PUBLIC SERVICE ENTERPRISE GROUP INC
Form 10-K
February 26, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2014
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

Commission File Number	Registrants, State of Incorporation, Address, and Telephone Number	I.R.S. Employer Identification No.
001-09120	PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED (A New Jersey Corporation) 80 Park Plaza, P.O. Box 1171 Newark, New Jersey 07101-1171 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza, P.O. Box 570 Newark, New Jersey 07101-0570 973 430-7000 http://www.pseg.com	22-1212800
001-34232	PSEG POWER LLC (A Delaware Limited Liability Company) 80 Park Plaza—T25 Newark, New Jersey 07102-4194 973 430-7000 http://www.pseg.com	22-3663480

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of Each Class	Name of Each Exchange On Which Registered
Public Service Enterprise Group Incorporated	Common Stock without par value	New York Stock Exchange
Public Service Electric and Gas Company	First and Refunding Mortgage Bonds 9 1/4% Series CC, due 2021 6 3/4% Series VV, due 2016 8%, due 2037 5%, due 2037	New York Stock Exchange
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange

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Securities registered pursuant to Section 12(g) of the Act:

Registrant	Title of Each Class
Public Service Electric and Gas Company	Medium-Term Notes
PSEG Power LLC	Limited Liability Company Membership Interest

Indicate by check mark whether each registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Public Service Enterprise Group Incorporated	Yes x	No ¨
Public Service Electric and Gas Company	Yes x	No ¨
PSEG Power LLC	Yes x	No ¨

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. Yes ¨ No x

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports) and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files). Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

Indicate by check mark whether each registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer x	Accelerated filer ¨	Non-accelerated filer ¨
Public Service Electric and Gas Company	Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x
PSEG Power LLC	Large accelerated filer ¨	Accelerated filer ¨	Non-accelerated filer x

Indicate by check mark whether any of the registrants is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

The aggregate market value of the Common Stock of Public Service Enterprise Group Incorporated held by non-affiliates as of June 30, 2014 was $20,598,517,672 based upon the New York Stock Exchange Composite Transaction closing price.

The number of shares outstanding of Public Service Enterprise Group Incorporated's sole class of Common Stock as of January 30, 2015 was 506,179,029.

As of January 30, 2015, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

PSEG Power LLC and Public Service Electric and Gas Company are wholly owned subsidiaries of Public Service Enterprise Group Incorporated and each meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K. Each is filing its Annual Report on Form 10-K with the reduced disclosure format authorized by General Instruction I.

DOCUMENTS INCORPORATED BY REFERENCE

Part of Form 10-K of Public Service Enterprise Group Incorporated	Documents Incorporated by Reference
III	Portions of the definitive Proxy Statement for the 2015 Annual Meeting of Stockholders of Public Service Enterprise Group Incorporated, which definitive Proxy Statement is expected to be filed with the Securities and Exchange Commission on or about March 9, 2015, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words “anticipate,” “intend,” “estimate,” “believe,” “expect,” “plan,” “should,” “hypothetical,” “potential,” “forecast,” “project,” variations of such words and similar expressions intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC) including our subsequent reports on Form 10-Q and Form 8-K and available on our website: http://www.pseg.com. These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulations, including market structures and transmission planning,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to manage our energy obligations, available supply and risks,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- any deterioration in our credit quality or the credit quality of our counterparties,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers, and any inability to obtain sufficient insurance coverage or recover proceeds of insurance with respect to such events,
- acts of terrorism, cybersecurity attacks or intrusions that could adversely impact our businesses,
- increases in competition in energy supply markets as well as for transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies, and

- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response.

All of the forward-looking statements made in this report are qualified by these cautionary statements and we cannot assure you that the results or developments anticipated by management will be realized or even if realized, will have the expected consequences to, or effects on, us or our business prospects, financial condition or results of operations. Readers are cautioned not to place undue reliance on these forward-looking statements in making any investment decision. Forward-looking statements made in this report apply only as of the date of this report. While we may elect to update forward-looking statements from time to time, we specifically disclaim any obligation to do so, even if internal estimates change, unless otherwise required by applicable securities laws.

The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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FILING FORMAT AND GLOSSARY

This combined Annual Report on Form 10-K is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information relating to any individual company is filed by such company on its own behalf. PSE&G and Power are each only responsible for information about itself and its subsidiaries.

Discussions throughout the document refer to PSEG and its direct operating subsidiaries, PSE&G and Power. Depending on the context of each section, references to "we," "us," and "our" relate to PSEG or to the specific company or companies being discussed. In addition, certain key acronyms and definitions are summarized in a glossary beginning on page 190.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may read and copy any document that we file at the Public Reference Room of the SEC at 100 F Street, N.E., Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. You may also obtain our filed documents from commercial document retrieval services, the SEC's internet website at www.sec.gov or our website at www.pseg.com. Information on our website should not be deemed incorporated into or as a part of this report. Our Common Stock is listed on the New York Stock Exchange under the ticker symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 20 Broad Street, New York, New York 10005.

PART I

ITEM 1. BUSINESS

We were incorporated under the laws of the State of New Jersey in 1985 and our principal executive offices are located at 80 Park Plaza, Newark, New Jersey 07102. We conduct our business through two direct wholly owned subsidiaries, Power and PSE&G, each of which also has its principal executive offices at 80 Park Plaza, Newark, New Jersey 07102.

We are an energy company with a diversified business mix. Our operations are located primarily in the Northeastern and Mid- Atlantic United States. Our business approach focuses on operational excellence, financial strength and disciplined investment. As a holding company, our profitability depends on our subsidiaries' operating results. Below are descriptions of our two principal direct operating subsidiaries.

PSE&G	Power
A New Jersey corporation, incorporated in 1924, which is a franchised public utility in New Jersey. It is also the provider of last resort for gas and electric commodity service for end users in its service territory. Earns revenues from its regulated rate tariffs under which it provides electric transmission and electric and gas distribution to residential, commercial and industrial customers in its service territory. It also offers appliance services and repairs to customers throughout its service territory. Has also implemented regulated demand response and energy efficiency programs and invested in solar generation within New Jersey.	A Delaware limited liability company formed in 1999 that integrates its merchant nuclear, fossil and renewable generating asset operations with its wholesale energy sales, fuel supply and energy trading functions. Earns revenues from selling under contract or on the spot market a range of diverse products such as electricity, natural gas, emissions credits and a series of energy-related products used to optimize the operation of the energy grid.

Our other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and our operating subsidiaries with certain management, administrative and general services at cost.

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The following is a more detailed description of our business, including a discussion of our:

- Business Operations and Strategy
- Competitive Environment
- Employee Relations
- Regulatory Issues
- Environmental Matters

BUSINESS OPERATIONS AND STRATEGY

PSE&G

Our regulated transmission and distribution public utility, PSE&G, distributes electric energy and gas to customers within a designated service territory running diagonally across New Jersey where approximately 6.2 million people, or about 70% of New Jersey's population resides.

Products and Services

Our utility operations primarily earn margins through the transmission and distribution of electricity and the distribution of gas.

- Transmission—the movement of electricity at high voltage from generating plants to substations and transformers, where it is then reduced to a lower voltage for distribution to homes, businesses and industrial customers. Our revenues for these services are based upon tariffs approved by the Federal Energy Regulatory Commission (FERC).
- Distribution—the delivery of electricity and gas to the retail customer’s home, business or industrial facility. Our revenues for these services are based upon tariffs approved by the New Jersey Board of Public Utilities (BPU).

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The commodity portion of our utility business' electric and gas sales is managed by basic generation service (BGS) and basic gas supply service (BGSS) suppliers. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for our utility operations.

We also earn margins through competitive services, such as appliance repair.

In addition to our current utility products and services, we have implemented several programs to increase the level of regulated solar generation within New Jersey, including:

- programs to help finance the installation of solar power systems throughout our electric service area, and
- programs to develop, own and operate solar power systems.

We have also implemented a set of energy efficiency and demand response programs to encourage conservation and energy efficiency by providing energy and cost saving measures directly to businesses and families. For additional information concerning these programs and the components of our tariffs, see Regulatory Issues—State Regulation and Part II, Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

How PSE&G Operates

We are a transmission owner in PJM Interconnection, L.L.C. (PJM) and we provide distribution service to 2.2 million electric customers and 1.8 million gas customers in a service area that covers approximately 2,600 square miles running diagonally across New Jersey. We serve the most heavily populated, commercialized and industrialized territory in New Jersey, including its six largest cities and approximately three hundred suburban and rural communities.

Transmission

We use formula rates for our transmission cost of service and investments. Formula-type rates provide a method of rate recovery where the transmission owner annually determines its revenue requirements through a fixed formula which considers Operations and Maintenance expenditures, Rate Base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. Our current approved rates provide for a base ROE of 11.68% on existing and new transmission investment, while certain investments are entitled to earn an additional incentive rate. For more information, see Regulatory Issues—Federal Regulation—Transmission Regulation.

Transmission Statistics

December 31, 2014		
Network Circuit Miles	Billing Peak Megawatt (MW)	Historical Annual Load Growth 2010-2014
1,659	9,515	(0.4)%

In April 2014, we completed our North Central Reliability project, an upgrade of 55 circuit miles of 138 kilovolts (kV) transmission line to 230 kV and conversion of six existing stations to 230 kV operation and our Burlington-Camden project, an upgrade of 37 circuit miles of 138 kV transmission line to 230 kV.

During 2014, we continued to execute four major regional transmission projects for which we were assigned construction responsibility by PJM:

Major Transmission Projects
As of December 31, 2014

Project	Total Estimated Project Costs Up To Millions	Total Project Spend	Expected In-Service Date
Susquehanna-Roseland 500 kV (A)	$790	$775	June 2015
Northeast Grid Reliability 230 kV	$907	$569	June-December 2015
Mickleton-Gloucester-Camden 230 kV	$435	$278	June 2015
Bergen-Linden Corridor 345 kV	$1,200	$40	June 2018

(A) On April 1, 2014, Phase One was completed on schedule, placing into service the eastern part of the transmission line from Hopatcong to Roseland, New Jersey. Construction of the transmission line from New Jersey to the Pennsylvania border was completed in 2014.

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Distribution

PSE&G distributes gas and electricity to end users in our respective franchised service territories. Our approved rates, established in our most recent gas and electric base rate proceeding completed in mid-2010, provide for an allowed ROE of 10.3% on distribution rate base. The BPU has also approved a series of PSE&G infrastructure, energy efficiency and renewable energy investment programs with cost recovery through various clause mechanisms, with allowed ROEs ranging from 9.75% to 10.3%. Our load requirements are split among residential, commercial and industrial customers, as described in the following table for 2014.

	% of 2014 Sales	
Customer Type	Electric	Gas
Commercial	58%	36%
Residential	32%	60%
Industrial	10%	4%
Total	100%	100%

While our customer base has remained steady, electric load has declined and gas load has increased as illustrated below:

Electric and Gas Distribution Statistics

	December 31, 2014				
	Number of Customers		Electric Sales and Gas Firm Sales (A)		Historical Annual Load Growth 2010-2014
Electric	2.2	Million	40,737	Gigawatt hours (GWh)	(0.6)%
Gas	1.8	Million	2,628	Million Therms	2.0%

(A)Excludes Contract Service Gas (CSG) rate class sales, which do not impact margin.

The decline in electric sales is the result of changes in customer usage patterns, including conservation and more energy efficient appliances. Gas firm sales increased to all customer classes as a result of lower gas prices and more favorable weather. Only gas firm sales impact margin.

Solar Generation

In order to support New Jersey's Energy Master Plan and the state's renewable energy goals, we have undertaken two major solar initiatives at PSE&G, the Solar Loan Program and the Solar 4 All and Solar 4 All Extension Programs. Our Solar Loan Program provides solar system financing to our residential and commercial customers. The loans are repaid with cash or solar renewable energy certificates (SRECs). We sell the SRECs used to repay the loans through a periodic auction, the proceeds of which are used to offset program costs. Our Solar 4 All Programs invest in utility-owned solar photovoltaic (PV) centralized solar systems installed on PSE&G property and third party sites, including landfill facilities, and solar panels installed on distribution system poles in our electric service territory. We sell the energy and capacity from the systems in the PJM wholesale electricity market. In addition, we sell SRECs generated by the projects through the same periodic auction used in the loan program, the proceeds of which are used to offset program costs. As of December 31, 2014, we have invested an aggregate of approximately $765 million in both solar programs.

Supply

Although commodity revenues make up almost 43% of our revenues, we make no margin on the default supply of electricity and gas since the actual costs are passed through to our customers.

All electric and gas customers in New Jersey have the ability to choose their own electric energy and/or gas supplier. Pursuant to BPU requirements, we serve as the supplier of last resort for two types of electric and gas customers within our service territory that are not served by another supplier. The first type, which represents about 80% of PSE&G’s load requirements, provides default supply service for smaller industrial and commercial customers and residential customers at seasonally-adjusted fixed prices for a three-year term (BGS-Residential Small Commercial Pricing (RSCP)). These rates change annually on June 1 and are based on the average price obtained at auctions in the current year and two prior years. The second type provides default supply for larger customers, with energy priced at hourly PJM real-time market prices for a contract term of 12 months (BGS-CIEP).

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We procure the supply to meet our BGS obligations through auctions authorized by the BPU for New Jersey's total BGS requirement. These auctions take place annually in February. Results of these auctions determine which energy suppliers are authorized to supply BGS to New Jersey's electric distribution companies (EDCs). Once validated by the BPU, electricity prices for BGS service are set. Approximately one-third of PSE&G's total BGS-RSCP eligible load is auctioned each year for a three-year term. For information on current prices, see Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

PSE&G procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with Power. The BPU has approved a mechanism designed to recover all gas commodity costs related to BGSS for residential customers. BGSS filings are made annually by June 1 of each year, with an effective date of October 1. PSE&G's revenues are matched with its costs using deferral accounting, with the goal of achieving a zero cumulative balance by September 30 of each year. In addition, we have the ability to put in place two self-implementing BGSS increases on December 1 and February 1 of 5% and also may reduce the BGSS rate at any time. See Part II, Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities for information on recent self-implementing credits. Any difference between rates charged under the BGSS contract and rates charged to our residential customers is deferred and collected or refunded through adjustments in future rates. Commercial and industrial customers that do not select third party suppliers are also supplied under the BGSS arrangement. These customers are charged a market-based price largely determined by prices for commodity futures contracts.

Markets and Market Pricing

Historically, there has been significant volatility in commodity prices. Such volatility can have a considerable impact on us since a rising commodity price environment results in higher delivered electric and gas rates for customers. This could result in decreased demand for electricity and gas, increased regulatory pressures and greater working capital requirements as the collection of higher commodity costs from our customers may be deferred under our regulated rate structure. A declining commodity price on the other hand, would be expected to have the opposite effect. For additional information, including the impact of natural gas commodity prices on electricity prices such as BGS, see Part II, Item 7. MD&A—Executive Overview of 2014 and Future Outlook.

Power

Through Power, we seek to produce low-cost electricity by efficiently operating our nuclear, coal, gas, oil-fired and renewable generation assets, while balancing generation output, fuel requirements and supply obligations through energy portfolio management. We use the generation we own combined with commodity contracts and financial instruments to cover our commitments for BGS in New Jersey and other bilateral supply contract agreements.

Products and Services

As a merchant generator, our profit is derived from selling a range of products and services under contract to power marketers and to others, such as investor-owned and municipal utilities, and to aggregators who resell energy to retail consumers, or in the open market. These products and services include:

- Energy—the electrical output produced by generation plants that is ultimately delivered to customers for use in lighting, heating, air conditioning and operation of other electrical equipment. Energy is our principal product and is priced on a usage basis, typically in cents per kilowatt hour (kWh) or dollars per megawatt hour (MWh).
- Capacity—distinct from energy, capacity is a market commitment that a given generation unit will be available to an Independent System Operator (ISO) for dispatch when it is needed to meet system demand. Capacity is typically priced in dollars per MW for a given sale period (e.g. day or month).
- Ancillary Services—related activities supplied by generation unit owners to the wholesale market that are required by the ISO to ensure the safe and reliable operation of the bulk power system. Owners of generation units may bid units into the ancillary services market in return for compensatory payments. Costs to pay generators for ancillary services are recovered through charges collected from market participants.
- Emissions Allowances and Congestion Credits—Emissions allowances (or credits) represent the right to emit a specific amount of certain pollutants. Allowance trading is used to control air pollution by providing economic incentives for achieving reductions in the emissions of pollutants. Congestion credits (or Financial Transmission Rights) are financial instruments that entitle the holder to a stream of revenues (or charges) based on the hourly congestion price

differences across a transmission path.

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Power also sells wholesale natural gas, primarily through a full-requirements BGSS contract with PSE&G to meet the gas supply requirements of PSE&G's customers. This long-term arrangement had been for an initial period which extended through March 31, 2012 and continued on a year-to-year basis unless terminated by either party with a one year notice. On March 19, 2014, the BPU approved an extension of the BGSS contract to March 31, 2019 and then year to year thereafter unless terminated by either party with a two year notice.

Approximately 46% of PSE&G's peak daily gas requirements is provided from Power's firm gas transportation capacity, which is available every day of the year. Power satisfies the remainder of PSE&G's requirements from storage contracts, liquefied natural gas, seasonal purchases, contract peaking supply, propane and refinery gas. Based upon the availability of natural gas beyond PSE&G's daily needs, Power also sells gas to others and uses it in its generation fleet.

In addition to its nuclear and fossil generation fleet, Power owns and operates 109 MW direct current (dc) of PV solar generation facilities and has a 50% ownership interest in a 208 MW oil-fired generation facility in Hawaii.

The remainder of this section about Power covers our nuclear and fossil fleet in the Mid-Atlantic and Northeast regions which comprise the vast majority of Power's operations and financial performance.

How Power Operates

Nearly all of our generation capacity consists of nuclear and fossil generation (13,146 MW) that is located in the Northeast and Mid-Atlantic regions of the United States in some of the country's largest and most developed electricity markets. For additional information see Item 2. Properties.

The map below shows the locations of our Northeast and Mid-Atlantic nuclear and fossil generation facilities:

•Generation Capacity

Our nuclear and fossil installed capacity utilizes a diverse mix of fuels: 46% gas, 28% nuclear, 18% coal, 7% oil and 1% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2014 was approximately 54,000 GWh. The generation mix by fuel type has changed slightly in recent years due to the relatively favorable price of natural gas as compared to coal, making it more economical to run certain of our gas units in place of our coal units. The following table indicates the proportionate share of generating output by fuel type in 2014.

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Generation by Fuel Type (A)	Actual 2014	
Nuclear:		
New Jersey facilities	37%	
Pennsylvania facilities	17%	
Fossil:		
Coal:		
Pennsylvania facilities	9%	
Connecticut facilities	2%	
Coal and Natural Gas:		
New Jersey facilities	3%	
Natural Gas and Oil:		
New Jersey facilities	24%	
New York facilities	8%	
Connecticut facilities	—%	(B)
Total	100%	

(A) Excludes pumped storage, solar facilities and fossil generation in Hawaii
(B) Less than one percent

- Generation Dispatch

Our generation units are typically characterized as serving one or more of three general energy market segments: base load; load following; and peaking, based on their operating capability and performance. On a capacity basis, our portfolio of generation assets consists of 34% base load, 44% load following and 22% peaking. This diversity helps to reduce the risk associated with market demand cycles and allows us to participate in the market at each segment of the dispatch curve.

- Base Load Units run the most and typically are called to operate whenever they are available. These units generally derive revenues from energy and capacity sales. Variable operating costs are low due to the combination of highly efficient operations and the use of relatively lower-cost fuels. Performance is generally measured by the unit's "capacity factor," or the ratio of the actual output to the theoretical maximum output. In 2014, our base load capacity factors were as follows:

Unit	2014 Capacity Factor
Nuclear	
Salem Unit 1	85.8%
Salem Unit 2 (A)	72.6%
Hope Creek	97.9%
Peach Bottom Unit 2	84.7%
Peach Bottom Unit 3	99.2%
Coal	
Keystone	77.4%
Conemaugh	73.9%

(A) Salem Unit 2's capacity factor in 2014 was negatively affected by an extended outage to make repairs to the unit's reactor coolant pumps.

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Load Following Units typically operate between 20% and 70% of the time. The operating costs are higher per unit of output than for base load units due to the use of higher-cost fuels such as oil, natural gas and, in some cases, coal or lower overall unit efficiency. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.

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- Peaking Units run the least amount of time and may utilize higher-priced fuels. These units typically operate less than 20% of the time. Costs per unit of output tend to be much higher than for base load units given the combination of higher heat rates and fuel costs. The majority of revenues are from capacity and ancillary service sales. The characteristics of these units enable them to capture energy revenues during periods of high energy prices.

In the energy markets in which we operate, owners of power plants specify to the ISO prices at which they are prepared to generate and sell energy based on the marginal cost of generating energy from each individual unit. The ISOs will generally dispatch in merit order, calling on the lowest variable cost units first and dispatching progressively higher-cost units until the point that the entire system demand for power (known as the system “load”) is satisfied reliably. Base load units are dispatched first, with load following units next, followed by peaking units.

During periods when one or more parts of the transmission grid are operating at full capability, thereby resulting in a constraint on the transmission system, it may not be possible to dispatch units in merit order without violating transmission reliability standards. Under such circumstances, the ISO may dispatch higher-cost generation out of merit order within the congested area and power suppliers will be paid an increased Locational Marginal Price (LMP) in congested areas, reflecting the bid prices of those higher-cost generation units.

