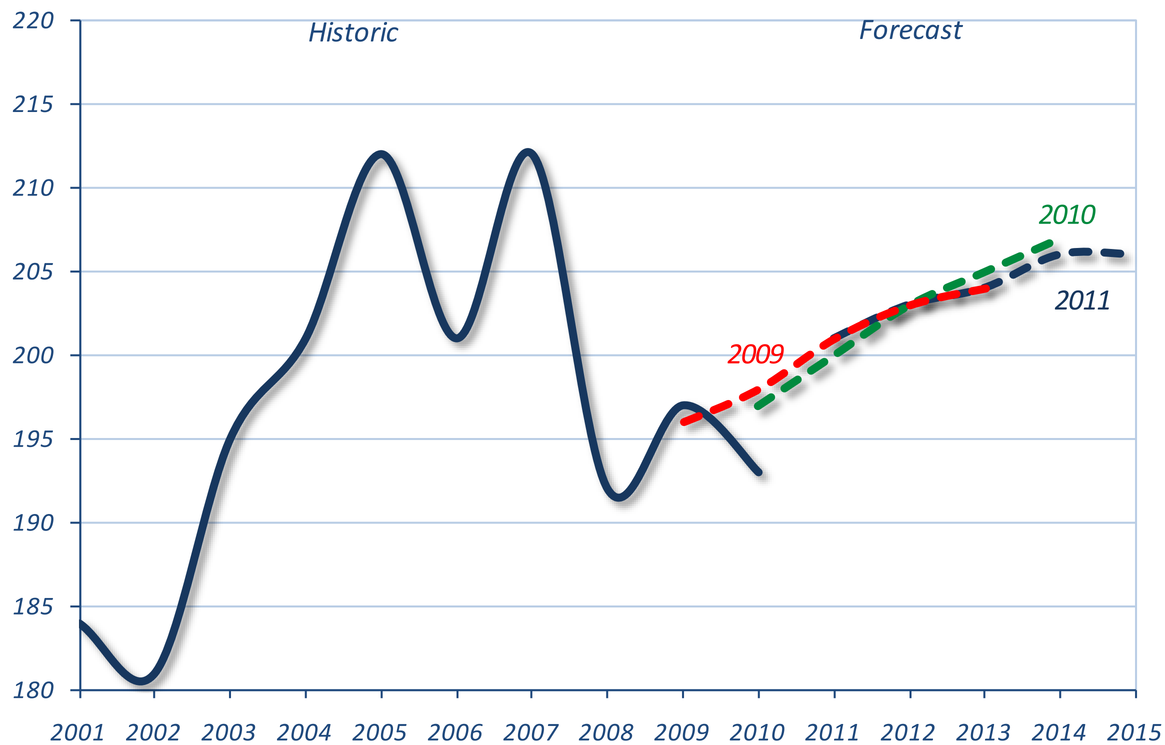
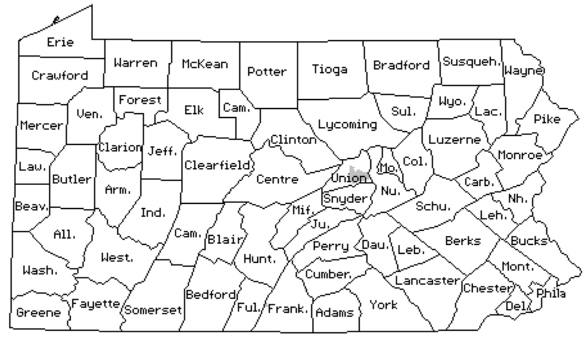


Figure 28 UGI Utilities Inc. peak load (MW)



Citizens' Electric Company



Citizens' Electric Company (Citizens') provides service to 6,814 customers in Union County, Pennsylvania. In 2010, Citizens' had retail energy sales totaling 159 GWh, down 1.0 percent from 2009. Residential sales accounted for 50.8 percent of Citizens' total sales, followed by industrial (30.9 percent) and commercial (17.8 percent). Average annual use per residential customer was 14,165 kWh at an average cost of 10.05 cents per kWh; operating revenues totaled $16.5 million.

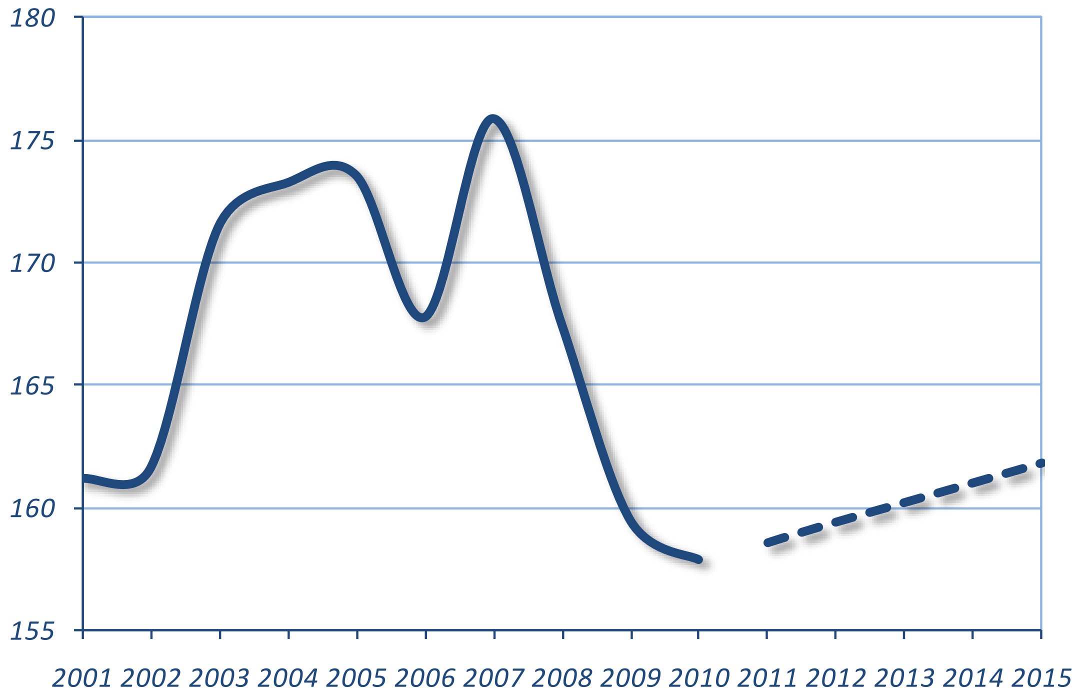
Over the next five years, Citizens' expects total energy demand growth to average 0.5 percent. Growth rates are the same (0.5 percent) for all three sectors. See Figure 29.

Citizens' 2010-11 winter peak load, occurring on Jan. 24, 2011, was 46.2 MW, a 19.4 percent increase from the winter peak of 2009. The 2010 summer peak load was 35.8 MW, a 4.1 percent increase. Peak load growth is projected to average 1.7 percent over the next five years, with peak load going from 46.2 MW to 50.2 MW in the winter of 2015-16.

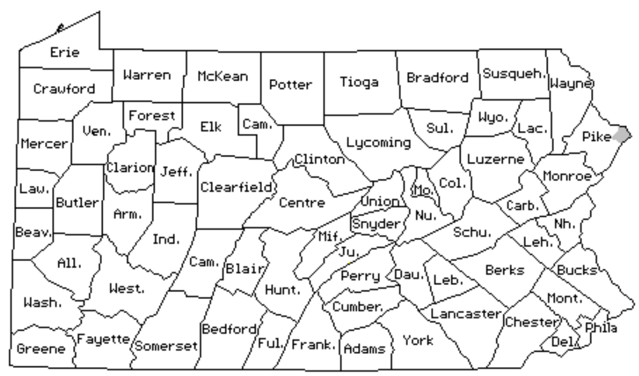
One of Citizens' largest customers generated 43 GWh of which Citizens' purchased 6 GWh, representing 3.6 percent of Citizens' net energy for load.

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 29 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 4,661 customers in Eastern Pike County, Northeastern Pennsylvania. In 2010, Pike's retail energy sales totaled 74 GWh, an increase of 1.5 percent from 2009 sales. Commercial sales continued to dominate Pike's market with 60.2 percent of the total sales, followed by residential with 39.2 percent. Pike has no industrial customers. Average annual use per residential customer was 8,105 kWh at an average cost of 8.31 cents per kWh; operating revenues totaled $6.4 million.

Over the next five years, total energy demand is projected to increase at an average annual rate of 1.5 percent, which includes a residential growth rate of 1.6 percent and a commercial growth rate of 1.4 percent. See Figure 30.

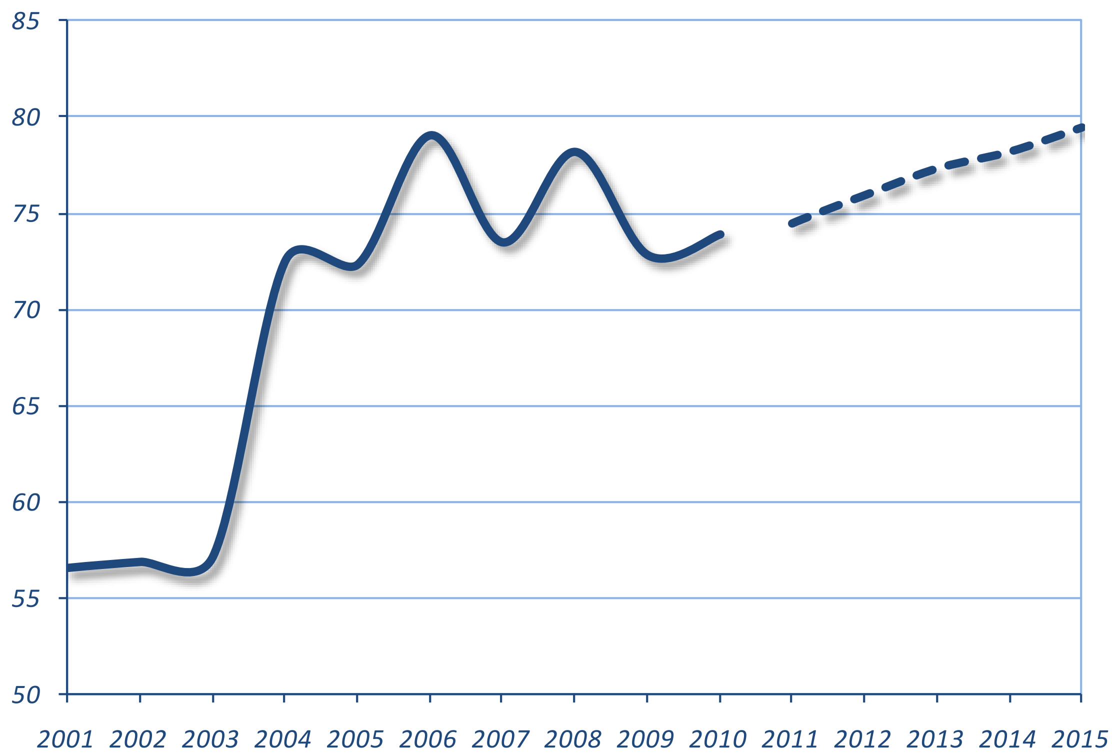
Pike's summer peak load, occurring on July 6, 2011, was 17.9 MW, a 17.0 percent increase from the summer peak of 2010. The 2010-11 winter peak load was 13.1 MW, a 6.5 percent increase.

