PUBLIC SERVICE ENTERPRISE GROUP INC
Form 10-K
February 26, 2016

table of contents

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, 2015
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 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 8%, due 2037 5%, due 2037	New York Stock Exchange
PSEG Power LLC	8 5/8% Senior Notes, due 2031	New York Stock Exchange

(Cover continued on next page)

table of contents

(Cover continued from previous page)
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. ¨
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, 2015 was $19,819,621,677 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 February 19, 2016 was 506,435,137.
As of February 19, 2016, 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.
Public Service Electric and Gas Company and PSEG Power LLC 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 2016 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, 2016, as specified herein.

table of contents

TABLE OF CONTENTS

table of contents

TABLE OF CONTENTS (continued)

table of contents

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 ongoing low pricing 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, including prudency reviews and disallowances,
- any deterioration in our credit quality or the credit quality of our counterparties,
- changes in federal and state environmental regulations and enforcement that could increase our costs or limit our operations,
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry,
- 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 or increase the cost 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,
- delays or unforeseen cost escalations in our construction and development activities, or the inability to recover the carrying amount of our assets,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- increases in competition in energy supply markets as well as for transmission projects,
- changes in technology, such as distributed generation and micro grids, and greater reliance on these technologies,
- changes in customer behaviors, including increases in energy efficiency, net-metering and demand response,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements,
- 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,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
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changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,

- an extended economic recession,
- an inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce, and
- changes in the credit quality and the ability of lessees to meet their obligations under our domestic leveraged leases.

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.

table of contents

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 191.

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, PSE&G and Power, 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.	A Delaware limited liability company formed in 1999 as a result of the deregulation and restructuring of the electric power industry in New Jersey. It integrates the operations of its merchant nuclear, fossil and renewable generating assets with its wholesale energy sales, fuel supply and energy transacting functions.
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.	Earns revenues from selling under contract or on the spot market a range of diverse products such as electricity, natural gas, emissions credits and other energy-related products used to optimize the operation of the energy grid.
Has also implemented regulated demand response and energy efficiency programs and invested in solar generation within New Jersey.	

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.

table of contents

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.

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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).

table of contents

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 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 300 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 that 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, 2015		
Network Circuit Miles	Billing Peak Megawatt (MW)	Historical Annual Load Growth 2011-2015
1,769	9,595	(2.3)%

In 2015, we completed:

- the final phase of our portion of the 500 kV Susquehanna-Roseland project, bolstering electric reliability by partnering with PPL Electric Utilities (PPL) to construct a 150 mile power line between PPL's nuclear switchyard in Susquehanna, Pennsylvania and our switchyard in Roseland, New Jersey, and
- our Mickleton-Gloucester-Camden project which consisted of upgrading 10 circuit miles of overhead transmission, installing approximately 16 underground circuit miles and 10 overhead circuit miles of new 230 kilovolt (kV) and modifications/upgrades at five existing stations.

table of contents

We are also continuing to execute the following projects that focus on reliability improvements and replacement of aging infrastructure which are included in the 2016-2018 capital spend of $4.7 billion for Transmission disclosed in Item 7. MD&A—Capital Requirements.

Major Transmission Projects As of December 31, 2015	
Project	Expected In-Service Date
Northeast Grid Reliability (230 kV)	June 2015-June 2016
Bergen-Linden Corridor (345 kV)	June 2018
PJM Regional Transmission Expansion Plan - multiple projects	Various
69 kV Upgrade - multiple projects	Various
Transmission Life Cycle - multiple projects to replace aging infrastructure	Various
Transmission Hardening - multiple reliability projects	Various

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 a 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 approved 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 2015:

	% of 2015 Sales	
Customer Type	Electric	Gas
Commercial	57%	37%
Residential	33%	59%
Industrial	10%	4%
Total	100%	100%

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

Electric and Gas Distribution Statistics

	December 31, 2015 Number of Customers		Electric Sales and Gas Firm Sales (A)		Historical Annual Load Growth 2011-2015
Electric	2.2	Million	41,715	Gigawatt hours (GWh)	(0.9)%
Gas	1.8	Million	2,523	Million Therms	2.1%

(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 as a result of lower gas prices. Only gas firm sales impact margin.

During 2015, PSE&G continued to execute its BPU-approved $1.2 billion Energy Strong Program 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.

table of contents

In addition, in November 2015, the BPU approved our settlement with the BPU Staff and the New Jersey Division of Rate Counsel regarding our Gas System Modernization Program (GSMP) through which we will invest $905 million over three years to modernize PSE&G's gas systems. The GSMP will replace approximately 510 miles of cast iron and unprotected steel gas mains and about 38,000 unprotected steel service lines to homes and businesses, including the uprating of the mains to higher pressure. The mains and service lines will be replaced with stronger, more durable plastic piping, reducing the potential for leaks and release of methane gas. The new elevated pressure systems also enable the installation of excess flow valves that automatically shut off gas flow if a service line is damaged, and better support the use of high-efficiency appliances.

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, 2015, we have invested an aggregate of approximately $818 million in both solar programs.

Supply

Although commodity revenues make up almost 41% 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-Commercial Industrial Energy Pricing (CIEP)).

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 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 up to 5% and also may reduce the BGSS rate at any time and/or provide bill credits. See 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

table of contents

impact of natural gas commodity prices on electricity prices such as BGS, see Item 7. MD&A—Executive Overview of 2015 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 to produce energy 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.

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. On March 19, 2014, the BPU approved an extension of the long-term BGSS contract to March 31, 2019 and then year-to-year thereafter unless terminated by either party with a two year notice.

Approximately 45% 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 and propane. Based upon the availability of natural gas beyond PSE&G's daily needs, Power sells gas to others and uses it for its generation fleet.

In addition to its nuclear and fossil generation fleet, Power owns and operates 148 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 comprises 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 (11,678 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.

table of contents

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: 42% gas, 32% nuclear, 21% coal, 4% 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 2015 was approximately 55,000 GWh. The generation mix by fuel type in recent years has reflected the relatively more favorable price of natural gas 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 2015.

Generation by Fuel Type (A)	Actual 2015	
Nuclear:		
New Jersey facilities	36%	
Pennsylvania facilities	18%	
Fossil:		
Coal:		
Pennsylvania facilities	9%	
Connecticut facilities	1%	
Coal and Natural Gas:		
New Jersey facilities	1%	
Natural Gas and Oil:		
New Jersey facilities	26%	
New York facilities	9%	
Connecticut facilities	—%	(B)
Total	100%	

(A) Excludes pumped storage, solar facilities and fossil generation in Hawaii which account for less than 1.5 percent of total generation.
(B) Less than one percent.

7

table of contents

During 2015, we completed the extended power uprate of 130 MW at our co-owned Peach Bottom 2 and 3 nuclear units and installation of an advanced gas path uprate of 31 MW at our Bergen generation station. We are also executing the following growth projects which are included in the 2016-2018 capital spend of $1.9 billion for Fossil Growth Opportunities disclosed in Item 7. MD&A—Capital Requirements.

Major Growth Projects
As of December 31, 2015

Project	Location	Expected In-Service Date
Keys Energy Center gas-fired combined cycle generating station (755 MW)	Maryland	2018
Sewaren 7 dual-fueled combined cycle generating station (540 MW)	New Jersey	2018
Bridgeport Harbor 5 gas-fired combined cycle generating station (485 MW)	Connecticut	2019
Bethlehem Energy Center (BEC) combined cycle uprate (58 MW)	New York	2017/2018

- 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 39% base load, 49% load following and 12% 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 both 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 2015, our base load capacity factors were as follows:

Unit	2015 Capacity Factor
Nuclear	
Salem Unit 1	93.9%
Salem Unit 2	85.9%
Hope Creek	88.6%
Peach Bottom Unit 2	95.7%
Peach Bottom Unit 3	89.6%
Coal	
Keystone	63.9%
Conemaugh	74.9%

- Load Following Units typically operate between 20% and 70% of the time. The operating costs are generally 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. These units usually have more flexible operating characteristics than base load units which enable them to more easily follow fluctuations in load. They operate less frequently than base load units and derive revenues from energy, capacity and ancillary services.

- Peaking Units run the least amount of time and in some cases may utilize higher-priced fuels. These units typically operate less than 20% of the time but can typically start very quickly in response to system needs. Costs per unit of output tend to be 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.

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table of contents

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 the low price of natural gas has resulted in changes in market price fluctuations from historical norms, wherein some gas-fired generation is now able 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 were retired in June 2015. Salem 3 continues to be used as an emergency backup generator for the Salem nuclear site.

(B) Keys Energy Center and Sewaren 7, which will replace Sewaren Units 1, 2, 3 and 4, are expected to be added to dispatch in 2018. Bridgeport Harbor Station 5 is scheduled to be added to dispatch in 2019. See Major Growth Projects above.

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

table of contents

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),
- conversion of uranium concentrates to uranium hexafluoride,

table of contents

- 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. 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. We currently have a coal supply contract from Indonesia under contract through 2017 for the Bridgeport facility and believe that additional coal would be available after 2017 as required.

- 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 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.

Power has contracted for approximately 125 million cubic feet-per-day of delivery capability on the PennEast Pipeline from eastern Pennsylvania to New Jersey with a targeted in-service date of November 2017. This additional delivery capability will be used to supplement the BGSS contract.

- Oil—Oil is used as the primary fuel for one load following steam unit and four 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 or barge.

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, environmental regulations, and other factors. For additional information, see Item 7. MD&A—Executive Overview of 2015 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 FERC:

- PJM Regional Transmission Organization—PJM conducts the largest centrally dispatched energy market in North America. It serves over 61 million people, nearly 19% of the total United States population, and has a record 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 19 million and a record 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 record 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.

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

table of contents

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 operate 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, much of which is produced in adjacent states (e.g. Pennsylvania). 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 units 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 transfer limitations 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 and incremental 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 transfer limitations of the transmission system in each area. Keystone and Conemaugh receive lower capacity prices than the majority of our PJM generating units since there are fewer constraints in that region and our generating units in 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 and incremental auctions which have been completed:

Delivery Year	MW-day
June 2015 to May 2016	$168
June 2016 to May 2017	$172
June 2017 to May 2018	$177
June 2018 to May 2019	$215

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.

We have obtained price certainty for our PJM capacity through May 2019 and New England capacity through May 2020 through the RPM and FCM pricing mechanisms, respectively.

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.

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

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

and

- legislative and/or regulatory actions that permit subsidized local electric power generation.

12

table of contents

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. 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)	2013-2016	2014-2017	2015-2018	2016-2019
PSE&G	$92.18	$97.39	$99.54	$96.38
Jersey Central Power & Light Company (JCP&L)	$83.70	$84.44	$80.42	$74.85
Atlantic City Electric Company	$87.27	$87.80	$86.06	$82.14
Rockland Electric Company	$92.58	$95.61	$90.66	$85.02

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 the effectiveness of our hedges. 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. 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 third party suppliers, 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 11, 2016, we had contracted for the following percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2018.

Base Load Generation	2016	2017	2018
Generation Sales	100%	70%-75%	25%-30%

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.

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 2020. 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. We take a more opportunistic approach in hedging both the fuel for and the anticipated output of our 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-

table of contents

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.

Taking into account the hedging strategy, our expected capacity revenues from the capacity market mechanisms described above and certain ancillary service payments such as reactive power, more than half of Power’s gross margin in the upcoming year is relatively certain.

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 $784 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2015, 73% 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, 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.

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 FERC and being implemented by PJM and other ISOs to eliminate contractual provisions that previously provided us a “right of first refusal” (ROFR) to

table of contents

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 would 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 limitations and constraints 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 implemented in the PJM and New England capacity markets and other proposed market changes discussed more fully in Regulatory Issues—Federal Regulation provide the opportunity for additional compensation in both the energy and capacity markets.

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 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-fueled stations.

In addition, pressures from renewable resources could increase over time. For example, many parts of the country, including the mid-western region served by 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 Regulations—Transmission Regulation.

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table of contents

EMPLOYEE RELATIONS

As of December 31, 2015, we had 13,025 employees within our subsidiaries, including 8,111 covered under collective bargaining agreements. Two of our collective bargaining union agreements will expire in November 2016, five in April 2017, two in October 2017, and one in May 2018. We believe we maintain satisfactory relationships with our employees.

Employees as of December 31, 2015

	PSE&G	Power	PSEG LI	Other
Non-Union	1,812	1,280	755	1,067
Union	4,968	1,659	1,476	8
Total Employees	6,780	2,939	2,231	1,075

REGULATORY ISSUES

Federal Regulation

FERC

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. 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 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.

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 FERC. We own various QFs through Power. QFs are subject to some, but not all, of the same FERC requirements as public utilities.

FERC also regulates Regional Transmission Operators (RTOs)/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/Market Power
- Energy Clearing Prices
- Capacity Market Issues
- Transmission Regulation
- Compliance

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 FERC for authority to make market-based rate (MBR) sales. For a requesting company to receive MBR authority, 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. 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 FERC any material change in facts from those 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 were granted MBR authority from FERC in October 2014. In order to retain its MBR authority, each of these entities will be required to submit its power uprate compliance filing to FERC by the end of December 2016.

16

table of contents

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. FERC rules also govern the overall design of these markets. At present, all units within a delivery zone receive a 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) which can vary by location. In addition, recent rule changes in the energy markets administered by PJM and ISO-NE (see Capacity Market Issues below) impose rigorous performance obligations and nonperformance penalties on resources during times of system stress. These FERC rules have a direct impact on the prices received by our units.

FERC has also recently ordered certain favorable changes to energy market price formation rules improving shortage pricing and enhancing bidding flexibility for units. We continue to advocate in this context for additional changes in market rules that would provide more transparency about energy market prices. We cannot predict what action 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 FERC. FERC regulates these markets and continues to examine whether the market design for each of these three capacity markets is working optimally. Issues presented in various forums include consideration of whether capacity market rules properly address and foster the development of state public policies, demand response (DR) and emerging technologies, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market outcomes. We cannot predict what action, if any, 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. During 2015, PJM implemented a new “Capacity Performance” (CP) mechanism that created a more robust capacity product definition with enhanced incentives for performance during emergency conditions and significant penalties for non-performance. However, aspects of FERC’s order are currently pending on rehearing before the FERC Commission and, ultimately, appeals of FERC’s rehearing order are likely. The CP mechanism was implemented for the 2015 base residual auction (covering the 2018-2019 Delivery Year) which concluded on August 21, 2015. The CP product will be implemented fully for the 2020-2021 Delivery Year. Based upon the August 2015 base residual auction results, the CP mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power but future impacts cannot be assured. Further compliance with the CP mechanism may entail additional performance risks and require additional investments.

In May 2014, in a case involving the proper level of compensation for DR resources in the energy markets, the D.C. Circuit Court of Appeals (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, FERC filed a petition to the U.S. Supreme Court to review the D.C. Court's ruling. In January 2016, the U.S. Supreme Court overturned the D.C. Court’s ruling and determined that FERC has the authority to regulate wholesale DR and market operators’ compensation of DR bids at full market value. This ruling removes any risk to DR’s participation in the energy and capacity markets. As a result, we expect activity to continue at the PJM stakeholder process regarding eligibility criteria for DR, including as a CP resource.

In September 2014, PJM filed at FERC to re-set the Variable Resource Requirement (VRR) curve for the RPM. PJM expects to reset the VRR 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, 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 FERC’s approval order on rehearing, taking exception to FERC’s approval of the manner in which PJM calculated the cost of capital and labor costs that form the basis for the Cost of New Entry 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. Rehearing was denied in December 2015 and the PSEG Companies, and a trade association, have sought review of FERC’s order at the D.C. Court.

An emerging issue in PJM involves the impact of subsidized generation on RPM market outcomes. This issue is most directly presented in connection with proposals pending before the Ohio Public Utility Commission whereby First Energy Corp. and American Electric Power are proposing to enter into power purchase agreements (PPAs) with their non-utility generation affiliates providing for above-market purchases from certain coal plants and a nuclear plant. The subsidies under these contracts would likely enable the affected generators to submit reduced bids into PJM capacity markets that are not reflective of their actual costs of operation and may prevent uneconomic generating facilities from retiring. Either of these conditions could artificially suppress capacity market prices, especially given that PJM’s currently effective “minimum offer price rule” (MOPR) would not apply to these plants as the MOPR only applies to new gas-fired units.

table of contents

We are unable to predict the results of these pending proceedings or any future related proceedings or to calculate the potential impacts on our business.

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. Significant quantities of capacity from MISO are imported into PJM which tends to have a downward effect on PJM capacity prices. However, recent enhancements to PJM market rules have tightened eligibility requirements for PJM imports and reduced these impacts. The issue of "capacity portability" from MISO continues to be examined in the stakeholder process.

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. ISO-NE also employs a mechanism, similar to PJM's CP mechanism, that provides incentives for performance and that imposes penalties for non-performance during times of system stress. We view this mechanism as generally positive for generating resources as providing more robust income streams. However, it also imposes additional penalty risk for non-performance. One aspect of the current market design that we do not support is the exemption from the MOPR in the capacity market afforded for up to 200 MW annually (600 MW cumulatively) of renewable resources. We believe that the exemption is unduly discriminatory and will artificially suppress capacity prices. In March 2015, in conjunction with other companies, we filed a petition for review with the D.C. Court of FERC's ruling accepting the exemption. On December 1, 2015, following a request by FERC for a voluntary remand of the order, the D.C. Court remanded the case to FERC for additional consideration. Also in December 2015, ISO-NE filed a proposal that would allow resource owners to submit bids in the capacity auction reflecting their desire to retire a resource. However, this proposal also includes elements which we believe would have an unwarranted disruptive effect on efficient price formation in the capacity market. We have filed in opposition to this proposal. Finally, demand curves for ISO-NE capacity zones, including potential changes to the system-wide demand curves, are under consideration in an ISO-NE stakeholder process. These curves could 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. Various matters pending before FERC could affect the competitiveness of this market and the outcome of these proceedings could result in artificial price suppression unless sufficient market protections are adopted.

One capacity market matter pending before FERC involves rules to govern payments and bidding requirements for generators proposing to exit the market but required to remain in service for reliability reasons. On March 19, 2015, FERC issued an order which held that units receiving special reliability payments could properly take those payments into account in formulating capacity market bids. We believe that this ruling could impact efficient price formation in the capacity market and could artificially suppress capacity market outcomes. On April 20, 2015, a trade association, Independent Power Producers of New York, Inc. (IPPNY) of which Power is a member filed for rehearing by FERC of this ruling. This rehearing is still pending. Also, in connection with this same proceeding, FERC required NYISO to submit a report addressing whether buyer-side mitigation measures are needed for new entry occurring in the "Rest of State" region and for uneconomic retention and repowering anywhere in the state. NYISO filed a report with FERC in December 2015 contending that these measures are not needed. The IPPNY has opposed NYISO's contentions. In addition, on May 8, 2015, the New York Public Service Commission and other New York agencies filed a complaint at FERC requesting certain exemptions from the NYISO rules that prevent capacity suppliers from submitting bids that are not market competitive. On October 9, 2015, FERC granted in part, certain of the requested exemptions for renewable resources and for resources being used by the owner for self-supply. The IPPNY has sought rehearing of this order. This rehearing is still pending.

Price Formation Initiatives

Power has been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. A recent development which is designed to increase market transparency involves a November 20, 2015 order in which FERC directed each RTO/ISO to publicly provide information related to certain price formation issues. If FERC’s initiative leads to reforms in the identified price formation issue areas, it could result in energy market prices that more accurately reflect prevailing system conditions and the costs of operating the marginal generating units. Specifically, each RTO/ISO was required to submit information regarding: (1) the ability of inflexible resources to set price; (2) how simultaneously occurring system outages are reflected in the market model; (3) the tools to anticipate near-term system conditions; (4) the allocation of costs associated with units dispatched for reliability out-of-merit; and (5) transparency. Each RTO/ISO was also directed to file a report that provides an update on its current practices in the identified topic areas, that provides the status of its efforts (if any) to address each of the five issues, and that fully responds to the questions contained in the FERC order by March 4, 2016. Following the submission of the RTOs’/ISOs’ reports, FERC will allow for public comment. FERC will use the reports and comments to determine what further action is appropriate.

table of contents

Reactive Power Rates

In June 2015, Power submitted a tariff filing with FERC to increase Power’s rates for reactive supply and voltage control service from approximately $27 million per year to about $39 million per year. The rates were last adjusted in 2008 and since that time various generating units have been de-activated, activated or improved with the net impact supportive of an upward rate adjustment. FERC accepted Power’s rate filing increase to become effective in January 2016, subject to refund, hearing and settlement procedures. FERC also referred the filing to the FERC Office of Enforcement for its evaluation. Power has participated in two settlement conferences to date with the FERC Trial Staff. Following settlement discussion with FERC Trial Staff, Power agreed to accept an overall rate of $34 million per year. Approval of this rate increase is currently pending before FERC.

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.

In 2013, the U.S. District Court in New Jersey found that the LCAPP was unconstitutional and declared the LCAPP null and void. This federal court decision was subsequently challenged on appeal in the U.S. Third Circuit Court of Appeals (Third Circuit). 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 (Fourth Circuit). Both appeals were denied, with the Fourth Circuit denying the appeal regarding the State of Maryland’s action in June 2014 and the Third Circuit denying the LCAPP appeal in September 2014. These denials have been challenged on appeal to the U.S. Supreme Court. In October 2015, the U.S. Supreme Court announced that it would consider the appeal of the Fourth Circuit's decision involving Maryland. The U.S. Supreme Court will hear the case and is expected to issue a decision in 2016. We cannot predict the outcome of this appeal.

Transmission Regulation

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 2016 Formula Rate Update with FERC for approximately $146 million in increased annual transmission revenues went into effect on January 1, 2016. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. The adjustment for 2016 will include the impact of the extension of bonus depreciation, which was enacted after our 2016 filing was made, and is estimated to reduce our 2016 revenue increase as filed by approximately $27 million. For additional information about our transmission formula rate, see Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

Transmission Policy Developments—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 and other companies appealed Order 1000 but this appeal was denied in 2014 by the D.C. Court. The current PJM rules retain carve-outs for projects that will continue to default to incumbents for construction responsibility, including immediately needed reliability projects, upgrades to existing transmission facilities, projects cost-allocated to a single transmission zone, and projects being built on existing rights-of-way and whose construction would interfere with incumbents’ use of their rights-of-way. While these carve-outs ameliorate the impacts of the Order 1000 ruling, we and several other companies appealed various aspects of the FERC order approving PJM’s implementation of Order 1000 on the grounds that FERC had not met the requisite legal burden in eliminating the ROFR from the PJM Tariff. This appeal remains pending in federal court.

In April 2013, PJM 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 in New Jersey. On July 29, 2015, the PJM Board approved the PJM staff's recommendation for a transmission project consisting of various components to be constructed by LS Power, PSE&G and Potomac Holding Company. In August 2015, PJM sent PSE&G a Construction Responsibility Letter (to which PSE&G responded on November 9 and again on February 16, 2016) awarding PSE&G three components of the project, estimated by PJM to cost approximately $126 million. PSE&G has accepted construction responsibility, subject to reaching agreement with PJM on a reasonable cost estimate. Discussions are ongoing with PJM regarding the cost estimate for PSE&G's portion of the work. On February 18, 2016, FERC issued an order granting PSE&G’s request that it be permitted to seek recovery of 100% of its portion of the Artificial Island projects costs if the project

table of contents

is cancelled for reasons beyond PSE&G's control. PSE&G continues to work with both PJM and its stakeholders to improve the rules governing open window processes in PJM.

In a September 2015 order, FERC directed that a technical conference be held to address "concerns regarding how PJM plans for local transmission projects." Parties in the case raised concerns that too many projects are being approved outside of the Regional Transmission Expansion Plan (RTEP) mechanism to address "local" reliability requirements without going through the Order 1000 open window process. Intervenors also complained that there is inadequate transparency regarding the PJM transmission owners' consideration and selection of Supplemental Projects (which are not approved by the PJM Board). PSE&G is participating in the process before FERC in support of the current PJM processes. In addition, certain PJM stakeholders have proposed an examination of the current planning rules, including changes with regard to criteria to be used for replacement of facilities that have reached their "end of life." PSE&G intends to actively participate in this process. However, we are unable to predict the outcome of these efforts.

In a February 2016 order, FERC reversed a previous order and accepted a filing by the PJM transmission owners seeking authority to assign costs for RTEP projects (subject to PJM Board approval requirements) solely addressing localized needs to customers within the local transmission owner's zone. FERC's action in this order provides an exemption from the Order 1000 open window procedures for projects constructed by transmission owners to meet local transmission planning criteria.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. In addition, in a separate proceeding, a merchant transmission operator has sought rehearing of the May 2014 order granting PSE&G's request for incentives related to the Bergen-Linden Corridor Project (BLC), solely with respect to the cost allocation for that project. That rehearing request remains pending. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey and may cause increased scrutiny regarding PSE&G's future capital investments. In addition, Power, as a BGS supplier, submits bids into the auction and obtains an obligation to provide services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these transmission costs, BGS suppliers may be entitled to an adjustment. However, suppliers may not be able to recoup these adjustments immediately as they are subject to BPU approval.

In one proceeding, Con Edison filed a complaint against PJM at FERC in November 2014 challenging PJM's allocation of costs for two PSE&G projects in northern New Jersey, including the BLC. In June 2015, FERC issued an order dismissing the complaint. Con Edison and a merchant generator have sought judicial review of certain aspects of FERC's order and Con Edison has filed a rehearing request with FERC.

Another 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 advanced settlement discussions at FERC. Under possible settlement outcomes under consideration, Power, as a BGS supplier could become obligated to pay amounts previously paid by other PJM transmission customers. However, Power does not believe that the anticipated level of any such potential payments would have a material effect on Power's financial statements.

In another complaint proceeding against PJM, in May 2015 and as amended in July 2015, a merchant transmission operator challenged PJM's allocation of costs for four PSE&G projects, including BLC. PSE&G filed an opposition to the complaint and the matter is currently pending at FERC. In August 2015, the Delaware Public Service Commission and the Maryland Public Service Commission also filed a complaint against PJM and certain transmission owners that have voting rights over cost allocation and rate design, including PSE&G, alleging that PJM tariff provisions allocate an excessive share of the Artificial Island project costs to them relative to the actual benefits of the project to residents of Delaware and Maryland. PSE&G participated in a group filing of transmission owners that opposed the complaint. PJM also answered the Delaware/Maryland complaint but stated that the Artificial Island cost allocation appeared "disproportionate" and raised "equity concerns." On January 12, 2016, we participated in a technical conference at FERC related to PJM cost allocation with the stated purpose of determining whether special allocation rules are needed for reliability projects based upon the reliability needs other than insufficient flow capability over the affected transmission facilities. We are unable to predict the outcome of these proceedings.

In June 2015, a transmission developer filed a complaint against PJM claiming that PJM wrongfully refused to provide data and a transparent process for evaluating transmission network upgrade requests that the transmission developer had submitted to PJM. According to the complaint, PJM and certain transmission owners wrongfully inflated the scope and associated costs of mitigation work needed to accommodate the developer's proposal in order to prevent it from pursuing its projects. Although not named as a respondent in the complaint, PSE&G is identified as one of the companies claimed to have been involved. In July 2015, PJM filed a response, which included a supporting affidavit from PSE&G, contesting the allegations. Settlement conferences in this matter are currently on-going.

Transmission Rate Proceedings—Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base ROEs. Certain of those complaints have

table of contents

resulted in decisions and others have been settled, resulting in reductions of 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, FERC commenced an audit of each of the PSEG companies that have MBR authority from FERC. The companies were audited by 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, 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 FERC explaining how we intend to implement FERC’s recommendations and we thereafter provided quarterly updates to FERC reporting on our progress in implementing the recommendations. At this time, we have satisfied all of FERC’s requirements.

FERC—For information about the preliminary non-public investigation initiated by the FERC Staff regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Reliability Standards—Congress has required FERC to put in place, through the North American Electric Reliability Council (NERC), national and regional reliability standards to ensure the reliability of the U.S. 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, 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, 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. We are on schedule to meet all NERC requirements.

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

table of contents

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 in 2016.

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 Item 8. Financial

Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities.

Energy Strong Program—In May 2014, the BPU issued an Order approving our Energy Strong program which provides for investment in our BPU jurisdictional electric and gas system to improve resiliency for the future. Under the settlement, PSE&G will invest up to $1.2 billion over an initial five-year period. The Order 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 investment in PSE&G's next base rate case. See Business—PSE&G—Distribution for additional information about Energy Strong.

table of contents

During 2015, the BPU approved two Energy Strong petitions which allow us to recover in base rates capitalized Energy Strong investment costs for projects placed in service through May 31, 2015. The BPU Orders provide for a total $24 million annual revenue increase.

Gas System Modernization Program (GSMP)—In November 2015, the BPU issued an Order approving the settlement of our GSMP through which PSE&G will invest $905 million over the next three years to modernize its gas system. The settlement enables the utility to replace up to 510 miles of gas mains and 38,000 service lines over a three-year period, with cost recovery at a 9.75% rate of return on equity on $650 million of the investment through an accelerated recovery mechanism. Under the settlement, PSE&G will seek recovery of the remaining $255 million of investment in its next base rate case. We expect to file our first investment recovery petition in 2016.

Connecticut Rate Filing—In June 2015, Power’s subsidiary, PSEG New Haven LLC, filed a mandatory annual rate case with the Connecticut Public Utilities Regulatory Authority (PURA) for recovery of its costs and investment in its Connecticut-based PSEG New Haven LCC peaking units. Power requested 2016 revenues of $21 million. On November 18, 2015, PURA issued a Final Decision to approve the entirety of Power’s request. The newly approved rates are effective as of January 1, 2016.

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. All briefs have been filed and 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. An update to the December 2011 EMP was released on December 31, 2015 which continued to emphasize the policies set forth in the December 2011 EMP while also addressing certain issues that have emerged since that time, placing an emphasis on improved system resiliency, critical energy infrastructure, emergency preparedness and cybersecurity.

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

ENVIRONMENTAL MATTERS

We are subject to federal, state and local laws and regulations with regard to environmental matters including, but not limited to:

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

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. Such laws and regulations may also affect the timing, cost, location, design, construction and operation of new facilities. 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.

table of contents

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 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 Mercury Air Toxics Standards (MATS) for both newly-built and existing electric generating sources under the National Emission Standard for Hazardous Air Pollutants (NESHAP) provisions of the CAA. The MATS established allowable levels for mercury as well as other hazardous air pollutants and went into effect in April 2015. On June 29, 2015, the U.S. Supreme Court held that it was unreasonable for the EPA to refuse to consider the materiality of costs in determining whether to regulate hazardous air pollutants from power plants and remanded the matter back to the D.C. Court. On December 15, 2015, the D.C. Court remanded the MATS to the EPA without vacating the rule. On December 1, 2015, the EPA proposed a Supplemental Finding that considers the materiality of costs in determining whether to regulate hazardous air pollutants from power plants in response to the U.S. Supreme Court's June ruling.
- 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. Among other things, the NESHAP include two exemptions that allow owners and operators of stationery emergency RICE to operate their engines without the installation and operation of emission controls (1) as part of an emergency DR program for 100 hours per year (100 hour exemption) or (2) as part of a financial arrangement with another entity per specified restrictions in non-emergency situations for 50 hours per year (50 hour exemption). 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. On May 1, 2015, the D.C. Court vacated the 100 hour exemption but thereafter granted a stay until May 1, 2016. On September 23, 2015, the D.C. Court granted the EPA's motion for voluntary remand of the 50 hour exemption provision to the EPA. While both provisions remain in place, the EPA will undergo proceedings to address the D.C. Court's orders. We believe that the impact of the D.C. Court's rulings would likely benefit Power's and its competitors' operations of their power generation peaking units.
- Cross-State Air Pollution Rule (CSAPR)—On January 1, 2015, the final CSAPR became effective which limits power plant emissions of Sulfur Dioxide (SO_2) and annual and ozone season nitrogen oxide (NO) in 28 states that contribute to the ability of downwind states to attain and/or maintain the 1997 and 2006 particulate matter and the 1997 ozone National Ambient Air Quality Standards (NAAQS). On April 6, 2015, the EPA revoked the 1997 ozone NAAQS of 80 parts per billion (ppb) and began implementation of the more stringent 2008 ozone NAAQS of 75 ppb. On December 3, 2015, the EPA published the proposed CSAPR Updating Rule to address the 2008 ozone NAAQS. The proposal establishes more stringent annual ozone season (May 1 through September 30) caps beginning May 1, 2017. We do not anticipate any material impact on our earnings or financial condition due to the CSAPR.
- Ozone Standard—In December 2014, the EPA proposed a rule to lower the ambient air quality standard for the level of ozone in the atmosphere from 75 ppb to a level in the range of 65-70 ppb. On October 1, 2015, the EPA finalized a standard of 70 ppb. To meet the new standard, the EPA and the states have to implement additional emission reduction strategies for NO and volatile organic compounds. Some portions of the Mid-Atlantic and New England states are not expected to be able to meet the new standard. Although the majority of our fossil generating units employ state-of-the-art NO emission controls, we cannot predict the outcome of this matter since new requirements of

the EPA and the states are unknown at this time. Numerous parties have filed petitions for review with the D.C. Court to challenge the rule.

table of contents

Climate Change

- CO_2 Regulation under the CAA—On October 23, 2015, the EPA published the New Source Performance Standards (NSPS) for new power plants. The NSPS establishes two emission standards for CO_2 for the following categories: (i) fossil fuel-fired utility boilers and integrated gasification combined cycle (IGCC) units, and (ii) natural gas combustion turbines. Simple cycle combustion turbines are exempt from the rule.