The following chart depicts the unconstrained merit order of dispatch of our units in PJM, the ISO in the region where most of our generation units are located, based on illustrative historical dispatch cost. It should be noted that market price fluctuations have resulted in changes from historical norms, with lower gas prices allowing some gas-fired generation to displace some coal-fired generation in the load-following portion of the curve.

(A) The National Park, Sewaren 6, Mercer 3, Salem 3, Burlington 8 and 11, Bergen 3, Edison 1, 2 and 3 and Essex 10, 11 and 12 peaking units are scheduled to be retired in June 2015. Salem 3 is expected to continue to be used as an emergency backup generator for the Salem nuclear site.

The size of each facility's circle in the above chart illustrates the relative MW generating capacity of that facility. For additional information on each of our generation facilities, see Item 2. Properties.

Typically, the bid price of the last unit dispatched by an ISO establishes the energy market-clearing price. After considering the market-clearing price and the effect of transmission congestion and other factors, the ISO calculates the LMP for every location in the system. The ISO pays all units that are dispatched their respective LMP for each MWh of energy produced, regardless of their specific bid prices. Since bids generally approximate the marginal cost of production, units with lower marginal costs typically generate higher operating profits than units with comparatively higher marginal costs.

This method of determining supply and pricing creates a situation where natural gas prices often have a major influence on the price that generators will receive for their output, especially in periods of relatively strong demand. Therefore, changes in the price of natural gas will often translate into changes in the wholesale price of electricity. This can be seen in the following

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graphs which present historical annual spot prices and forward calendar prices as averaged over each year at two liquid trading hubs.

Historical data implies that the price of natural gas will continue to have a strong influence on the price of electricity in the primary markets in which we operate.

The prices reflected in the preceding graphs above do not necessarily illustrate our contract prices, but they are representative of market prices at relatively liquid hubs, with nearer-term forward pricing generally resulting from more liquid markets than pricing for later years. In addition, the prices do not reflect locational differences resulting from congestion or other factors, such as the availability of natural gas from the Marcellus and other shale-gas regions, which can be considerable. While these prices provide some perspective on past and future prices, the forward prices are volatile and there can be no assurance that such prices will remain in effect or that we will be able to contract output at these forward prices.

Fuel Supply

- Nuclear Fuel Supply—We have long-term contracts for nuclear fuel. These contracts provide for:
- purchase of uranium (concentrates and uranium hexafluoride),

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- conversion of uranium concentrates to uranium hexafluoride,
- enrichment of uranium hexafluoride, and
- fabrication of nuclear fuel assemblies.
- Coal Supply—Our Keystone, Conemaugh and Bridgeport stations operate on coal. Our Hudson and Mercer stations have the ability to operate on both coal and natural gas. We have coal contracts with numerous suppliers. Coal is delivered to our units through a combination of rail, truck, barge and ocean shipments.

In order to control emissions levels, our Bridgeport 3 unit uses a specific type of coal obtained from Indonesia. If the supply from Indonesia or equivalent coal from other sources were not available for this facility, its long-term operations would be adversely impacted since additional material capital expenditures would be required to modify this station to enable it to operate using a broader mix of coal sources.

- Gas Supply—Natural gas is the primary fuel for the bulk of our load following and peaking fleet. We purchase gas directly from natural gas producers and marketers. These supplies are transported to New Jersey by four interstate pipelines with which we have contracted. In addition, we have firm gas transportation contracts to serve a portion of the gas requirements for our Bethlehem Energy Center (BEC) station in New York.

We have 1.3 billion cubic feet-per-day of firm transportation capacity and 0.9 billion cubic feet-per-day of firm storage delivery under contract to meet our obligations under the BGSS contract. This capacity includes approximately 0.6 billion cubic feet-per-day of access to the northeast Pennsylvania Marcellus shale gas region. On an as-available basis, this firm transportation capacity may also be used to serve the gas supply needs of our generation fleet.

In September 2014, Power obtained an equity interest with an expected investment of $100 million-$120 million in the approximately 110 mile PennEast Pipeline to transport natural gas from eastern Pennsylvania to New Jersey with a targeted in-service date of November 2017. Power has contracted for approximately 125 million cubic feet-per-day of delivery capability on the PennEast Pipeline.

- Oil—Oil is used as the primary fuel for one load following steam unit and six combustion turbine peaking units and can be used as an alternate fuel by several load following and peaking units that have dual-fuel capability. Oil for operations is drawn from on-site storage and is generally purchased on the spot market and delivered by truck, barge or pipeline.

We expect to be able to meet the fuel supply demands of our customers and our own operations. However, the ability to maintain an adequate fuel supply could be affected by several factors not within our control, including changes in prices and demand, curtailments by suppliers, severe weather and other factors. For additional information, see Part II, Item 7. MD&A—Executive Overview of 2014 and Future Outlook and Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Markets and Market Pricing

The vast majority of Power’s generation assets are located in three centralized, competitive electricity markets operated by ISO organizations all of which are subject to the regulatory oversight of the FERC:

- PJM Regional Transmission Organization—PJM conducts the largest centrally dispatched energy market in North America. It serves over 61 million people, nearly 20% of the total United States population, and has a peak demand of 165,492 MW. The PJM Interconnection 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. The majority of our generating stations operate in PJM.
- New York—The New York ISO (NYISO) is the market coordinator for New York State and is responsible for managing the New York Power Pool and for administering its energy marketplace. This service area has a population of about 20 million and a peak demand of 33,956 MW. Our BEC station operates in New York.
- New England—The ISO-New England (ISO-NE) is the market coordinator for the New England Power Pool and for administering its energy marketplace which covers Maine, New Hampshire, Vermont, Massachusetts, Connecticut and Rhode Island. This service area has a population of about 14 million and a peak demand of 28,130 MW. Our Bridgeport and New Haven stations operate in Connecticut.

The price of electricity varies by location in each of these markets. Depending upon our production and our obligations, these price differentials may increase or decrease our profitability.

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Commodity prices, such as electricity, gas, coal, oil and emissions, as well as the availability of our diverse fleet of generation units to operate, also have a considerable effect on our profitability. These commodity prices have been, and continue to be, subject to significant market volatility. Over the long-term, the higher the forward prices are, the more attractive an environment exists for us to contract for the sale of our anticipated output. However, higher prices also increase the cost of replacement power, thereby placing us at greater risk should our generating units fail to function effectively or otherwise become unavailable.

Over the past few years, lower wholesale natural gas prices have resulted in lower electric energy prices. One of the reasons for the lower natural gas prices is greater supply from more recently-developed sources, such as shale gas. This trend has reduced margin on forward sales as we re-contract our expected generation output.

In addition to energy sales, we earn revenue from capacity payments for our generating assets. These payments are compensation for committing our generating capacity to the ISO for dispatch at its discretion. Capacity payments reflect the value to the ISO of assurance that there will be sufficient generating capacity available at all times to meet system reliability and energy requirements. Currently, there is sufficient capacity in the markets in which we operate. However, in certain areas of these markets there are transmission system constraints which raise concerns about reliability and create a more acute need for capacity.

In PJM and ISO-NE, where we operate most of our generation, the market design for capacity payments provides for a structured, forward-looking, transparent capacity pricing mechanism. This is through the Reliability Pricing Model (RPM) in PJM and the Forward Capacity Market (FCM) in ISO-NE. These mechanisms provide greater transparency regarding the value of capacity and provide a pricing signal to prospective investors in new generating facilities so as to encourage expansion of capacity to meet future market demands.

The prices to be received by generating units in PJM for capacity have been set through RPM base residual auctions and depend upon the zone in which the generating unit is located. For each delivery year, the prices differ in the various areas of PJM, depending on the constraints in each area of the transmission system. Keystone and Conemaugh receive lower prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in northern New Jersey usually receive higher pricing.

Our PJM generating units are located in several zones and Power expects to realize the following average capacity prices from the base auctions which have been completed:

Delivery Year	MW-day
June 2014 to May 2015	$166
June 2015 to May 2016	$167
June 2016 to May 2017	$169
June 2017 to May 2018	$165

The price that must be paid by an entity serving load in the various zones is also set through these auctions. These prices can be higher or lower than the prices noted in the table above due to import and export capability to and from lower-priced areas.

Like PJM and ISO-NE, the NYISO provides capacity payments to its generating units, but unlike the other two markets, the New York market does not provide a forward price signal beyond a six month auction period.

We have obtained price certainty for our PJM capacity through May 2018 and New England capacity through May 2019 through the RPM and FCM pricing mechanisms, respectively.

On a prospective basis, many factors may affect the capacity pricing, including but not limited to:

- load and demand,
- available amounts of demand response resources,
- capacity imports from external regions,
- availability of generating capacity (including retirements, additions, derates, forced outage rates, etc.),
- transmission capability between zones,
-

pricing mechanisms, including potentially increasing the number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM and the other ISOs may propose over time, including PJM's recent proposal that provides the opportunity for additional energy and capacity market compensation to generators like Power that certify their availability during emergency system conditions, and

- legislative and/or regulatory actions that permit states to subsidize local electric power generation.

For additional information on the RPM and FCM markets, as well as on state subsidization through various mechanisms, see Regulatory Issues—Federal Regulation.

Hedging Strategy

To mitigate volatility in our results, we seek to contract in advance for a significant portion of our anticipated electric output, capacity and fuel needs. We seek to sell a portion of our anticipated lower-cost generation over a multi-year forward horizon, normally over a period of two to three years. We believe this hedging strategy increases stability of earnings.

Among the ways in which we hedge our output are: (1) sales at PJM West and (2) BGS and similar full-requirements contracts. Sales at PJM West reflect block energy sales at the liquid PJM Western Hub and other transactions that seek to secure price certainty for our generation related products. In addition, the BGS-RSCP contract, a full-requirements contract that includes energy and capacity, ancillary and other services, is awarded for three-year periods through an auction process managed by the BPU. The volume of BGS contracts and the mix of electric utilities that our generation operations serve will vary from year to year. Pricing for the BGS contracts, including a capacity component, for recent and future periods by purchasing utility is as follows:

Load Zone ($/MWh)	2012-2015	2013-2016	2014-2017	2015-2018
PSE&G	$83.88	$92.18	$97.39	$99.54
Jersey Central Power & Light Company (JCP&L)	$81.76	$83.70	$84.44	$80.42
Atlantic City Electric Company	$85.10	$87.27	$87.80	$86.06
Rockland Electric Company	$92.51	$92.58	$95.61	$90.66

Although we enter into these hedges in an effort to provide price certainty for a large portion of our anticipated generation, there is variability in both our actual output as well as in our hedges. Our actual output will vary based upon total market demand, the relative cost position of our units compared to other units in the market and the operational flexibility of our units. Our hedge volume can also vary, depending on the type of hedge into which we have entered. The BGS auction, for example, results in a contract that provides for the supplier to serve a percentage of the default load of a New Jersey EDC, that is, the load that remains after some customers have chosen to be served directly either by third party suppliers or through municipal aggregation. The amount of power supplied through the BGS auction varies based on the level of the EDC's default load, which is affected by the number of customers who are served by a third party supplier, as well as by other factors such as weather and the economy.

In recent years, as market prices declined from previous levels, there was an incentive for more of the smaller commercial and industrial electric customers to switch to third party suppliers. In a falling price environment, this has a negative impact on our margins, as the anticipated BGS pricing is replaced by lower spot market pricing. As average BGS rates have declined to a level that more closely resembles current market prices, customers may see less of an incentive to switch to third party suppliers. We are unable to determine the degree to which this switching, or "migration," will continue, but the impact on our results could be material should market prices fall or rise significantly.

As of February 12, 2015, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2017.

Base Load Generation	2015	2016	2017
Generation Sales	100%	80%-85%	40%-45%

In a changing market environment, this hedging strategy may cause our realized prices to differ materially from current market prices. In a rising price environment, this strategy normally results in lower margins than would have been the case had no hedging activity been conducted. Alternatively, in a falling price environment, this hedging strategy will tend to create margins higher than those implied by the then-current market.

We take a more opportunistic approach in hedging our anticipated natural gas-fired generation. The generation from these units is less predictable, as a significant portion of these units will only dispatch when aggregate market demand has exceeded the supply provided by lower-cost units. Additionally, the recent development of low-cost gas supplies in the Marcellus region presents opportunities during certain portions of the year to procure gas for our generating units at attractive prices.

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Our fuel strategy is to maintain certain levels of uranium in inventory and to make periodic purchases to support such levels. Our nuclear fuel commitments cover approximately 100% of our estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2019. We also have various long-term fuel purchase commitments for coal to support our fossil generation stations. These purchase obligations are consistent with our strategy in general to enter into contracts for our fuel supply in comparable volumes to our sales contracts.

Other

Energy Holdings primarily owns and manages a portfolio of lease investments. Over the past several years, we have terminated all of our international leveraged leases in order to reduce the cash tax exposure related to these leases. We have also reduced our risk by opportunistically monetizing all of our previous international investments.

The majority of Energy Holdings' remaining $836 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2014, 69% of our total leveraged lease investments were rated as below investment grade by Standard & Poor's.

Energy Holdings' leveraged leasing portfolio is designed to provide a fixed rate of return. Leveraged lease investments involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease financing, the lessor purchases an asset to be leased. The purchase price is typically financed 80% with debt provided by the creditor and the balance comes from equity funds provided by the lessor. The creditor provides long-term financing to the transaction secured by the property subject to the lease. Such long-term financing is non-recourse to the lessor and, with respect to our lease investments, is not presented on our Consolidated Balance Sheets.

The lessor acquires economic and tax ownership of the asset and then leases it to the lessee for a period of time no greater than 80% of its remaining useful life. As the owner, the lessor is entitled to depreciate the asset under applicable federal and state tax guidelines. The lessor receives income from lease payments made by the lessee during the term of the lease and from tax benefits associated with interest and depreciation deductions with respect to the leased property. Our ability to realize these tax benefits is dependent on operating gains generated by our other operating subsidiaries and allocated pursuant to the consolidated tax sharing agreement between us and our operating subsidiaries.

Lease rental payments are unconditional obligations of the lessee and are set at levels at least sufficient to service the non-recourse lease debt. The lessor is also entitled to any residual value associated with the leased asset at the end of the lease term. An evaluation of the after-tax cash flows to the lessor determines the return on the investment. Under accounting principles generally accepted in the United States (GAAP), the leveraged lease investment is recorded net of non-recourse debt and income is recognized as a constant return on the net unrecovered investment.

For additional information on leases, including the credit, tax and accounting risks, see Item 1A. Risk Factors, Part II, Item 7A. Quantitative and Qualitative Disclosures About Market Risk—Credit Risk, and Item 8. Financial Statements and Supplementary Data—Note 7. Financing Receivables.

In accordance with a twelve year Amended and Restated Operations Services Agreement (OSA) entered into by PSEG LI and the LIPA, PSEG LI commenced operating LIPA’s electric T&D system in Long Island, New York on January 1, 2014. As required by the OSA, PSEG LI also provides certain administrative support functions to LIPA. PSEG LI uses its brand in the Long Island T&D service area. Pursuant to the OSA, PSEG LI acts as LIPA's agent in performing many of its obligations and in return (a) receives reimbursement for pass-through operating expenditures, (b) receives a fixed management fee and (c) is eligible to receive an incentive fee contingent on meeting established performance metrics. In addition, there is the opportunity for the parties to extend the contract for an additional eight years subject to the achievement by PSEG LI of certain performance levels during the initial term of the OSA. Also, as of January 2015, Power began providing fuel procurement and power management services to LIPA under separate agreements.

On July 1, 2014, PSEG LI submitted a proposal to LIPA to invest up to $200 million of capital in equipment at customer facilities that would improve energy efficiency and reduce peak load. PSEG LI proposed to make the investments from 2015 through 2018 and recover its investment and earn a return over approximately ten years. On October 6, 2014, PSEG LI filed an interim update which increased the size of the proposed program to approximately $345 million, reaffirmed its original investment proposal to fund up to $200 million of the program and also offered an alternate economic structure which included a performance incentive mechanism rather than utilizing PSEG LI’s capital. The New York State Department of Public Service will review the proposal and make a recommendation to

LIPA which is expected to take action on the proposal in 2015.

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COMPETITIVE ENVIRONMENT
PSE&G
Our transmission and distribution business is minimally impacted when customers choose alternate electric or gas suppliers since we earn our return by providing transmission and distribution service, not by supplying the commodity. Increased reliance by customers on net-metered generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities. The demand for electric energy and gas by customers is affected by customer conservation, economic conditions, weather and other factors not within our control.
Changes in the current policies for building new transmission lines, such as those ordered by the FERC and being implemented by PJM and other ISOs to eliminate contractual provisions that previously provided us a “right of first refusal” (ROFR) to construct projects in our service territory, could result in third party construction of transmission lines in our area in the future and also allow us to seek opportunities to build in other service territories. These implementing rules within the regions are still in flux so both the extent of the risk within our service territory and the opportunities for our transmission business elsewhere remain difficult to assess. For additional information, see the discussion in Regulatory Issues—Federal Regulation—Transmission Regulation, below.
Construction of new local generation also has the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints.
Power
Various market participants compete with us and one another in buying and selling in the wholesale energy markets, entering into bilateral contracts and selling to aggregated retail customers. Our competitors include:
- merchant generators,
- domestic and multi-national utility generators,
- energy marketers,
- banks, funds and other financial entities,
- fuel supply companies, and
- affiliates of other industrial companies.

New additions of lower-cost or more efficient generation capacity could make our plants less economic in the future. Although it is not clear if this capacity will be built or, if so, what the economic impact will be, such additions could impact market prices and our competitiveness.
Our business is also under competitive pressure due to demand side management (DSM) and other efficiency efforts aimed at changing the quantity and patterns of usage by consumers which could result in a reduction in load requirements. A reduction in load requirements can also be caused by economic cycles, weather, municipal aggregation and other customer migration and other factors. In addition, how resources such as demand response and capacity imports are permitted to bid into the capacity markets also affects the prices paid to generators such as Power in these markets. It is also possible that advances in technology, such as distributed generation and micro grids, will reduce the cost of alternative methods of producing electricity to a level that is competitive with that of most central station electric production. To the extent that additions to the electric transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, our revenues could be adversely affected. Changes in the rules governing what types of transmission will be built, who is selected to build transmission and who will pay the costs of future transmission could also impact our revenues.
Adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, would have the effect of artificially depressing prices in the competitive wholesale market and thus have the potential to harm competitive markets, on both a short-term and a long-term basis. At the same time, changes such as that proposed by PJM and discussed more fully in Regulatory Issues—Federal Regulation provide the opportunity for additional compensation in both the energy and capacity markets for being available (and making the necessary investments to ensure availability) during emergency conditions.
Environmental issues, such as restrictions on emissions of carbon dioxide (CO_2) and other pollutants, may also have a competitive impact on us to the extent that it becomes more expensive for some of our plants to remain compliant,

thus affecting our ability to be a lower-cost provider compared to competitors without such restrictions. In addition, most of our plants, which are located in the Northeast where rules are more stringent, can be at an economic disadvantage compared to our competitors in certain Midwest states. If any new legislation or regulations were to require our competitors to meet the

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environmental standards currently imposed upon us, we would likely have an economic advantage since we have already installed significant pollution-control technology at most of our fossil stations.

In addition, pressures from renewable resources could increase over time. For example, many parts of the country, including the mid-western region within the footprint of the Midwest Independent System Operator (MISO), the PJM region and the California ISO, have either implemented or proposed implementing changes to their respective regional transmission planning processes that may enable the construction of large amounts of “public policy” transmission to move renewable generation to load centers. For additional information, see the discussion in Regulatory Issues—Federal Regulation.

EMPLOYEE RELATIONS

As of December 31, 2014, we had 12,689 employees within our subsidiaries, including 7,958 covered under collective bargaining agreements. Four of our collective bargaining union agreements will expire in April 2017, two in October 2017 and one in May 2018. Effective January 1, 2014, in connection with our management contract with LIPA, we assumed the collective bargaining agreement between National Grid Electric Services LLC, LIPA's previous management contractor, and a labor union. That union contract will expire in November, 2016. We believe we maintain satisfactory relationships with our employees.

Employees as of December 31, 2014	PSE&G	Power	PSEG LI	Other
Non-Union	1,693	1,282	725	1,031
Union	4,832	1,691	1,427	8
Total Employees	6,525	2,973	2,152	1,039

REGULATORY ISSUES

Federal Regulation

FERC

The FERC is an independent federal agency that regulates the transmission of electric energy and gas in interstate commerce and the sale of electric energy and gas at wholesale pursuant to the Federal Power Act (FPA) and the Natural Gas Act. PSE&G and the generation and energy trading subsidiaries of Power are public utilities as defined by the FPA. The FERC has extensive oversight over such public utilities. FERC approval is usually required when a public utility seeks to: sell or acquire an asset that is regulated by the FERC (such as a transmission line or a generating station); collect costs from customers associated with a new transmission facility; charge a rate for wholesale sales under a contract or tariff; or engage in certain mergers and internal corporate reorganizations.

The FERC also regulates generating facilities known as qualifying facilities (QFs). QFs are cogeneration facilities that produce electricity and another form of useful thermal energy, or small power production facilities where the primary energy source is renewable, biomass, waste or geothermal resources. QFs must meet certain criteria established by the FERC. We own various QFs through Power. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

The FERC also regulates Regional Transmission Operators/ISOs, such as PJM, and their energy and capacity markets. For us, the major effects of FERC regulation fall into five general categories:

- Regulation of Wholesale Sales—Generation/Market Issues
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

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Regulation of Wholesale Sales—Generation/Market Issues

Market Power

Under FERC regulations, public utilities must receive FERC authorization to sell power in interstate commerce. They can sell power at cost-based rates or apply to the FERC for authority to make market-based rate (MBR) sales. For a requesting company to receive MBR authority, the FERC must first make a determination that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. The FERC requires that holders of MBR tariffs file an update every three years demonstrating that they continue to lack market power and/or that their market power has been sufficiently mitigated and report in the interim to the FERC any material change in facts from those the FERC relied on in granting MBR authority.

