PUBLIC SERVICE ENTERPRISE GROUP INC
Form 10-K
February 28, 2019

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K
(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2018
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 Newark, New Jersey 07102 973 430-7000 http://www.pseg.com	22-2625848
001-00973	PUBLIC SERVICE ELECTRIC AND GAS COMPANY (A New Jersey Corporation) 80 Park Plaza Newark, New Jersey 07102 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 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)

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

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

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

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

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

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

Indicate by check mark whether the registrants have submitted electronically every Interactive Data File required to be submitted 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 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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Public Service Enterprise Group Incorporated	Large accelerated filer x	Accelerated filer o	Non-accelerated filer o	Smaller reporting company o	Eme comp
Public Service Electric and Gas Company	Large accelerated filer o	Accelerated filer o	Non-accelerated filer x	Smaller reporting company o	Eme comp
PSEG Power LLC	Large accelerated filer o	Accelerated filer o	Non-accelerated filer x	Smaller reporting company o	Eme comp

If any of the registrants is an emerging growth company, indicate by check mark if such registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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, 2018 was $27,172,268,280 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 15, 2019 was 504,999,536.

As of February 15, 2019, 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 2019 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 12, 2019, as specified herein.

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report about our and our subsidiaries' future performance, including, without limitation, future revenues, earnings, strategies, prospects, consequences and all other statements that are not purely historical constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Such forward-looking statements are subject to risks and uncertainties, which could cause actual results to differ materially from those anticipated. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used herein, the words "anticipate," "intend," "estimate," "believe," "expect," "plan," "should," "hypothetical," "potential," "forecast," "project," variations of such words and similar expressions intended to identify forward-looking statements. Factors that may cause actual results to differ are often presented with the forward-looking statements themselves. Other factors that could cause actual results to differ materially from those contemplated in any forward-looking statements made by us herein are discussed in Item 1A. Risk Factors, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), Item 8. Financial Statements and Supplementary Data—Note 14. Commitments and Contingent Liabilities, and other filings we make with the United States Securities and Exchange Commission (SEC), including our subsequent reports on Form 10-Q and Form 8-K. These factors include, but are not limited to:

- fluctuations in wholesale power and natural gas markets, including the potential impacts on the economic viability of our generation units;
- our ability to obtain adequate fuel supply;
- any inability to manage our energy obligations with available supply;
- PSE&G's proposed investment programs may not be fully approved by regulators and its capital investment may be lower than planned;
- increases in competition in wholesale energy and capacity markets;
- changes in technology related to energy generation, distribution and consumption and customer usage patterns;
- economic downturns;
- third-party credit risk relating to our sale of generation output and purchase of fuel;
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements;
- changes in state and federal legislation and regulations, and PSE&G's ability to recover costs and earn returns on authorized investments;
- the impact of any future rate proceedings;
- risks associated with our ownership and operation of nuclear facilities, including regulatory risks, such as compliance with the Atomic Energy Act and trade control, environmental and other regulations, as well as financial, environmental and health and safety risks;
- the impact on our New Jersey nuclear plants of the failure of such plants to be selected to participate in the Zero Emissions Certificate (ZEC) program or adverse changes to the capacity market construct;
- adverse changes in energy industry laws, policies and regulations, including market structures and transmission planning;
- changes in federal and state environmental regulations and enforcement;
- delays in receipt of, or an inability to receive, necessary licenses and permits;
- adverse outcomes of any legal, regulatory or other proceeding, settlement, investigation or claim applicable to us and/or the energy industry;
- changes in tax laws and regulations;
- the impact of our holding company structure on our ability to meet our corporate funding needs, service debt and pay dividends;
- lack of growth or slower growth in the number of customers or changes in customer demand;
- any inability of Power to meet its commitments under forward sale obligations;

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- reliance on transmission facilities that we do not own or control and the impact on our ability to maintain adequate transmission capacity;
- any inability to successfully develop, obtain regulatory approval for, or construct generation, transmission and distribution projects;
- any equipment failures, accidents, severe weather events or other incidents that impact our ability to provide safe and reliable service to our customers;
- our inability to exercise control over the operations of generation facilities in which we do not maintain a controlling interest;
- any inability to recover the carrying amount of our long-lived assets and leveraged leases;
- any inability to maintain sufficient liquidity;
- any inability to realize anticipated tax benefits or retain tax credits;
- challenges associated with recruitment and/or retention of key executives and a qualified workforce;
- the impact of our covenants in our debt instruments on our operations; and
- the impact of acts of terrorism, cybersecurity attacks or intrusions.

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, results of operations or cash flows. 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 in light of new information or future events, unless otherwise required by applicable securities laws.
The forward-looking statements contained in this report are intended to qualify for the safe harbor provisions of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended.

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FILING FORMAT

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.

WHERE TO FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the SEC. You may 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 trading symbol PEG. You can obtain information about us at the offices of the New York Stock Exchange, Inc., 11 Wall 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. 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. Also invests in regulated solar generation projects and regulated energy efficiency and related programs in New Jersey.	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 and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets. Earns revenues from the generation and marketing of power and natural gas to hedge business risks and optimize the value of its portfolio of power plants, other contractual arrangements and oil and gas storage facilities. This is achieved primarily by selling power and transacting in natural gas and other energy-related products, on the spot market or using short-term or long-term contracts for physical and financial products. Also earns revenues from solar generation facilities under long-term sales contracts for power and environmental products.

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

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 (T&D) public utility, PSE&G, distributes electric energy and gas to customers within a designated service territory running diagonally across New Jersey where approximately 6.2 million people, or about 70% of New Jersey's population resides.

Products and Services

Our utility operations primarily earn margins through the T&D 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

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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).

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 is 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 our service territory.

In addition to our current utility products and services, we have implemented several programs to invest in 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.

How PSE&G Operates

We are a transmission owner in PJM Interconnection, L.L.C. (PJM) and we provide distribution service to 2.3 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 densely 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 Operation and Maintenance expenditures, rate base and capital investments and applies an approved return on equity (ROE) in developing the weighted average cost of capital. 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 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.

We continue to invest in transmission projects that are included for review in the FERC-approved PJM transmission expansion process. These projects focus on reliability improvements and replacement of aging infrastructure with planned capital spending of $3.4 billion for transmission in 2019-2021 as disclosed in Item 7. MD&A—Capital Requirements.

Distribution

PSE&G distributes gas and electricity to end users in our respective franchised service territories. In October 2018, the BPU issued an Order approving the settlement of our distribution base rate proceeding with new rates effective November 1, 2018. The Order provides for a distribution rate base of $9.5 billion, a 9.60% ROE for our distribution business and a 54% equity component of our capitalization structure. 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. Our load requirements are split among residential, commercial and industrial customers, as described in the following table for 2018:

	% of 2018 Sales	
Customer Type	Electric	Gas
Commercial	58%	38%
Residential	33%	58%
Industrial	9%	4%
Total	100%	100%

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Our customer base has modestly increased since 2014, with electric and gas loads increasing as illustrated below:

Electric and Gas Distribution Statistics

	December 31, 2018				
	Number of Customers		Electric Sales and Firm Gas Sales (A)		Historical Annual Load Growth 2014-2018
Electric	2.3	Million	41,889	Gigawatt hours (GWh)	0.3%
Gas	1.8	Million	2,630	Million Therms	1.7%

(A) Excludes sales from Gas rate classes that do not impact margin, specifically Contract, Non-Firm Transportation, Cogeneration Interruptible and Interruptible Services.

Electric sales were essentially flat with increases due to growth in the number of customers and improved economic conditions offset by conservation and more energy efficient appliances. Firm gas sales increased as a result of growth in the number of customers and customer response to continued low gas prices. Only firm gas sales impact margin.

PSE&G completed its BPU-approved Energy Strong Program I (ES I) in 2018. Under ES I, PSE&G, at an investment of $1 billion, completed the replacement and modernization of 240 miles of low-pressure cast iron gas mains in or near flood areas. PSE&G upgraded all of its electric substations that were damaged by water in recent storms; made investments that will create redundancy in the electric distribution system, reducing outages when damage occurs; and deployed technologies to better monitor system operations, enabling PSE&G to restore customers more quickly in the event of an electric outage. Concerning PSE&G's gas system, PSE&G upgraded five natural gas metering stations, two liquefied propane stations and a liquefied natural gas station affected by severe weather or located in flood zones.

In 2018, PSE&G also essentially completed its Gas System Modernization Program (GSMP I), which was approved by the BPU in late 2015. By June 2019, through GSMP I, we will have invested approximately $900 million to replace approximately 450 miles of cast iron and unprotected steel gas mains and about 40,000 unprotected steel service lines to homes and businesses, including uprating of the mains to higher pressure. The mains and service lines were replaced with stronger, more durable plastic piping, reducing the potential for leaks and release of methane gas. The new elevated pressure system also includes the installation of excess flow valves on each gas service that automatically shut off gas flow if a service line is abruptly damaged, and better supports the use of high-efficiency appliances.

In May 2018, PSE&G received approval for the Gas System Modernization Program II (GSMP II), an expanded, five-year program to invest $1.9 billion over five years beginning in 2019 to replace approximately 875 miles of cast iron and unprotected steel mains in addition to other improvements to the gas system.

In June 2018, we filed for our Energy Strong Program II (ES II), a proposed five-year $2.5 billion program to harden, modernize and make our electric and gas distribution systems more resilient. The size and duration of ES II, as well as certain other elements of the program, are subject to BPU approval. A procedural schedule has been issued with the review process expected to conclude in mid-2019.

In October 2018, we filed our proposed Clean Energy Future (CEF) program with the BPU, a six-year estimated $3.6 billion investment program covering four programs; (i) an Energy Efficiency (EE) program totaling $2.5 billion of investment designed to achieve energy efficiency targets required under New Jersey's Clean Energy law; (ii) an Electric Vehicle (EV) infrastructure program; (iii) an Energy Storage (ES) program and (iv) an Energy Cloud (EC) program which will include installing approximately two million electric smart meters and associated infrastructure. The procedural process for the CEF-EE program is expected to conclude by the third quarter of 2019. The CEF-EV/ES and CEF-EC programs will have separate procedural schedules. For additional information regarding the New Jersey Division of Rate Counsel's motions related to these programs, see Item 7. MD&A—Executive Overview of 2018 and Future Outlook.

Solar Generation

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® 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 received through periodic auctions and use the proceeds 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.

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Supply

Although commodity revenues make up almost 39% 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 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 commercial and industrial (C&I) 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).

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. Note 14. 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. Note 7. Regulatory Assets and Liabilities. 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. C&I 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 fluctuations 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.

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. Our commitments for load, such as BGS in New Jersey and other bilateral supply contracts, are backed by the generation we own and may be combined with the use of physical commodity purchases and financial instruments from the market to optimize the economic efficiency of serving the load. Power is a public utility within the meaning of the Federal Power Act (FPA) and the payments it receives and how it operates are subject to FERC regulation.

Power is also subject to certain regulatory requirements imposed by state utility commissions such as those in New York and Connecticut.

Products and Services

As a merchant generator and power marketer, our profit is derived from selling a range of products and services under contract to an array of customers including utilities, other power marketers, such as retail energy providers, or counterparties in the open market. These products and services may be transacted bilaterally or through exchange markets and include but are not limited to:

- 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).

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- 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.
- Congestion and Renewable Energy Credits—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. Renewable Energy Credits (RECs) are obtained through Power's owned renewable generation or purchased in the open market. Electric suppliers of load are required to deliver a certain amount or percentage of their delivered power from renewable resources as mandated by applicable regulatory requirements.

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. In 2014, the BPU approved an extension of the long-term BGSS contract to March 31, 2019, and thereafter the contract remains in effect 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.

Power also owns and operates 414 MW direct current (dc) of PV solar generation facilities and has an additional 52 MW dc of PV solar generation in construction. Power also 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's Generation Operates

Nearly all of our generation capacity consists of nuclear and fossil generation (11,458 MW) that is located in the Northeast and Mid-Atlantic regions of the United States in some of the country's largest and most developed electricity markets. For additional information see Item 2. Properties.

The map below shows the locations of our Northeast and Mid-Atlantic nuclear and fossil generation facilities, including the Bridgeport Harbor 5 (BH5) project currently under construction:

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- Generation Capacity

Our nuclear and fossil installed capacity utilizes a diverse mix of fuels. As of December 31, 2018, our fuel mix was comprised of 51% gas, 32% nuclear, 10% coal, 5% oil and 2% pumped storage. This fuel diversity helps to mitigate risks associated with fuel price volatility and market demand cycles. Our total generating output in 2018 was approximately 55,800 gigawatt hours (GWh). The generation mix by fuel type in recent years has reflected the relatively more favorable price of natural gas compared to coal. The following table indicates the proportionate share of generating output by fuel type in 2018.

Generation by Fuel Type (A)	Actual 2018	
Nuclear:		
New Jersey facilities	37%	
Pennsylvania facilities	19%	
Fossil:		
Natural Gas and Oil:		
New Jersey facilities	21%	
New York facilities	9%	
Maryland facilities	4%	
Connecticut facilities	—%	(B)
Coal:		
Pennsylvania facilities	10%	
Connecticut facilities	—%	(B)
Total	100%	

(A) Excludes pumped storage, solar facilities and fossil generation in Hawaii which account for less than 2.5 percent of total generation.

(B) Less than one percent.

In mid-2018, we commenced commercial operations of our Keys Energy Center (Keys), a 761 MW gas-fired combined cycle generating station in Maryland and Sewaren 7, a 538 MW dual-fueled combined cycle generating station in New Jersey.

In July 2018, Exelon, co-owner of the Peach Bottom nuclear facilities in Pennsylvania, submitted a second 20-year license renewal application with the Nuclear Regulatory Commission (NRC) for Peach Bottom Units 2 and 3. It is anticipated that the NRC’s review process will take approximately two years from submission of the application. Peach Bottom Units 2 and 3 are currently licensed to operate through 2033 and 2034, respectively.

In February 2016, the proposed generating facility, BH5, a 485 MW dual-fueled combined cycle generation project, was awarded a capacity obligation. Construction continues on BH5, which is targeted for commercial operation in mid-2019.

- Generation Dispatch

Our generation units have historically been 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.

- 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 2018, the base load capacity factors for the following units were:

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Unit	2018 Capacity Factor
Nuclear	
Salem Unit 1	97.9%
Salem Unit 2	84.6%
Hope Creek	88.8%
Peach Bottom Unit 2	93.4%
Peach Bottom Unit 3	94.2%
Coal	
Keystone	83.4%
Conemaugh	76.9%

- Load Following Units' 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 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.

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. It should be noted that the sustained lower pricing of natural gas over the past several years has resulted in changes in relative operating costs compared to historical norms, enabling some gas-fired generation to displace some generation by other fuel types. This change, combined with the addition of new, more efficient generation capacity, has altered the historical dispatch order of certain plants in the markets where we operate.

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.

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 gross margins 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.

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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. As shown above, prices may vary by location resulting from congestion or other factors, such as the availability of natural gas from the Marcellus (Leidy) and other shale-gas regions. These variations can be considerable. Concurrent with the development of regional shale gas, we have been increasing our purchases from the Marcellus/Utica shale gas regions and in 2018 they accounted for approximately 70% of the gas we procured. 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,
  - enrichment of uranium hexafluoride, and
  - fabrication of nuclear fuel assemblies.

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- Coal Supply—The Keystone, Conemaugh and Bridgeport Harbor 3 (BH3) stations operate on coal. Coal is delivered to these units through a combination of rail, truck, barge and ocean shipments.

To control emissions levels, our BH3 unit uses a specific type of coal obtained from Indonesia. We have coal inventory at the BH3 station as well as off-site storage to meet the plant's projected requirements.

- 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 contracted for this winter season to serve a portion of the gas requirements for our Bethlehem Energy Center (BEC) in New York and hold year-round firm gas transportation to serve the majority of the requirements of Keys in Maryland.

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 volume includes capacity from the Pennsylvania and Ohio shale gas regions where we purchase the majority of our natural gas. On an as-available basis, this firm transportation capacity may also be used to serve the gas supply needs of our New Jersey generation fleet.

Power has contracted for approximately 125,000 dekatherms/day of delivery capability on the PennEast Pipeline from eastern Pennsylvania to New Jersey. This delivery capability will be used to supplement the BGSS contract when it becomes operational.

- 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 a 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 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 and a discussion of risks, see Item 1A. Risk Factors, Item 7. MD&A—Executive Overview of 2018 and Future Outlook and Item 8. Note 14. 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 65 million people, nearly 20% 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 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 15 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 on our production and our obligations, these price differentials may increase or decrease our profitability.

Commodity prices, such as electricity, gas, coal, oil and environmental products, as well as the availability of our diverse fleet of generation units to operate, also have a considerable effect on our profitability. Over the long-term, the higher the forward prices are, the more attractive an environment exists for us to contract for the sale of our anticipated output. However, higher prices also increase the cost of replacement power; thereby placing us at greater

risk should our generating units fail to operate effectively or otherwise become unavailable.
Over the past several 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

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produced in states adjacent to New Jersey (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 to encourage expansion of capacity to meet future market demands. For additional information regarding FERC actions related to the capacity market construct, see Regulatory Issues—Federal Regulation.

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 in Pennsylvania 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. The average capacity prices that Power expects to receive from the base and incremental auctions which have been completed are disclosed in Item 8. Note 3. Revenues. 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 disclosed in Note 3. Revenues due to the import and export capability to and from lower-priced areas.

We have obtained price certainty for our PJM capacity through May 2022 and New England capacity through May 2026 for BH5 and May 2022 for New Haven 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 impacting the capacity auction or that permit subsidized local electric power generation.

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

Hedging Strategy

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

Among the ways in which we hedge our output are: (1) sales at PJM West or other nodes within PJM corresponding to our generation portfolio and (2) BGS and similar full-requirements contracts. Sales in PJM generally reflect block energy sales at the liquid PJM Western Hub or other basis locations when available 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

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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)	2016-2019	2017-2020	2018-2021	2019-2022
PSE&G	$96.38	$90.78	$91.77	$98.04
Jersey Central Power & Light Company (JCP&L)	$74.85	$69.08	$73.11	$77.15
Atlantic City Electric Company	$82.14	$75.49	$81.23	$87.40
Rockland Electric Company	$85.02	$80.50	$85.94	$88.03

Although we enter into these hedges 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 C&I 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.

Reflecting February 2019 BGS auction results, the contracted percentages of our anticipated base load generation output for the next three years with modest amounts beyond 2021 are as follows:

Base Load Generation	2019	2020	2021
Generation Sales	100%	95%-100%	30%-35%

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 2020 and a significant portion through 2021.

We also have various long-term fuel purchase commitments for coal to support our Keystone and Conemaugh 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 more efficient load following units can be estimated with a moderate degree of certainty. The peaking units are 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. The natural gas-fired units are hedged based on their expected generation; however, at much lower thresholds than baseload generation. Additionally, the recent development of low-cost gas supplies in the Marcellus region presents opportunities during certain portions of the year to procure gas for our generating units at attractive prices.

More than half of Power’s expected gross margin in 2019 relates to our hedging strategy, our expected revenues from the capacity market mechanisms described above and certain ancillary service payments such as reactive power.

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Energy Holdings Lease Investments

Energy Holdings primarily owns and manages a portfolio of domestic lease investments. The majority of Energy Holdings' $540 million of domestic lease investments are primarily energy-related leveraged leases. As of December 31, 2018, the counterparties for 55% of our total leveraged lease investments were rated below investment grade by Standard & Poor's (S&P). See Item 8. Note 9. Financing Receivables for additional information.

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. Note 9. Financing Receivables.

LIPA Operating Services Agreement (OSA)

In accordance with a twelve year Amended and Restated OSA entered into by PSEG LI and 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. Under 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. Also, there is an 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. Further, since January 2015, Power provides fuel procurement and power management services to LIPA under separate agreements.

COMPETITIVE ENVIRONMENT

PSE&G

Our T&D 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. Construction of new local generation and changing customer usage patterns also have the potential to reduce the need for the construction of new transmission to transport remote generation and alleviate system constraints. 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" to construct projects in our service territory, could result in third-party construction of transmission lines in our area in the future and also allow us to seek opportunities to build in other service territories. These rules continue to evolve 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.