Over the next five years, Pike projects its system peak load to increase from 17.9 MW in summer 2010 to 19.4 MW in 2015, or an average annual increase of 1.6 percent.

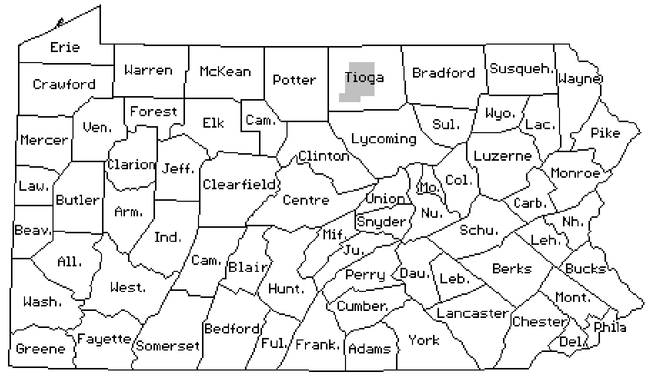
For the purpose of regulation, Pike is a small distribution company with no generating capability. O&R does not own any generating facilities.

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

Figure 30 Pike County Light & Power energy demand (GWh)



Wellsboro Electric Company



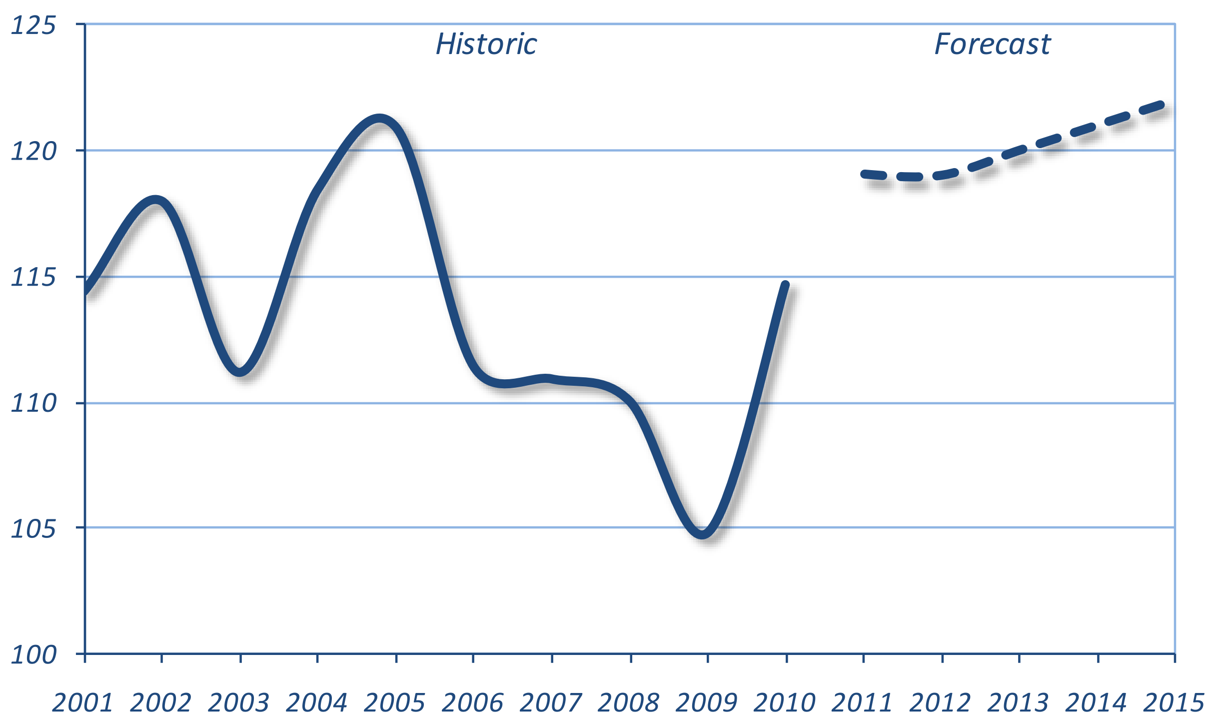
Wellsboro Electric Company (Wellsboro) provides electric service to 6,151 customers in Tioga County, North Central Pennsylvania. In 2010, Wellsboro's energy sales totaled 115 GWh, up 9.3 percent from 2009. Industrial sales accounted for 37.1 percent of the total, followed by residential (37.0 percent) and commercial (25.7 percent). Average annual use per residential customer was 8,503 kWh at an average cost of 11.34 cents per kWh; operating revenues totaled $12.5 million.

Over the next five years, Wellsboro expects total energy consumption to grow at an average annual rate of 1.3 percent. This includes a residential growth rate of 1.1 percent, a commercial rate of 1.0 percent, and an industrial rate of 1.5 percent. See Figure 31.

Wellsboro's summer peak load is projected to grow from 20.3 MW in 2010 to 24 MW by the year 2015, or a levelized annual growth rate of 3.4 percent.

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

Figure 31 Wellsboro Electric Company energy demand (GWh)



Section 3 – Regional Reliability

Regional Reliability Assessments

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 *2010 Long-Term Reliability Assessment*[59] 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 system and to make recommendations for their remedy.

NERC states that the electric industry has adequate plans to provide reliable electric service across North America through 2019. Planning reserve margins have increased compared to 2009 projections due mainly to the economic recession, which has reduced demand projections. For

[59] NERC, *2010 Long-Term Reliability Assessment*, October 2010.

the past two years, both peak demand and energy projections have shown significant decreases. Generally, recession effects account for a deferment of peak demand about four years, meaning that demand projected for 2008 will not be realized until 2012. Summer peak demand in the United States is expected to increase from 772 GW in 2010 to 870 GW in 2019, or an annual growth rate of 1.3 percent. Net Energy for Load is predicted to rise at the rate of 1.6 percent per year. The 2019 anticipated summer reserve margin is 21.5 percent.

Uncertainty inherent in projections of peak demand must be considered to maintain adequate reserve margins. The future demand for electricity depends on several interrelated variables:

- Future economic growth,
- Price and availability of other energy sources,
- Technological changes,
- Higher efficiency appliances and equipment,
- Customer-driven conservation efforts,
- Industrial cogeneration, and
- Effectiveness of industry-driven conservation and demand-side management programs.

The recent economic recession attributes to the greater uncertainty in future electricity use, necessitating continuous updates to demand forecasts. In the United States, there is an estimated 10 percent probability that summer peak demand will increase above 977 MW in 2019.

In a recent report[60], NERC states that while the electric industry is capable of responding to demand growth over the long-term, a potential rapid growth in the short-term could place it in a position where adequate resources cannot be fully deployed in a manner to meet adequacy requirements. For RFC, the NERC Scenario Case would advance the need for additional resources by three years to 2014. For the PJM portion of RFC, under the scenario, reserves would drop below the NERC reference level by 2015, decreasing to 13 percent by 2017. The report points out, however, that the entire PJM RTO would have adequate reserves through 2016.

NERC states that the existing transmission system and planned additions “appear generally adequate to reliably meet customer electricity requirements.” The continued reliability of the bulk power system depends on the ability to site and permit new facilities in a timely manner. About 39,000 circuit miles of new high-voltage transmission are projected for the next 10 years. Nearly 6,500 miles of transmission are currently considered delayed for up to three years.

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[60] NERC, *2010 Special Reliability Scenario Assessment: Potential Reliability Impacts of Swift Demand Growth after a Long-Term Recession,* August 2010.

*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 are 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.[61] Changes have not been made to the data to reflect the transfer of FirstEnergy and Duke Energy into the PJM RTO.

Compliance Standards

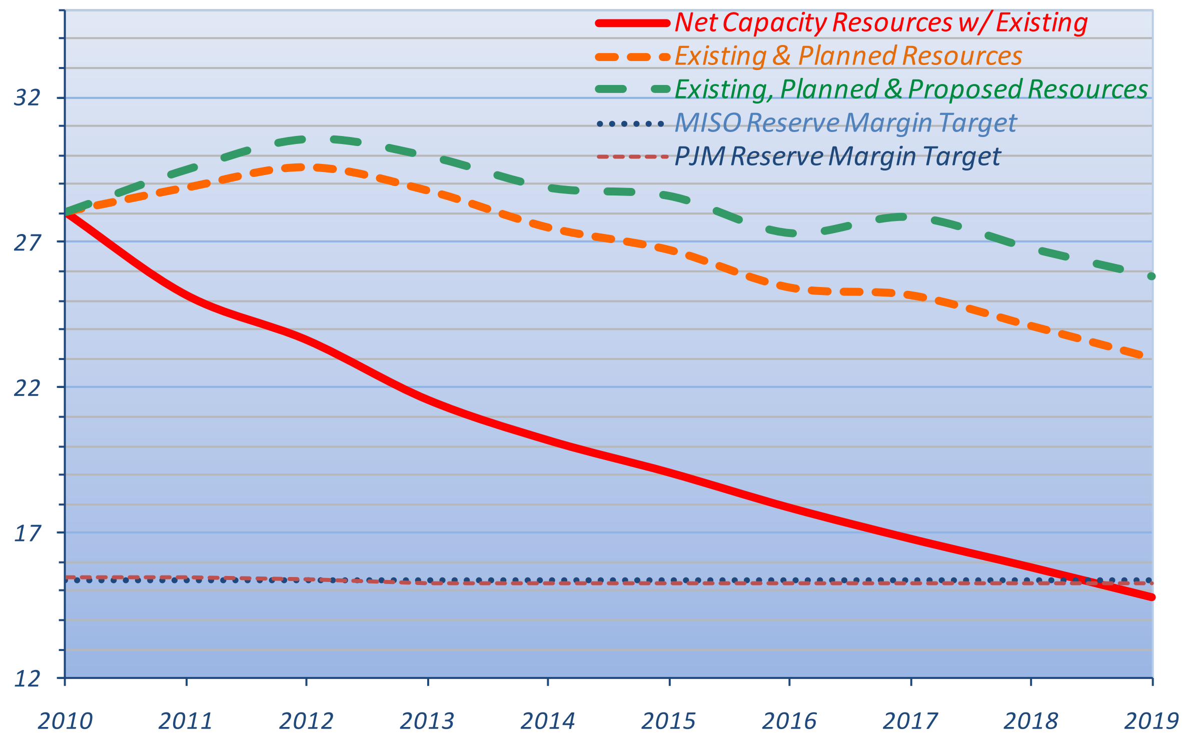
Analyses were conducted by PJM and MISO to determine the reserve margins that were equivalent to the RFC Loss of Load Expectation (LOLE) criterion of not exceeding one occurrence in 10 years (0.1 day/year) on an annual basis for their planning area. The PJM reserve margin target was 15.5 percent for 2010 and 2011, 15.4 percent for 2012, and 15.3 percent through 2019. The 2010 PJM Reserve Requirement Study recommends a 15.5 percent margin for 2012.[62] The MISO reserve margin target for 2010 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.[63]

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 28.0 percent in 2010, to 25.8 percent in 2019. 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 to 14.8 percent in 2019, which is an improvement over the previous forecast, due mainly to current economic conditions. See Figure 32.