PSE&G, PSEG Energy Resources & Trade LLC, PSEG Power Connecticut, PSEG Fossil LLC, PSEG Nuclear LLC and PSEG New Haven LLC all have been granted MBR authority from the FERC. Each of these companies, except PSEG New Haven LLC (which received MBR authority in May 2012), filed a market power update with the FERC at the end of 2013. In an order issued in October 2014, the FERC accepted these filings as having satisfied the requirements for retention of MBR authority.

Energy Clearing Prices

Energy clearing prices in the markets in which we operate are generally based on bids submitted by generating units. Under FERC-approved market rules, bids are subject to price caps and mitigation rules applicable to certain generation units. The FERC rules also govern the overall design of these markets. At present, all units receive a single clearing price based on the bid of the marginal unit (i.e. the last unit that must be dispatched to serve the needs of load). These FERC rules have a direct impact on the energy prices received by our units.

As a result of the polar vortex and related cold weather events in January 2014, there were both gas and electric price spikes in the Northeast markets, including in PJM. The FERC has examined the facts surrounding these price spikes, as well as “lessons learned” from the various Regional Transmission Operators/Independent System Operators (RTO/ISO) and potential changes in market rules intended to encourage dual fuel capability of generating units, the purchase of firm fuel to operate these units and the construction of additional natural gas pipeline capacity. As discussed below, PJM has proposed changes to its capacity market construct to develop a new capacity product that would be compensated in both the energy and capacity markets for availability during emergency conditions on the system. The FERC is also examining price formation issues, focusing on levels of compensation to generators in the energy and ancillary services markets, and we are advocating in this context for changes in market rules that would provide more transparency about energy market prices. We cannot predict what action the FERC might ultimately take, but such an examination could lead to future rule changes.

Capacity Market Issues

PJM, the NYISO and the ISO-NE each have capacity markets that have been approved by the FERC. The FERC regulates these markets and continues to examine whether the market design for each of these three capacity markets is working optimally. Specific issues being considered by the FERC are whether capacity market rules properly address and foster the development of state public policies, demand response (DR) and emerging technologies and whether generators are being sufficiently compensated in the capacity market. We cannot predict what action, if any, the FERC might take with regard to capacity market design.

PJM—The RPM is the locational installed capacity market design for the PJM region, including a forward auction for installed capacity. Under the RPM, generators located in constrained areas within PJM are paid more for their capacity as an incentive to ensure adequate supply where generation capacity is most needed. The mechanics of the RPM in PJM continue to evolve and be refined in stakeholder proceedings and FERC proceedings in which we are active. There is currently significant activity concerning three topics: (i) the future role of DR in the RPM market in light of a decision by the D.C. Circuit Court of Appeals (D.C. Court) holding that DR is not a FERC-jurisdictional product, (ii) PJM’s development of a new capacity product called a Capacity Performance (CP) product, and (iii) the setting of the Cost of New Entry (CONE) value for the RPM demand curve for the auctions to be conducted in the next four years.

In May 2014, in a case involving the proper level of compensation for DR resources in the energy markets, the D.C. Court held that DR is not a FERC-jurisdictional product, thereby calling into question DR resources’ ability to participate in either the energy or capacity markets in the future. In January 2015, the FERC filed a petition to the U.S.

Supreme Court to review the D.C. Court's ruling. The D.C. Court's decision has been stayed until the U.S. Supreme Court acts on this petition, which is not expected to occur until the end of April. In the meantime, FirstEnergy Corp. has filed a complaint at the FERC which argues that DR resources should no longer participate in the PJM capacity market and seeks to invalidate the results of the last RPM Base Residual Auction that was conducted in May 2014. In addition, PJM has recently submitted a filing at the FERC, conditioned on denial by the U.S. Supreme Court of the FERC's petition for review, that if accepted by the FERC, would only

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allow DR to participate in the capacity market through adjustment of the demand curve rather than as a capacity resource that receives a revenue stream. Should the FERC accept PJM's filing, this new model would be in effect for the upcoming May 2015 Base Residual Auction and could have an upward effect on the auction's clearing prices.

In September 2014, PJM filed at the FERC to re-set the Variable Resource Requirement (VRR) curve for the RPM, as going forward will be done every four years. Establishment of the VRR curve is a critical component in determining how generators are paid in the capacity auction. In November 2014, the FERC accepted PJM’s filing, which we believe represents an improvement over the status quo in terms of appropriately setting the demand curve. However, we and other generators have challenged the FERC’s approval order on rehearing, taking exception with the FERC’s approval of the manner in which PJM calculated the cost of capital and labor costs that form the basis for the CONE component of the demand curve, which we believe have been set too low and do not accurately reflect the costs of building a new generating unit in PJM. The rehearing request remains pending at the FERC.

On December 12, 2014, PJM filed a proposal at the FERC to implement a CP mechanism. Under this mechanism, PJM has created a more robust capacity product definition with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. While there is no specific eligibility requirement, the CP resource must represent that it has made, or will make, the necessary investments to ensure that the resource has the capability to provide energy when emergency conditions on the system exist. CP resources will be able to offer into the capacity market up to Net CONE (the CONE value including offsets for expected energy and ancillary services revenues), but risk remains that bids up to Net CONE may be challenged by regulatory authorities from the standpoint of bidding behavior even when supported by a commercially reasonable assessment of costs. This new product, if accepted by the FERC, will be phased in over the next few years, with full implementation for the 2020-2021 delivery year. PJM’s approach may provide the opportunity for enhanced capacity market revenue streams for Power. However, there may be requirements for additional investment and there are additional performance risks, as well as risks associated with our ability to bid in a manner that would ensure recovery of any capital investment.

MISO—MISO does not have a mandatory capacity market in place, as load serving entities may submit Fixed Resource Adequacy Plans in lieu of participating in the capacity auction. In the May 2013 RPM auction, the difference between the MISO and PJM capacity markets was highlighted, as significant amounts of MISO generation were bid as imports into PJM and cleared in RPM. MISO is seeking to facilitate additional exports. The FERC tightened the rules in 2014 and permitted PJM to establish annual capacity import limits, which were then incorporated into the 2017/2018 planning parameters for the May 2014 base residual auction. We believe that this action had a resultant upward effect on prices in PJM. The FERC continues to examine this "capacity portability" issue and, in response to a complaint filed by a utility company in Indiana, the FERC is also examining whether current PJM/MISO rules regarding capacity imports and exports entered into under the Joint Operating Agreement between the regions are appropriate.

ISO-NE—ISO-NE’s market for installed capacity in New England provides fixed capacity payments for generators, imports and DR. The market design consists of a forward-looking auction for installed capacity that is intended to recognize the locational value of resources on the system and contains incentive mechanisms to encourage availability during stressed system conditions. In May 2014, the FERC issued an order requiring the implementation of a downward sloping demand curve, similar to the design in place in PJM, for use in ISO-NE's ninth capacity market auction, which was recently held and effective in the 2018-2019 delivery year. This action decreased volatility in capacity prices and, in conjunction with an ISO-established seven-year locked-in clearing price for new resources (other than certain subsidized renewable resources) incented the clearing of new generation in the auction. One aspect of this May 2014 FERC order that we did not support was the exemption from the Minimum Offer Price Rule afforded annually up to 600 MW of renewable resources. We challenged this portion of the order on rehearing on the grounds that we believe that it is unduly discriminatory and will suppress capacity prices. In an order issued in January 2015, the FERC denied our rehearing request.

In addition, in the FERC order referenced above, the FERC directed the ISO-NE to develop demand curves for each capacity zone in the market. The ISO-NE is currently conducting a stakeholder proceeding and expects to make a filing with the FERC in the next few months. The shape of the demand curve in the zones will have a significant impact upon the revenues our generation can expect to receive in the capacity market in New England.

NYISO—NYISO operates a short-term capacity market that provides a forward price signal only for six months into the future. Prior to 2013, the NYISO capacity model had recognized only two separate zones that potentially may separate in price: New York City and Long Island. In August 2013, the FERC issued an order approving a third capacity zone that would encompass the super zone that includes the lower Hudson Valley and New York City which took effect on May 1, 2014.

In January 2014, the FERC issued an order accepting the NYISO's proposed reference unit (a generation unit with no environmental controls) that should be used for the purposes of establishing the CONE in the "rest of State" zone (excluding the lower Hudson Valley, New York City and Long Island), which may have the effect of depressing capacity prices. This order will set the demand curve on which future capacity prices paid to generators will be based for the period May 1, 2014 through April 30, 2017. That order was upheld by the FERC on rehearing in May 2014 and the federal appellate court subsequently denied motions for a stay of the effect of the order.

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Discussions at the FERC concerning other potential changes to NYISO capacity markets, including rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons, are also ongoing.

Long-Term Capacity Agreement Pilot Program Act (LCAPP)—In 2011, the State of New Jersey enacted the LCAPP to subsidize approximately 2,000 MW of new natural gas-fired generation. The LCAPP provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey EDCs. The SOCA required each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into three SOCAs as directed by the State, but did so under protest reserving their rights.

In 2013, the U.S. District Court in New Jersey found that the LCAPP was unconstitutional and declared the LCAPP null and void. As a result of that decision, PSE&G terminated its SOCA contracts. This federal court decision was subsequently challenged on appeal in the U.S. Third Circuit Court of Appeals. The State of Maryland also took similar action to subsidize above-market new generation. This action was also determined to be unconstitutional in 2013 in the U.S. District Court in Maryland and such decision was challenged in the U.S. Fourth Circuit Court of Appeals. Both appeals were denied, with the U.S. Fourth Circuit Court of Appeals denying the appeal regarding the State of Maryland's action in June 2014 and the U.S. Third Circuit Court of Appeals denying the LCAPP appeal in September 2014. These denials have now been challenged on appeal to the U.S. Supreme Court, which action remains pending.

Transmission Regulation

The FERC has exclusive jurisdiction to establish the rates and terms and conditions of service for interstate transmission. We currently have FERC-approved formula rates in effect to recover the costs of our transmission facilities. Under this formula, rates are put into effect in January of each year based upon our internal forecast of annual expenses and capital expenditures. Rates are subsequently trued up to reflect actual annual expenses and capital expenditures. Our allowed ROE is 11.68% for both existing and new transmission investments and we have received incentive rates, affording a higher ROE, for certain large scale transmission investments.

Our 2015 Formula Rate Update with the FERC for approximately $182 million in increased annual transmission revenues went into effect on January 1, 2015. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. The adjustment for 2015 will include the impact of the extension of bonus depreciation, which was enacted after the filing was made, and is estimated to reduce our 2015 revenue increase as filed by approximately $21 million. For additional information about our transmission formula rate, see Part II, Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

- Transmission Policy Developments—The FERC concluded in Order 1000 that the incumbent transmission owner should not always have a ROFR to construct and own transmission projects in its service territory. We had challenged the FERC's elimination of the ROFR in federal court. In August 2014, our challenge was rejected by the D.C. Court. PJM is currently implementing its rules under which the construction of certain types of transmission projects will no longer be subject to a ROFR for incumbents. In May 2014, the FERC approved PJM's rules, which retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including projects being built on existing right-of-way and whose construction would interfere with incumbents' use of their right-of-way. Several companies, including PSE&G, have appealed various aspects of this approval order.

The FERC has also approved the "state agreement approach" to cost allocation under which transmission projects being built to address public policy concerns may be placed into PJM's planning process if the state sponsoring the project agrees to pay the costs of the project. To date, no such projects have been placed into the planning process but this mechanism could potentially facilitate transmission projects that are not needed for reliability or market efficiency under PJM standards for transmission, including potential offshore wind projects proposed by third parties, should a state or states agree to fund the costs of such projects.

In addition, in September 2014, PJM filed at the FERC to add another category of project - the "multi-driver" project - to its planning process. This type of project would contain reliability, economic and/or public policy elements. Projects falling within this category would be required to independently satisfy all of the different drivers in order to be approved. However, this category could also serve as a vehicle for the development of large, public policy-driven projects. In October 2014, the FERC issued a deficiency letter regarding PJM's "multi-driver" filing seeking additional information and clarification with respect to the filing, to which PJM responded in December 2014. We have protested the filing on the grounds that this new project category is not needed for reliability and that the rules to allocate costs for these projects are unclear. The FERC has recently issued an order accepting PJM’s filing. We are currently considering whether to seek rehearing.

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PJM's first action toward complying with Order 1000 began in April 2013, when it initiated its first "open window" solicitation process to allow both incumbents and non-incumbents the opportunity to submit transmission project proposals to address identified high voltage issues at Artificial Island. PJM has not yet concluded this process. On January 30, 2015, PSE&G filed a complaint against PJM at the FERC, asserting that PJM had failed to follow its tariff rules governing the process and requesting that the FERC direct PJM to do so. If the FERC grants the complaint, one outcome could be that PJM will be required to re-start the entire selection process for this project. The FERC could also require PJM to make changes to the rules governing future competitive solicitations.

In addition, the FERC is currently considering two significant transmission cost allocation matters. The first involves a November 2014 complaint brought by Con Edison against PJM at the FERC challenging PJM's allocation of costs for two PSE&G projects in northern New Jersey, including the Bergen-Linden Corridor Project (BLC Project) discussed below. We have opposed Con Edison's complaint. The other proceeding is a matter remanded from a federal appellate court concerning the appropriate cost allocation for certain 500 kV projects in PJM that either have been built or are in the process of being built, including the Susquehanna-Roseland project. This matter is currently in settlement discussions at the FERC. Resolution of these two proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey.

- Transmission Rate Proceedings—In December 2013, PSE&G was assigned construction responsibility by PJM of a new transmission project that will provide a double-circuit 345 kV line in the BLC Project to maintain reliability. Phases One through Three of the BLC Project are scheduled to be in service in 2016, 2017 and 2018, respectively, with certain components of Phase One required to be in service as early as June 2015. The estimated construction costs of the BLC Project are $1.2 billion. On March 28, 2014, we filed a petition with the FERC seeking incentives for the BLC Project, specifically recovery of Construction Work in Progress in rate base and authorization to recover 100% of all prudently incurred development and construction costs if the BLC Project is abandoned or canceled, in whole or in part, for reasons beyond the control of PSE&G. In May 2014, the FERC issued an order granting our petition requesting incentives. A merchant transmission company has challenged its allocated cost responsibility for the BLC Project and the order granting PSE&G's request for incentives related to that project.

There are several complaints pending at the FERC against transmission owners around the country, challenging those transmission owners' base ROEs. While we are not the subject of a challenge to the ROE employed in PSE&G's transmission formula rate, the results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

Compliance

- FERC Audit—In November 2012, the FERC commenced an audit of each of the PSEG companies that have MBR authority from the FERC. The companies were audited by the FERC for compliance with its rules for (i) receiving and retaining MBR authority, (ii) the filing of electric quarterly reports (EQRs), and (iii) our generating units' receipt of payments from the RTO/ISO when they are required to run for reliability reasons when it is not economical for them to do so. On October 16, 2014, the FERC issued a final, public audit report that contained two findings and recommendations for enhanced review and reporting of our EQRs. In November 2014, we submitted a compliance plan to the FERC explaining how we intend to implement the FERC's recommendations and we are providing quarterly updates to the FERC until we have implemented all such recommendations.
- FERC—In the first quarter of 2014, Power discovered that it incorrectly calculated certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market. Upon discovery of the errors, we retained outside counsel to assist in the conduct of an investigation into the matter. As the investigation proceeded, additional pricing errors in the bids were identified and it was further determined that the quantity of energy that Power offered into the energy market for its fossil peaking units differed from the amount for which Power was compensated in the capacity market for those units. On September 2, 2014, the FERC staff initiated a preliminary, non-public staff investigation into the matter. This investigation, which is ongoing, could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with this matter, or the applicability of mitigating factors. See Part II, Item 8. Financial Statements and Supplementary Data. Note 12. Commitments and Contingent Liabilities—FERC Compliance for further discussion of this matter.

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Reliability Standards—Congress has required the FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the United States electric transmission and generation system (grid) and to prevent major system blackouts. There has been considerable focus recently on physical security in light of, among other things, a substation attack in California that occurred in 2013. As a result, the FERC directed the NERC to draft a physical security standard intended to further protect assets deemed "critical" to reliability of the grid. In November 2014, the FERC issued an order approving the NERC's proposed physical security standard. Under the standard, utilities will be required to identify critical substations as well as develop threat assessment plans to be reviewed by independent third parties. In our case, the third party is PJM. As part of these plans, utilities could decide or be required to build additional redundancy into their systems. This standard will supplement the Critical Infrastructure Protection standards that are already in place and that establish physical and cybersecurity protections for critical systems.

Commodity Futures Trading Commission (CFTC)

In accordance with the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act), the SEC and the CFTC are in the process of implementing a new regulatory framework for swaps and security-based swaps. The legislation was enacted to reduce systemic risk, increase transparency and promote market integrity within the financial system by providing for the registration and comprehensive regulation of swap dealers and by imposing recordkeeping, data reporting, margin and clearing requirements with respect to swaps. To implement the Dodd-Frank Act, the CFTC has engaged in a comprehensive rulemaking process and has issued a number of proposed and final rules addressing many of the key issues. We are currently subject to record keeping and data reporting requirements applicable to commercial end users. The CFTC has also proposed rules establishing position limits for trading in certain commodities, such as natural gas, and we are currently analyzing the potential impact of these rules on our business.

Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive regulation by the NRC, a federal agency established to regulate nuclear activities to ensure protection of public health and safety, as well as the security and protection of the environment. Such regulation involves testing, evaluation and modification of all aspects of plant operation in light of NRC safety and environmental requirements. Continuous demonstration to the NRC that plant operations meet requirements is also necessary. The NRC has the ultimate authority to determine whether any nuclear generating unit may operate. The current operating licenses of our nuclear facilities expire in the years shown in the following table:

Unit	Year
Salem Unit 1	2036
Salem Unit 2	2040
Hope Creek	2046
Peach Bottom Unit 2	2033
Peach Bottom Unit 3	2034

As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in 2011, the NRC began performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan have resulted in additional regulation for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants currently meet the stringent applicable design and safety specifications of the NRC.

In 2011, a NRC task force submitted a report containing various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. The NRC staff also issued a document which provided for a prioritization of the task force recommendations. The NRC approved the staff's prioritization and implementation recommendations subject to a number of conditions. Among other things, the NRC advised the staff to give the highest priority to those activities that can achieve the greatest safety benefit and/or have the broadest applicability (Tier 1), to review filtration of boiling water reactor (BWR) primary containment vents and encouraged the staff to create requirements based on a performance-based system which allows for flexible approaches and the ability to address a diverse range of site-specific circumstances and conditions and strive to implement the requirements by 2016.

Separately, a petition was filed with the NRC in April 2011 seeking suspension of the operating licenses of all General Electric BWRs utilizing the Mark I containment design in the United States, including our Hope Creek and Peach Bottom units, pending completion of the NRC review. Fukushima Daiichi Units 1-4 are BWRs equipped with Mark I containments. The petition named 23 of the then total 104 active commercial nuclear reactors in the United States. In March 2014, the NRC formally closed the petition without opting to conduct further proceedings.

The NRC issued letters and orders to licensees implementing the Tier 1 recommendations in March 2012. In March 2013, the NRC initiated a rulemaking process for improvements to venting systems at 31 U.S. BWRs with “Mark I” and “Mark II” containments (similar to those at Fukushima), which include our Hope Creek and Peach Bottom units. In June 2013, the NRC issued orders requiring Mark I and Mark II licensees to upgrade or replace their reliable hardened vents with containment venting systems designed and installed to remain functional during severe accident conditions. We are implementing the diverse and flexible strategies and spent fuel pool level indication modifications in accordance with the regulatory requirements at the Salem, Hope Creek and Peach Bottom nuclear units. For our Hope Creek and Peach Bottom units, final installation of the required modifications is expected to occur during the planned refueling outages in 2016-2018.

The NRC is currently developing the regulatory basis for drywell filtration strategies rulemaking. The NRC expects to complete its evaluation and vote on a final rule in 2017. The NRC continues to evaluate potential revisions to its requirements in connection with its operational and safety reviews of nuclear facilities in the United States as a result of the Fukushima Daiichi incident.

We are unable to predict the final outcome of these reviews or the cost of any actions we would need to take to comply with any new regulations, including possible modifications to our Salem, Hope Creek and Peach Bottom facilities, but such cost could be material.

State Regulation

Since our operations are primarily located within New Jersey, our principal state regulator is the BPU, which oversees electric and natural gas distribution companies in New Jersey. We are also subject to various other states’ regulations due to our operations in those states.

Our New Jersey utility operations are subject to comprehensive regulation by the BPU including, among other matters, regulation of retail electric and gas distribution rates and service, the issuance and sale of certain types of securities and compliance matters. PSE&G's participation in solar, demand response and energy efficiency programs is also regulated by the BPU, as the terms and conditions of these programs are approved by the BPU. BPU regulation can also have a direct or indirect impact on our power generation business as it relates to energy supply agreements and energy policy in New Jersey.