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Power

Various market participants compete with us and one another in transacting in the wholesale energy markets, entering into bilateral contracts and selling to individual and aggregated retail customers. Our competitors include:

- merchant generators,
- domestic and multi-national utility generators,
- energy marketers and retailers,
- private equity firms, banks 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 generation revenues.

Adverse changes in energy industry law, policies and regulation could have significant economic, environmental and reliability consequences. For example, PJM, NYISO and 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. Various forums are considering how the competitive market framework can incorporate or be reconciled with state public policies that support particular resources, resource attributes or emerging technologies, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market prices. We cannot predict what action, if any, FERC might take with regard to capacity market designs but it may have an impact on Power’s generation portfolio. For additional information, see the discussion in Regulatory Issues—Federal Regulation.

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.

While it is our expectation that continued efforts may be undertaken by the federal and state governments to preserve the existing base nuclear generating plants, we still believe that pressures from renewable resources will continue to increase.

EMPLOYEE RELATIONS

As of December 31, 2018, we had 13,145 employees within our subsidiaries, including 8,145 covered under collective bargaining agreements with eight unions expiring from 2019 through 2022. We believe we maintain satisfactory relationships with our employees.

Employees as of December 31, 2018	PSE&G	Power	PSEG LI	Services

Non-Union	2,003	1,057	899	1,041
Union	5,315	1,065	1,510	255
Total Employees	7,318	2,122	2,409	1,296

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REGULATORY ISSUES

In the ordinary course of our business, we are subject to regulation by, and are party to various claims and regulatory proceedings with, FERC, the BPU, the Commodity Futures Trading Commission and various state and federal environmental regulators, among others. For information regarding material matters, other than those discussed below, see Item 8. Note 14. Commitments and Contingent Liabilities.

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 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 that wish to sell power at market rates must receive FERC authorization (MBR Authority) to sell power in interstate commerce before making power sales. 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 determine that the requesting company lacks market power in the relevant markets and/or that market power in the relevant markets is sufficiently mitigated. The following PSEG companies are public utilities and currently have MBR Authority: PSE&G, PSEG Energy Resources & Trade (ER&T), PSEG Fossil, PSEG Nuclear, PSEG Power Connecticut, PSEG New Haven, PSEG Energy Solutions, PSEG Keys Energy Center LLC, Pavant Solar II LLC, San Isabel Solar LLC and Bison Solar LLC. FERC requires that holders of MBR Authority 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.

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 provide an opportunity for bonus payments or require the payment of penalties depending on whether a unit is available during a performance hour.

FERC has also 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 regarding operator actions affecting energy market prices and would promote better alignment between generation dispatch decisions and energy market price outcomes. Certain reforms, such as a reform that

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would allow prices to better reflect scarcity conditions in which short-term demand is met by fast-start resources, are currently pending before FERC. However, we cannot predict whether they will be adopted.
In February 2019, the PJM Board approved a filing to modify the curves used for pricing reserves with FERC. The reforms include a 30-minute reserve product in real-time, more dynamic reserve requirements to better capture operator actions taken to maintain reliability, and improvement to the curves used to price reserves during reserve shortage conditions. If placed into effect, this reform is expected to improve energy and reserve prices by ensuring that when operators commit resources to ensure reliability, the commitments are reflected in market clearing prices. However, this reform could result in lower capacity payments. There is no timeline for this type of filing and therefore we cannot predict when FERC will act on the filing or the outcome of this matter.
Capacity Market Issues
PJM, NYISO and 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. Various forums are considering how the competitive market framework can incorporate or be reconciled with state public policies that support particular resources, resource attributes or emerging technologies, whether generators are being sufficiently compensated in the capacity market and whether subsidized resources may be adversely affecting capacity market prices. We cannot predict what action, if any, FERC might take with regard to capacity market designs.
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.
In June 2018, FERC issued an order finding that PJM’s current capacity market construct was not just and reasonable. FERC found that the RPM market design was not sufficiently competitive because it enabled state-supported resources to bid below their costs which resulted in suppressed clearing prices. In particular, FERC found that nuclear generating units that receive zero emission certificate (ZEC) payments were of concern. FERC initiated a separate proceeding to develop a mechanism to protect resources that do not receive subsidies and proposed a Fixed Resource Alternative option that removes subsidized resources along with a commensurate amount of load. PSEG and other parties have sought rehearing of FERC’s order, which is still pending.
In response to FERC’s order, PJM proposed a minimum offer price rule (MOPR) with a significant number of exceptions and a “resource carve-out” (RCO) option that would carve certain resources out of the capacity market that have actionable subsidies. If this proposal is ultimately adopted by FERC and our New Jersey nuclear units receive ZECs, they may become subject to the MOPR and would be required to submit capacity bids at a level that may be above the auction clearing price. Under this scenario, if Hope Creek, Salem 1 and Salem 2 nuclear units are awarded ZECs, they may not clear the capacity auction in whole or in part, and they may not receive capacity payments. However, these units may be eligible for the RCO option and receive payments directly from New Jersey Load-serving entities through a mechanism approved by the BPU. The BPU could utilize the existing BGS mechanism for this purpose.
PJM also proposed an alternative to the RCO option that includes a two-tiered “repricing” option. Under this proposal, PJM would run an initial auction to determine which resources would receive a commitment and a second auction to determine the price to pay the capacity resources. If this mechanism was adopted by FERC, it would likely have a favorable impact on the capacity payments received by non-nuclear units within the PSEG generating fleet but could adversely affect the nuclear units if, as ZEC recipients, they participate as RCO resources and have to make payments to other plants. We are unable to predict the outcome of the FERC proceeding or any BPU efforts to effectuate the RCO option.
In October 2018, PJM filed with FERC to revise the shape of the Variable Resource Requirement (VRR) curve that will be implemented for the capacity auction that will be held in August 2019. The VRR curve is the administratively determined demand curve that serves as one of the key elements for establishing the amount of generation capacity to be procured in the auction. PJM contends that its proposal will lower capacity prices as compared to the currently

effective VRR curve. PSEG protested PJM's proposal on the grounds that it would result in understated prices for capacity relative to the cost of constructing a new reference generating unit and will result in prices that are unjust and unreasonable. This matter is pending before FERC and we cannot predict the outcome.

ISO-NE—ISO-NE's market for installed capacity in New England provides fixed capacity payments for generators, imports and demand response. 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 Capacity Performance mechanism, that provides incentives for performance and that imposes charges 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 financial risk for non-performance. In March 2018, FERC approved proposed changes to the FCM referred to as the

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Competitive Auctions and Sponsored Policy Resources (CASPR) to accommodate clean and renewable energy policy resources. The CASPR design creates a second auction that commences immediately following the Forward Capacity Auction and provides the opportunity for certain renewable, clean and alternative energy resources to acquire supply obligations when they cannot clear economically in the Forward Capacity Auction. The CASPR design also phases out the exemption from the MOPR in the capacity market afforded for up to 200MW annually (600 MW cumulatively) of renewable resources, an aspect of the market design that we did not support due to the capacity market suppression associated with this mechanism. The effective date of these CASPR provisions will be implemented beginning with the Forward Capacity Auction to be held in February 2019.

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. In March 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. In April 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, which was denied by FERC at the end of 2017. 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. The matter remains pending before FERC. In addition, in May 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. In October 2015, FERC granted in part, certain of the requested exemptions for renewable resources and resources being used by the owner for self-supply. The IPPNY has challenged NYISO’s proposed implementation of the newly required exemptions. This challenge is still pending.

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.

For additional information about our transmission filings, see Item 8. Note 7. Regulatory Assets and Liabilities.

Transmission Policy Developments—There are several matters pending before FERC that concern the allocation of costs associated with transmission projects contending that insufficient levels of costs are being allocated to customers in the PSE&G transmission zone. Projects involved include the Artificial Island project and the Bergen-Linden Corridor project in New Jersey. In April 2016, FERC issued orders denying the complaints and leaving the current cost allocation in effect as to the Bergen-Linden project. In October 2017, FERC accepted the Artificial Island Cost allocation filing on the grounds that PJM correctly applied its Tariff. However, FERC deferred a ruling on whether the cost allocation methodology applied to the Artificial Island project is appropriate. FERC will decide this issue in a separate proceeding that is currently pending. It is anticipated that additional proceedings are likely to occur.

Another proceeding is a matter remanded from a federal appellate court concerning the appropriate cost allocation for certain 500 kilovolt (kV) projects in PJM that either have been built or are in the process of being built. In May 2018, FERC approved a settlement for this matter that is expected to result in increased annual cost allocations to customers in the PSE&G transmission zone. The cost reallocation was implemented by PJM in July 2018. Under this settlement, Power, as a BGS supplier is obligated to pay amounts previously paid by other PJM transmission customers. In November 2018, the BPU authorized BGS suppliers to collect increased allocation amounts from BGS customers through a pass-through provision in the BGS supplier contracts.

Transmission Rate Proceedings and Return on Equity—Numerous complaints have been filed at FERC in recent years seeking to reduce the base ROE of transmission owners across the country. Many of those complaints were resolved through agreement and settlement resulted in ROE reductions while others remain pending in the FERC adjudication process or are being litigated in the courts. Recent court decisions, as well as proposed changes to the ROE calculation methodology discussed below, create some uncertainty as to the timing and outcome of these complaints. The results of these settlements and proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

In October 2018, FERC issued an order establishing a new framework for determining whether a company’s ROE is unjust and unreasonable. The order was issued in a proceeding that was remanded to FERC from D.C. Circuit concerning the

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establishment of the New England Transmission Owners' ROE. FERC's order proposes a new method for evaluating whether an existing ROE remains just and reasonable. Under FERC's approach, FERC will determine a composite zone of reasonableness based on the results of three financial models, and if the targeted utility's existing ROE falls within the range of just and reasonable ROEs for its risk profile, FERC will dismiss the complaint. However, if FERC determines that an existing ROE is unjust and unreasonable, it proposes to rely on four financial models: a discounted cash flow, a risk premium analysis, a capital-asset pricing model analysis and an expected earnings analysis. We are analyzing the potential impact of these methodologies and cannot predict the outcome of this proceeding.

Compliance

Reliability Standards—Congress has required FERC to put in place, through the North American Electric Reliability Corporation (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. As a result, FERC directed 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 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 (CIP) standards that are already in place and that establish physical and cybersecurity protections for critical systems. We are taking steps to meet these obligations. FERC directed NERC to develop a new reliability standard to provide security controls for supply chain management associated with the procurement of industrial control system hardware, software, and services related to bulk electric system operations. When adopted, compliance with these new standards would be expected to impose additional obligations and costs.

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 recordkeeping and data reporting requirements applicable to commercial end users. The CFTC has also re-proposed rules establishing position limits for trading in certain commodities, such as natural gas, and we will begin complying with these rules once they become final.

Nuclear Regulatory Commission (NRC)

Our operation of nuclear generating facilities is subject to comprehensive regulation by the Nuclear Regulatory Commission (NRC), a federal agency established to regulate nuclear activities to ensure the 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 NRC conducts ongoing reviews of nuclear industry operating experience and may issue or revise regulatory requirements as a result of these ongoing reviews. 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 the Salem, Hope Creek and Peach Bottom facilities, but such costs 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.

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 proceedings. Recovery of these costs or investments is subject to BPU approval for

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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. Note 7. Regulatory Assets and Liabilities.

New Jersey Energy Master Plan (EMP)—In May 2018, the New Jersey governor signed an executive order directing the BPU and other New Jersey executive branch agencies to prepare a new EMP by June 1, 2019. While not having the force of law, the EMP provides an overview of energy policy in New Jersey. The new EMP will, among other issues: focus on New Jersey converting to 100% clean energy sources by January 1, 2050; incorporate New Jersey's offshore wind development goals; include provisions to guide the continued development of solar energy, including community solar; make recommendations to bolster energy storage in New Jersey; and explore methods to incentivize the use of clean, efficient energy and electric technology alternatives in New Jersey's transportation sector and at its ports.

In January 2018, the governor of New Jersey signed Executive Order No. 8 directing the BPU to begin the process of moving the state toward its 2030 goal of 3,500 MW of offshore wind energy generation. An initial solicitation was established for 1,100 MW of offshore wind, with bids due in December 2018. For a discussion of our involvement with offshore wind in New Jersey, see Item 7. MD&A—Executive Overview of 2018 and Future Outlook.

Energy Efficiency Initiatives—In May 2018, the New Jersey governor signed legislation that requires the state's electric and gas utilities to implement energy efficiency programs that are expected to achieve energy savings targets for electric and gas usage within five years of the utility's implementation of its BPU-approved energy efficiency programs. To meet these savings targets, energy usage reductions and peak demand reductions that result from utility and non-utility based programs and investments (including building code changes) will be counted. The initial targets are 2% of annual electric usage and 0.75% of annual gas usage with the targets then being reassessed periodically by the BPU. The specific energy savings target for each public electric and gas utility will be determined from an energy efficiency study to be completed within a year from enactment of the legislation. The legislation requires utilities to make annual filings with the BPU outlining their planned investments and proposed programs for cost-effectively achieving the targeted energy savings. These filings are also expected to address the utility's return of and on those investments and recovery of lost revenues associated with the lower sales. The BPU is required to adopt rules to implement the legislation within one year of enactment.

Infrastructure Investment Program (IIP)—The BPU has enacted IIP regulations that encourage utilities to construct, install or remediate utility plant and facilities related to reliability, resiliency and/or safety to support the provision of safe and adequate service. Under these regulations, utilities can seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain non-revenue producing infrastructure that enhances reliability, resiliency, and/or safety.

BGSS Process—In November 2017, a filing was made by the Retail Energy Supply Association (RESA) with the BPU requesting that the BPU revisit the BGSS process and establish a gas capacity release program. In March 2018, the RESA filed an amended petition with the BPU requesting a formal proceeding to establish a gas capacity release program. This filing applies to all New Jersey gas utilities. The matter remains pending.

BPU 2018 Storm Investigation—The BPU conducted an investigation of the state's EDCs' responses to the March 2018 late winter storms. Based on the findings of the investigation, the BPU implemented certain recommendations that it deemed essential to facilitate the continued provision of safe, proper and adequate service; to help mitigate future outages; and to help develop more effective responses and coordination of resources. These recommendations imposed several specific follow-up requirements on the EDCs concerning, among other things, weather forecasting; updates to the EDCs' event level classification matrices and emergency operations plans; and submission of a plan and cost benefit analysis for the implementation of Advanced Metering Infrastructure (AMI).

In January 2019, PSE&G filed a response to the request for a plan and cost benefit analysis for the implementation of AMI. The response highlighted a number of customer and operational benefits associated with the deployment of AMI, and incorporated PSE&G's EC Business case and direct testimony from the CEF-EC proceeding previously filed with the BPU. PSE&G has filed all responses to the follow-up requirements specified by the BPU.

Federal Tax Legislation —As a result of the enactment of the Tax Cuts and Jobs Act of 2017 (Tax Act), various state regulatory authorities, including the BPU, took action to ensure that excess federal income taxes previously collected in rates are returned to customers. We have adjusted our revenue requirement in certain of our rate matters as a result of the change in the federal income tax rate.

Additional matters and information on our specific filings are discussed in Item 8. Note 7. Regulatory Assets and Liabilities.

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Cybersecurity

In an effort to reduce the likelihood and severity of cybersecurity incidents, we have established a comprehensive cybersecurity program designed to protect and preserve the confidentiality, integrity and availability of our company's and our customers' information and our systems. Our cybersecurity program is built on technical, procedural, and people-focused measures to detect, protect against, respond to, and recover from cyber threats to our systems and information including company, employee and customer data. Features of our program include: identifying critical information and systems; conducting cyber risk assessments of our and third-party systems; maintaining awareness of cyber threats and vulnerabilities through partnerships with public and private entities, as well as industry groups; maintaining and testing our cybersecurity incident response plans and systems; training personnel on cybersecurity issues; cybersecurity awareness throughout our company with electronic notices and seminars; and periodically reviewing industry best practices and operational benchmarking. Cybersecurity and the effectiveness of our cybersecurity processes are discussed by senior management and at Board and Audit Committee meetings. Our strategy for managing cyber-related risks is integrated within our enterprise risk management processes.

In addition, we are subject to federal and state requirements designed to further protect against cybersecurity threats to critical infrastructure, as discussed below. For a discussion of the risks associated with cybersecurity threats, see Item 1A. Risk Factors.

Federal—NERC, at the direction of FERC, has implemented national and regional reliability standards to ensure the reliability of the grid and to prevent major system blackouts. NERC CIP standards establish cybersecurity and physical security protections for critical systems and facilities. These standards are also designed to develop coordination, threat sharing and interaction between utilities and various government agencies regarding potential cybersecurity and physical threats against the nation's electric grid.

FERC further directed NERC to develop a new reliability standard to provide security controls for supply chain management associated with the procurement of industrial control system hardware, software, and services related to bulk electric system operations. FERC approved these supply chain risk management standards in October 2018, with an implementation date of July 1, 2020. We are taking steps to meet these additional obligations. Compliance with these new standards would be expected to impose additional costs.

State—The BPU requires utilities, including PSE&G, to, among other things, implement a cybersecurity program that defines and implements organization accountabilities and responsibilities for cyber risk management activities, and establishes policies, plans, processes and procedures for identifying and mitigating cyber risk to critical systems. Additional requirements of this order include, but are not limited to: (i) annually inventorying critical utility systems; (ii) annually assessing risks to critical utility systems; (iii) implementing controls to mitigate cyber risks to critical utility systems; (iv) monitoring log files of critical utility systems; (v) reporting cyber incidents to the BPU; and (vi) establishing a cybersecurity incident response plan and conducting biennial exercises to test the plan.

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.

We expect there will be changes to existing environmental laws and regulations that could significantly impact the manner in which our operations are currently conducted. Such laws and regulations may also affect the timing, cost, location, design, construction and operation of new facilities. 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.

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 and Item 8. Note 14. Commitments and Contingent Liabilities.

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Air Pollution Control

Our facilities are subject to federal regulation under the Clean Air Act (CAA) that requires controls of emissions from sources of air pollution and imposes recordkeeping, 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 (HAPS) and went into effect in April 2015. In June 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. In April 2016, the EPA released the final 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 ruling. The 2016 Supplemental Finding determined that HAPS from existing electric generating units should be regulated and that the environmental and health benefits derived from the reduction in emissions of both HAPS and co-benefit pollutants far outweighed the cost of compliance. Industry participants and various state authorities filed petitions with the D.C. Circuit challenging the EPA's Supplemental Finding. The D.C. Circuit is holding the case in abeyance pending further directions from the EPA.

In December 2018, the EPA issued a proposed Supplemental Finding to reverse the 2016 Supplemental Finding, concluding that the analysis should not include the benefits from the reduction in emissions from co-benefit pollutants. Although the EPA proposed that it will retain the emission standards and other requirements of MATS, it is seeking comment on two alternatives to potentially rescind MATS. Finally, the EPA proposal concluded that no additional regulations are required. We do not expect this Supplemental Finding, if finalized as proposed, to impact the operation of our facilities.

Climate Change

CO_2 Regulation under the CAA—In October 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 units, and (ii) natural gas combustion turbines. Simple cycle combustion turbines are exempt from the rule.

In October 2015, the EPA also published the Clean Power Plan (CPP), a greenhouse gas (GHG) emissions regulation under the CAA for existing power plants.

In August 2018, the EPA released the proposed Affordable Clean Energy (ACE) rule as a replacement for the CPP. The proposed ACE rule gives states great flexibility to evaluate specific heat rate improvement technologies and practices to be applied at coal-fired electric generating units. States have three years from the date of finalization to submit a plan that establishes a standard of performance that reflects the degree of emission limitation through the application of heat rate improvement technologies and practices. We cannot estimate the impact of this action on our business or results of operations.

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 secondary markets.