[61] NERC, *2010 Long-Term Reliability Assessment*, October 2010.
[62] PJM, *2010 PJM Reserve Requirement Study*, Sept. 30, 2010.
[63] RFC, *Long Term Resource Assessment 2010-2019*, October 2010.

Figure 32 RFC 2010-2019 reserve margin comparison (%)



The system peak load of the PJM RTO for summer 2010 was 136,465 MW or 7.6 percent higher than the 2009 peak load of 126,805 MW. The weather normalized peak load for 2010 was 135,080 MW. The PJM RTO summer peak load growth is projected to average 1.3 percent over the next 10 years. The summer peak in 2021 is forecasted to be 176,060 MW.[64]

PJM installed generating capacity totaled 166,512 MW at the end of 2010, which was dominated by coal (40.8 percent), natural gas (29.1 percent) and nuclear (18.3 percent). A 2010 generation of 734,678 GWh included 49.3 percent coal and 34.6 percent nuclear. See Figures 33 and 34.[65]

At the time of PJM's 2010 summer peak load, the actual reserve margin for existing capacity resources was 30,047 MW, or 22.0 percent. Planned resources increase the capacity by 29,550 MW by the end of the assessment period. PJM should meet its reserve requirement through 2019.

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[64] PJM, *2011 PJM Load Forecast Report*, January 2011.
[65] Monitoring Analytics, LLC, *2010 State of the Market Report for PJM, Vol. 2*, March 10, 2011.

Figure 33 PJM 2010 installed capacity by fuel type

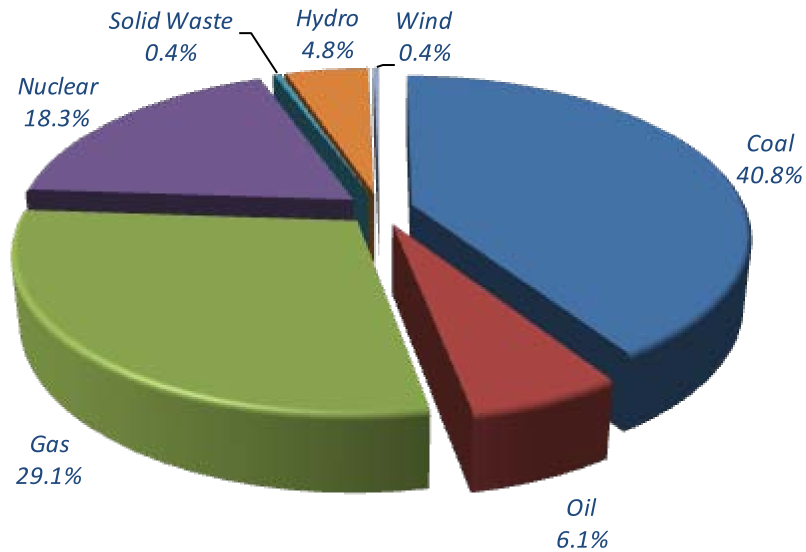
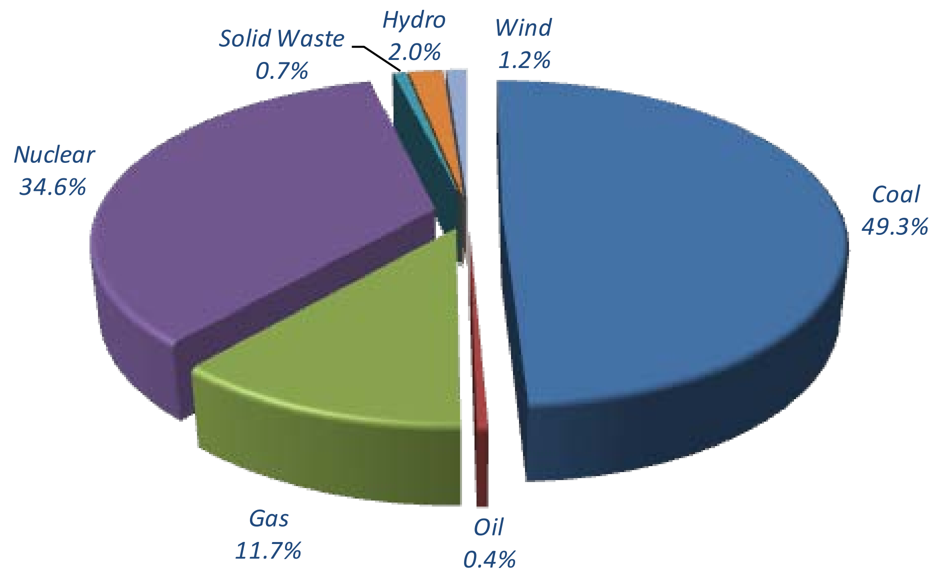


Figure 34 PJM 2010 generation by fuel type



At the end of 2010, 76,415 MW of capacity were in generation request queues for construction through 2018, compared to an average installed capacity of approximately 167,000 MW. Although it is clear that not all generation in the queues will be built, PJM has added capacity annually since 2000.

Most steam units in PJM are from 30 to 50 years old, and significant retirements of steam units are likely to occur within the next 10 to 20 years, particularly if stricter environmental regulations make steam units more costly to operate. While steam units comprise 47.3 percent of all current MW, steam units 40 years of age and older comprise 84.6 percent of all MW 40 years of age and older, and 92.5 percent of such MW if hydroelectric is excluded from the total.

The MISO net internal peak demand for summer 2010 was 104,288 MW, assuming a 4.55 percent diversity level.[66] For summer 2019, the net internal demand is projected to be 115,769 MW, or an equivalent compound growth rate of 1.2 percent. The MISO market had 131,235 MW of net capacity resources for the 2010 summer.[67]

The MISO reserve margin for existing capacity resources is 22,354 MW for 2011, which is 23.8 percent, based on net internal demand. Total resources are expected to grow to 124,828 MW in 2019, resulting in a projected reserve margin of 16.1 percent, still above the reserve margin target.

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.

Over the next seven years, there are plans within the RFC region for the addition of more than 1,830 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 (TrAIL) consists of a new 500-kV circuit from 502 Junction to Mount 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. Crews have erected all 661 structures and strung all the wire that make up the TrAIL project – the first backbone upgrade to the Mid-Atlantic regional transmission grid built in decades. TrAIL is now energized and has met the June 2011 in-service deadline.

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, which is unlikely due to the ongoing review of the National Park Service.

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. The facilities were originally expected to be in service in 2012. Based on the findings of the latest analyses, projected

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[66] Midwest ISO, *2011 Summer Resource Assessment*.
[67] Midwest ISO, *2010 Long Term Resource Assessment.*

reliability violations have moved several years into the future, and PJM is directing that further development of the PATH project be suspended while PJM conducts a more rigorous analysis of the potential need for PATH.

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. PJM has confirmed the need for the MAPP project by June 1, 2015.

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.

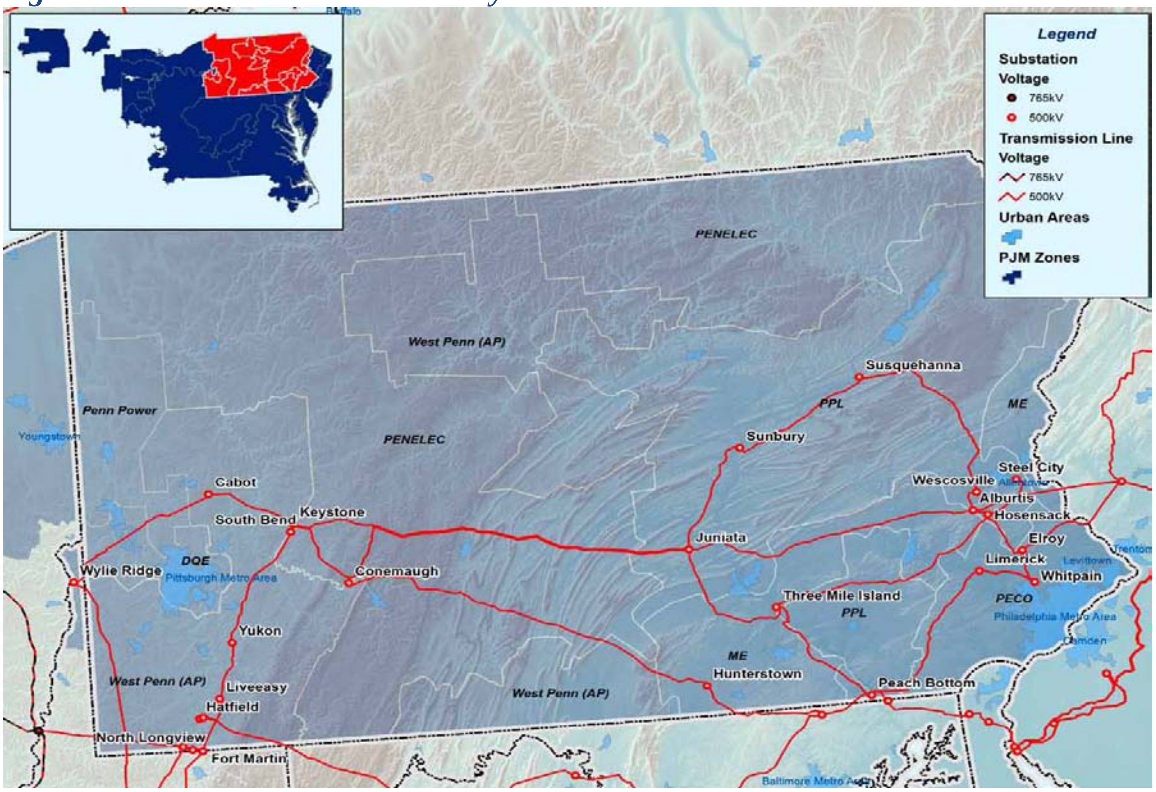
Pennsylvania

The Pennsylvania electric power outlook generally reflects the projections of RFC, which are based on projections of the PJM RTO and the Midwest ISO. 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 35, including Penn Power.[68]

[68] PJM, *2010 Regional Transmission Expansion Plan*, Feb. 28, 2011, p. 385.