We must file electric and gas rate cases with the BPU in order to change our utility base distribution rates. Our last base rate case was settled in 2010. As a result of our Energy Strong order discussed below, we are required to file our next base rate case proceeding no later than November 1, 2017. In addition to base rates, we recover certain costs or earn on certain investments pursuant to mechanisms known as adjustment clauses. These clauses permit the flow-through of costs to, or the recovery of investments from, customers related to specific programs, outside the context of base rate case proceedings. Recovery of these costs or investments is subject to BPU approval for which we make periodic filings. Delays in the pass-through of costs or recovery of investments under these mechanisms could result in significant changes in cash flow. For additional information on our specific filings, see Part II, Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

Energy Strong Program—In February 2013, we filed a petition with the BPU describing the improvements we recommend making to our BPU jurisdictional electric and gas system to improve resiliency for the future. The changes that were described, designated as the “Energy Strong Program,” would be made over a ten-year period. In this petition, we sought approval to invest \$0.9 billion in our gas distribution system and \$1.7 billion in our electric distribution system over an initial five-year period, plus associated expenses, and to receive contemporaneous recovery of and on such investments. In May 2014, the BPU issued an Order approving the settlement of our Energy Strong program. Under the settlement, PSE&G will invest \$1.22 billion to (1) upgrade all of its electric substations that were damaged by water in recent storms; make investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deploy technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in the event of an electric outage, and (2) with respect to PSE&G’s gas system, replace and modernize 250 miles of low-pressure cast iron gas mains in or near flood areas; and upgrade five natural gas metering stations and a liquefied natural gas station recently affected by severe weather or located in flood zones. The settlement provides for cost recovery at a 9.75% rate of ROE on the first $1.0 billion of the investment, plus associated Allowance for Funds Used Under Construction, and will occur for completed projects on a semi-annual (for electric investments) or annual (for gas investments) basis. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, which as noted above, is to be filed no later than November 1, 2017.

In September 2014, PSE&G filed its initial Energy Strong cost recovery petition, seeking BPU approval to recover in base rates capitalized Energy Strong electric investment costs expected to be in service through November 30, 2014. This request was updated in December 2014 for actual costs and recovery of an estimated annual revenue increase of $1.1 million effective March 1, 2015.

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Energy Efficiency Economic Stimulus Extension II (EEE Ext II)—In August 2014, we filed for approval from the BPU of an EEE Ext II Program to extend three EEE subprograms (multi-family, direct install and hospital efficiency). We proposed to extend the subprograms' offerings under the same clause recovery process as currently approved while seeking additional capital expenditures of approximately $96 million and additional administrative costs of $14 million. The matter is pending.

Consolidated Tax Adjustments (CTA)—New Jersey is one of only a few states that make CTA in setting rates for regulated utilities. These adjustments to rate base are made during the rate setting process and are intended to allocate to utility customers a portion of the tax benefits realized from the filing of a consolidated federal tax return by the utility's parent corporation. The BPU has been considering the appropriateness of the adjustment and the methodology and mechanics of the calculation for some time. On October 22, 2014, the BPU approved a proposal by its Staff that limits the tax benefit period to be considered in the calculation to five years, sets the rate base adjustment at 25% of any such tax benefit and eliminates from the process any tax benefits tied to transmission earnings. In accordance with this October action, this CTA policy will be applied only with respect to future rate cases. The adoption of these modifications by the BPU is not expected to have a material impact on PSE&G's current earnings nor in its next rate case filing. On November 5, 2014, the New Jersey Division of Rate Counsel appealed the BPU's decision. The appeal remains pending.

New Jersey Energy Master Plan (EMP)—New Jersey law requires that an EMP be developed every three years, the purpose of which is to ensure safe, secure and reasonably-priced energy supply, foster economic growth and development and protect the environment. While not having the force of law, the EMP provides an overview of energy policy in New Jersey and may provide both opportunities and challenges for PSEG. The most recent EMP was finalized in December 2011 and placed an emphasis on expanding in-state electricity resources, reducing energy costs, recognizing the impact of climate change and setting new targets for a renewable portfolio standard and goals for energy supplies from clean energy sources.

Additional matters are discussed in Part II, Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

ENVIRONMENTAL MATTERS

Changing environmental laws and regulations significantly impact the manner in which our operations are currently conducted and impose costs on us to reduce the health and environmental impacts of our operations. To the extent that environmental requirements are more stringent and compliance more costly in certain states where we operate compared to other states that are part of the same market, such rules may impact our ability to compete within that market. Due to evolving environmental regulations, it is difficult to project future costs of compliance and their impact on competition. Capital costs of complying with known pollution control requirements are included in our estimate of construction expenditures in Item 7. MD&A—Capital Requirements. The costs of compliance associated with any new requirements that may be imposed by future regulations are not known, but may be material.

Areas of environmental regulation may include, but are not limited to:

- air pollution control,
- climate change,
- water pollution control,
- hazardous substance liability, and
- fuel and waste disposal.

For additional information related to environmental matters, including proceedings not discussed below, as well as anticipated expenditures for installation of pollution control equipment, hazardous substance liabilities and fuel and waste disposal costs, see Item 1A. Risk Factors, Item 3. Legal Proceedings and Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) which requires controls of emissions from sources of air pollution and imposes record keeping, reporting and permit requirements. Our facilities are also subject to requirements established under state and local air pollution laws. The CAA requires all major sources, such as our generation facilities, to obtain and keep current an operating permit. The costs of compliance associated with any new requirements that may be imposed and included in these permits in the future could be material and are not included in our estimates of capital expenditures.

- Hazardous Air Pollutants Regulation—In February 2012, the Environmental Protection Agency (EPA) published under the National Emission Standard for Hazardous Air Pollutants provisions of the Clean Air Act, Mercury Air

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Toxics Standards (MATS) for both newly-built and existing electric generating sources. The impact to our fossil generation fleet in New Jersey and Connecticut and our jointly-owned coal-fired generating facilities in Pennsylvania is further discussed in Part II, Item 8. Financial and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

- Demand Response (DR) Reciprocating Internal Combustion Engines (RICE) Litigation—In March 2013, Power filed a petition at the EPA challenging the National Emission Standards for Hazardous Air Pollutants (NESHAP) for RICE issued in January 2013. In April 2013, Power, along with several other energy companies, filed a petition for review at the D.C. Court which remains pending. Among other things, the final EPA rule allows owners and operators of stationary emergency RICE to operate their engines as part of an emergency DR program without the installation and operation of emission controls or compliance with emission limits otherwise applicable to non-emergency counterparts. This waiver of NESHAP standards results in disparate treatment of different generation technology types. In its appeal, Power sought more stringent emission control standards for RICE to support more competitive markets, particularly the PJM capacity market. In August 2014, the EPA denied the March 2013 petition and in October 2014, Power appealed the EPA's denial to the D.C. Court.
- Cross-State Air Pollution Rule (CSAPR)—In July 2011, the EPA issued the final CSAPR, which limits power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season NO_x in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards (NAAQS). In August 2012, the D.C. Court vacated CSAPR and ordered that the existing Clean Air Interstate Rule (CAIR) requirements remain in effect until an appropriate substitute rule has been promulgated. The purpose of CAIR is to improve ozone and fine particulate air quality within states that have not demonstrated achievement of the NAAQS. CAIR was implemented through a cap-and-trade program and, to date, the impact has not been material to us as the allowances allocated to our stations were sufficient. In April 2014, the Supreme Court overturned the D.C. Court's ruling. In October 2014, the D.C. Court lifted the stay on CSAPR. On November 21, 2014, the EPA issued a notice to implement CSAPR effective January 1, 2015. We do not anticipate any material impact on our earnings or financial condition due to the CSAPR.

Climate Change

- CO_2 Regulation Under the CAA—In April 2012, the EPA published the proposed New Source Performance Standards (NSPS) under the CAA for greenhouse gas (GHG) emissions for new power plants only. In June 2013, the President directed the EPA to propose revised NSPS for new power plants by September 20, 2013, propose GHG regulations for existing power plants by June 1, 2014, finalize such regulations by June 1, 2015 and require states to submit GHG implementation regulations by June 30, 2016.

In January 2014, the EPA proposed revised NSPS for new power plants. The revised NSPS establish three emission standards for CO_2 for the following categories: (i) fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units, (ii) large natural gas combustion turbines, and (iii) small natural gas combustion turbines. The EPA is requesting comment on use of an electric output sales threshold to determine applicability to the NSPS. This electric output sales threshold would eliminate the outright exclusion of simple cycle combustion turbines which was proposed in the initial April 2012 NSPS. We cannot predict the final outcome of these proposed standards.

In June 2014, the EPA issued a proposed GHG emissions regulation for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction (BSER). The BSER consists of four components: (i) heat rate improvements at existing coal-fired power plants, (ii) increased use of existing natural gas combined cycle capacity, (iii) operation of zero-emitting generation (renewables and nuclear), and (iv) increased use of demand-side energy efficiency. States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions.

Since the EPA has requested comments on many aspects of the proposal, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact. A final rule is expected in mid-summer 2015.

The FERC will hold a series of technical conferences early in 2015 to discuss the implications of compliance approaches to the EPA’s proposed GHG regulation for existing power plants. The conferences will focus on issues related to electric reliability, wholesale electric markets and operations and energy infrastructure.

In August 2014, an Ohio-based energy company and several states filed petitions for review with the D.C. Circuit Court. The parties are challenging the EPA's authority to regulate existing electric generating units under the existing source performance standards section of the CAA. The matter is pending.

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- Climate-Related Legislation or Regulation—The federal government may consider legislative and/or regulatory proposals to define a national energy policy and address climate change. Proposals under consideration include, but are not limited to, provisions to establish a national clean energy portfolio standard and to establish an energy efficiency resource standard. Provisions of any new proposal may present material risks and opportunities to our businesses. The final design of any legislation or regulation will determine the impact on us, which we are not now able to reasonably estimate.
- Regional Greenhouse Gas Initiative (RGGI)—In response to concerns over global climate change, some states have developed initiatives to stimulate national climate legislation through CO_2 emission reductions in the electric power industry. Certain northeastern states (RGGI States), including New York and Connecticut where we have generation facilities, have state-specific rules in place to enable the RGGI regulatory mandate in each state to cap and reduce CO_2 emissions.

These rules make allowances available through a regional auction whereby generators may acquire allowances that are each equal to one ton of CO_2 emissions. Generators are required to submit an allowance for each ton emitted over a three-year period. Allowances are available through the auction or through secondary markets.

In February 2013, the RGGI States released an updated Model Rule that, among other things, reduced the amount of available regional CO_2 allowances beginning in 2014. Each RGGI State must implement the changes through state-specific regulations. We do not expect these changes, or any future changes, to the RGGI rules will have a material impact on us.

New Jersey withdrew from RGGI beginning in 2012. As a result, our New Jersey facilities are no longer obligated to acquire CO_2 emission allowances. This action has been challenged by environmental groups in the New Jersey state court. In March 2014, the Appellate Division of the New Jersey Superior Court ruled that the New Jersey Department of Environmental Protection (NJDEP) improperly withdrew its regulation under which RGGI had been implemented. The Court gave the NJDEP 60 days to initiate a public process to either repeal or amend that regulation to provide that it is applicable only when New Jersey is a participant in a regional or other established greenhouse gas program. In July 2014, the NJDEP published its intent to formally repeal the rules implementing RGGI in New Jersey. We cannot predict the outcome of this matter.

New Jersey also adopted the Global Warming Response Act in 2007, which calls for stabilizing its GHG emissions to 1990 levels by 2020, followed by a further reduction of greenhouse emissions to 80% below 2006 levels by 2050. To reach this goal, the NJDEP, the BPU, other state agencies and stakeholders are required to evaluate methods to meet and exceed the emission reduction targets, taking into account their economic benefits and costs.

Water Pollution Control

The Federal Water Pollution Control Act (FWPCA) prohibits the discharge of pollutants to U.S. waters from point sources, except pursuant to a National Pollutant Discharge Elimination System (NPDES) permit issued by the EPA or by a state under a federally authorized state program. The FWPCA authorizes the imposition of technology-based and water quality-based effluent limits to regulate the discharge of pollutants into surface waters and ground waters. The EPA has delegated authority to a number of state agencies, including those in New Jersey, New York and Connecticut, to administer the NPDES program through state action. We also have ownership interests in facilities in other jurisdictions that have their own laws and implement regulations to control discharges to their surface waters and ground waters that directly govern our facilities in those jurisdictions.

- Steam Electric Effluent Guidelines—In April 2013, the EPA issued notice of a proposed rule that would further limit the discharge of pollutants in wastewater from the operation of coal-fired generating facilities. Our co-owned Keystone and Conemaugh facilities continue to use technologies that generate these wastewater discharges. However, our other coal-fired facilities no longer discharge many of these types of wastewater pollutants. We are unable to predict the impact on Keystone and Conemaugh but do not believe there would be any material impact on our other coal-fired facilities. The EPA is expected to finalize the rule in September 2015.

In addition to regulating the discharge of pollutants, the FWPCA regulates the intake of surface waters for cooling. The use of cooling water is a significant part of the generation of electricity at steam-electric generating stations. Section 316(b) of the FWPCA requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The impact of regulations under Section 316(b) can be significant, particularly at steam-electric generating stations which do not have closed cycle cooling and do not use cooling towers to recycle water for cooling purposes. The installation of cooling towers at an existing generating station can impose significant engineering challenges and significant costs, which can affect the economic viability of a particular plant.

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- Cooling Water Intake Structure Regulation—In 2011, the EPA published a new proposed rule under Section 316(b) which did not establish any particular technology as the best technology available (e.g. closed-cycle cooling). Instead, the proposed rule established marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. We reviewed the proposed rule, assessed the potential impact on our generating facilities and used this information to develop our comments to the EPA which were filed in August 2011. In June 2012, the EPA posted a Notice of Data Availability (NODA) requesting comment on a series of technical issues related to the impingement mortality proposed standards. The EPA also posted a second NODA outlining its plans to finalize a “Willingness to Pay” survey it initiated to develop non-use benefits data in support of the initial rule proposal. We and industry trade associations submitted comments on both NODAs in July 2012. In May 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day.

The EPA did not mandate closed cycle cooling as “Best Technology Available.” Instead, the EPA set a fish impingement mortality standard that relies on a technology-based approach. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. The rule also requires that entrainment BTA decisions rely on site-specific analysis that includes an assessment of social costs-social benefits.

The EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the BTA of each facility that seeks permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. In August 2014, the EPA established October 14, 2014 as the effective date for each state to implement the provisions of the rule going forward when considering the renewal of permits for existing facilities on a case by case basis. In September 2014, several environmental non-governmental groups and certain energy industry groups filed motions to litigate the provisions of the rule. This case is pending at the U.S. Second Circuit Court of Appeals. In two related actions on October 17, 2014 and November 20, 2014, several environmental non-governmental groups initiated challenges to the Endangered Species Act provisions of the 316 (b) rule.

We are assessing the potential impact of the rule on each of our affected facilities and are unable to predict the outcome of permitting decisions and the effect, if any, that they may have on our future capital requirements, financial condition or results of operations, although such impacts could be material. See Part II, Item 8. Financial Statements and Supplementary Data— Note 12. Commitments and Contingent Liabilities for additional information.

In October 2013, the Delaware Riverkeeper Network and several other environmental groups filed a lawsuit in the Superior Court of New Jersey seeking to force the NJDEP to take action on our pending application for permit renewal at Salem either by denying the application or issuing a draft for public comment. An application for renewal of the permit was submitted in January 2006 and the NJDEP had delayed action pending the EPA’s finalization of the Clean Water Act 316(b) regulations. In November 2014, the environmental groups announced settlement of the lawsuit filed with the NJDEP and that the NJDEP has committed to issue a draft permit by June 30, 2015.

- Waters of the United States—In April 2014, the EPA Administrator and the Assistant Secretary of the Army (Civil Works) jointly published a proposed rule to clarify the definition of waters of the U.S. under the Clean Water Act (CWA) programs in order to protect the streams and wetlands that form the foundation of the nation’s water resources. This definition will have broad application to all areas of compliance under the CWA, including permitted discharges and construction activities. On November 14, 2014, we participated with other energy companies in submitting comments on the proposed rule. Given the broad nature of the proposed rule, we are unable to determine the materiality of the impacts that might result from the final rule.

Hazardous Substance Liability

The production and delivery of electricity, the distribution of gas and, formerly, the manufacture of gas, results in various by-products and substances classified by federal and state regulations as hazardous. These regulations may impose liability for damages to the environment from hazardous substances, including obligations to conduct environmental remediation of discharged hazardous substances as well as monetary payments, regardless of the absence of fault and the absence of any prohibitions against the activity when it occurred, as compensation for injuries to natural resources. See Item 3. Legal Proceedings. Our historic operations and the operations of hundreds of other companies along the Passaic and Hackensack Rivers are alleged by federal and state agencies to have discharged substantial contamination into the Passaic River/Newark Bay Complex. For additional information, see Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

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- Site Remediation—The Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA) and the New Jersey Spill Compensation and Control Act (Spill Act) require the remediation of discharged hazardous substances and authorize the EPA, the NJDEP and private parties to commence lawsuits to compel clean-ups or reimbursement for such remediation. The clean-ups can be more complicated and costly when the hazardous substances are in a body of water.
- Natural Resource Damages—CERCLA and the Spill Act authorize the assessment of damages against persons who have discharged a hazardous substance, causing an injury to natural resources. Pursuant to the Spill Act, the NJDEP requires persons conducting remediation to characterize injuries to natural resources and to address those injuries through restoration or damages. The NJDEP adopted regulations concerning site investigation and remediation that require an ecological evaluation of potential damages to natural resources in connection with an environmental investigation of contaminated sites. The NJDEP also issued guidance to assist parties in calculating their natural resource damage liability for settlement purposes, but has stated that those calculations are applicable only for those parties that volunteer to settle a claim for natural resource damages before a claim is asserted by the NJDEP. We are currently unable to assess the magnitude of the potential financial impact of this regulatory change, although such impacts could be material.

Fuel and Waste Disposal

- Nuclear Fuel Disposal—The federal government has entered into contracts with the operators of nuclear power plants for transportation and ultimate disposal of spent nuclear fuel. To pay for this service, nuclear plant owners are required to contribute to a Nuclear Waste Fund. In accordance with the Nuclear Waste Policy Act of 1982, in 2009 the U.S. Department of Energy (DOE) conducted its annual review of the adequacy of the Nuclear Waste Fee and concluded that the current fee of 1/10 cent per kWh was adequate to recover program costs. In 2011, we joined the Nuclear Energy Institute (NEI) and fifteen other nuclear plant operators in a lawsuit in federal court seeking suspension of the Nuclear Waste Fee. In June 2012, the court ruled that the DOE failed to justify continued payments by electricity consumers into the Nuclear Waste Fund and ordered the DOE to conduct a complete reassessment of this fee. Spent nuclear fuel generated in any reactor can be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites. In May 2014, the DOE advised us that as of May 16, 2014, the nuclear waste fee was being suspended/reduced to zero. The elimination of this fee is expected to result in an annualized pre-tax benefit of approximately $30 million.

We have on-site storage facilities that are expected to satisfy the storage needs of Salem 1, Salem 2, Hope Creek, Peach Bottom 2 and Peach Bottom 3 through the end of their operating licenses.

- Low Level Radioactive Waste—As a by-product of their operations, nuclear generation units produce low level radioactive waste. Such waste includes paper, plastics, protective clothing, water purification materials and other materials. These waste materials are accumulated on site and disposed of at licensed permanent disposal facilities. New Jersey, Connecticut and South Carolina have formed the Atlantic Compact, which gives New Jersey nuclear generators continued access to the Barnwell waste disposal facility which is owned by South Carolina. We believe that the Atlantic Compact will provide for adequate low level radioactive waste disposal for Salem and Hope Creek through the end of their current licenses including full decommissioning, although no assurances can be given. Low Level Radioactive Waste is periodically being shipped to the Barnwell site from Salem and Hope Creek. Additionally, there are on-site storage facilities for Salem, Hope Creek and Peach Bottom, which we believe have the capacity for at least five years of temporary storage for each facility.
- Coal Combustion Residuals (CCRs)—In 2010, the EPA published a proposed rule offering three main options for the management of CCRs under the Resource Conservation and Recovery Act (RCRA). One of these options regulates CCRs as a hazardous waste while the other two options would continue to regulate the disposal of CCRs as a non-hazardous waste. In 2012, several environmental organizations and CCR marketers brought a citizens' suit against the EPA in federal court arguing that the EPA failed to perform its mandatory duty under RCRA to review and revise, if necessary, the RCRA rule applicable to CCRs. The EPA issued a final rule on December 19, 2014 which regulates CCRs as non-hazardous and requires that facility owners implement a series of actions to close or upgrade existing CCR surface impoundments and/or landfills. It also establishes new provisions for the construction of new surface impoundments and landfills. Our Hudson and Mercer generating stations, along with our co-owned Keystone and

Conemaugh stations, are subject to the provisions of this rule. The scope of the work entailed to comply has not yet been finalized but we expect that the impacts of this rule will not be material to our results of operations, financial condition or cash flows.

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SEGMENT INFORMATION

Financial information with respect to our business segments is set forth in Part II, Item 8. Financial Statements and Supplementary Data—Note 22. Financial Information by Business Segments.

ITEM 1A. RISK FACTORS

The following factors should be considered when reviewing our business. These factors could have a material adverse impact on our financial position, results of operations or net cash flows and could cause results to differ materially from those expressed elsewhere in this report.

The factors discussed in Item 7. MD&A may also have a material adverse effect on our results of operations and cash flows and affect the market prices for our publicly-traded securities. While we believe that we have identified and discussed the key risk factors affecting our business, there may be additional risks and uncertainties that are not presently known or that are not currently believed to be significant.