On October 23, 2015, the EPA published the Clean Power Plan (CPP), a greenhouse gas (GHG) emissions regulation under the CAA 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 three components: (i) heat rate improvements at existing coal-fired power plants, (ii) increased use of existing natural gas combined cycle capacity, and (iii) operation of incremental zero-emitting generation (renewables and nuclear). States may choose these or other methodologies to achieve the necessary reductions of CO_2 emissions.

Each state must submit a compliance plan to the EPA by September 6, 2016 or seek a two-year extension to September 6, 2018. States can comply using an emission rate-based plan (pounds CO_2/MWh) or a mass-based plan (tons). Compliance with the final rule is effective January 1, 2022.

The EPA, FERC and the U.S. Department of Energy (DOE) announced that they plan to meet at least quarterly to evaluate states' plans and identify reliability concerns so adjustments can be made before the final plans are submitted. The agencies are engaging various stakeholders, including the Regional Transmission Operators/Independent System Operators. The agencies will continue to meet after the states' plans are in effect to assess if revisions are required.

On October 23, 2015, the EPA also published proposed federal implementation requirements for states that do not submit an EPA-approved compliance plan. Comments were due by January 21, 2016.

Numerous states, including New Jersey, and several industry groups filed petitions for review with the D.C. Court to challenge the CPP. In addition, the petitioners sought a stay of the rule. On January 21, 2016, the D.C. Court declined to stay the CPP. However, on February 9, 2016, the U.S. Supreme Court stayed the rule pending further review of the case.

The U.S. Supreme Court's decision to stay the implementation of the CPP will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted.

- 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.

On November 17, 2015 the RGGI States initiated a 2016 Program Review stakeholder process. The focus of the 2016 Program Review is the post-2020 caps on GHG emissions and the incorporation of the EPA's CPP requirements.

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. On August 3, 2015, the NJDEP published its formal repeal of the rules implementing RGGI in New Jersey.

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.

table of contents

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—On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Mercer and Bridgeport Harbor stations and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. We are unable to predict if this rule will have a material impact on our future capital requirements, financial condition and results of operations.

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.

- Cooling Water Intake Structure Regulation—In May 2014, the EPA issued a final cooling water intake rule under Section 316(b) of the Clean Water Act (CWA) 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 has structured the rule so that each state Permitting Director 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 a 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 petitions for review of the rule and the case has been assigned to the U.S. Second Circuit Court of Appeals (Second Circuit). Environmental organizations, including but not limited to the environmental petitioners in the Second Circuit, have also filed suit under the Endangered Species Act (ESA) challenging the Biological Opinion issued by U.S. Fish & Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS) on the 316(b) rule in the U.S. District Court for the Northern District of California. Parties to these cases filed motions seeking to consolidate this secondary action with the primary case residing with the Second Circuit. The Second Circuit has agreed to consolidate the case and to allow industry petitioners to amend their petition to include review of the Biological Opinion issued by the FWS and NMFS and to add both parties as Respondents. This means that the FWS and NMFS will be parties to the 316(b) litigation, and the ESA claims against them will not be proceeding in the U.S. District Court. Briefings before the court are scheduled to begin in 2016 but the schedule has not yet been established.

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 Item 8. Financial Statements and Supplementary Data— Note 12. Commitments and Contingent Liabilities for additional information.

On June 30, 2015, the NJDEP issued a draft New Jersey Pollutant Discharge Elimination System (NJPDES) permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit was subject to a public notice and comment period. We participated in the NJDEP's August 5, 2015 public hearing and submitted comments on the draft permit on September 18, 2015. The NJDEP may make revisions before issuing the

table of contents

final permit which is expected in the first half of 2016. For additional information, see Item 8. Note 12. Commitments and Contingent Liabilities.

We are actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA's CWA Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, we would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire the BH3 within five years of the effective date of the final permit. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in the summer of 2016 indicating a potential retirement date for BH3 by summer 2021, which is four years earlier than the current estimated useful life ending in 2025. If the permit is not issued and the conditions below are not met, we will seek to operate BH3 through the current estimated useful life.

Separately, we have also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that we would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates, which could occur in 2017. Absent those conditions being met, and the permit renewal referred to above not being issued, we will seek to operate BH3 through the current estimated useful life. In February 2016, the proposed generating facility was awarded a capacity obligation. Construction is expected to commence in 2017, with operations expected to begin in mid-2019.

- 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 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. The final rule was published on June 29, 2015 and we are reviewing it to determine the materiality of the impacts that might result from the final rule. Some states, including New Jersey, are subject to state requirements beyond those imposed under federal law. While we do not anticipate material impacts to projects in New Jersey, the new definition could impose requirements in other states and regions that could impact the development of renewables.

Various states, industry coalitions and environmental organizations have initiated legal action related to the provisions of the final rule. On October 9, 2015, the Sixth Circuit Court of Appeals issued a stay of the rule pending further court action.

- Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance—In April 2015, we determined that monitoring and reporting practices related to certain permitted wastewater discharges at our Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject us to fines and penalties. We have notified the CTDEEP of the issues and have taken actions to investigate and resolve the potential non-compliance. We cannot predict the impact of this matter.
- Endangered Species Act—On June 16, 2015, the Sierra Club and another environmental group submitted to the NJDEP a sixty-day notice of intent to sue alleging the agency has caused violations of the Endangered Species Act by allowing our Mercer generation station to operate in a manner which has caused the mortality of certain species of sturgeon. Among other things, the notice requested the NJDEP to prioritize completion of a permit renewal action for Mercer which addresses the alleged Endangered Species Act violations. We cannot predict the outcome of this action.

Hazardous Substance Liability

The production and delivery of electricity and the distribution and 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. The EPA is also evaluating the Hackensack River, a tributary to Newark Bay, for inclusion in the Superfund program. We no longer manufacture gas. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

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-

table of contents

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 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. Since May 2014, the DOE reduced the nuclear waste fee to zero. Prior to the elimination of this fee, the annualized pre-tax cost was 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)—On December 19, 2014, the EPA issued a final rule 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. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. The impact of this final rule was not material to our results of operations, financial condition or cash flows. See Item 8. Note 12. Commitments and Contingent Liabilities for additional information.

SEGMENT INFORMATION

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

table of contents

EXECUTIVE OFFICERS OF THE REGISTRANT (PSEG)

Name	Age as of December 31, 2015	Office	Effective Date First Elected to Present Position
Ralph Izzo	58	Chairman of the Board, President and Chief Executive Officer (PSEG)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (PSE&G)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Power)	
		Chairman of the Board and Chief Executive Officer (Energy Holdings)	April 2007 to present
		Chairman of the Board and Chief Executive Officer (Services)	January 2010 to present
Daniel J. Cregg	52	Executive Vice President and CFO (PSEG)	October 2015 to present
		Executive Vice President and CFO (PSE&G)	October 2015 to present
		Executive Vice President and CFO (Power)	October 2015 to present
		Vice President-Finance (PSE&G)	June 2013 to October 2015
		Vice President-Finance (Power)	December 2011 to June 2013
		President (Energy Resources & Trade LLC)	May 2011 to December 2011
		Vice President-Finance (Power)	December 2006 to May 2011
William Levis	59	President and Chief Operating Officer (Power)	June 2007 to present
Ralph LaRossa	52	President and Chief Operating Officer (PSE&G)	October 2006 to present
		Chairman of the Board of PSEG Long Island LLC	October 2013 to present
Derek M. DiRisio	51	President (Services)	August 2014 to present
		Vice President and Controller (PSEG)	January 2007 to August 2014
		Vice President and Controller (PSE&G)	January 2007 to August 2014
		Vice President and Controller (Power)	January 2007 to August 2014
		Vice President and Controller (Energy Holdings)	January 2007 to August 2014
		Vice President and Controller (Services)	January 2007 to August 2014
Stuart J. Black	53	Vice President and Controller (PSEG)	August 2014 to present
		Vice President and Controller (PSE&G)	August 2014 to present
		Vice President and Controller (Power)	August 2014 to present
		Vice President (Services) and Assistant Controller (Power)	March 2010 to August 2014
		Vice President of Internal Auditing Services (Services)	January 2005 to March 2010
Tamara L. Linde	51	Executive Vice President and General Counsel (PSEG)	July 2014 to present
		Executive Vice President and General Counsel (PSE&G)	July 2014 to present
		Executive Vice President and General Counsel (Power)	July 2014 to present
		Vice President - Regulatory (Services)	December 2006 to July 2014

table of contents

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 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 have a major impact on the price that generators receive for their output, especially in periods of relatively weak or 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. Consequently, our margin may continue to be reduced as a result of sustained lower electricity prices.

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,
- 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,
- environmental regulation and legislation,
- weather conditions,
- electric supply disruptions, including plant outages and transmission disruptions, and
- development of new fuels and new technologies for the production of power.

table of contents

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, 2015, it may have had to provide approximately $864 million in additional collateral.

- 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 our 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 the default mechanisms that 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 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, including business management, the terms and rates of transmission and distribution services, investment strategies, the financing of our operations and the payment of dividends, as well 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 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. As a result of our Energy Strong order, we are required to file our next base rate case proceeding no later than November 1, 2017. In addition, our utility has received approval for several clause recovery mechanisms, some of which provide for recovery of costs and earn returns on authorized investments. These clause mechanisms require periodic updates to be reviewed and approved by the BPU and are subject to prudency reviews. Our utility's transmission rates are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. The formula rate is also subject to prudency review. In addition, transmission ROEs have recently become the target of certain state utility commissions, municipal utilities, consumer advocates and consumer groups seeking to lower customer rates. These agencies and groups have filed complaints at FERC asking 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 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 be required to obtain 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.

table of contents

- 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, 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 connection with an ongoing investigation by the FERC Staff regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units, we may incur potential disgorgement and other penalties which span a wide range depending on the success of our legal arguments. If our legal arguments do not prevail in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to PSEG’s and Power’s results of operations in the quarterly and annual periods in which they are recorded. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

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 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.

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 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 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. Any such addition to the transmission

system could have a material adverse impact on our financial condition and results of operations.
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

table of contents

PJM cost allocation determinations have been recently challenged at FERC, the resolution of which could impact costs borne by New Jersey ratepayers and increase customer bills.

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, the 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. Changes in these laws, or violations of existing laws, could result in significant increases in our compliance costs, capital expenditures to bring existing facilities into compliance, operating costs for remediation and clean-up actions, civil penalties or damages from actions brought by third parties for alleged health or property damages. Any such increase in our costs could have a material impact on our financial condition, results of operations and cash flows. We may also be unable to successfully recover certain of these cost increases through existing regulatory rate structures or our contracts with our customers.

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,
- limit or prevent continued operation of existing facilities,
- limit or prevent the sale of energy from these facilities, or
- result in significant additional costs, each of which could materially affect our business, financial condition, 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 emissions 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. For example, in 2015 the EPA published new rules for both new and existing power plants. We may be required to incur significant costs to comply with these regulations and to continue operation of our fossil generation facilities, which could include 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—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 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 CTEEP were to require installation of closed-cycle cooling or its equivalent at any of 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 cash flows and would require further economic review to determine whether to continue operations or decommission any such station.

- 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

table of contents

associated with our former Manufactured Gas Plant (MGP) operations are one source of such costs. In addition, the historic operations of PSEG companies and the operations of numerous 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 in violation of various statutes. The EPA is also evaluating the Hackensack River, a tributary to Newark Bay, for inclusion in the Superfund program. We are also 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. For a discussion of these and other environmental matters, see Item 8. Note 12. Commitments and Contingent Liabilities.

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

More than half of our total generation output each year is provided by our nuclear fleet, which comprises approximately one-third 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.

In the event of non-compliance with applicable legislation, regulation and licenses, the NRC may increase regulatory oversight, impose fines, and/or shut down a unit, depending on its assessment of the severity of the non-compliance. If a serious nuclear incident were to occur, our business, reputation, financial condition and results of operations could be materially adversely affected. In each case, the amount and types of insurance commercially available to cover losses that might arise in connection with the operation of our nuclear fleet are limited and may be insufficient to cover any costs we may incur.

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 or 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,

table of contents

capacity, ancillary services and fuel supply in the markets served. A decrease in prevailing market prices could have a material adverse effect on our financial condition and results of operations.

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.

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.

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, including prolonged periods of adverse commodity and capacity prices, 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 on acceptable terms or at all.

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,

table of contents

- utilities,
- banks, funds and other financial entities,
- fuel supply companies,
- affiliates of other industrial companies, and
- distributed generation.

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 which could adversely affect our financial condition and results of operations.
- 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 solar installations, 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. Advances in these or other technologies could reduce the cost of power production, increase reliance by customers on on-site generation, including solar, and changes in customer behaviors could result in decreased reliance on our system, each of which could adversely impact our cash flows, financial condition, results of operations, competitive position and investment opportunities.

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.

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 and harm our reputation. 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, fines/penalties, 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.

table of contents

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 business and results of 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 our 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 and transmission and distribution facilities, all of which are dependent on the operation of our information technology systems. Our ability to market our generation output and acquire and hedge fuel and power are also dependent on our information technology systems. Our information technology 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.

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 security measures we have taken and will take in the future can protect us against all possible occurrences.
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, 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. This could have a material adverse effect on our financial condition, results of operations and cash flows.

table of contents

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 unable to realize anticipated tax benefits or retain existing tax credits.
The deferred tax assets and tax credits of PSEG, PSE&G or Power are evaluated for ultimate realizability. While presently not the case, a valuation allowance may be recorded against the deferred tax assets if we estimate that such assets are more likely than not to be unrealizable. A valuation allowance related to deferred tax assets or the monetization of tax credits can be affected by changes to tax laws, statutory tax rates and future taxable income levels. In the event that we determine that we would not be able to realize all or a portion of our deferred tax assets in the future or the benefit of tax credits, we would reduce such amounts through a charge to income tax expense in the period in which that determination was made, which could have a material adverse impact on our financial condition and results of operations.
Because PSEG is a holding company, its ability to meet its corporate funding needs, service debt and pay dividends could be limited.
PSEG is a holding company with no material assets other than the stock or membership interests of its subsidiaries and project affiliates. Accordingly, all of the operations of PSEG are conducted by its subsidiaries and project affiliates which are separate and distinct legal entities that have no obligation, contingent or otherwise, to pay any amounts when due on the debt of, or to make any funds available to PSEG to pay such amounts and satisfy its other corporate funding needs. These corporate funding needs include PSEG's operating expenses, the payment of interest on and principal of its outstanding indebtedness and the payment of dividends on its capital stock. As a result, PSEG can give no assurances that its subsidiaries and project affiliates will be able to transfer funds to PSEG to meet all of these obligations.
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.
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.

table of contents

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 Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Generation Facilities

Power

As of December 31, 2015, Power's share of 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	451	100%	451	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	447	100%	447	Oil/Gas	Load Following
Total Steam		5,955		3,309		
Nuclear:						
Hope Creek	NJ	1,176	100%	1,176	Nuclear	Base Load
Salem 1 & 2	NJ	2,294	57%	1,317	Nuclear	Base Load
Peach Bottom 2 & 3 (B)	PA	2,502	50%	1,251	Nuclear	Base Load
Total Nuclear		5,972		3,744		
Combined Cycle:						
Bergen	NJ	1,229	100%	1,229	Gas/Oil	Load Following
Linden	NJ	1,242	100%	1,242	Gas/Oil	Load Following
Bethlehem	NY	757	100%	757	Gas	Load Following
Kalaeloa	HI	208	50%	104	Oil	Load Following
Total Combined Cycle		3,436		3,332		
Combustion Turbine:						
Essex	NJ	81	100%	81	Gas/Oil	Peaking
Kearny	NJ	456	100%	456	Gas/Oil	Peaking
Burlington	NJ	168	100%	168	Gas/Oil	Peaking
Linden	NJ	336	100%	336	Gas/oil	Peaking
New Haven Harbor	CT	129	100%	129	Gas/Oil	Peaking
Bridgeport Harbor	CT	17	100%	17	Oil	Peaking
Total Combustion Turbine		1,187		1,187		
Pumped Storage:						
Yards Creek (C)	NJ	420	50%	210		Peaking
Total Power Plants		16,970		11,782		

(A) Operated by GenOn Northeast Management Company
(B) Operated by Exelon Generation.
(C) Operated by Jersey Central Power & Light Company.

As of December 31, 2015, Power also owned and operated 148 MW direct current (dc) of photovoltaic solar generation facilities in various states.

PSE&G

As of December 31, 2015, PSE&G had 114 MW-dc of installed solar capacity throughout New Jersey.

table of contents

Transmission and Distribution Facilities

PSE&G

As of December 31, 2015, PSE&G's electric transmission and distribution system included 24,022 circuit miles, of which 8,226 circuit miles were underground, and 848,496 poles, of which 549,636 poles were jointly-owned. Primarily all of this property is located in New Jersey.

In addition, as of December 31, 2015, PSE&G owned four electric distribution headquarters and five subheadquarters in four operating divisions, all located in New Jersey.

As of December 31, 2015, 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, 2015, PSE&G owned and operated 18,112 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 60 natural gas metering and regulating stations, all located in New Jersey, of which 24 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, 2015, PSE&G owned 43 switching stations in New Jersey with an aggregate installed capacity of 29,090 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.

table of contents

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 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 Potential Responsible Party (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 Remedial Investigation and Feasibility Study (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, as the current owner of the Gates Construction Corporation Landfill, received a letter from the NJDEP asserting 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.

table of contents

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 February 19, 2016, there were 66,445 registered holders.

The graph below shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2010 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.

	2010	2011	2012	2013	2014	2015
PSEG	$100.00	$108.20	$104.91	$114.72	$153.93	$149.45
S&P 500	$100.00	$102.12	$118.38	$156.64	$177.99	$180.50
DJ Utilities	$100.00	$119.59	$121.49	$136.89	$178.61	$173.21
S&P Electrics	$100.00	$119.81	$121.30	$137.31	$176.88	$168.37

table of contents

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
2015			
First Quarter	$44.45	$39.00	$0.39
Second Quarter	$43.97	$38.93	$0.39
Third Quarter	$43.91	$38.16	$0.39
Fourth Quarter	$44.18	$36.80	$0.39
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

On February 16, 2016, our Board of Directors approved a $0.41 per share common stock dividend for the first quarter of 2016. This reflects an indicative annual dividend rate of $1.64 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.
The following table indicates our common share repurchases in the open market during the fourth quarter of 2015 to satisfy obligations under various equity compensation award grants:

Three Months Ended December 31, 2015	Total Number of Shares Purchased	Average Price Paid per Share
October 1-October 31	—	$—
November 1-November 30	199,102	$40.47
December 1-December 31	20,000	$38.28

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2015:

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	1,707,250	$36.00	15,248,540
Employee Stock Purchase Plan	—	—	3,589,032
Total	1,707,250	$36.00	18,837,572

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 2015 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 2015 and Future Outlook.

table of contents

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,	2015	2014	2013	2012	2011
	Millions, except Earnings per Share				
Operating Revenues (A)	$10,415	$10,886	$9,968	$9,781	$11,079
Income from Continuing Operations (B)	$1,679	$1,518	$1,243	$1,275	$1,407
Net Income	$1,679	$1,518	$1,243	$1,275	$1,503
Earnings per Share:					
Income from Continuing Operations					
Basic (A)	$3.32	$3.00	$2.46	$2.52	$2.78
Diluted (A)	$3.30	$2.99	$2.45	$2.51	$2.77
Net Income					
Basic	$3.32	$3.00	$2.46	$2.52	$2.97
Diluted	$3.30	$2.99	$2.45	$2.51	$2.96
Dividends Declared per Share	$1.56	$1.48	$1.44	$1.42	$1.37
As of December 31,					
Total Assets (C)	$37,535	$35,287	$32,480	$31,694	$29,791
Long-Term Obligations (C) (D)	$8,837	$8,218	$7,830	$6,670	$7,452

(A) Operating Revenues for 2015 and 2014 includes $375 million and $389 million, respectively, for Long Island Electric Utility Servco, LLC (Servco), a wholly owned subsidiary of PSEG Long Island LLC (PSEG LI). See Item 8. Financial Statements and Supplementary Data—Note 3. Variable Interest Entities for additional information.

(B) Income from Continuing Operations includes an after-tax insurance recovery for Superstorm Sandy of $102 million for 2015 and an after-tax charge of $170 million for 2011 related to certain leveraged leases.

(C) Total Assets and Long-Term Obligations for the years ended December 31, 2014, 2013, 2012 and 2011 include reclassified debt issuance costs from Noncurrent Assets to Long-Term Debt of $46 million, $42 million, $31 million and $30 million, respectively. See Item 8. Financial Statements and Supplementary Data—Note 2. Recent Accounting Standards for additional information.

(D) Includes capital lease obligations.

PSE&G and Power

Omitted pursuant to conditions set forth in General Instruction I of Form 10-K.

table of contents

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 is engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU, and
- Power, our multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy transacting functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. Power’s subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA), and the states in which they operate.

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 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 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 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 2015 and key factors that we expect may 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 2015 AND FUTURE OUTLOOK

2015 Overview

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand. 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 and other infrastructure projects, and
- maintaining and expanding a reliable generation fleet with the flexibility to utilize a diverse mix of fuels which allows us to respond to market volatility and capitalize on opportunities as they arise.

table of contents

Financial Results
The results for PSEG, PSE&G and Power for the years ended December 31, 2015 and 2014 are presented below:

	Years Ended December 31,	
	2015	2014
Earnings (Losses)	Millions, except per share data	
PSE&G	$787	$725
Power	856	760
Other	36	33
PSEG Net Income	$1,679	$1,518
PSEG Net Income Per Share (Diluted)	$3.30	$2.99

Our $161 million 2015 over 2014 increase in Net Income was due primarily to higher transmission revenues at PSE&G, higher mark-to-market (MTM) gains and lower generation costs driven by lower natural gas and coal prices at Power and insurance recoveries of Superstorm Sandy costs, primarily at Power. These increases were partially offset by higher pension and other postretirement benefit (OPEB) costs and lower capacity revenues and Nuclear Decommissioning Trust (NDT) activity at Power. For a more detailed discussion of our financial results, see Results of Operations.

During 2015, we grew earnings, maintained cash flows and sustained a strong balance sheet. We effectively deployed capital without the need for additional equity, while our solid credit ratings aided our ability to access capital and credit markets. The greater emphasis on capital spending for projects on which we receive contemporaneous returns at PSE&G, our regulated utility, in recent years has yielded strong results and allowed us to increase our dividend. These actions to transition our business to meet market conditions and investor expectations reflect our multi-year, long-term approach to managing our company. Our focus has been to invest capital in T&D and other infrastructure projects aimed at maintaining service reliability to our customers and bolstering our system resiliency. At Power, our merchant generator, we strive to improve performance and reduce costs in order to enhance the value of our generation fleet in light of low gas prices, environmental considerations and competitive market forces that reward efficiency and reliability.

At PSE&G, in 2015 we continued to make investments and seek recovery on such investments made to improve the resiliency of our gas and electric distribution system as part of our Energy Strong program that was approved by the BPU in 2014. As approved, the Energy Strong program provides for up to $1.2 billion of investment, with 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 up to $220 million of investment in PSE&G's next base rate case, which is to be filed no later than November 1, 2017.

In November 2015, the BPU approved our settlement with the BPU Staff and the New Jersey Division of Rate Counsel regarding PSE&G’s Gas System Modernization Program (GSMP) through which we will invest $905 million over three years to modernize PSE&G's gas systems. The order provides for cost recovery at a 9.75% rate of return on equity on the first $650 million of the investment through an accelerated recovery mechanism. PSE&G will seek recovery of the remaining $255 million of investment in its next base rate case. For additional information, see Item 1. Business—Regulatory Issues—State Regulation.

Effective January 1, 2015, PSE&G's formula rate increased our annual transmission revenues by approximately $182 million. Each year, we file estimated transmission revenues subject to true up with actual current year data. The true-up adjustment for 2015, which will be filed in the Spring of 2016, will primarily include the impact on rate base of the extension of bonus depreciation, which was enacted after the filing was made, and is estimated to reduce our 2015 annual revenue increase by approximately $21 million. In October 2015, we filed our 2016 Annual Formula Rate Update with FERC, which will provide $146 million in increased annual transmission revenues effective January 1, 2016. Our 2016 transmission revenues will be adjusted for the impact of the continued extension of bonus

depreciation, which was enacted after our 2016 filing was made, and is estimated to reduce our 2016 revenues as filed by approximately $27 million.
Over the past few years, these types of investments have altered our business mix to reflect a higher percentage contribution by PSE&G.
During 2015, Power successfully improved its performance for both nuclear and fossil operations, with continued upgrades in efficiency and output, while mitigating environmental impacts. Power’s results benefited from access to natural gas supplies through its existing firm pipeline transportation contracts. Power manages these contracts for the benefit of PSE&G’s customers through the basic gas supply service (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

table of contents

make third party sales and supply gas to its generating units in New Jersey. Power's strategic hedging practices and ability to use market conditions to its advantage help it to balance some of the volatility of the merchant power business.

Three recent investments reflect our recognition of the value of opportunistic growth in the Power business. In June 2015, we acquired a development project to construct a 755 MW gas-fired combined cycle generating station (Keys Energy Center) in Maryland with completion expected in 2018 at an estimated investment of $825 million - $875 million. In August 2015, we announced our plan to construct Sewaren 7, a new 540 MW dual-fueled combined cycle generating plant in Woodbridge, New Jersey, scheduled to be in-service for the summer of 2018 at an estimated investment of $625 million - $675 million. The Sewaren 7 plant will replace Sewaren Units 1, 2, 3 and 4. In February 2016, we announced our plan to build Bridgeport Harbor Station 5 (BH5), a 485 MW gas-fired combined cycle generating plant on our existing Bridgeport Harbor station site in Bridgeport, Connecticut scheduled to be in-service for the summer of 2019 at an estimated investment of more than $550 million. These additions to our fleet expand our geographic diversity and are expected to contribute to the overall efficiency of operations.

In the PJM capacity auction held in August 2015 for the 2018-2019 delivery year, Power cleared 8,634 MW of its generating capacity at an average price of $215 MW-day. The capacity that Power cleared for the 2018-2019 delivery year included Sewaren 7 and Keys Energy Center generation plants. In the two prior PJM capacity auctions covering the 2016-2017 and 2017-2018 delivery years, Power cleared approximately 8,700 MW at average prices of $172 MW-day and $177 MW-day, respectively. In The ISO-NE auction held in February 2016, Power cleared BH5 at an average price of $232 MW-day for the 2019-2020 delivery year.

Regulatory, Legislative and Other Developments

In our pursuit of operational excellence, financial strength and disciplined investment, we closely monitor and engage with stakeholders on 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

FERC's rule under Order 1000 altered the right of first refusal (ROFR) previously held by incumbent utilities to build transmission within their respective service territories, creating the potential that new transmission projects in our service territory could be assigned to third parties rather than PSE&G. Order 1000 also presents opportunities for us to construct transmission outside of our service territory. In April 2013, PJM Interconnection, L.L.C. (PJM) initiated a 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 in New Jersey. In August 2015, PJM awarded PSE&G three components of the transmission project, estimated by PJM to cost approximately $126 million. PSE&G has accepted construction responsibility, subject to reaching agreement with PJM on a reasonable cost estimate. Discussions are ongoing with PJM regarding the cost estimate for PSE&G's portion of the work. See Item 1. Business—Regulatory Issues—Federal Regulation—Transmission Regulation for additional information.

There are several matters pending before FERC that concern the allocation of costs associated with transmission projects being constructed by PSE&G. Regardless of how these proceedings are resolved, PSE&G's ability to recover the costs of these projects will not be affected. However, the result of these proceedings could ultimately impact the amount of costs borne by ratepayers in New Jersey and may cause increased scrutiny regarding PSE&G's future capital investments. In addition, Power, as a basic generation service (BGS) supplier, submits bids into the auction and obtains an obligation to provide services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these transmission costs, BGS suppliers may be entitled to an adjustment. However, suppliers may not be able to recoup these adjustments immediately as they are subject to BPU approval. We do not believe that these matters will have a material effect on Power's financial statements.

Wholesale Power Market Design

Capacity market design, including the Reliability Pricing Model (RPM) in PJM, remains an important focus for us. In May 2014, a federal court issued a rule that vacated a FERC Order in which FERC had determined that demand response (DR) providers should receive full market compensation for power and held that FERC has no jurisdiction over DR. In January 2016, the U.S. Supreme Court overturned the federal court's decision which removed any risk to DR's participation in the energy and capacity markets.

In a separate development of significance to the wholesale capacity market, in December 2014 PJM filed at FERC its proposal for a capacity performance (CP) product to include generators, DR and energy efficiency providers, which will be required to perform during emergency conditions, as a supplement to the base capacity product. The proposal included enhanced performance-based incentives and penalties. In June 2015, FERC conditionally accepted the proposal and the CP mechanism was implemented for the 2015 capacity auction noted above. We believe that the auction pricing adequately reflects the

table of contents

increased costs that could result from operating under more stringent rules for generation availability. Based on the auction results, the CP mechanism appears to have provided the opportunity for enhanced capacity market revenue streams for Power, but future impacts cannot be assured. Further, there may be requirements for additional investment and there are additional performance risks.

Applications for rehearing of FERC's capacity performance order are pending. See Item 1. Business—Regulatory Issues—Federal Regulation—Capacity Market Issues for additional information.

We have also been actively involved both through stakeholder processes and through filings at FERC in seeking improvements to the rules for setting prices for energy in the day-ahead and real-time markets administered by PJM and other system operators. A November 2015 development which we view as positive involves both a notice of proposed rulemaking on dispatch intervals and scarcity pricing and a separate order directing the system operators to submit reports on five other price formation issues. We believe that, if implemented, these changes will improve energy price formation in the future.

See Item 1. Business—Regulatory Issues—Federal Regulation—Price Formation Initiatives for additional information.

An emerging issue in PJM involves the impact of subsidized existing generation on RPM market outcomes. These subsidies would likely enable the affected generators to submit reduced bids into PJM capacity markets that are not reflective of their actual costs of operation and may prevent uneconomic generating facilities from retiring. Either of these conditions could artificially suppress capacity market prices, especially given that PJM’s currently effective “minimum offer price rule” (MOPR) would not apply to these plants because it only applies to new gas-fired units. See Item 1. Business—Regulatory Issues—Federal Regulation—Capacity Market Issues for additional information.