Figure 35 PJM service area in Pennsylvania



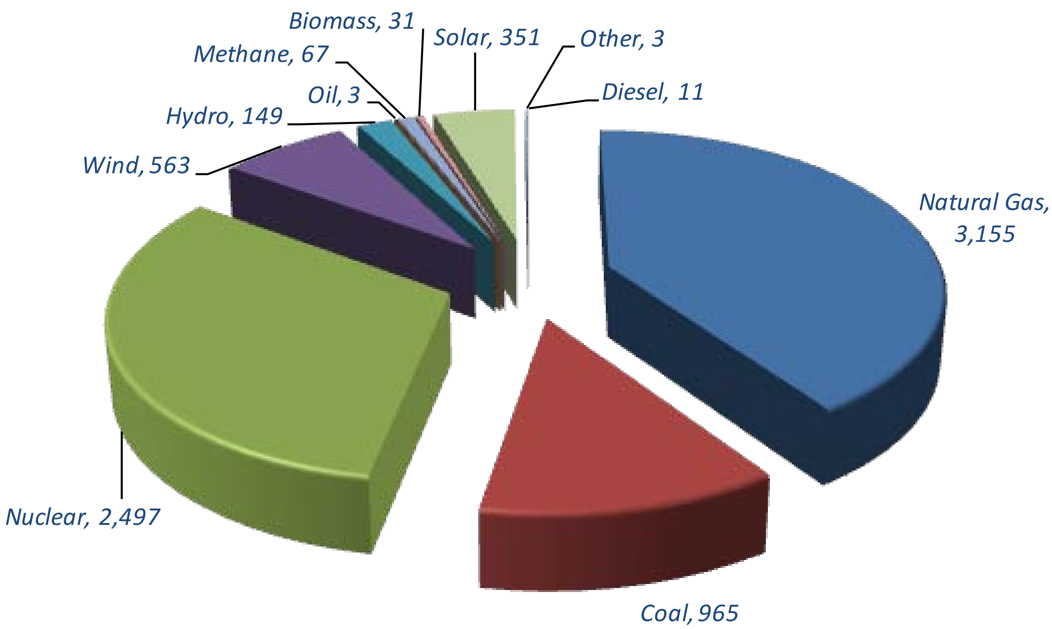
Load-serving entities (LSEs) acquire capacity resources by entering into bilateral agreements, participating in the PJM-operated capacity market, owning generation, and/or pursuing load management options. The PJM generator interconnection process ensures that new capacity resources satisfy LSE requirements 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 for the performance of feasibility studies and other technical reviews.

Proposed new generating plants and increased capacity of existing plants located in Pennsylvania total 7,795 MW through 2018. These facilities are either under study (active), under construction, partially in-service or in-service. Natural gas projects make up over 40 percent of queued capacity. This additional capacity may be used to serve Pennsylvania customers or out-of-state customers. See Figure 36.[69] Appendix B lists the current PJM interconnection requests for new generating resources located in Pennsylvania.

[69] *Ibid.*, p. 393.

Figure 36 PJM queued generating capacity in Pennsylvania by fuel type



The generating capacity located in Pennsylvania totals 46,580 MW.[70] As stated earlier, the output of some of these facilities may serve loads outside of Pennsylvania. See Figure 37. Appendix C lists the existing generation facilities located in Pennsylvania.

The state's 2010 aggregate non-coincident summer peak demand was 29,515 MW. In 2010, Pennsylvania's net electric generation totaled 229,788 GWh, up 5.2 percent from 2009. Figure 38 shows the 2010 generation distribution by fuel type.[71] "Other" includes wind, solar and biomass sources.

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[70] Electric Power Generation Association.
[71] U.S. DOE Energy Information Administration, *Electric Power Monthly*, March 2011.

Figure 37 Existing generating capacity in Pennsylvania by fuel type

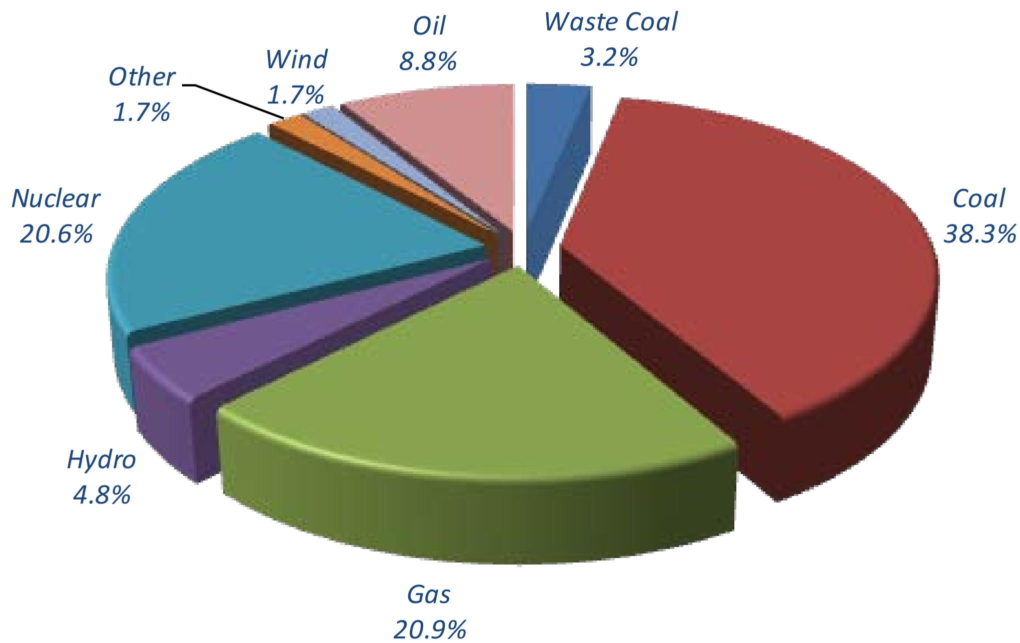
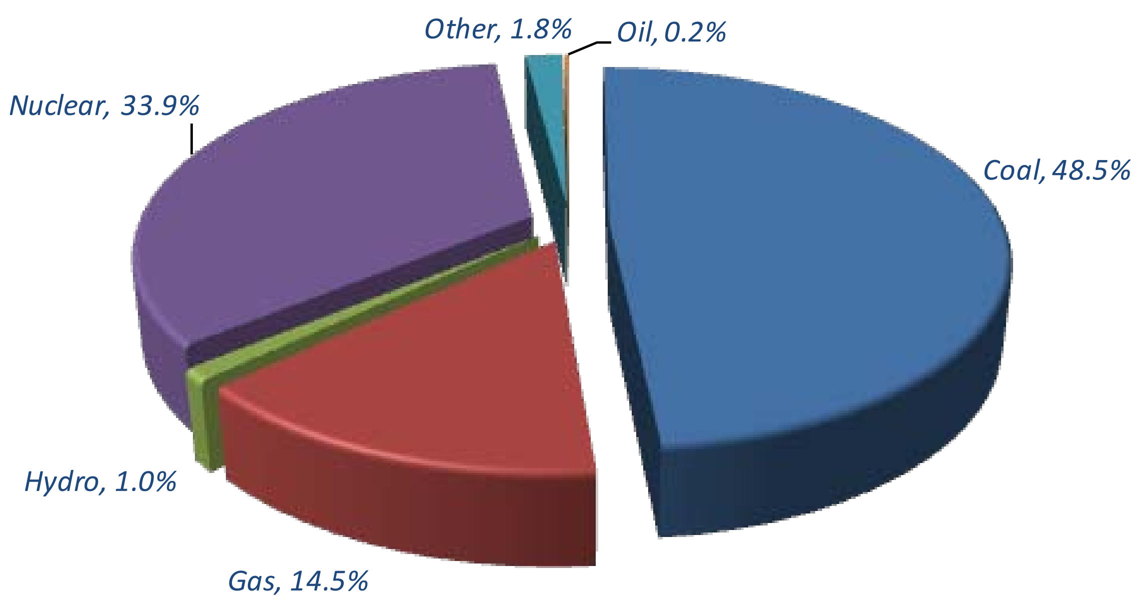


Figure 38 2010 generation in Pennsylvania by fuel type



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 2019, 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 28.0 percent in 2010 to 25.8 percent in 2019. This assumes that about 30 percent of conceptual seasonal capability will become available during the last five years of the forecast period.

In 2010, Pennsylvania retail sales increased 2.8 percent over the 2009 level, following a 4.2 percent decrease from 2008. The current average aggregate five-year projection of growth in energy demand is 0.9 percent per year. This includes a residential growth rate of 0.4 percent, a commercial rate of 1.2 percent and an industrial rate of 1.4 percent.

Over the past 15 years, the aggregate non-coincident peak load for the major EDCs increased at an average rate of 1.0 percent per year. The peak load is expected to increase at an average annual growth rate of 0.5 percent.

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.

* * * * *

Appendix A – Data Tables

The following tables provide actual and projected peak load and residential, commercial and industrial energy demand. Actual data covers years 2001 through 2010. Five-year projections are those filed with the Commission in years 2001 through 2011.

For Met-Ed, Penelec, Penn Power and PPL, the 2010 actual and 2011-15 forecast of commercial and industrial (C&I) sales reflect a redefinition of C&I customers; i.e., the commercial class now includes small C&I customers, and the industrial class includes large C&I customers.