We are subject to comprehensive and evolving regulation by federal, state and local regulatory agencies that affects, or may affect, our businesses.

We are subject to regulation by federal, state and local authorities. Changes in regulation can cause significant delays in or materially affect business planning and transactions and can materially increase our costs. Regulation affects almost every aspect of our businesses, such as our ability to:

- Obtain fair and timely rate relief—PSE&G's retail rates are regulated by the BPU and its wholesale transmission rates are regulated by the FERC. The retail rates for electric and gas distribution services are established in a base rate case and remain in effect until a new base rate case is filed and concluded. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of and on the authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU. Our utility's transmission rates are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. Transmission ROEs have recently become the target of certain state utility commissions, municipal utilities, consumer advocates and consumer groups seeking to lower customer rates in New England and New York. These agencies and groups have filed complaints at the FERC asking the FERC to reduce the base ROE of various transmission owners. They point to changes in the capital markets as justification for lowering the ROE of these companies. While we are not the subject of any of these complaints, they could set a precedent for FERC-regulated transmission owners, such as PSE&G. Inability to obtain fair or timely recovery of all our costs, including a return of or on our investments in rates, could have a material adverse impact on our business.
- Obtain required regulatory approvals—The majority of our businesses operate under MBR authority granted by the FERC, which has determined that our subsidiaries do not have unmitigated market power and that MBR rules have been satisfied. Failure to maintain MBR eligibility, or the effects of any severe mitigation measures that may be required if market power was evaluated differently in the future, could have a material adverse effect on us.

We may also require various other regulatory approvals to, among other things, buy or sell assets, engage in transactions between our public utility and our other subsidiaries, and, in some cases, enter into financing arrangements, issue securities and allow our subsidiaries to pay dividends. Failure to obtain these approvals on a timely basis could materially adversely affect our results of operations and cash flows.

- Comply with regulatory requirements—There are federal standards, including mandatory NERC and Critical Infrastructure Protection standards, in place to ensure the reliability of the U. S. electric transmission and generation system and to prevent major system black-outs. We have been, and will continue to be, periodically audited by the NERC for compliance and are subject to penalties for non-compliance with applicable NERC standards.

Further, the FERC requires compliance with all of its rules and orders, including rules concerning Standards of Conduct, market behavior and anti-manipulation rules, reporting, interlocking directorate rules and cross-subsidization.

In addition, Power is currently being investigated by the FERC Staff with respect to errors in certain of its bids submitted for its fossil-generating units into the PJM market. See Item 1. Federal Regulation—Compliance—FERC for further information on this matter.

We are subject to the reporting and record-keeping requirements of the Dodd-Frank Act, as implemented by the CFTC, and may in the future be subject to CFTC requirements regarding position limits for trading of certain

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commodities. As part of the Dodd-Frank Act compliance, we will need to be vigilant in monitoring and reporting our swap transactions.

The BPU conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues. The BPU is near completion of a combined management audit and affiliate transactions audit of PSE&G.

We are exposed to commodity price volatility as a result of our participation in the wholesale energy markets.

The material risks associated with the wholesale energy markets known or currently anticipated that could adversely affect our operations include:

- Price fluctuations and collateral requirements—We expect to meet our supply obligations through a combination of generation and energy purchases. We also enter into derivative and other positions related to our generation assets and supply obligations. As a result, we are subject to the risk of price fluctuations that could affect our future results and impact our liquidity needs. These include:
- variability in costs, such as changes in the expected price of energy and capacity that we sell into the market,
- increases in the price of energy purchased to meet supply obligations or the amount of excess energy sold into the market,
- variation in the relative prices of electricity and gas at the hubs within the markets,
- the cost of fuel to generate electricity, and
- the cost of emission credits and congestion credits that we use to transmit electricity.

In the markets where we operate, natural gas prices typically have a major impact on the price that generators receive for their output, especially in periods of relatively strong demand. Therefore, significant changes in the price of natural gas usually translate into significant changes in the wholesale price of electricity.

Over the past few years, wholesale prices for natural gas have declined from the peak levels experienced in 2008. One reason for this decline is increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which has reduced our margins as nuclear and coal generation costs have not declined similarly. Over that time, generation by our coal units was also adversely affected by the relatively lower price of natural gas as compared to coal, making it sometimes more economic to run certain of our gas units than our coal units.

Natural gas prices may remain at low levels for an extended period and continue to decline if further advances in technology result in greater volumes of shale gas production.

Many factors may affect capacity pricing in PJM, including but not limited to:

- changes in load and demand,
- changes in the available amounts of demand response resources,
- changes in available generating capacity (including retirements, additions, derates, forced outage rates, etc.),
- increases in transmission capability between zones, and
- changes to the pricing mechanism, including increasing the potential number of zones to create more pricing sensitivity to changes in supply and demand, as well as other potential changes that PJM may propose over time, including issues currently pending at the FERC regarding compensation for generators that certify their availability during emergency conditions.

Potential changes to the rules governing energy markets in which the output of our plants is sold also poses risk to our business, as discussed further below.

As market prices for energy and fuel fluctuate, our forward energy sale and forward fuel purchase contracts could require us to post substantial additional collateral, thus requiring us to obtain additional sources of liquidity during periods when our ability to do so may be limited. If Power were to lose its investment grade credit rating, it would be required under certain agreements to provide a significant amount of additional collateral in the form of letters of credit or cash, which would have a material adverse effect on our liquidity and cash flows. If Power had lost its investment grade credit rating as of December 31, 2014, it may have had to provide approximately $945 million in additional collateral.

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- Our cost of coal and nuclear fuel may substantially increase—Our coal and nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel needs over the next several years. However, it will be necessary to enter into additional arrangements to acquire coal and nuclear fuel in the future. Although our fuel contract portfolio provides a degree of hedging against these market risks, future increases in our fuel costs cannot be predicted with certainty and could materially and adversely affect liquidity, financial condition and results of operations. While our generation runs on diverse fuels, allowing for flexibility, the mix of fuels ultimately used can impact earnings.
- Third party credit risk—We sell generation output and buy fuel through the execution of bilateral contracts. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure to perform by these counterparties could have a material adverse impact on our results of operations, cash flows and financial position. In the spot markets, we are exposed to the risks of whatever default mechanisms exist in those markets, some of which attempt to spread the risk across all participants, which may not be an effective way of lessening the severity of the risk of the amounts at stake. The impact of economic conditions may also increase such risk.

We are subject to numerous federal and state environmental laws and regulations that may significantly limit or affect our businesses, adversely impact our business plans or expose us to significant environmental fines and liabilities.

We are subject to extensive environmental regulation by federal, state and local authorities regarding air quality, water quality, site remediation, land use, waste disposal, aesthetics, impact on global climate, natural resources damages and other matters. These laws and regulations affect the manner in which we conduct our operations and make capital expenditures. Future changes may result in significant increases in compliance costs.

Delay in obtaining, or failure to obtain and maintain, any environmental permits or approvals, or delay in or failure to satisfy any applicable environmental regulatory requirements, could:

- prevent construction of new facilities,
- prevent continued operation of existing facilities,
- prevent the sale of energy from these facilities, or
- result in significant additional costs, each of which could materially affect our business, results of operations and cash flows.

In obtaining required approvals and maintaining compliance with laws and regulations, we focus on several key environmental issues, including:

- Concerns over global climate change could result in laws and regulations to limit CO_2 emissions or other GHG produced by our fossil generation facilities—Federal and state legislation and regulation designed to address global climate change through the reduction of GHG emissions could materially impact our fossil generation facilities. The current direction in this area is the EPA’s proposed regulation of existing fossil-fueled generating facilities under the existing source performance standards section of the CAA. Legislation enacted in the states where our generation facilities are located establishes aggressive goals for the reduction of CO_2 emissions over a 40-year period. Multiple states are developing or have developed state-specific or regional initiatives to obtain CO_2 emissions reductions in the electric power industry. The RGGI is such a program in the Northeast. There could be significant costs incurred to continue operation of our fossil generation facilities, including the potential need to purchase CO_2 emission allowances. Such expenditures could materially affect the continued economic viability of one or more such facilities.
- CO_2 Litigation—In addition to legislative and regulatory initiatives, the outcome of certain legal proceedings regarding alleged impacts of global climate change not involving us could be material to the future liability of energy companies. If relevant federal or state common law were to develop that imposed liability upon those that emit GHGs for alleged impacts of GHGs emissions, such potential liability to our fossil generation operations could be material.
- Potential closed-cycle cooling requirements—Our Salem nuclear generating facility has a permit from the NJDEP allowing for its continued operation with its existing cooling water system. That permit expired in July 2006. Our application to renew the permit, filed in February 2006, estimated the costs associated with cooling towers for Salem to be approximately $1 billion, of which our share was approximately $575 million. The renewal filing has not been updated since the 2006 filing.

The EPA issued a proposed rule in 2011 regarding regulation of cooling water intake structures. Following the receipt of extensive comments on its proposed rule, the EPA finalized this rule on May 19, 2014 with an effective date of October 14, 2014. The EPA did not mandate closed cycle cooling as the BTA. Instead, the EPA set a fish

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impingement mortality standard that relies on a technology-based approach. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. The rule also requires that entrainment BTA decisions rely on site-specific analysis that includes an assessment of social costs-social benefits.

The EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis. In connection with the assessment of the BTA of each facility that seeks permit renewal, the rule requires that facilities conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. State actions to renew permits under the provisions of this rule are ongoing at this time.

If the NJDEP or the Connecticut Department of Environmental Protection were to require installation of closed-cycle cooling or its equivalent at our Salem, Mercer, Hudson, Bridgeport, Sewaren or New Haven generating stations, the related increased costs and impacts would be material to our financial position, results of operations and net cash flows and would require further economic review to determine whether to continue operations or decommission the stations.

- Remediation of environmental contamination at current or formerly-owned facilities—We are subject to liability under environmental laws for the costs of remediating environmental contamination of property now or formerly owned by us and of property contaminated by hazardous substances that we generated. Remediation activities associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. Also, we are currently involved in a number of proceedings relating to sites where other hazardous substances may have been discharged and may be subject to additional proceedings in the future, the related costs of which could have a material adverse effect on our financial condition, results of operations and cash flows. New Jersey law places affirmative obligations on us to investigate and, if necessary, remediate contaminated property upon which we were in any way responsible for a discharge of hazardous substances, impacting the speed by which we will need to investigate contaminated properties, which could adversely impact cash flow. We cannot predict what further actions, if any, or the costs or the timing thereof, that may be required with respect to these or other natural resource damages claims. However, exposure to natural resource damages could subject us to additional potentially material liability.

Our ownership and operation of nuclear power plants involve regulatory, financial, environmental, health and safety risks.

Approximately half of our total generation output each year is provided by our nuclear fleet, which comprises approximately one-fourth of our total owned generation capacity. For this reason, we are exposed to risks related to the continued successful operation of our nuclear facilities and issues that may adversely affect the nuclear generation industry. These include:

- Storage and Disposal of Spent Nuclear Fuel—We currently use on-site storage for spent nuclear fuel. Disposal of nuclear materials, including the availability or unavailability of a permanent repository for spent nuclear fuel, could impact future operations of these stations. In addition, the availability of an off-site repository for spent nuclear fuel may affect our ability to fully decommission our nuclear units in the future.
- Regulatory and Legal Risk—The NRC may modify, suspend or revoke licenses, or shut down a nuclear facility and impose substantial civil penalties for failure to comply with the Atomic Energy Act, related regulations or the terms and conditions of the licenses for nuclear generating facilities. As with all of our generation facilities, as discussed above, our nuclear facilities are also subject to comprehensive, evolving environmental regulation. Our nuclear generating facilities are currently operating under NRC licenses that expire in 2033 through 2046.
- Operational Risk—Operations at any of our nuclear generating units could degrade to the point where the affected unit needs to be shut down or operated at less than full capacity. If this were to happen, identifying and correcting the causes may require significant time and expense. Since our nuclear fleet provides approximately half of our generation output, any significant outage could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations.
- Nuclear Incident or Accident Risk—Accidents and other unforeseen problems have occurred at nuclear stations, both in the United States and elsewhere. The consequences of an accident can be severe and may include loss of life, significant property damage and/or a change in the regulatory climate. We have nuclear units at two sites. It is possible that an accident or other incident at a nuclear generating unit could adversely affect our ability to continue to

operate unaffected units located at the same site, which would further affect our financial condition, operating results and cash flows. An accident or incident at a nuclear unit not owned by us could also affect our ability to continue to operate our units. Any resulting financial impact from a nuclear accident may exceed our resources, including insurance coverages. Further, as a licensed nuclear operator subject to the Price-Anderson Act and a member of a nuclear industry mutual insurance company, Power is subject to potential retroactive assessments as a result of a nuclear incident or retroactive adverse loss experience.

We may be adversely affected by changes in energy regulatory policies, including energy and capacity market design rules and developments affecting transmission.

The energy industry continues to be regulated and the rules to which our businesses are subject are always at risk of being changed. Our business has been impacted by established rules that create locational capacity markets in each of PJM, ISO-NE and NYISO. Under these rules, generators located in constrained areas are paid more for their capacity so there is an incentive to locate in those areas where generation capacity is most needed. Because much of our generation is located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM’s locational capacity market design rules and New England forward capacity market rules have been challenged in court and continue to evolve. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

In January 2011, New Jersey enacted a law establishing a LCAPP which provided for the construction of subsidized base load or mid-merit electric power generation. The LCAPP legislation was invalidated on constitutional grounds by a federal court order issued in October 2013 and a subsequent challenge in the U.S. Court of Appeals for the Third Circuit upheld that decision. that decision has now been filed with the U.S. Supreme Court for consideration on appeal. However, future state actions in New Jersey and elsewhere to subsidize the construction of new generation could have the effect of artificially depressing prices in the competitive wholesale market on both a short-term and long-term basis.

We could also be impacted by a number of other events, including regulatory or legislative actions, including, among other things, direct and indirect subsidies, favoring non-competitive markets and/or technologies and energy efficiency and demand response initiatives. Further, some of the market-based mechanisms in which we participate, including BGS auctions, are at times the subject of review or discussion by some of the participants in the New Jersey and federal regulatory and political arenas. We can provide no assurance that these mechanisms will continue to exist in their current form, nor otherwise be modified.

To the extent that additions to the transmission system relieve or reduce congestion in eastern PJM where most of our plants are located, Power's capacity and energy revenues could be adversely affected. Moreover, through changes encouraged by the FERC to transmission planning processes, or through RTO/ISO initiatives to change their planning processes, such as the recently accepted multi-driver project category in PJM, more transmission may ultimately be built to facilitate renewable generation or support other public policy initiatives.

The FERC has also eliminated the ROFR, which will have the effect of allowing third parties to build certain types of transmission projects in the service territories of incumbent utilities such as PSE&G. As a result, we could face competitive pressures for our transmission business in New Jersey, as well as in in other utilities’ service territories where we will be able to seek opportunities to build. Changes to FERC policies regarding transmission planning and rate treatment for transmission investment, including ROEs and incentive rates, could also have an impact on our transmission business. In addition, certain PJM cost allocation determinations have been recently challenged at the FERC, the resolution of which could impact costs borne by New Jersey ratepayers and increase customer bills.

We face significant competition in the merchant energy markets.

Our wholesale power and marketing businesses are subject to significant competition that may adversely affect our ability to make investments or sales on favorable terms and achieve our annual objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings. Decreased competition could negatively impact results through a decline in market liquidity. Some of our competitors include:

- merchant generators,
- domestic and multi-national utility rate-based generators,
- energy marketers,
- utilities,
- banks, funds and other financial entities,
- fuel supply companies,
- affiliates of other industrial companies, and

- distributed generation.

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Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy markets, potentially resulting in erosion of our market share and impairment in the value of our power plants.

Changes in customer usage patterns and technology could adversely impact us.

- DSM and other efficiency efforts—DSM and other efficiency efforts aimed at changing the quantity and patterns of consumers' usage could result in a reduction in load requirements.
- Changes in technology and/or customer behaviors—It is possible that advances in technology will reduce the cost of alternative methods of producing electricity, including distributed generation, such as fuel cells, micro turbines, micro grids, windmills and net-metered PV (solar) cells, to a level that is competitive with that of most central station electric production. Large customers, such as universities and hospitals, continue to explore potential micro grid installation. Substantial micro grid penetration can impact energy costs, system performance and demand growth. It is also possible that electric customers may significantly decrease their electric consumption due to demand-side energy conservation programs. Changes in technology and usage, such as municipal aggregation, could also alter the channels through which retail electric customers buy electricity, which could adversely affect our financial results. Increased reliance by customers on on-site generation, including solar, and changes in customer behaviors can result in decreased reliance on our system and impact our revenues and investment opportunities.

Our inability to balance energy obligations with available supply could negatively impact results.

The revenues provided by the operation of our generating stations are subject to market risks that are beyond our control. Generation output will either be used to satisfy wholesale contract requirements, other bilateral contracts or be sold into competitive power markets. Participants in the competitive power markets are not guaranteed any specified rate of return on their capital investments. Generation revenues and results of operations are dependent upon prevailing market prices for energy, capacity, ancillary services and fuel supply in the markets served.

Our generation business frequently involves the establishment of forward sale positions in the wholesale energy markets on long-term and short-term bases. To the extent that we have produced or purchased energy in excess of our contracted obligations, a reduction in market prices could reduce profitability. Conversely, to the extent that we have contracted obligations in excess of energy we have produced or purchased, an increase in market prices could reduce profitability. If the strategy we utilize to hedge our exposure to these various risks is not effective, we could incur significant losses. Our market positions can also be adversely affected by the level of volatility in the energy markets that, in turn, depends on various factors, including weather in various geographical areas, short-term supply and demand imbalances, customer migration and pricing differentials at various geographic locations. These risks cannot be predicted with certainty.

Increases in market prices also affect our ability to hedge generation output and fuel requirements as the obligation to post margin increases with increasing prices.

Any inability to recover the carrying amount of our assets could result in future impairment charges which could have a material adverse impact on our financial condition and results of operations.

In accordance with accounting guidance, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset's or group of assets' carrying amount may not be recoverable. Significant reductions in our expected revenues or cash flows for an extended period of time resulting from such events could result in future asset impairment charges, which could have a material adverse impact on our financial condition and results of operations.

Inability to access sufficient capital at reasonable rates or commercially reasonable terms or maintain sufficient liquidity in the amounts and at the times needed could adversely impact our business.

Capital for projects and investments has been provided primarily by internally-generated cash flow and external financings. We have significant capital requirements and will need continued access to debt capital from outside sources in order to efficiently fund the construction and other cash flow needs of our businesses. The ability to arrange financing and the costs of capital depend on numerous factors including, among other things, general economic and market conditions, the availability of credit from banks and other financial institutions, investor confidence, the success of current projects and the quality of new projects.

The ability to have continued access to the credit and capital markets at a reasonable economic cost is dependent upon our current and future capital structure, financial performance, our credit ratings and the availability of capital under reasonable terms and conditions. As a result, no assurance can be given that we will be successful in obtaining re-financing for maturing debt or financing for projects and investments.

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Financial market performance directly affects the asset values of our nuclear decommissioning trust funds and defined benefit plan trust funds. Sustained decreases in asset value of trust assets could result in the need for significant additional funding.

The performance of the financial markets will affect the value of the assets that are held in trust to satisfy our future obligations under our pension and postretirement benefit plans and to decommission our nuclear generating plants. A decline in the market value of our pension assets could result in the need for us to make significant contributions in the future to maintain our funding at sufficient levels.

An extended economic recession would likely have a material adverse effect on our businesses.

Our results of operations may be negatively affected by sustained downturns or sluggishness in the economy, including low levels in the market prices of commodities. Adverse conditions in the economy affect the markets in which we operate and can negatively impact our results. Declines in demand for energy will reduce overall sales and cash flows, especially as customers reduce their consumption of electricity and gas. Although our utility business is subject to regulated allowable rates of return, overall declines in electricity and gas sold and/or increases in non-payment of customer bills would materially adversely affect our liquidity, financial condition and results of operations.

We may be adversely affected by equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers and remain competitive and could result in substantial financial losses.

The success of our businesses is dependent on our ability to continue providing safe and reliable service to our customers while minimizing service disruptions. We are also exposed to the risk of equipment failures, accidents, severe weather events, or other incidents which could result in damage to or destruction of our facilities or damage to persons or property. For instance, equipment failures in our natural gas distribution could give rise to a variety of hazards and operating risks, such as leaks, accidental explosions and mechanical problems, which could cause substantial financial losses. PSE&G operates and maintains more than 17,700 miles of distribution mains that transport gas to 1.8 million customers. PSE&G also operates and maintains the largest cast iron infrastructure in any one state in the country at approximately 4,000 miles.

In addition, the physical risks of severe weather events, such as experienced from Hurricane Irene and Superstorm Sandy, and of climate change, changes in sea level, temperature and precipitation patterns and other related phenomena have further exacerbated these risks. Such issues experienced at our facilities, or by others in our industry, could adversely impact our revenues, increase costs to repair and maintain our systems, subject us to potential litigation and/or damage claims and increase the level of oversight of our utility and generation operations and infrastructure through investigations or through the imposition of additional regulatory or legislative requirements. Such actions could adversely affect our costs, competitiveness and future investments, which could be material to our financial position, results of operations and cash flow.

Acts of war or terrorism could adversely affect our operations.

Our businesses and industry may be impacted by acts and threats of war or terrorism. These actions could result in increased political, economic and financial market instability and volatility in fuel prices which could materially adversely affect our operations. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities, could be direct or indirect targets or be affected by terrorist or other criminal activity. Such events could severely disrupt business operations and prevent us from servicing our customers. In addition, new or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

Cybersecurity attacks or intrusions could adversely impact our businesses.