In September 2017, the RGGI States announced their new post-2020 program for a cap on regional CO_2 emissions, which would require a decline in CO_2 emissions in 2021 and each year thereafter, resulting in a 30% reduction in the

CO_2 emissions cap by 2030.
New Jersey 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 New Jersey Department of Environmental Protection (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. In December 2018, the NJDEP proposed two rules that begin New Jersey’s re-entry into RGGI. The first proposal is the mechanism that establishes New Jersey’s initial cap on GHG emissions of 18 million tons in 2020. The proposal follows the RGGI model rule with a cap that will decline three percent annually through 2030 to a final cap of 11.5 million tons. New Jersey is committed to a start date of January 1, 2020. The second proposal establishes the framework for how New Jersey will

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spend the RGGI auction proceeds. We cannot estimate the impact of this action on our business or results of operations at this time.

Water Pollution Control

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

Steam Electric Effluent Guidelines—In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG 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, and gasification wastewater. Power’s Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations have bottom ash transport water discharges that are regulated under the ELG Rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the ELG Rule.

Through various orders, the EPA has stayed the compliance dates in the ELG Rule and has announced plans to further revise the requirements and compliance dates of the ELG Rule. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

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 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, based on studies related to impingement mortality and entrainment and submit the results with their permit applications to be conducted by the facilities seeking renewal permits. Several environmental organizations and certain energy industry groups have filed suit under the CWA and the Endangered Species Act. The cases have been consolidated at the Second Circuit and a decision remains pending.

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. Note 14. Commitments and Contingent Liabilities for additional information.

Hazardous Substance Liability

The production and delivery of electricity and the distribution and manufacture of gas result 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. 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. Note 14. 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-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 address injuries to natural resources 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.

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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. Under the Nuclear Waste Policy Act of 1982 (NWPA), nuclear plant owners are required to contribute to a Nuclear Waste Fund to pay for this service. Since May 2014, the United States Department of Energy (DOE) reduced the nuclear waste fee to zero. No assurances can be given that this fee will not be increased in the future. The NWPA allows spent nuclear fuel generated in any reactor to be stored in reactor facility storage pools or in Independent Spent Fuel Storage Installations located at reactors or away from reactor sites.

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.

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EXECUTIVE OFFICERS OF THE REGISTRANT (PSEG)

Name	Age as of December 31, 2018	Office	Effective Date First Elected to Present Position
Ralph Izzo	61	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)	April 2007 to present
		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	55	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
David M. Daly	57	President and Chief Operating Officer (PSE&G)	October 2017 to present
		Chairman of the Board of PSEG Long Island LLC	October 2017 to present
		President and Chief Operating Officer (PSEG Long Island LLC)	October 2013 to October 2017
Ralph A. LaRossa	55	President and Chief Operating Officer (Power)	October 2017 to present
		President and Chief Operating Officer (PSE&G)	October 2006 to October 2017
		Chairman of the Board of PSEG Long Island LLC	October 2013 to October 2017
Derek M. DiRisio	54	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
Tamara L. Linde	54	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
Stuart J. Black	56	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

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ITEM 1A. RISK FACTORS

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

MARKET AND COMPETITION RISKS

Fluctuations in the wholesale power and natural gas markets could negatively affect our financial condition, results of operations and cash flows.

In the markets where we operate, natural gas prices have a major impact on the price that generators receive for their output. Over the past several years, wholesale prices for natural gas have remained well below the peak levels experienced in 2008, in part due to increased shale gas production as extraction technology has improved. Lower gas prices have resulted in lower electricity prices, which have reduced our margins as nuclear and coal generation costs have not declined similarly.

PSEG and Power continue to monitor their remaining coal assets, including the Keystone and Conemaugh generating stations, to ensure their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact our ability to operate or maintain these assets in the future. These generating stations may be impacted by factors such as continued depressed wholesale power prices or capacity factors, among other things. Any early retirement of these coal units before the end of their current estimated useful lives or change in the classification as held for use may have a material adverse impact on PSEG's and Power's future financial results.

We may be unable to obtain an adequate fuel supply in the future.

We obtain substantially all of our physical natural gas and nuclear fuel supply from third parties pursuant to arrangements that vary in term, pricing structure, firmness and delivery flexibility. Our fuel supply arrangements must be coordinated with transportation agreements, balancing agreements, storage services, financial hedging transactions and other contracts to ensure that the natural gas and nuclear fuel are delivered to our power plants at the times, in the quantities and otherwise in a manner that meets the needs of our generation portfolio and our customers. We must also comply with laws and regulations governing the transportation of such fuels.

We are exposed to increases in the price of natural gas and nuclear fuel, and it is possible that sufficient supplies to operate our generating facilities profitably may not continue to be available to us. Significant changes in the price of natural gas and nuclear fuel could affect our future results and impact our liquidity needs. In addition, we face risks with regard to the delivery to, and the use of natural gas and nuclear fuel by, our power plants including the following:

- transportation may be unavailable if pipeline infrastructure is damaged or disabled;
- pipeline tariff changes may adversely affect our ability to, or cost to, deliver such fuels;
- creditworthiness of third-party suppliers, defaults by third-party suppliers on supply obligations and our ability to replace supplies currently under contract may delay or prevent timely delivery;
- market liquidity for physical supplies of such fuels or availability of related services (e.g. storage) may be insufficient or available only at prices that are not acceptable to us;
- variation in the quality of such fuels may adversely affect our power plant operations;
- legislative or regulatory actions or requirements, including those related to pipeline integrity inspections, may increase the cost of such fuels;
- fuel supplies diverted to residential heating may limit the availability of such fuels for our power plants; and
- the loss of critical infrastructure, terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe storms or other similar occurrences could impede the delivery of such fuels.

Our nuclear units have a diversified portfolio of contracts and inventory that provide a substantial portion of our fuel raw material needs over the next several years. However, each of our nuclear units has contracted with a single fuel fabrication services provider, and transitioning to an alternative provider could take an extended period of time.

Certain of our other generation facilities also require fuel or other services that may only be available from one or a limited number of suppliers. The availability and price of this fuel may vary due to supplier financial or operational disruptions, transportation disruptions and force majeure. At times, such fuel may not be available at any price, or we may not be able to transport it to our facilities on a timely basis. In this case, we may not be able to run those facilities even if it would be profitable. If we had sold forward the

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power from such a facility, we could be required to supply or purchase power from alternate sources, perhaps at a loss. This could have a material adverse impact on our business, the financial results of specific plants and on our results of operations.

In 2018, a petition was filed with the U.S. Department of Commerce by two uranium mining companies seeking relief under Section 232 of the Trade Expansion Act of 1962, as amended, from imports of uranium products, alleging that these imports threaten national security. In July 2018, the Secretary of Commerce announced the initiation of an investigation in response to the petition. The relief sought by the petitioners would require U.S. nuclear reactors to purchase at least 25% of their uranium needs from domestic mines over the next ten years, although the Department of Commerce and ultimately the President will make an independent determination regarding an appropriate remedy regarding uranium imports and national security. The outcome of this petition could increase nuclear fuel costs in future periods, which would have an adverse impact on the results of operations, cash flows and financial positions of our nuclear facilities.

Although our fuel contract portfolio provides a degree of hedging against these market risks, such hedging may not be effective and future increases in our fuel costs could materially and adversely affect our liquidity, financial condition and results of operations. While our generation runs on a mix of fuels, primarily natural gas and nuclear fuel, an increase in the cost of any particular fuel ultimately used could impact our results of operations.

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

Factors that may cause market price fluctuations include:

- increases and decreases in generation capacity, including the addition of new supplies of power as a result of the development of new power plants, expansion of existing power plants or additional transmission capacity;
- power transmission or fuel transportation capacity constraints or inefficiencies;
- power supply disruptions, including power plant outages and transmission disruptions;
- weather conditions, particularly unusually mild summers or warm winters in our market areas;
- quarterly and seasonal fluctuations;
- economic and political conditions that could negatively impact the demand for power;
- changes in the supply of, and demand for, energy commodities;
- development of new fuels or new technologies for the production or storage of power;
- federal and state regulations and actions of the ISOs; and
- federal and state power, market and environmental regulation and legislation, including financial incentives for new renewable energy generation capacity that could lead to oversupply.

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 or if our internal policies and procedures designed to monitor the exposure to these various risks are not effective, we could incur material 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.

PSE&G's proposed investment programs may not be fully approved by regulators, which could result in lower than desired service levels to customers, and actual capital investment by PSE&G may be lower than planned, which would cause lower than anticipated rate base.

PSE&G is a regulated public utility that operates and invests in an electric T&D system and a gas distribution system as well as certain regulated clean energy investments, including solar and energy efficiency within New Jersey. PSE&G invests in capital projects to maintain and improve its existing T&D system and to address various public policy goals and meet customer

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expectations. Transmission projects are subject to review in the FERC-approved PJM transmission expansion process while distribution and clean energy projects are subject to approval by the BPU. We cannot be certain that any proposed project will be approved as requested or at all. In particular, PSE&G is currently seeking approval for a number of investment programs from the BPU including our ES II, a proposed five-year $2.5 billion program to harden, modernize and make our electric and gas distribution systems more resilient; and our proposed CEF program, a six-year estimated $3.6 billion investment program focused on achieving New Jersey's EE targets, supporting EV infrastructure, deploying ES, and implementing an EC program. If these programs and other programs that PSE&G may file from time to time are only approved in part, or not at all, or if the approval fails to allow for the timely recovery of all of PSE&G's costs, including a return of, or on, its investment, PSE&G will have a lower than anticipated rate base, thus causing its future earnings to be lower than anticipated. If these programs are not approved, that could also adversely affect our service levels for customers. Further, the BPU could take positions to exclude or limit utility participation in certain areas, such as renewable generation, energy efficiency, electric vehicle infrastructure and energy storage, which would limit our relationship with customers and narrow our future growth prospects.

We face significant competition in the wholesale energy and capacity 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 business objectives. Increased competition could contribute to a reduction in prices offered for power and could result in lower earnings and cash flows. Decreased competition could negatively impact results through a decline in market liquidity. Regulatory, environmental, industry and other operational developments will have a significant impact on our ability to compete in energy and capacity markets, potentially resulting in erosion of our market share and impairment in the value of our power plants. Recently, certain states have taken, or are considering taking, actions to subsidize or otherwise provide economic support to renewables, energy efficiency initiatives and existing, uneconomic generation facilities that could adversely affect capacity and energy prices. Increased generation supply and lower energy prices due to these subsidies could have an adverse impact on our results of operations.

The introduction or expansion of technologies related to energy generation, distribution and consumption and changes in customer usage patterns could adversely impact us.

The power generation business has seen a substantial change in the technologies used to produce power. Newer generation facilities are often more efficient than aging facilities, which may put some of these older facilities at a competitive disadvantage to the extent newer facilities are able to consume the same or less fuel to achieve a higher level of generation output. Federal and state incentives for the development and production of renewable sources of power have allowed for the penetration of competing technologies, such as wind, solar, and commercial-sized power storage. Additionally, the development of DSM tools and practices can impact peak demand requirements for some of our markets at certain times during the year. The continued development of subsidized, competing power generation technologies and significant development of DSM tools and practices could alter the market and price structure for power generation and could result in a reduction in load requirements, negatively impacting our financial condition, results of operations and cash flows. Technological advances driven by federal laws mandating new levels of energy efficiency in end-use electric devices or other improvements in, or applications of, technology could also lead to declines in per capita energy consumption.

Advances in distributed generation technologies, such as fuel cells, micro turbines, micro grids, windmills and net-metered solar installations, may reduce the cost of alternative methods of producing electricity 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. Certain states, such as Massachusetts and California, are also considering mandating the use of power storage resources to replace uneconomic or retiring generation facilities. Such developments could (i) affect the price of energy, (ii) reduce energy deliveries as customer-owned generation becomes more cost-effective, (iii) require further improvements to our distribution systems to address changing load demands, and (iv) make portions of our transmission and/or distribution facilities obsolete prior to the end of their useful lives. These technologies could also result in further declines in commodity prices or demand for delivered energy.

Some or all of these factors could result in a lack of growth or decline in customer demand for electricity or number of customers, and may cause us to fail to fully realize anticipated benefits from significant capital investments and expenditures, which could have a material adverse effect on our financial position, results of operations and cash flows. These factors could also materially affect our results of operations, cash flows or financial positions through, among other things, reduced operating revenues, increased operating and maintenance expenses, and increased capital expenditures, as well as potential asset impairment charges or accelerated depreciation and decommissioning expenses over shortened remaining asset useful lives.

Economic downturns 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 for power, generation capacity and natural gas, which can fluctuate substantially. Increased unemployment of residential customers and decreased demand for products and services provided by C&I customers resulting from an economic downturn could lead to declines in the demand for energy and an increase in the number of uncollectible

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customer balances, which would negatively impact our overall sales and cash flows. Although our utility business is subject to regulated allowable rates of return, overall declines in electricity and gas sold could materially adversely affect our financial condition, results of operations and cash flows. Additionally, prolonged economic downturns that negatively impact our financial condition, results of operations and cash flows could result in future material impairment charges to write down the carrying value of certain assets to their respective fair values.

We are subject to third-party credit risk relating to our sale of generation output and purchase of fuel.

We sell generation output and buy fuel through the execution of bilateral contracts. We also seek to contract in advance for a significant proportion of our anticipated output capacity and fuel needs. These contracts are subject to credit risk, which relates to the ability of our counterparties to meet their contractual obligations to us. Any failure of these counterparties to perform could require Power to purchase or sell energy or fuel in the wholesale markets at less favorable prices and incur additional losses, which 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 sharing mechanisms that exist in those markets, some of which attempt to spread the risk across all participants. Therefore, a default by a third party could increase our costs, which could negatively impact our results of operations and cash flows.

Financial market performance directly affects the asset values of our nuclear decommissioning trust (NDT) Fund and defined benefit plan trust funds. Market performance and other factors could decrease the value of trust assets and 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 defined benefit plans and to decommission our nuclear generating plants. A decline in the market value of our NDT Fund could increase Power's funding requirements to decommission its nuclear plants. A decline in the market value of the defined benefit plan trust funds could increase our pension plan funding requirements. The market value of our trusts could be negatively impacted by decreases in the rate of return on trust assets, decreased interest rates used to measure the required minimum funding levels and future government regulation. Additional funding requirements for our defined benefit plans could be caused by changes in required or voluntary contributions, an increase in the number of employees becoming eligible to retire and changes in life expectancy assumptions. Increased costs could also lead to additional funding requirements for our decommissioning trust. Failure to adequately manage our investments in our NDT Fund and defined benefit plan trusts could result in the need for us to make significant cash contributions in the future to maintain our funding at sufficient levels, which would negatively impact our results of operations, cash flows and financial position.

REGULATORY, LEGISLATIVE AND LEGAL RISKS

PSE&G's revenues, earnings and results of operations are dependent upon state laws and regulations that affect distribution and related activities.

PSE&G is subject to regulation by the BPU. Such regulation affects almost every aspect of its businesses, including its retail rates, and failure to comply with these regulations could have a material adverse impact on PSE&G's ability to operate its business and could result in fines, penalties or sanctions. The retail rates for electric and gas distribution services are established in a base rate proceeding and remain in effect until a new base rate proceeding is filed and concluded. 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. 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 results of operations and cash flows. In addition, if legislative and regulatory structures were to evolve in such a way that PSE&G's exclusive rights to serve its regulated customers were eroded, its future earnings could be negatively impacted.

Efforts designed to promote and expand the use of energy efficiency measures and distributed generation technologies, such as rooftop solar and battery storage, in PSE&G's service territories could result in customers leaving the electric distribution system and an increase in customer net energy metering. Over time, customer adoption of these and other technologies and increased energy efficiency could adversely impact PSE&G's revenue and ability to fully recover its costs, which could require PSE&G to pursue a rate proceeding to adjust revenue requirements or seek recovery though other mechanisms.

The BPU also 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. A finding by the BPU of non-compliance with these requirements could result in fines, a reduction in PSE&G's authorized base rate or the disallowance of the recovery of certain costs, which could have a material adverse impact on our business, results of operations and cash flows.

In addition, PSE&G procures the supply requirements of its default service BGSS gas customers through a full-requirements contract with Power. Government officials, legislators and advocacy groups are aware of the affiliation between PSE&G and Power. In periods of rising utility rates, those officials and advocacy groups may question or challenge costs and transactions

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incurred by PSE&G with Power, irrespective of any previous regulatory processes or approvals underlying those transactions. The occurrence of such challenges may subject Power to a level of scrutiny not faced by other unaffiliated competitors in those markets and could adversely affect retail rates received by PSE&G in an effort to offset any perceived benefit to Power from the affiliation.

PSE&G periodically files base rate proceedings. Such proceedings are at times contentious, lengthy and subject to appeal, which could lead to uncertainty as to the ultimate results and which could introduce time delays in effectuating rate changes.

PSE&G periodically files base rate proceedings with the BPU. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups and various consumers of energy, who have differing concerns but who have the common objective of limiting rate increases or even reducing rates. The proceedings generally have timelines that may not be limited by statute. Decisions are subject to appeal, potentially leading to additional uncertainty associated with the approval proceedings. The potential duration of such proceedings creates a risk that rates ultimately approved by the applicable regulatory body may not be sufficient for PSE&G to recover its costs by the time the rates become effective. Established rates are also subject to subsequent reviews by state regulators, whereby various portions of rates could be adjusted, including recovery mechanisms for costs associated with the procurement of electricity or gas, bad debt, manufactured gas plant (MGP) remediation, smart grid infrastructure and energy efficiency, demand response and renewable energy programs. If future base rate proceedings are protracted or result in approved rates that do not allow PSE&G to fully recover its costs or result in ROEs that are below historical levels, our financial condition, results of operations and cash flows would be materially adversely impacted.

We are subject to comprehensive federal regulation that affects, or may affect, our businesses.

We are subject to regulation by federal authorities. Such regulation affects almost every aspect of our businesses, including management and operations; the terms and rates of transmission services; investment strategies; the financing of our operations and the payment of dividends. Failure to comply with these regulations could have a material adverse impact on our ability to operate our business and could result in fines, penalties or sanctions.

Recovery of wholesale transmission rates—PSE&G's wholesale transmission rates are regulated by FERC and are recovered through a FERC-approved formula rate. The revenue requirements are reset each year through this formula. 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 with FERC asking 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.

NERC Compliance—NERC, at the direction of FERC, has implemented mandatory NERC Operations and CIP standards to ensure the reliability of the U.S. Bulk Electric System, which includes electric transmission and generation systems, and to prevent major system black-outs. NERC CIP standards establish cybersecurity and physical security protections for critical systems and facilities. We have been, and will continue to be, periodically audited by NERC for compliance and are subject to penalties for non-compliance with applicable NERC standards. An audit of PSE&G's compliance with CIP physical and cybersecurity standards was performed in the fourth quarter of 2018, the results of which are under review. We cannot determine what actions, if any, NERC or FERC may take. Failure to comply with such standards could result in penalties or increased costs to bring such facilities into compliance. Such penalties and costs, as well as lost revenue from prolonged outages required to bring facilities into compliance with these standards, could materially adversely impact our business, results of operations and cash flows.

MBR Authority and Other Regulatory Approvals—Under FERC regulations, public utilities that wish to sell power at market rates must receive MBR Authority before making power sales, and the majority of our businesses operate with such authority. Failure to maintain MBR authorization, 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 our business,

financial condition and results of operations.
Oversight by the CFTC relating to derivative transactions—The CFTC has regulatory oversight of the swap and futures markets and options, including energy trading, and licensed futures professionals such as brokers, clearing members and large traders. Changes to regulations or adoption of additional regulations by the CFTC, including any regulations relating to position limits on futures and other derivatives or margin for derivatives and increased investigations by the CFTC, could negatively impact Power's ability to hedge its portfolio in an efficient, cost-effective manner by, among other things, potentially decreasing liquidity in the forward commodity and derivatives markets or limiting Power's ability to utilize non-cash collateral for derivatives transactions.
We may also be required to obtain various other regulatory approvals to, among other things, buy or sell assets, engage in

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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.