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

		Projected Peak Load Requirments (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	2771	2661										
2002	2886	2682	2850									
2003	2686	2702	2884	2822								
2004	2646	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	2889						2910	3194	3067	2836	2854	
2011								3242	3128	2857	2863	2944
2012									3191	2850	2860	3000
2013										2890	2917	3053
2014											2960	3088
2015												3125

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

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	3584	3643										
2002	3924	3681	3671									
2003	3759	3716	3726	3697								
2004	3886	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	4327						4243	4372	4371	4188	4117	
2011								4453	4444	4181	4184	4213
2012									4527	4171	4267	4275
2013										4197	4352	4332
2014											4448	4402
2015												4474

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

		Projected Commercial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	6170	6231										
2002	6458	6336	6324									
2003	6346	6438	6467	6436								
2004	6454	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	6712						7259	7302	6815	6627	6428	
2011								7457	6878	6583	6501	6681
2012									6952	6533	6585	6782
2013										6527	6666	6854
2014											6742	6957
2015												7056

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

		Projected Industrial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	3283	3576										
2002	3328	3615	3315									
2003	3189	3651	3382	3349								
2004	3229	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	2987						3464	3420	3084	2933	2440	
2011								3467	3140	2851	2407	2865
2012									3141	2777	2395	2846
2013										2726	2385	2815
2014											2359	2770
2015												2724

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

		Projected Peak Load Requirements (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	2486	2455										
2002	2616	2504	2503									
2003	2438	2553	2554	2527								
2004	2468	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	2715						2915	2915	2915	2932	2687	
2011								2972	2972	3017	2640	2869
2012									3032	3085	2630	2775
2013										3158	2668	2815
2014											2731	2872
2015												2952

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

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	4496	4430										
2002	4721	4501	4607									
2003	4895	4577	4708	4846								
2004	5071	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	5666						5764	6037	6037	5836	5587	
2011								6187	6187	5969	5552	5424
2012									6341	6109	5577	5226
2013										6232	5682	5386
2014											5799	5547
2015												5650

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

		Projected Commercial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	3855	3751										
2002	3985	3860	3976									
2003	4018	3970	4096	4057								
2004	4251	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	3006						4908	5108	5108	5020	4671	
2011								5244	5244	5152	4706	2955
2012									5375	5291	4783	2959
2013										5421	4887	3019
2014											4963	3090
2015												3158

* The 2010 actual and 2011 forecast are based on a reclassification of the commercial and industrial classes.

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

		Projected Industrial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	4186	4312										
2002	4012	4409	4263									
2003	3986	4490	4341	3954								
2004	4042	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	5288						4221	4193	4193	3842	3538	
2011								4201	4201	4035	3497	5443
2012									4209	4047	3528	5545
2013										4048	3731	5589
2014											4021	5610
2015												5625

* The 2010 actual and 2011 forecast are based on a reclassification of the commercial and industrial classes.

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

		Projected Peak Load Requirements (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	2337	2321										
2002	2693	2347	2337									
2003	2308	2373	2375	2410								
2004	2425	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	2659						2711	2711	2711	2630	2465	
2011								2750	2750	2661	2452	2515
2012									2789	2688	2458	2544
2013										2715	2496	2579
2014											2531	2625
2015												2662

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

		Projected Commercial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	4538	4472										
2002	4697	4549	4613									
2003	4727	4626	4730	4782								
2004	4792	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	3671						5367	5277	5277	5213	5196	
2011								5356	5356	5265	5215	3562
2012									5436	5320	5257	3526
2013										5364	5343	3593
2014											5424	3650
2015												3698

* The 2010 actual and 2011 forecast are based on a reclassification of the commercial and industrial classes.

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

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	3991	3977										
2002	4167	4021	4043									
2003	4187	4065	4089	4194								
2004	4249	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	4656						4614	4662	4662	4614	4569	
2011								4727	4727	4662	4489	4460
2012									4793	4721	4443	4304
2013										4776	4442	4387
2014											4486	4539
2015												4653

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

		Projected Industrial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	4392	4857										
2002	4315	5144	4670									
2003	4391	5214	4783	4492								
2004	4589	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	5748						4930	4983	4983	4538	4126	
2011								5013	5013	4859	4222	6026
2012									5043	4889	4370	6175
2013										4922	4607	6266
2014											4674	6304
2015												6325

* The 2010 actual and 2011 forecast are based on a reclassification of the commercial and industrial classes.

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

		Projected Peak Load Requirements (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	1011	883										
2002	869	904	918									
2003	855	930	947	891								
2004	898	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	903						965	965	965	941	896	
2011								980	980	963	890	944
2012									994	981	899	947
2013										995	930	983
2014											977	1002
2015												1010

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

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	1391	1360										
2002	1533	1395	1447									
2003	1513	1430	1483	1512								
2004	1545	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	1696						1835	1758	1758	1761	1701	
2011								1789	1789	1806	1708	1664
2012									1821	1860	1721	1624
2013										1904	1714	1638
2014											1739	1664
2015												1684

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

		Projected Commercial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	1220	1162										
2002	1268	1206	1270									
2003	1291	1251	1327	1279								
2004	1296	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	1311						1535	1496	1496	1394	1428	
2011								1532	1532	1424	1408	1300
2012									1569	1491	1449	1267
2013										1535	1500	1272
2014											1535	1277
2015												1278

* The 2010 actual and 2011 forecast are based on a reclassification of the commercial and industrial classes.

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

		Projected Industrial Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	1539	1618										
2002	1505	1644	1514									
2003	1481	1677	1516	1521								
2004	1554	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	1488						1626	1741	1741	1517	1226	
2011								1748	1748	1687	1214	1527
2012									1755	1694	1238	1652
2013										1700	1370	1705
2014											1596	1725
2015												1738

* The 2010 actual and 2011 forecast are based on a reclassification of the commercial and industrial classes.

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

		Projected Peak Load Requirements (Year Forecast Was Filed)										
Year	**Actual**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
2001	6583	6850										
2002	6970	6960	7000									
2003	7197	7060	7070	6790								
2004	7335	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	7365						7710	7400	7500	7250	7207	
2011								7480	7580	7320	7227	7101
2012									7680	7360	7283	7138
2013										7450	7366	7142
2014											7487	7216
2015												7282

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

		Projected Residential Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
2001	12269	12176										
2002	12640	12324	12391									
2003	13266	12478	12514	12868								
2004	13441	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	14206						15036	14702	14562	14340	14384	
2011								14828	14608	14246	14390	14142
2012									14770	14350	14226	14120
2013										14443	14164	14005
2014											14325	14161
2015												14335

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

		Projected Commercial Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
2001	11778	11291										
2002	12117	11431	11850									
2003	12273	11561	12033	12212								
2004	12576	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	10667						14492	14045	14253	14486	14098	
2011								14290	14596	14631	14642	10756
2012									14907	14926	14907	10860
2013										15228	15295	11022
2014											15827	11251
2015												11499

* The 2010 actual and 2011 forecast are based on a reclassification of the commercial and industrial classes.

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

		Projected Industrial Energy Demand (Year Forecast Was Filed)										
Year	**Actual**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**
2001	10319	10963										
2002	9853	11255	10780									
2003	9599	11521	11135	10355								
2004	9611	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	12045						10214	10059	9228	9141	8506	
2011								10084	9005	8879	8365	12151
2012									9009	8866	8211	12116
2013										8864	8110	12269
2014											8054	12450
2015												12686

* The 2010 actual and 2011 forecast are based on a reclassification of the commercial and industrial classes.

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

		Projected Peak Load Requirements (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	7948	7392										
2002	8164	7451	8012									
2003	7696	7510	8076	8229								
2004	7567	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	8864						9293	9480	8940	9091	8114	
2011								9622	9074	9227	8236	8786
2012									9210	9365	8359	8770
2013										9506	8485	8842
2014											8612	8916
2015												8991

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

		Projected Commercial* Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	7604	7315										
2002	8019	7446	7732									
2003	8077	7578	7963	8135								
2004	8414	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	8472						9407	9587	9436	9052	8572	
2011								9779	9625	9233	8744	8589
2012									9817	9417	8918	8705
2013										9606	9097	8879
2014											9279	9057
2015												9238

* 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	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	11178	11278										
2002	12335	11385	11634									
2003	12259	11488	11733	12020								
2004	12507	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	13896						14870	13852	14313	13855	13151	
2011								14129	14599	14132	13414	13912
2012									14891	14415	13683	14037
2013										14703	13956	14317
2014											14235	14604
2015												14896

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

		Projected Industrial* Energy Demand (Year Forecast Was Filed)										
Year	Actual	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	15312	15405										
2002	15323	15406	15324									
2003	15518	15408	15417	15130								
2004	15741	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	15824						17415	17125	17597	17202	16207	
2011								17467	17949	17546	16531	15991
2012									18308	17897	16861	16153
2013										18254	17199	16476
2014											17543	16806
2015												17142

* Large Commercial & Industrial

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

Year	Actual	Projected Peak Load Requirements (Year Forecast Was Filed)										
		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	3677	3141										
2002	3582	3445	3458									
2003	3455	3465	3505	3535								
2004	3407	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	3988						3895	4028	4036	3990	3788	
2011								4078	4083	4032	3755	3757
2012									4123	4084	3771	3754
2013										4120	3809	3786
2014											3951	3879
2015												3928

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

Year	Actual	Projected Residential Energy Demand (Year Forecast Was Filed)										
		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	6325	6192										
2002	6459	6260	6374									
2003	6641	6329	6471	6486								
2004	6724	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	7401						7447	7761	7774	7264	7147	
2011								7869	7892	7233	7104	7139
2012									7965	7248	7085	7122
2013										7102	6952	7047
2014											7008	7073
2015												7148

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

Year	Actual	Projected Commercial Energy Demand (Year Forecast Was Filed)										
		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	4360	4326										
2002	4497	4395	4458									
2003	4529	4449	4543	4577								
2004	4691	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	4983						5318	5365	5327	5160	4966	
2011								5452	5387	5275	4987	4909
2012									5462	5353	5059	4931
2013										5450	5169	4979
2014											5307	5091
2015												5229

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

Year	Actual	Projected Industrial Energy Demand (Year Forecast Was Filed)										
		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
2001	7955	8481										
2002	7957	8597	8006									
2003	7747	8663	8116	7885								
2004	8039	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	7617						8634	8728	8699	8711	7612	
2011								8766	8799	8906	7740	7833
2012									8844	9093	7936	8025
2013										9246	8105	8146
2014											8214	8264
2015												8346

Appendix B – Plant Additions and Upgrades

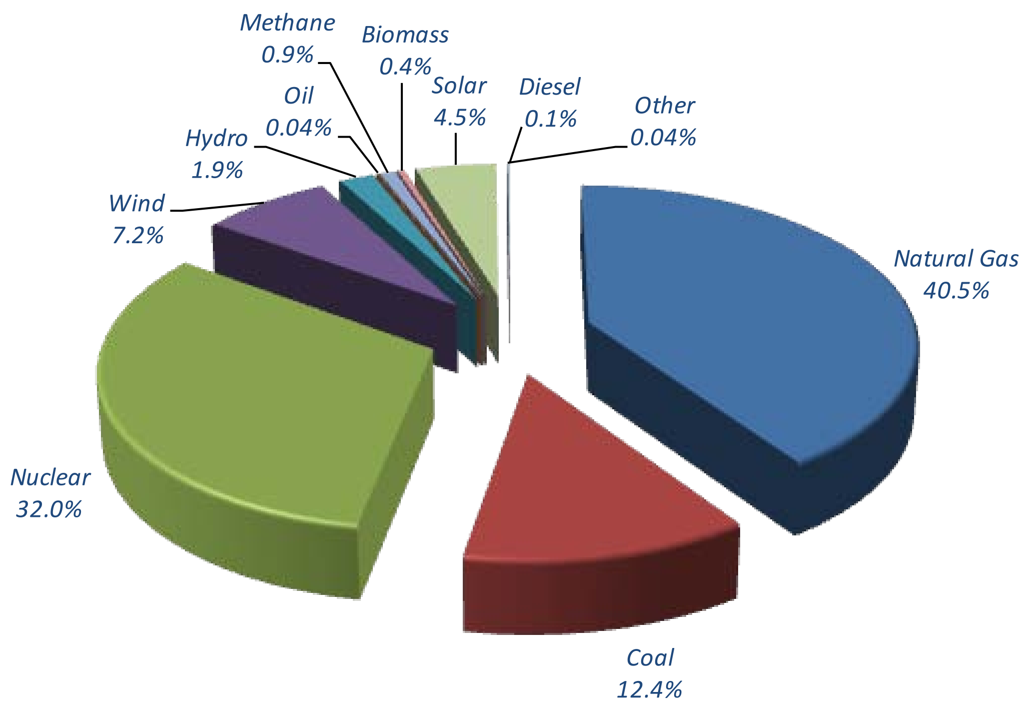
The following data represents PJM interconnection requests for new generating resources located in Pennsylvania. As of Jan. 31, 2011, PJM has received 560 interconnection requests for new generating resources or incremental additions to existing resources since 1999, totaling 104,902 MW. Of this total, 13,782 MW or 13.1 percent of all PJM queued were placed in service. Projects withdrawn totaled 81,322 MW or 77.5 percent, representing 293 projects. New capacity under construction amounts to 1,365 MW.