We own and/or operate generating stations, transmission and distribution facilities, which are dependent on the operation of our computing systems. Our ability to market our generation output and acquire and hedge fuel and power are also dependent on our computing systems. Our computing systems may be impacted by cybersecurity attacks, hostile technological intrusions or inadvertent disclosure of company and/or customer information or a cybersecurity attack may leverage our information technology to cause disruptions at another company. Cybersecurity threats to our operations include:

- Disruption of the operation of our assets and the power grid,
- Theft of confidential company, employee, shareholder, vendor or customer information,
- General business system and process interruption or compromise, including preventing us from servicing our customers, collecting revenues or the ability to record, process and/or report financial information correctly, and
- Breaches of vendors' infrastructures where our confidential information is stored.

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If a significant cybersecurity event or breach should occur, it could result in material costs for repair and remediation, breach notification, operations and increased capital costs. Such a cybersecurity incident could also cause us to be non-compliant with applicable laws, regulations or contracts that require us to securely maintain confidential data, causing us to incur costs related to legal claims or proceedings, regulatory fines and increased scrutiny and possible damage to our reputation and brand, resulting in a reduction in customer confidence. We devote resources to network and application security, encryption and other measures to protect our computing systems and infrastructure from unauthorized access or misuse and interface with numerous external entities to improve our cybersecurity situational awareness. However, given the ever changing nature of cybersecurity threats, there can be no assurance the steps we take can protect us against all possible occurrences.

Inability to successfully develop or construct generation, transmission and distribution projects within budget could adversely impact our businesses.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of required environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities and modernizing existing infrastructure. Currently, we have several significant projects underway or being contemplated.

Our success will depend, in part, on our ability to obtain necessary regulatory approvals, complete these projects within budgets, on commercially reasonable terms and conditions and, in our regulated businesses, our ability to recover the related costs through rates. Any delays, cost escalations or otherwise unsuccessful construction and development could materially affect our financial position, results of operations and cash flows.

We may be unable to achieve, or continue to sustain, our expected levels of operating performance.

One of the key elements to achieving the results in our business plan is the ability to sustain generating operating performance and capacity factors at expected levels since our forward sales of energy and capacity assume acceptable levels of operating performance. This is especially important at our lower-cost facilities. Operations at any of our plants could degrade to the point where the plant has to shut down or operate at less than full capacity. Some issues that could impact the operation of our facilities are:

- breakdown or failure of equipment, information technology, processes or management effectiveness,
- disruptions in the transmission of electricity,
- labor disputes,
- fuel supply interruptions,
- transportation constraints,
- limitations which may be imposed by environmental or other regulatory requirements,
- permit limitations, and
- operator error or catastrophic events such as fires, earthquakes, explosions, floods, severe storms, acts of terrorism or other similar occurrences.

Identifying and correcting any of these issues may require significant time and expense. Depending on the materiality of the issue, we may choose to close a plant rather than incur the expense of restarting it or returning it to full capacity. In either event, to the extent that our operational targets are not met, we could have to operate higher-cost generation facilities or meet our obligations through higher-cost open market purchases.

Challenges associated with retention of a qualified workforce could adversely impact our businesses.

Our operations depend on the retention of a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation, transmission and distribution operations, could result in various operational challenges. These challenges may include the lack of appropriate replacements, the loss of institutional and industry knowledge and the increased costs to hire and train new personnel. This has the potential to become more critical over the next several years as a growing number of employees become eligible to retire.

In addition, because a significant portion of our employees are covered under collective bargaining agreements, our success will depend on our ability to successfully renegotiate these agreements as they expire. Inability to do so may result in employee strikes or work stoppages which would disrupt our operations and could also result in increased costs.

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Our receipt of payment of receivables related to our domestic leveraged leases is dependent upon the credit quality and the ability of lessees to meet their obligations.

Our receipt of payments of equity rent, debt service and other fees related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors. The factors which may impact future lease cash flow include, but are not limited to, new environmental legislation regarding air quality and other discharges in the process of generating electricity, market prices for fuel and electricity, including the impact of low gas prices on our coal generation investments, overall financial condition of lease counterparties and the quality and condition of assets under lease. If a lessee were to default, we could potentially be required to impair our current investment balances.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, PSE&G and Power

None.

ITEM 2. PROPERTIES

Our subsidiaries own all of our physical property. We believe that we and our subsidiaries maintain adequate insurance coverage against loss or damage to plants and properties, subject to certain exceptions, to the extent such property is usually insured and insurance is available at a reasonable cost. For a discussion of nuclear insurance, see Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

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Generation Facilities

Power

As of December 31, 2014, Power's share of summer installed fossil and nuclear generating capacity is shown in the following table:

Name	Location	Total Capacity (MW)	% Owned	Owned Capacity (MW)	Principal Fuels Used	Mission
Steam:						
Hudson	NJ	620	100%	620	Coal/Gas	Load Following
Mercer	NJ	632	100%	632	Coal/Gas	Load Following
Sewaren	NJ	453	100%	453	Gas	Load Following
Keystone (A)	PA	1,711	23%	391	Coal	Base Load
Conemaugh (A)	PA	1,711	23%	385	Coal	Base Load
Bridgeport Harbor	CT	383	100%	383	Coal	Load Following
New Haven Harbor	CT	443	100%	443	Oil	Load Following
Total Steam		5,953		3,307		
Nuclear:						
Hope Creek	NJ	1,178	100%	1,178	Nuclear	Base Load
Salem 1 & 2	NJ	2,307	57%	1,324	Nuclear	Base Load
Peach Bottom 2 & 3 (B)	PA	2,242	50%	1,121	Nuclear	Base Load
Total Nuclear		5,727		3,623		
Combined Cycle:						
Bergen	NJ	1,198	100%	1,198	Gas	Load Following
Linden	NJ	1,300	100%	1,300	Gas	Load Following
Bethlehem	NY	774	100%	774	Gas	Load Following
Kalaeloa	HI	208	50%	104	Oil	Load Following
Total Combined Cycle		3,480		3,376		
Combustion Turbine (C):						
Essex	NJ	623	100%	623	Gas	Peaking
Edison	NJ	516	100%	516	Gas	Peaking
Kearny	NJ	452	100%	452	Gas	Peaking
Burlington	NJ	376	100%	376	Oil/Gas	Peaking
Linden	NJ	347	100%	347	Gas	Peaking
Mercer	NJ	115	100%	115	Oil	Peaking
Sewaren	NJ	105	100%	105	Oil	Peaking
Bergen	NJ	21	100%	21	Gas	Peaking
National Park	NJ	21	100%	21	Oil	Peaking
Salem 3	NJ	38	57%	22	Oil	Peaking
New Haven Harbor	CT	129	100%	129	Gas/Oil	Peaking
Bridgeport Harbor	CT	17	100%	17	Oil	Peaking
Total Combustion Turbine		2,760		2,744		
Pumped Storage:						
Yards Creek (D)	NJ	400	50%	200		Peaking
Total Power Plants		18,320		13,250		

(A) Operated by GenOn Northeast Management Company

(B) Operated by Exelon Generation. In March 2015, our share of Peach Bottom 2's installed generation capacity is expected to increase by 65 MW as a result of an extended power uprate completed in 2014. A similar increase is expected to occur in the first quarter of 2016 at Peach Bottom 3 after work is completed in late 2015.

(C) 1,545 MW of owned installed combustion turbine capacity will be retired in 2015.

(D) Operated by JCP&L Company

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As of December 31, 2014, Power also owned and operated 109 MW direct current (dc) of photovoltaic solar generation facilities in various states.

PSE&G

As of December 31, 2014, PSE&G had 99 MWdc of installed solar capacity throughout New Jersey.

Transmission and Distribution Facilities

PSE&G

As of December 31, 2014, PSE&G's electric transmission and distribution system included 23,872 circuit miles, of which 8,191 circuit miles were underground, and 846,058 poles, of which 548,854 poles were jointly-owned. Approximately 100% of this property is located in New Jersey.

In addition, as of December 31, 2014, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2014, the daily gas capacity of PSE&G's 100%-owned peaking facilities (the maximum daily gas delivery available during the three peak winter months) consisted of liquid petroleum air gas (LPG) and liquefied natural gas (LNG) and aggregated 2,790,420 therms (270,914,563 cubic feet on an equivalent basis of 100,000 Btu/therm and 1,030 Btu/cubic foot) as shown in the following table:

Plant	Location	Daily Capacity (Therms)
Burlington LNG	Burlington, NJ	772,500
Camden LPG	Camden, NJ	384,000
Central LPG	Edison, NJ	839,040
Harrison LPG	Harrison, NJ	794,880
Total		2,790,420

As of December 31, 2014, PSE&G owned and operated 17,792 miles of gas mains, owned 12 gas distribution headquarters and two sub-headquarters, all in four operating regions located in New Jersey and owned one meter shop in New Jersey serving all such areas. In addition, PSE&G operated 62 natural gas metering and regulating stations, all located in New Jersey, of which 26 were located on land owned by customers or natural gas pipeline suppliers and were operated under lease, easement or other similar arrangement. In some instances, the pipeline companies owned portions of the metering and regulating facilities.

PSE&G's First and Refunding Mortgage, securing the bonds issued thereunder, constitutes a direct first mortgage lien on substantially all of PSE&G's property.

PSE&G's electric lines and gas mains are located over or under public highways, streets, alleys or lands, except where they are located over or under property owned by PSE&G or occupied by it under easements or other rights. PSE&G deems these easements and other rights to be adequate for the purposes for which they are being used.

In addition, as of December 31, 2014, PSE&G owned 43 switching stations in New Jersey with an aggregate installed capacity of 28,777 megavolt-amperes (MVA) and 246 substations with an aggregate installed capacity of 8,179 MVA. In addition, four of our substations in New Jersey having an aggregate installed capacity of 109 MVA were operated on leased property.

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ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, other than those discussed below, see Item 1. Business—Regulatory Issues and Environmental Matters and Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Superstorm Sandy

For a discussion of the lawsuit in New Jersey state court related to recoveries for property damage under PSEG's insurance policies, see Part II, Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Environmental Matters

The following items are environmental matters involving governmental authorities not discussed elsewhere in this Form 10-K. We do not expect expenditures for any such site relating to the items listed below, individually or for all such current sites in the aggregate, to have a material effect on our financial condition, results of operations and net cash flows.

(1) Claim by the EPA, Region III, under CERCLA with respect to a Cottman Avenue Superfund Site, a former non-ferrous scrap reclamation facility located in Philadelphia, Pennsylvania, owned and formerly operated by Metal Bank of America, Inc. PSE&G, other utilities and other companies are alleged to be liable for contamination at the site and PSE&G has been named as a PRP. A Final Remedial Design Report was submitted to the EPA in September of 2002. This document presented the design details of the EPA’s selected remediation remedy. PSE&G and other utility companies as members of a PRP group entered into a Consent Decree and agreed to implement a negotiated EPA selected remediation remedy. The PRP group implementation of the remedy was completed in 2010. Although subject to EPA approval and oversight, long-term monitoring activities designed to demonstrate the effectiveness of the implemented remedy are planned through 2018 at an estimated cost of $2.8 million.

(2) The EPA sent PSE&G, Power and approximately 157 other entities a notice that the EPA considered each of the entities to be a PRP with respect to contamination in Berry’s Creek in Bergen County, New Jersey and requesting that the PRPs perform a RI/FS on Berry’s Creek and the connected tributaries and wetlands. Berry’s Creek flows through approximately 6.5 miles of areas that have been used for a variety of industrial purposes and landfills. The EPA estimates that the study could cost approximately $18 million. As members of a PRP Group, Power and certain of the other entities named in the EPA Notice entered into an Administrative Settlement Agreement and Order on Consent in 2008 to conduct the RI/FS, which is estimated to be completed in 2017/2018.

(3) In January 2010, we received a letter from the NJDEP asserting that we are the current owner of the Gates Construction Corporation Landfill and that the subject landfill has not been properly closed in accordance with the NJDEP Solid Waste Regulations. Power has retained an environmental consultant to prepare a closure plan acceptable to the NJDEP.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed on the New York Stock Exchange, Inc. As of December 31, 2014, there were 69,735 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2009 in our common stock and the subsequent reinvestment of quarterly dividends, the S&P Composite Stock Price Index, the Dow Jones Utilities Index and the S&P Electric Utilities Index.

	2009	2010	2011	2012	2013	2014
PSEG	$100.00	$99.91	$108.11	$104.82	$114.62	$153.80
S&P 500	$100.00	$115.03	$117.47	$136.18	$180.18	$204.75
DJ Utilities	$100.00	$106.44	$127.30	$129.32	$145.70	$190.13
S&P Electrics	$100.00	$103.42	$124.99	$124.24	$133.97	$175.52

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The following table indicates the high and low sale prices for our common stock and dividends paid for the periods indicated:

Common Stock	High	Low	Dividend per Share
2014			
First Quarter	$38.44	$31.25	$0.37
Second Quarter	$41.38	$36.91	$0.37
Third Quarter	$40.68	$34.05	$0.37
Fourth Quarter	$43.77	$36.37	$0.37
2013			
First Quarter	$34.34	$29.78	$0.36
Second Quarter	$36.61	$31.21	$0.36
Third Quarter	$34.53	$31.66	$0.36
Fourth Quarter	$34.32	$31.65	$0.36

On February 17, 2015, our Board of Directors approved a $0.39 per share common stock dividend for the first quarter of 2015. This reflects an indicated annual dividend rate of $1.56 per share.
The following table indicates our common share repurchases in the open market during the fourth quarter of 2014 to satisfy obligations under various equity compensation award grants:

Three Months Ended December 31, 2014	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$—
November 1-November 30	245,942	$41.35
December 1-December 31	11,050	$41.77

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2014:

Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans
Long-Term Incentive Plan	2,075,850	$35.35	15,925,279
Employee Stock Purchase Plan	—	$—	3,589,032
Total	2,075,850	$35.35	19,514,311

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Financial Statements and Supplementary Data—Note 17. Stock Based Compensation.
PSE&G
We own all of the common stock of PSE&G. For additional information regarding PSE&G's ability to continue to pay dividends, see Item 7. MD&A—Executive Overview of 2014 and Future Outlook.
Power

We own all of Power's outstanding limited liability company membership interests. For additional information regarding Power's ability to pay dividends, see Item 7. MD&A—Executive Overview of 2014 and Future Outlook.

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ITEM 6. SELECTED FINANCIAL DATA
PSEG
The information presented below should be read in conjunction with the MD&A and the Consolidated Financial Statements and Notes to Consolidated Financial Statements (Notes).

PSEG					
Years Ended December 31,	2014	2013	2012	2011	2010
	Millions, except Earnings per Share				
Operating Revenues (A)	$10,886	$9,968	$9,781	$11,079	$11,793
Income from Continuing Operations (B)	$1,518	$1,243	$1,275	$1,407	$1,557
Net Income	$1,518	$1,243	$1,275	$1,503	$1,564
Earnings per Share:					
Income from Continuing Operations					
Basic (A)	$3.00	$2.46	$2.52	$2.78	$3.08
Diluted (A)	$2.99	$2.45	$2.51	$2.77	$3.07
Net Income					
Basic	$3.00	$2.46	$2.52	$2.97	$3.09
Diluted	$2.99	$2.45	$2.51	$2.96	$3.08
Dividends Declared per Share	$1.48	$1.44	$1.42	$1.37	$1.37
As of December 31,					
Total Assets	$35,333	$32,522	$31,725	$29,821	$29,909
Long-Term Obligations (C)	$8,264	$7,872	$6,701	$7,482	$7,847

(A) Operating Revenues for 2014 includes $389 million for Long Island Electric Utility Servco, LLC (Servco), a wholly owned subsidiary of PSEG LI. See Item 8. Financial Statements and Supplementary Data—Note 3. Variable Interest Entities for additional information.

(B) Income from Continuing Operations for 2011 includes an after-tax charge of $170 million related to certain leveraged leases.

(C) Includes capital lease obligations.

PSE&G and Power
Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by Public Service Enterprise Group Incorporated (PSEG), Public Service Electric and Gas Company (PSE&G) and PSEG Power LLC (Power). Information contained herein relating to any individual company is filed by such company on its own behalf. PSE&G and Power each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of two reportable segments, our principal direct wholly owned subsidiaries, which are:

- PSE&G, our public utility company which primarily provides electric transmission services and distribution of electric energy and natural gas, implements demand response and energy efficiency programs and invests in solar generation in New Jersey, and
- Power, our wholesale energy supply company that integrates its nuclear, fossil and renewable generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid-Atlantic United States.

PSEG's other direct wholly owned subsidiaries are: PSEG Energy Holdings L.L.C. (Energy Holdings), which earns its revenues primarily from its portfolio of lease investments; PSEG Long Island LLC (PSEG LI), which effective January 1, 2014, operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under a contractual agreement; and PSEG Services Corporation (Services), which provides us and these operating subsidiaries with certain management, administrative and general services at cost.

Our business discussion in Part I, Item 1. Business provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part I, Item 1A. Risk Factors provides information about factors that could have a material adverse impact on our businesses. The following discussion provides an overview of the significant events and business developments that have occurred during 2014 and key factors that we expect will drive our future performance. This discussion refers to the Consolidated Financial Statements (Statements) and the related Notes to Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements and Notes.

EXECUTIVE OVERVIEW OF 2014 AND FUTURE OUTLOOK

2014 Overview

Our business plan seeks to achieve growth while managing risks. We continue our focus on operational excellence, financial strength and disciplined investment. These guiding principles have provided the base from which we have been able to execute our strategic initiatives, including:

- Growing our utility operations through continued investment in T&D infrastructure projects with greater diversity of regulatory oversight, and
- Maintaining a reliable generation fleet with the flexibility to utilize a diverse mix of fuels to allow us to respond to market volatility and capitalize on opportunities as they arise in the locations in which we operate.

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Financial Results

The results for PSEG, PSE&G and Power for the years ended December 31, 2014 and 2013 are presented below:

	Years Ended December 31,	
	2014	2013
Earnings (Losses)	Millions, except per share data	
PSE&G	$725	$612
Power	760	644
Other	33	(13)
PSEG Net Income	$1,518	$1,243
PSEG Net Income Per Share (Diluted)	$2.99	$2.45

Our $275 million 2014 over 2013 increase in Net Income was due primarily to higher transmission revenues at PSE&G and mark-to-market gains in 2014 as compared to losses in 2013 and higher volumes of gas sales under the BGSS contract and to third party customers at Power. In addition, the increase was also due to lower Operations and Maintenance (O&M) costs at PSE&G and Power, principally related to a reduction in pension and other postretirement employee benefit (OPEB) costs. These factors were partially offset by lower volumes of electricity sold under the BGS contract and higher fuel costs incurred to generate electricity at Power. For a more detailed discussion of our financial results, see Results of Operations.

At PSE&G, our regulated utility, we continued to invest capital in T&D infrastructure projects aimed at maintaining the reliability of our service to our customers. PSE&G’s results for 2014 reflect the favorable impacts from these investments as well as a slowly improving economy. Effective January 1, 2014, PSE&G's formula rate increased our annual transmission revenues by approximately $171 million. In October 2014, we filed our 2015 Formula Rate Update with the Federal Energy Regulatory Commission (FERC) for approximately $182 million in increased annual transmission revenues which went into effect on January 1, 2015. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. The adjustment for 2015 will include the impact of the extension of bonus depreciation, which was enacted after the filing was made, and is estimated to reduce our 2015 revenue increase as filed by approximately $21 million. Over the past few years, these types of investments have altered the business mix of our overall results of operations to reflect a higher percentage contribution by PSE&G.

Power’s results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts during the cold weather experienced in the first quarter of 2014. Power manages these contracts for the benefit of PSE&G’s customers through the BGSS arrangement. The contracts are sized to ensure delivery of a reliable gas supply to PSE&G customers on peak winter days. When pipeline capacity beyond the customers’ needs is available, Power can use it to make third party sales and supply gas to its generating units in New Jersey.

Power’s 2014 results were unfavorably impacted by an extended refueling outage at Salem Unit 2. A planned refueling outage began on April 12, 2014 but was extended due to repairs to the reactor coolant pump turning vanes. Salem Unit 2 returned to service on July 14, 2014.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor significant regulatory and legislative developments. Transmission planning rules and wholesale power market design are of particular importance to our results and we continue to advocate for policies and rules that promote fair and efficient electricity markets.

Transmission Planning

The FERC’s rule under Order 1000 altered the right of first refusal (ROFR) previously held by incumbent utilities to build all transmission within their respective service territories. Our challenge to the rule itself was rejected by the federal court. However, the FERC's action presents opportunities for us to construct transmission outside of our service territory as long as the applicable rules are clear to all participating transmission developers. In April 2013, PJM Interconnection, L.L.C. (PJM) initiated a solicitation process pursuant to Order 1000 to review technical solutions to improve the operational performance in the Artificial Island area, consisting of our Salem and Hope Creek nuclear generation facilities. PJM has not yet made a decision in this process. On January 30, 2015, PSE&G filed a complaint against PJM at the FERC, arguing that PJM had failed to follow its rules during this process and requesting that the FERC order PJM to do so. If the FERC grants this complaint, the FERC could order PJM to re-start the entire process or make changes to the rules governing future competitive solicitations.