Environmental Regulation

We continue to advocate for the development and implementation of fair and reasonable rules by the EPA and state environmental regulators. In particular, section 316(b) of the Federal Water Pollution Control Act (FWPCA) requires that cooling water intake structures, which are a significant part of the generation of electricity at steam-electric generating stations, reflect the best technology available for minimizing adverse environmental impacts. Implementation of Section 316(b) could adversely impact future nuclear and fossil operations and costs. In June 2015, the New Jersey Department of Environmental Protection (NJDEP) issued a draft New Jersey Pollutant Discharge Elimination System (NJPDES) permit governing cooling water intake structures for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The NJDEP may make revisions before issuing the final permit which is expected during the first half of 2016. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

In October 2015, the EPA published the Clean Power Plan (CPP), a greenhouse gas (GHG) emissions regulation under the Clean Air Act (CAA) for existing power plants. The regulation establishes state-specific emission targets based on implementation of the best systems of emission reduction. Each state must submit a compliance plan to the EPA by September 6, 2016 or seek a two-year extension to September 6, 2018. We continue to work with FERC and other federal and state regulators, as well as industry partners, to determine the potential impact of these regulations. Numerous states, including New Jersey and several industry groups, filed petitions for review with the D.C. Court to challenge the CPP. In addition, the petitioners sought a stay of the rule. On January 21, 2016, the D.C. Court declined to stay the CPP. However, on February 9, 2016, the U.S. Supreme Court stayed the rule pending further review of the case.

The U.S. Supreme Court’s decision to stay the implementation of the CPP will delay deadlines for submission of state requests for extensions and final plans. If the CPP is upheld, new deadlines will need to be established and the effective date of the compliance period may be impacted. See Item 1. Business—Environmental Matters—Climate Change for additional information.

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 regulations if and when they are implemented. In addition, state environmental regulations governing emissions from power plants also have a significant impact on our operations. In the second quarter of 2015, we retired 1,545 MW of fully depreciated combustion turbine capacity that would not be able to comply with the more stringent emission standards for high electric demand day units (HEDD) under the New Jersey HEDD regulations for nitrous oxide, which reduces our capacity revenues.

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. In particular, the historic operations of PSEG companies and the operations of numerous 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 in violation of various statutes. We are also 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, and the costs of any such remediation efforts could be material.

table of contents

For further information regarding the matters described above as well as other matters that may impact our financial condition and results of operations, see Item 1. Business—Environmental Matters, Item 3. Legal Proceedings, and Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

FERC Compliance

The FERC Staff has initiated a preliminary non-public investigation regarding errors in the calculation of certain components of Power's cost-based bids for its New Jersey fossil generating units in the PJM energy market and the quantity of energy that Power offered into the energy market for its fossil peaking units compared to the amounts for which Power was compensated in the capacity market for those units. This investigation is ongoing. The amounts of potential disgorgement and other potential penalties that we may incur span a wide range depending on the success of our legal arguments. If our legal arguments do not prevail, in whole or in part with FERC or in a judicial challenge that we may choose to pursue, it is likely that Power would record losses that would be material to PSEG's and Power's results of operations in the quarterly and annual periods in which they are recorded. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities.

Bonus Depreciation

In December 2015, Congress passed the Protecting Americans from Tax Hikes Act of 2015 (Tax Act). The Tax Act includes an extension of the bonus depreciation rules. For federal tax purposes, bonus depreciation allows a tax deduction equal to the applicable percentage of qualifying assets that are placed in service during the applicable year. The extension of bonus depreciation associated with changes under the Tax Act is expected to reduce the rate of growth in PSE&G’s rate base given an anticipated increase in deferred taxes; it is also expected to have a significant cash benefit over the next several years. For more detailed information, refer to Item 8. Financial Statements and Supplementary Data—Note 19. Income Taxes.

Change in Accounting Estimate

At the end of 2015, we changed the approach used to measure future service and interest costs for pension and other post-retirement benefits. For 2015 and prior, we calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, we have elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans’ liability cash flows. We believe the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans’ liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change will be reflected prospectively. We estimate this will reduce 2016 pension and OPEB expense by approximately $34 million and $13 million, respectively, net of amounts capitalized.

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 2015, our

- total nuclear fleet achieved an average capacity factor of 90%,
- nuclear output increased by 3.1% and combined cycle output by 11.4%, (including record performance at the Linden Units 1 and 2 and the Bethlehem Energy Center (BEC) combined cycle units) as compared to the same period in 2014,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 55 TWh while addressing unit outages and balancing fuel availability and price volatility, and
- utility ranked highest in electric and gas service business customer satisfaction among large utilities in the eastern United States and was recognized as the most reliable utility in the Mid-Atlantic region.

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 2015 as we:

- had cash on hand of $394 million as of December 31, 2015,

- maintained solid investment grade credit ratings,
- extended the expiration dates for approximately $2.0 billion of five-year credit facilities for PSEG, PSE&G and Power from 2018 to 2020,
- received cash federal tax benefits from the extension of bonus depreciation, and

table of contents

- increased our indicative 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, Energy Strong distribution program, GSMP, Keys Energy Center, Sewaren 7, BH5 and other planned projects, without the issuance of new equity.

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 2015, we commenced construction of the Keys Energy Center in Maryland and Sewaren 7 in New Jersey, each of which generating station cleared in the 2018/2019 capacity auction. In addition, we:

- placed into service the final phase of our 500 kV Susquehanna-Roseland and 230 kV Mickleton-Gloucester-Camden transmission projects,
- made additional investments in transmission infrastructure projects,
- secured approval to extend three Energy Efficiency Economic Stimulus subprograms to allow for additional capital expenditures and administrative expenses to provide energy efficiency assistance to hospitals, healthcare facilities and residential multi-family housing units,
- received approval for our GSMP and continued to execute our Energy Strong and other existing BPU-approved utility programs,
- completed the power ascension for the extended power uprate at our co-owned Peach Bottom 2 and 3 nuclear stations,
- completed installation of equipment to increase output and improve efficiency at our Bergen 2 combined cycle gas unit similar to our 2014 installation at our Linden plant, and
- placed into service a 13 MW-direct current (dc) solar energy facility near Waldorf, Maryland, acquired and placed into service a 25 MW-dc solar energy facility near San Francisco, California and acquired a 63 MW-dc solar energy project near Salt Lake City, Utah which is expected to be in-service by the end of 2016.

In January 2016, we acquired a 26 MW-dc solar energy project in Martin County, North Carolina and expect commercial operation by July 2016. In February 2016, we acquired a 36 MW-dc solar energy project in Larimer County, Colorado and expect commercial operation by the fourth quarter of 2016.

In February 2016, we announced our plan to commence construction of BH5 in 2017, with operations expected to begin in mid-2019. See Financial Results above for additional information.

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 with low gas prices, 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 utility capital investment program, including our Energy Strong program, GSMP 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,
- effectively manage construction of our Keys Energy Center, Sewaren 7 and other generation projects,
- advocate for measures to ensure the implementation by PJM and FERC of market design and transmission planning 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 and manage LIPA's fuel supply and generation dispatch obligations.

table of contents

For 2016 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,
- FERC Staff's continuing investigation of certain of Power's New Jersey fossil generating unit bids in the PJM energy market,
- 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,
- the potential for continued reductions in demand and sustained lower natural gas and electricity prices, both at market hubs and the locations where we operate, and
- delays and other obstacles that might arise in connection with the construction of our T&D, generation and other development projects, including in connection with permitting and regulatory approvals.

Our primary investment opportunities are in two areas: our regulated utility business and our merchant power business. We continually assess a broad range of strategic options to maximize long-term stockholder value. In assessing our options, we consider a wide variety of factors, including the performance and prospects of our businesses; the views of investors, regulators and rating agencies; our existing indebtedness and restrictions it imposes; and tax considerations, among other things. Strategic options available to us include:

- the acquisition, construction or disposition of transmission and distribution facilities and/or generation units,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition of new businesses,
- the expansion of our geographic footprint,
- continued or expanded participation in solar, demand response and energy efficiency programs, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency and modernizing existing infrastructure.

There can be no assurance, however, that we will successfully develop and execute any of the strategic options noted above, or any additional options we may consider in the future. The execution of any such strategic plan may not have the expected benefits or may have unexpected adverse consequences.

RESULTS OF OPERATIONS

	Years Ended December 31,		
	2015	2014	2013
Earnings (Losses)	Millions		
PSE&G	$787	$725	$612
Power (A)	856	760	644
Other (B)	36	33	(13)
PSEG Net Income	$1,679	$1,518	$1,243
PSEG Net Income Per Share (Diluted)	$3.30	$2.99	$2.45

(A) Power's results in 2015 include an after-tax insurance recovery for Superstorm Sandy of $102 million. Power's 2014 and 2013 results include after-tax expenses of $17 million and $32 million, respectively, for Operation and Maintenance (O&M) costs net of insurance recoveries in 2013, 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.

table of contents

The 2015 year-over-year increase in our Net Income was driven primarily by:
- higher revenues due to increased investments in transmission projects,
- lower generation costs due to lower fuel costs, primarily reflecting lower natural gas and coal prices,
- higher MTM gains in 2015, and
- insurance recoveries of Superstorm Sandy costs, primarily at Power.

These increases were partially offset by:
- lower capacity revenues resulting from lower average auction prices coupled with lower ancillary and operating reserve revenues in the PJM region,
- lower realized gains and higher other-than-temporary impairments related to the NDT Fund, and
- higher pension and OPEB costs, net of amounts capitalized.

The 2014 year-over-year increase in our Net Income was driven by:
- 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 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, net of amounts capitalized.

These increases were partially offset by:
- lower volumes of electricity sold under Power's BGS contracts resulting from serving fewer tranches in 2014, and
- higher generation costs due to higher fuel costs.

Our results include the realized gains, losses and earnings on Power's NDT Fund and other related NDT activity. Realized gains and losses, interest and dividend income and other costs related to the NDT Fund are recorded in Other Income (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 O&M Expense and the depreciation related to the ARO asset is recorded in Depreciation and Amortization Expense. In 2014, we restructured portions of our NDT Fund and realized a pre-tax gain of $65 million.

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, 2015, 2014 and 2013 include the changes related to NDT Fund and MTM activity shown in the chart below:

Years Ended December 31,	2015	2014	2013
	Millions, after tax		
NDT Fund and Related Activity	$8	$68	$40
Non-Trading MTM Gains (Losses)	$93	$66	$(74)

table of contents

PSEG

Our results of operations are primarily comprised of the results of operations of our principal operating subsidiaries, PSE&G and Power, 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)		Increase / (Decrease)	
	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	Millions			Millions	%	Millions	%
Operating Revenues	$10,415	$10,886	$9,968	$(471)	(4)	$918	9
Energy Costs	3,261	3,886	3,536	(625)	(16)	350	10
Operation and Maintenance	2,978	3,150	2,887	(172)	(5)	263	9
Depreciation and Amortization	1,214	1,227	1,178	(13)	(1)	49	4
Income from Equity Method Investments	12	13	11	(1)	(8)	2	18
Other Income (Deductions)	152	229	159	(77)	(34)	70	44
Other-Than-Temporary Impairments	53	20	12	33	N/A	8	67
Interest Expense	393	389	402	4	1	(13)	(3)
Income Tax Expense	1,001	938	812	63	7	126	16

The 2015 and 2014 amounts in the preceding table for Operating Revenues and O&M costs each include $375 million and $389 million, respectively, 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 PSE&G and Power provide a detailed explanation of their respective variances.

PSE&G

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	Millions			Millions	%	Millions	%
Operating Revenues	$6,636	$6,766	$6,655	$(130)	(2)	$111	2
Energy Costs	2,722	2,909	2,841	(187)	(6)	68	2
Operation and Maintenance	1,560	1,558	1,639	2	—	(81)	(5)
Depreciation and Amortization	892	906	872	(14)	(2)	34	4
Taxes Other Than Income Taxes	—	—	68	—	N/A	(68)	(100)
Other Income (Deductions)	75	58	51	17	29	7	14
Interest Expense	280	277	293	3	1	(16)	(5)
Income Tax Expense	470	449	381	21	5	68	18

Year Ended December 31, 2015 as compared to 2014

Operating Revenues decreased $130 million due primarily to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $212 million due primarily to an increase in transmission revenues.

- Transmission revenues were $164 million higher due to increased investments in transmission projects.

53

table of contents

- Electric distribution revenues increased $31 million due primarily to higher sales volumes due to weather.
- Gas distribution revenues increased $17 million due primarily to higher Weather Normalization Clause (WNC) revenue of $35 million due to warmer weather in 2015 compared to 2014, partially offset by $18 million due to lower sales volumes.

Clause Revenues decreased $154 million due primarily to lower Securitization Transition Charge (STC) revenues of $86 million, lower Societal Benefit Charges (SBC) of $31 million, lower Margin Adjustment Clause (MAC) of $29 million, and lower Solar Pilot Recovery Charges (SPRC) of $8 million. The changes in STC, SBC, 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 STC, SBC, MAC or SPRC collections.

Commodity Revenue decreased $187 million due to lower Gas revenues, partially offset by higher Electric revenues. This is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Gas revenues decreased $266 million due primarily to lower BGSS prices of $295 million, partially offset by $29 million from higher sales volumes. The average price of natural gas was 29% lower to the customer in 2015 than in 2014.
- Electric revenues increased $79 million due primarily to $120 million in higher net BGS revenues, comprised of $166 million from higher sales volumes, partially offset by lower prices of $46 million. BGS sales volume increased due primarily to weather. The BGS net revenue increase was partially offset by $41 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.

Operating Expenses

Energy Costs decreased $187 million. This is entirely offset by Commodity Revenue.

Operation and Maintenance increased $2 million, primarily due to increases of

- $33 million in pension and OPEB expenses, net of amounts capitalized,
- $13 million in transmission operating expenses,
- $7 million in gas bad debt expense, and
- a $49 million net increase due primarily to various increases, including information technology expenditures, wages, appliance service costs and preventative maintenance,
- almost entirely offset by a $90 million net reduction in costs related to various clause mechanisms, GPRC and the Capital Infrastructure Program (CIP), and
- $10 million of insurance recovery proceeds.

Depreciation and Amortization decreased $14 million due primarily to a $69 million decrease in amortization of Regulatory Assets, partially offset by an increase in depreciation of $55 million due to additional plant in service.

Other Income (Deductions) net increase of $17 million in Allowance for Funds Used During Construction.

Interest Expense increased $3 million primarily due to increases of

- $12 million due to net issuances in the latter half of 2014, and
- $9 million due to net issuances in 2015,
- partially offset by a decrease of $17 million due to the redemption of securitization debt in 2015.

Income Tax Expense increased $21 million due primarily to higher pre-tax income.

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.

table of contents

- Gas distribution revenues decreased $5 million due primarily to lower 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 TEFA tax effective January 1, 2014, lower CIP related revenue of $11 million, partially offset by higher sales volumes of $54 million, and higher revenue from GPRC of $6 million.
- Electric distribution revenues decreased $45 million due primarily to a $45 million decrease due to the 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 SBC of $32 million and lower STC revenues of $18 million. The changes in clause revenue 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 clause revenue collections.

Commodity Revenues increased $68 million due to lower 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 NUG energy and collections of 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.

Operating Expenses

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

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

- $73 million in pension and OPEB expenses, net of amounts capitalized, and
- $21 million in costs related to clause mechanisms, GPRC and CIP,
- partially offset by a $13 million net increase in operational expenses due primarily to an increase in storm related costs of $8 million.

Depreciation and Amortization increased $34 million due primarily to increases of $47 million in additional plant in service 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.

Interest Expense decreased $16 million primarily due to decreases of

- $16 million due to partial redemption of securitization debt of 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.

table of contents

Power

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2015	2014	2013	2015 vs. 2014		2014 vs. 2013	
	Millions			Millions	%	Millions	%
Operating Revenues	$4,928	$5,434	$5,063	$(506)	(9)	$371	7
Energy Costs	2,150	2,747	2,496	(597)	(22)	251	10
Operation and Maintenance	1,057	1,186	1,224	(129)	(11)	(38)	(3)
Depreciation and Amortization	291	292	273	(1)	—	19	7
Income from Equity Method Investments	14	14	16	—	—	(2)	(13)
Other Income (Deductions)	97	170	105	(73)	(43)	65	62
Other-Than-Temporary Impairments	53	20	12	33	N/A	8	67
Interest Expense	121	122	116	(1)	(1)	6	5
Income Tax Expense	511	491	419	20	4	72	17

Year Ended December 31, 2015 as compared to 2014

Operating Revenues decreased $506 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $172 million due primarily to

- a decrease of $192 million due primarily to lower capacity revenues resulting from lower average auction prices and the retirement of older peaking units in June 2015, coupled with lower ancillary and operating reserve revenues in the PJM region, and
- lower net revenues of $73 million due primarily to lower energy volumes sold in the New England (NE) region and lower average realized prices in the NE and New York (NY) regions, partially offset by higher energy volumes sold in the NY and PJM regions. Also included in the net decrease is $22 million due to lower MTM gains in 2015.
- partially offset by an increase of $56 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions coupled with higher average prices in the NE region, and
- an increase of $37 million due primarily to higher volumes of electricity sold under the BGS contract at higher average prices.

Gas Supply Revenues decreased $336 million due primarily to

- a net decrease of $214 million in sales under the BGSS contract, substantially comprised of lower average sales prices, and
- a decrease of $122 million on sales to third party customers, of which $93 million was due to lower average sales prices and $29 million to lower volumes sold.

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 decreased $597 million due to

- Generation costs decreased $254 million due primarily to lower fuel costs of $330 million reflecting lower average realized natural gas and coal prices and the utilization of lower volumes of oil and coal. MTM gains in 2015 as compared to MTM losses in 2014 resulted in a $66 million decrease. These decreased costs were partially offset by higher congestion costs in the PJM region of $140 million.
- Gas costs decreased $343 million mainly related to a decrease in average gas costs on both obligations under the BGSS contract and sales to third parties.

table of contents

Operation and Maintenance decreased $129 million due primarily to

- a decrease of $145 million due to insurance recoveries received in 2015 related to Superstorm Sandy, and
- a net decrease of $61 million related to our fossil plants, largely due to higher costs incurred in 2014 for planned outage costs, including maintenance and installation of upgraded technology at our Linden combined cycle gas generating plant, partially offset by planned outage costs in 2015 at our BEC generating plant and installation of upgraded technology at our combined cycle Bergen plant,
- partially offset by an increase of $51 million at our nuclear facilities, primarily due to higher planned outage costs at our 100%-owned Hope Creek and 50%-owned Peach Bottom 3 nuclear plants in 2015 as compared to our 57%-owned Salem nuclear unit 2 in 2014, and
- a $30 million increase due to higher pension and OPEB costs, net of amounts capitalized.

Other Income (Deductions) decreased $73 million due primarily to lower net realized gains from the NDT Fund, partially offset by a $28 million insurance recovery related to Superstorm Sandy.

Other-Than-Temporary Impairments increased $33 million due primarily to an increase in impairments of equity securities in the NDT Fund.

Income Tax Expense increased $20 million in 2015 due primarily to higher pre-tax income.

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 NY and 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.

table of contents

Operation and Maintenance decreased $38 million due primarily to

- lower pension and OPEB costs, net of amounts capitalized 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.

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.

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 arrangements. 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 may include the issuance of long-term debt securities and the incurrence of additional indebtedness under credit facilities. Our current 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. PSEG also has a $500 million term loan credit agreement that is scheduled to expire in November 2017. 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. 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.

table of contents

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, 2015, our operating cash flow increased by $759 million. For the year ended December 31, 2014, our operating cash flow increased by $2 million. The net changes were primarily due to net changes from our subsidiaries as discussed below and higher tax payments in 2014 at the parent company and Energy Holdings.

PSE&G

PSE&G's operating cash flow increased $292 million from $1,833 million to $2,125 million for the year ended December 31, 2015, as compared to 2014, due primarily to

- higher earnings,
- a $311 million reduction in tax payments, and
- an increase of $102 million due to higher customer billings in the fourth quarter of 2014 primarily as a result of increased usage due to weather,
- partially offset by a decrease of $250 million related to a change in regulatory deferrals, primarily driven by the return of prior year overcollections to customers for BGSS gas costs, Gas WNC charges and BGS costs.

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 WNC and GPRC rate recoveries, and
- an increase of $83 million due to decrease in employee benefit plan funding,
- partially offset by $199 million related to higher tax payments.

Power

Power's operating cash flow increased $281 million from $1,425 million to $1,706 million for the year ended December 31, 2015, as compared to 2014, primarily resulting from

- higher earnings,
- a decrease in margin deposit requirements of $144 million, and
- a $78 million increase from net collection of counterparty receivables,
- partially offset by an increase of $325 million in tax payments.

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.

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, 2015 were as follows:

table of contents

Company/Facility	As of December 31, 2015 Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$1,000	$221	$779
PSE&G	600	167	433
Power	2,600	164	2,436
Total	$4,200	$552	$3,648

As of December 31, 2015, 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. PSEG's credit facilities are available to back-stop its Commercial Paper Program and issue letters of credit under which as of December 31, 2015, $211 million of Commercial Paper was outstanding. PSE&G's credit facility primary use is to support its Commercial Paper Program under which as of December 31, 2015, $153 million was outstanding. Most of our credit facilities expire in 2019 and 2020. 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 had $171 million of 6.75% Mortgage Bonds mature in January 2016.

Power has $303 million of 5.32% Senior Notes and $250 million of 2.75% maturing in September 2016.

For a discussion of our long-term debt transactions during 2015 and into 2016, 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, 2015, PSE&G's Mortgage coverage ratio was 3.87 to 1 and the Mortgage would permit up to approximately $4.0 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, customary default provisions that could result in the potential acceleration of indebtedness under the defaulting company's agreement. We have not defaulted under these agreements.

In particular, PSEG's bank credit agreements contain provisions under which certain events, including an acceleration of material indebtedness under PSE&G's and Power's respective financing agreements, a failure by PSE&G or Power to satisfy certain final judgments and certain bankruptcy events by PSE&G or Power, that would constitute an event of default under the PSEG bank credit agreements. Under the PSEG bank credit agreements, it would also be an event of default if either PSE&G or Power ceases to be wholly owned by PSEG. The PSE&G and Power bank credit agreements include similar default provisions; however such provisions only relate to the respective borrower under such agreement and its subsidiaries and do not contain cross default provisions to each other. The PSE&G and Power bank credit agreements do not include cross default provisions relating to PSEG.

There are no cross default provisions in PSEG's or PSE&G's indentures. Power's indenture includes cross default provisions similar to those described above for PSEG; however, such provisions only relate to Power's subsidiaries and do not cross default to PSEG or PSE&G.

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

table of contents

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.

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	2015	2014	2013
Per Share	$1.56	$1.48	$1.44
in Millions	$789	$748	$728

On February 16, 2016, our Board of Directors approved a $0.41 per share common stock dividend for the first quarter of 2016. This reflects an indicative annual dividend rate of $1.64 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 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 2015, Moody's published research reports on PSEG, PSE&G and Power and the existing ratings and outlooks were unchanged. In May 2015, S&P published updated research reports and revised the outlook to stable from positive for PSEG's Corporate Credit Rating and Power's Senior Notes. S&P also affirmed the senior unsecured rating of BBB+ at Power and the mortgage bond rating of A at PSE&G. In September 2015, Moody's published an updated research report on PSEG and revised the outlook to positive from stable. In September and October 2015, Fitch published full rating reports on PSEG and Power leaving ratings and outlooks unchanged. In October 2015, PSEG ended a contractual agreement with Fitch to provide credit rating services for PSEG, PSE&G and Power. In January 2016, S&P published updated research reports on PSEG and PSE&G and the existing ratings and outlooks were unchanged.

	Moody's (A)	S&P (B)
PSEG		
Outlook	Positive	Stable
Commercial Paper	P2	A2
PSE&G		
Outlook	Stable	Stable
Mortgage Bonds	Aa3	A
Commercial Paper	P1	A2

Power		
Outlook	Stable	Stable
Senior Notes	Baa1	BBB+

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

61

table of contents

(lowest) for short-term securities.

(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.

Other Comprehensive Income

For the year ended December 31, 2015, we had Other Comprehensive Loss of $12 million on a consolidated basis. Other Comprehensive Loss was due primarily to a $27 million decrease in net unrealized gains related to Available-for-Sale Securities and $10 million of unrealized losses on derivative contracts accounted for as hedges, partially offset by a $25 million decrease in our consolidated liability for pension and postretirement benefits. 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 projections include Allowance for Funds Used During Construction and Interest Capitalized During Construction for PSE&G and Power, respectively. These amounts are subject to change, based on various factors. We will continue to approach non-regulated solar and other renewable investments opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2016	2017	2018
		Millions	
PSE&G:			
Transmission	$1,765	$1,740	$1,210
Distribution			
Baseline	655	645	580
Clause Recovery			
Energy Strong	340	250	55
Gas System Modernization Program	240	305	315
Solar/Energy Efficiency	85	80	50
Total PSE&G	$3,085	$3,020	$2,210
Power:			
Baseline	$270	$205	$260
Environmental/Regulatory	40	45	60
Fossil Growth Opportunities	740	745	390
Nuclear Expansion	15	10	5
Solar Growth Opportunities	230	20	—
Total Power	$1,295	$1,025	$715
Other	$55	$40	$35
Total PSEG	$4,435	$4,085	$2,960

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:

- Transmission—investments focused on reliability improvements and replacement of aging infrastructure.
- Baseline—investments for new business, reliability improvements, and replacement of defective equipment.

- Energy Strong—Electric and Gas Distribution reliability investment program focused on system hardening and resiliency.

table of contents

- Gas System Modernization Program—Gas Distribution investment program to replace aging infrastructure.
- Solar/Energy Efficiency—investments associated with grid-connected solar, solar loan programs, and customer energy efficiency programs.

In 2015, PSE&G made $2,692 million of capital expenditures, primarily for transmission and distribution system reliability. This does not include expenditures for cost of removal, net of salvage, of $120 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 new construction, including Keys Energy Center, Sewaren 7 and BH5, and 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 Growth Opportunities—investments associated with the construction of utility-scale photovoltaic facilities.

In 2015, Power made $881 million of capital expenditures, excluding $236 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.

table of contents

	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					
PSEG (Parent)	$500	$—	$500	$—	$—
PSE&G	6,879	171	750	759	5,199
Power	2,253	553	250	450	1,000
Long-Term Non-Recourse Project Financing					
Other	7	7	—	—	—
Interest on Recourse Debt					
PSEG (Parent)	18	8	10	—	—
PSE&G	4,572	269	517	460	3,326
Power	1,004	114	184	163	543
Interest on Non-Recourse Project Financing					
Other	—	—	—	—	—
Capital Lease Obligations					
Power	3	1	1	—	1
Operating Leases					
PSE&G	108	12	17	13	66
Power	44	2	4	5	33
Services	211	13	26	26	146
Other	4	2	2	—	—
Energy-Related Purchase Commitments					
Power	2,903	786	1,048	562	507
Total Contractual Cash Obligations	$18,506	$1,938	$3,309	$2,438	$10,821
Commercial Commitments					
Standby Letters of Credit					
PSEG (Parent)	$10	$10	$—	$—	$—
PSE&G	14	14	—	—	—
Power	209	209	—	—	—
Guarantees and Equity Commitments					
Power	56	52	—	—	4
Total Commercial Commitments	$289	$285	$—	$—	$4
Liability Payments for Uncertain Tax Positions					
PSEG	$158	$158	$—	$—	$—
PSE&G	102	102	—	—	—
Power	42	42	—	—	—

table of contents

OFF-BALANCE SHEET ARRANGEMENTS

Power

Power issues guarantees in conjunction with certain of its energy contracts. See Item 8. Financial Statements and Supplementary Data—Note 12. Commitments and Contingent Liabilities for further discussion.

Other

Through Energy Holdings, we have investments in leveraged leases that are accounted for in accordance with GAAP Accounting for Leases. Leveraged lease investments generally involve three parties: an owner/lessor, a creditor and a lessee. In a typical leveraged lease arrangement, 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 is not presented on our Consolidated Balance Sheets. In the event of default, the leased asset, and in some cases the lessee, secures the loan. As a lessor, Energy Holdings has ownership rights to the property and rents the property to the lessees for use in their business operations. For additional information, see Item 8. Financial Statements and Supplementary Data—Note 6. Long-Term Investments and Note 7. Financing Receivables.

In the event that collection of the minimum lease payments to be received by Energy Holdings is no longer reasonably assured, Energy Holdings may deem that a lessee has a high probability of defaulting on the lease obligation, and would consider the need to record an impairment of its investment. In the event the lease is ultimately rejected by a Bankruptcy Court, the fair value of the underlying asset and the associated debt would be recorded on the Consolidated Balance Sheets instead of the net equity investment in the lease.

CRITICAL ACCOUNTING ESTIMATES

Under GAAP, many accounting standards require the use of estimates, variable inputs and assumptions (collectively referred to as estimates) that are subjective in nature. Because of this, differences between the actual measure realized versus the estimate can have a material impact on results of operations, financial position and cash flows. We have determined that the following estimates are considered critical to the application of rules that relate to the respective businesses.

Accounting for Pensions

PSEG sponsors several qualified and nonqualified pension plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The market-related value of plan assets held for the qualified pension plan is equal to the fair value of these assets as of year-end. The plan assets are comprised of investments in both debt and equity securities which are valued using quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. We calculate pension costs using various economic and demographic assumptions.

Assumptions and Approach Used: Economic assumptions include the discount rate and the long-term rate of return on trust assets. Demographic assumptions include projections of future mortality rates, pay increases and retirement patterns.

Assumption	2015	2014	2013
Discount Rate	4.54 %	4.20 %	5.00 %
Rate of Return on Plan Assets	8.00 %	8.00 %	8.00 %

The discount rate used to calculate pension obligations is determined as of December 31 each year, our measurement date. The discount rate is determined by developing a spot rate curve based on the yield to maturity of a universe of high quality corporate bonds with similar maturities to the plan obligations. The spot rates are used to discount the estimated plan distributions. The discount rate is the single equivalent rate that produces the same result as the full spot rate curve.

At the end of 2015, we changed the approach used to measure future service and interest costs for pension benefits. For 2015 and prior, we calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, we have elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans' liability cash flows. We believe the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans' liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change will be reflected prospectively. We estimate this will reduce 2016 pension expense by approximately $47

table of contents

million or $34 million, net of amounts capitalized, as compared to the 2016 amount that would have been derived from applying our 2015 and prior years' methodology.
Our expected rate of return on plan assets reflects current asset allocations, historical long-term investment performance and an estimate of future long-term returns by asset class and long-term inflation assumptions.
Based on the above assumptions, we have estimated net periodic pension expense in 2016 of approximately $56 million or $40 million, net of amounts capitalized.
We utilize a corridor approach that reduces the volatility of reported pension expense/income. The corridor requires differences between actuarial assumptions and plan results be deferred and amortized as part of expense/income. This occurs only when the accumulated differences exceed 10% of the greater of the pension benefit obligation or the fair value of plan assets as of each year-end. The excess would be amortized over the average remaining service period of the active employees, which is approximately eight years.
Effect if Different Assumptions Used: As part of the business planning process, we have modeled future costs assuming an 8.00% rate of return and a 4.54% discount rate for 2016. Actual future pension expense/income and funding levels will depend on future investment performance, changes in discount rates, market conditions, funding levels relative to our projected benefit obligation and accumulated benefit obligation and various other factors related to the populations participating in the pension plans.
The following chart reflects the sensitivities associated with a change in certain assumptions. The effects of the assumption changes shown below solely reflect the impact of that specific assumption.

	% Change	Impact on Pension Benefit Obligation as of December 31, 2015	Increase to Pension Expense in 2016	Increase to Pension Expense, net of Amounts Capitalized in 2016
Assumption		Millions		
Discount Rate	(1)%	$706	$75	$54
Expected Rate of Return on Plan Assets	(1)%	N/A	$49	$35

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.
Hedge and MTM Accounting
Current guidance requires us to recognize the fair value of derivative instruments, not designated as normal purchases or normal sales, at their fair value on the balance sheet. Many contracts qualify for normal purchases and normal sales exemption and are accounted for upon settlement.
Assumptions and Approach Used: In general, the fair value of our derivative instruments is determined by reference to quoted market prices from contracts listed on exchanges or from brokers. Some of these derivative contracts are long-term and rely on forward price quotations over the entire duration of the derivative contracts.
For a small number of contracts where quoted market prices are not available, we utilize mathematical models that rely on historical data to develop forward pricing information in the determination of fair value.
We have entered into various derivative instruments to manage risk from changes in commodity prices and interest rates. In accordance with our hedging strategy, derivatives that are hedging these risks and qualify are designated as either cash flow hedges or fair value hedges. For derivatives designated as hedges, the change in the value of a derivative instrument is measured against the offsetting change in the value of the underlying contract, anticipated transaction or other business condition that the derivative instrument is intended to hedge. This is known as the measure of hedge effectiveness. Changes in the fair value of the effective portion of a derivative instrument designated as a fair value hedge, along with changes in the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in current period earnings. Changes in the fair value of the effective portion of derivative instruments designated as cash flow hedges are reported in Accumulated Other Comprehensive Income (Loss), net of

tax, until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. During periods of extreme price volatility, there will be significant changes in the value recorded in Accumulated Other Comprehensive Income (Loss). As of December 31, 2015, we had no commodity contracts designated as cash flow hedges.