<u>Note:</u> *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
G06	Martins Creek #4	850	30	Under Construction	2012 Q1	Coal	PPL
G51_W60	Hatfield Ferry 500 kV	525	525	Under Construction	2013 Q1	Coal	APS
K02	East Towanda-Moshannon 230kV	70	0	Suspended	2012 Q2	Wind	PENELEC
M12	Susquehanna #2	2520	107	Partially In-Service	2011 Q3	Nuclear	PPL
M26	Champion	272	272	Suspended	2013 Q4	Coal	APS
N32	Gans 138kV	50	10.1	Under Construction	2011 Q4	Wind	APS
N36	Gold-Sabinsville 115kV	50	10	Suspended	2011 Q2	Wind	PENELEC
O19	Somerset 115kV	33	6.6	Suspended	2013 Q2	Wind	PENELEC
O52	Gold-Potter Co 115kV	50	10	Suspended	2011 Q2	Wind	PENELEC
O56	Osterburg East 115kV	76	15.2	Suspended	2013 Q1	Wind	PENELEC
O60	Berlin 23 kV	5	1.08	Suspended	2012 Q1	Wind	PENELEC
O72	Hooversville-Central City	60	12	Under Construction	2012 Q4	Wind	PENELEC
P01	Westover-Madera 115kV	65	13	Suspended	2011 Q4	Wind	PENELEC
P04	Peach Bottom 500kV	557	550	In-Service	2011 Q1	Natural Gas	PECO
P28	Mehoopany 115kV	150	30	Suspended	2012 Q2	Wind	PENELEC
Q25	Donegal-Iron City 138kV	80	16	Suspended	2014 Q1	Wind	APS
Q28	Eldred-Frackville 230kV	170	34	Suspended	2011 Q3	Wind	PPL
Q34	Garrett 115kV	100	20	Suspended	2011 Q2	Wind	PENELEC
Q36	Philipsburg - Tyrone North 115kV	50	10	Suspended	2011 Q1	Wind	PENELEC
Q47	Peach Bottom	2532	140	Under Construction	2013 Q2	Nuclear	PECO
Q53	Summit-West Fall 115kV	38	7.6	In-Service	2011 Q2	Wind	PENELEC
R01	Susquehanna	800	800	Active	2018 Q4	Nuclear	PPL
R02	Susquehanna	800	800	Active	2018 Q4	Nuclear	PPL
R32	Salix - Claysburg 115kV	75	15	Under Construction	2011 Q4	Wind	PENELEC
R43	Frackville - Hauto #3	20	4	Suspended	2012 Q2	Wind	PPL
S103	Warren 115kV	57	57	In-Service	2011 Q2	Natural Gas	PENELEC
S29B	Somerset 23kV	7	5.7	Under Construction	2011 Q1	Methane	PENELEC
S42	Eldred-Fairview	18	3.6	Under Construction	2012 Q1	Wind	PPL
S64	York Inc. 115kV	18	18	Active	2011 Q1	Biomass	ME
T117	Hunlock Creek 69kV	126	126	Under Construction	2012 Q2	Natural Gas	UGI
T156	Champion	292	20	Active	2011 Q1	Coal	APS
T174	Yukon-Browns Run 500kV	930	900	Active	2011 Q2	Natural Gas	APS
U1-010	Peach Bottom	575	18	In-Service	2011 Q1	Natural Gas	PECO
U1-051	Clearfield	130	16.9	Active	2011 Q4	Wind	PENELEC
U1-068	York 115kV	51	10	In-Service	2011 Q1	Natural Gas	ME
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	2014 Q2	Hydro	PPL
U2-055	Karthaus-Milesburg 230kV	89	11.5	Active	2012 Q3	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
U3-029	Beaver Valley #1	950	37	Under Construction	2013 Q4	Nuclear	DL
U3-030	Beaver Valley #2	951	38	Under Construction	2012 Q4	Nuclear	DL
U4-014	Siegfried-Hauto 69kV	10	3.8	Under Construction	2011 Q4	Solar	PPL
V1-027	Limerick	1213	20	Partially In-Service	2011 Q2	Nuclear	PECO

Status of Pennsylvania's Plant Additions and Upgrades

Queue	PJM Substation	MW	MWC	Status	In Service	Fuel	Transmission Owner
V2-027	South Milton	2	1.62	Under Construction	2013 Q3	Methane	PPL
V3-030	St. Benedict-Patton 46kV	31	3.98	Active	2012 Q4	Wind	PENELEC
V3-040	Siegfried-Hauto 69kV	10	3.8	Under Construction	2013 Q2	Solar	PPL
V3-041	Daleville	4	3.2	Under Construction	2011 Q4	Methane	PECO
V3-042	Thompson 115kV	84	10.9	Active	2012 Q4	Wind	PENELEC
V3-044	Glendon 34.5kV	5	4.8	Under Construction	2011 Q2	Methane	ME
V3-051	Letort	3	0.4	In-Service	2011 Q1	Wind	PPL
V3-062	McConnellsburg-Guilford 138kV	20	7.6	Active	2011 Q4	Solar	APS
V4-012	Morgantown	5	4.8	Under Construction	2012 Q1	Methane	PPL
V4-020	North Temple 230kV	650	650	Active	2014 Q2	Natural Gas	ME
V4-027	Quarryville	5	1.9	Under Construction	2012 Q1	Solar	PPL
V4-045	Peach Bottom	2722	320	Active	2015 Q4	Nuclear	PECO
V4-052	West Reading	10	6	Under Construction	2011 Q1	Natural Gas	ME
V4-072	Blue Ridge Landfill	5	4.8	Under Construction	2012 Q2	Methane	APS
V4-075	Warwick 12kV	2	0.76	Under Construction	2012 Q1	Solar	PPL
V4-076	Carlisle Pike 23kV	5	2	Under Construction	2011 Q2	Solar	PENELEC
V4-077	Montgomery Avenue 12.47kV	13	4.9	Under Construction	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 Q4	Solar	APS
W1-014	Saint Thomas 34kV II	20	7.6	Active	2011 Q4	Solar	APS
W1-015	Shade Gap 115kV	70	9.1	Active	2013 Q4	Wind	PENELEC
W1-045	Roxbury 23 kV	14	5.13	Active	2011 Q3	Solar	PENELEC
W1-046	Face Rock 69kV	15	5.7	Under Construction	2012 Q1	Solar	PPL
W1-050	Keller & Valley 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
W1-054	South Akron-Prince	11	11.4	Under Construction	2011 Q4	Methane	PPL
W1-064	Grand Point 12kV	2	1.6	Active	2011 Q1	Methane	APS
W1-075	Hunterstown 115kV	20	7.6	Active	2012 Q4	Solar	ME
W1-104	Bellefonte 12kV	1	0.25	Active	2011 Q4	Solar	APS
W1-105	Reamstown	3	1.14	Active	2011 Q4	Solar	PPL
W1-106	West Carlisle	5	1.9	Active	2011 Q4	Solar	PPL
W1-107	Grove City road 12kV	2	0.74	Active	2011 Q4	Solar	APS
W1-108	Grays Ferry 230kV	163	13	Active	2011 Q2	Natural Gas	PECO
W1-111	Harwood-Berwick 69kV	20	0	Active	2012 Q1	Storage	PPL
W1-114	Port Carbon	3	1.14	Under Construction	2012 Q4	Solar	PPL
W1-115	Tamanend	3	1.14	Under Construction	2012 Q4	Solar	PPL
W2-010	Conemaugh Unit 1	870	20	Active	2013 Q2	Coal	PENELEC
W2-011	Conemaugh Unit 2	870	20	Active	2013 Q2	Coal	PENELEC
W2-018	Cumberland County Landfill	5	4.8	Active	2012 Q3	Methane	PENELEC
W2-028	Limerick #1	1218	5	Active	2012 Q2	Nuclear	PECO
W2-029	Limerick #2	1218	5	Active	2013 Q2	Nuclear	PECO
W2-059	Strasburg 12kV	2	1	Under Construction	2012 Q4	Diesel	PPL
W2-081	Port Carbon 12kV	3	1.14	Active	2011 Q1	Solar	PPL
W2-092	Hunterstown 115kV II	20	7.6	Active	2013 Q2	Solar	ME