PJM filed with the FERC, and the FERC has recently accepted, a new “multi-driver” category of transmission projects, which projects may include a combination of reliability, economic and public policy elements. Changes to the factors used in making determinations in the PJM project planning and cost-allocation processes could have significant implications for the types of projects selected and the utility customers ultimately charged for the costs of such new transmission facilities. See Part I, Item 1. Business—Federal Regulation—Transmission Regulation—Transmission Policy Developments.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM), remains an important focus for us. In May 2014, a federal court issued a rule that vacated a FERC Order in which the FERC had determined that demand response (DR) providers should receive full market compensation for power and held that the FERC has no jurisdiction over DR. A subsequent challenge to the participation of DR as a resource in the PJM capacity market is pending at the FERC as is a filing made by PJM at the FERC that would remove DR as a supply resource in upcoming auctions. In addition, PJM has filed at the FERC to reset the demand curve for the RPM, which FERC subsequently accepted. We generally supported PJM’s approach in the filing but sought rehearing on certain issues, including the proper level of labor costs required to build new generation in New Jersey, which is pending. Further, in December 2014, PJM filed at the FERC its proposal for a capacity performance product to include generators, DR and energy efficiency providers who would certify as to availability during emergency conditions, as a supplement to base capacity and with enhanced performance-based incentives and penalties. The implications of these developments could be significant for the capacity market. See Part I, Item 1. Business—Regulatory Issues—Federal Regulation—Capacity Market Issues—PJM for additional information.

Under the PJM capacity auction conducted in May 2014, Power cleared 8,693 MW of its generating capacity at an average price of $164.61 MW-day for the 2017-2018 delivery period, a price consistent with what has been realized in the past three auctions. For a more detailed discussion on the RPM capacity auction, refer to Part I, Item 1. Business—Federal Regulation—Capacity Market Issues—PJM.

In 2014, appeals to challenge the federal court rulings that the New Jersey Long-Term Capacity Agreement Pilot Program Act to subsidize above-market new generation and a similar action taken by Maryland were unconstitutional and null and void were each denied. The appellants subsequently sought review at the U.S. Supreme Court and the U.S. Supreme Court has not yet acted. For additional information, refer to Part I, Item 1. Business—Regulatory Issues—Federal Regulation—Capacity Market Issues—Long-Term Capacity Agreement Pilot Program Act.

A critical aspect of our wholesale energy marketing business is the continued retention of market-based rate (MBR) authority from the FERC for our operating subsidiaries that engage in such activities. On October 14, 2014, the FERC issued an Order that accepted our triennial market power update, concluding that our submission satisfied its requirements for retention of MBR authority.

Environmental Regulation

We also advocate for the development and implementation of fair and reasonable rules by the U.S. Environmental Protection Agency (EPA) and state environmental regulators. On May 19, 2014, the EPA released the final Clean Water Act Section 316(b) rule on cooling water intake that establishes new requirements for the regulation of cooling water intakes at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. Eight of Power’s generating facilities and three of its jointly-owned generating facilities are subject to the rule. As adopted by the EPA, the rule requires that cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts, primarily by reducing the amount of fish and shellfish that are impinged or entrained at a cooling water intake structure. Under this standard, power facilities have the flexibility to select one of several options as their method of compliance. However, the EPA has structured the rule so that each state will continue to consider renewal permits for existing power facilities on a case by case basis, and will require facilities to conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. A federal court challenge to the EPA rule is pending. We are unable to predict the outcome that these permitting decisions may take and the effect, if any, that they may have on us although such impacts could be material. See Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities and Part I, Item 1. Business—Environmental Matters—Water Pollution Control for additional

information.
In June 2014, the EPA issued a proposed greenhouse gas emissions regulation for existing power plants. The regulation establishes state-specific emission rate targets based on implementation of the best system of emission reduction. States may choose these or other methodologies to achieve the necessary reductions of carbon dioxide emissions. The EPA had requested comment on many aspects of the proposal and therefore, the final rule may look considerably different than the proposal. We continue to work with state and federal regulators, as well as industry partners, to determine the potential impact of the regulation. See Part I, Item 1. Business—Environmental Matters—Climate Change for additional information.

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In addition, Clean Air Act (CAA) regulations governing hazardous air pollutants under the EPA's Maximum Achievable Control Technology rules are also of significance; however, we believe our generation business remains well-positioned for such air pollution control regulations if and when they are implemented.

Other Developments

In recent years we have been impacted by severe weather conditions, including Hurricane Irene in 2011 and Superstorm Sandy in 2012, the latter storm resulting in the highest level of customer outages in our history. For more detailed information, refer to Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities—Superstorm Sandy. We have begun work in our gas and electric distribution systems to improve resiliency. The New Jersey Board of Public Utilities (BPU) approved the settlement of our Energy Strong Proposal in a total amount of $1.22 billion. The settlement provides for cost recovery at a 9.75% rate of return on equity on the first $1.0 billion of the investment, plus associated allowance for funds used during construction, through an accelerated recovery mechanism. We will seek recovery of the remaining $220 million of investment in PSE&G's next base rate case, which is to be filed no later than November 1, 2017. We filed our initial Energy Strong cost recovery petition, seeking BPU approval to recover in base rates an estimated annual revenue increase of $1.1 million effective March 1, 2015. This increase represents capitalized Energy Strong electric investment costs in service through November 30, 2014. For additional information, refer to Part I, Item 1. Business—Regulatory Issues—State Regulation—Energy Strong Program.

In September 2014, the BPU approved substantially our entire request for a determination that our storm related costs, in the total amount of $366 million, were prudently incurred and recoverable in a future base rate proceeding, subject to offset for the amount of insurance proceeds received. For additional information, refer to Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

On January 1, 2014, we commenced operation of the LIPA T&D system under a twelve-year contract with opportunity to extend for an additional eight years. In addition, in January 2015, Power assumed responsibility for fuel procurement and power management services to LIPA under separate agreements.

In the first and second quarters of 2014, Power discovered and further investigated (i) incorrect calculations for certain components of its cost-based bids for its New Jersey fossil generating units in the PJM energy market and (ii) differences in the quantity of energy that Power offered into the energy market for its fossil peaking units from the amount for which Power was compensated in the capacity market for those units. We informed the FERC, PJM and the PJM Independent Market Monitor of these issues, and have corrected these errors. Power has an ongoing process of implementing improved procedures to help mitigate the risk of similar issues occurring in the future. In the third quarter of 2014, the FERC Staff initiated a preliminary, non-public staff investigation into the matter. This investigation could result in the FERC seeking disgorgement of any over-collected amounts, civil penalties and non-financial remedies. It is not possible at this time to reasonably estimate the ultimate impact or predict any resulting penalties, other costs associated with this matter, or the applicability of mitigating factors. For more detailed information regarding this matter, refer to Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities—FERC Compliance.

Operational Excellence

We emphasize operational performance while developing opportunities in both our competitive and regulated businesses. Flexibility in our generating fleet has allowed us to take advantage of market opportunities presented during the year as we remain diligent in managing costs. In 2014, our

- diverse fuel mix and dispatch flexibility allowed us to generate approximately 54,000 GWh, while addressing unit outages and balancing fuel availability and price volatility,
- Bergen 1 and 2 and Linden 1 Units and our combined cycle gas turbine fleet overall achieved record generation,
- Hope Creek Unit achieved its second best generation ever,
- construction of transmission and solar projects proceeded on schedule and within budget, and
- utility ranked highest in electric and gas service business customer satisfaction among large utilities in the eastern United States.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during 2014 as we:

- had cash on hand of $402 million as of December 31, 2014,

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- extended the expiration dates of PSEG's $500 million and Power's $1.6 billion five-year credit facilities from 2017 to 2019, and maintained substantial liquidity,
- maintained solid investment grade credit ratings, and
- paid an annual dividend of $1.48 and increased our indicated annual dividend for 2015 to $1.56 per share.

We expect to be able to fund our transmission projects required under PJM's reliability program, our Energy Strong program and other projects with internally generated cash and external debt financing.

Disciplined Investment

We utilize rigorous investment criteria when deploying capital and seek to invest in areas that complement our existing business and provide reasonable risk-adjusted returns. These areas include upgrading our energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. In 2014 we:

- placed into service our 230 kV Burlington-Camden and 230 kV North Central Reliability transmission projects,
- made additional investments in transmission infrastructure projects,
- continued to execute our existing BPU-approved utility programs,
- completed installation of equipment to increase output and improve efficiency at our Linden combined cycle gas generating plant and continue to plan for the installation of such equipment at our Bergen 2 and Bethlehem Energy Center (BEC) combined cycle gas units,
- completed the physical upgrades for the extended power uprate at Peach Bottom Unit 2,
- acquired an equity interest with an expected investment of $100 million-$120 million in the approximately 110 mile PennEast Pipeline to transport natural gas from eastern Pennsylvania to New Jersey, and
- acquired rights to solar energy facilities located near El Paso, Texas and Burlington, Vermont, totaling 16.6 MWdc which became operational in late 2014 and a 12.9 MWdc solar energy facility located near Waldorf, Maryland which we expect to be operational before June 2015.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in a slow-moving economy and a cost-constrained environment, to capitalize on or otherwise address appropriately regulatory and legislative developments that impact our business and to respond to the issues and challenges described below. In order to do this, we must continue to

- focus on controlling costs while maintaining safety and reliability and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions,
- execute our capital investment program, including our Energy Strong program and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- advocate for measures to ensure the implementation by PJM and the FERC of market design rules that continue to promote fair and efficient electricity markets,
- engage multiple stakeholders, including regulators, government officials, customers and investors, and
- successfully operate the LIPA T&D system.

For 2015 and beyond, the key issues and challenges we expect our business to confront include:

- regulatory and political uncertainty, both with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, as well as with respect to the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim, applicable to us and/or the energy industry,
- uncertainty in the slowly improving national and regional economic recovery, continuing customer conservation efforts, changes in energy usage patterns and evolving technologies, which impact customer behaviors and demand,

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- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate, and
- delays and other obstacles that might arise in connection with the construction of our T&D projects, including in connection with permitting and regulatory approvals.

RESULTS OF OPERATIONS

	Years Ended December 31,		
	2014	2013	2012
Earnings (Losses)	Millions		
PSE&G (A)	$725	$612	$528
Power (A)	760	644	666
Other (B)	33	(13)	81
PSEG Net Income	$1,518	$1,243	$1,275
PSEG Net Income Per Share (Diluted)	$2.99	$2.45	$2.51

(A) PSE&G's results in 2012 include after-tax expenses of $24 million for O&M costs and Power's results in 2014, 2013 and 2012 include after-tax expenses of $17 million, $32 million and $39 million, respectively, for O&M costs net of insurance recoveries in 2013 and 2012, due to severe damage caused by Superstorm Sandy. See Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

(B) Other includes after-tax activities at the parent company, PSEG LI and Energy Holdings as well as intercompany eliminations.

The 2014 year-over-year increase in our Net Income was driven primarily by:

- mark-to-market (MTM) gains in 2014 resulting from a decrease in prices on forward positions, as compared to MTM losses in 2013,
- higher sales volumes under the basic gas supply service (BGSS) contract due to colder average temperatures in the 2014 winter heating season,
- higher volumes of gas sold to third party customers,
- higher revenues due to increased investments in transmission projects, and
- lower O&M expense at PSE&G and Power, largely due to a reduction in pension and OPEB costs.

These increases were partially offset by

- lower volumes of electricity sold under Power's basic generation service (BGS) contracts resulting from serving fewer tranches in 2014, and
- higher generation costs due to higher fuel costs.

The 2013 year-over-year decrease in our Net Income was driven by:

- lower volumes of electricity sold under Power's BGS contracts at lower average prices,
- lower volumes of wholesale load contracts in the PJM and New England (NE) regions,
- unfavorable amounts related to the MTM activity, discussed below,
- higher generation costs due to higher fuel costs,
- higher planned outage and maintenance costs at certain of our fossil and nuclear plants, partially offset by cost control measures,
- the absence of the gain on the Dynegy leveraged lease settlement in 2012, and

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- higher Income Tax Expense due to the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012 (see Item 8. Financial Statements and Supplementary Data—Note 19. Income Taxes).

These decreases were largely offset by

- higher capacity revenues in the PJM region resulting from higher average prices as well as higher generation sold primarily in the PJM region,
- higher average gas prices on increased sales to third party customers, and
- higher revenues due to increased investments in transmission projects.

Our results include the realized gains, losses and earnings on Power's Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity. Net realized gains, interest and dividend income and other costs related to the NDT Fund are recorded in Other Income and Deductions, and impairments on certain NDT securities are recorded as Other-Than-Temporary Impairments. Interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) is recorded in Operation and Maintenance Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense. In 2014 and 2012, we restructured portions of our NDT Fund and realized gains of $65 million and $59 million, respectively.

Our results also include the after-tax impacts of non-trading MTM activity, which consist of the financial impact from positions with forward delivery dates.

The combined after-tax impact on Net Income for the years ended December 31, 2014, 2013 and 2012 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2014	2013	2012
	Millions, after tax		
NDT Fund and Related Activity	$68	$40	$52
Non-Trading MTM Gains (Losses)	$66	$(74)	$(10)

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, Power and PSE&G, excluding charges related to intercompany transactions, which are eliminated in consolidation. For additional information on intercompany transactions, see Item 8. Financial Statements and Supplementary Data—Note 23. Related-Party Transactions.

	Years Ended December 31,			Increase / (Decrease) 2014 vs. 2013		Increase / (Decrease) 2013 vs. 2012	
	2014	2013	2012				
	Millions			Millions	%	Millions	%
Operating Revenues	$10,886	$9,968	$9,781	$918	9	$187	2
Energy Costs	3,886	3,536	3,719	350	10	(183)	(5)
Operation and Maintenance	3,150	2,887	2,632	263	9	255	10
Depreciation and Amortization	1,227	1,178	1,054	49	4	124	12
Income from Equity Method Investments	13	11	12	2	18	(1)	(8)
Other Income and (Deductions)	229	159	162	70	44	(3)	(2)
Other-Than-Temporary Impairments	20	12	18	8	67	(6)	(33)
Interest Expense	389	402	423	(13)	(3)	(21)	(5)
Income Tax Expense	938	812	736	126	16	76	10

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The 2014 amounts in the preceding table for Operating Revenues and O&M Costs each include $389 million for Servco. These amounts represent the O&M pass-through costs for the Long Island operations, the full reimbursement of which is reflected in Operating Revenues. See Item 8. Financial Statements and Supplementary Data—Note 3. Variable Interest Entities for further explanation. The following discussions for Power and PSE&G provide a detailed explanation of their respective variances.

PSE&G

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
PSE&G	2014	2013	2012	2014 vs. 2013		2013 vs. 2012	
	Millions			Millions	%	Millions	%
Operating Revenues	$6,766	$6,655	$6,626	$111	2	$29	—
Energy Costs	2,909	2,841	3,159	68	2	(318)	(10)
Operation and Maintenance	1,558	1,639	1,508	(81)	(5)	131	9
Depreciation and Amortization	906	872	778	34	4	94	12
Taxes Other Than Income Taxes	—	68	98	(68)	(100)	(30)	(31)
Other Income (Deductions)	58	51	47	7	14	4	9
Interest Expense	277	293	295	(16)	(5)	(2)	(1)
Income Tax Expense	449	381	307	68	18	74	24

Year Ended December 31, 2014 as compared to 2013

Operating Revenues increased $111 million due primarily to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $88 million due primarily to an increase in transmission revenues.

- Transmission revenues were $138 million higher due to increased investments in transmission projects.
- Gas distribution revenues decreased $5 million due primarily to lower Weather Normalization Clause (WNC) revenue of $32 million due to more normal weather compared to the prior year, lower Transitional Energy Facilities Assessment (TEFA) revenue of $22 million due to elimination of the TEFA tax effective January 1, 2014, lower Capital Infrastructure Program (CIP) related revenue of $11 million, partially offset by higher sales volumes of $54 million, and higher revenue from Solar and Energy Efficiency Recovery Charges (formerly RRC and currently Green Program Recovery Charges (GPRC)) of $6 million.
- Electric distribution revenues decreased $45 million due primarily to a $45 million decrease due to elimination of the TEFA tax in 2014, lower sales volumes of $17 million and lower CIP related revenue of $5 million, partially offset by higher GPRC of $22 million.

Clause Revenues decreased $51 million due primarily to lower Societal Benefit Charges (SBC) of $32 million, lower Securitization Transition Charge (STC) revenues of $18 million, and lower Margin Adjustment Clause (MAC) of $7 million, partially offset by higher Solar Pilot Recovery Charge (SPRC) of $6 million. The changes in SBC, STC, MAC and SPRC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, STC, MAC or SPRC collections.

Commodity Revenue increased $68 million due to higher Electric and Gas revenues. This is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues increased $22 million due primarily to $64 million in higher BGS revenues, partially offset by $42 million in lower revenues from the sale of Non-Utility Generation (NUG) energy and collections of Non-Utility Generation Charges (NGC) due primarily to lower prices. BGS sales increased 2% due primarily to weather.
- Gas revenues increased $46 million due to higher BGSS volumes of $93 million, partially offset by lower BGSS prices of $47 million. The average price of natural gas was 5% lower in 2014 than in 2013.

Other Operating Revenues increased $6 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

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Operating Expenses

Energy Costs increased $68 million. This is entirely offset by Commodity Revenue.

- Electric costs increased $22 million or 1% due to $75 million of increased deferred cost recovery, $30 million in higher BGS volumes and a $2 million increase in NUG prices, partially offset by $78 million in lower NUG volumes and $7 million from lower BGS prices. BGS volume increased 2% due to customer migration from third party suppliers (TPS).
- Gas costs increased $46 million or 5% due to $93 million or 10% in higher sales volumes due primarily to weather, partially offset by $47 million or 5% in lower prices.

Operation and Maintenance decreased $81 million, of which the most significant components were decreases of

- $73 million in pension and other postretirement benefits (OPEB) expenses, and
- $21 million in costs related to SBC, GPRC and CIP,
- partially offset by a $12 million net increase in operational expenses due primarily to increases in storm related costs of $8 million, wages of $6 million and transmission related costs of $2 million, partially offset by a $4 million decrease in general operating expenses, and
- a $1 million increase in gas bad debt expense.

Depreciation and Amortization increased $34 million due primarily to increases of

- $47 million in additional plant in service, and
- $2 million in software amortization,
- partially offset by a $15 million decrease in amortization of Regulatory Assets.

Taxes Other Than Income Taxes decreased $68 million due to the elimination of the TEFA tax in 2014.

Other Income and (Deductions) net increase of $7 million was due primarily to increases of

- $7 million in Allowance for Funds Used During Construction, and
- $1 million in solar loan interest income,
- partially offset by a $1 million decrease in Rabbi Trust interest and gains.

Interest Expense decreased $16 million primarily due to decreases of

- $16 million due to partial redemption of securitization debt in 2014,
- $25 million due to maturities of $725 million in 2013, and
- $5 million due to maturities of $500 million in 2014,
- partially offset by an increase of $14 million due to the issuance of $1,250 million of debt in 2014, and
- an increase of $17 million due to the issuance of $1,500 million of debt in 2013.

Income Tax Expense increased $68 million due primarily to higher pre-tax income.

Year ended December 31, 2013 as compared to 2012

Operating Revenues increased $29 million due primarily to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $223 million due primarily to an increase in transmission revenues.

- Transmission revenues were $184 million higher due to increased investments in transmission projects.
- Gas distribution revenues increased $24 million due primarily to higher sales volumes of $70 million, higher CIP related revenue of $23 million and higher revenue from Solar and Energy Efficiency Recovery Charges of $5 million, partially offset by lower WNC revenue of $67 million due to more normal weather compared to the prior year and lower TEFA revenue of $7 million due to a lower TEFA rate.

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- Electric distribution revenues increased $15 million due primarily to higher GPRC of $37 million and higher CIP related revenue of $11 million, partially offset by lower TEFA revenue of $23 million due to a lower TEFA rate and lower sales volumes of $10 million.

Clause Revenues increased $110 million due primarily to STC revenues of $51 million, higher SBC of $47 million and a higher SPRC of $11 million. The changes in STC, SBC and SPRC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on STC, SBC or SPRC collections.

Commodity Revenue decreased $318 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $308 million due primarily to $169 million in lower BGS revenues and $139 million in lower revenues from the sale of NUG energy and collections of NGC due primarily to lower prices. BGS sales decreased 4% due primarily to customer migration to TPS and weather.
- Gas revenues decreased $10 million due to lower BGSS prices of $121 million, partially offset by higher BGSS volumes of $111 million. The average price of natural gas was 12% lower in 2013 than in 2012.

Other Operating Revenues increased $14 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Operating Expenses

Energy Costs decreased $318 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $308 million or 14% due to $214 million in lower BGS and NUG volumes, $35 million of lower BGS prices, and $59 million for decreased deferred cost recovery. BGS and NUG volumes decreased 10% due primarily to customer migration to TPS.
- Gas costs decreased $10 million or 1% due to $121 million or 12% in lower prices, partially offset by $111 million or 11% in higher sales volumes due primarily to weather.

Operation and Maintenance increased $131 million, of which the most significant components were increases of

- $131 million in costs related to SBC, GPRC and CIP,
- $24 million in transmission related costs, and
- $10 million in appliance service costs,
- partially offset by the absence of $40 million in transmission and distribution storm damages in 2012,
- a $10 million decrease in pension and OPEB expenses, and
- an $11 million decrease in gas bad debt expense.

Depreciation and Amortization increased $94 million due primarily to increases of

- $59 million in amortization of Regulatory Assets, and
- $33 million in additional plant in service.

Taxes Other Than Income Taxes decreased $30 million due to a lower TEFA rate, partially offset by higher sales volumes for gas.