For our wholesale energy business, many of the forward sale, forward purchase, option and other contracts are derivative instruments that hedge commodity price risk, but do not meet the requirements for either cash flow or fair value hedge

table of contents

accounting. The changes in value of such derivative contracts are marked to market through earnings as the related commodity prices fluctuate. As a result, our earnings may experience significant fluctuations depending on the volatility of commodity prices.

Effect if Different Assumptions Used: Any significant changes to the fair market values of our derivatives instruments could result in a material change in the value of the assets or liabilities recorded on our Consolidated Balance Sheets and could result in a material change to the unrealized gains or losses recorded in our Consolidated Statements of Operations.

For additional information regarding Derivative Financial Instruments, see Item 8. Financial Statements and Supplementary Data—Note 15. Financial Risk Management Activities.

Long-Lived Assets

In accordance with GAAP, 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 asset group's carrying amount may not be recoverable.

Assumptions and Approach Used: In the event certain triggers exist indicating an asset/asset group may not be recoverable, an undiscounted cash flow test is performed to determine if an impairment exists. When the carrying value of a long-lived asset/asset group exceeds the undiscounted estimate of future cash flows associated with the asset/asset group, an impairment may exist to the extent that the fair value of the asset/asset group is less than its carrying amount. These tests require significant estimates and judgment when developing expected future cash flows; however, generating units are typically evaluated at a regional portfolio level.

Effect if Different Assumptions Used: The above cash flow tests and fair value estimates may be impacted by changes in forecasted power prices, fuel costs, dispatch rates, other operating and capital expenditures and the cost of borrowing which if different, could significantly impact the outcome, triggering additional impairment tests or write-offs.

Lease Investments

Our Investments in Leases, included in Long-Term Investments on our Consolidated Balance Sheets, are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. A significant portion of the estimated residual value of leased assets is related to merchant power plants leased to other energy companies. See Item 8. Financial Statements and Supplementary Data – Note 6. Long-Term Investments and Note 7. Financing Receivables.

Assumptions and Approach Used: Residual values are the estimated values of the leased assets at the end of the respective lease terms. The estimated values are calculated by discounting the cash flows related to the leased assets after the lease term. For the merchant power plants, the estimated discounted cash flows are dependent upon various assumptions, including:

- estimated forward power and capacity prices in the years after the lease,
- related prices of fuel for the plants,
- dispatch rates for the plants,
- future capital expenditures required to maintain the plants,
- future operation and maintenance expenses, and
- discount rates.

Residual valuations are performed annually for each plant subject to lease using specific assumptions tailored to each plant. Those annual valuations are compared to the recorded residual values to determine if an impairment is warranted.

Effect if Different Assumptions Used: A significant change to the assumptions, such as a large decrease in near-term power prices that affects the market's view of long-term power prices, or a change in the credit rating or bankruptcy of a counterparty, could result in an impairment of one or more of the residual values, but not necessarily to all of the residual values. However, if, because of changes in assumptions, all the residual values related to the merchant energy plants were deemed to be zero, we would recognize an after-tax charge to income of approximately $177 million.

Asset Retirement Obligations (ARO)

PSE&G, Power and Services recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists. These AROs are recorded at fair value in the period in which they are incurred and are capitalized as part of the carrying amount of the related long-lived assets. PSE&G, as a rate-regulated entity, recognizes regulatory assets or liabilities as a result

table of contents

of timing differences between the recording of costs and costs recovered through the rate-making process. We accrete the ARO liability to reflect the passage of time.

Assumptions and Approach Used: Because quoted market prices are not available for AROs, we estimate the initial fair value of an ARO by calculating discounted cash flows that are dependent upon various assumptions, including:

- estimation of dates for retirement, which can be dependent on environmental and other legislation,
- amounts and timing of future cash expenditures associated with retirement, settlement or remediation activities,
- discount rates,
- cost escalation rates,
- market risk premium,
- inflation rates, and
- if applicable, past experience with government regulators regarding similar obligations.

We obtain updated cost studies triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2015. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset which impacts the amount of accretion and depreciation expense recognized in future periods.

Nuclear Decommissioning AROs

AROs related to the future decommissioning of Power’s nuclear facilities comprised 94% of Power’s total AROs as of December 31, 2015. Power determines its AROs for its nuclear units by assigning probability weighting to various discounted cash flow outcomes for each of its nuclear units that incorporate the assumptions above as well as:

- license renewals,
- early shutdown,
- safe storage for a period of time after retirement, and
- recovery from the federal government of costs incurred for spent nuclear fuel.

Effect if Different Assumptions Used: Changes in the assumptions could result in a material change in the ARO balance sheet obligation and the period over which we accrete to the ultimate liability. For example, a decrease of 1% in the discount rate would result in a $37 million increase in the Nuclear ARO as of December 31, 2015. An increase of 1% in the inflation rate would result in a $191 million increase in the Nuclear ARO as of December 31, 2015. Also, if we did not assume that we would recover from the federal government the costs incurred for spent nuclear fuel, the Nuclear ARO would increase by $267 million at December 31, 2015.

Accounting for Regulated Businesses

PSE&G prepares its financial statements to comply with GAAP for rate-regulated enterprises, which differs in some respects from accounting for non-regulated businesses. In general, accounting for rate-regulated enterprises should reflect the economic effects of regulation. As a result, a regulated utility is required to defer the recognition of costs (Regulatory Asset) or recognize obligations (Regulatory Liability) if the rates established are designed to recover the costs and if the competitive environment makes it probable that such rates can be charged or collected. This accounting results in the recognition of revenues and expenses in different time periods than that of enterprises that are not regulated.

Assumptions and Approach Used: PSE&G recognizes Regulatory Assets where it is probable that such costs will be recoverable in future rates from customers and Regulatory Liabilities where it is probable that refunds will be made to customers in future billings. The highest degree of probability is an order from the BPU either approving recovery of the deferred costs over a future period or requiring the refund of a liability over a future period.

Virtually all of PSE&G’s regulatory assets and liabilities are supported by BPU orders. In the absence of an order, PSE&G will consider the following when determining whether to record a Regulatory Asset or Liability:

- past experience regarding similar items with the BPU,
- treatment of a similar item in an order by the BPU for another utility,
- passage of new legislation, and

table of contents

• recent discussions with the BPU.

All deferred costs are subject to prudence reviews by the BPU. When the recovery of a Regulatory Asset or payment of a Regulatory Liability is no longer probable, PSE&G charges or credits earnings, as appropriate.

Effect if Different Assumptions Used: A change in the above assumptions may result in a material impact on our results of operations or our cash flows. See Item 8. Financial Statements and Supplementary Data—Note 5. Regulatory Assets and Liabilities for a description of the amounts and nature of regulatory balance sheet amounts.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The risk inherent in our market-risk sensitive instruments and positions is the potential loss arising from adverse changes in commodity prices, equity security prices and interest rates as discussed in the Notes to Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

Additionally, we are exposed to counterparty credit losses in the event of non-performance or non-payment. We have a credit management process, which is used to assess, monitor and mitigate counterparty exposure. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on our financial condition, results of operations or net cash flows.

Commodity Contracts

The availability and price of energy-related commodities are subject to fluctuations from factors such as weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market rules and other events. To reduce price risk caused by market fluctuations, we enter into supply contracts and derivative contracts, including forwards, futures, swaps and options with approved counterparties. These contracts, in conjunction with physical sales and other services, help reduce risk and optimize the value of owned electric generation capacity.

Value-at-Risk (VaR) Models

VaR represents the potential losses, under normal market conditions, for instruments or portfolios due to changes in market factors, for a specified time period and confidence level. We estimate VaR across our commodity businesses. MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The MTM VaR calculation does not include market risks associated with activities that are subject to accrual accounting, primarily our generating facilities and some load serving activities.

The VaR models used are variance/covariance models adjusted for the change of positions with 95% and 99.5% confidence levels and a one-day holding period for the MTM activities. The models assume no new positions throughout the holding periods; however, we actively manage our portfolio.

	MTM VaR	
	Millions	
Years Ended December 31,	2015	2014
95% Confidence Level, Loss could exceed VaR one day in 20 days		
Period End	$24	$36
Average for the Period	$17	$30
High	$40	$195
Low	$8	$14
99.5% Confidence Level, Loss could exceed VaR one day in 200 days		
Period End	$38	$56
Average for the Period	$26	$46
High	$63	$306

Low	$12	$22

table of contents

See Item 8. Financial Statements and Supplementary Data—Note 15. Financial Risk Management Activities for a discussion of credit risk.

Interest Rates

We are subject to the risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, we use a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

As of December 31, 2015, a hypothetical 10% increase in market interest rates would result in

- less than $1 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $323 million decrease in the fair value of debt, including a $270 million decrease at PSE&G and a $53 million decrease at Power.

Debt and Equity Securities

We have $5.4 billion of assets in our pension plan trusts. Although fluctuations in market prices of securities within this portfolio do not directly affect our earnings in the current period, changes in the value of these investments could affect

- our future contributions to these plans,
- our financial position if our accumulated benefit obligation under our pension plans exceeds the fair value of the pension trust funds, and
- future earnings, as we could be required to adjust pension expense and the assumed rate of return.

The NDT Fund is comprised primarily of fixed income and equity securities and has a balance $1,754 million as of December 31, 2015. As of December 31, 2015, the portfolio includes $865 million of equity securities and $847 million in fixed income securities. The fair market value of the assets in the NDT Fund will fluctuate primarily depending upon the performance of equity markets. As of December 31, 2015, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $87 million.

We use duration to measure the interest rate sensitivity of the fixed income portfolio. Duration is a summary statistic of the effective average maturity of the fixed income portfolio. The benchmark for the fixed income component of the NDT Fund currently has a duration of 5.68 years and a yield of 2.59%. The portfolio's value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2015, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $48 million.

Credit Risk

See Item 8. Financial Statements and Supplementary Data—Note 15. Financial Risk Management Activities for a discussion of credit risk and a discussion about Power's and PSE&G's credit risk.

Energy Holdings has credit risk related to its investments in leases, which totaled $60 million, net of deferred taxes of $724 million, as of December 31, 2015. These leveraged leases are concentrated in the U.S. energy industry. See Item 8. Financial Statements and Supplementary Data—Note 7. Financing Receivables for counterparties' credit ratings and other information. The credit exposure to the lessees is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverages are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a temporary market downturn or degradation in operating performance of the leased assets. In any lease transaction, in the event of a default, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. Under a worst-case scenario, if a foreclosure were to occur, Energy Holdings would record a pre-tax write-off up to its outstanding gross investment in these facilities. Also, in the event of a potential foreclosure, the net tax benefits generated by Energy Holdings' portfolio of investments could be materially reduced in the period in which gains associated with the potential forgiveness of debt at these projects occurs. The amount and timing of

table of contents

any potential reduction in net tax benefits is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, the amount of lease debt outstanding, any cash trapped at the projects and negotiations during such potential foreclosure process. The potential loss of earnings, impairment and/or tax payments could have a material impact to our financial position, results of operations and net cash flows.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

This combined Form 10-K is separately filed by PSEG, PSE&G and 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 as to any other company.

table of contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Stockholders of
Public Service Enterprise Group Incorporated
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(a). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2016, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2016

table of contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Sole Stockholder of
Public Service Electric and Gas Company
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, common stockholder’s equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(b). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2016

table of contents

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM
To the Board of Directors and Sole Member of
PSEG Power LLC
Newark, New Jersey

We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of operations, comprehensive income, member’s equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the consolidated financial statement schedule listed in the Index at Item 15(B)(c). These consolidated financial statements and consolidated financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the consolidated financial statements and consolidated financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such consolidated financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 25, 2016

table of contents

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions, except per share data

	Years Ended December 31,		
	2015	2014	2013
OPERATING REVENUES	$10,415	$10,886	$9,968
OPERATING EXPENSES			
Energy Costs	3,261	3,886	3,536
Operation and Maintenance	2,978	3,150	2,887
Depreciation and Amortization	1,214	1,227	1,178
Taxes Other Than Income Taxes	—	—	68
Total Operating Expenses	7,453	8,263	7,669
OPERATING INCOME	2,962	2,623	2,299
Income from Equity Method Investments	12	13	11
Other Income	254	290	213
Other Deductions	(102)	(61)	(54)
Other-Than-Temporary Impairments	(53)	(20)	(12)
Interest Expense	(393)	(389)	(402)
INCOME BEFORE INCOME TAXES	2,680	2,456	2,055
Income Tax (Expense) Benefit	(1,001)	(938)	(812)
NET INCOME	$1,679	$1,518	$1,243
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
BASIC	505	506	506
DILUTED	508	508	508
NET INCOME PER SHARE:			
BASIC	$3.32	$3.00	$2.46
DILUTED	$3.30	$2.99	$2.45

See Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2015	2014	2013
NET INCOME	$1,679	$1,518	$1,243
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $34, $26 and $(54) for the years ended 2015, 2014 and 2013, respectively	(27)	(27)	55
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $7, $(8) and $7 for the years ended 2015, 2014 and 2013, respectively	(10)	12	(9)
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(18), $120 and $(172) for the years ended 2015, 2014 and 2013, respectively	25	(173)	247
Other Comprehensive Income (Loss), net of tax	(12)	(188)	293
COMPREHENSIVE INCOME	$1,667	$1,330	$1,536

See Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2015	2014
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$394	$402
Accounts Receivable, net of allowances of $67 and $52 in 2015 and 2014, respectively	1,068	1,254
Tax Receivable	305	211
Unbilled Revenues	197	284
Fuel	463	538
Materials and Supplies, net	513	484
Prepayments	135	108
Derivative Contracts	242	240
Deferred Income Taxes	—	11
Regulatory Assets	164	323
Regulatory Assets of Variable Interest Entities (VIEs)	—	249
Other	13	15
Total Current Assets	3,494	4,119
PROPERTY, PLANT AND EQUIPMENT	35,494	32,196
Less: Accumulated Depreciation and Amortization	(8,955)	(8,607)
Net Property, Plant and Equipment	26,539	23,589
NONCURRENT ASSETS		
Regulatory Assets	3,196	3,192
Long-Term Investments	1,233	1,307
Nuclear Decommissioning Trust (NDT) Fund	1,754	1,780
Long-Term Tax Receivable	171	64
Long-Term Receivable of VIEs	495	580
Other Special Funds	227	212
Goodwill	16	16
Other Intangibles	102	84
Derivative Contracts	77	77
Restricted Cash of VIEs	—	24
Other	231	243
Total Noncurrent Assets	7,502	7,579
TOTAL ASSETS	$37,535	$35,287

See Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2015	2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$734	$624
Securitization Debt of VIEs Due Within One Year	—	259
Commercial Paper and Loans	364	—
Accounts Payable	1,369	1,178
Derivative Contracts	76	132
Accrued Interest	96	95
Accrued Taxes	42	21
Deferred Income Taxes	—	173
Clean Energy Program	142	142
Obligation to Return Cash Collateral	128	121
Regulatory Liabilities	123	186
Regulatory Liabilities of VIEs	42	—
Other	459	547
Total Current Liabilities	3,575	3,478
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	8,166	7,303
Regulatory Liabilities	175	258
Regulatory Liabilities of VIEs	—	39
Asset Retirement Obligations	679	743
Other Postretirement Benefit (OPEB) Costs	1,228	1,277
OPEB Costs of Servco	375	452
Accrued Pension Costs	487	440
Accrued Pension Costs of Servco	114	126
Environmental Costs	415	417
Derivative Contracts	27	33
Long-Term Accrued Taxes	212	208
Other	181	112
Total Noncurrent Liabilities	12,059	11,408
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
CAPITALIZATION		
LONG-TERM DEBT	8,834	8,215
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2015 and 2014— 534 shares	4,915	4,876
Treasury Stock, at cost, 2015 and 2014— 28 shares	(671)	(635)
Retained Earnings	9,117	8,227
Accumulated Other Comprehensive Loss	(295)	(283)
Total Common Stockholders' Equity	13,066	12,185

Noncontrolling Interest	1	1
Total Stockholders’ Equity	13,067	12,186
Total Capitalization	21,901	20,401
TOTAL LIABILITIES AND CAPITALIZATION	$37,535	$35,287

See Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$1,679	$1,518	$1,243
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,214	1,227	1,178
Amortization of Nuclear Fuel	213	200	192
Provision for Deferred Income Taxes (Other than Leases) and ITC	685	515	270
Non-Cash Employee Benefit Plan Costs	161	47	243
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	26	(4)	31
Net (Gain) Loss on Lease Investments	—	(3)	2
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(143)	(93)	79
Change in Accrued Storm Costs	12	(3)	(90)
Net Change in Regulatory Assets and Liabilities	(60)	190	2
Cost of Removal	(120)	(98)	(93)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(38)	(166)	(104)
Net Change in Certain Current Assets and Liabilities			
Tax Receivable	(94)	30	19
Accrued Taxes	(91)	(156)	81
Margin Deposit	122	(22)	(43)
Other Current Assets and Liabilities	288	(31)	261
Employee Benefit Plan Funding and Related Payments	(109)	(95)	(231)
Other	174	104	118
Net Cash Provided By (Used In) Operating Activities	3,919	3,160	3,158
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(3,863)	(2,820)	(2,811)
Proceeds from Sale of Capital Leases and Investments	14	25	50
Proceeds from Sales of Available-for-Sale Securities	1,501	1,915	1,159
Investments in Available-for-Sale Securities	(1,552)	(1,934)	(1,170)
Other	(42)	(78)	(29)
Net Cash Provided By (Used In) Investing Activities	(3,942)	(2,892)	(2,801)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	364	(60)	(203)
Issuance of Long-Term Debt	1,350	1,250	2,000
Redemption of Long-Term Debt	(600)	(500)	(1,025)
Redemption of Securitization Debt	(259)	(237)	(226)
Cash Dividend Paid on Common Stock	(789)	(748)	(728)
Other	(51)	(64)	(61)
Net Cash Provided By (Used In) Financing Activities	15	(359)	(243)
Net Increase (Decrease) in Cash and Cash Equivalents	(8)	(91)	114
Cash and Cash Equivalents at Beginning of Period	402	493	379
Cash and Cash Equivalents at End of Period	$394	$402	$493

Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$447	$538	$241
Interest Paid, Net of Amounts Capitalized	$381	$382	$385
Accrued Property, Plant and Equipment Expenditures	$510	$382	$336

See Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
Millions

	Common Stock		Treasury Stock		Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
	Shs.	Amount	Shs.	Amount				
Balance as of January 1, 2013	534	$4,833	(28)	$(607)	$6,942	$(388)	$1	$10,781
Net Income	—	—	—	—	1,243	—	—	1,243
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(219)	—	—	—	—	—	293	—	293
Comprehensive Income								1,536
Cash Dividends on Common Stock	—	—	—	—	(728)	—	—	(728)
Other	—	28	—	(8)	—	—	—	20
Balance as of December 31, 2013	534	$4,861	(28)	$(615)	$7,457	$(95)	$1	$11,609
Net Income	—	—	—	—	1,518	—	—	1,518
Other Comprehensive Income (Loss), net of tax (expense) benefit of $138	—	—	—	—	—	(188)	—	(188)
Comprehensive Income								1,330
Cash Dividends on Common Stock	—	—	—	—	(748)	—	—	(748)
Other	—	15	—	(20)	—	—	—	(5)
Balance as of December 31, 2014	534	$4,876	(28)	$(635)	$8,227	$(283)	$1	$12,186
Net Income	—	—	—	—	1,679	—	—	1,679
Other Comprehensive Income (Loss), net of tax (expense) benefit of $23	—	—	—	—	—	(12)	—	(12)
Comprehensive Income								1,667
Cash Dividends on Common Stock	—	—	—	—	(789)	—	—	(789)
Other	—	39	—	(36)	—	—	—	3
Balance as of December 31, 2015	534	$4,915	(28)	$(671)	$9,117	$(295)	$1	$13,067

See Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2015	2014	2013
OPERATING REVENUES	$6,636	$6,766	$6,655
OPERATING EXPENSES			
Energy Costs	2,722	2,909	2,841
Operation and Maintenance	1,560	1,558	1,639
Depreciation and Amortization	892	906	872
Taxes Other Than Income Taxes	—	—	68
Total Operating Expenses	5,174	5,373	5,420
OPERATING INCOME	1,462	1,393	1,235
Other Income	79	61	54
Other Deductions	(4)	(3)	(3)
Interest Expense	(280)	(277)	(293)
INCOME BEFORE INCOME TAXES	1,257	1,174	993
Income Tax (Expense) Benefit	(470)	(449)	(381)
NET INCOME	$787	$725	$612

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2015	2014	2013
NET INCOME	$787	$725	$612
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $0, $0 and $1 for the years ended 2015, 2014 and 2013, respectively	(1)	1	(1)
COMPREHENSIVE INCOME	$786	$726	$611

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2015	2014
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$198	$310
Accounts Receivable, net of allowances of $67 and $52 in 2015 and 2014, respectively	787	864
Accounts Receivable-Affiliated Companies	222	274
Unbilled Revenues	197	284
Materials and Supplies	148	133
Prepayments	31	42
Regulatory Assets	164	323
Regulatory Assets of VIEs	—	249
Derivative Contracts	13	18
Deferred Income Taxes	—	24
Other	9	7
Total Current Assets	1,769	2,528
PROPERTY, PLANT AND EQUIPMENT	23,732	21,103
Less: Accumulated Depreciation and Amortization	(5,504)	(5,183)
Net Property, Plant and Equipment	18,228	15,920
NONCURRENT ASSETS		
Regulatory Assets	3,196	3,192
Long-Term Investments	330	348
Other Special Funds	49	53
Derivative Contracts	—	8
Restricted Cash of VIEs	—	24
Other	105	113
Total Noncurrent Assets	3,680	3,738
TOTAL ASSETS	$23,677	$22,186

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2015	2014
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$171	$300
Securitization Debt of VIEs Due Within One Year	—	259
Commercial Paper and Loans	153	—
Accounts Payable	724	574
Accounts Payable—Affiliated Companies	292	379
Accrued Interest	70	68
Clean Energy Program	142	142
Deferred Income Taxes	—	165
Obligation to Return Cash Collateral	128	121
Regulatory Liabilities	123	186
Regulatory Liabilities of VIEs	42	—
Other	297	381
Total Current Liabilities	2,142	2,575
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	5,181	4,575
OPEB Costs	937	967
Accrued Pension Costs	202	173
Regulatory Liabilities	175	258
Regulatory Liabilities of VIEs	—	39
Environmental Costs	365	364
Asset Retirement Obligations	218	290
Derivative Contracts	11	—
Long-Term Accrued Taxes	109	116
Other	114	67
Total Noncurrent Liabilities	7,312	6,849
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
CAPITALIZATION		
LONG-TERM DEBT	6,650	5,975
STOCKHOLDER’S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2015 and 2014—132 shares	892	892
Contributed Capital	695	695
Basis Adjustment	986	986
Retained Earnings	4,999	4,212
Accumulated Other Comprehensive Income	1	2
Total Stockholder’s Equity	7,573	6,787
Total Capitalization	14,223	12,762
TOTAL LIABILITIES AND CAPITALIZATION	$23,677	$22,186

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$787	$725	$612
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	892	906	872
Provision for Deferred Income Taxes and ITC	386	310	198
Non-Cash Employee Benefit Plan Costs	95	27	156
Cost of Removal	(120)	(98)	(93)
Change in Accrued Storm Costs	12	(3)	(90)
Net Change in Other Regulatory Assets and Liabilities	(60)	190	2
Net Change in Certain Current Assets and Liabilities:			
Accounts Receivable and Unbilled Revenues	165	63	(5)
Materials and Supplies	(15)	(18)	(1)
Prepayments	11	(18)	5
Accounts Payable	45	(3)	19
Accounts Receivable/Payable-Affiliated Companies, net	—	(167)	100
Other Current Assets and Liabilities	(29)	6	40
Employee Benefit Plan Funding and Related Payments	(91)	(83)	(166)
Other	47	(4)	(4)
Net Cash Provided By (Used In) Operating Activities	2,125	1,833	1,645
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,692)	(2,164)	(2,175)
Proceeds from Sales of Available-for-Sale Securities	21	103	38
Investments in Available-for-Sale Securities	(22)	(101)	(20)
Solar Loan Investments	11	7	(15)
Other	11	—	—
Net Cash Provided By (Used In) Investing Activities	(2,671)	(2,155)	(2,172)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	153	(60)	(203)
Issuance of Long-Term Debt	850	1,250	1,500
Redemption of Long-Term Debt	(300)	(500)	(725)
Redemption of Securitization Debt	(259)	(237)	(226)
Contributed Capital	—	175	100
Other	(10)	(14)	(17)
Net Cash Provided By (Used In) Financing Activities	434	614	429
Net Increase (Decrease) in Cash and Cash Equivalents	(112)	292	(98)
Cash and Cash Equivalents at Beginning of Period	310	18	116
Cash and Cash Equivalents at End of Period	$198	$310	$18
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$(28)	$283	$84
Interest Paid, Net of Amounts Capitalized	$261	$259	$275
Accrued Property, Plant and Equipment Expenditures	$396	$292	$246

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

table of contents

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDER'S EQUITY
Millions

	Common Stock	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2013	$892	$420	$986	$2,875	$2	$5,175
Net Income	—	—	—	612	—	612
Other Comprehensive Income, net of tax (expense) benefit of $1	—	—	—	—	(1)	(1)
Comprehensive Income						611
Contributed Capital		100				100
Balance as of December 31, 2013	$892	$520	$986	$3,487	$1	$5,886
Net Income	—	—	—	725	—	725
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	1	1
Comprehensive Income						726
Contributed Capital	—	175	—	—	—	175
Balance as of December 31, 2014	$892	$695	$986	$4,212	$2	$6,787
Net Income	—	—	—	787	—	787
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	(1)	(1)
Comprehensive Income						786
Balance as of December 31, 2015	$892	$695	$986	$4,999	$1	$7,573

See disclosures regarding Public Service Electric and Gas Company included in the Notes to Consolidated Financial Statements.

table of contents

PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2015	2014	2013
OPERATING REVENUES	$4,928	$5,434	$5,063
OPERATING EXPENSES			
Energy Costs	2,150	2,747	2,496
Operation and Maintenance	1,057	1,186	1,224
Depreciation and Amortization	291	292	273
Total Operating Expenses	3,498	4,225	3,993
OPERATING INCOME	1,430	1,209	1,070
Income from Equity Method Investments	14	14	16
Other Income	169	222	154
Other Deductions	(72)	(52)	(49)
Other-Than-Temporary Impairments	(53)	(20)	(12)
Interest Expense	(121)	(122)	(116)
INCOME BEFORE INCOME TAXES	1,367	1,251	1,063
Income Tax (Expense) Benefit	(511)	(491)	(419)
NET INCOME	$856	$760	$644

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

table of contents

PSEG POWER LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2015	2014	2013
NET INCOME	$856	$760	$644
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $32, $28 and $(55) for the years ended 2015, 2014 and 2013, respectively	(25)	(30)	57
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $7, $(8) and $7 for the years ended 2015, 2014 and 2013, respectively	(11)	12	(10)
Pension/OPEB adjustment, net of tax (expense) benefit of $(16), $101, and $(151) for the years ended 2015, 2014 and 2013 respectively	24	(147)	218
Other Comprehensive Income (Loss), net of tax	(12)	(165)	265
COMPREHENSIVE INCOME	$844	$595	$909

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

table of contents

PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2015	2014
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$12	$9
Accounts Receivable	217	334
Accounts Receivable—Affiliated Companies	276	313
Short-Term Loan to Affiliate	363	584
Fuel	463	538
Materials and Supplies, net	363	350
Derivative Contracts	223	207
Prepayments	25	17
Other	7	7
Total Current Assets	1,949	2,359
PROPERTY, PLANT AND EQUIPMENT	11,354	10,732
Less: Accumulated Depreciation and Amortization	(3,227)	(3,217)
Net Property, Plant and Equipment	8,127	7,515
NONCURRENT ASSETS		
NDT Fund	1,754	1,780
Long-Term Investments	119	121
Goodwill	16	16
Other Intangibles	102	84
Other Special Funds	55	49
Derivative Contracts	77	62
Other	51	51
Total Noncurrent Assets	2,174	2,163
TOTAL ASSETS	$12,250	$12,037

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

table of contents

PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2015	2014
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$553	$300
Accounts Payable	432	424
Accounts Payable—Affiliated Companies	33	118
Derivative Contracts	76	132
Deferred Income Taxes	—	43
Accrued Interest	25	27
Other	107	140
Total Current Liabilities	1,226	1,184
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	2,347	2,065
Asset Retirement Obligations	457	450
OPEB Costs	230	248
Derivative Contracts	16	33
Accrued Pension Costs	166	153
Long-Term Accrued Taxes	35	41
Other	87	71
Total Noncurrent Liabilities	3,338	3,061
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 12)		
LONG-TERM DEBT	1,684	2,234
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	5,014	4,558
Accumulated Other Comprehensive Loss	(240)	(228)
Total Member's Equity	6,002	5,558
TOTAL LIABILITIES AND MEMBER'S EQUITY	$12,250	$12,037

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

table of contents

PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2015	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$856	$760	$644
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	291	292	273
Amortization of Nuclear Fuel	213	200	192
Provision for Deferred Income Taxes and ITC	261	221	122
Interest Accretion on Asset Retirement Obligation	26	30	23
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(143)	(93)	79
Non-Cash Employee Benefit Plan Costs	48	13	66
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(38)	(166)	(104)
Net Change in Certain Current Assets and Liabilities:			
Fuel, Materials and Supplies	62	19	(8)
Margin Deposit	122	(22)	(43)
Accounts Receivable	63	(15)	(4)
Accounts Payable	(46)	(59)	28
Accounts Receivable/Payable-Affiliated Companies, net	(84)	220	—
Other Current Assets and Liabilities	(36)	(6)	72
Employee Benefit Plan Funding and Related Payments	(11)	(7)	(46)
Other	122	38	53
Net Cash Provided By (Used In) Operating Activities	1,706	1,425	1,347
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(1,117)	(626)	(609)
Proceeds from Sales of Available-for-Sale Securities	1,422	1,557	1,084
Investments in Available-for-Sale Securities	(1,455)	(1,573)	(1,102)
Short-Term Loan—Affiliated Company, net	221	206	(216)
Other	(72)	(88)	(18)
Net Cash Provided By (Used In) Investing Activities	(1,001)	(524)	(861)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Long-Term Debt	—	—	500
Cash Dividend Paid	(400)	(895)	(705)
Redemption of Long-Term Debt	(300)	—	(300)
Contributed Capital	—	—	24
Other	(2)	(3)	(6)
Net Cash Provided By (Used In) Financing Activities	(702)	(898)	(487)
Net Increase (Decrease) in Cash and Cash Equivalents	3	3	(1)
Cash and Cash Equivalents at Beginning of Period	9	6	7
Cash and Cash Equivalents at End of Period	$12	$9	$6
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$393	$68	$291
Interest Paid, Net of Amounts Capitalized	$116	$119	$106

Accrued Property, Plant and Equipment Expenditures	$114	$91	$90

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

table of contents

PSEG POWER LLC
CONSOLIDATED STATEMENTS OF MEMBER’S EQUITY
Millions

	Contributed Capital	Basis Adjustment	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance as of January 1, 2013	$2,190	$(986)	$4,754	$(328)	$5,630
Net Income	—	—	644	—	644
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(199)	—	—	—	265	265
Comprehensive Income					909
Contributed Capital	24	—	—	—	24
Cash Dividends Paid	—	—	(705)		(705)
Balance as of December 31, 2013	$2,214	$(986)	$4,693	$(63)	$5,858
Net Income	—	—	760	—	760
Other Comprehensive Income (Loss), net of tax (expense) benefit of $121	—	—	—	(165)	(165)
Comprehensive Income					595
Cash Dividends Paid	—	—	(895)	—	(895)
Balance as of December 31, 2014	$2,214	$(986)	$4,558	$(228)	$5,558
Net Income	—	—	856	—	856
Other Comprehensive Income (Loss), net of tax (expense) benefit of $23	—	—	—	(12)	(12)
Comprehensive Income					844
Cash Dividends Paid	—	—	(400)	—	(400)
Balance as of December 31, 2015	$2,214	$(986)	$5,014	$(240)	$6,002

See disclosures regarding PSEG Power LLC included in the Notes to Consolidated Financial Statements.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1. Organization, Basis of Presentation and Summary of Significant Accounting Policies

Public Service Enterprise Group Incorporated (PSEG) is a holding company with a diversified business mix within the energy industry. Its operations are primarily in the Northeastern and Mid-Atlantic United States and in other select markets. PSEG’s principal direct wholly owned subsidiaries are:

- Public Service Electric and Gas Company (PSE&G)—which is a public utility engaged principally in the transmission of electricity and distribution of electricity and natural gas in certain areas of New Jersey. PSE&G is subject to regulation by the New Jersey Board of Public Utilities (BPU) and the Federal Energy Regulatory Commission (FERC). PSE&G also invests in solar generation projects and has implemented energy efficiency and demand response programs in New Jersey, which are regulated by the BPU.
- PSEG Power LLC (Power)—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply and energy transacting functions primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. Power’s subsidiaries are subject to regulation by FERC, the Nuclear Regulatory Commission (NRC), the Environmental Protection Agency (EPA) and the states in which they operate.