Status of Pennsylvania's Plant Additions and Upgrades

Queue	PJM Substation	MW	MWC	Status	In Service	Fuel	Transmission Owner
W2-093	Hunterstown 115kV III	20	7.6	Active	2013 Q2	Solar	ME
W2-094	Straban 13.2 kV	3	1.1	Active	2012 Q2	Solar	ME
W2-096	West Carlisle-Newville 1 69kV	20	7.6	Active	2012 Q2	Solar	PPL
W2-097	West Carlisle-Newville 2 69kV	20	7.6	Active	2012 Q2	Solar	PPL
W2-098	Hunterstown 115kV IV	20	7.6	Active	2013 Q2	Solar	ME
W3-008	Mercersburg 34.5kV	20	7.6	Active	2012 Q3	Solar	APS
W3-021A	Corry East 115kV	70	9.1	Active	2014 Q4	Wind	PENELEC
W3-022	Frackville-Eldred #1 230kV	150	19.5	Active	2014 Q4	Wind	PPL
W3-023	Frackville-Eldred #2 230kV	120	15.6	Active	2014 Q4	Wind	PPL
W3-042	Mercersburg 34.5kV	16	6.08	Active	2012 Q2	Solar	APS
W3-072	St. Thomas-Guilford 34.5kV	20	7.6	Active	2012 Q3	Solar	APS
W3-093	Lyon Station	3	0	Active	2011 Q4	Storage	ME
W3-096	Perkiomen	3	0.95	Active	2011 Q2	Solar	PECO
W3-099	Erie East 230 kV	100	13	Active	2014 Q3	Wind	PENELEC
W3-153	Heaton 34kV	3	1	Active	2011 Q2	Solar	PECO
W3-167	Nottingham II	10	3.8	Active	2011 Q4	Solar	PPL
W3-168	Germantown 13.2 kV	15	5.7	Active	2012 Q2	Solar	ME
W3-169	North Hanover 12.5kV	12	4.56	Active	2012 Q2	Solar	ME
W4-012	Whetstone 115kV	120	15.6	Active	2014 Q4	Wind	PENELEC
W4-013	Frack-Orwigsburg 69kV	50	6.5	Active	2014 Q4	Wind	PPL
W4-022	Hunterstown 230kV	100	38	Active	2014 Q4	Solar	PENELEC

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

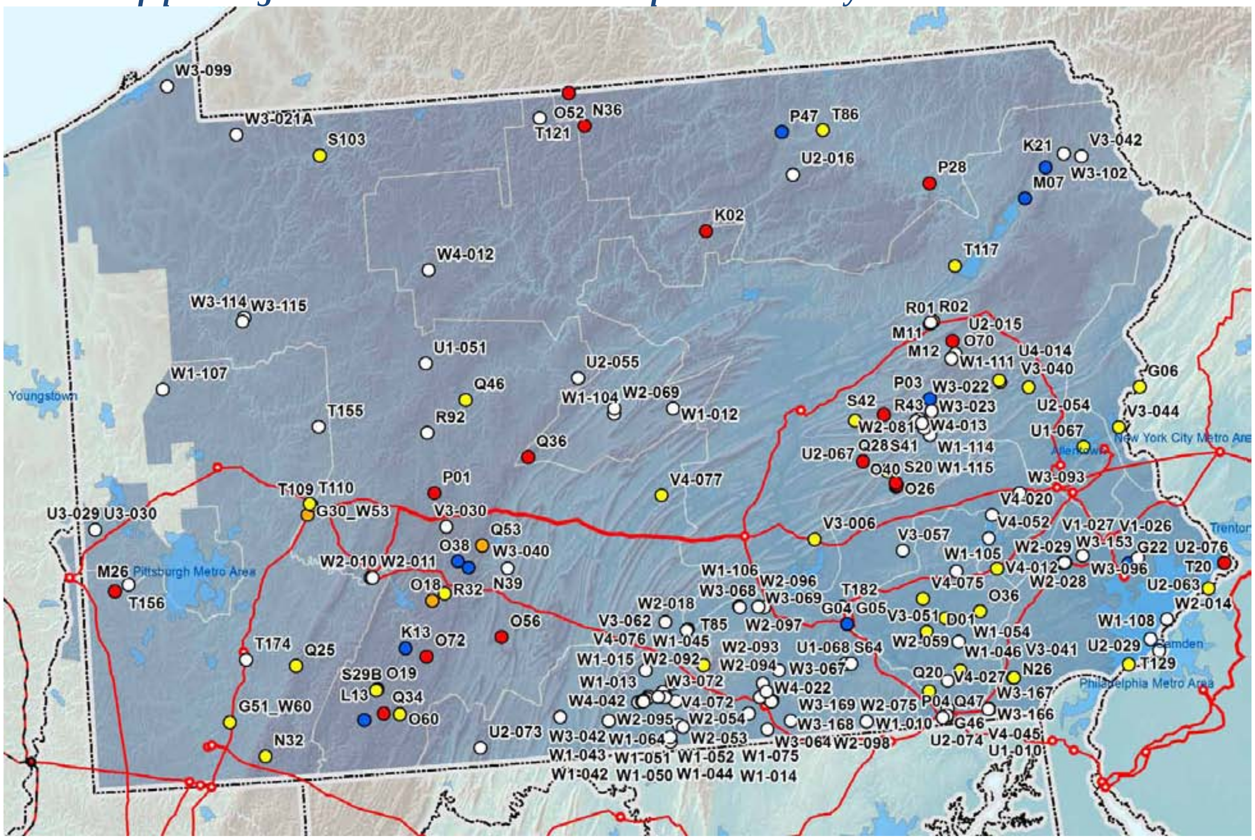
Source: PJM

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	Dec-11	Reliability impacts identified
Eddystone 1	279	PE	49	May-11	May-11	Reliability impacts identified
Eddystone 2	309	PE	49	May-11	May-12	Reliability impacts identified
Cromby Diesel	2.7	PE	43	May-11	May-11	No reliability issues
Brunot Island 1B	15	DUQ	39	Jul-11	Jul-11	No reliability issues
Brunot Island 1C	15	DUQ	39	Jul-11	Jul-11	No reliability issues

Source: PJM.com (as of May 24, 2011)

Location of queued generation interconnection requests in Pennsylvania

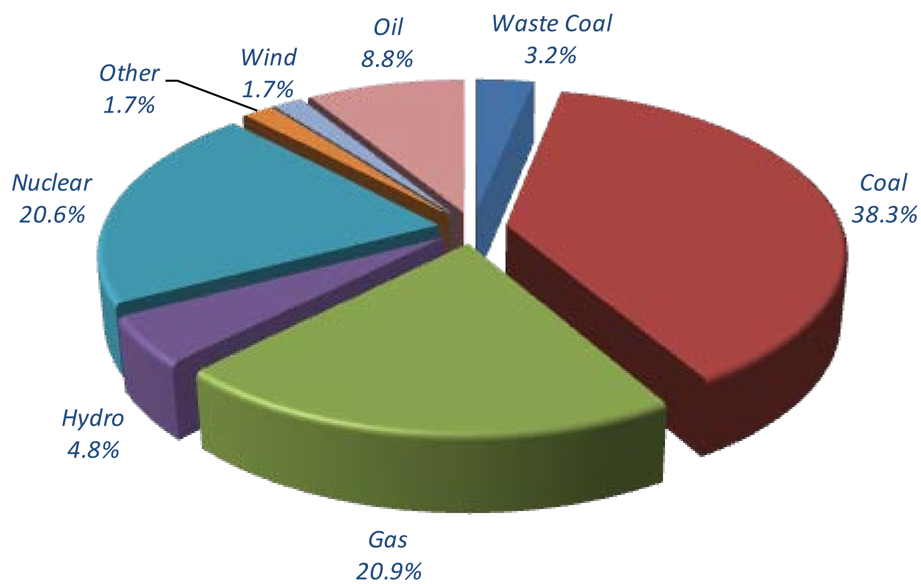


Source: PJM 2010 Regional Transmission Expansion Plan

Appendix C – Existing Generating Facilities

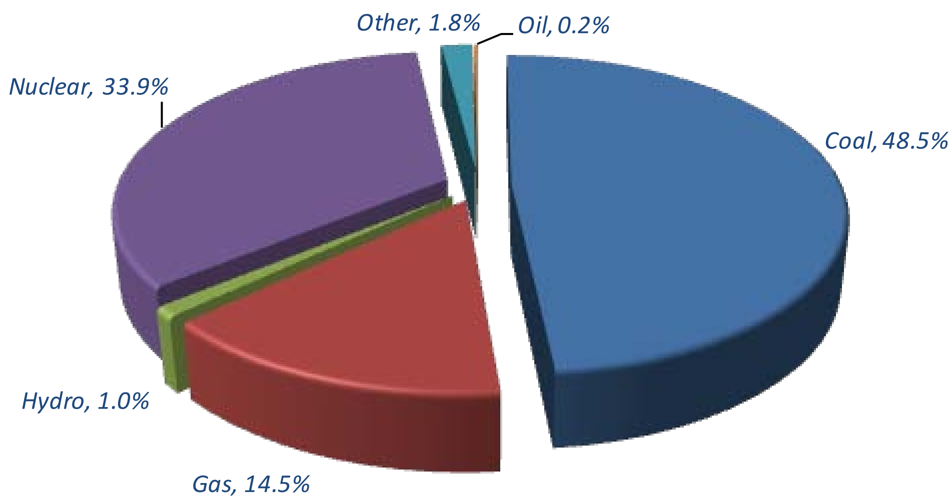
The following represents the most recently available data on existing generating facilities located in Pennsylvania. Below is a summary of generating capacity by fuel type, and the distribution of electric generation by fuel type for 2010.