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

Approximately half of our total generation output each year is provided by our nuclear fleet. 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. In addition to the risk of retirement discussed below, risks associated with the operation of nuclear facilities include:

Storage and Disposal of Spent Nuclear Fuel—Federal law requires the DOE to provide for the permanent storage of spent nuclear fuel but the DOE has not yet begun accepting spent nuclear fuel. Until a federal site is available, we use on-site storage for spent nuclear fuel, which is reimbursed by the DOE. However, future capital expenditures may be required to increase spent fuel storage capacity at our nuclear facilities. Once a federal site is available, the DOE may impose fees to support a permanent repository. In addition, the on-site storage for spent nuclear fuel may significantly increase the decommissioning costs of our nuclear units.

Regulatory and Legal Risk—We may be required to substantially increase capital expenditures or operating or decommissioning costs at our nuclear facilities to the extent there is a change in the Atomic Energy Act or the applicable regulations, trade controls or the environmental rules and regulations applicable to nuclear facilities; a modification, suspension or revocation of licenses issued by the NRC; the imposition of civil penalties for failure to comply with the Atomic Energy Act, related regulations, trade controls or the terms and conditions of the licenses for nuclear generating facilities; or the shutdown of one of our nuclear facilities. Any such event could have a material adverse effect on our financial position or results of operations.

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. Any significant outages could result in reduced earnings as we would need to purchase or generate higher-priced energy to meet our contractual obligations.

In addition, if a unit cannot be operated through the end of its current estimated useful life, our results of operations could be adversely affected by increased depreciation rates, impairment charges and accelerated future decommissioning costs.

Nuclear Incident or Accident Risk—Accidents and other unforeseen problems have occurred at nuclear stations, both in the U.S. 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, results of operations 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 an industry nuclear incident or retrospective premiums due to adverse industry loss experience and such assessments may be material.

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.

Decommissioning—NRC regulations require that licensees of nuclear generating facilities demonstrate reasonable assurance that funds will be available to decommission the facility at the end of its useful life. PSEG Nuclear has established an NDT Fund to satisfy these obligations. However, forecasting trust fund investment earnings and costs to decommission nuclear generating stations requires significant judgment, and actual results could differ significantly from current estimates. If we determine that it is necessary to retire one of our nuclear generating stations before the end of its useful life, there is a risk that it will no longer meet the NRC minimum funding requirements due to the earlier commencement of decommissioning activities and a shorter time period over which the NDT investments could appreciate in value. A shortfall could require PSEG to post parental guarantees or make additional cash contributions to ensure that the NDT Fund continues to satisfy the NRC minimum funding requirements. As a result, our financial position or cash flows could be significantly adversely affected.

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There is no assurance that our New Jersey nuclear plants will be selected to participate in the Zero Emission Certificate (ZEC) program. Absent a material financial change, failure of any of these plants to be selected would result in the retirement of all of these nuclear plants.

In May 2018, the governor of New Jersey signed legislation, referred to as the ZEC legislation, that recognizes that nuclear power is a critical component of New Jersey's clean energy portfolio and an important element of a diverse energy generation portfolio that currently meets approximately 40 percent of New Jersey's electric power needs. The ZEC legislation creates a ZEC program to be administered by the BPU.

In December 2018, Power submitted applications to the BPU for the Salem 1 and 2 and Hope Creek nuclear plants. As required, Power's three applications each included a certification pursuant to which Power confirmed that each of the Salem 1, Salem 2 and Hope Creek plants will cease operations within three years absent a material financial change. Power's submittal further attested that the nuclear plants are not expected to cover their costs and operating and market risks as defined in the ZEC legislation, absent a material financial change.

In the event that any of the Salem 1, Salem 2 and Hope Creek plants is not selected to receive ZEC payments in April 2019 by the BPU and do not otherwise experience a material financial change, Power will take all necessary steps to retire all of these plants at or prior to their refueling outages scheduled for the Fall 2019 in the case of Hope Creek, Spring 2020 in the case of Salem 2 and Fall 2020 in the case of Salem 1. Alternatively, if all of the Salem 1, Salem 2 and Hope Creek plants are selected to receive ZEC payments in April 2019 but the financial condition of the plants is materially adversely impacted by potential changes to the capacity market construct being considered by FERC (absent sufficient capacity revenues provided under a program approved by the BPU in accordance with a FERC authorized capacity mechanism), Power would still take all necessary steps to retire all of these plants. The costs and accounting charges associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, potential penalties associated with the early termination of capacity obligations and fuel contracts, accelerated asset retirement costs, severance costs, environmental remediation costs and, in certain circumstances, potential additional funding of the NDT Fund, would be material to both PSEG and Power.

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 has historically been located in constrained areas in PJM and ISO-NE, the existence of these rules has had a positive impact on our revenues. PJM's capacity market design rules and ISO-NE's FCM rules continue to evolve, most recently in response to efforts to integrate public policy initiatives into the wholesale markets. Any changes to these rules may have an adverse impact on our financial condition, results of operations and cash flows.

We could also be impacted by a number of other events, including regulatory or legislative actions such as direct and indirect subsidies, favoring certain types of resources and/or technologies. 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 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, 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.

We are subject to numerous federal, state and local 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 federal, state and local environmental laws and regulations 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 how we conduct our operations and make capital expenditures. There have been a number of recent changes to existing environmental laws and regulations and this trend may continue. Changes in these laws, or violations of laws, could result in significant increases in our compliance costs, capital expenditures to bring our 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 and could require further economic review to determine whether to continue operations or decommission an affected facility. We may also be unable to successfully recover certain of these cost increases through our existing regulatory rate structures, in the case of PSE&G, or our contracts with our customers, in the case of Power.

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Environmental laws and regulations have generally become more stringent over time, and this trend is likely to continue. In particular:

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 2018 the NJDEP published new rules that establish a mechanism for New Jersey to re-enter the RGGI. This will have cost implications for our fossil generation facilities. Such expenditures could materially affect the continued economic viability of one or more such facilities. 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—In 2014, the EPA finalized rules regarding the regulation of cooling water intake structures. 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. The rule requires that facilities seeking permit renewals conduct a wide range of studies related to impingement mortality and entrainment and submit the results with their permit applications. State actions to renew permits under the provisions of this rule are ongoing at this time.

If the NJDEP or the Connecticut Department of Energy and Environmental Protection were to require installation of closed-cycle cooling or its equivalent at any of our Salem, Bridgeport 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 associated with our former MGP operations are one source of such costs. In addition, the historic operations of our 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 flows. 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 14. Commitments and Contingent Liabilities.

We may not receive necessary licenses and permits in a timely manner or at all, which could adversely impact our business and results of operations.

We must periodically apply for licenses and permits from various regulatory authorities, including environmental regulatory authorities, and abide by their respective orders. Delay in obtaining, or failure to obtain and maintain, any permits or approvals, including environmental permits or approvals, or delay in or failure to satisfy any applicable 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 addition, the process of obtaining licenses and permits from regulatory authorities may be delayed or defeated by concerted community opposition and such delay or defeat could have a material effect on our business.

We cannot predict the outcome of any legal, regulatory or other proceeding, settlement, investigation or claim relating to our business activities. An adverse determination could negatively impact our financial condition, results of operations and cash flows.

From time to time we are involved in legal, regulatory and other proceedings or claims arising out of our business operations, the most significant of which are summarized in Item 8. Note 13. Commitments and Contingent Liabilities. Adverse outcomes

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in any of these proceedings could require significant expenditures that could have a material adverse effect on our financial condition, results of operations and cash flows.

Changes in tax law and regulation and the inherent difficulty in quantifying potential tax effects of business decisions could negatively impact our results of operations and cash flows.

The Tax Act made significant changes to U.S. tax law. Among other things, the statutory U.S. corporate income tax rate decreased from a maximum of 35% to 21%, effective January 1, 2018, and certain changes were made to bonus depreciation and interest disallowance rules. However, the Tax Act is unclear in certain respects and will require interpretations and the implementation of regulations by the Internal Revenue Service (IRS), as well as state taxing authorities. Further, the Tax Act could be subject to potential amendments and technical corrections. We cannot assess the impact that any such interpretations, regulations, amendments or corrections could have on our results of operations or financial condition.

In 2018 the IRS issued a Notice of Proposed Rulemaking (Notice) regarding the application of tax depreciation rules and issued proposed regulations addressing the interest disallowance rules. However, certain aspects of the Notice and proposed regulations are unclear; therefore, we recorded taxes based on our interpretation of the relevant statutes. These interpretations are subject to change based on several factors including, but not limited to, the IRS issuing final guidance and/or further clarification. We are subject to the provisions of the Financial Accounting Standards Board Accounting Standards Codification 740, Income Taxes, which require that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate change was enacted. The impact of the rate change in 2017’s financial statements is discussed in Item 8. Note 21. Income Taxes.

In addition, we are required to make judgments in order to estimate our obligations to taxing authorities. These tax obligations include income, real estate, sales and use and employment-related taxes. These judgments can include reserves for potential adverse outcomes regarding tax positions that have been taken that could be subject to challenge by the tax authorities. If our actual tax obligations materially differ from our estimated obligations, our results of operations and cash flows could be materially adversely affected.

OPERATIONAL RISKS

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 interests of its subsidiaries. Accordingly, all of the operations of PSEG are conducted by its subsidiaries, which are separate and distinct legal entities that have no obligation, contingent or otherwise, to pay the debt of PSEG or to make any funds available to PSEG to pay such debt or 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 will be able to transfer funds to PSEG to meet all of these obligations.

Lack of growth or slower growth in the number of customers, or a decline in customer demand, could adversely impact our financial condition, results of operations and cash flows.

Growth in customer accounts and growth of customer usage each directly influence the demand for electricity and the need for additional generation, transmission and distribution facilities. Customer growth and customer usage may be affected by a number of factors, including:

- the impacts of economic downturns, including increased unemployment and less demand from C&I customers;
- regulatory incentives to reduce energy consumption;
- mandated energy efficiency measures;
- DSM tools;
- technological advances; and
- a shift in the composition of our customer base from C&I customers to residential customers.

Some or all of these factors could result in a lack of growth or decline in customer demand for electricity and may prevent us from fully realizing the benefits from significant capital investments and expenditures, which could have a material adverse effect on our financial position, results of operations and cash flows.

There may be periods when Power may not be able to meet its commitments under forward sale obligations at a reasonable cost or at all.

A substantial portion of Power's generation output has been sold forward under fixed price power sales contracts and Power also sells forward the output from its intermediate and peaking facilities when it deems it commercially advantageous to do so.

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Our forward sales of energy and capacity assume sustained, 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 or work stoppages;
- fuel supply interruptions;
- transportation constraints;
- limitations which may be imposed by environmental or other regulatory requirements; and
- operator error, terrorist attacks (including cybersecurity breaches) or catastrophic events such as fires, earthquakes, explosions, floods, severe storms 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.

Because the obligations under most of these agreements are not contingent on a unit being available to generate power, Power is generally required to deliver power to the buyer, even in the event of a plant outage, fuel supply disruption or a reduction in the available capacity of the unit. To the extent that Power does not have sufficient lower cost capacity to meet its commitments under its forward sale obligations, Power would be required to supply replacement power either by running its other higher cost power plants or by obtaining power from third-party sources at market prices that could substantially exceed the contract price. This could have a material adverse effect on our financial condition, results of operations and cash flows. If Power fails to deliver the contracted power, it would be required to pay the difference between the market price at the delivery point and the contract price, and the amount of such payments could be substantial.

In addition, 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.

Certain of our generation facilities rely on transmission facilities that we do not own or control and that may be subject to transmission constraints. Our inability to maintain adequate transmission capacity could restrict our ability to deliver wholesale electric power to our customers and we may either incur additional costs or forgo revenues. Conversely, improvements to certain transmission systems could also reduce revenues.

We depend on transmission facilities owned and operated by others to deliver the wholesale power we sell from our generation facilities. If transmission is disrupted or if the transmission capacity infrastructure is inadequate, our ability to sell and deliver wholesale power may be adversely impacted. If a region’s power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in transmission infrastructure. We also cannot predict whether transmission facilities will invest in specific markets to accommodate competitive access to those markets.

In addition, in certain of the markets in which we operate, energy transmission congestion may occur and we may be deemed responsible for congestion costs if we schedule delivery of power between congestion zones during times when congestion occurs between the zones. If we were liable for such congestion costs, our financial results could be adversely affected.

A portion of our generation is located in load pockets. Investment in transmission systems to reduce or eliminate these load pockets could negatively impact the value or profitability of our existing generation facilities in these areas.

Inability to successfully develop, obtain regulatory approval for, or construct generation, transmission and distribution projects 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 T&D facilities; and modernizing existing infrastructure pursuant to investment programs entitled to current recovery.

Currently, we have several significant projects underway or being contemplated.

The successful construction and development of these projects will depend, in part, on our ability to:

- obtain necessary governmental and regulatory approvals;
- obtain environmental permits and approvals;
- obtain community support for such projects to avoid delays in the receipt of permits and approvals from regulatory authorities;

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- complete such projects within budgets and on commercially reasonable terms and conditions;
- obtain any necessary debt financing on acceptable terms and/or necessary governmental financial incentives;
- ensure that contracting parties, including suppliers, perform under their contracts in a timely and cost effective manner; and
- at PSE&G, 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. Further, any unexpected failure of our existing facilities, including failure associated with breakdowns, forced outages or any unanticipated capital expenditures could result in reduced profitability. Modifications to existing facilities may require us to install the best available control technology or to achieve the lowest achievable emission rates required by then-current regulations, which would likely result in substantial additional capital expenditures.

In addition, the successful operation of new or upgraded generation facilities or transmission or distribution projects is subject to risks relating to supply interruptions; work stoppages and labor disputes; weather interferences; unforeseen engineering and environmental problems, including those related to climate change; and the other risks described herein. Any of these risks could cause our return on these investments to be lower than expected or they could cause these facilities to operate below expected capacity or availability levels, which would adversely impact our financial condition and results of operations through lost revenue, increased expenses, higher maintenance costs and penalties.

FERC Order 1000 has generally opened transmission development to competition from independent developers, allowing such developers to compete with incumbent utilities for the construction and operation of transmission facilities in its service territory. While Order 1000 retains limited carve-outs for certain 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, increased competition for transmission projects could decrease the value of new investments that would be subject to recovery by PSE&G under its rate base, which could have a material adverse impact on our financial condition and results of operations. In addition, certain 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.

In January 2018, the governor of New Jersey signed Executive Order No. 8 directing the BPU to begin the process of moving the state toward its 2030 goal of 3,500 MW of offshore wind energy generation. An initial solicitation was established for 1,100 MW of offshore wind, with bids due in December. In connection with the bid submitted by Ocean Wind, LLC, a wholly owned subsidiary of Ørsted US Offshore Wind, referred to as the Ocean Wind project, PSEG agreed to provide energy management services and the potential lease of land for use in project development. We also retained an option to acquire an equity interest in the project. If the Ocean Wind bid is successful and PSEG elects to acquire an equity interest, PSEG would be required to incur additional capital expenditures. The amount of such capital expenditures, if any, cannot be determined at this time.

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 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.

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. For our T&D business, the cost of storm restoration efforts may not be fully recoverable through the regulatory process. In addition, the inability to restore power to our customers on a timely basis could also materially damage our reputation.

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We own less than a controlling interest in some of our generating facilities.
We have limited control over the operation of some of our generating facilities, including the Keystone, Conemaugh and Peach Bottom facilities, because our investments represent less than a controlling interest. We seek to exert a degree of influence with respect to the management and operation of projects in which we own less than a controlling interest by negotiating to obtain positions on management committees or to receive certain limited governance rights. However, we may not always succeed in such negotiations. As a result, we may be dependent on our partners to operate such facilities. The approval of our partners also may be required for us to transfer our interest in such projects. Reliance on our partners for the management and operation of these facilities could result in a lower return on these facilities than what we believe we could have otherwise achieved.
Any inability to recover the carrying amount of our long-lived assets and leveraged leases could result in future impairment charges which could have a material adverse impact on our financial condition and results of operations.
Long-lived assets represent approximately 76%, 82% and 70% of the total assets of PSEG, PSE&G and Power, respectively, as of December 31, 2018. 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.
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. 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. Our receipt of payments related to our leveraged lease portfolio in accordance with the lease contracts can be impacted by various factors, including 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 Powerton coal generation investment; overall financial condition of lease counterparties; and the quality and condition of assets under lease.
There can be no assurance that a continuation or worsening of the adverse economic conditions would not lead to additional write-downs at any of our other generation units in our leveraged lease portfolio, and such write-downs could be material.
Inability to maintain sufficient liquidity in the amounts and at the times needed or access sufficient capital at reasonable rates or on commercially reasonable terms could adversely impact our business.
Funding for our investments in capital improvement and additions, scheduled payments of principal and interest on our existing indebtedness and the extension and refinancing of such indebtedness has been provided primarily by internally-generated cash flow and external financings. We have significant capital requirements and depend on our ability to generate cash in the future from our operations and continued access to capital and credit markets to efficiently fund our cash flow needs. Our ability to generate cash flow is dependent upon, among other things, industry conditions and general economic, financial, competitive, legislative, regulatory and other factors. The ability to arrange financing and the costs of such financing depend on numerous factors including, among other things.

- general economic and capital market conditions;
- the availability of credit from banks and other financial institutions;
- tax, regulatory and securities law developments;
- for PSE&G, our ability to obtain necessary regulatory approvals for the incurrence of additional indebtedness;
- investor confidence in us and our industry;
- our current level of indebtedness and compliance with covenants in our debt agreements;
- the success of current projects and the quality of new projects;
- our current and future capital structure;
- our financial performance and the continued reliable operation of our business; and

- maintenance of our investment grade credit ratings.

Market disruptions, such as economic downturns experienced in the U.S. and abroad in recent years, the bankruptcy of an unrelated energy company, changes in market prices for electricity and gas, and actual or threatened terrorist attacks, may increase our cost of borrowing or adversely affect our ability to access capital. As a result, no assurance can be given that we will be successful in obtaining financing for projects and investments, to extend or refinance maturing debt or for our other cash

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flow needs on acceptable terms or at all, which could materially adversely impact our financial position, results of operations and future growth.

In addition, if Power were to lose its investment grade credit rating from S&P or Moody's, 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.

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 ability to realize these assets. 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 based on available evidence including cumulative and forecasted pre-tax book earnings at the time the estimate is made. 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.

Challenges associated with recruitment and/or retention of key executives and a skilled workforce could adversely impact our businesses.

Our operations depend on the recruitment and retention of key executives and a skilled workforce. The loss or retirement of key executives or other employees, including those with the specialized knowledge required to support our generation and T&D operations, could result in various operational challenges. Certain events, such as the potential for early retirement of our nuclear facilities, can make it more difficult to retain these employees. We may incur increased costs for contractors to replace employees, and the loss of institutional and industry knowledge and the increased costs to hire and lengthy time to train new personnel could result in lower productivity, resulting in increased costs, which would negatively impact our results of operations. This has the potential to become more critical as a growing number of employees become eligible to retire.

As of December 31, 2018, approximately 73% of our employees were covered by collective bargaining agreements. As a result, 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, all of which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Covenants in our debt instruments may adversely affect our operations.

PSEG's, PSE&G's and Power's debt instruments contain events of default customary for financings of their type, including cross accelerations to other debt of that entity and, in the case of PSEG's and Power's bank credit agreements, certain change of control events. Power's bank credit agreements and outstanding notes also contain limitations on the incurrence of subsidiary debt and liens and certain of Power's outstanding notes require Power to repurchase such notes upon certain change of control events. Our ability to comply with these covenants may be affected by events beyond our control. If we fail to comply with the covenants and are unable to obtain a waiver or amendment, or a default exists and is continuing under such debt, the lenders or the holders or trustee of such debt, as applicable, could give notice and declare outstanding borrowings and other obligations under such debt immediately due and payable. We may not be able to obtain waivers, amendments or alternative financing, or if obtainable, it could be on terms that are not acceptable to us. Any of these events could adversely impact our financial condition, results of operations and cash flows.

Cybersecurity attacks or intrusions could adversely impact our businesses.