PSEG's other direct wholly owned subsidiaries include PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; PSEG Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) transmission and distribution (T&D) system under an Operations Services Agreement (OSA); and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries at cost.

Basis of Presentation

The respective financial statements included herein have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) applicable to Annual Reports on Form 10-K and in accordance with accounting guidance generally accepted in the United States (GAAP).

Significant Accounting Policies

Principles of Consolidation

Each company consolidates those entities in which it has a controlling interest or is the primary beneficiary. See Note 3. Variable Interest Entities. Entities over which the companies exhibit significant influence, but do not have a controlling interest and/or are not the primary beneficiary, are accounted for under the equity method of accounting. For investments in which significant influence does not exist and the investor is not the primary beneficiary, the cost method of accounting is applied. All intercompany accounts and transactions are eliminated in consolidation.

PSE&G and Power also have undivided interests in certain jointly-owned facilities, with each responsible for paying its respective ownership share of construction costs, fuel purchases and operating expenses. PSE&G and Power consolidate their portion of any revenues and expenses related to their respective jointly-owned facilities in the appropriate revenue and expense categories.

Accounting for the Effects of Regulation

In accordance with accounting guidance for rate-regulated entities, PSE&G’s financial statements reflect the economic effects of regulation. PSE&G defers the recognition of costs (a Regulatory Asset) or records the recognition of obligations (a Regulatory Liability) if it is probable that, through the rate-making process, there will be a corresponding increase or decrease in future rates. Accordingly, PSE&G has deferred certain costs and recoveries, which are being amortized over various future periods. To the extent that collection of any such costs or payment of liabilities becomes no longer probable as a result of changes in regulation and/or competitive position, the associated Regulatory Asset or Liability is charged or credited to income. Management believes that PSE&G’s transmission and distribution businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 5. Regulatory Assets and Liabilities.

Derivative Financial Instruments

Each company uses derivative financial instruments to manage risk pursuant to its business plans and prudent practices.

Derivative instruments, not designated as normal purchases or sales, are recognized on the balance sheet at their fair value. Changes in the fair value of a derivative that is highly effective as and that is designated and qualifies as a fair value hedge, along with changes of the fair value of the hedged asset or liability that are attributable to the hedged risk, are recorded in

93

current period earnings. Changes in the fair value of a derivative that is highly effective as and that is designated and qualifies as a cash flow hedge are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. Any hedge ineffectiveness is included in current period earnings. For derivative contracts that do not qualify or are not designated as cash flow or fair value hedges or as normal purchases or sales, changes in fair value are recorded in current period earnings.

Many contracts qualify for the normal purchases and normal sales exemption and are accounted for upon settlement. For additional information regarding derivative financial instruments, see Note 15. Financial Risk Management Activities.

Revenue Recognition

PSE&G's regulated electric and gas revenues are recorded primarily based on services rendered to customers. PSE&G records unbilled revenues for the estimated amount customers will be billed for services rendered from the time meters were last read to the end of the respective accounting period. The unbilled revenue is estimated each month based on usage per day, the number of unbilled days in the period, estimated seasonal loads based upon the time of year and the variance of actual degree-days and temperature-humidity-index hours of the unbilled period from expected norms.

Regulated revenues from the transmission of electricity are recognized as services are provided based on a FERC-approved annual formula rate mechanism. This mechanism provides for an annual filing of estimated revenue requirement with rates effective January 1 of each year. After completion of the annual period ending December 31, PSE&G files a true-up whereby it compares its actual revenue requirement to the original estimate to determine any over or under collection of revenue. PSE&G records the estimated financial statement impact of the difference between the actual and the filed revenue requirement as a refund or deferral for future recovery when such amounts are probable and can be reasonably estimated in accordance with accounting guidance for rate-regulated entities.

The majority of Power's revenues relate to bilateral contracts, which are accounted for on the accrual basis as the energy is delivered. Power's revenue also includes changes in the value of energy derivative contracts that are not designated as normal purchases or sales or as cash flow or fair value hedges of other positions. See Note 15. Financial Risk Management Activities for further discussion.

PJM Interconnection, L.L.C. (PJM), the Independent System Operator-New England (ISO-NE) and the New York Independent System Operator (NYISO) facilitate the dispatch of energy and energy-related products. Power generally reports sales and purchases conducted with those individual ISOs on a net hourly basis in either Revenues or Energy Costs in its Consolidated Statement of Operations, the classification of which depends on the net hourly activity. Capacity revenue and expense is also reported net based on Power's net sale or purchase position in the individual ISOs.

PSEG LI is the primary beneficiary of Long Island Electric Utility Servco, LLC (Servco). For transactions in which Servco acts as principal, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and Operations and Maintenance (O&M) Expense, respectively. See Note 3. Variable Interest Entities for further information.

Depreciation and Amortization

PSE&G calculates depreciation under the straight-line method based on estimated average remaining lives of the several classes of depreciable property. These estimates are reviewed on a periodic basis and necessary adjustments are made as approved by the BPU or FERC. The depreciation rate stated as a percentage of original cost of depreciable property was as follows:

	2015 Avg Rate		2014 Avg Rate		2013 Avg Rate	
PSE&G Depreciation Rate	2.46	%	2.47	%	2.48	%

Power calculates depreciation on generation-related assets under the straight-line method based on the assets' estimated useful lives. The estimated useful lives are:

- general plant assets—3 years to 20 years
- fossil production assets—19 years to 79 years
- nuclear generation assets—approximately 60 years
- pumped storage facilities—76 years
- solar assets—25 years

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Taxes Other Than Income Taxes

Excise taxes and the transitional energy facilities assessment (TEFA) collected from PSE&G's customers are presented in the financial statements on a gross basis. Effective January 1, 2014, the TEFA was eliminated. For the year ended December 31, 2013, $74 million and $68 million of the TEFA were included in Operating Revenues and Taxes Other Than Income Taxes, respectively, in the Consolidated Statements of Operations.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalized During Construction (IDC)

AFUDC represents the cost of debt and equity funds used to finance the construction of new utility assets at PSE&G. IDC represents the cost of debt used to finance construction at Power. The amount of AFUDC or IDC capitalized as Property, Plant and Equipment is included as a reduction of interest charges or other income for the equity portion. The amounts and average rates used to calculate AFUDC or IDC for the years ended December 31, 2015, 2014 and 2013 were as follows:

	AFUDC/IDC Capitalized					
	2015		2014		2013	
	Millions	Avg Rate	Millions	Avg Rate	Millions	Avg Rate
PSE&G	$65	8.01 %	$44	8.09 %	$34	8.11 %
Power	$27	5.14 %	$24	5.14 %	$23	5.36 %

Income Taxes

PSEG and its subsidiaries file a consolidated federal income tax return and income taxes are allocated to PSEG's subsidiaries based on the taxable income or loss of each subsidiary in accordance with a tax sharing agreement between PSEG and each of its affiliated subsidiaries. Allocations between PSEG and its subsidiaries are recorded through intercompany accounts. Investment tax credits deferred in prior years are being amortized over the useful lives of the related property.

Uncertain income tax positions are accounted for using a benefit recognition model with a two-step approach, a more-likely-than-not recognition criterion and a measurement attribute that measures the position as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. If it is not more-likely-than-not that the benefit will be sustained on its technical merits, no benefit will be recorded. Uncertain tax positions that relate only to timing of when an item is included on a tax return are considered to have met the recognition threshold. See Note 19. Income Taxes for further discussion.

Impairment of Long-Lived Assets

In accordance with GAAP, 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, including prolonged periods of adverse commodity and capacity prices, could potentially indicate an asset's or asset group's carrying amount may not be recoverable. In such an event, an undiscounted cash flow analysis is performed to determine if an impairment exists. When a long-lived asset's or asset group's carrying amount exceeds the associated undiscounted estimated future cash flows, the asset/asset group is considered impaired to the extent that its fair value is less than its carrying amount. An impairment would result in a reduction of the value of the long-lived asset/asset group through a non-cash charge to earnings.

For Power, cash flows for long-lived assets and asset groups are determined at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. The cash flows from the generation units are generally evaluated at a regional portfolio level (PJM, NYISO, ISO-NE) along with cash flows generated from the customer supply and risk management activities, inclusive of cash flows from contracts, including those that are accounted for as derivatives or that meet the normal purchases and normal sales exemption. In certain cases, generation assets are evaluated on an individual basis where those assets are individually contracted on a long-term basis with a third party and operations are independent of other generation assets (typically Power's solar plants and Kalaeloa).

Cash and Cash Equivalents

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less.

Accounts Receivable—Allowance for Doubtful Accounts

PSE&G’s accounts receivable are reported in the balance sheet as gross outstanding amounts adjusted for doubtful accounts. The allowance for doubtful accounts reflects PSE&G’s best estimates of losses on the accounts receivable balances. The allowance is based on accounts receivable aging, historical experience, write-off forecasts and other currently available evidence.

Accounts receivable are charged off in the period in which the receivable is deemed uncollectible. Recoveries of accounts receivable are recorded when it is known they will be received.

Materials and Supplies and Fuel

PSE&G's and Power's materials and supplies are carried at average cost and charged to inventory when purchased and expensed or capitalized to Property, Plant and Equipment, as appropriate, when installed or used. Fuel inventory at Power is valued at the lower of average cost or market and includes stored natural gas, coal, fuel oil and propane used to generate power and to satisfy obligations under Power's gas supply contracts with PSE&G. The costs of fuel, including transportation costs, are included in inventory when purchased and charged to Energy Costs when used or sold. The cost of nuclear fuel is capitalized within Property, Plant and Equipment and amortized to fuel expense using the units-of-production method.

Property, Plant and Equipment

PSE&G's additions to and replacements of existing property, plant and equipment are capitalized at cost. The cost of maintenance, repair and replacement of minor items of property is charged to expense as incurred. At the time units of depreciable property are retired or otherwise disposed of, the original cost, adjusted for net salvage value, is charged to accumulated depreciation.

Power capitalizes costs, including those related to its jointly-owned facilities, which increase the capacity or extend the life of an existing asset, represent a newly acquired or constructed asset or represent the replacement of a retired asset. The cost of maintenance, repair and replacement of minor items of property is charged to appropriate expense accounts as incurred. Environmental costs are capitalized if the costs mitigate or prevent future environmental contamination or if the costs improve existing assets' environmental safety or efficiency. All other environmental expenditures are expensed as incurred.

Available-for-Sale Securities

These securities comprise the Nuclear Decommissioning Trust (NDT) Fund, a master independent external trust account maintained to provide for the costs of decommissioning upon termination of operations of Power's nuclear facilities and amounts that are deposited to fund a Rabbi Trust which was established to meet the obligations related to non-qualified pension plans and deferred compensation plans.

Realized gains and losses on available-for-sale securities are recorded in earnings and unrealized gains and losses on such securities are recorded as a component of Accumulated Other Comprehensive Income (Loss) (except credit losses on debt securities which are recorded in earnings). Securities with unrealized losses that are deemed to be other-than-temporarily impaired are recorded in earnings. See Note 8. Available-for-Sale Securities for further discussion.

Pension and Other Postretirement Benefits (OPEB) Plans

The market-related value of plan assets held for the qualified pension and OPEB plans is equal to the fair value of those assets as of year-end. Fair value is determined using quoted market prices and independent pricing services based upon the security type as reported by the trustee at the measurement date (December 31) for all plan assets.

PSEG recognizes a long-term receivable primarily related to future funding by LIPA of Servco's recognized pension and OPEB liabilities. This receivable is presented separately on the Consolidated Balance Sheet of PSEG as a noncurrent asset because it is restricted.

Pursuant to the OSA, Servco records expense only to the extent of its contributions to its pension plan trusts and for OPEB payments made to retirees.

See Note 11. Pension and Other Postretirement Benefits (OPEB) and Savings Plans for further discussion.

Basis Adjustment

PSE&G and Power have recorded a Basis Adjustment in their respective Consolidated Balance Sheets related to the generation assets that were transferred from PSE&G to Power in August 2000 at the price specified by the BPU. Because the transfer was between affiliates, the transaction was recorded at the net book value of the assets and liabilities rather than the transfer price. The difference between the total transfer price and the net book value of the generation-related assets and liabilities, $986 million, net of tax, was recorded as a Basis Adjustment on PSE&G's and

Power's Consolidated Balance Sheets. The $986 million is an addition to PSE&G’s Common Stockholder’s Equity and a reduction of Power’s Member’s Equity. These amounts are eliminated on PSEG’s consolidated financial statements.

Use of Estimates

The process of preparing financial statements in conformity with GAAP requires the use of estimates and assumptions regarding certain types of assets, liabilities, revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 2. Recent Accounting Standards

New Standards Adopted in 2015

Simplifying the Presentation of Debt Issuance Costs

This standard was issued to simplify presentation of debt issuance costs. The standard requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. The recognition and measurement guidance for debt issuance costs are not affected by this standard.

The update is effective for annual and interim reporting periods beginning after December 15, 2015. Early adoption is permitted for financial statements that have not been previously issued; therefore, PSEG has elected to early adopt these amendments in the fourth quarter of 2015 on a retrospective basis and therefore reclassified debt issuance costs in the 2014 Consolidated Balance Sheets. Unamortized debt issuance costs for PSE&G and Power were $41 million and $8 million, respectively, as of December 31, 2015 and $37 million and $9 million, respectively, as of December 31, 2014.

Balance Sheet Classification of Deferred Taxes

This standard was issued to reduce complexity in the presentation of deferred taxes. The new guidance requires that all deferred tax assets and liabilities be classified as noncurrent on the balance sheet. The guidance is effective for annual and interim periods beginning after December 15, 2016. Early application is permitted as of the beginning of an interim or annual reporting period and the guidance may be applied either prospectively to all deferred tax assets and liabilities or retrospectively to all periods presented. PSEG has elected to early adopt the guidance as of the fourth quarter of 2015 and to apply it prospectively. Prior periods were not retrospectively adjusted.

New Standards Issued But Not Yet Adopted

Revenue from Contracts with Customers

This accounting standard was issued to clarify the principles for recognizing revenue and to develop a common standard that would remove inconsistencies in revenue requirements; improve comparability of revenue recognition practices across entities, industries, jurisdictions and capital markets; and provide improved disclosures.

The guidance provides a five-step model to be used for recognizing revenue for the transfer of promised goods and services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.

The update was originally to be effective for annual and interim reporting periods beginning after December 15, 2016; however, the Financial Accounting Standards Board issued new guidance deferring the effective date by one year to periods beginning after December 31, 2017. Early application will be permitted as of the original effective date. PSEG is currently analyzing the impact of this standard on its financial statements.

Recognition and Measurement of Financial Assets and Financial Liabilities

This accounting standard will change how entities measure equity investments that are not consolidated or accounted for under the equity method and how they will present changes in the fair value of financial liabilities measured under the fair value option that are attributable to their own credit. Under the new guidance, equity investments (other than those accounted for using the equity method) will now have to be measured at fair value through Net Income instead of Other Comprehensive Income (Loss). For equity investments which do not have readily determinable fair values, the impairment assessment will be simplified by requiring a qualitative assessment to identify impairments. The new standard also changes certain disclosures.

The accounting standard is effective for annual and interim reporting periods beginning after December 15, 2017. Early application is permitted for fiscal years or interim periods for which financial statements have not been issued. PSEG is currently analyzing the impact of this standard on our financial statements; however, PSEG expects increased volatility in net income due to changes in fair value of our equity securities within the NDT and Rabbi Trust Funds.

Leases

This accounting standard replaces existing lease accounting guidance and requires lessees to recognize all leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee would recognize a lease asset and corresponding lease obligation. A lessee would classify its leases as either finance leases or operating leases based on whether control of the underlying assets has transferred to the lessee. A lessor would classify its leases as operating or direct financing leases, or as sales-type leases based on whether control of the underlying assets has transferred to the lessee. Both the lessee and lessor models require additional disclosure of key information. The standard requires lessees and lessors to apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements.

The accounting standard is effective for annual and interim periods beginning after December 15, 2018 with retrospective application to previously issued financial statements for 2018 and 2017. Early application is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Note 3. Variable Interest Entities (VIEs)

VIEs for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remain with these VIEs.

VIE for which PSEG LI is the Primary Beneficiary

PSEG LI consolidates Servco, a marginally capitalized VIE, which was created for the purpose of operating LIPA's T&D system in Long Island, New York as well as providing administrative support functions to LIPA. PSEG LI is the primary beneficiary of Servco because it directs the operations of Servco, the activity that most significantly impacts Servco's economic performance and it has the obligation to absorb losses of Servco that could potentially be significant to Servco. Such losses would be immaterial to PSEG.

Pursuant to the OSA, Servco's operating costs are reimbursable entirely by LIPA, and therefore, PSEG LI's risk is limited related to the activities of Servco. PSEG LI has no current obligation to provide direct financial support to Servco. In addition to reimbursement of Servco’s operating costs as provided for in the OSA, PSEG LI receives an annual contract management fee. PSEG LI’s annual contractual management fee, in certain situations, could be partially offset by Servco's annual storm costs not approved by the Federal Emergency Management Agency, limited contingent liabilities and penalties for failing to meet certain performance metrics.

For transactions in which Servco acts as principal, such as transactions with its employees for labor and labor-related activities, including pension and OPEB-related transactions, Servco records revenues and the related pass-through expenditures separately in Operating Revenues and O&M Expense, respectively. In 2015 and 2014, Servco recorded $375 million and $389 million, respectively, of O&M costs, the full reimbursement of which was reflected in Operating Revenues. For transactions in which Servco acts as an agent for LIPA, it records revenues and the related expenses on a net basis, resulting in no impact on PSEG's Consolidated Statement of Operations.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 4. Property, Plant and Equipment and Jointly-Owned Facilities
Information related to Property, Plant and Equipment as of December 31, 2015 and 2014 is detailed below:

	PSE&G	Power	Other	PSEG Consolidated
	Millions			
2015				
Transmission and Distribution:				
Electric Transmission	$7,554	$—	$—	$7,554
Electric Distribution	7,553	—	—	7,553
Gas Transmission	89	—	—	89
Gas Distribution	5,875	—	—	5,875
Construction Work in Progress	1,459	—	—	1,459
Plant Held for Future Use	26	—	—	26
Other	411	—	—	411
Total Transmission and Distribution	22,967	—	—	22,967
Generation:				
Fossil Production	—	7,005	—	7,005
Nuclear Production	—	2,202	—	2,202
Nuclear Fuel in Service	—	785	—	785
Other Production-Solar	569	389	—	958
Construction Work in Progress	—	892	—	892
Total Generation	569	11,273	—	11,842
Other	196	81	408	685
Total	$23,732	$11,354	$408	$35,494

	PSE&G	Power	Other	PSEG Consolidated
	Millions			
2014				
Transmission and Distribution:				
Electric Transmission	$5,845	$—	$—	$5,845
Electric Distribution	7,295	—	—	7,295
Gas Transmission	89	—	—	89
Gas Distribution	5,479	—	—	5,479
Construction Work in Progress	1,304	—	—	1,304
Plant Held for Future Use	15	—	—	15
Other	401	—	—	401
Total Transmission and Distribution	20,428	—	—	20,428
Generation:				
Fossil Production	—	6,964	—	6,964
Nuclear Production	—	1,751	—	1,751
Nuclear Fuel in Service	—	889	—	889
Other Production-Solar	521	314	—	835
Construction Work in Progress	—	714	—	714
Total Generation	521	10,632	—	11,153

Other	154	100	361	615
Total	$21,103	$10,732	$361	$32,196

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G and Power have ownership interests in and are responsible for providing their respective shares of the necessary financing for the following jointly-owned facilities. All amounts reflect the share of PSE&G's and Power's jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as operating expenses.

		As of December 31,			
		2015		2014	
	Ownership Interest	Plant	Accumulated Depreciation	Plant	Accumulated Depreciation
		Millions			
PSE&G:					
Transmission Facilities	Various	$166	$72	$162	$69
Power:					
Coal Generating:					
Conemaugh	23 %	$404	$154	$397	$142
Keystone	23 %	$408	$163	$396	$151
Nuclear Generating:					
Peach Bottom	50 %	$1,219	$262	$1,087	$236
Salem	57 %	$990	$276	$916	$236
Nuclear Support Facilities	Various	$226	$60	$218	$49
Pumped Storage Facilities:					
Yards Creek	50 %	$42	$24	$41	$24
Merrill Creek Reservoir	14 %	$1	$—	$1	$—

Power holds undivided ownership interests in the jointly-owned facilities above. Power is entitled to shares of the generating capability and output of each unit equal to its respective ownership interests. Power also pays its ownership share of additional construction costs, fuel inventory purchases and operating expenses. Power's share of expenses for the jointly-owned facilities is included in the appropriate expense category. Each owner is responsible for any financing with respect to its pro rata share of capital expenditures.

Power co-owns Salem and Peach Bottom with Exelon Generation. Power is the operator of Salem and Exelon Generation is the operator of Peach Bottom. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

GenOn Northeast Management Company is a co-owner and the operator for Keystone Generating Station and Conemaugh Generating Station. A committee appointed by the co-owners provides oversight. Proposed O&M budgets and requests for major capital expenditures are reviewed and approved as part of the normal Power governance process.

Power is a co-owner in the Yards Creek Pumped Storage Generation Facility. Jersey Central Power & Light Company (JCP&L) is also a co-owner and the operator of this facility. JCP&L submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Power is a minority owner in the Merrill Creek Reservoir and Environmental Preserve in Warren County, New Jersey. Merrill Creek Owners Group is the owner-operator of this facility. The operator submits separate capital and O&M budgets, subject to Power's approval as part of the normal Power governance process.

Note 5. Regulatory Assets and Liabilities

PSE&G prepares its financial statements in accordance with GAAP for regulated utilities as described in Note 1. Organization and Basis of Presentation and Summary of Significant Accounting Policies. PSE&G has deferred certain costs based on rate orders issued by the BPU or FERC or based on PSE&G’s experience with prior rate cases. Most of PSE&G’s Regulatory Assets and Liabilities as of December 31, 2015 are supported by written orders, either explicitly or implicitly through the BPU’s treatment of various cost items. These costs will be recovered and amortized over various future periods.

Regulatory Assets and other investments and costs incurred under our various infrastructure filings and clause mechanisms are subject to prudence reviews and can be disallowed in the future by regulatory authorities. To the extent that collection of any

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

infrastructure or clause mechanism revenue, Regulatory Assets or payments of Regulatory Liabilities is no longer probable, the amounts would be charged or credited to income.
PSE&G had the following Regulatory Assets and Liabilities:

	As of December 31,		
	2015	2014	Recovery/Refund Period
	Millions		
Regulatory Assets			
Current			
New Jersey Clean Energy Program	$142	$142	Annual filing for recovery (2)
Stranded Costs (including $249 in 2014 related to VIEs)	—	412	Through December 2015 (2)
Underrecovered Electric Energy Costs—Basic Generation Service	11	—	Annual filing for recovery (1) (2)
Weather Normalization Clause (WNC)	10	—	Annual filing for recovery (2)
Solar and Energy Efficiency Recovery Charges (Green Program Recovery Charges (GPRC))	1	13	Annual filing for recovery (1) (2)
Other	—	5	Various
Total Current Regulatory Assets	$164	$572	
Noncurrent			
Pension and OPEB Costs	$1,270	$1,265	Various
Deferred Income Taxes	467	473	Various
Manufactured Gas Plant (MGP) Remediation Costs	431	434	Various (2)
Storm Damage Deferrals	233	245	To be determined
Remediation Adjustment Charge (RAC) (Other SBC)	174	164	Through 2022 (1) (2)
Conditional Asset Retirement Obligation	152	138	Various
Electric Transmission Cost of Removal	133	91	Through depreciation rates
GPRC	104	134	Various (1) (2)
Unamortized Loss on Reacquired Debt and Debt Expense	67	74	Over remaining debt life
Mark-to-Market (MTM) Contracts	63	75	Through 2017
Other	102	99	Various
Total Noncurrent Regulatory Assets	$3,196	$3,192	
Total Regulatory Assets	$3,360	$3,764	

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31,		
	2015	2014	Recovery/Refund Period
	Millions		
Regulatory Liabilities			
Current			
Stranded Costs (including $42 in 2015 related to VIEs)	$64	$—	Through December 2016 (2)
GPRC	36	6	Annual filing for recovery (1) (2)
Societal Benefit Clause (SBC)	31	13	Various (1) (2)
FERC Formula Rate True-up	19	—	Annual filing for recovery (1) (2)
Gas Margin Adjustment Clause	13	28	Annual filing for recovery (1) (2)
Overrecovered Gas Costs —Basic Gas Supply Service	1	46	Annual filing for recovery (1) (2)
WNC	—	31	Annual filing for recovery (2)
Deferred Income Taxes	—	28	Various
Overrecovered Electric Energy Costs— Basic Generation Service	—	21	Annual filing for recovery (1) (2)
Overrecovered Non-Utility Generation Charge (NGC)	1	13	Annual filing for recovery (1) (2)
Total Current Regulatory Liabilities	$165	$186	
Noncurrent			
Electric Distribution Cost of Removal	$122	$133	Through depreciation rates
FERC Formula Rate True-up	49	26	Annual filing for recovery (1) (2)
Stranded Costs (including $39 in 2014 related to VIEs)	—	134	Through December 2016 (2)
Other	4	4	Various
Total Noncurrent Regulatory Liabilities	$175	$297	
Total Regulatory Liabilities	$340	$483	

(1) Recovered/Refunded with interest.
(2) Recoverable/Refundable per specific rate order.

All Regulatory Assets and Liabilities are excluded from PSE&G’s rate base unless otherwise noted. The Regulatory Assets and Liabilities in the table above are defined as follows:

- Conditional Asset Retirement Obligation: These costs represent the differences between rate regulated cost of removal accounting and asset retirement accounting under GAAP. These costs will be recovered in future rates.
- Deferred Income Taxes: These amounts represent the portion of deferred income taxes that will be recovered or refunded through future rates, based upon established regulatory practices.
- Electric and Gas Cost of Removal: PSE&G accrues and collects in rates for the cost of removing, dismantling and disposing of its transmission and distribution assets upon retirement. The regulatory asset or liability for non-legally required cost of removal represents the difference between amounts collected in rates and costs actually incurred.
- FERC Formula Rate True-up: Overcollection or undercollection of transmission earnings calculated using a FERC approved formula.

- Gas Margin Adjustment Clause: This mechanism credits Firm delivery customers for net distribution margin revenue collected from Transportation Gas Service Non-Firm (TSG-NF) delivery customers. The balance represents the difference between the net margin collected from the TSG-NF Customers versus bill credits provided to Firm delivery customers.
- GPRC: These costs are amounts associated with various renewable energy and energy efficiency programs. Components of the GPRC include: Carbon Abatement, Energy Efficiency Economic Stimulus Program, Energy Efficiency Economic (EEE) Extension Program, EEE Extension II Program, the Demand Response Program, Solar

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Generation Investment Program (Solar 4 All), Solar 4 All Extension, Solar Loan II Program and Solar Loan III Program.

- MGP Remediation Costs: Represents the low end of the range for the remaining environmental investigation and remediation program cleanup costs for manufactured gas plants that are probable of recovery in future rates. Once these costs are incurred, they are recovered through the RAC in the SBC.
- MTM Contracts: The estimated fair value of gas hedge contracts and gas cogeneration supply contracts. The regulatory asset/liability is offset by a derivative asset/liability and, with respect to the gas hedge contracts only, an intercompany receivable/payable on the Consolidated Balance Sheets.
- New Jersey Clean Energy Program: The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs through the first half of 2016. Once the rates are measured, they are recovered through the SBC.
- NGC: These costs represent the difference between rate payer collections and the cost of non-utility generation netted against amounts realized from selling that energy at market rates through PJM.
- Overrecovered Electric Energy Costs: These costs represent the overrecovered amounts associated with Basic Generation Service (BGS), as approved by the BPU. Pursuant to BPU requirements, PSE&G serves as the supplier of last resort for electric customers within its service territory that are not served by another supplier. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for PSE&G's operations. For BGS, interest is accrued on both overrecovered and underrecovered balances.
- Overrecovered Gas Costs: These costs represent the overrecovered amounts associated with Basic Gas Supply Service (BGSS), as approved by the BPU. Pursuant to BPU requirements, PSE&G serves as the supplier of last resort for gas customers within its service territory that are not served by another supplier. Pricing for those services are set by the BPU as a pass-through, resulting in no margin for PSE&G's operations. For BGSS, interest is accrued only on overrecovered balances.
- Pension and OPEB Costs: Pursuant to the adoption of accounting guidance for employers' defined benefit pension and OPEB plans, PSE&G recorded the unrecognized costs for defined benefit pension and other OPEB plans on the balance sheet as a Regulatory Asset. These costs represent actuarial gains or losses, prior service costs and transition obligations as a result of adoption, which have not been expensed. These costs are amortized and recovered in future rates.
- RAC (Other SBC): Costs incurred to clean up manufactured gas plants which are recovered over seven years.
- SBC: The SBC, as authorized by the BPU and the New Jersey Electric Discount and Energy Competition Act, includes costs related to PSE&G's electric and gas business as follows: (1) the Universal Service Fund (USF); (2) Energy Efficiency and Renewable Energy Programs; (3) Electric bad debt expense; and (4) the RAC for incurred MGP remediation expenditures. All components accrue interest on both over and underrecoveries.
- Storm Damage Deferrals: Costs incurred in the cleanup of major storms in 2010 through 2015. As of December 31, 2015, this includes the $220 million of storm costs, net of insurance recoveries, primarily as a result of Hurricane Irene and Superstorm Sandy, approved for future recovery under a BPU Order received in September 2014.
- Stranded Costs: This reflects the overrecovered balance of costs, which were recovered through the securitization transition charges authorized by the BPU in irrevocable financing orders and collected by PSE&G, as servicer on behalf of Transition Funding and Transition Funding II, respectively. Collected funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs and taxes. During 2015, Transition Funding and Transition Funding II paid their final securitization bond payments and as of December 31, 2015, no further debt or related costs remain.

Transition Funding and Transition Funding II are wholly owned, bankruptcy-remote subsidiaries of PSE&G that purchased certain transition property from PSE&G and issued transition bonds secured by such property. The transition property consists principally of the rights to receive electricity consumption-based per kilowatt-hour (kWh) charges from PSE&G's electric distribution customers, which represent irrevocable rights to receive amounts sufficient to recover certain of PSE&G's transition costs related to deregulation, as approved by the BPU.