Existing generating capacity in Pennsylvania



Source: Electric Power Generation Association

2010 generation in Pennsylvania



Source: U.S DOE/Energy Information Administration

Pennsylvania's Existing Electric Generating Facilities

Company Name	Plant Name	Fuel Type	Alternate Fuel Type	Tech. Type	MW
A/C Power-Colver Operations	Colver Power Project (75% owned in 2010)	Waste Coal		ST-S	76.00
AES Corporation	Beaver Valley	Coal		ST/S	120.00
AES Corporation	AES Ironwood LLC	Gas	Oil/WSTH	CC	771.00
AES Wind Generation	Armenia Mountain	Wind		WTG	100.50
Allegheny Electric Cooperative*	William F Matson Hydroelectric Plant	Water		HY	21.70
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
Bear Creek Wind Power Project Partners*	Bear Creek Wind Farm	Wind		WTG	24.00
Brookfield Renewable Power, Inc.	Piney Dam (PA) Hydroelectric Plant	Water		HY	28.80
Calpine Corp.	Bethlehem Commerce Plant	Gas	WSTH	CC	1130.00
Chambersburg Borough Electric Dept	Chambersburg Power Plant	Gas	Oil	IC	30.47
Cogentrix Energy LLC*	Northhampton Generating Station	Waste Coal	Tires	ST-S	112.00
Cogentrix Energy LLC*	Scrubgrass Generating Plant	Waste Coal		ST	85.00
Community Energy, Inc.*	Locust Ridge Wind Farm I	Wind	None	WTG	26.00
Consolidated Rail Corporation	Juniata Locomotive Shop	Coal		ST-H	10.00
Constellation Energy, Inc. (10.6%)	Conemaugh Generating Station	Coal		ST	181.00
Constellation Energy, Inc. (21%)	Keystone Generating Station	Coal		ST	359.00
Constellation Generation Group*	Safe Harbor Hydroelectric Plant (66.7% owner)	Water		HY	278.00
Constellation Power Inc.	Handsome Lake Plant	Gas		SC	268.00
Constellation Power Inc. (50% owner w/partner	Panther Creek Energy Facility	Waste Coal		ST-S	95.00
Constellation Power, Inc. (25%)	Colver Power Project (25% in 2010)	Waste Coal		ST-S	26.00
Covanta Energy Corporation	Covanta Plymouth Renewable Energy Ltd.	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 Corp.	Montenay Montgomery LP	Other		ST	32.10
Covanta Energy Corp.	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 (DEI)	Fairless Energy LLC	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 University	Duquesne Uniersity Cogeneration Plant	Gas		GT/ST	4.75
Dynegy, Inc.	Ontelaunee Energy Center	Gas	WSTH	CCGT	580.00
E.On Climate and Renewables	Stony Creek Wind Farm	Wind		WTG	52.50
Ebensburg Power Co.* (Partnership)	Ebensburg Power Co	Waste Coal		ST-S	50.00
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	2289.00
Exelon Nuclear*	Three Mile Island	Nuclear		ST-PWR	837.00
Exelon Nuclear* (50% owned)	Peach Bottom Atomic Power St., Units 2&3	Nuclear		ST-BWR	1148.00
Exelon Power Generation Co. LLC*	Chester Peaking Plant	Oil		GT	39.00
Exelon Power Generation Co. LLC*	Conemaugh (20.72% owned)	Coal		ST	352.00
Exelon Power Generation Co. LLC* ?	Conemaugh Peaking Plant	Oil		IC/Diesel	2.00
Exelon Power Generation Co. LLC* (retire 5/201	Cromby Generating Station 1	Coal		ST	144.00
Exelon Power Generation Co. LLC* (retire 5/201	Cromby Generating Station 2	Oil	Natural Gas	ST	201.00
Exelon Power Generation Co. LLC*	Cromby Peaking Plant (20.72% owned)	Oil		IC/Diesel	3.00
Exelon Power Generation Co. LLC*	Croydon Peaking Plant	Oil		GT	391.00
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*	Eddystone Peaking Plant	Oil		ST	60.00
Exelon Power Generation Co. LLC*	Exelon-Conergy Solar Energy Center	Other		PV	3.00
Exelon Power Generation Co. LLC*	Fairless Hills Generating (Peaking)	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% owned)	Coal		ST	357.00
Exelon Power Generation Co. LLC*	Keystone Peaking Plant (20.99% owned)	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	6.00

Pennsylvania's Existing Electric Generating Facilities

Company Name	Plant Name	Fuel Type	Alternate Fuel Type	Tech. Type	MW
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 Corp.*	Allegheny Lock & Dam 5 & 6	Water		HY	13.00
FirstEnergy Corp.* eff 2/25/11 (2010 Allegheny	Armstrong Generating Station	Coal		ST	356.00
FirstEnergy Corp.* eff 2/25/11 (2010 Allegheny	Hatfield's Ferry Power Station	Coal		ST	1710.00
FirstEnergy Corp.*	Hunlock Creek Power Station	Gas		GT	44.00
FirstEnergy Corp.* eff 2/25/11 (2010 Allegheny	Lake Lynn Hydroelectric Project	Water		HY	52.00
FirstEnergy Corp.* eff 2/25/11 (2010 Allegheny	Mitchell Generating Station	Coal	Oil	ST	370.00
FirstEnergy Corp.* eff 2/25/11 (2010 Allegheny	Springdale, Units 1,2,3,4 & 5	Gas		CC/GT	628.00
FirstEnergy Generation Corp.*	Bruce Mansfield Plant	Coal		ST	2490.00
FirstEnergy Generation Corp.*	Seneca Pumped Storage Plant	Water		HY	451.00
FirstEnergy Nuclear Operating Co.*	Beaver Valley Power Station	Nuclear		ST-PWR	1815.00
Gamesa	Locust Ridge II	Wind		WTG	102.00
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
GenOn Energy, Inc.*	Blossburg Plant (Mothball Pending)	Gas		GT	19.00
GenOn Energy, Inc.*	Brunot Island Generating Station	Gas	Oil	CC/GT	289.00
GenOn Energy, Inc.*	Cheswick Generating Station	Coal	Diesel	ST	565.00
GenOn Energy, Inc.* (& undisclosed partner)	Conemaugh Power Plant (16% owned-281 MW)	Coal	Oil	IC/ST	415.00
GenOn Energy, Inc.*	Elrama Generating Station	Coal		ST	460.00
GenOn Energy, Inc.*	FR Philips Generating Station	Coal		ST	411.30
GenOn Energy, Inc.*	Hamilton Generating Station	Oil		GT	20.00
GenOn Energy, Inc.*	Hunterstown Generating Station	Gas	Diesel	CC	60.00
GenOn Energy, Inc.*	Hunterstown Generating Station	Gas		CC	810.00
GenOn Energy, Inc.* (& undisclosed partner)	Keystone Generating Station (16.25% owned)	Coal	Oil	IC/ST	288.00
GenOn Energy, Inc.*	Mountain Generating Station	Gas	Oil	GT	40.00
GenOn Energy, Inc.*	New Castle Generating Station	Coal	Oil	ST/IC	333.00
GenOn Energy, Inc.*	Orrtanna Generating Station	Oil		GT	20.00
GenOn Energy, Inc.*	Portland Generating Station	Coal	Gas	GT/ST	570.00
GenOn Energy, Inc.*	Seward Generating Station	Waste Coal		ST	521.00
GenOn Energy, Inc.*	Shawnee Generating Station	Oil		GT	20.00
GenOn Energy, Inc.*	Shawville Generating Station	Coal	Oil	ST	603.00
GenOn Energy, Inc.*	Titus Generating Station	Coal	Gas	ST/GT	274.00
GenOn Energy, Inc.*	Tolna Station	Oil		GT	40.00
GenOn Energy, Inc.*	Warren Generating Station	Gas	Oil	GT	68.00
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	59.00
Koppers, Inc.	Koppers Montgomery Cogeneration Plant	Other		ST-S	10.00
Liberty Electric Power LLC	Liberty Electric Power LLC	Gas		CC	610.00
Lycoming County Resource Management Servic	Lycoming County Ladfill	Gas		IC/H	1.00
Merck & Co., Inc.	West Point (PA) Merck Plant	Gas		GT/ST	30.25
Midwest Generation LLC	Homer City (EME) Generation	Coal		ST	2012.00
Morris Energy Group LLC (MEG)	York Solar Plant	Gas	Oil/WSTH	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

Pennsylvania's Existing Electric Generating Facilities

Company Name	Plant Name	Fuel Type	Alternate Fuel Type	Tech. Type	MW
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 Thermal, LLC	NRG Energy Paxton LLC	Gas	Oil	ST-S	12.60
PEI Power Corp.	Archbald Power Station	Other		GT/ST	70.00
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
PPL Generation LLC*	Allentown Generating Station	Oil		GT	64.00
PPL Generation LLC*	Conemaugh Power Plant (16.25% owned)	Coal		IC/ST	278.00
PPL Generation LLC*	Fishbach Generating Station	Oil		GT	37.20
PPL Generation LLC*	Harrisburg Generating Station	Oil		GT	64.00
PPL Generation LLC*	Harwood (PA) Generation Station	Oil		GT	32.00
PPL Generation LLC*	Jenkins Generating Station	Oil		GT	32.00
PPL Generation LLC*	Lock Haven Generating Station	Oil		GT	18.60
PPL Generation LLC*	Lower Mt. Bethel Energy LLC	Gas		CC	623.00
PPL Generation LLC*	PPL Brunner Island	Coal		ST	1500.00
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	2360.00
PPL Generation LLC*	PPL Wallenpaupack LLC	Water		HY	44.00
PPL Generation LLC* 3/2011 sold to LS Power	Safe Harbor Hydroelectric Plant (33.3% owned)	Water		HY	104.00
PPL Generation LLC*	Suburban Generation Station c/o Martins Creek	Oil		GT	29.00
PPL Generation LLC*	West Shore Generating Station	Oil		GT	37.20
PPL Generation LLC*	Williamsport Generating Station	Oil		GT	32.00
PPL Renewable Energy*	Lebanon County Landfill (2007)	Other		IC	3.20
Power Systems Operations	Ebensburg Power Co	Waste Coal		ST-S	48.50
Procter & Gamble	Mehoopany Plant	Gas		GT-S	53.00
PSEG Fossil (23% owned)*	Conemaugh Power Plant	Coal		IC/ST	384.00
PSEG Fossil (23% owned)*	Keystone Generating Station	Coal	Oil	IC/ST	391.00
PSEG Power (50% owned)	Peach Bottom Atomic Power St., Units 2&3	Nuclear		ST-BWR	1140.00
Republic Services, Inc.	Modern Landfill	Gas	None	IC	9,00
Rohm and Haas Co.	Bristol	Oil		ST	1.50
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
Sunbury Generation LLC	Sunbury Steam Station	Coal	Oil	ST/GT/IC	462.50
Temple University	Temple Univ. Standby Electric Gen. Facility	Gas		IC-H	16.00
UGI Energy Services	Crayola Solar Park	Other		PV	1.00
UGI Energy Services	Hegins Landfill Gas-to Electricity Plant	Other		IC	11.00
UGI Development Co.*	Conemaugh (5.97% ownership)	Coal		ST	102.00
United States Steel Corp.	Clairton USX B Plant	Other	Gas	GT/S/ST/S	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 LLC (WM)	Lake View Landfill	Gas	None	IC	6.10
WM Renewable Energy LLC (WM)	Pottstown Plant	Other		GT	6.40
Olympus Power LLC/York Haven Power CO. LLC	York Haven Hydro Station	Water	None	HY	22.60
Total MW in PA					46579.93

*=verified data

Revised 5/11

Source: Electric Power Generation Association

Technology Type

Classification of plant sites by the technology type (prime mover) of the individual units may include mixed technologies, which are reflected in combination of the following abbreviations:

CC	Combined-cycle total unit
CCSS	Combined-cycle single shaft
FC	Fuel Cell
GT	Gas or combustion turbine in single cycle
GT/C	Gas or combustion turbine in combined cycle
GT/H	Gas or combustion turbine with heat recovery
GT/S	Gas or combustion turbine with steam sendout
GT/T	Gas or combustion turbine in topping configuration with existing conventional boiler and T/G
HY	Hydroelectric turbine (conventional)
HY-P	Hydroelectric turbine (pump storage)
IC	Gas or liquid-fuel internal combustion (reciprocating) engine
IC-H	Internal combustion engine with heat recovery
ORC	Organic Rankine-cycle (vapor) turbine or organic Rankine-cycle energy converter
PV	Photovoltaic cells (solar)
ST	Steam turbine
ST-H	Steam turbine with heat recovery
ST-S	Steam turbine with steam sendout
TEX	Turbo expander/gas expander
WTG	Wind turbine generator

EPGA

Three Mile Island