Cybersecurity threats to the U.S. energy market infrastructure are increasing in sophistication, magnitude and frequency. We rely on information technology systems that utilize sophisticated digital systems and network infrastructure to operate our generation and T&D systems. We also store sensitive data, intellectual property and proprietary or personally identifiable information regarding our business, employees, shareholders, customers and vendors on our systems and conduct power marketing and hedging activities. In addition, the operation of our business is dependent upon the information technology systems of third parties, including our vendors, regulators, RTOs and ISOs, among others. Our and third-party information technology systems may be vulnerable to cybersecurity attacks involving domestic or foreign sources. A cybersecurity attack may also leverage such information technology to cause disruptions at a third party. Cybersecurity impacts to our operations include:

- disruption of the operation of our assets, the fuel supply chain and the power grid,
- theft of confidential company, employee, shareholder, vendor or customer information, which may cause us to be in breach of certain covenants and contractual obligations,
- 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

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- breaches of vendors' infrastructures where our confidential information is stored.

We and our third-party vendors have been and likely will continue to be subject to attempted cybersecurity attacks. While there has been no material impact on our business or operations from these attempted attacks, if a significant cybersecurity event or breach should occur within our company or with one of our material vendors, we could be exposed to significant loss of revenue, material repair costs to intellectual and physical property, significant fines and penalties for non-compliance with existing laws and regulations, significant litigation costs, increased costs to finance our businesses, damage to our reputation and loss of confidence from our customers, regulators, investors, vendors and employees. Similarly, a significant cybersecurity event or breach experienced by a competitor, regulatory authority, RTO, ISO, or vendor could also materially impact our business and results of operations via enhanced legal and regulatory requirements. For a discussion of state and federal cybersecurity regulatory requirements and information regarding our cybersecurity program, see Item 1. Business—Regulatory Issues.

The market for cybersecurity insurance is relatively new and coverage available for cybersecurity events may evolve as the industry matures. While we maintain insurance relating to cybersecurity events, such insurance is subject to a number of exclusions and may be insufficient to offset any losses, costs or damage we experience.

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 and insurance market instability and volatility in power and fuel markets, which could materially adversely affect our business and results of operations, including our ability to access capital on terms and conditions acceptable to us. In addition, our infrastructure facilities, such as our generating stations, T&D facilities and information technology systems, 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. New or updated security regulations may require us to make changes to our current measures which could also result in additional expenses.

ITEM 1B. UNRESOLVED STAFF COMMENTS

PSEG, PSE&G and Power

None.

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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. Note 14. Commitments and Contingent Liabilities.

Generation Facilities

Power

As of December 31, 2018, 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
Steam:					
Keystone (A)	PA	1,711	23%	391	Coal
Conemaugh (A)	PA	1,711	23%	385	Coal
Bridgeport Harbor	CT	383	100%	383	Coal
New Haven Harbor	CT	448	100%	448	Oil/Gas
Total Steam		4,253		1,607	
Nuclear:					
Hope Creek	NJ	1,173	100%	1,173	Nuclear
Salem 1 & 2	NJ	2,278	57%	1,308	Nuclear
Peach Bottom 2 & 3 (B)	PA	2,450	50%	1,225	Nuclear
Total Nuclear		5,901		3,706	
Combined Cycle:					
Keys (C)	MD	761	100%	761	Gas
Bergen	NJ	1,229	100%	1,229	Gas/Oil
Linden	NJ	1,300	100%	1,300	Gas/Oil
Sewaren 7 (D)	NJ	538	100%	538	Gas/Oil
Bethlehem	NY	815	100%	815	Gas
Kalaeloa	HI	208	50%	104	Oil
Total Combined Cycle		4,851		4,747	
Combustion Turbine:					
Essex	NJ	81	100%	81	Gas/Oil
Kearny	NJ	456	100%	456	Gas/Oil
Burlington	NJ	168	100%	168	Gas/Oil
Linden	NJ	336	100%	336	Gas/Oil
New Haven Harbor	CT	130	100%	130	Gas/Oil
Bridgeport Harbor	CT	17	100%	17	Oil
Total Combustion Turbine		1,188		1,188	
Pumped Storage:					
Yards Creek (E)	NJ	420	50%	210	
Total Power Plants		16,613		11,458	

(A) Operated by GenOn Northeast Management Company.
(B) Operated by Exelon Generation.
(C) Commenced commercial operation in mid-2018.

(D) Commenced commercial operation in mid-2018, replacing our 100%-owned steam generation Sewaren Units 1 through 4 that had a 445 MW capacity.

(E) Operated by Jersey Central Power & Light Company.

As of December 31, 2018, Power also owned and operated 414 MW dc of PV solar generation facilities in various states.

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PSE&G

Primarily all of PSE&G’s property is located in New Jersey and PSE&G’s First and Refunding Mortgage, which secures 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.

Electric Property and Facilities

As of December 31, 2018, PSE&G’s electric T&D system included approximately 24,000 circuit miles, and 855,000 poles, of which 64% are jointly-owned. In addition, PSE&G owns and operates 52 switching stations with an aggregate installed capacity of 37,378 megavolt-amperes (MVA) and 244 substations with an aggregate installed capacity of 8,228 MVA. Four of those substations, having an aggregate installed capacity of 109 MVA are operated on leased property. In addition, PSE&G owns four electric distribution headquarters and five electric sub-headquarters.

Gas Property and Facilities

As of December 31, 2018, PSE&G’s gas system included approximately 18,000 miles of gas mains, 12 gas distribution headquarters, two sub-headquarters, and one meter shop serving all of its gas territory in New Jersey. In addition, PSE&G operates 58 natural gas metering and regulating stations, of which 22 are located on land owned by customers or natural gas pipeline suppliers and are operated under lease, easement or other similar arrangement. In some instances, the pipeline companies own portions of the metering and regulating facilities. PSE&G also owns one liquefied natural gas and three liquid petroleum air gas peaking facilities. The daily gas capacity of these peaking facilities (the maximum daily gas delivery available during the three peak winter months) is approximately 2.8 million therms in the aggregate.

Solar

As of December 31, 2018, PSE&G had 122 MW dc of installed PV solar capacity throughout New Jersey.

ITEM 3. LEGAL PROCEEDINGS

We are party to various lawsuits and environmental and regulatory matters, including in the ordinary course of business. For information regarding material legal proceedings, see Item 1. Business—Regulatory Issues and Environmental Matters and Item 8. Note 14. Commitments and Contingent Liabilities.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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. under the trading symbol “PEG.” As of February 15, 2019, there were 58,399 registered holders.

The following graph shows a comparison of the five-year cumulative return assuming $100 invested on December 31, 2013 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.

	2013	2014	2015	2016	2017	2018
PSEG	$100.00	$134.36	$130.62	$153.85	$187.34	$196.09
S&P 500	$100.00	$113.68	$115.24	$129.02	$157.17	$150.27
DJ Utilities	$100.00	$130.65	$126.65	$149.67	$169.65	$173.01
S&P Electrics	$100.00	$128.98	$122.73	$142.72	$160.00	$166.57

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On February 19, 2019, our Board of Directors approved a $0.47 per share common stock dividend for the first quarter of 2019. This reflects an indicative annual dividend rate of $1.88 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.

In December 2018, we entered into a share repurchase plan that complies with Rule 10b5-1 of the Securities Exchange Act of 1934, as amended, solely with respect to the repurchase of shares to satisfy obligations under equity compensation awards that are expected to vest or be exercised in 2019. There were no common share repurchases in the open market during the fourth quarter of 2018.

The following table indicates the securities authorized for issuance under equity compensation plans as of December 31, 2018:

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	231,933	$ 33.49	12,992,138
Employee Stock Purchase Plan	—	—	2,888,361
Total	231,933	$ 33.49	15,880,499

For additional discussion of specific plans concerning equity-based compensation, see Item 8. Note 19. 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—Liquidity and Capital Resources.

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—Liquidity and Capital Resources.

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

PSEG					
Years Ended December 31,	2018	2017	2016	2015	2014
	Millions, except Earnings per Share				
Operating Revenues (A)	$9,696	$9,094	$8,966	$10,415	$10,886
Income from Continuing Operations (B)(C)(D)	$1,438	$1,574	$887	$1,679	$1,518
Net Income (B)(C)(D)	$1,438	$1,574	$887	$1,679	$1,518
Earnings per Share:					
Income from Continuing Operations					
Basic	$2.85	$3.12	$1.76	$3.32	$3.00
Diluted	$2.83	$3.10	$1.75	$3.30	$2.99
Net Income					
Basic	$2.85	$3.12	$1.76	$3.32	$3.00
Diluted	$2.83	$3.10	$1.75	$3.30	$2.99
Dividends Declared per Share	$1.80	$1.72	$1.64	$1.56	$1.48
As of December 31,					
Total Assets	$45,326	$42,716	$40,070	$37,535	$35,287
Long-Term Obligations (E)	$13,168	$12,071	$10,897	$8,837	$8,218

(A) Amounts for 2017 and 2016 have been retrospectively adjusted to reflect new guidance for Revenue from Contracts with Customers adopted on January 1, 2018. Amounts for 2015 and 2014 were not required to be adjusted for this guidance and are therefore not comparative. For additional information, see Item 8. Note 2. Recent Accounting Standards.

(B) Income from Continuing Operations and Net Income for 2018 includes after-tax net unrealized losses on equity securities of approximately $125 million in accordance with new accounting guidance effective January 1, 2018.

(C) Income from Continuing Operations and Net Income include an after-tax gain for 2018 of $39 million from the sale of Power’s Hudson and Mercer coal/gas generation plants and after-tax expenses for 2017 and 2016 of $577 million and $396 million, respectively, related to the early retirement of these plants; after-tax charges for 2018, 2017 and 2016 totaling $5 million, $45 million and $92 million, respectively, related to investments in REMA’s leveraged leases; and an after-tax insurance recovery for 2015 of $102 million for Superstorm Sandy. See Item 8. Note 4. Early Plant Retirements, Note 8. Long-Term Investments and Note 9. Financing Receivables for additional information.

(D) Income from Continuing Operations and Net Income for 2017, include the non-cash net income benefit of $745 million, primarily resulting from the remeasurement of deferred tax liabilities required due to the enactment of the Tax Act in December 2017. See Item 8. Note 21. Income Taxes for additional information for 2017.

(E) Includes capital lease obligations.

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

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

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

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

- PSE&G—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 regulated solar generation projects and energy efficiency and related programs in New Jersey, which are regulated by the BPU, and
- Power—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. 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 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; PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; and PSEG Services Corporation (Services), which provides certain management, administrative and general services to PSEG and its subsidiaries 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 2018 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 the Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements and Notes.

EXECUTIVE OVERVIEW OF 2018 AND FUTURE OUTLOOK

Our business plan is designed to achieve growth while managing the risks associated with fluctuating commodity prices and changes in customer demand.

PSE&G

At PSE&G, our focus is on enhancing system reliability and resiliency, meeting customer expectations and supporting public policy objectives by investing capital in T&D infrastructure and clean energy projects. Over the past few years, our investments have altered our business mix to reflect a higher percentage of earnings contribution by PSE&G. Over the next five years, we expect to invest between $11 billion and $16 billion in our business which is expected to provide an annual rate base growth of 7%—9%. We completed our Energy Strong Program I (ES I) and essentially completed our Gas System Modernization Program I (GSMP I). See Item 1. Business—Business Operations and Strategy—PSE&G for a description of these programs.

In May 2018, we received approval for our Gas System Modernization Program II (GSMP II), an expanded, five-year program to invest $1.9 billion beginning in 2019 to replace approximately 875 miles of cast iron and unprotected steel mains in addition to other improvements to the gas system. Approximately $1.6 billion will be recovered through periodic rate roll-ins, with the remaining $300 million to be recovered through a future base rate proceeding. As part of the settlement, PSE&G agreed to file a base rate proceeding no later than five years from the commencement of the program, to maintain a base level of gas distribution capital expenditures of $155 million per year and to achieve certain leak reduction targets.

In June 2018, we filed for our Energy Strong Program II (ES II), a proposed five-year $2.5 billion program to harden, modernize and make our electric and gas distribution systems more resilient. The size and duration of ES II, as well as certain other elements of the program, are subject to BPU approval. The review process is expected to conclude in mid-2019.

In October 2018, we filed our proposed Clean Energy Future (CEF) program with the BPU, a six-year estimated $3.6 billion investment covering four programs; (i) an Energy Efficiency (EE) program totaling $2.5 billion of investment designed to achieve energy efficiency targets required under New Jersey's Clean Energy law; (ii) an Electric Vehicle (EV) infrastructure program; (iii) an Energy Storage (ES) program and (iv) an Energy Cloud (EC) program which will include installing approximately two million electric smart meters and associated infrastructure. The review process for the CEF-EE program is expected to conclude by the third quarter of 2019. The CEF-EV/ ES and CEF-EC programs will have separate procedural schedules.

In November 2018, the New Jersey Division of Rate Counsel (Rate Counsel) filed a motion to dismiss the CEF-EC filing on the basis that the BPU announced a moratorium on electric distribution companies' AMI program. In December 2018, Rate Counsel filed a motion to stay the CEF-EV/ES filing, arguing that the BPU should conclude other regulatory proceedings addressing EVs and ES, including the new Energy Master Plan and initiatives required by the Clean Energy Act, before it rules on PSE&G's program. We opposed Rate Counsel's motions, asking for the BPU to permit these filings to proceed. There is no timetable for the BPU to decide on Rate Counsel's motions.

Also, in October 2018, the BPU issued an Order approving the settlement of our distribution base rate proceeding with new rates effective November 1, 2018. The settlement resulted in a net reduction in overall annual revenues of approximately $13 million, comprised of a $212 million increase in base revenues, which includes the recovery of deferred storm costs, and the return of tax benefits largely due to tax reform of approximately $225 million. The Order provides for a distribution rate base of $9.5 billion, a 9.6% return on equity (ROE) for our distribution business and a 54% equity component of our capitalization structure.

Power

At Power, we strive to improve performance and reduce costs in order to optimize cash flow generation from our fleet in light of low wholesale power and gas prices, environmental considerations and competitive market forces that reward efficiency and reliability. Power continues to move its fleet toward improved efficiency and believes that its investment program enhances its competitive position with the addition of efficient, clean, reliable combined cycle gas turbine capacity. Our commitments for load, such as basic generation service (BGS) in New Jersey and other bilateral supply contracts, are backed by this generation or may be combined with the use of physical commodity purchases and financial instruments from the market to optimize the economic efficiency of serving our obligations. Power's hedging practices and ability to capitalize on market opportunities help it to balance some of the volatility of the merchant power business. More than half of Power's expected gross margin in 2018 relates to our hedging strategy, our expected revenues from the capacity market mechanisms and certain ancillary service payments such as reactive power.

Our investments in Keys Energy Center (Keys), Sewaren 7 and Bridgeport Harbor Station Unit 5 (BH5) reflect our recognition of the value of opportunistic growth in the Power business. These additions to our fleet both expand our geographic diversity and adjust our fuel mix and enhance the environmental profile and overall efficiency of Power's generation fleet.

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 opportunities in a rapidly evolving market as we remain diligent in managing costs. In 2018, our

- utility achieved continued strong reliability and customer satisfaction results, as well as comprehensive storm preparation and restoration efforts, and ongoing cost control,
- diverse fuel mix and dispatch flexibility allowed us to generate approximately 56 terawatt hours while addressing fuel availability and price volatility, and
- total nuclear fleet achieved a capacity factor of 91.4%.

Financial Strength

Our financial strength is predicated on a solid balance sheet, positive operating cash flow and reasonable risk-adjusted returns on increased investment. Our financial position remained strong during 2018 as we

- maintained sufficient liquidity,
- maintained solid investment grade credit ratings, and
- increased our indicative annual dividend for 2018 to $1.80 per share.

We expect to be able to fund our planned capital requirements, as described in Liquidity and Capital Resources, and the impacts of the Tax Cuts and Jobs Act of 2017 (Tax Act) without the issuance of new equity. For additional information on the impacts of the Tax Act, see Item 8. Note 7. Regulatory Assets and Liabilities and Note 21. Income Taxes.

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The financial results for PSEG, PSE&G and Power for the years ended December 31, 2018 and 2017 are presented below:

	Years Ended December 31,	
	2018	2017
	Millions, except per share data	
PSE&G	$1,067	$973
Power	365	479
Other	6	122
PSEG Net Income	$1,438	$1,574
PSEG Net Income Per Share (Diluted)	$2.83	$3.10

Our 2018 over 2017 decrease in Net Income was due primarily to the one-time favorable impacts in 2017 of new tax legislation at Power and Holdings, discussed below, and the recognition in 2018 of net unrealized losses on NDT Fund equity securities at Power in accordance with new accounting guidance. The decrease was partially offset by charges in 2017 related to the early retirement of our Hudson and Mercer units, as well as a lower federal tax rate at Power and higher earnings from T&D investments and the favorable impact of new rates upon settlement of the distribution base rate proceeding, discussed above, at PSE&G. For a more detailed discussion of our financial results, see Results of Operations.

Disciplined Investment

We utilize rigorous 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 2018, we

- made additional investments in T&D infrastructure projects,
- continued to execute our GSMP I, Energy Efficiency and other existing BPU-approved utility programs,
- received approval for our GSMP II program and filed our proposed ES II and CEF programs, and
- commenced commercial operation of Sewaren 7 and Keys generation facilities and continued construction of our BH5 generation project, which is targeted for commercial operation in mid-2019.

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. For additional information about regulatory, legislative and other developments that may affect the company, see Item 1. Business—Regulatory Issues.

Transmission Planning

There are several matters pending before FERC that may impact the allocation of costs associated with transmission projects, including those 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 customers in New Jersey. In addition, as a BGS supplier, Power provides services that include specified transmission costs. If the allocation of the costs associated with the transmission projects were to increase these BGS-related transmission costs, BGS suppliers would be entitled to recovery, subject to BPU approval. We do not believe that these matters will have a material effect on Power's business or results of operations.

Several complaints have been filed and several remain pending at FERC against transmission owners around the country, challenging those transmission owners' base ROE. Certain of those complaints have resulted in decisions and others have been settled, resulting in reductions of those transmission owners' base ROEs. The results of these other proceedings could set precedents for other transmission owners with formula rates in place, including PSE&G.

In October 2018, FERC issued an order establishing a new framework for determining whether a company's ROE is unjust and unreasonable. FERC proposes to rely on financial models to establish a composite zone of reasonableness that will be used to determine whether an ROE complaint should be dismissed. If FERC determines that an ROE for a company is not just and reasonable, it intends to reset the ROE based on averaging the results of various financial models. We are still analyzing the potential impact of these methodologies and cannot predict the outcome of ongoing ROE proceedings.

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Wholesale Power Market Design

In June 2018, FERC issued an order finding that PJM's current capacity market is not just and reasonable because it enabled state-supported resources to bid below their costs which resulted in suppressed clearing prices. In particular, FERC found that nuclear generating units that receive zero emission certificate (ZEC) payments were of concern. Depending on the outcome of this matter, our generating stations could also be impacted. For additional information see Item 1. Business—Regulatory Issues—Federal Regulation.

In February 2019, the PJM Board approved a filing to modify the curves used for pricing reserves with FERC. The reforms include a 30-minute reserve product in real-time, more dynamic reserve requirements to better capture operator actions taken to maintain reliability, and improvement to the curves used to price reserves during reserve shortage conditions. If placed into effect, this reform is expected to improve energy and reserve prices by ensuring that when operators commit resources to ensure reliability, the commitments are reflected in market clearing prices. However, this reform could result in lower capacity payments. There is no timeline for this type of filing and therefore we cannot predict when FERC will act on the filing or the outcome of this matter.

In October 2018, PJM filed with FERC to revise the shape of the Variable Resource Requirement (VRR) curve that will be implemented for the capacity auction to be held in August 2019. The VRR curve is the administratively determined demand curve that serves as one of the key elements for establishing the amount of generation capacity to be procured in the auction. PJM contends that its proposal will lower capacity prices as compared to the currently effective VRR curve. PSEG protested PJM's proposal on the grounds that it would result in understated prices for capacity relative to the cost of constructing a new reference generating unit and will result in prices that are unjust and unreasonable. This matter is pending before FERC and we cannot predict the outcome.