Effective January 1, 2016, PSE&G commenced refunding the overcollections from customers associated with Stranded Costs and expects to fully refund these liabilities in 2016.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

- Unamortized Loss on Reacquired Debt and Debt Expense: Represents losses on reacquired long-term debt and expenses associated with issuances of new debt, which are recovered through rates over the remaining life of the debt.
- Underrecovered Electric Energy Costs: These costs represent the underrecovered amounts associated with BGS, as approved by the BPU. For BGS, interest is accrued on both overrecovered and underrecovered balances.
- WNC: This represents the over- or under- collection of gas margin refundable or recoverable under the BPU's weather normalization clause. The WNC requires PSE&G to calculate, at the end of each October-to-May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred. Over recoveries are refunded to customers in the next winter season while under recoveries (subject to an earnings cap) are collected from customers in the next winter season.

Significant 2015 regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

- Energy Strong Recovery Filing—In February 2015, the BPU approved PSE&G's initial Energy Strong filing to recover in base rates an estimated annual electric revenue increase of $1 million effective March 1, 2015. This increase represents capitalized Energy Strong electric investment costs in service through November 30, 2014. In August 2015, the BPU approved PSE&G's second Energy Strong petition to recover in base rates an estimated annual revenue increases in electric revenues of $6 million and gas revenues of $17 million effective September 1, 2015. These increases represent a return on investment and recovery of Energy Strong capitalized investment costs placed in service from December 1, 2014 through May 31, 2015 for electric and from June 1, 2014 through May 31, 2015 for gas.

In September 2015, PSE&G filed an Energy Strong electric cost recovery petition seeking BPU approval to recover the revenue requirements associated with Energy Strong capitalized investment costs placed in service from June 1, 2015 through November 30, 2015. In February 2016, the BPU approved PSE&G's request for an annualized increase in electric revenue requirements of $10 million with rates effective March 1, 2016.

- BGSS—In January 2015 and March 2015, PSE&G filed letters with the BPU to provide self-implementing bill credits for February, March and April 2015. When combined with the January 2015 bill credit filed with the BPU in 2014, a total of $243 million was returned to customers for the period January 1 to April 30, 2015. In April 2015, the BPU issued an Order approving PSE&G's BGSS rate of 45 cents per therm which had been implemented on October 1, 2014 as final.

In June 2015, PSE&G made its Annual BGSS Filing with the BPU requesting a reduction of $70 million in annual BGSS revenues. In September 2015, the BPU approved a Stipulation in this matter on a provisional basis and the BGSS rate was reduced from approximately 45 cents to 40 cents per therm effective October 1, 2015. In February 2016, the BPU issued an Order approving PSE&G's BGSS rate of 40 cents per therm as final.

In November, 2015, PSE&G filed with the BPU for a self-implementing three-month bill credit of 25 cents per therm for the months of December 2015 and January and February 2016. The bill credits are estimated to provide approximately $155 million to customers. The specific amount returned will depend on actual usage over that period.

- WNC—On April 15, 2015, the BPU approved PSE&G's final filing with respect to excess revenues collected during the colder than normal 2013-2014 Winter Period (October 1, 2013 through May 31, 2014). Effective October 1, 2014, PSEG commenced returning $45 million in revenues to its customers during the 2014-2015 Winter Period (October 1, 2014 through May 31, 2015).

In September 2015, the BPU approved PSE&G's filing on a provisional basis with respect to excess revenues collected during the colder than normal 2014-2015 Winter Period. Effective October 1, 2015, PSE&G commenced returning $40 million in revenues to its customers during the 2015-2016 Winter Period (October 1, 2015 through May 31, 2016). In January 2016, the BPU gave final approval to the provisional rates.

- Solar and Energy Efficiency - GPRC and Solar Pilot Recovery Charges (SPRC)—In April 2015, the BPU approved PSE&G's petition for an EEE Extension II Program to extend three EEE subprograms (multi-family, direct install and hospital efficiency). The Order allows PSE&G to extend the subprogram offerings under the same clause recovery process as its existing EEE Program and allows for $95 million of additional capital expenditures over the next three years and an allowance for $12 million of additional administrative expenses over the next 15 years. The EEE Extension II Program was added as a ninth component of the GPRC rate effective May 1, 2015.

In July of each year, PSE&G files for annual recovery for its Green Program investments which include a return on its investment and recovery of expenses. In May 2015, the BPU approved PSE&G’s July 2014 filing requesting recovery of costs and investments in the first eight combined components of the electric and gas GPRC for the period October 1, 2014 through September 30, 2015. In July 2015, PSE&G filed its annual GPRC and SPRC cost recovery petitions with the BPU, requesting recovery of costs and investments for the first eight combined components of the electric and gas GPRC, as well as the electric SPRC. The filings proposed rates for the period October 1, 2015 through September 30, 2016 designed to recover approximately $66 million and $10 million in electric and gas revenues, respectively, on an annual basis associated with PSE&G's implementation of these BPU approved programs. In September 2015, the BPU approved the July 2015 filings on a provisional basis, with new rates effective October 1, 2015. In November 2015, PSE&G filed updated costs with the BPU. In January 2016, the BPU gave final approval for rates set to recover adjusted amounts based on this update of approximately $57 million and $8 million in electric and gas revenues, respectively, on an annual basis with rates effective February 1, 2016.

- Transmission Formula Rate Filings—In June 2015, PSE&G filed its 2014 true-up adjustment pertaining to its formula rates in effect for 2014, which resulted in an adjustment of $19 million less than the 2014 originally filed revenues. The adjustment was primarily due to the impact of bonus depreciation and lower interest rates which PSE&G had recognized in its Consolidated Statement of Operations for the year ended December 31, 2014. In accordance with PSE&G’s formula rate protocols this Rate Year 2014 true-up adjustment has been incorporated into PSE&G's Annual Formula Rate Update for the 2016 Rate Year.

The 2016 Annual Formula Rate Update was filed with FERC in October 2015 and provides for $146 million in increased annual transmission revenues effective January 1, 2016. Each year, transmission revenues are adjusted to reflect items such as updating estimates used in the filing with actual data. The adjustment for 2016 will include the impact of the extension of bonus depreciation, which was enacted after our 2016 filing was made. This adjustment will be incorporated with the 2016 true-up adjustments filed in 2017 and will be incorporated into PSE&G’s Annual Formula Rate Update for the 2017 Rate Year.

- RAC—In August 2015, the BPU approved PSE&G's filing with respect to its RAC 22 petition allowing recovery of $85 million effective September 1, 2015 related to net Manufactured Gas Plant expenditures from August 1, 2013 through July 31, 2014.
- USF/Lifeline—In September 2015, the BPU approved rates set to recover costs incurred under the USF/Lifeline energy assistance programs effective October 1, 2015.
- SBC and NGC—In May 2015, PSE&G filed a petition to recover approximately $311 million in actual SBC and NGC costs incurred through December 31, 2014 under its Energy Efficiency & Renewable Energy Programs, Social Programs and NGC. In January 2016, the BPU approved PSE&G’s petition with rates effective February 1, 2016.

Note 6. Long-Term Investments

Long-Term Investments as of December 31, 2015 and 2014 included the following:

	As of December 31,	
	2015	2014
	Millions	
PSE&G		
Life Insurance and Supplemental Benefits	$150	$156
Solar Loans	175	187
Other Investments	5	5
Power		
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	119	121
Energy Holdings		
Lease Investments	784	836
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	—	2
Total Long-Term Investments	$1,233	$1,307

(A) During the three years ended December 31, 2015, 2014 and 2013, the amount of dividends from these investments was $16 million, $17 million and $11 million, respectively.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Leases
Energy Holdings has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG's Consolidated Balance Sheets. As an equity investor, Energy Holdings' equity investments in the leases are comprised of the total expected lease receivables over the lease terms plus the estimated residual values at the end of the lease terms, reduced for any income not yet earned on the leases. This amount is included in Long-Term Investments on PSEG's Consolidated Balance Sheets. The more rapid depreciation of the leased property for tax purposes creates tax cash flow that will be repaid to the taxing authority in later periods. As such, the liability for such taxes due is recorded in Deferred Income Taxes on PSEG's Consolidated Balance Sheets. The following table shows Energy Holdings' gross and net lease investment as of December 31, 2015 and 2014, respectively.

	As of December 31,	
	2015	2014
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$631	$691
Estimated Residual Value of Leased Assets	519	525
Total Investment in Rental Receivables	1,150	1,216
Unearned and Deferred Income	(366)	(380)
Gross Investments in Leases	784	836
Deferred Tax Liabilities	(724)	(738)
Net Investments in Leases	$60	$98

The pre-tax income and income tax effects, excluding gains and losses on sales, related to investments in leases were as follows:

	Years Ended December 31,		
	2015	2014	2013
	Millions		
Pre-Tax Income (Loss) from Leases	$12	$24	$11
Income Tax Expense (Benefit) on Pre-Tax Income from Leases	$5	$32	$6

Equity Method Investments
Power had the following equity method investments as of December 31, 2015:

Name	As of December 31, 2015	Location	% Owned
	Millions		
Power			
Keystone Fuels, LLC	$16	PA	23%
Conemaugh Fuels, LLC	$14	PA	23%
PennEast Pipeline	$5	PA	12%
Kalaeloa	$84	HI	50%

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 7. Financing Receivables
PSE&G
PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with solar renewable energy certificates (SRECs) generated from the installed solar electric system. The following table reflects the outstanding loans, including the noncurrent portion reported in Note 6. Long-Term Investments, by class of customer, none of which would be considered "non-performing."

Credit Risk Profile Based on Payment Activity		
	As of December 31,	
Consumer Loans	2015	2014
	Millions	
Commercial/Industrial	$177	$188
Residential	12	13
	$189	$201

Energy Holdings
Energy Holdings had a net investment in domestic energy and real estate assets subject to leveraged lease accounting of $60 million as of December 31, 2015 and $98 million as of December 31, 2014 (See Note 6. Long-Term Investments).
The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings.

Counterparties' Credit Rating Standard and Poor's (S&P) as of December 31, 2015	Lease Receivables, Net of Non-Recourse Debt As of December 31, 2015
	Millions
AA	$17
BBB+ - BBB-	316
BB-	134
CCC+	164
	$631

The "BB-" and the "CCC+" ratings in the preceding table represent lease receivables related to coal-fired assets in Illinois and Pennsylvania, respectively. As of December 31, 2015, the gross investment in the leases of such assets, net of non-recourse debt, was $573 million, ($(30) million, net of deferred taxes). A more detailed description of such assets under lease is presented in the following table.

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions					
Powerton Station Units 5 and 6	IL	$134	64 %	1,538	Coal	BB-	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$84	64 %	1,044	Coal	BB-	NRG Energy, Inc.

Keystone Station Units 1 and 2	PA	$ 121	17 %	1,711	Coal	CCC+	NRG REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 121	17 %	1,711	Coal	CCC+	NRG REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 113	100 %	603	Coal	CCC+	NRG REMA, LLC

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease and may include letters of credit or affiliate guarantees. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and attempt to seek recovery of their investment, potentially including stepping into the lease directly to protect their investments. While these actions could ultimately protect or mitigate the loss of value, they could require the use of significant capital investments and trigger certain material tax obligations. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims. Failure to recover adequate value could ultimately lead to a foreclosure on the assets under lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities to the Internal Revenue Service (IRS).

Although all lease payments are current, no assurances can be given that future payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flows include, but are not limited to, new environmental legislation and regulation regarding air quality, water and other discharges in the process of generating electricity, market prices for fuel, electricity and capacity, overall financial condition of lease counterparties and the quality and condition of assets under lease.

NRG REMA, LLC (NRG) notified PJM that it deactivated the coal-fired units at the Shawville generating facility in June 2015 and has disclosed that it expects to return the Shawville units to service in the summer of 2016 with the ability to use natural gas.

Note 8. Available-for-Sale Securities

NDT Fund

In accordance with NRC regulations, entities owning an interest in nuclear generating facilities are required to determine the costs and funding methods necessary to decommission such facilities upon termination of operation. As a general practice, each nuclear owner places funds in independent external trust accounts it maintains to provide for decommissioning. Power is required to file periodic reports with the NRC demonstrating that its NDT Fund meets the formula-based minimum NRC funding requirements.

Power maintains an external master NDT to fund its share of decommissioning for its five nuclear facilities upon their respective termination of operation. The trust contains two separate funds: a qualified fund and a non-qualified fund. Section 468A of the Internal Revenue Code limits the amount of money that can be contributed into a qualified fund. Power’s share of decommissioning costs related to its five nuclear units was estimated to be between $2.8 billion and $3.0 billion, including contingencies. The liability for decommissioning recorded on a discounted basis as of December 31, 2015 was approximately $429 million and is included in the Asset Retirement Obligation. The trust funds are managed by third-party investment advisors who operate under investment guidelines developed by Power. Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$693	$185	$(13)	$865
Debt Securities				
Government Obligations	483	8	(3)	488
Other Debt Securities	366	3	(10)	359
Total Debt Securities	849	11	(13)	847
Other Securities	42	—	—	42

Total NDT Available-for-Sale Securities	$1,584	$196	$(26)	$1,754

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$685	$220	$(8)	$897
Debt Securities				
Government Obligations	430	9	(1)	438
Other Debt Securities	333	9	(3)	339
Total Debt Securities	763	18	(4)	777
Other Securities	106	—	—	106
Total NDT Available-for-Sale Securities	$1,554	$238	$(12)	$1,780

These amounts in the preceding tables do not include receivables and payables for NDT Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as shown in the following table.

	As of December 31, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$17	$10
Accounts Payable	$10	$2

The following table shows the value of securities in the NDT Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2015				As of December 31, 2014			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$151	$(13)	$1	$—	$162	$(8)	$1	$—
Debt Securities								
Government Obligations (B)	245	(2)	19	(1)	95	—	28	(1)
Other Debt Securities (C)	222	(7)	36	(3)	99	(1)	30	(2)
Total Debt Securities	467	(9)	55	(4)	194	(1)	58	(3)
NDT Available-for-Sale Securities	$618	$(22)	$56	$(4)	$356	$(9)	$59	$(3)

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over companies with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2015.

(B)

Debt Securities (Government)—Unrealized losses on Power’s NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of December 31, 2015.

(C) Debt Securities (Corporate)—Power’s investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2015.

The proceeds from the sales of and the net realized gains on securities in the NDT Fund were:

	Years Ended December 31,		
	2015	2014	2013
	Millions		
Proceeds from Sales (A)	$1,397	$1,448	$1,070
Net Realized Gains (Losses):			
Gross Realized Gains	$97	$177	$112
Gross Realized Losses	(37)	(23)	(26)
Net Realized Gains (Losses) on NDT Fund	$60	$154	$86

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.

Gross realized gains and gross realized losses disclosed in the preceding table were recognized in Other Income and Other Deductions, respectively, in PSEG’s and Power’s Consolidated Statements of Operations. Net unrealized gains of $86 million (after-tax) are included in Accumulated Other Comprehensive Loss on PSEG's and Power’s Consolidated Balance Sheets as of December 31, 2015.

The available-for-sale debt securities held as of December 31, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$16
1 - 5 years	209
6 - 10 years	200
11 - 15 years	57
16 - 20 years	49
Over 20 years	316
Total NDT Available-for-Sale Debt Securities	$847

The cost of these securities was determined on the basis of specific identification.

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2015, other-than-temporary impairments of $53 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as a "Rabbi Trust."

PSEG classifies investments in the Rabbi Trust as available-for-sale. The following tables show the fair values, gross unrealized gains and losses and amortized cost bases for the securities held in the Rabbi Trust.

	As of December 31, 2015			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$12	$10	$—	$22
Debt Securities				
Government Obligations	108	1	(1)	108
Other Debt Securities	82	—	(1)	81
Total Debt Securities	190	1	(2)	189
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	$204	$11	$(2)	$213

	As of December 31, 2014			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$12	$11	$—	$23
Debt Securities				
Government Obligations	89	2	—	91
Other Debt Securities	74	1	—	75
Total Debt Securities	163	3	—	166
Other Securities	2	—	—	2
Total Rabbi Trust Available-for-Sale Securities	$177	$14	$—	$191

These amounts in the preceding tables do not include receivables and payables for Rabbi Trust Fund transactions which have not settled at the end of each period. Such amounts are included in Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets as show in the following table.

	As of December 31, 2015	As of December 31, 2014
	Millions	
Accounts Receivable	$1	$1
Accounts Payable	$—	$—

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table shows the value of securities in the Rabbi Trust Fund that have been in an unrealized loss position for less than 12 months and greater than 12 months:

	As of December 31, 2015				As of December 31, 2014			
	Less Than 12 Months		Greater Than 12 Months		Less Than 12 Months		Greater Than 12 Months	
	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses	Fair Value	Gross Unrealized Losses
	Millions							
Equity Securities (A)	$—	$—	$—	$—	$—	$—	$—	$—
Debt Securities								
Government Obligations (B)	53	(1)	2	—	2	—	—	—
Other Debt Securities (C)	46	(1)	9	—	24	—	—	—
Total Debt Securities	99	(2)	11	—	26	—	—	—
Rabbi Trust Available-for-Sale Securities	$99	$(2)	$11	$—	$26	$—	$—	$—

(A) Equity Securities—Investments in marketable equity securities within the Rabbi Trust Fund is through a mutual fund which invests primarily in common stocks within a broad range of industries and sectors.

(B) Debt Securities (Government)—Unrealized losses on PSEG's Rabbi Trust investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the U.S. government or an agency of the U.S. government, it is not expected that these securities will settle for less than their amortized cost basis, since PSEG does not intend to sell nor will it be more-likely-than-not required to sell. PSEG does not consider these securities to be other-than-temporarily impaired as of December 31, 2015.

(C) Debt Securities (Corporate)—PSEG's investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since PSEG does not intend to sell these securities nor will it be more-likely-than-not required to sell, PSEG does not consider these debt securities to be other-than-temporarily impaired as of December 31, 2015.

The proceeds from the sales of and the net realized gains on securities in the Rabbi Trust Fund were:

	Years Ended December 31,		
	2015	2014	2013
	Millions		
Proceeds from Rabbi Trust Sales (A)	$104	$467	$89
Net Realized Gains (Losses):			
Gross Realized Gains	$3	$4	$4
Gross Realized Losses	(2)	(3)	(3)
Net Realized Gains (Losses) on Rabbi Trust	$1	$1	$1

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Gross realized gains and gross realized losses disclosed in the above table were recognized in Other Income and Other Deductions, respectively, in the Consolidated Statements of Operations. Net unrealized gains of $5 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheets as of December 31, 2015. The Rabbi Trust available-for-sale debt securities held as of December 31, 2015 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$3
1 - 5 years	49
6 - 10 years	44
11 - 15 years	5
16 - 20 years	8
Over 20 years	80
Total Rabbi Trust Available-for-Sale Debt Securities	$189

The cost of these securities was determined on the basis of specific identification.

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities. In 2015, there were no other-than-temporary impairments recognized on investments of the Rabbi Trust.
The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of December 31, 2015	As of December 31, 2014
	Millions	
PSE&G	$42	$41
Power	52	45
Other	119	105
Total Rabbi Trust Available-for-Sale Securities	$213	$191

Note 9. Goodwill and Other Intangibles
As of December 31, 2015 and 2014, Power had goodwill of $16 million related to the Bethlehem Energy Center facility. Power conducted an annual review for goodwill impairment as of October 31, 2015 and concluded that goodwill was not impaired. No events occurred subsequent to that date which would require a further review of goodwill for impairment.
In addition to goodwill, as of December 31, 2015 and 2014, Power had intangible assets of $102 million and $84 million, respectively, related to emissions allowances and renewable energy credits. Emissions expense includes impairments of emissions allowances and costs for emissions, which is recorded as emissions occur. As load is served

under contracts requiring energy from renewable sources, the related expense is recorded. Such expenses for the years ended December 31, 2015, 2014 and 2013 were as follows:

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Years Ended December 31,		
	2015	2014	2013
	Millions		
Emissions Expense	$13	$10	$6
Renewable Energy Expense	$91	$59	$26

Note 10. Asset Retirement Obligations (AROs)

PSEG, PSE&G and Power have recorded various AROs which represent legal obligations to remove or dispose of an asset or some component of an asset at retirement.

PSE&G has conditional AROs primarily for legal obligations related to the removal of treated wood poles and the requirement to seal natural gas pipelines at all sources of gas when the pipelines are no longer in service. PSE&G does not record an ARO for its protected steel and poly-based natural gas lines, as management believes that these categories of gas lines have an indeterminable life.

Power's ARO liability primarily relates to the decommissioning of its nuclear power plants in accordance with NRC requirements. Power has an independent external trust that is intended to fund decommissioning of its nuclear facilities upon termination of operation. For additional information, see Note 8. Available-for-Sale Securities. Power also identified conditional AROs primarily related to Power's fossil generation units and solar facilities, including liabilities for removal of asbestos, stored hazardous liquid material and underground storage tanks from industrial power sites, and demolition of certain plants, and the restoration of the sites at which they reside, when the plants are no longer in service. To estimate the fair value of its AROs, Power uses a probability weighted, discounted cash flow model which, on a unit by unit basis, considers multiple outcome scenarios that include significant estimates and assumptions, and are based on third party decommissioning cost estimates, cost escalation rates, inflation rates and discount rates.

Updated cost studies are obtained triennially unless new information necessitates more frequent updates. The most recent cost study was done in 2015. When assumptions are revised to calculate fair values of existing AROs, the ARO balance and corresponding long-lived asset are adjusted which impact the amount of accretion and depreciation expense recognized in future periods. For PSE&G, Regulatory Assets and Regulatory Liabilities result when accretion and amortization are adjusted to match rates established by regulators resulting in the regulatory deferral of any gain or loss.

The changes to the ARO liabilities for PSEG, PSE&G and Power during 2014 and 2015 are presented in the following table:

	PSEG	PSE&G	Power	Other
	Millions			
ARO Liability as of January 1, 2014	$677	$274	$400	$3
Liabilities Settled	(2)	(2)	—	—
Liabilities Incurred	23	3	20	—
Accretion Expense	30	—	30	—
Accretion Expense Deferred and Recovered in Rate Base (A)	15	15	—	—
ARO Liability as of December 31, 2014	$743	$290	$450	$3
Liabilities Settled	(5)	(4)	(1)	—
Liabilities Incurred	14	1	12	1
Accretion Expense	26	—	26	—
Accretion Expense Deferred and Recovered in Rate Base (A)	16	16	—	—
Revision to Present Values of Estimated Cash Flows	(115)	(85)	(30)	—
ARO Liability as of December 31, 2015	$679	$218	$457	$4

(A) Not reflected as expense in Consolidated Statements of Operations

During 2015, PSE&G recorded a reduction to its ARO liabilities primarily due to the impact of lower inflation rates. These changes had no impact in PSE&G’s Consolidated Statement of Operations.

During 2015, Power recorded a reduction to its ARO liabilities, primarily due to changes in the inflation and discount rates and changes in assumptions related to the weighted probabilities for nuclear AROs partially offset by increases in estimated costs to decommission our nuclear units pursuant to our most recent cost study. These changes did not result in any material impact in Power's Consolidated Statement of Operations.

Note 11. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG’s and its participating affiliates’ current and former employees who meet certain eligibility criteria. Eligible employees participate in non-contributory pension and OPEB plans sponsored by PSEG and administered by Services. In addition, represented and nonrepresented employees are eligible for participation in PSEG’s two defined contribution plans described below.

PSEG, PSE&G and Power are required to record the under or over funded positions of their defined benefit pension and OPEB plans on their respective balance sheets. Such funding positions of each PSEG company are required to be measured as of the date of its respective year-end Consolidated Balance Sheets. For underfunded plans, the liability is equal to the difference between the plan’s benefit obligation and the fair value of plan assets. For defined benefit pension plans, the benefit obligation is the projected benefit obligation. For OPEB plans, the benefit obligation is the accumulated postretirement benefit obligation. In addition, GAAP requires that the total unrecognized costs for defined benefit pension and OPEB plans be recorded as an after-tax charge to Accumulated Other Comprehensive Income (Loss), a separate component of Stockholders’ Equity. However, for PSE&G, because the amortization of the unrecognized costs is being collected from customers, the accumulated unrecognized costs are recorded as a Regulatory Asset. The unrecognized costs represent actuarial gains or losses and prior service costs which had not been expensed.

For PSE&G, the Regulatory Asset is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations. For Power, the charge to Accumulated Other Comprehensive Income (Loss) is amortized and recorded as net periodic pension cost in the Consolidated Statements of Operations.

At the end of 2015, PSEG changed the approach used to measure future service and interest costs for pension benefits. For 2015 and prior, PSEG calculated service and interest costs utilizing a single weighted-average discount rate derived from the yield curve used to measure the plan obligations. For 2016 and beyond, PSEG has elected to calculate service and interest costs by applying the specific spot rates along that yield curve to the plans’ liability cash flows. PSEG believes the new approach provides a more precise measurement of service and interest costs by aligning the timing of the plans’ liability cash flows to the corresponding spot rates on the yield curve. This change does not affect the measurement of the plan obligations. As a change in accounting estimate, this change will be reflected prospectively.

Amounts for Servco are not included in any of the following pension and OPEB benefit information for PSEG and its affiliates but rather are separately disclosed later in this note.

The following table provides a roll-forward of the changes in the benefit obligation and the fair value of plan assets during each of the two years in the periods ended December 31, 2015 and 2014. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year (A)	$5,722	$4,812	$1,638	$1,414
Service Cost	123	104	22	18
Interest Cost	234	234	67	69
Actuarial (Gain) Loss (B)	(289)	838	(45)	210
Gross Benefits Paid	(268)	(266)	(70)	(73)
Benefit Obligation at End of Year (A) (B)	$5,522	$5,722	$1,612	$1,638
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$5,293	$5,116	$361	$319
Actual Return on Plan Assets	(11)	433	(1)	28
Employer Contributions	25	10	84	87
Gross Benefits Paid	(268)	(266)	(70)	(73)
Fair Value of Assets at End of Year	$5,039	$5,293	$374	$361
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	$(483)	$(429)	$(1,238)	$(1,277)
Additional Amounts Recognized in the Consolidated Balance Sheets				
Noncurrent Assets (included in Other Special Funds)	$14	$21	$—	$—
Current Accrued Benefit Cost	(10)	(10)	(10)	—
Noncurrent Accrued Benefit Cost	(487)	(440)	(1,228)	(1,277)
Amounts Recognized	$(483)	$(429)	$(1,238)	$(1,277)
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets (C)				
Prior Service Cost	$(83)	$(102)	$(25)	$(39)
Net Actuarial Loss	1,710	1,724	438	495
Total	$1,627	$1,622	$413	$456

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits.

(B) In October 2014, the Society of Actuaries' Retirement Plans Experience Committee issued its final report on mortality tables (RP-2014 Mortality Tables Report). As of December 31, 2014, PSEG updated its mortality assumptions based on the information contained in this report. The impact of this change is reflected in Actuarial (Gain) Loss in 2014 and added $314 million and $79 million to the Benefit Obligations for Pension and OPEB, respectively, since December 31, 2013.

(C) Includes $658 million ($386 million, after-tax) and $702 million ($411 million, after-tax) in Accumulated Other Comprehensive Loss related to Pension and OPEB as of December 31, 2015 and 2014, respectively.

The pension benefits table above provides information relating to the funded status of all qualified and nonqualified pension plans and OPEB plans on an aggregate basis. As of December 31, 2015, PSEG had funded approximately 91% of its projected benefit obligation. This percentage does not include $213 million of assets in the Rabbi Trust as of December 31, 2015 which were used partially to fund the nonqualified pension plans. As of December 31, 2015, the nonqualified pension plans included in the projected benefit obligation in the above table were $159 million. The fair values of the Rabbi Trust assets are included in Other Special Funds on the Consolidated Balance Sheets.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Accumulated Benefit Obligation
The accumulated benefit obligation for all PSEG's defined benefit pension plans was $5.4 billion as of December 31, 2015 and $5.5 billion as of December 31, 2014.
The following table provides the components of net periodic benefit cost for the years ended December 31, 2015, 2014 and 2013.

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2015	2014	2013	2015	2014	2013
	Millions					
Components of Net Periodic Benefit Cost (Credit)						
Service Cost	$123	$104	$116	$22	$18	21
Interest Cost	234	234	215	67	69	63
Expected Return on Plan Assets	(414)	(399)	(348)	(31)	(26)	(21)
Amortization of Net						
Prior Service Cost	(19)	(18)	(19)	(14)	(14)	(14)
Actuarial Loss	150	56	188	43	23	42
Net Periodic Benefit Cost (Credit)	$74	$(23)	$152	$87	$70	$91

Pension costs and OPEB costs for PSEG, PSE&G and Power are detailed as follows:

	Pension Benefits Years Ended December 31,			Other Benefits Years Ended December 31,		
	2015	2014	2013	2015	2014	2013
	Millions					
PSE&G	$40	$(19)	$91	$55	$46	$65
Power	21	(7)	43	27	20	23
Other	13	3	18	5	4	3
Total Benefit Cost (Credit)	$74	$(23)	$152	$87	$70	$91

The following table provides the pre-tax changes recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Deferred Assets:

	Pension		OPEB	
	2015	2014	2015	2014
	Millions			
Net Actuarial (Gain) Loss in Current Period	$136	$803	$(14)	$208
Amortization of Net Actuarial Gain (Loss)	(150)	(56)	(43)	(23)
Amortization of Prior Service Credit	19	18	14	14
Total	$5	$765	$(43)	$199

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Amounts that are expected to be amortized from Accumulated Other Comprehensive Loss, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2016 are as follows:

	Pension Benefits 2016	Other Benefits 2016
	Millions	
Actuarial (Gain) Loss	$158	$40
Prior Service Cost	$(18)	$(14)

The following assumptions were used to determine the benefit obligations and net periodic benefit costs:

	Pension Benefits			Other Benefits		
	2015	2014	2013	2015	2014	2013
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	4.54%	4.20%	5.00%	4.58%	4.21%	5.01%
Rate of Compensation Increase	3.61%	3.61%	4.61%	3.61%	3.61%	4.61%
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount Rate	4.20%	5.00%	4.20%	4.21%	5.01%	4.20%
Expected Return on Plan Assets	8.00%	8.00%	8.00%	8.00%	8.00%	8.00%
Rate of Compensation Increase	3.61%	4.61%	4.61%	3.61%	4.61%	4.61%
Assumed Health Care Cost Trend Rates as of December 31						
Administrative Expense				3.00%	3.00%	3.00%
Health Care Costs						
Immediate Rate				7.75%	7.40%	7.83%
Ultimate Rate				4.75%	5.00%	5.00%
Year Ultimate Rate Reached				2025	2022	2021
				Millions		
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$12	$13	$12
Postretirement Benefit Obligation				$194	$201	$161
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$(10)	$(10)	$(9)
Postretirement Benefit Obligation				$(160)	$(165)	$(134)

Plan Assets

All the investments of pension plans and OPEB plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension and OPEB plans are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 16. Fair Value Measurements for more information on fair value guidance. Use of the Master Trust permits the commingling of pension plan assets and OPEB plan assets for investment and administrative purposes. Although assets of the plans are commingled in the Master Trust, the Trustee maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Trustee to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans. As of December 31, 2015, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 93% and 7%, respectively.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tables present information about the investments measured at fair value on a recurring basis as of December 31, 2015 and 2014, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2015			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions			
Cash Equivalents (A)	$103	$ 102	$ 1	$ —
Common Stocks (B)				
Commingled-United States	1,980	1,980	—	—
Commingled-International	987	987	—	—
Other	816	816	—	—
Bonds (C)				
Government (United States & Foreign)	602	—	602	—
Other	906	—	906	—
Private Equity (D)	19	—	—	19
Total	$5,413	$ 3,885	$ 1,509	$ 19

	Recurring Fair Value Measurements as of December 31, 2014			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions			
Cash Equivalents (A)	$153	$ 92	$ 61	$ —
Common Stocks (B)				
Commingled-United States	2,292	2,292	—	—
Commingled-International	1,005	1,005	—	—
Other	727	727	—	—
Bonds (C)				
Government (United States & Foreign)	509	—	509	—
Other	943	—	943	—
Private Equity (D)	25	—	—	25
Total	$5,654	$ 4,116	$ 1,513	$ 25

(A) Certain open-ended mutual funds with mainly short-term investments are valued based on unadjusted quoted prices in active market (Level 1). Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

(B) Wherever possible, fair values of equity investments in stocks and in commingled funds are derived from quoted market prices as substantially all of these instruments have active markets (primarily Level 1). Most investments in stocks are priced utilizing the principal market close price or in some cases midpoint, bid or ask price.