Other Income and (Deductions) net increase of $4 million was due primarily to

- a $5 million increase in solar loan interest income,
- partially offset by a $1 million decrease in Rabbi Trust interest and gains.

Interest Expense experienced no material change.

Income Tax Expense increased $74 million due primarily to higher pre-tax income and the absence of tax benefits related to the settlement of the 1997-2006 IRS audits in 2012.

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Power

Power	Years Ended December 31, 2014	2013	2012	Increase / (Decrease) 2014 vs. 2013		Increase / (Decrease) 2013 vs. 2012	
	Millions			Millions	%	Millions	%
Operating Revenues	$5,434	$5,063	$4,873	$371	7	$190	4
Energy Costs	2,747	2,496	2,381	251	10	115	5
Operation and Maintenance	1,186	1,224	1,127	(38)	(3)	97	9
Depreciation and Amortization	292	273	242	19	7	31	13
Income from Equity Method Investments	14	16	15	(2)	(13)	1	7
Other Income (Deductions)	170	105	111	65	62	(6)	(5)
Other-Than-Temporary Impairments	20	12	18	8	67	(6)	(33)
Interest Expense	122	116	132	6	5	(16)	(12)
Income Tax Expense	491	419	433	72	17	(14)	(3)

Year Ended December 31, 2014 as compared to 2013

Operating Revenues increased $371 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues increased $263 million due primarily to

- higher revenues of $366 million due primarily to MTM gains in 2014 resulting from a decrease in prices on forward positions and higher energy volumes sold in the New York and New England (NE) regions, and
- a net increase of $27 million due primarily to higher volumes on wholesale load contracts in the PJM region, offset in part by lower wholesale load volumes in the NE region,
- partially offset by a decrease of $89 million due to lower volumes of electricity sold as a result of serving fewer tranches in 2014 under our BGS contracts and lower average pricing, and
- a net decrease of $41 million due primarily to a decrease in operating reserve revenue, partially offset by higher ancillary revenue in the PJM region.

Gas Supply Revenues increased $93 million due primarily to

- a net increase of $44 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2014 winter heating season, partially offset by lower average gas prices, and
- a net increase of $49 million due to higher sales volumes to third party customers.

Other Operating Revenues increased $15 million due to transition fees related to fuel management and power supply management contracts with LIPA.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power’s obligation under its BGSS contract with PSE&G. Energy Costs increased $251 million due to

- Generation costs increased $252 million due primarily to higher fuel costs, reflecting higher average realized natural gas prices, the unfavorable MTM impact from lower average natural gas prices on forward positions and the utilization of higher volumes of gas and oil. These increased costs were partially offset by lower congestion costs in the PJM region.
- Gas costs decreased $1 million related to a decrease of $137 million in average gas inventory costs, substantially offset by $136 million of higher volumes sold under the BGSS contract and to third party customers due to colder average temperatures during the 2014 winter heating season.

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Operation and Maintenance decreased $38 million due primarily to

- lower pension and OPEB costs of $42 million,
- a decrease of $15 million due primarily to the outage of our 100%-owned Hope Creek nuclear facility in the fall of 2013, which was partially offset by the extension of our 57%-owned nuclear Salem Unit 2 refueling outage in 2014, and
- a decrease of $27 million due to lower storm costs related to Superstorm Sandy,
- partially offset by an increase of $40 million related primarily to higher planned outage and maintenance costs at our fossil plants, including maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant and outages at our Keystone and Hudson facilities.

Depreciation and Amortization increased $19 million due primarily to a higher depreciable fossil and nuclear asset base.

Income from Equity Method Investments experienced no material change.

Other Income (Deductions) increased $65 million due primarily to higher realized gains from the NDT Fund due to the restructuring of the portfolio in 2014.

Other-Than-Temporary Impairments increased $8 million due to an increase in impairments of the NDT Fund.

Interest Expense increased $6 million due primarily to the issuance of a $250 million 2.45% Senior Note and a $250 million 4.30% Senior Note in November 2013, partially offset by the maturity of $300 million of 2.50% Senior Notes in April 2013.

Income Tax Expense increased $72 million in 2014 due primarily to higher pre-tax income.

Year ended December 31, 2013 as compared to 2012

Operating Revenues increased $190 million due to changes in generation and supply revenues.

Generation Revenues increased $102 million due primarily to

- an increase of $341 million due to higher capacity revenues resulting from higher average auction prices and an increase in operating reserve revenues in PJM, and
- higher net revenues of $36 million due primarily to higher generation sold in the PJM and NE regions partly offset by higher MTM losses in 2013 resulting from an increase in prices on forward positions in the PJM and NE regions,
- partially offset by a decrease of $155 million due primarily to lower volumes of electricity sold under our BGS contracts and lower average pricing, and
- a net decrease of $120 million due to lower volumes on wholesale load contracts in the PJM and NE regions.

Gas Supply Revenues increased $88 million due primarily to

- a net increase of $40 million in sales under the BGSS contract, substantially comprised of higher sales volumes due to colder average temperatures during the 2013 winter heating season, partially offset by lower average gas prices, and
- a net increase of $48 million due primarily to higher average gas prices and higher sales volumes to third party customers.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power’s obligation under its BGSS contract with PSE&G. Energy Costs increased $115 million due to

- Generation costs increased $75 million due primarily to $84 million of higher fuel costs, reflecting higher average realized natural gas prices, higher nuclear fuel costs and the utilization of higher volumes of coal and oil, partially offset by lower average coal prices and lower average unrealized natural gas prices on forward positions.
- Gas costs increased $40 million, principally related to obligations under the BGSS contract, reflecting higher sales volumes in 2013 due to colder average temperatures during the 2013 winter heating season and higher volumes on third party sales, partially offset by lower average gas inventory costs.

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Operation and Maintenance increased $97 million due primarily to

- higher planned outage and maintenance costs in 2013, mainly at our gas-fired BEC plant in New York, Bergen gas-fired plant in New Jersey, Linden gas-fired plant in New Jersey and 23%-owned Conemaugh coal-fired plant in Pennsylvania, partially offset by lower storm costs in 2013, and
- higher outage costs at our nuclear generating facilities, primarily at our 100%-owned Hope Creek station.

Depreciation and Amortization increased $31 million due primarily to a higher depreciable asset base at Fossil and Nuclear, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut in June 2012, completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 2 in October 2012, and placing two solar facilities into service in the fourth quarter of 2012. In addition, an update to the nuclear asset retirement obligation became effective in November 2012, causing higher depreciation in 2013.

Income from Equity Method Investments experienced no material change.

Other Income (Deductions) decreased $6 million due primarily to lower NDT Fund realized gains in 2013, partially offset by lower NDT Fund realized losses in 2013. In addition, we recognized a loss on the extinguishment of debt in 2012.

Other-Than-Temporary Impairments decreased $6 million due to lower impairments on the NDT Fund in 2013.

Interest Expense decreased $16 million due primarily to a decrease of $23 million resulting from the maturity of $300 million of 2.50% of Senior Notes in April 2013, and the early redemptions of $250 million of 5.00% medium term notes and various tax-exempt bonds in December 2012, partially offset by higher interest costs of $6 million in 2013 since interest capitalization ceased for our Kearny and New Haven gas-fired peaking projects on their June 2012 in-service date.

Income Tax Expense decreased $14 million in 2013 due primarily to lower pre-tax income.

LIQUIDITY AND CAPITAL RESOURCES

The following discussion of our liquidity and capital resources is on a consolidated basis, noting the uses and contributions, where material, of our two direct major operating subsidiaries.

Financing Methodology

We expect our capital requirements to be met through internally generated cash flows and external financings, consisting of short-term debt for working capital needs and long-term debt for capital investments.

PSE&G's sources of external liquidity include a $600 million multi-year syndicated credit facility. PSE&G's commercial paper program is the primary vehicle for meeting seasonal, intra-month and temporary working capital needs. PSE&G does not engage in any intercompany borrowing or lending. PSE&G maintains back-up facilities in an amount sufficient to cover the commercial paper and letters of credit outstanding. PSE&G's dividend payments to PSEG are consistent with its capital structure objectives which have been established to maintain investment grade credit ratings. PSE&G's long-term financing plan is designed to replace maturities, fund a portion of its capital program and manage short-term debt balances. Generally, PSE&G uses either secured medium-term notes or first mortgage bonds to raise long-term capital.

PSEG, Power, Energy Holdings, PSEG LI and Services participate in a corporate money pool, an aggregation of daily cash balances designed to efficiently manage their respective short-term liquidity needs. Servco does not participate in the corporate money pool. Servco's short-term liquidity needs are met through an account funded and owned by LIPA.

PSEG's sources of external liquidity include multi-year syndicated credit facilities totaling $1 billion. These facilities are available to back-stop PSEG's commercial paper program, issue letters of credit and for general corporate purposes. These facilities may also be used to provide support to PSEG's subsidiaries. PSEG's credit facilities and the commercial paper program are available to support PSEG working capital needs or to temporarily fund growth opportunities in advance of obtaining permanent financing. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power's sources of external liquidity include $2.6 billion of syndicated multi-year credit facilities. Additionally, from time to time, Power maintains bilateral credit agreements designed to enhance its liquidity position. Power has $100 million of bilateral credit agreements that are scheduled to expire in September 2015. Credit capacity is primarily used to provide collateral in support of Power's forward energy sale and forward fuel purchase contracts as the market prices for energy and fuel fluctuate, and to meet potential collateral postings in the event of a credit rating downgrade below investment grade. Power's dividend payments to PSEG are also designed to be consistent with its capital structure objectives which have been established to maintain investment grade credit ratings and provide sufficient financial flexibility. Generally, Power issues senior unsecured debt to raise long-term capital.

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Operating Cash Flows

We expect our operating cash flows combined with cash on hand and financing activities to be sufficient to fund capital expenditures and shareholder dividend payments.

For the year ended December 31, 2014, our operating cash flow increased by $2 million. For the year ended December 31, 2013, our operating cash flow increased by $371 million. The net changes were primarily due to net changes from our subsidiaries as discussed below and tax payments at the parent company and Energy Holdings.

PSE&G

PSE&G's operating cash flow increased $188 million from $1,645 million to $1,833 million for the year ended December 31, 2014, as compared to 2013, due primarily to

- higher earnings,
- an increase of $188 million due to an increase from a net change in regulatory deferrals, primarily related to over collections of BGSS gas costs, the over collection of gas revenues due to the Gas Weather Normalization clause and GPRC rate recoveries,
- an increase of $83 million due to decrease in employee benefit plan funding,
- partially offset by $199 million related to higher tax payments.

PSE&G's operating cash flow increased $389 million from $1,256 million to $1,645 million for the year ended December 31, 2013, as compared to 2012, due primarily to

- higher earnings,
- an increase of $134 million due to an increase from a net change in regulatory deferrals, primarily related to over collections of BGSS gas costs and the collection of prior year deficiency revenues under the Gas Weather Normalization clause mechanism, and
- a decrease of $47 million in benefit plan funding,
- partially offset by $114 million related to higher tax payments.

Power

Power's operating cash flow increased $78 million from $1,347 million to $1,425 million for the year ended December 31, 2014, as compared to 2013, primarily resulting from

- lower tax payments,
- partially offset by increase of $87 million in payments to counterparties, and
- a decrease of $11 million due to collection of counterparty receivables.

Power's operating cash flow decreased $106 million from $1,453 million to $1,347 million for the year ended December 31, 2013, as compared to 2012, primarily resulting from

- lower earnings, and
- higher tax payments,
- partially offset by a decrease of $73 million related to margin deposits, and
- a decrease of $26 million in employee benefit plan funding.

Short-Term Liquidity

We continually monitor our liquidity and seek to add capacity as needed to meet our liquidity requirements. Each of our credit facilities is restricted as to availability and use to the specific companies as listed below; however, if necessary, the PSEG facilities can also be used to support our subsidiaries' liquidity needs. Our total credit facilities and available liquidity as of December 31, 2014 were as follows:

Company/Facility	As of December 31, 2014 Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$1,000	$8	$992
PSE&G	600	14	586
Power	2,700	197	2,503
Total	$4,300	$219	$4,081

As of December 31, 2014, our credit facility capacity was in excess of our projected maximum liquidity requirements over our 12 month planning horizon. Our maximum liquidity requirements are based on stress scenarios that incorporate changes in commodity prices and the potential impact of Power losing its investment grade credit rating. PSE&G's credit facility primary use is to support its Commercial Paper Program under which as of December 31, 2014, no amounts were outstanding. Most of our credit facilities expire in 2018 and 2019. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities and Note 13. Schedule of Consolidated Debt.

Long-Term Debt Financing

PSE&G has $300 million of 2.70%, Series G Medium Term Notes maturing in May 2015.

Power has a $300 million of 5.50% Senior Notes maturing in December 2015.

For a discussion of our long-term debt transactions during 2014 and into 2015, see Item 8. Financial Statements and Supplementary Data—Note 13. Schedule of Consolidated Debt.

Debt Covenants

Our credit agreements contain maximum debt to equity ratios and other restrictive covenants and conditions to borrowing. We are currently in compliance with all of our debt covenants. Continued compliance with applicable financial covenants will depend upon our future financial position, level of earnings and cash flows, as to which no assurances can be given.

In addition, under its First and Refunding Mortgage (Mortgage), PSE&G may issue new First and Refunding Mortgage Bonds against previous additions and improvements, provided that its ratio of earnings to fixed charges calculated in accordance with its Mortgage is at least 2 to 1, and/or against retired Mortgage Bonds. As of December 31, 2014, PSE&G's Mortgage coverage ratio was 5.6 to 1 and the Mortgage would permit up to approximately $3.8 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

Default Provisions

Our bank credit agreements and indentures contain various default provisions that could result in the potential acceleration of payment under the defaulting company's agreement. We have not defaulted under these agreements. PSEG's bank credit agreements contain cross default provisions under which events at Power or PSE&G, including payment defaults, bankruptcy events, the failure to satisfy certain final judgments or other events of default under their financing agreements, would each constitute an event of default. Under the bank credit agreements, it would be an event of default if both PSE&G and Power cease to be wholly owned by PSEG.

There are no cross default provisions to affiliates in PSE&G's or Power's credit agreements or indentures.

Ratings Triggers

Our debt indentures and credit agreements do not contain any material 'ratings triggers' that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral requirements. In the event that we are not able to affirm representations and warranties on credit agreements, lenders would not be required to make loans.

In accordance with BPU requirements under the BGS contracts, PSE&G is required to maintain an investment grade credit rating. If PSE&G were to lose its investment grade rating, it would be required to file a plan to assure continued payment for the BGS requirements of its customers.

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PSE&G is the servicer for the bonds issued by PSE&G Transition Funding LLC and PSE&G Transition Funding II LLC. Cash collected by PSE&G to service these bonds is commingled with PSE&G's other cash until it is remitted to the bond trustee each month. If PSE&G were to lose its investment grade rating, PSE&G would be required to remit collected cash daily to the bond trustee. PSE&G is prohibited from advancing its own funds to make payments related to such bonds.

Fluctuations in commodity prices or a deterioration of Power's credit rating to below investment grade could increase Power's required margin postings under various agreements entered into in the normal course of business. Power believes it has sufficient liquidity to meet the required posting of collateral which would likely result from a credit rating downgrade at today's market prices.

Common Stock Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	2014	2013	2012
Per Share	$1.48	$1.44	$1.42
in Millions	$748	$728	$718

On February 17, 2015, our Board of Directors approved a $0.39 per share common stock dividend for the first quarter of 2015. This reflects an indicated annual dividend rate of $1.56 per share. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Credit Ratings shown are for securities that we typically issue. Outlooks are shown for Corporate Credit Ratings (S&P) and Issuer Credit Ratings (Moody's and Fitch) and can be Stable, Negative, or Positive. There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security.

In May 2014, Moody's published updated research reports on PSEG, PSE&G and Power and the existing ratings and outlooks were unchanged. In May 2014, S&P published updated research reports and revised the outlook to positive from stable for PSEG's Corporate Credit Rating. S&P also affirmed the senior unsecured rating of BBB+ at Power and mortgage bond rating of A at PSE&G. In October 2014, Fitch affirmed the ratings and outlooks for PSEG, PSE&G and Power.

	Moody's (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	Stable	Positive	Stable
Commercial Paper	P2	A2	F2
PSE&G			
Outlook	Stable	Positive	Stable
Mortgage Bonds	Aa3	A	A+
Commercial Paper	P1	A2	F2
Power			
Outlook	Stable	Positive	Stable
Senior Notes	Baa1	BBB+	BBB+

(A)

Moody’s ratings range from Aaa (highest) to C (lowest) for long-term securities and P1 (highest) to NP (lowest) for short-term securities.

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(B) S&P ratings range from AAA (highest) to D (lowest) for long-term securities and A1 (highest) to D (lowest) for short-term securities. The Corporate Credit Rating outlook does not apply to PSEG's or PSE&G's Commercial Paper Rating or PSE&G's Mortgage Bond rating.

(C) Fitch ratings range from AAA (highest) to D (lowest) for long-term securities and F1 (highest) to D (lowest) for short-term securities.

Other Comprehensive Income

For the year ended December 31, 2014, we had Other Comprehensive Loss of $188 million on a consolidated basis. Other Comprehensive Loss was due primarily to a $173 million increase in our consolidated liability for pension and postretirement benefits and a $27 million decrease in net unrealized gains related to Available-for-Sale Securities, and was partially offset by $12 million of unrealized gains on derivative contracts accounted for as hedges. See Item 8. Financial Statements and Supplementary Data—Note 20. Accumulated Other Comprehensive Income (Loss), Net of Tax for additional information.

CAPITAL REQUIREMENTS

It is expected that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected capital construction and investment expenditures, excluding nuclear fuel purchases, for the next three years are presented in the table below. These amounts are subject to change, based on various factors. We will continue to approach non-regulated solar and other renewables investments opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2015	2016	2017
		Millions	
PSE&G:			
Transmission			
Reliability Enhancements	$1,420	$1,230	$1,185
Facility Replacement	165	185	200
Support Facilities	5	35	15
Environmental/Regulatory	5	5	5
Distribution			
Reliability Enhancements	285	435	295
Facility Replacement	385	235	225
Support Facilities	55	50	55
New Business	155	160	160
Environmental/Regulatory	40	50	55
Renewables	100	80	80
Total PSE&G	$2,615	$2,465	$2,275
Power:			
Baseline	$225	$220	$190
Environmental/Regulatory	60	50	45
Fossil Growth Opportunities	20	—	20
Nuclear Expansion	95	20	10
Solar Expansion	155	105	—
Total Power	$555	$395	$265
Services	$50	$35	$35
Total PSEG	$3,220	$2,895	$2,575

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PSE&G

PSE&G's projections for future capital expenditures include material additions and replacements to its transmission and distribution systems to meet expected growth and to manage reliability. As project scope and cost estimates develop, PSE&G will modify its current projections to include these required investments. PSE&G's projected expenditures for the various items reported above are primarily comprised of the following:

- Reliability Enhancements—investments made to maintain the reliability and efficiency of the system or function.
- Facility Replacement—investments made to replace systems or equipment in kind.
- Support Facilities—ancillary equipment needed to support the business lines, such as computers, office furniture and buildings and structures housing support personnel or equipment/inventory.
- New Business—investments made in support of new business (e.g. to add new customers).
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Renewables—investments made in response to regulatory or legal mandates relating to renewable energy.

In 2014, PSE&G made $2,170 million of capital expenditures, including $2,164 million of investment in plant, primarily for transmission and distribution system reliability and $6 million in solar loan investments. This does not include expenditures for cost of removal, net of salvage, of $98 million, which are included in operating cash flows.

Power

Power's projected expenditures for the various items listed above are primarily comprised of the following:

- Baseline—investments to replace major parts and enhance operational performance.
- Environmental/Regulatory—investments made in response to environmental, regulatory or legal mandates.
- Fossil Growth Opportunities—investments associated with upgrades to increase efficiency and output at combined cycle plants.
- Nuclear Expansion—investments associated with certain Nuclear capital projects, primarily at existing facilities designed to increase operating output.
- Solar Expansion—investments associated with the construction of utility-scale photovoltaic facilities.

In 2014, Power made $460 million of capital expenditures, excluding $166 million for nuclear fuel, primarily related to various projects at Fossil and Nuclear.

Disclosures about Long-Term Maturities, Contractual and Commercial Obligations and Certain Investments

The following table reflects our contractual cash obligations and other commercial commitments in the respective periods in which they are due. In addition, the table summarizes anticipated recourse and non-recourse debt maturities for the years shown. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 13. Schedule of Consolidated Debt.

The table below does not reflect any anticipated cash payments for pension obligations due to uncertain timing of payments or liabilities for uncertain tax positions since we are unable to reasonably estimate the timing of liability payments in individual years beyond 12 months due to uncertainties in the timing of the effective settlement of tax positions. See Item 8. Financial Statements and Supplementary Data—Note 19. Income Taxes for additional information.

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	Total Amount Committed Millions	Less Than 1 Year	2 - 3 Years	4- 5 Years	Over 5 Years
Contractual Cash Obligations					
Long-Term Recourse Debt Maturities					
PSE&G	$6,329	$300	$171	$1,250	$4,608
Transition Funding (PSE&G)	251	251	—	—	—
Transition Funding II (PSE&G)	8	8	—	—	—
Power	2,553	300	553	294	1,406
Long-Term Non-Recourse Project Financing					
Other	16	16	—	—	—
Interest on Recourse Debt					
PSE&G	4,113	248	473	427	2,965
Transition Funding (PSE&G)	11	11	—	—	—
Transition Funding II (PSE&G)	—	—	—	—	—
Power	1,142	131	207	179	