Distribution

Effective in January 2018, the BPU adopted Infrastructure Investment Program (IIP) regulations that encourage utilities to construct, install, or remediate utility plant and facilities related to reliability, resiliency, and/or safety to support the provision of safe and adequate service. Under these regulations, utilities can seek authority to make specified infrastructure investments in programs extending for up to five years with accelerated cost recovery mechanisms. The BPU characterized the IIP regulations as a regulatory initiative intended to create a financial incentive for utilities to accelerate the level of investment needed to promote the timely rehabilitation and replacement of certain traditional utility infrastructure that enhances reliability, resiliency, and/or safety. Since these regulations were adopted, the BPU approved our GSMP II and we filed our ES II and CEF-EC programs with the BPU.

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 Clean Water Act 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) and related state regulations could adversely impact future nuclear and fossil operations and costs.

In August 2018, the EPA released the proposed Affordable Clean Energy (ACE) rule as a replacement for the EPA's Clean Power Plan. The proposed ACE rule gives states great flexibility to evaluate specific heat rate improvement technologies and practices to be applied at coal-fired electric generating units. States have three years from the date of finalization to submit a plan that establishes a standard of performance that reflects the degree of emission limitation through the application of heat rate improvement technologies and practices. We cannot estimate the impact of this action on our business or results of operations at this time.

We are also 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.

In December 2018, the New Jersey Department of Environmental Protection proposed two rules that begin the state's re-entry into the Regional Greenhouse Gas Initiative (RGGI). The first proposal is the mechanism rulemaking that establishes the state's initial cap on greenhouse gas emissions of 18 million tons in 2020. The proposal follows the RGGI model rule with a cap that will decline three percent annually through 2030 to a final cap of 11.5 million tons. New Jersey is committed to a start date of January 1, 2020. The second proposal establishes the framework for how the state will spend the RGGI auction proceeds. We cannot estimate the impact of this action on our business or results of operations at this time.

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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 8. Note 14. Commitments and Contingent Liabilities.

Early Plant Retirements

Nuclear

In May 2018, the governor of New Jersey signed legislation, referred to as the ZEC legislation, that recognizes that nuclear power is a critical component of New Jersey's clean energy portfolio and an important element of a diverse energy generation portfolio that currently meets approximately 40 percent of New Jersey's electric power needs. The ZEC legislation creates a Zero Emission Certificate (ZEC) program to be administered by the BPU. The BPU subsequently established processes to evaluate applications by qualified nuclear plants and to review and approve changes to the New Jersey's electric distribution companies' tariffs to provide for the purchase of ZECs from selected nuclear plants and recover those ZEC payments through a non-bypassable distribution charge (ZEC charge) in the amount of $0.004 per kilowatt-hour (which is equivalent to approximately $10 per megawatt hour (MWh) in payments to selected nuclear plants. ZECs will be awarded to selected nuclear plants, if any, in April 2019 at which time ZEC revenue would commence and would continue for approximately three years. Nuclear plants receiving ZEC payments will be obligated to maintain operations, subject to exceptions specified in the ZEC legislation. The ZEC legislation requires nuclear plants to reapply for any subsequent three year periods. The ZEC payment may be adjusted by the BPU (a) at any time to offset environmental or fuel diversity payments that a selected nuclear plant may receive from another source or (b) at certain times specified in the ZEC legislation if the BPU determines that the purposes of the ZEC legislation can be achieved through a reduced charge that will nonetheless be sufficient to achieve the state's air quality and other environmental objectives by preventing the retirement of nuclear plants.

In December 2018, Power submitted applications to the BPU for the Salem 1 and 2 and Hope Creek nuclear plants. These were the only applications received by the BPU. As required, Power's three applications each included a certification pursuant to which Power confirmed that each of the Salem 1, Salem 2 and Hope Creek plants will cease operations within three years absent a material financial change. Power's submittal further attested that the nuclear plants are not expected to cover their costs and operating and market risks as defined in the ZEC legislation, absent a material financial change. As a result, absent a material financial change, Power will retire all three plants unless all of the plants receive ZECs. Power operates its nuclear plants as an interdependent fleet on a common site with shared costs and services, which allows them to achieve economies of scale. A decision to retire one nuclear plant would also adversely impact Power's ability to attract and retain qualified employees at its remaining plants. Power believes that the retirement of any individual nuclear plant would have the effect of decreasing the scale of its nuclear operations; however, the complex nature of operating nuclear plants would not decrease the attention required from management for the safe operation of the remaining nuclear operations. As a result, Power's decision to retire any nuclear plant would be made at the site level and would result in the retirement of all of these New Jersey nuclear plants.

Given the anticipated timing of the BPU's decision on which nuclear plants, if any, have been selected to receive ZECs, which is expected in April 2019, in March 2019 Power will submit to the PJM Independent Market Monitor and the PJM Office of Interconnection a request for a preliminary exception to PJM's Reliability Pricing Model must-offer requirement with respect to Power's interest for each of the Salem 1, Salem 2 and Hope Creek plants in connection with the 2022/2023 capacity auction expected to be held in August 2019. Power will also submit a deactivation notice to the extent that its filing deadline occurs prior to the award of ZECs by the BPU. If all of the Salem and Hope Creek plants are selected to receive ZECs, the preliminary exception and requested deactivation notice, as applicable, would be withdrawn.

In the event that any of the Salem 1, Salem 2 and Hope Creek plants is not selected to receive ZEC payments in April 2019 by the BPU and do not otherwise experience a material financial change, Power will take all necessary steps to retire all of these plants at or prior to their refueling outages scheduled for the Fall 2019 in the case of Hope Creek, Spring 2020 in the case of Salem 2 and Fall 2020 in the case of Salem 1. Alternatively, if all of the Salem 1, Salem 2 and Hope Creek plants are selected to receive ZEC payments in April 2019 but the financial condition of the plants is materially adversely impacted by potential changes to the capacity market construct being considered by FERC (absent sufficient capacity revenues provided under a program approved by the BPU in accordance with a FERC authorized capacity mechanism), Power would still take all necessary steps to retire all of these plants. The costs and accounting charges associated with any such retirement, which may include, among other things, accelerated depreciation and amortization or impairment charges, potential penalties associated with the early termination of capacity obligations and fuel contracts, accelerated asset retirement costs, severance costs, environmental remediation costs and, in certain circumstances, potential additional funding of the Nuclear Decommissioning Trust (NDT) Fund, would be material to both PSEG and Power.

Following any action to retire its nuclear plants, Power would take the necessary steps to satisfy its capacity obligations through 2022 with other assets in its fleet or through market purchases. Power intends to decommission any retired nuclear plant using the “SAFESTOR” process, which is a process approved by the NRC. As a result, Power believes adequate funds are available in the NDT Fund for the early retirement of the nuclear plants. To the extent another decommissioning process is employed, the NDT Fund would not be sufficient to cover the costs of decommissioning all the nuclear plants upon early retirement.

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Fossil

In December 2018, Power completed the sale of the sites of the retired Hudson and Mercer units. Power transferred all land rights and structures on the sites to a third-party purchaser, along with the assumption of the environmental liabilities for the sites. As a result of the sale and transfer of liabilities, Power recorded a pre-tax gain in 2018 of $54 million in Operation and Maintenance (O&M) Expense.

In addition, PSEG and Power continue to monitor their other coal assets, including their interest in the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events out of PSEG's and Power's control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the classification as held for use of our remaining coal units may have a material adverse impact on PSEG's and Power's future financial results.

California Solar Facilities

As part of its solar production portfolio, Power owns and operates two California-based solar facilities with an aggregate capacity of approximately 30 MW direct current whose output is sold to Pacific Gas and Electric Company (PG&E) under power purchase agreements (PPAs) with twenty year terms. The net book value of these solar facilities was approximately $57 million as of December 31, 2018. In January 2019, PG&E and its parent company PG&E Corporation filed for Chapter 11 bankruptcy protection. Power cannot predict the ultimate outcome that this bankruptcy proceeding will have on our ability to collect all of the future revenues from these facilities due under the PPAs; however, any adverse changes to the terms of Power's PPAs as a result of this bankruptcy proceeding could result in the future impairment of these assets in amounts up to their current net book value.

Offshore Wind

In January 2018, the governor of New Jersey signed Executive Order No. 8 directing the BPU to begin the process of moving the state toward its 2030 goal of 3,500 MW of offshore wind energy generation. An initial solicitation was established for 1,100 MW of offshore wind, with bids due in December 2018. In connection with the bid submitted by Ocean Wind, LLC, a wholly owned subsidiary of Ørsted US Offshore Wind, referred to as the Ocean Wind project, PSEG agreed to provide energy management services and the potential lease of land for use in project development. We also retained an option to acquire an equity interest in the project. We expect to make a decision regarding an equity investment in the Ocean Wind project in the second half of 2019.

Leveraged Leases

In December 2018, NRG REMA, LLC (REMA) emerged from its in-court proceeding under Chapter 11 of the Bankruptcy Code. Upon emergence, PSEG received $31.5 million in cash in exchange for transferring the ownership interests in Keystone and Conemaugh to the debtholders of REMA and satisfaction of all other claims asserted against REMA, as well as certain amendments to the Shawville lease. The Shawville lease amendments, among other things, will allow REMA to express interest in a renewal on or after November 24, 2019. In addition, REMA has agreed to fund qualifying credit support up to $36 million. As a result of the restructuring, Energy Holdings recognized a pre-tax gain in Operating Revenues of approximately $12 million ($9 million after tax). In addition, the remaining deferred tax liabilities related to these lease investments were reclassified to current tax liabilities. PSEG expects to pay approximately $120 million to taxing authorities resulting from this restructuring activity.

Additional facilities in our leveraged lease portfolio include the Joliet and Powerton generating facilities. Converted natural gas units such as Shawville and Joliet may have higher operating costs and fuel consumption, as well as longer start-up times, compared to newer combined cycle gas units. Powerton is a coal-fired generating facility in Illinois. Each of these three facilities may not be as economically competitive as newer combined cycle gas units and could continue to be adversely impacted by the same economic conditions experienced by other less efficient natural gas and coal generation facilities, which could require Energy Holdings to write down the residual value of the leveraged lease receivables associated with these facilities.

Tax Legislation

In December 2017, the Tax Act, among other things, decreased the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018, and made certain changes to bonus depreciation and interest disallowance rules.

As a result of the Tax Act, we recorded a one-time, non-cash earnings benefit of $745 million in 2017, including $588 million related to Power and $147 million related to Energy Holdings. This benefit was primarily due to the remeasurement of deferred tax balances. In addition, PSE&G recorded excess deferred taxes of approximately $2.1 billion and recorded an approximate $2.9 billion revenue impact of these excess deferred taxes as Regulatory Liabilities.

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Beginning in 2018, PSEG, on a consolidated basis, is incurring lower income tax expense resulting in a decrease in its effective income tax rate that has led to an increase in PSEG's and Power's Net Income. To the extent allowed under the Tax Act, Power's operating cash flows will reflect the full expensing of capital investments for income tax purposes. For PSE&G, the Tax Act has led to lower customer rates due to lower income tax expense recoveries and the BPU and FERC have approved our proposal to refund excess deferred income tax Regulatory Liabilities. See Item 8. Note 7. Regulatory Assets and Liabilities for additional information. The impact of the lower federal income tax rate on PSE&G was reflected in PSE&G's distribution base rate proceeding and its 2018 transmission formula rate filings. The Tax Act is generally expected to result in lower operating cash flows for PSE&G resulting from the elimination of bonus depreciation, partially offset by higher revenues due to the higher rate base.

In August 2018, the Internal Revenue Service (IRS) issued a Notice of Proposed Rulemaking (Notice) regarding the application of tax depreciation rules as amended by the Tax Act. While the Notice provides some guidance as to the application of the changes made by the Tax Act to the bonus depreciation rules, certain aspects remain unclear. Further, in November 2018 the IRS issued Proposed Regulations addressing the interest disallowance rules contained in the Tax Act. For non-regulated businesses, these rules set a cap on the amount of interest that can be deducted in a given year. Any amount that is disallowed can be carried forward indefinitely. For 2018, PSEG and Power expect that a portion of their interest will be disallowed in the current period but realized in future periods. However, certain aspects of the proposed regulations are unclear; therefore, we recorded taxes based on our interpretation of the relevant statute.

We recorded amounts based on our interpretation of the Tax Act, the depreciation rules contained in the Notice and proposed interest disallowance regulations. Such amounts are subject to change based on several factors, including but not limited to, the IRS and state taxing authorities issuing final guidance and/or further clarification. Any further guidance or clarification could impact PSEG's, PSE&G's and Power's financial statements. For additional information, see Item 8. Note 21. Income Taxes.

As a result of the enactment of the Tax Act, various state regulatory authorities, including the BPU, have taken action to ensure that excess federal income taxes previously collected in rates are returned to customers. We adjusted the revenue requirement in certain of our rate matters as a result of the change in the federal income tax rate. See Item 8. Note 7. Regulatory Assets and Liabilities for additional information.

In July 2018, the State of New Jersey made changes to its income tax laws, including imposing a temporary surtax on allocated corporate taxable income of 2.5% effective January 1, 2018 and 2019 and 1.5% in 2020 and 2021, as well as requiring corporate taxpayers to file in a combined reporting group as defined under New Jersey law starting in 2019. Both provisions include an exemption for public utilities. We believe PSE&G meets the definition of a public utility and, therefore, will not be impacted by the temporary surtax or be included in the combined reporting group. We expect these new provisions to unfavorably affect our non-utility business. In accordance with GAAP accounting for income taxes, deferred taxes are required to be measured at the enacted tax rate expected to apply to taxable income in the periods in which the deferred taxes are expected to settle. The newly enacted New Jersey tax legislation did not have a material impact on PSEG's deferred income tax balance.

Amendments to Other Postretirement Employee Benefit (OPEB) Plans

In December 2018, PSEG amended certain provisions of its OPEB plans applicable to all current and future Medicare-eligible retirees and spouses who receive or will receive subsidized healthcare from PSEG. Effective January 1, 2021, the PSEG-sponsored Medicare-eligible plans will be replaced by a Medicare private exchange. For each Medicare-eligible retiree and spouse, PSEG will provide annual credits to a Health Reimbursement Arrangement, which can be used to pay for medical, prescription drug, and dental plan premiums, as well as certain out-of-pocket costs. The amendment resulted in a $559 million reduction in PSEG's OPEB obligation as of December 31, 2018 and is expected to decrease net periodic benefit costs in 2019.

Future Outlook

Our future success will depend on our ability to continue to maintain strong operational and financial performance in an environment with low gas prices, to capitalize on or otherwise address 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, reliability and customer satisfaction and complying with applicable standards and requirements,
- successfully manage our energy obligations and re-contract our open supply positions in response to changes in prices and demand,
- obtain approval of and execute our utility capital investment program, including ES II, GSMP II, our CEF program and other investments for growth that yield contemporaneous and reasonable risk-adjusted returns, while enhancing the resiliency of our infrastructure and maintaining the reliability of the service we provide to our customers,
- effectively manage construction of BH5 and our other generation projects,

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- 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.

In addition to the risks described elsewhere in this Form 10-K for 2019 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 proceedings,
- the review by the BPU of our application to select our New Jersey nuclear generation units to receive payments under the ZEC program,
- the continuing impacts of the Tax Act and changes in state tax laws, and
- the impact of reductions in demand and lower natural gas and electricity prices and increasing environmental compliance costs.

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, customers 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 T&D facilities, clean energy investments and/or generation projects, including offshore wind opportunities,
- the disposition or reorganization of our merchant generation business or other existing businesses or the acquisition or development of new businesses,
- the expansion of our geographic footprint, including the operation of T&D facilities outside of our traditional service territory, and
- investments in capital improvements and additions, including the installation of environmental upgrades and retrofits, improvements to system resiliency, modernizing existing infrastructure and participation in transmission projects through FERC's "open window" solicitation process.

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,		
	2018	2017	2016
Earnings (Losses)	Millions		
PSE&G	$1,067	$973	$889
Power (A)(B)	365	479	18
Other (B)(C)	6	122	(20)
PSEG Net Income	$1,438	$1,574	$887
PSEG Net Income Per Share (Diluted)	$2.83	$3.10	$1.75

(A) Power's results in 2018 include an after-tax gain of $39 million from the sale of its Hudson and Mercer coal/gas generation plants and after-tax expenses of $577 million and $396 million in 2017 and 2016, respectively, related to

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the early retirement of these generation plants. See Item 8. Note 4. Early Plant Retirements for additional information.

(B) Results in 2017 include the non-cash net income benefit of $745 million, including $588 million related to Power and $147 million related to Energy Holdings, resulting from the remeasurement of deferred tax liabilities required due to the enactment of the Tax Act in December 2017.

(C) Other includes after-tax activities at the parent company, PSEG LI and Energy Holdings as well as intercompany eliminations. Energy Holdings recorded after-tax charges totaling $5 million, $45 million and $92 million related to its investments in REMA's leveraged leases in 2018, 2017 and 2016, respectively. See Item 8. Note 8. Long-Term Investments and Note 9. Financing Receivables for further information.

Power's results above include the NDT Fund activity and the impacts of non-trading commodity mark-to-market (MTM) activity, which consist of the financial impact from positions with future delivery dates.

The variances in our Net Income attributable to changes related to the NDT Fund and MTM are shown in the following table:

Years Ended December 31,	2018	2017	2016
	Millions, after tax		
NDT Fund and Related Activity (A) (B)	$(90)	$62	$—
Non-Trading MTM Gains (Losses) (C)	$(84)	$(99)	$(100)

(A) NDT Fund Income (Expense) includes gains and losses on NDT securities which are recorded in Net Gains (Losses) on Trust Investments. See Item 8. Note 10. Trust Investments for additional information. NDT Fund Income (Expense) also includes interest and dividend income and other costs related to the NDT Fund recorded in Other Income (Deductions), interest accretion expense on Power's nuclear Asset Retirement Obligation (ARO) recorded in O&M Expense and the depreciation related to the ARO asset recorded in Depreciation and Amortization (D&A) Expense.

(B) Net of tax (expense) benefit of $54 million, $(72) million and $(5) million for the years ended December 31, 2018, 2017 and 2016, respectively.

(C) Net of tax benefit of $33 million, $68 million and $68 million for the years ended December 31, 2018, 2017 and 2016, respectively.

The 2018 year-over-year decrease in Net Income was driven largely by

- non-cash Net Income benefits in 2017 related to new tax legislation (See Item 8. Note 21. Income Taxes) at Power and Energy Holdings, and
- recognition in 2018 of net unrealized losses on equity securities in the NDT Fund in accordance with new accounting guidance effective January 1, 2018 (See Item 8. Note 2. Recent Accounting Standards and Note 10. Trust Investments),

These decreases were partially offset by

- accelerated depreciation in 2017 related to early retirement of our Hudson and Mercer coal/gas generation units at Power (See Item 8. Note 4. Early Plant Retirements),
- the favorable impact at Power from the lower federal tax rate effective January 1, 2018, and
- higher earnings due to investments in T&D programs and the favorable impact of new rates effective November 1, 2018 as a result of the BPU approval of our distribution base rate proceeding.

The 2017 year-over-year increase in our Net Income was driven primarily by:

- non-cash Net Income benefits related to new tax legislation (See Item 8. Note 21. Income Taxes) at Power and Energy Holdings,
- higher transmission revenues,
- higher net NDT gains in 2017, and
- lower charges related to investments in certain leveraged leases at Energy Holdings (See Item 8. Note 8. Long-Term Investments).

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These increases were partially offset by:

- higher charges related to the early retirement of our Hudson and Mercer coal/gas generation units at Power (See Item 8. Note 4. Early Plant Retirements), and
- lower volumes of energy sold at lower average realized sales prices under the BGS contracts and in the PJM and New England regions.

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. Note 25. Related-Party Transactions.