(C) Investments in fixed income securities including bond funds are priced using an evaluated pricing approach or the most recent exchange or quoted bid (primarily Level 2).

(D)

Limited partnership interests in private equity funds are valued using significant unobservable inputs as there is little, if any, market activity. In addition, there may be transfer restrictions on private equity securities. The process for determining the fair value of such securities relied on commonly accepted valuation techniques, including the use of earnings multiples based on comparable public securities, industry-specific non-earnings-based multiples and

discounted cash flow models. These inputs require significant management judgment or estimation (primarily Level 3).
Reconciliations of the beginning and ending balances of the Pension and OPEB Plans' Level 3 assets for the years ended December 31, 2015 and 2014 are as follows:

	Balance as of January 1, 2015	Purchases/ (Sales)	Transfer In/ (Out)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2015
	Millions					
Private Equity	$25	$(10)	$—	$1	$3	$19

	Balance as of January 1, 2014	Purchases/ (Sales)	Transfer In/ (Out)	Actual Return on Asset Sales	Actual Return on Assets Still Held	Balance as of December 31, 2014
	Millions					
Private Equity	$25	$(5)	$—	$3	$2	$25

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans as of the measurement date, December 31:

	As of December 31,	
Investments	2015	2014
Equity Securities	70 %	71 %
Fixed Income Securities	28	26
Other Investments	2	3
Total Percentage	100 %	100 %

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. PSEG's latest asset/liability study indicates that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. Derivative financial instruments are used by the plans' investment managers primarily to adjust the fixed income duration of the portfolio and hedge the currency risk component of foreign investments. The expected long-term rate of return on plan assets was 8.00% as of December 31, 2015 and will remain unchanged for 2016. This expected return was determined based on the study discussed above, including a premium for active management and considered the plans' historical annualized rate of return since inception, which was 9.3%.

Plan Contributions

PSEG plans to contribute $21 million into its qualified pension plans and $14 million into its OPEB plan, respectively, during 2016.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Estimated Future Benefit Payments
The following pension benefit and postretirement benefit payments are expected to be paid to plan participants.

Year	Pension Benefits	Other Benefits
	Millions	
2016	$285	$81
2017	295	84
2018	305	87
2019	317	91
2020	329	95
2021-2025	1,818	518
Total	$3,349	$956

401(k) Plans
PSEG sponsors two 401(k) plans, which are Employee Retirement Income Security Act (ERISA) defined contribution retirement plans. Eligible represented employees of PSEG's subsidiaries participate in the PSEG Employee Savings Plan (Savings Plan), while eligible non-represented employees of PSEG's subsidiaries participate in the PSEG Thrift and Tax-Deferred Savings Plan (Thrift Plan). Eligible employees may contribute up to 50% of their compensation to these plans. PSEG matches 50% of such employee contributions up to 7% of pay for Savings Plan participants and up to 8% of pay for Thrift Plan participants.
The amount paid for employer matching contributions to the plans for PSEG, PSE&G and Power are detailed as follows:

	Thrift Plan and Savings Plan		
	Years Ended December 31,		
	2015	2014	2013
	Millions		
PSE&G	$22	$20	$19
Power	12	11	10
Other	5	5	4
Total Employer Matching Contributions	$39	$36	$33

Servco Pension and OPEB
At the direction of LIPA, effective January 1, 2014, Servco established benefit plans that provide substantially the same benefits to its employees as those previously provided by National Grid Electric Services LLC (NGES), the predecessor T&D system manager for LIPA. Since the vast majority of Servco's employees had worked under NGES' T&D operations services arrangement with LIPA, Servco's plans provide certain of those employees with pension and OPEB vested credit for prior years' services earned while working for NGES. The benefit plans cover all employees of Servco for current service. Under the OSA, all of these and any future employee benefit costs are to be funded by LIPA. See Note 3. Variable Interest Entities. These obligations, as well as the offsetting long-term receivable, are separately presented on the Consolidated Balance Sheet of PSEG.
The following table provides a roll-forward of the changes in Servco's benefit obligation and the fair value of its plan assets during the years ended December 31, 2015 and 2014. It also provides the funded status of the plans and the amounts recognized and amounts not recognized on the Consolidated Balance Sheets at the end of both years.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
		Millions		
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year	$195	$—	$452	$—
Service Cost	26	20	17	13
Interest Cost	9	7	21	17
Actuarial (Gain) Loss	(20)	42	(114)	107
Gross Benefits Paid	—	—	(1)	—
Plan Amendments	1	126	—	315
Benefit Obligation at End of Year (A)	$211	$195	$375	$452
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$69	$—	$—	$—
Actual Return on Plan Assets	(2)	2	—	—
Employer Contributions	30	67	1	—
Gross Benefits Paid	—	—	(1)	—
Fair Value of Assets at End of Year	$97	$69	$—	$—
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	$(114)	$(126)	$(375)	$(452)
Additional Amounts Recognized in the Consolidated Balance Sheets				
Accrued Pension Costs of Servco	$(114)	$(126)	N/A	N/A
OPEB Costs of Servco	N/A	N/A	(375)	(452)
Amounts Recognized (B)	$(114)	$(126)	$(375)	$(452)

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits.

(B) Amounts equal to the accrued pension and OPEB costs of Servco are offset in Long-Term Receivable of VIE on PSEG's Consolidated Balance Sheet.

Pension and OPEB costs of Servco are accounted for according to the OSA. Servco recognizes expenses for contributions to its pension plan trusts and for OPEB payments made to retirees. Operating Revenues are recognized for the reimbursement of these costs. The pension-related revenues and costs for 2015 and 2014 were $30 million and $67 million, respectively. Servco has contributed its entire planned contribution amount to its pension plan trusts during 2015. The OPEB-related revenues earned and costs incurred in 2015 and 2014 were immaterial.

The following assumptions were used to determine the benefit obligations of Servco:

	Pension Benefits		Other Benefits	
	2015	2014	2015	2014
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31				
Discount Rate	4.92 %	4.50 %	4.97 %	4.60 %
Rate of Compensation Increase	3.25 %	3.25 %	3.25 %	3.25 %
Assumed Health Care Cost Trend Rates as of December 31				
Administrative Expense			5.00 %	5.00 %
Health Care Costs				
Immediate Rate			7.55 %	7.33 %
Ultimate Rate			4.75 %	5.00 %

Year Ultimate Rate Reached	2025	2021
	Millions	
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs		
Postretirement Benefit Obligation	$75	$160
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs		
Postretirement Benefit Obligation	$(60)	$(106)

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Plan Assets

All the investments of Servco's pension plans are held in a trust account by the Trustee and consist of an undivided interest in an investment account of the Master Trust. The investments in the pension are measured at fair value within a hierarchy that prioritizes the inputs to fair value measurements into three levels. See Note 16. Fair Value Measurements for more information on fair value guidance. The Actuary maintains supporting records for the purpose of allocating the net gain or loss of the investment account to the respective participating plans. The net investment income of the investment assets is allocated by the Actuary to each participating plan based on the relationship of the interest of each plan to the total of the interests of the participating plans.

The following tables present information about Servco's investments measured at fair value on a recurring basis as of December 31, 2015 and 2014, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2015			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions			
Cash Equivalents (A)	$—	$ —	$ —	$ —
Common Stocks (B)				
Commingled-United States	68	68	—	—
Bonds (C)				
Other	29	—	29	—
Total	$97	$ 68	$ 29	$ —

	Recurring Fair Value Measurements as of December 31, 2014			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions			
Cash Equivalents (A)	$1	$ —	$ 1	$ —
Common Stocks (B)				
Commingled-United States	48	48	—	—
Bonds (C)				
Other	20	—	20	—
Total	$69	$ 48	$ 21	$ —

(A) Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

(B) Wherever possible, fair values of equity investments in commingled stock funds are derived from quoted market prices as substantially all of these instruments have active markets (primarily Level 1). Most investments in stocks are priced utilizing the principal market close price or in some cases midpoint, bid or ask price.

(C) Investments in fixed income securities including bond funds are priced using an evaluated pricing approach or the most recent exchange or quoted bid (primarily Level 2).

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following table provides the percentage of fair value of total plan assets for each major category of plan assets held for the qualified pension and OPEB plans of Servco as of the measurement date, December 31:

	As of December 31,			
Investments	2015		2014	
Equity Securities	71	%	70	%
Fixed Income Securities	29		29	
Other Investments	—		1	
Total Percentage	100	%	100	%

Servco utilizes forecasted returns, risk, and correlation of all asset classes in order to develop a portfolio designed to produce the maximum return opportunity per unit of risk. The results from Servco's latest asset/liability study indicated that a long-term target asset allocation of 70% equities and 30% fixed income is consistent with the funds' financial objectives. The expected long-term rate of return on plan assets was 7.7% as of December 31, 2015 and will remain unchanged for 2016. This expected return was determined based on the study discussed above, including a premium for active management.

Plan Contributions

Servco plans to contribute $28 million into its pension plan during 2016.

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to Servco's plan participants:

Year	Pension Benefits	Other Benefits
	Millions	
2016	$1	$3
2017	2	5
2018	3	7
2019	4	8
2020	6	10
2021-2025	60	80
Total	$76	$113

Servco 401(k) Plans

Servco sponsors two 401(k) plans, which are defined contribution retirement plans subject to ERISA. Eligible non-represented employees of Servco participate in the Long Island Electric Utility Servco LLC Incentive Thrift Plan I (Thrift Plan I), and eligible represented employees of Servco participate in the Long Island Electric Utility Servco LLC Incentive Thrift Plan II (Thrift Plan II). Participants in the Plans may contribute up to 50% of their eligible compensation to these plans, not to exceed the IRS maximums, including any Catch-Up Contributions for those employees age 50 and above. Servco does not provide an employer match or core contribution for employees in Thrift Plan II. For employees in Thrift Plan I, Servco matches 50% of such employee contributions up to 8% of eligible compensation and provides core contributions (based on years of service and age) to employees who do not participate in Servco's Retirement Income Plan. The amounts expensed by Servco for employer matching contributions for the years ended December 31, 2015, 2014 and 2013 were immaterial and pursuant to the OSA, Servco recognizes Operating Revenues for the reimbursement of these costs.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 12. Commitments and Contingent Liabilities

Guaranteed Obligations

Power's activities primarily involve the purchase and sale of energy and related products under transportation, physical, financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

Power has unconditionally guaranteed payments to counterparties by its subsidiaries in commodity-related transactions in order to

- support current exposure, interest and other costs on sums due and payable in the ordinary course of business, and
- obtain credit.

Under these agreements, guarantees cover lines of credit between entities and are often reciprocal in nature. The exposure between counterparties can move in either direction.

In order for Power to incur a liability for the face value of the outstanding guarantees, its subsidiaries would have to

- fully utilize the credit granted to them by every counterparty to whom Power has provided a guarantee, and
- all of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

Power believes the probability of this result is unlikely. For this reason, Power believes that the current exposure at any point in time is a more meaningful representation of the potential liability under these guarantees. This current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.

Power is subject to

- counterparty collateral calls related to commodity contracts, and
- certain creditworthiness standards as guarantor under performance guarantees of its subsidiaries.

Changes in commodity prices can have a material impact on collateral requirements under such contracts, which are posted and received primarily in the form of cash and letters of credit. Power also routinely enters into futures and options transactions for electricity and natural gas as part of its operations. These futures contracts usually require a cash margin deposit with brokers, which can change based on market movement and in accordance with exchange rules.

In addition to the guarantees discussed above, Power has also provided payment guarantees to third parties on behalf of its affiliated companies. These guarantees support various other non-commodity related contractual obligations.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The face value of outstanding guarantees, current exposure and margin positions as of December 31, 2015 and 2014 are shown below:

	As of December 31, 2015	As of December 31, 2014
	Millions	
Face Value of Outstanding Guarantees	$1,734	$1,814
Exposure under Current Guarantees	$172	$273
Letters of Credit Margin Posted	$122	$159
Letters of Credit Margin Received	$192	$40
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$—	$—
Counterparty Cash Margin Received	$(15)	$(13)
Net Broker Balance Deposited (Received)	$(5)	$115
In the Event Power were to Lose its Investment Grade Rating		
Additional Collateral that could be Required	$864	$945
Liquidity Available under PSEG’s and Power’s Credit Facilities to Post Collateral	$3,215	$3,495
Additional Amounts Posted		
Other Letters of Credit	$51	$45

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 15. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

In the event of a deterioration of Power’s credit rating to below investment grade, which would represent a three level downgrade from its current S&P and Moody’s ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

In addition to amounts for outstanding guarantees, current exposure and margin positions, PSEG and Power have posted letters of credit to support Power's various other non-energy contractual and environmental obligations. See preceding table. PSEG also issued a $106 million guarantee to support Power's payment obligations related to its equity interest in the PennEast natural gas pipeline and a $21 million guarantee to support Power's payment obligations related to construction of a 755 MW gas-fired combined cycle generating station in Maryland. In the event that PSEG were to be downgraded to below investment grade and failed to meet minimum net worth requirements, these guarantees would each have to be replaced by a letter of credit.

Environmental Matters

Passaic River

Historic operations of PSEG companies 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 in violation of various statutes as discussed as follows.

Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA)

In 2002, the U.S. Environmental Protection Agency (EPA) determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a “Superfund” site under CERCLA. This designation allows the EPA to clean up such sites and to compel responsible parties to perform cleanups or reimburse the government for cleanups led by the EPA.

The EPA further determined that there was a need to perform a comprehensive study of the entire 17-miles of the lower Passaic River. PSE&G and certain of its predecessors conducted operations at properties in this area of the Passaic River. The properties included one operating electric generating station (Essex Site), which was transferred to Power, one former generating station and four former manufactured gas plant (MGP) sites.

In early 2007, 73 Potentially Responsible Parties (PRPs), including PSE&G and Power, formed a Cooperating Parties Group (CPG) and agreed to assume responsibility for conducting a Remedial Investigation and Feasibility Study (RI/FS) of the 17 miles of the lower Passaic River. At such time, the CPG also agreed to allocate, on an interim basis, the associated costs of the RI/FS among its members on the basis of a mutually agreed upon formula. For the purpose of this interim allocation, which has been revised as parties have exited the CPG, approximately seven percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately one percent is attributable to Power's generating stations. These interim allocations are not binding on PSE&G or Power in terms of their respective shares of the costs that will be ultimately required to remediate the 17 miles of the lower Passaic River. PSEG has provided notice to insurers concerning this potential claim.

In June 2008, the EPA and Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus) entered into an early action agreement whereby Tierra/Maxus agreed to remove a portion of the heavily dioxin-contaminated sediment located in the lower Passaic River. The portion of the Passaic River identified in this agreement was located immediately adjacent to Tierra/Maxus' predecessor company's (Diamond Shamrock) facility. Pursuant to the agreement between the EPA and Tierra/Maxus, the estimated cost for the work to remove the sediment in this location was $80 million. Phase I of the removal work has been completed. Pursuant to this agreement, Tierra/Maxus have reserved their rights to seek contribution for these removal costs from the other PRPs, including Power and PSE&G. This agreement and the work undertaken pursuant to the action agreement will not affect the ultimate remedy that the EPA will select for the remediation of the 17-mile stretch of the lower Passaic River.

In 2012, Tierra/Maxus withdrew from the CPG and refused to participate as members going forward, other than with respect to their obligation to fund the EPA's portion of its RI/FS oversight costs. At such time, the remaining members of the CPG, in agreement with the EPA, commenced the removal of certain contaminated sediments at Passaic River Mile 10.9 at an estimated cost of $25 million to $30 million. PSEG's share of the cost of that effort is approximately three percent. The remaining CPG members have reserved their rights to seek reimbursement from Tierra/Maxus for the costs of the River Mile 10.9 removal.

On April 11, 2014, the EPA released its revised draft "Focused Feasibility Study" (FFS) which contemplates the removal of 4.3 million cubic yards of sediment from the bottom of the lower eight miles of the 17-mile stretch of the Passaic River. The revised draft FFS sets forth various alternatives for remediating this portion of the Passaic River. The EPA's estimated costs to remediate the lower eight miles of the Passaic River range from $365 million for a targeted remedy to $3.3 billion for a deep dredge of this portion of the Passaic River. The EPA also identified in the revised draft FFS its preferred alternative, which would involve dredging the lower eight miles of the river bank-to-bank and installing an engineered cap. The estimated cost in the revised draft FFS for the EPA's preferred alternative is $1.7 billion on a discounted basis. No provisional cost allocation has been made by the CPG for the work contemplated by the revised draft FFS, and the work contemplated by the revised draft FFS is not subject to the CPG's cost sharing allocation agreed to in connection with the removal work for River Mile 10.9 or in connection with the conduct of the RI/FS.

The revised draft FFS was subject to a public comment period, and remains subject to the EPA's response to comments submitted, a design phase and at least an estimated five years for completion of the work. The public comment period for the revised draft FFS closed on August 21, 2014. Over 300 comments were submitted by a variety of entities potentially impacted by the revised draft FFS, including the CPG, individual companies, municipalities, public officials, citizens groups, Amtrak, NJ Transit and others.

The CPG, which consisted of 54 members as of December 31, 2015, provided a draft RI and draft FS, both relating to the entire 17 miles of the lower Passaic River, to the EPA on February 18, 2015 and April 30, 2015, respectively. The estimated total cost of the RI/FS is approximately $163 million, which the CPG continues to incur. Of the estimated $163 million, as of December 31, 2015, the CPG had spent approximately $147 million, of which PSEG's total share was approximately $10 million.

The draft FS sets forth various alternatives for remediating the lower Passaic River. The draft FS sets forth the CPG’s estimated costs to remediate the lower 17 miles of the Passaic River which range from approximately $518 million to $3.2 billion. The CPG identified a targeted remedy in the draft FS which would involve removal, treatment and disposal of contaminated sediments taken from targeted locations within the entire 17 miles of the lower Passaic River. The estimated cost in the draft FS for the targeted remedy ranges from approximately $518 million to $772 million. No provisional cost allocation has been made by the CPG for the work contemplated by the draft FS. However, based on (i) the low end of the range of the current estimates of costs to remediate, (ii) PSE&G's and Power's estimates of their share of those costs, and (iii) the continued ability of PSE&G to recover such costs in its rates, PSE&G accrued a $10 million Environmental Costs Liability and a corresponding Regulatory Asset and Power accrued a $3 million Other Noncurrent Liability and a corresponding O&M Expense in the first quarter of 2015.

The EPA will consider the comments received on its revised draft FFS and is expected to consider the CPG’s RI/FS prior to issuing a Record of Decision (ROD) of a selected remedy for the lower Passaic River. The EPA has broad authority to implement its selected remedy through the ROD and PSEG cannot at this time predict how the implementation of the ROD might impact PSE&G's and Power's ultimate liability. Until (i) the RI/FS is finalized, (ii) a final remedy is determined by the EPA or through litigation, (iii) PSE&G's and Power's respective shares of the costs, both in the aggregate as well as individually, are determined, and (iv) PSE&G's continued ability to recover the costs in its rates is determined, it is not possible to predict this matter's ultimate impact on our financial statements. It is possible that PSE&G and Power will record additional costs beyond what they have accrued, and that such costs could be material, but PSEG cannot at the current time estimate the amount or range of any additional costs.

Natural Resource Damage Claims

In 2003, the New Jersey Department of Environmental Protection (NJDEP) directed PSEG, PSE&G and 56 other PRPs to arrange for a natural resource damage assessment and interim compensatory restoration of natural resource injuries along the lower Passaic River and its tributaries pursuant to the New Jersey Spill Compensation and Control Act. The NJDEP alleged that hazardous substances had been discharged from the Essex Site and the Harrison Site. The NJDEP estimated the cost of interim natural resource injury restoration activities along the lower Passaic River at approximately $950 million. In 2007, agencies of the U.S. Department of Commerce and the U.S. Department of the Interior (the Passaic River federal trustees) sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

Newark Bay Study Area

The EPA has established the Newark Bay Study Area, which it defines as Newark Bay and portions of the Hackensack River, the Arthur Kill and the Kill Van Kull. In August 2006, the EPA sent PSEG and 11 other entities notices that it considered each of the entities to be a PRP with respect to contamination in the Study Area. The notice letter requested that the PRPs fund an EPA-approved study in the Newark Bay Study Area. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but PSEG has not consented to fund the third phase. PSE&G and Power are unable to estimate their respective portions of the possible loss or range of loss related to this matter.

MGP Remediation Program

PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $431 million and $499 million through 2021, including its $10 million share for the Passaic River as discussed above. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $431 million as of December 31, 2015. Of this amount, $76 million was recorded in Other Current Liabilities and $355 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $431 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

Prevention of Significant Deterioration (PSD)/New Source Review (NSR)

The PSD/NSR regulations, promulgated under the Clean Air Act (CAA), require major sources of certain air pollutants to obtain permits, install pollution control technology and obtain offsets, in some circumstances, when those sources undergo a "major modification," as defined in the regulations. The federal government may order companies that are not in compliance with the PSD/NSR regulations to install the best available control technology at the affected plants and to pay monetary penalties ranging from $25,000 to $37,500 per day for each violation, depending upon when the alleged violation occurred.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent the PSD/NSR permitting process prior to being put into service, which the EPA alleges was required under the CAA. The notice of violation states that the EPA may issue an order requiring compliance with the relevant CAA provisions and may seek injunctive relief and/or civil penalties. Power owns approximately 23% of the plant. Power cannot predict the outcome of this matter.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), National Pollutant Discharge Elimination System permits expire within five years of their effective date. In order to renew these permits, but allow a plant to continue to operate, an owner or operator must file a permit application no later than six months prior to expiration of the permit. States with delegated federal authority for this program manage these permits. The NJDEP manages the permits under the New Jersey Pollutant Discharge Elimination System (NJPDES) program. Connecticut and New York also have permits to manage their respective pollutant discharge elimination system programs.

In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. On June 30, 2015, the NJDEP issued a draft permit for Salem. The draft permit does not require installation of cooling towers and allows Salem to continue to operate utilizing the existing once-through cooling water system with certain required system modifications. The draft permit was subject to a public notice and comment period. The NJDEP may make revisions before issuing the final permit expected during the first half of 2016. Power participated in the NJDEP’s August 5, 2015 public hearing and submitted comments on the draft permit on September 18, 2015.

On May 19, 2014, the EPA issued a final rule that establishes new requirements for the regulation of cooling water intake structures at existing power plants and industrial facilities with a design flow of more than two million gallons of water per day. On August 15, 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. On September 5, 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. Power is unable to determine the ultimate impact of these actions on the implementation of the rule.

State permitting decisions could have a material impact on Power’s ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power’s once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities, and could result in acceleration of decommissioning activities. For example, in Power’s application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power’s share would have been approximately $575 million. The filing has not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power’s forecasted capital expenditures.

Power is unable to predict the outcome of these permitting decisions and the effect, if any, that they may have on Power's future capital requirements, financial condition or results of operations.

Power is actively engaged with the Connecticut Department of Energy and Environmental Protection (CTDEEP) regarding renewal of the current permit for the cooling water intake structure at Bridgeport Harbor Station Unit 3 (BH3). To address compliance with the EPA’s Clean Water Act Section 316(b) final rule, the current proposal under consideration is that, if a final permit is issued, Power would continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire the BH3 within five years of the effective date of the final permit. Based on current discussions with the CTDEEP, if the proposal is accepted, a final permit could be issued in the summer of 2016 indicating a potential retirement date for BH3 by summer 2021, which is four years earlier than the current estimated useful life ending in 2025. If the permit is not issued and the conditions below are not met, Power will seek to operate BH3 through the current estimated useful life.

Separately, Power has also negotiated a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut. That CEBA provides that Power would retire BH3 early if all its precedent conditions occur, which include receipt of all final permits to build and operate a proposed new combined cycle generating facility on the same site that BH3 currently operates, which could occur in 2017. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power will seek to operate BH3 through the current estimated useful life.

If either the permit renewal is received, or all the conditions precedent in the CEBA occur, a triggering event will be deemed to have occurred and Power will test its New England generating fleet for impairment at that time. The New England generation fleet currently has a net book value of approximately $210 million.

In February 2016, the proposed generating facility was awarded a capacity obligation. Construction is expected to commence in 2017, with operations expected to begin in mid-2019.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Bridgeport Harbor National Pollutant Discharge Elimination System (NPDES) Permit Compliance
In April 2015, Power determined that monitoring and reporting practices related to certain permitted wastewater discharges at its Bridgeport Harbor station may have violated conditions of the station's NPDES permit and applicable regulations and could subject it to fines and penalties. Power has notified the CTDEEP of the issues and has taken actions to investigate and resolve the potential non-compliance. Power cannot predict the impact of this matter.
Steam Electric Effluent Guidelines
On September 30, 2015, the EPA issued a new Effluent Guidelines Limitation Rule for steam electric generating units. The rule establishes new best available technology economically achievable (BAT) standards for fly ash transport water, bottom ash transport water, flue gas desulfurization and flue gas mercury control wastewater. The EPA provides an implementation period for currently existing discharges of three years or up to eight years if a facility needs more time to implement equipment upgrades and provide supporting information to its permitting authority. In the intervening time period, existing discharge standards continue to apply. Power's Mercer and Bridgeport Harbor stations and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under this rule. Power is unable to predict if this rule will have a material impact on its future capital requirements, financial condition and results of operations.
Coal Combustion Residuals (CCRs)
On December 19, 2014, the EPA issued a final rule 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. Power's Hudson and Mercer generating stations, along with its co-owned Keystone and Conemaugh stations, are subject to the provisions of this rule. On April 17, 2015, the final rule was published with an effective date of October 19, 2015. Accordingly in June 2015, Power recorded an additional asset retirement obligation to comply with the final CCR rule which was not material to Power’s results of operations, financial condition or cash flows.
Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)
PSE&G obtains its electric supply requirements through the annual New Jersey BGS auctions for two categories of customers who choose not to purchase electric supply from third party suppliers. The first category, which represents about 80% of PSE&G's load requirement, are residential and smaller commercial and industrial customers (BGS-Residential Small Commercial Pricing (RSCP)). The second category are larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Pricing (CIEP)). Pursuant to applicable BPU rules, PSE&G enters into the Supplier Master Agreement with the winners of these BGS auctions following the BPU’s approval of the auction results. PSE&G has entered into contracts with winning BGS suppliers, including Power, to purchase BGS for PSE&G’s load requirements. The winners of the auction (including Power) are responsible for fulfilling all the requirements of a PJM Load Serving Entity including the provision of capacity, energy, ancillary services, transmission and any other services required by PJM. BGS suppliers assume all volume risk and customer migration risk and must satisfy New Jersey’s renewable portfolio standards.
The BGS-CIEP auction is for a one-year supply period from June 1 to May 31 with the BGS-CIEP auction price measured in dollars per MW-day for capacity. The final price for the BGS-CIEP auction year commencing June 1, 2016 is $335.33 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2016 of $272.78 per MW-day. Energy for BGS-CIEP is priced at hourly PJM locational marginal prices for the contract period.
PSE&G contracts for its anticipated BGS-RSCP load on a three-year rolling basis, whereby each year one-third of the load is procured for a three-year period. The contract prices in dollars per MWh for the BGS-RSCP supply, as well as the approximate load, are as follows:

	Auction Year				
	2013	2014	2015	2016	
36-Month Terms Ending	May 2016	May 2017	May 2018	May 2019	(A)
Load (MW)	2,800	2,800	2,900	2,800	

$ per MWh	$92.18	$97.39	$99.54	$96.38

(A) Prices set in the 2016 BGS auction will become effective on June 1, 2016 when the 2013 BGS auction agreements expire.

Power seeks to mitigate volatility in its results by contracting in advance for the sale of most of its anticipated electric output as well as its anticipated fuel needs. As part of its objective, Power has entered into contracts to directly supply PSE&G and other New Jersey electric distribution companies (EDCs) with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

PSE&G has a full-requirements contract with Power to meet the gas supply requirements of PSE&G's gas customers. Power has entered into hedges for a portion of these anticipated BGSS obligations, as permitted by the BPU. The BPU permits PSE&G to recover the cost of gas hedging up to 115 billion cubic feet or 80% of its residential gas supply annual requirements through the BGSS tariff. Current plans call for Power to hedge on behalf of PSE&G approximately 70 billion cubic feet or 50% of its residential gas supply annual requirements. For additional information, see Note 23. Related-Party Transactions.

Minimum Fuel Purchase Requirements

Power's nuclear fuel strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to in the following table may include estimated quantities to be purchased that deviate from contractual nominal quantities. Power's nuclear fuel commitments cover approximately 100% of its estimated uranium, enrichment and fabrication requirements through 2017 and a significant portion through 2020 at Salem, Hope Creek and Peach Bottom.

Power has various long-term fuel purchase commitments for coal through 2018 to support its fossil generation stations.

Power also has various multi-year contracts for natural gas and firm transportation and storage capacity for natural gas that are primarily used to meet its obligations to PSE&G. When there is excess delivery capacity available, Power can use the gas to supply its fossil generating stations.

As of December 31, 2015, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2020
	Millions
Nuclear Fuel	
Uranium	$475
Enrichment	$394
Fabrication	$204
Natural Gas	$1,023
Coal	$300

Regulatory Proceedings

FERC Compliance

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, PSEG retained outside counsel to assist in the conduct of an investigation into the matter and self-reported the errors. As the internal investigation proceeded, additional pricing errors in the bids were identified. 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. PSEG informed FERC, PJM and the PJM Independent Market Monitor (IMM) of these additional issues, corrected the identified errors, and modified the bid quantities for Power's peaking units. Power continues to implement procedures to help mitigate the risk of similar issues occurring in the future.

During the three month period ended March 31, 2014, based upon its best estimate available at the time, Power recorded a charge to income in the amount of $25 million related to this matter. No additional charges to income have been recorded for this matter since that time.

In September 2014, FERC Staff initiated a preliminary, non-public staff investigation into the matter and issued data requests covering a period from 2002 through the date of the self-report. This investigation is ongoing. Since that time, Power has and is continuing to respond to data requests from FERC Staff, including recent data requests in which Power has recalculated certain of its energy bids in PJM for a five year period, and may receive additional data requests or other fact finding. The FERC Staff investigation is still in the fact finding stage and there is considerable uncertainty around FERC's response to PSEG's legal arguments and the amount of disgorgement or other remedies FERC may ultimately seek.

PSEG is unable to reasonably estimate the range of possible loss for this matter; however, the amounts of potential disgorgement and other potential penalties that Power may incur span a wide range depending on the success of PSEG's legal arguments. These arguments include that Power's energy market bids in a substantial majority of the hours were below the allowed rate under the Tariff and therefore any errors in those hours were immaterial and that it is unclear whether the quantity of the bids violated any legal requirement. If PSEG's legal arguments do not prevail in whole or in part with FERC or in a judicial challenge that PSEG may choose to pursue, it is likely that Power would record additional losses and that such additional losses would be material to PSEG's and Power's Consolidated Statements of Operations in the quarterly and annual periods in which they are recorded.

New Jersey Clean Energy Program

In June 2015, the BPU established the funding level for fiscal year 2016 applicable to its Renewable Energy and Energy Efficiency programs. The fiscal year 2016 aggregate funding for all EDCs is $345 million with PSE&G's share of the funding at $200 million. PSE&G has a remaining current liability of $142 million as of December 31, 2015 for its outstanding share of the fiscal year 2016 and remaining fiscal year 2015 funding, respectively. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are recovered from PSE&G ratepayers through the SBC.

Superstorm Sandy

In late October 2012, Superstorm Sandy caused severe damage to PSE&G's T&D system throughout its service territory as well as to some of Power's generation infrastructure in the northern part of New Jersey. Strong winds and the resulting storm surge caused damage to switching stations, substations and generating infrastructure.

PSEG maintains insurance coverage against loss or damage to plants and certain properties, subject to certain exceptions and limitations, to the extent such property is usually insured and insurance is available at a reasonable cost. In June 2013, PSEG, PSE&G and Power filed suit in New Jersey state court (NJ Court) against its insurance carriers seeking an interpretation that the insurance policies cover their losses resulting from damage caused by Superstorm Sandy's storm surge.