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2018	2017	2016	2018 vs. 2017		2017 vs. 2016	
	Millions			Millions	%	Millions	%
Operating Revenues	$9,696	$9,094	$8,966	$602	7	$128	1
Energy Costs	3,225	2,778	2,901	447	16	(123)	(4)
Operation and Maintenance	3,015	2,901	2,991	114	4	(90)	(3)
Depreciation and Amortization	1,158	1,986	1,476	(828)	(42)	510	35
Income from Equity Method Investments	15	14	11	1	7	3	27
Net Gains (Losses) on Trust Investments	(143)	134	(6)	(277)	N/A	140	N/A
Other Income (Deductions)	85	82	102	3	4	(20)	(20)
Non-Operating Pension and OPEB Credits (Costs)	76	—	(22)	76	N/A	22	N/A
Interest Expense	476	391	385	85	22	6	2
Income Tax (Benefit) Expense	417	(306)	411	723	N/A	(717)	N/A

The 2018, 2017 and 2016 amounts in the preceding table for Operating Revenues and O&M costs each include $458 million, $438 million and $410 million, respectively, for PSEG LI’s subsidiary, Long Island Electric Utility Servco, LLC (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. Note 5. Variable Interest Entity for further explanation. The Income Tax Benefit in 2017 includes the non-cash benefit resulting from the remeasurement of deferred tax liabilities required due to the enactment of the Tax Act in December 2017. The following discussions for PSE&G and Power provide a detailed explanation of their respective variances.

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PSE&G

	Years Ended December 31,			Increase / (Decrease) 2018 vs. 2017		Increase / (Decrease) 2017 vs. 2016	
	2018	2017	2016				
	Millions			Millions	%	Millions	%
Operating Revenues	$6,471	$6,324	$6,303	$147	2	$21	—
Energy Costs	2,520	2,421	2,644	99	4	(223)	(8)
Operation and Maintenance	1,575	1,458	1,465	117	8	(7)	—
Depreciation and Amortization	770	685	565	85	12	120	21
Net Gains (Losses) on Trust Investments	(1)	2	—	(3)	N/A	2	N/A
Other Income (Deductions)	80	85	79	(5)	(6)	6	8
Non-Operating Pension and OPEB Credits (Costs)	59	(8)	(15)	67	N/A	7	(47)
Interest Expense	333	303	289	30	10	14	5
Income Tax Expense	344	563	515	(219)	(39)	48	9

Year Ended December 31, 2018 as compared to 2017

Operating Revenues increased $147 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $44 million.

- Transmission revenues increased $180 million due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.
- Gas distribution revenues increased $67 million due to $63 million from higher sales volumes, $36 million from the inclusion of the GSMP I in base rates, $25 million from an increase in the distribution tariff rates effective November 1, 2018 and $2 million in higher collections of Green Program Recovery Charges (GPRC). These increases were partially offset by lower Weather Normalization Clause (WNC) revenues of $31 million, a $26 million reduction for Tax Adjustment Credits (TAC) and a $2 million reduction in ES I collections.
- Electric distribution revenues increased $62 million due primarily to a $49 million increase in sales volume, a $17 million increase in ES I collections, $6 million from an increase in the distribution tariff rates effective November 1, 2018 and $4 million in higher collections of GPRC. These increases were partially offset by a reduction of $14 million in TAC.
- Transmission, electric distribution and gas distribution revenue requirements were $265 million lower as a result of rate reductions due to the Tax Act which reduced the corporate income tax rate. This decrease is offset in Income Tax Expense.

Clause Revenues increased $2 million due to higher Societal Benefit Charges (SBC) of $14 million, and $2 million in higher Solar Pilot Recovery Charge (SPRC) collections, partially offset by decreases of $7 million in Margin Adjustment Clause (MAC) revenues and $7 million in TAC and GPRC deferrals. The changes in SBC, SPRC and MAC collections and TAC and GPRC deferrals were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, D&A and Interest and Tax Expense. PSE&G does not earn margin on SBC, SPRC or MAC collections or on TAC or GPRC deferrals.

Commodity Revenues increased $99 million due to higher Electric revenues and higher Gas revenues. This increase is entirely offset with increased Energy Costs. PSE&G earns no margin on the provision of BGS and basic gas supply service (BGSS) to retail customers.

- Electric revenues increased $73 million due to $67 million in higher net BGS revenues reflecting $148 million from higher BGS sales volumes partially offset by $81 million from lower prices, and $6 million in higher revenues from solar renewable energy credit (SREC) sales.
-

Gas revenues increased $26 million due to $65 million from higher BGSS sales volumes, which were partially offset by lower BGSS prices of $42 million, and $3 million in higher BGSS Asset Charges.

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Operating Expenses

Energy Costs increased $99 million. This is entirely offset by Commodity Revenues.

Operation and Maintenance increased $117 million, due to a $24 million increase in electric distribution maintenance expenditures, a $24 million increase in transmission maintenance expenditures, a $16 million increase in appliance service costs, a $12 million net increase for various clause mechanisms and GPRC expenditures, a $9 million increase in storm-related costs, an $8 million increase in gas distribution expenditures, a $6 million net increase in pension and OPEB expenses, net of amounts capitalized, a $3 million increase in damage claims, and a $15 million increase in other operating expenses.

Depreciation and Amortization increased $85 million due primarily to an increase in depreciation of $81 million due to additional plant placed into service, a $7 million net increase in amortization of Regulatory Assets primarily due to the settlement of our base rate proceeding and an increase of $5 million in software amortization, partially offset by a $7 million increase in capitalized depreciation.

Non-Operating Pension and OPEB Credits (Costs) reflect an increase of $67 million in credits primarily due to the adoption of new accounting guidance effective January 1, 2018 which no longer allows for the capitalization of any portion of these benefit costs. See Item 8. Note 2. Recent Accounting Standards.

Other Income (Deductions) decreased $5 million due primarily to a $2 million decrease in the Allowance for Funds Used During Construction (AFUDC) and a $3 million decrease in solar loan interest.

Interest Expense increased $30 million due primarily to increases of $16 million due to long-term debt issuances in May and December 2017, $8 million due to net long-term debt issuances in 2018 and $4 million in clause-related interest.

Income Tax Expense decreased $219 million due primarily to the decrease in the federal statutory income tax rate from 35% in 2017 to 21% in 2018 and lower pretax income.

Year Ended December 31, 2017 as compared to 2016

Operating Revenues increased $21 million due to changes in delivery, clause, commodity and other operating revenues.

Delivery Revenues increased $166 million due primarily to an increase in transmission revenues.

- Transmission revenues were $152 million higher due to higher revenue requirements calculated through our transmission formula rate, primarily to recover required investments.
- Gas distribution revenues increased $30 million due to a $16 million increase due to Energy Strong I, $10 million from inclusion of the GSMP I in base rates, $4 million in higher collections of GPRC and an increase of $2 million due to higher sales volumes. These increases were partially offset by lower WNC revenues of $2 million.
- Electric distribution revenues decreased $16 million due primarily to a $28 million decrease in sales volume and $14 million in lower collections of GPRC, partially offset by a $26 million increase in Energy Strong I revenues.

Clause Revenues increased $75 million due to the absence of the return in 2016 to customers of overcollections of Securitization Transition Charge (STC) revenues of $59 million, higher GPRC collections of $28 million and higher MAC revenues of $4 million. These increases were partially offset by lower SBC of $17 million. The changes in STC, GPRC, MAC and SBC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, D&A and Interest Expense. PSE&G does not earn margin on STC, GPRC, MAC or SBC collections.

Commodity Revenues decreased $223 million due to lower Electric revenues partially offset by higher Gas revenues. This decrease is entirely offset with decreased Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $288 million due to $199 million in lower BGS revenues reflecting $109 million from lower sales volumes and $90 million from lower prices, $61 million in lower collections of Non-Utility Generation (NUG) Charges due primarily to lower prices, a $14 million decrease from sales of SRECs and $14 million in lower revenues from the decreased sales volume of NUG energy.
- Gas revenues increased $65 million due to higher BGSS prices of $68 million and $2 million from higher sales volumes, partially offset by $5 million in lower BGSS Asset Charges.

Operating Expenses

Energy Costs decreased $223 million. This is entirely offset by Commodity Revenues.
Operation and Maintenance decreased $7 million due primarily to a $15 million decrease in appliance service costs, partially offset by an $8 million net increase in other operating expenses.

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Depreciation and Amortization increased $120 million due primarily to a $61 million net increase in amortization of Regulatory Assets, including the absence of the STC liability that ended in 2016, and an increase in depreciation of $59 million due to additional plant placed into service in 2017.
Non-Operating Pension and OPEB Credits (Costs) reflect a decrease in costs of $7 million due primarily to a decrease in the amortization of the net unrecognized actuarial pension loss, partially offset by the impacts of capitalization.
Other Income (Deductions) increased $6 million due primarily to an increase in AFUDC.
Interest Expense increased $14 million due primarily to an $11 million increase due to net long-term debt issuances in 2016 and $9 million due to net long-term debt issuances in 2017, partially offset by a decrease of $6 million due to clause-related interest for BGSS in 2016.
Income Tax Expense increased $48 million due primarily to higher pre-tax income.
Power

	Years Ended December 31,			Increase / (Decrease)		Increase / (Decrease)	
	2018	2017	2016	2018 vs. 2017		2017 vs. 2016	
	Millions			Millions	%	Millions	%
Operating Revenues	$4,146	$3,860	$3,861	$286	7	$(1)	—
Energy Costs	2,197	1,913	1,824	284	15	89	5
Operation and Maintenance	999	1,046	1,139	(47)	(4)	(93)	(8)
Depreciation and Amortization	354	1,268	881	(914)	(72)	387	44
Income from Equity Method Investments	15	14	11	1	7	3	27
Net Gains (Losses) on Trust Investments	(140)	125	(6)	(265)	N/A	131	N/A
Other Income (Deductions)	21	20	23	1	5	(3)	(13)
Non-Operating Pension and OPEB Credits (Costs)	15	8	(4)	7	88	12	N/A
Interest Expense	76	50	84	26	52	(34)	(40)
Income Tax Expense (Benefit)	66	(729)	(61)	795	N/A	(668)	N/A

Year Ended December 31, 2018 as compared to 2017
Operating Revenues increased $286 million due to changes in generation, gas supply and other operating revenues.
Generation Revenues increased $199 million due primarily to

- a net increase of $113 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM region coupled with the commencement of commercial operations for Keys and Sewaren 7 in mid-2018, partially offset by lower average realized prices and higher purchases for wholesale load contracts in the PJM region,
- a net increase of $110 million due to lower MTM net losses in 2018 as compared to 2017. Of this amount, there was a $153 million increase due to gains on positions reclassified to realized upon settlement, partially offset by a net decrease of $43 million due to changes in forward prices,
- a net increase of $26 million in capacity revenues due primarily to increases in auction prices in the PJM region,
- a net increase of $24 million resulting from a prior year reduction to revenue for excess federal income tax previously collected by Power’s subsidiary, PSEG New Haven LLC, from ratepayers due to the change in federal tax rates, and
- a net increase of $7 million due to higher sales related to new solar projects,
- partially offset by a decrease of $82 million in electricity sold under our BGS contracts due to lower prices and lower volumes.

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Gas Supply Revenues increased $87 million due primarily to

- an increase of $61 million in sales under the BGSS contract, of which $53 million was due to increases in sales volumes as a result of periods of colder weather in the heating season, coupled with $8 million due to higher average sales prices, and
- an increase of $42 million related to sales to third parties, of which $26 million was due to higher sales volumes and $16 million to higher average sales prices,
- partially offset by a decrease of $16 million due to net MTM losses in 2018 compared to net gains in 2017.

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 $284 million due to

Generation costs increased $167 million due primarily to

- higher fuel costs of $158 million reflecting utilization of higher volumes of gas and oil in the PJM region, primarily due to the commencement of commercial operations of Keys and Sewaren 7 fossil stations in mid-2018, coupled with higher prices of natural gas in the PJM and New York regions and higher coal costs in the PJM and New England (NE) regions, and
- an increase of $40 million due to MTM losses in 2018 as compared to gains in 2017 due to changes in forward prices,
- partially offset by a net decrease of $22 million primarily due to a decrease in the volume of energy purchased in the NE region to serve load obligations, and
- a net decrease of $14 million due to charges primarily related to additional retirement costs incurred in 2017 associated with the early retirement of the Hudson and Mercer units.

Gas costs increased $117 million due primarily to

- an increase of $75 million related to sales under the BGSS contract due primarily to a $51 million increase in volumes sold due to periods of colder weather during the heating season in 2018 as compared to 2017, and $24 million of higher average gas costs, and
- an increase of $38 million related to sales to third parties, of which $25 million was due to an increase in volumes sold coupled with $13 million due to higher average gas costs.

Operation and Maintenance decreased $47 million due primarily to

- a $67 million decrease at our fossil plants, due primarily to a pre-tax gain of $54 million on the sale of the Hudson and Mercer units in 2018 and associated shutdown costs incurred in 2017, partially offset by higher planned outage costs in 2018 associated with our various other fossil plants,
- partially offset by a $22 million net increase at our nuclear facilities primarily due to higher planned outage costs at our 100%-owned Hope Creek nuclear plant in 2018 as compared to our 57%-owned Salem Unit 1 nuclear plant in 2017, coupled with higher accretion directly related to an increase in the nuclear ARO in 2017.

Depreciation and Amortization decreased $914 million due primarily to

- a $964 million decrease primarily due to accelerated depreciation recorded in 2017 for the early retirement of the Hudson and Mercer units,
- partially offset by a $23 million increase due to Keys and Sewaren 7 fossil stations being placed into service,
- an increase of $12 million in depreciation due to the increase in the nuclear ARO in late 2017, and
- a $7 million increase in 2018 due primarily to a higher nuclear asset base from increased capitalized asset retirement costs.

Net Gains (Losses) on Trust Investments decreased $265 million due primarily to

- the inclusion in 2018 of $209 million of net unrealized losses on equity investments in the NDT Fund in accordance with new accounting guidance, and
- a $64 million decrease in net realized gains on NDT Fund investments,

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- partially offset by a $12 million decrease in other-than-temporary impairments of equity securities in the NDT Fund.

Non-Operating Pension and OPEB Credits (Costs) reflect an increase in credits of $7 million due primarily to an increase in the expected return on pension plan assets.

Interest Expense increased $26 million due primarily to a $15 million increase due to a June 2018 debt issuance and $11 million in lower capitalized interest as a result of Keys and Sewaren 7 fossil stations being placed into service.

Income Tax Expense increased $795 million due primarily to a one-time benefit recorded in 2017 as a result of the remeasurement of deferred tax balances and higher pre-tax income in 2018. This increase was partially offset by the favorable impacts in 2018 of a decrease in the federal statutory income tax rate from 35% in 2017 to 21% and the remeasurement of the reserve for uncertain tax positions in connection with a 2015 claim to carry back tax-defined nuclear decommissioning costs and the 2011 and 2012 federal tax audit.

Year Ended December 31, 2017 as compared to 2016

Operating Revenues decreased $1 million due to changes in generation, gas supply and other operating revenues.

Generation Revenues decreased $112 million due primarily to

- a decrease of $100 million in electricity sold under our BGS contracts due primarily to lower volumes coupled with lower prices,
- a decrease of $41 million in energy sales in the PJM and NE regions due primarily to lower average realized prices,
- a decrease of $24 million in revenue expected to be returned to ratepayers associated with excess federal income tax previously collected by Power’s subsidiary, PSEG New Haven LLC, due to the change in federal tax rates effective January 1, 2018,
- a decrease of $12 million in operating reserves in the PJM region,
- a charge of $10 million due to an increase in the FERC accrual related to the PJM bidding matter,
- a decrease of $7 million due to higher MTM losses in 2017 as compared to 2016. Of this amount, $120 million was due to increased forward prices, partially offset by a decrease of $113 million due to lower gains on positions reclassified to realized upon settlement in 2017 as compared to 2016,
- partially offset by a net increase of $53 million due primarily to higher volumes of electricity sold under wholesale load contracts in the PJM and NE regions,
- a net increase of $18 million in capacity revenues in the PJM and NE regions due to increases in cleared capacity and capacity auction prices, and
- an increase of $11 million due to higher sales related to new solar projects.

Gas Supply Revenues increased $110 million due primarily to

- an increase of $67 million in sales under the BGSS contract, of which $40 million was due to higher average sales prices coupled with a $27 million increase in sales volumes due to periods of colder weather in the heating season,
- a net increase of $24 million due to higher MTM gains in 2017 as compared to 2016, and
- an increase of $19 million related to sales to third parties, of which $48 million was due to higher average sales prices, partially offset by $29 million of 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 increased $89 million due to

Gas costs increased $66 million due to

- an increase of $50 million related to sales under the BGSS contract, of which $31 million was due to higher average gas costs, coupled with a $19 million increase in volumes sold due to periods of colder weather in the heating season, and
- an increase of $16 million related to sales to third parties, of which $44 million was due to higher average gas costs, partially offset by a $28 million decrease in volumes sold.

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Generation costs increased $23 million due primarily to

- higher fuel costs of $31 million reflecting higher average realized prices for natural gas coupled with the utilization of higher volumes of coal, partially offset by the utilization of lower volumes of gas,
- an increase of $17 million due to MTM losses in 2017 as compared to MTM gains in 2016,
- a net increase of $17 million primarily due to an increase in the volume of energy purchases in the NE region to serve load obligations, and
- a net increase of $10 million primarily due to higher transmission charges resulting from higher rates,
- partially offset by a net decrease of $50 million due to charges associated with the announced early retirement of the Mercer and Hudson units in 2016, primarily related to lower coal inventory write-downs in 2017, partially offset by additional retirement costs incurred in 2017.

Operation and Maintenance decreased $93 million due to

- a $72 million decrease at our fossil plants, due primarily to the retirement of the Hudson and Mercer units and higher planned outage costs in 2016, and
- a $35 million net decrease at our nuclear facilities primarily due to lower planned outage costs at our 57%-owned Salem nuclear plants in 2017 as compared to our 100%-owned Hope Creek nuclear plant and Salem Unit 1 nuclear plant in 2016,
- partially offset by a $5 million increase of costs related to new solar plants placed into service in 2017.

Depreciation and Amortization increased $387 million due primarily to

- $346 million of higher depreciation for Hudson and Mercer, primarily due to the accelerated expense related to the early retirement of those units,
- a $15 million increase due to the accelerated retirement date for the Bridgeport Harbor unit 3,
- an $11 million increase due primarily to a higher nuclear asset base, and
- $11 million of higher depreciation due to new solar projects.

Net Gains (Losses) on Trust Investments increased $131 million due primarily to a $113 million increase in net realized gains on NDT Fund investments and lower other-than-temporary impairments of equity securities of $16 million in the NDT Fund.

Non-Operating Pension and OPEB Credits (Costs) reflect an increase in credits of $12 million due primarily to a decrease in the amortization of the net unrecognized actuarial pension loss.

Interest Expense decreased $34 million due primarily to

- a $24 million decrease due to higher interest capitalized for the construction of three new fossil stations: BH5, Sewaren 7 and Keys, and
- a net $7 million decrease due to debt maturities in September 2016, partially offset by a debt issuance in June 2016.

Income Tax Expense decreased $668 million due primarily to the one-time benefit recorded as a result of the remeasurement of deferred tax balances required due to the enactment of the Tax Act in December 2017.

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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 revolving credit facility. PSE&G uses internally generated cash flow and its commercial paper program to meet 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/capital contributions from 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 revolving credit facilities totaling $1.5 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 $1.1 billion of term loan credit agreements, of which $350 million is scheduled to expire in June 2019 and $700 million in November 2020. From time to time, PSEG may make equity contributions or provide credit support to its subsidiaries.

Power’s sources of external liquidity include $2.1 billion of multi-year revolving 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 that Power is downgraded to below investment grade by Standard & Poor’s (S&P) or Moody’s. 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.

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, 2018, our operating cash flow decreased by $347 million. For the year ended December 31, 2017, our operating cash flow decreased by $53 million. The net changes were primarily due to net changes from our subsidiaries as discussed below and net tax payments at Energy Holdings in 2018 as compared to tax refunds in 2017.

PSE&G

PSE&G’s operating cash flow increased $15 million from $1,838 million to $1,853 million for the year ended December 31, 2018, as compared to 2017, due primarily to an increase of $171 million relating to accounts receivable and unbilled revenues resulting from higher collections and lower prices and volumes in 2018 and higher earnings, offset by tax payments in 2018 as compared to tax refunds in 2017.

PSE&G’s operating cash flow decreased $58 million from $1,896 million to $1,838 million for the year ended December 31, 2017, as compared to 2016, due primarily to lower tax refunds and a decrease of $50 million related to a change in regulatory deferrals. These amounts were partially offset by higher earnings and $30 million in decreased vendor payments.