As of December 31, 2012, PSE&G had incurred approximately $295 million of costs to restore service to PSE&G's distribution and transmission systems and $5 million to repair its infrastructure and return it to pre-storm conditions. Of the costs incurred, approximately $40 million was recognized in O&M Expense, $75 million was recorded as Property, Plant and Equipment and $180 million was recorded as a Regulatory Asset because such costs were deferred as approved by the BPU under an Order received in December 2012. Of the $295 million, $36 million related to insured property. PSE&G recognized $6 million of insurance proceeds. There were no significant additional costs incurred since 2012.

PSE&G made a filing with the BPU to review the prudency of unreimbursed incremental storm restoration costs, including O&M and capital expenditures associated with Superstorm Sandy and certain other extreme weather events, for recovery in its next base rate case or sooner through a BPU-approved cost recovery mechanism. In September 2014, the BPU approved its filing.

Power had incurred $193 million of storm-related costs from 2012 through 2014, primarily for repairs at certain generating stations in Power's fossil fleet. These costs were recognized primarily in O&M Expense, offset by $44 million of insurance recoveries in 2013 and 2012. Power incurred an additional $2 million of O&M costs in 2015 which were recognized primarily in O&M Expense.

In the first half of 2015, PSEG reached settlements with its insurers with respect to claims for coverage of its Superstorm Sandy-related losses. PSEG received an additional $214 million under these settlements (consisting of $159 million and $55 million recognized in the three months ended March 31, 2015 and June 30, 2015, respectively), bringing cumulative insurance proceeds to $264 million. Of the $214 million recognized in 2015, PSE&G and Power recorded $35 million and $179 million, respectively. In addition to the $35 million recognized in 2015, PSE&G recognized the aforementioned $6 million of previously deferred insurance recoveries, resulting in reductions in Regulatory Assets of $20 million, O&M Expense of $10 million and Property, Plant and Equipment of $11 million. Power recorded reductions in both O&M Expense of $145 million and Property, Plant and Equipment of $6 million and an increase in Other Income of $28 million.

The claim filed by PSEG, PSE&G and Power related to Superstorm Sandy insurance coverage is now fully resolved.

Nuclear Insurance Coverages and Assessments

Power is a member of an industry mutual insurance company, Nuclear Electric Insurance Limited (NEIL), which provides the property, decontamination and decommissioning liability insurance at the Salem/Hope Creek and Peach

Bottom sites. NEIL also provides replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in case of adverse loss experience. Power’s maximum potential liabilities under these assessments are included in the table and notes below. Certain provisions in the NEIL policies provide that the insurer may suspend coverage with respect to all nuclear units on a site without notice if the NRC suspends or revokes the operating license for any unit on that site, issues a shutdown order with respect to such unit or issues a confirmatory order keeping such unit down.

Power is also a member of the joint underwriting association, American Nuclear Insurers (ANI), which provides nuclear liability insurance coverage at the Salem/Hope Creek and Peach Bottom sites. The ANI policies are designed to satisfy the financial protection requirements outlined in the Price-Anderson Act.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The ANI and NEIL policies all include coverage for claims arising out of acts of terrorism, however, NEIL policies are subject to an industry aggregate limit of $3.2 billion plus such additional amounts as NEIL recovers for such losses from reinsurance, indemnity and any other source applicable to such losses.

The Price-Anderson Act sets the “limit of liability” for claims that could arise from an incident involving any licensed nuclear facility in the United States. The “limit of liability” is based on the number of licensed nuclear reactors and is adjusted at least every five years based on the Consumer Price Index. The current “limit of liability” is $13.5 billion. All owners of nuclear reactors, including Power, have provided for this exposure through a combination of private insurance and mandatory participation in a financial protection pool as established by the Price-Anderson Act. Under the Price-Anderson Act, each licensee can be assessed $127 million per reactor per incident, payable at not more than $19 million per reactor per incident per year. If the damages exceed the “limit of liability,” the Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Power’s maximum aggregate assessment per incident is $401 million (based on Power’s ownership interests in Hope Creek, Peach Bottom and Salem) and its maximum aggregate annual assessment per incident is $60 million. Further, a decision by the U.S. Supreme Court, not involving Power, has held that the Price-Anderson Act did not preclude awards based on state law claims for punitive damages.

Power’s insurance coverages and maximum retrospective assessments for its nuclear operations are as follows:

Type and Source of Coverages	Total Site Coverage Millions		Retrospective Assessments
Public and Nuclear Worker Liability (Primary Layer):			
ANI	$375	(A)	$—
Nuclear Liability (Excess Layer):			
Price-Anderson Act	13,113	(B)	401
Nuclear Liability Total	$13,488	(C)	$401
Property Damage (Primary Layer):			
NEIL Primary (Salem/Hope Creek and Peach Bottom)	$1,500		$46
Property Damage (Excess Layers)			
NEIL Excess (Salem/Hope Creek and Peach Bottom)	600	(D)	6
Property Damage Total (Per Site)	$2,100		$52
Accidental Outage:			
NEIL I (Peach Bottom)	$245	(E)	$8
NEIL I (Salem)	281	(E)	9
NEIL I (Hope Creek)	490	(E)	7
Replacement Power Total	$1,016		$24

(A) The primary limit for Public Liability is a per site aggregate limit with no potential for assessment. The Nuclear Worker Liability represents the potential liability from third party workers claiming exposure to the nuclear energy hazard. This coverage is subject to an industry aggregate limit that is subject to reinstatement at ANI discretion.

(B) Retrospective premium program under the Price-Anderson Act liability provisions of the Atomic Energy Act of 1954, as amended. Power is subject to retrospective assessment with respect to loss from an incident at any licensed nuclear reactor in the United States that produces greater than 100 MW of electrical power. This retrospective assessment can be adjusted for inflation every five years. The last adjustment was effective as of September 10, 2013. The next adjustment is due on or before September 10, 2018. This retrospective program is in excess of the Public and Nuclear Worker Liability primary layers.

(C) Limit of liability under the Price-Anderson Act for each nuclear incident.

(D)

For nuclear event property limits in excess of $1.5 billion, Power participates in a $600 million nuclear event Blanket Limit Policy. The blanket limit policy is shared with Exelon Generation and covers the following facilities: Braidwood, Byron, Clinton, Dresden, La Salle, Limerick, Oyster Creek, Quad Cities, TMI-1 Peach Bottom, Salem and Hope Creek. This limit is not subject to reinstatement in the event of a loss. Participation in this program reduces Power's premium and the associated potential assessment. In addition, for non-nuclear event limits in excess of $1.5 billion, Power maintains a $600 million limit shared by the Salem and Hope Creek facilities. Exelon maintains a $600 million non-nuclear event limit shared by Peach Bottom, Braidwood, Byron, Clinton, Dresden, LaSalle, Limerick, Oyster Creek, Quad Cities, and the TMI-1 facilities.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(E) Peach Bottom 2 and 3 have an aggregate indemnity limit based on a weekly indemnity of $2.3 million for 52 weeks followed by 80% of the weekly indemnity for 68 weeks. Salem 1 and 2 have an aggregate indemnity limit based on a weekly indemnity of $2.5 million for 52 weeks followed by 80% of the weekly indemnity for 76 weeks. Hope Creek has an aggregate indemnity limit based on a weekly indemnity of $4.5 million for 52 weeks followed by 80% of the weekly indemnity for 71 weeks.

Minimum Lease Payments

The total future minimum payments under various operating leases as of December 31, 2015 are:

	PSE&G	Power	Services	Other	Total
	Millions				
2016	$12	$2	$13	$2	$29
2017	9	2	13	1	25
2018	8	2	13	1	24
2019	7	2	13	—	22
2020	6	3	13	—	22
Thereafter	66	33	146	—	245
Total Minimum Lease Payments	$108	$44	$211	$4	$367

Note 13. Schedule of Consolidated Debt

Long-Term Debt

	Maturity	As of December 31, 2015	2014
		Millions	
PSEG (Parent)			
Term Loan:			
Variable	2017	$500	$—
Total Term Loan		500	—
Fair Value of Swaps (A)		6	22
Amounts Due Within One Year		(6)	(8)
Unamortized Discount Related to Debt Exchange (B)		—	(8)
Total Long-Term Debt of PSEG (Parent)		$500	$6

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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	Maturity	As of December 31, 2015	2014
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (C):			
6.75%	2016	$171	$171
9.25%	2021	134	134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		320	320
Pollution Control Bonds (C):			
Floating Rate (D)	2033	50	50
Floating Rate (D)	2046	50	50
Total Pollution Control Bonds		100	100
Medium-Term Notes (MTNs) (C):			
2.70%	2015	—	300
5.30%	2018	400	400
2.30%	2018	350	350
1.80%	2019	250	250
2.00%	2019	250	250
7.04%	2020	9	9
3.50%	2020	250	250
2.38%	2023	500	500
3.75%	2024	250	250
3.15%	2024	250	250
3.05%	2024	250	250
3.00%	2025	350	—
5.25%	2035	250	250
5.70%	2036	250	250
5.80%	2037	350	350
5.38%	2039	250	250
5.50%	2040	300	300
3.95%	2042	450	450
3.65%	2042	350	350
3.80%	2043	400	400
4.00%	2044	250	250
4.05%	2045	250	—
4.15%	2045	250	—
Total MTNs		6,459	5,909
Principal Amount Outstanding		6,879	6,329
Amounts Due Within One Year		(171)	(300)
Net Unamortized Discount and Debt Issuance Costs		(58)	(54)
Total Long-Term Debt of PSE&G (excluding Transition Funding and Transition Funding II)		$6,650	$5,975

135

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Maturity	As of December 31, 2015	2014
		Millions	
Transition Funding (PSE&G)			
Securitization Bonds:			
6.89%	2014-2015	$—	$251
Principal Amount Outstanding		—	251
Amounts Due Within One Year		—	(251)
Total Securitization Debt of Transition Funding		—	—
Transition Funding II (PSE&G)			
Securitization Bonds:			
4.57%	2014-2015	—	8
Principal Amount Outstanding		—	8
Amounts Due Within One Year		—	(8)
Total Securitization Debt of Transition Funding II		—	—
Total Long-Term Debt of PSE&G		$6,650	$5,975

	Maturity	As of December 31, 2015	2014
		Millions	
Power			
Senior Notes:			
5.50%	2015	$—	$300
5.32%	2016	303	303
2.75%	2016	250	250
2.45%	2018	250	250
5.13%	2020	406	406
4.15%	2021	250	250
4.30%	2023	250	250
8.63%	2031	500	500
Total Senior Notes		2,209	2,509
Pollution Control Notes:			
Floating Rate (D)	2019	44	44
Total Pollution Control Notes		44	44
Principal Amount Outstanding		2,253	2,553
Amounts Due Within One Year		(553)	(300)
Net Unamortized Discount and Debt Issuance Costs		(16)	(19)
Total Long-Term Debt of Power		$1,684	$2,234

(A) PSEG entered into various interest rate swaps to hedge the fair value of certain debt at Power. The fair value adjustments from these hedges are reflected as offsets to long-term debt on the Consolidated Balance Sheets. For additional information, see Note 15. Financial Risk Management Activities.

(B)

In September 2009, Power completed an exchange offer with eligible holders of Energy Holdings' 8.50% Senior Notes due 2011 in order to manage long-term debt maturities. Since the debt exchange was between two subsidiaries of the same parent company, PSEG, and treated as a debt modification for accounting purposes, the resulting premium was deferred and is being amortized over the term of the newly issued debt. The remaining deferred amount of $3 million as of December 31, 2015 is reflected as an offset to Long-Term Debt due within one year on PSEG's Consolidated Balance Sheets.

(C) Secured by essentially all property of PSE&G pursuant to its First and Refunding Mortgage.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(D) The Pollution Control Financing Authority of Salem County bonds and the Pennsylvania Economic Development Authority (PEDFA) bond that are serviced and secured by PSE&G Pollution Control Bonds and Power Pollution Control Notes, respectively, are variable rate bonds that are in weekly reset mode. In October 2014, Power executed an extension of the letter of credit backing the PEDFA bond which expires on November 30, 2019.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2015 are as follows:

Year	PSEG (Parent)	PSE&G	Power	Energy Holdings Non-Recourse Debt	Total
	Millions				
2016	$—	$171	$553	$7	$731
2017	500	—	—	—	500
2018	—	750	250	—	1,000
2019	—	500	44	—	544
2020	—	259	406	—	665
Thereafter	—	5,199	1,000	—	6,199
Total	$500	$6,879	$2,253	$7	$9,639

Long-Term Debt Financing Transactions

During 2015, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:

PSEG (Parent)

- entered into an agreement for a new term loan maturing November 2017. The term loan has a balance of $500 million at an interest rate of 1 month LIBOR + 0.875% and can be terminated at any time without penalty.

PSE&G

- issued $350 million of 3.00% Secured Medium-Term Notes, Series K due May 2025,
- issued $250 million of 4.05% Secured Medium-Term Notes, Series K due May 2045,
- issued $250 million of 4.15% Secured Medium-Term Notes, Series K due November 2045,
- paid $300 million of 2.70% Secured Medium-Term Notes at maturity,
- paid $251 million of Transition Funding's securitization debt, and
- paid $8 million of Transition Funding II's securitization debt.

Power

- paid $300 million of 5.50% Senior Notes at maturity.

PSE&G

PSE&G had $171 million of 6.75% Mortgage Bonds mature in January 2016.

Short-Term Liquidity

PSEG meets its short-term liquidity requirements, as well as those of Power, primarily with cash and through the issuance of commercial paper. PSE&G maintains its own separate commercial paper program to meet its short-term liquidity requirements. Each commercial paper program is fully back-stopped by its own separate credit facilities.

The commitments under our $4.2 billion credit facilities are provided by a diverse bank group. As of December 31, 2015, our total available credit capacity was $3.6 billion.

As of December 31, 2015, no single institution represented more than 7% of the total commitments in our credit facilities.

As of December 31, 2015, our total credit capacity was in excess of our anticipated maximum liquidity requirements.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Each of our credit facilities is restricted as to availability and use to the specific companies as listed in the following table; 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, 2015 were as follows:

Company/Facility	As of December 31, 2015 Total Facility Millions	Usage (D)	Available Liquidity	Expiration Date	Primary Purpose
PSEG					
5-year Credit Facility	$500	$10	$490	Apr 2019	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility (A)	500	211	289	Apr 2020	CP Support/Funding/Letters of Credit
Total PSEG	$1,000	$221	$779		
PSE&G					
5-year Credit Facility (B)	$600	$167	$433	Apr 2020	CP Support/Funding/Letters of Credit
Total PSE&G	$600	$167	$433		
Power					
5-year Credit Facility	$1,600	$161	$1,439	Apr 2019	Funding/Letters of Credit
5-year Credit Facility (C)	1,000	3	997	Apr 2020	Funding/Letters of Credit
Total Power	$2,600	$164	$2,436		
Total	$4,200	$552	$3,648		

(A) PSEG facility will be reduced by $23 million in April 2016 and $12 million in March 2018.
(B) PSE&G facility will be reduced by $29 million in April 2016 and $14 million in March 2018.
(C) Power facility will be reduced by $48 million in April 2016 and $24 million in March 2018.
(D) The primary use of PSEG's and PSE&G's credit facilities is to support their respective Commercial Paper Programs under which as of December 31, 2015, $211 million and $153 million, respectively, were outstanding. The weighted average interest rates on PSEG's and PSE&G's Commercial Paper Programs were 0.96% and 0.91%, respectively, at December 31, 2015.

Fair Value of Debt

The estimated fair values, carrying amounts and methods used to determine fair value of long-term debt as of December 31, 2015 and 2014 are included in the following table and accompanying notes as of December 31, 2015 and 2014. See Note 16. Fair Value Measurements for more information on fair value guidance and the hierarchy that prioritizes the inputs to fair value measurements into three levels.

	December 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$503	$506	$14	$22
PSE&G (B)	6,821	7,235	6,275	6,912
Transition Funding (PSE&G) (B)	—	—	251	261
Transition Funding II (PSE&G) (B)	—	—	8	8
Power - Recourse Debt (B)	2,237	2,508	2,534	2,930
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	7	7	16	16

$9,568	$10,256	$9,098	$10,149

(A) Fair value includes a $500 million floating rate term loan in 2015 and net offsets in 2015 and 2014 to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power. The fair value of the term loan debt (Level 2 measurement) was considered to be equal to the carrying value because the interest payments are based on LIBOR rates that are reset monthly. Carrying amount includes such fair value reduced by the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(B) Given that most bonds do not trade, the fair value amounts of taxable debt securities (primarily Level 2 measurements) are generally determined by a valuation model that is based on a conventional discounted cash flow methodology and utilizes assumptions of current market pricing curves. In order to incorporate the credit risk into the discount rates, pricing is obtained (i.e. U.S. Treasury rate plus credit spread) based on expected new issue pricing across each of the companies' respective debt maturity spectrum. The credit spreads of various tenors obtained from this information are added to the appropriate benchmark U.S. Treasury rates in order to determine the current market yields for the various tenors. The yields are then converted into discount rates of various tenors that are used for discounting the respective cash flows of the same tenor for each bond or note.

(C) Non-recourse project debt is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

Note 14. Schedule of Consolidated Capital Stock

	As of December 31,			
	Outstanding Shares		Book Value	
	2015	2014	2015	2014
			Millions	
PSEG Common Stock (no par value) (A)				
Authorized 1,000,000,000 shares	505,282,421	505,836,592	$4,244	$4,241

(A) PSEG did not issue any new shares under the Dividend Reinvestment and Stock Purchase Plan (DRASPP) or the Employee Stock Purchase Plan (ESPP) in 2015 or 2014. Total authorized and unissued shares of common stock available for issuance through PSEG's DRASPP, ESPP and various employee benefit plans amounted to approximately 7 million shares as of December 31, 2015.

As of December 31, 2015, PSE&G had an aggregate of 7.5 million shares of $100 par value and 10 million shares of $25 par value Cumulative Preferred Stock, which were authorized and unissued and which, upon issuance, may or may not provide for mandatory sinking fund redemption.

Note 15. Financial Risk Management Activities

The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.

Derivative accounting guidance requires that a derivative instrument be recognized as either an asset or a liability at fair value, with changes in fair value of the derivative recognized in earnings each period. Other accounting treatments are available through special election and designation provided that the derivative instrument meets specific, restrictive criteria, both at the time of designation and on an ongoing basis. These alternative permissible treatments include normal purchase normal sale (NPNS), cash flow hedge and fair value hedge accounting. PSEG, Power and PSE&G have applied the NPNS scope exception to certain derivative contracts for the forward sale of generation, power procurement agreements and fuel agreements. Transactions receiving NPNS treatment are accounted for upon settlement. For a derivative instrument that qualifies and is designated as a cash flow hedge, the changes in the fair value of such a derivative that are highly effective are recorded in Accumulated Other Comprehensive Income (Loss) until earnings are affected by the variability of cash flows of the hedged transaction. For a derivative instrument that qualifies and is designated as a fair value hedge, the gains or losses on the derivative as well as the offsetting losses or gains on the hedged item attributable to the hedged risk are recognized in earnings each period. Power and PSE&G enter into additional contracts that are derivatives, but do not qualify for or are not designated as either cash flow hedges or fair value hedges. These transactions are economic hedges and are recorded at fair market value.

Commodity Prices

Within PSEG and its affiliate companies, Power has the most exposure to commodity price risk. Power is exposed to commodity price risk primarily relating to changes in the market price of electricity, fossil fuels and other commodities. Fluctuations in market prices result from changes in supply and demand, fuel costs, market conditions, weather, state and federal regulatory policies, environmental policies, transmission availability and other factors. Power uses a variety of derivative and non-derivative instruments to manage the commodity price risk of its electric generation facilities, including physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.

Cash Flow Hedges

PSEG and Power use forward sale contracts, swaps and futures contracts to hedge certain forecasted natural gas sales made to support the BGSS contract with PSE&G. Historically, these derivative transactions qualified and were designated as cash flow hedges. PSEG and Power had no contracts designated as cash flow hedges as of December 31, 2015.

As of December 31, 2015 and 2014, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity was as follows:

	As of December 31,	
	2015	2014
	Millions	
Fair Value of Cash Flow Hedges	$—	$18
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$—	$10

Economic Hedges

Power enters into derivative contracts that do not qualify or are not designated as either cash flow or fair value hedges. Power enters into financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. These transactions are economic hedges, intended to mitigate exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of these contracts are recorded in earnings. PSE&G is a party to a long-term natural gas sales derivative contract to optimize its pipeline capacity utilization. Changes in the fair market value of the contract are recorded in Regulatory Assets and Regulatory Liabilities.

Interest Rates

PSEG, Power and PSE&G are subject to the risk of fluctuating interest rates in the normal course of business. Exposure to this risk is managed by targeting a balanced debt maturity profile which limits refinancing in any given period or interest rate environment. In addition, they have used a mix of fixed and floating rate debt and interest rate swaps.

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of December 31, 2015, PSEG had interest rate swaps outstanding totaling $550 million. These swaps convert $300 million of Power’s $303 million of 5.32% Senior Notes due September 2016 and Power’s $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying forecasted interest payments of the debt. As of December 31, 2015 and 2014, the fair value of all the underlying hedges was $6 million and $22 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was immaterial as of December 31, 2015 and 2014.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Consolidated Balance Sheets. The following tables also include disclosures for offsetting derivative assets and liabilities which are subject to a master netting or similar agreement. In general, the terms of the agreements provide that in the event of an early termination the counterparties have the right to offset amounts owed or owing under that and any other agreement with the same counterparty. Accordingly, and in accordance with our accounting policy, these positions have been offset on the Consolidated Balance Sheets of Power, PSE&G and PSEG.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following tabular disclosure does not include the offsetting of trade receivables and payables.

	As of December 31, 2015						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related Contracts	Not Designated Energy-Related Contracts	Netting (B)	Total Power	Not Designated Energy-Related Contracts	Fair Value Hedges Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$—	$700	$(477)	$223	$13	$6	$242
Noncurrent Assets	—	208	(131)	77	—	—	77
Total Mark-to-Market Derivative Assets	$—	$908	$(608)	$300	$13	$6	$319
Derivative Contracts							
Current Liabilities	$—	$(513)	$437	$(76)	$—	$—	$(76)
Noncurrent Liabilities	—	(132)	116	(16)	(11)	—	(27)
Total Mark-to-Market Derivative (Liabilities)	$—	$(645)	$553	$(92)	$(11)	$—	$(103)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$—	$263	$(55)	$208	$2	$6	$216

	As of December 31, 2014						
	Power (A)				PSE&G (A)	PSEG (A)	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related Contracts	Not Designated Energy-Related Contracts	Netting (B)	Total Power	Not Designated Energy-Related Contracts	Fair Value Hedges Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$18	$597	$(408)	$207	$18	$15	$240
Noncurrent Assets	—	171	(109)	62	8	7	77
Total Mark-to-Market Derivative Assets	$18	$768	$(517)	$269	$26	$22	$317
Derivative Contracts							
Current Liabilities	$—	$(568)	$436	$(132)	$—	$—	$(132)
Noncurrent Liabilities	—	(138)	105	(33)	—	—	(33)
Total Mark-to-Market Derivative (Liabilities)	$—	$(706)	$541	$(165)	$—	$—	$(165)
Total Net Mark-to-Market Derivative Assets	$18	$62	$24	$104	$26	$22	$152

(Liabilities)

(A) Substantially all of Power's and PSEG's derivative instruments are contracts subject to master netting agreements. Contracts not subject to master netting or similar agreements are immaterial and did not have any collateral posted or received as of December 31, 2015 and 2014. PSE&G does not have any derivative contracts subject to master netting or similar agreements.

(B) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. All cash collateral received or posted that has been allocated to derivative positions, where the right of offset exists, has been offset in the Consolidated Balance Sheets. As of December 31, 2015 and 2014, net cash collateral (received) paid of $(55) million and $24 million, respectively, were netted against the corresponding net derivative contract positions. Of the $(55) million as of December 31, 2015, $(53) million and $(16) million were netted against current assets and noncurrent assets, respectively, and $12 million and $2 million were netted against current liabilities and noncurrent liabilities, respectively. Of the $24 million as of December 31, 2014, cash collateral of $(4) million and $(8) million were netted against current assets and noncurrent assets, respectively, and $32 million and $4 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded to a below investment grade rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on the NYMEX and ICE must adhere to comprehensive collateral and margin requirements.

The aggregate fair value of all derivative instruments with credit risk-related contingent features in a liability position that are not fully collateralized (excluding transactions on the NYMEX and ICE that are fully collateralized) was $78 million and $127 million as of December 31, 2015 and 2014, respectively. As of December 31, 2015 and 2014, Power had the contractual right of offset of $12 million and $18 million, respectively, related to derivative instruments that are assets with the same counterparty under master agreements and net of margin posted. If Power had been downgraded to a below investment grade rating, it would have had additional collateral obligations of $66 million and $109 million as of December 31, 2015 and 2014, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $864 million and $945 million as of December 31, 2015 and 2014, respectively, discussed in Note 12. Commitments and Contingent Liabilities.

The following shows the effect on the Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the years ended December 31, 2015, 2014 and 2013:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)			Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)			Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)		
	Years Ended December 31,				Years Ended December 31,			Years Ended December 31,		
	2015	2014	2013		2015	2014	2013	2015	2014	2013
	Millions				Millions					
PSEG										
Energy-Related Contracts	$3	$12	$(4)	Operating Revenues	$20	$(9)	$13	$—	$—	$(1)
Interest Rate Swaps (A)	—	—	—	Interest Expense	—	—	(1)	—	—	—
Total PSEG	$3	$12	$(4)		$20	$(9)	$12	$—	$—	$(1)

Power										
Energy-Related Contracts	$3	$12	$(4)	Operating Revenues	$20	$(9)	$13	$—	$—	$(1)
Total Power	$3	$12	$(4)		$20	$(9)	$13	$—	$—	$(1)

(A) Includes amounts for PSEG parent.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following reconciles the AOCI for derivative activity included in the Accumulated Other Comprehensive Loss of PSEG on a pre-tax and after-tax basis:

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2013	$(4)	$(2)
Gain Recognized in AOCI	12	7
Plus: Loss Reclassified into Income	9	5
Balance as of December 31, 2014	$17	$10
Gain Recognized in AOCI	3	2
Less: Gain Reclassified into Income	(20)	(12)
Balance as of December 31, 2015	$—	$—

The following shows the effect on the Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the years ended December 31, 2015, 2014 and 2013:

Derivatives Not Designated as Hedges	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives	Pre-Tax Gain (Loss) Recognized in Income on Derivatives		
		Years Ended December 31,		
		2015	2014	2013
		Millions		
PSEG and Power				
Energy-Related Contracts	Operating Revenues	$412	$(348)	$(128)
Energy-Related Contracts	Energy Costs	(8)	32	106
Total PSEG and Power		$404	$(316)	$(22)

Power's derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $19 million, $20 million and $19 million for the years ended December 31, 2015, 2014 and 2013, respectively.

The following reflects the gross volume, on an absolute value basis, of derivatives as of December 31, 2015 and 2014:

Type	Notional	Total	PSEG	Power	PSE&G
	Millions				
As of December 31, 2015					
Natural Gas	Dth	201	—	168	33
Electricity	MWh	299	—	299	—
Financial Transmission Rights (FTRs)	MWh	23	—	23	—
Interest Rate Swaps	U.S. Dollars	550	550	—	—
As of December 31, 2014					
Natural Gas	Dth	274	—	216	58
Electricity	MWh	310	—	310	—
FTRs	MWh	15	—	15	—

Interest Rate Swaps	U.S. Dollars	850	850	—	—

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Credit Risk

Credit risk relates to the risk of loss that we would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. We have established credit policies that we believe significantly minimize credit risk. These policies include an evaluation of potential counterparties' financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements, which allow for the netting of positive and negative exposures associated with a single counterparty. In the event of non-performance or non-payment by a major counterparty, there may be a material adverse impact on Power's and PSEG's financial condition, results of operations or net cash flows.

As of December 31, 2015, 92% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of December 31, 2015. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
	Millions				Millions	
Investment Grade—External Rating	$451	$175	$276	1	$160	(A)
Non-Investment Grade—External Rating	24	—	24	—	—	
Investment Grade—No External Rating	12	1	11	—	—	
Non-Investment Grade—No External Rating	1	—	1	—	—	
Total	$488	$176	$312	1	$160	

(A) Represents net exposure with PSE&G.

As of December 31, 2015, collateral held from counterparties where Power had credit exposure included $14 million in cash collateral and $162 million in letters of credit.

As of December 31, 2015, Power had 133 active counterparties.

PSE&G's supplier master agreements are approved by the BPU and govern the terms of its electric supply procurement contracts. These agreements define a supplier's performance assurance requirements and allow a supplier to meet its credit requirements with a certain amount of unsecured credit. The amount of unsecured credit is determined based on the supplier's credit ratings from the major credit rating agencies and the supplier's tangible net worth. The credit position is based on the initial market price, which is the forward price of energy on the day the procurement transaction is executed, compared to the forward price curve for energy on the valuation day. To the extent that the forward price curve for energy exceeds the initial market price, the supplier is required to post a parental guaranty or other security instrument such as a letter of credit or cash, as collateral to the extent the credit exposure is greater than the supplier's unsecured credit limit. As of December 31, 2015, primarily all of the posted collateral was in the form of parental guarantees. The unsecured credit used by the suppliers represents PSE&G's net credit exposure. PSE&G's suppliers' credit exposure is calculated each business day. As of December 31, 2015, PSE&G had no net credit exposure with suppliers, including Power.

PSE&G is permitted to recover its costs of procuring energy through the BPU-approved BGS tariffs. PSE&G's counterparty credit risk is mitigated by its ability to recover realized energy costs through customer rates.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 16. Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. Accounting guidance for fair value measurement emphasizes that fair value is a market-based measurement, not an entity-specific measurement, and establishes a fair value hierarchy that distinguishes between assumptions based on market data obtained from independent sources and those based on an entity’s own assumptions. The hierarchy prioritizes the inputs to fair value measurement into three levels:

Level 1—measurements utilize quoted prices (unadjusted) in active markets for identical assets or liabilities that PSEG, PSE&G and Power have the ability to access. These consist primarily of listed equity securities and money market mutual funds.

Level 2—measurements include quoted prices for similar assets and liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, and other observable inputs such as interest rates and yield curves that are observable at commonly quoted intervals. These consist primarily of non-exchange traded derivatives such as forward contracts or options and most fixed income securities.

Level 3—measurements use unobservable inputs for assets or liabilities, based on the best information available and might include an entity’s own data and assumptions. In some valuations, the inputs used may fall into different levels of the hierarchy. In these cases, the financial instrument’s level within the fair value hierarchy is based on the lowest level of input that is significant to the fair value measurement. As of December 31, 2015, these consisted primarily of long-term gas supply and certain electric load contracts.

The following tables present information about PSEG’s, PSE&G’s and Power's respective assets and (liabilities) measured at fair value on a recurring basis as of December 31, 2015 and December 31, 2014, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

table of contents NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	Recurring Fair Value Measurements as of December 31, 2015				
Description	Total	Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Cash Equivalents (A)	$326	$—	$326	$—	$—
Derivative Contracts:					
Energy-Related Contracts (B)	$313	$(608)	$—	$896	$25
Interest Rate Swaps (C)	$6	$—	$—	$6	$—
NDT Fund (D)					
Equity Securities	$865	$—	$865	$—	$—
Debt Securities—Govt Obligations	$488	$—	$—	$488	$—
Debt Securities—Other	$359	$—	$—	$359	$—
Other Securities	$42	$—	$42	$—	$—
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$22	$—	$22	$—	$—
Debt Securities—Govt Obligations	$108	$—	$—	$108	$—
Debt Securities—Other	$81	$—	$—	$81	$—
Other Securities	$2	$—	$2	$—	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(103)	$553	$—	$(644)	$(12)
PSE&G					
Assets:					
Cash Equivalents (A)	$160	$—	$160	$—	$—
Derivative Contracts:					
Energy Related Contracts (B)	$13	$—	$—	$—	$13
Rabbi Trust (D)					
Equity Securities—Mutual Funds	$5	$—	$5	$—	$—
Debt Securities—Govt Obligations	$21	$—	$—	$21	$—
Debt Securities—Other	$16	$—	$—	$16	$—
Other Securities	$—	$—	$—	$—	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(11)	$—	$—	$—	$(11)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$300	$(608)	$—	$896	$12
NDT Fund (D)					
Equity Securities	$865	$—	$865	$—	$—
Debt Securities—Govt Obligations	$488				