Power

Power's operating cash flow decreased $242 million from $1,326 million to $1,084 million for the year ended December 31, 2018, as compared to 2017, due to an increase in margin deposit requirements of $157 million, lower earnings, a decrease in fuels, materials and supplies of $81 million and an increase of $52 million in payments to counterparties, offset by tax refunds in 2018 as compared to tax payments in 2017, and a $96 million increase from net collections of counterparty receivables.

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Power’s operating cash flow increased $71 million from $1,255 million to $1,326 million for the year ended December 31, 2017, as compared to 2016, primarily resulting from a decrease of $61 million in payments to counterparties, a $26 million increase from higher net collections of counterparty receivables, and higher earnings. These amounts were partially offset by higher tax payments and an increase in margin deposit requirements of $14 million.

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. 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, 2018 were as follows:

	As of December 31, 2018		
Company/Facility	Total Facility	Usage	Available Liquidity
	Millions		
PSEG	$1,500	$759	$ 741
PSE&G	600	288	312
Power	2,100	154	1,946
Total	$4,200	$1,201	$ 2,999

As of December 31, 2018, 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 from S&P or Moody’s, which would represent a three level downgrade from its current S&P or Moody’s ratings. In the event of a deterioration of Power’s credit rating, certain of Power’s agreements allow the counterparty to demand further performance assurance. The potential additional collateral that we would be required to post under these agreements if Power were to lose its investment grade credit rating was approximately $857 million and $848 million as of December 31, 2018 and 2017, respectively.

For additional information, see Item 8. Note 15. Debt and Credit Facilities.

Long-Term Debt Financing

During the next twelve months, PSEG has a $350 million floating rate term loan maturing in June 2019 and $400 million of 1.60% Senior Notes maturing in November 2019. PSE&G has $250 million of 1.80% Medium Term Notes maturing in June 2019 and $250 million of 2.00% Medium Term Notes maturing in August 2019. Power has a letter of credit backing $44 million of Pennsylvania Economic Development Financing Authority Variable Rate Demand Bonds which expires in November 2019.

For a discussion of our long-term debt transactions during 2018, see Item 8. Note 15. Debt and Credit Facilities.

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, 2018, PSE&G’s Mortgage coverage ratio was 3.8 to 1 and the Mortgage would permit up to approximately $6.3 billion aggregate principal amount of new Mortgage Bonds to be issued against additions and improvements to its property.

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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.
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. Power's bank credit agreements and outstanding notes also contain limitations on the incurrence of subsidiary debt and liens and certain of Power's outstanding notes require Power to repurchase such notes upon certain change of control events.
There are no cross acceleration provisions in PSEG's or PSE&G's indentures. However, PSEG's existing notes include a cross acceleration provision that may be triggered upon the acceleration of more than $75 million of indebtedness incurred by PSEG. Such provision does not extend to an acceleration of indebtedness by any of PSEG's subsidiaries. Power's indenture includes a cross acceleration provision similar to that described above for PSEG's existing notes except that such provision may be triggered upon the acceleration of more than $50 million of indebtedness incurred by Power or any of its subsidiaries. Such provision does not cross accelerate to PSEG, any of PSEG's subsidiaries (other than Power and its subsidiaries), PSE&G or any of PSE&G's subsidiaries.
Ratings Triggers
Our debt indentures and credit agreements do not contain any material "ratings triggers" that would cause an acceleration of the required interest and principal payments in the event of a ratings downgrade. However, in the event of a downgrade, any one or more of the affected companies may be subject to increased interest costs on certain bank debt and certain collateral requirements. In the event that we are not able to affirm representations and warranties on credit agreements, lenders would not be required to make loans.
In accordance with BPU requirements under the BGS contracts, PSE&G is required to maintain an investment grade credit rating. If PSE&G were to lose its investment grade rating, it would be required to file a plan to assure continued payment for the BGS requirements of its customers.
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 to below investment grade by S&P or Moody's at today's market prices.
Common Stock Dividends

	Years Ended December 31,		
Dividend Payments on Common Stock	2018	2017	2016
Per Share	$1.80	$1.72	$1.64
in Millions	$910	$870	$830

On February 19, 2019, our Board of Directors approved a $0.47 per share common stock dividend for the first quarter of 2019. This reflects an indicative annual dividend rate of $1.88 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. For additional information related to cash dividends on our common stock, see Item 8. Note 23. Earnings Per Share (EPS) and

Dividends.

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

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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.

	Moody's (A)	S&P (B)
PSEG		
Outlook	Stable	Stable
Senior Notes	Baa1	BBB
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 (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.

Other Comprehensive Income

For the year ended December 31, 2018, we had Other Comprehensive Income of $28 million on a consolidated basis. Other Comprehensive Income was due primarily to an increase of $46 million related to pension and other postretirement benefits, partially offset by $17 million of net unrealized losses related to Available-for-Sale Securities and $1 million of unrealized losses on derivative contracts accounted for as hedges. See Item 8. Note 22. Accumulated Other Comprehensive Income (Loss), Net of Tax for additional information.

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CAPITAL REQUIREMENTS

We expect 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 AFUDC and Interest Capitalized During Construction for PSE&G and Power, respectively. These amounts are subject to change, based on various factors. Amounts shown below for GSMP and Solar/Energy Efficiency programs are for currently approved programs. We intend to continue to invest in infrastructure modernization and will seek to extend these and related programs as appropriate. We will also continue to approach potential growth investments for Power opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

	2019	2020	2021
		Millions	
PSE&G:			
Transmission	$1,350	$ 1,145	$875
Distribution	740	820	820
Gas System Modernization Program	420	455	435
Solar/Energy Efficiency	70	55	5
Total PSE&G	$2,580	$ 2,475	$2,135
Power:			
Baseline	$165	$ 130	$150
Growth Opportunities	225	20	15
Other	5	15	20
Total Power	$395	$ 165	$185
Other	$40	$ 55	$40
Total PSEG	$3,015	$ 2,695	$2,360

PSE&G

PSE&G's projections for future capital expenditures include material additions and replacements to its T&D 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.
- Distribution—investments for new business, reliability improvements, modernization and replacement of equipment that has reached the end of its useful life.
- 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 June 2018, we filed for our ES II, a proposed five-year $2.5 billion program to harden, modernize and make our electric and gas distribution systems more resilient. The size and duration of ES II, as well as certain other elements of the program, are subject to BPU approval.

In October 2018, we filed our proposed CEF program with the BPU, a six-year estimated $3.6 billion investment program focused on achieving New Jersey's energy efficiency targets, supporting electric vehicle infrastructure, deploying energy storage, and implementing an EC program which will include installing approximately two million electric smart meters and associated infrastructure. The size and duration of the CEF program, as well as certain other elements of the program, are subject to BPU approval.

ES II and the CEF program are not included in PSE&G's projected capital expenditures in the above table.

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In 2018, PSE&G made $2,901 million of capital expenditures, primarily for T&D system reliability. This does not include expenditures for cost of removal, net of salvage, of $160 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.
- Growth Opportunities—investments associated with new construction, including BH5, and with upgrades to increase efficiency and output at combined cycle plants.
- Other—includes investments made in response to environmental, regulatory and legal mandates and other capital projects.

In 2018, Power made $815 million of capital expenditures, excluding $181 million for nuclear fuel, primarily related to various projects at Fossil and Nuclear.

Disclosures about Contractual Obligations

The following table reflects our contractual cash obligations in the respective periods in which they are due. In addition, the table summarizes anticipated debt maturities for the years shown. For additional information, see Item 8. Note 15. Debt and Credit Facilities.

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. Note 21. Income Taxes for additional information.

	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	$2,450	$750	$1,000	$700	$—
PSE&G	9,258	500	693	825	7,240
Power	2,850	44	1,356	950	500
Interest on Recourse Debt					
PSEG	152	61	72	19	—
PSE&G	5,564	342	651	609	3,962
Power	830	134	224	148	324
Operating Leases					
PSE&G	118	15	21	16	66
Power	110	11	26	22	51
Services	178	14	29	30	105
Other	5	1	3	1	—
Energy-Related Purchase Commitments					
Power	2,742	774	918	586	464
Total Contractual Cash Obligations	$24,257	$2,646	$4,993	$3,906	$12,712
Liability Payments for Uncertain Tax Positions					
PSEG	$112	$112	$—	$—	$—
PSE&G	62	62	—	—	—
Power	34	34	—	—	—

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OFF-BALANCE SHEET ARRANGEMENTS

PSEG and Power issue guarantees, primarily in conjunction with certain of Power's energy contracts. See Item 8. Note 14. Commitments and Contingent Liabilities for further discussion.

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. Note 8. Long-Term Investments and Note 9. 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 the lessee in a Bankruptcy Court proceeding, 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 accounting principles generally accepted in the United States (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 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	2018	2017	2016
Discount Rate	4.41 %	3.73 %	4.29 %
Expected Rate of Return on Plan Assets	7.80 %	7.80 %	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.

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, long-term inflation assumptions and a premium for active management.

Based on the above assumptions, we have estimated a net periodic pension expense in 2019 of approximately $49 million, or $11 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 fourteen years.

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Effect if Different Assumptions Used: As part of the business planning process, we have modeled future costs assuming a 7.80% expected rate of return and a 4.41% discount rate for 2019 expense. 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.

Assumption	% Change	Impact on Pension Benefit Obligation as of December 31, 2018	Increase to Pension Expense in 2019	Increase to Pension Expense, net of Amounts Capitalized in 2019
		Millions		
Discount Rate	(1)%	$ 746	$ 39	$ 32
Expected Rate of Return on Plan Assets	(1)%	N/A	$ 50	$ 50

See Item 7A. Quantitative and Qualitative Disclosures About Market Risk for additional information.
Derivative Instruments
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 executing derivative transactions. Derivative instruments are used 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.
Current accounting guidance requires us to recognize all derivatives on the balance sheet at their fair value, except for derivatives that qualify for and are designated as normal purchases and normal sales contracts.
Assumptions and Approach Used: In general, the fair value of our derivative instruments is determined primarily by end of day clearing market prices from an exchange, such as NYMEX, Intercontinental Exchange and Nodal Exchange, or auction prices. Fair values of other energy contracts may be based on broker quotes.
For a small number of contracts where limited observable inputs or pricing information are available, modeling techniques are employed in determination of their fair value using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable.
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, or are not designated as, either cash flow or fair value hedge 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. Note 1. Organization, Basis of Presentation and Significant Accounting Policies, Note 17. Financial Risk Management Activities and Note 18. Fair Value Measurements.
Long-Lived Assets

Management evaluates long-lived assets for impairment and reassesses the reasonableness of their related estimated useful lives whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate, counterparty credit worthiness, or market conditions, could potentially indicate an asset’s or asset group’s carrying amount may not be recoverable or an asset’s probability of operating through its estimated remaining useful life changes.

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. Significant inputs include forward power prices, fuel costs, dispatch rates, other operating and capital expenditures and the cost of borrowing.

In addition, long-lived assets are depreciated under the straight-line method based on estimated useful lives. An asset's operating useful life is generally based upon operational experience with similar asset types and other non-operational factors. In the ordinary course, management, together with an asset's co-owners in the case of certain of our jointly-owned assets, makes a number of decisions that impact the operation of our generation assets beyond the current year. These decisions may have a direct impact on the estimated remaining useful lives of our assets and will be influenced by the financial outlook of the assets, including future market conditions such as forward energy and capacity prices, operating and capital investment costs and any state or federal legislation and regulations, among other items.

The assumptions used by management incorporate inherent uncertainties that are at times difficult to predict and could result in impairment charges or accelerated depreciation in future periods if actual results materially differ from the estimated assumptions utilized in our forecasts.

Effect if Different Assumptions Used: The above cash flow tests, and fair value estimates and estimated remaining useful lives may be impacted by a change in the assumptions noted above and could significantly impact the outcome, triggering additional impairment tests, write-offs or accelerated depreciation. For additional information on the potential impacts on our future financial statements that may be caused by a change in useful lives of certain of our generating assets. See Item 8. Note 4. Early Plant Retirements and Note 6. Property, Plant and Equipment and Jointly-Owned Facilities.

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. Note 8. Long-Term Investments and Note 9. Financing Receivables.

Assumptions and Approach Used: Residual values are the estimated values of the leased assets at the end of the respective lease per the original lease terms, net of any subsequent impairments. 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 O&M expenses,
- discount rates, and
- the current estimated economic viability of the plants after the end of the base lease term.

A review of the residual valuations is performed at least annually for each plant subject to lease using specific assumptions tailored to each plant. Those 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, 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 $80 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 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 with the corresponding expense recorded in O&M.

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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 2018. When we revise any assumptions used to calculate fair values of existing AROs, we adjust the ARO balance and corresponding long-lived asset which generally 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 93% of Power's total AROs as of December 31, 2018. 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:
- financial feasibility and impacts on potential early shutdown,
- license renewals,
- SAFESTOR alternative, which assumes the nuclear facility can be safely stored and subsequently decommissioned in a period within 60 years after operations,
- DECON alternative, which assumes decommissioning activities begin after operations, 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. Had the following assumptions been applied, our estimates of the approximate impacts on the Nuclear ARO as of December 31, 2018 are as follows:
- A decrease of 1% in the discount rate would result in a $32 million increase in the Nuclear ARO.
- An increase of 1% in the inflation rate would result in a $260 million increase in the Nuclear ARO.
- If we were not reimbursed by the federal government for spent fuel costs as prescribed under the Nuclear Waste Policy Act, the Nuclear ARO would increase by $346 million.
- If we would elect or be required to decommission under a DECON alternative at Salem and Hope Creek, the Nuclear ARO would increase by $635 million.
- If Power were to increase its early shutdown probability to 100% and retire Hope Creek and Salem starting in the Fall of 2019, which is significantly earlier than the end of their current license periods, the Nuclear ARO would increase by $314 million. For additional information, see Item 8. Note 4. Early Plant Retirements.

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

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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 Regulatory 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
- 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. Note 7. 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. 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.

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	MTM VaR Millions			
Years Ended December 31,	2018		2017	
95% Confidence Level, Loss could exceed VaR one day in 20 days				
Period End	$	21	$	39
Average for the Period	$	14	$	10
High	$	46	$	39
Low	$	6	$	5
99.5% Confidence Level, Loss could exceed VaR one day in 200 days				
Period End	$	32	$	60
Average for the Period	$	22	$	15
High	$	72	$	60
Low	$	9	$	8

See Item 8. Note 17. 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, 2018, a hypothetical 10% increase in market interest rates would result in

- $2 million of additional annual interest costs related to both the current and long-term portion of long-term debt, and
- a $426 million decrease in the fair value of debt, including an $18 million decrease at PSEG, a $354 million decrease at PSE&G and a $54 million decrease at Power.

Debt and Equity Securities

We have $5.6 billion of assets in a trust for our pension and OPEB plans. 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. As of December 31, 2018, the portfolio included $900 million of equity securities and $978 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, 2018, a hypothetical 10% change in the equity market would impact the value of the equity securities in the NDT Fund by approximately $90 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 5.87 years and a yield of 3.28%. The portfolio’s value will appreciate or depreciate by the duration with a 1% change in interest rates. As of December 31, 2018, a hypothetical 1% increase in interest rates would result in a decline in the market value for the fixed income portfolio of approximately $57 million.

Credit Risk

See Item 8. Note 17. 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 $186 million, net of deferred taxes of $354 million, as of December 31, 2018. These leveraged leases are concentrated in the U.S. energy industry. See Item 8. Note 9. Financing Receivables for counterparties’ credit ratings and other information. The credit exposure to the lessees is partially

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mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Credit enhancements include affiliate guarantees and partial collateralization of the lessee with non-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 amount and timing of any potential reduction in net tax benefits generated by Energy Holdings' portfolio of investments is dependent upon a number of factors including, but not limited to, the time of a potential foreclosure, 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.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Public Service Enterprise Group Incorporated
Newark, New Jersey

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Public Service Enterprise Group Incorporated and subsidiaries (the “Company”) as of December 31, 2018 and 2017, 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, 2018, the related notes and the consolidated financial statement schedule listed in the Index at Item 15(B)(a) (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2019

We have served as the Company's auditor since 1934.

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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

Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of Public Service Electric and Gas Company and subsidiaries (the “Company”) as of December 31, 2018 and 2017, 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, 2018, the related notes and the consolidated financial statement schedule listed in the Index at Item 15(B)(b) (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting 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.
Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2019

We have served as the Company's auditor since 1934.

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

Opinion on the Financial Statements
We have audited the accompanying consolidated balance sheets of PSEG Power LLC and subsidiaries (the “Company”) as of December 31, 2018 and 2017, 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, 2018, the related notes and the consolidated financial statement schedule listed in the Index at Item 15(B)(c) (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion
These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.
We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting 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.
Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Parsippany, New Jersey
February 27, 2019

We have served as the Company's auditor since 2000.

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

	Years Ended December 31,		
	2018	2017	2016
OPERATING REVENUES	$9,696	$9,094	$8,966
OPERATING EXPENSES			
Energy Costs	3,225	2,778	2,901
Operation and Maintenance	3,015	2,901	2,991
Depreciation and Amortization	1,158	1,986	1,476
Total Operating Expenses	7,398	7,665	7,368
OPERATING INCOME	2,298	1,429	1,598
Income from Equity Method Investments	15	14	11
Net Gains (Losses) on Trust Investments	(143)	134	(6)
Other Income (Deductions)	85	82	102
Non-Operating Pension and OPEB Credits (Costs)	76	—	(22)
Interest Expense	(476)	(391)	(385)
INCOME BEFORE INCOME TAXES	1,855	1,268	1,298
Income Tax Benefit (Expense)	(417)	306	(411)
NET INCOME	$1,438	$1,574	$887
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING:			
BASIC	504	505	505
DILUTED	507	507	508
NET INCOME PER SHARE:			
BASIC	$2.85	$3.12	$1.76
DILUTED	$2.83	$3.10	$1.75

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2018	2017	2016
NET INCOME	$1,438	$1,574	$887
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $11, $(37) and $(41) for the years ended 2018, 2017 and 2016, respectively	(17)	44	42
Unrealized Gains (Losses) on Cash Flow Hedges, net of tax (expense) benefit of $1, $1 and $(1) for the years ended 2018, 2017 and 2016, respectively	(1)	(2)	2
Pension/Other Postretirement Benefit Costs (OPEB) adjustment, net of tax (expense) benefit of $(18), $(4) and $8 for the years ended 2018, 2017 and 2016, respectively	46	(8)	(12)
Other Comprehensive Income (Loss), net of tax	28	34	32
COMPREHENSIVE INCOME	$1,466	$1,608	$919

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2018	December 31, 2017
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$177	$313
Accounts Receivable, net of allowances of $63 in 2018 and $59 in 2017	1,435	1,348
Tax Receivable	242	127
Unbilled Revenues	240	296
Fuel	331	289
Materials and Supplies, net	571	577
Prepayments	94	118
Derivative Contracts	11	29
Regulatory Assets	389	211
Other	17	4
Total Current Assets	3,507	3,312
PROPERTY, PLANT AND EQUIPMENT	44,201	41,231
Less: Accumulated Depreciation and Amortization	(9,838)	(9,434)
Net Property, Plant and Equipment	34,363	31,797
NONCURRENT ASSETS		
Regulatory Assets	3,399	3,222
Long-Term Investments	896	932
Nuclear Decommissioning Trust (NDT) Fund	1,878	2,133
Long-Term Receivable of VIEs	624	686
Rabbi Trust Fund	224	231
Goodwill	16	16
Other Intangibles	143	114
Derivative Contracts	1	7
Other	275	266
Total Noncurrent Assets	7,456	7,607
TOTAL ASSETS	$45,326	$42,716

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2018	2017
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$1,294	$1,000
Commercial Paper and Loans	1,016	542
Accounts Payable	1,451	1,694
Derivative Contracts	11	16
Accrued Interest	110	103
Accrued Taxes	26	48
Clean Energy Program	143	128
Obligation to Return Cash Collateral	136	129
Regulatory Liabilities	311	47
Other	437	461
Total Current Liabilities	4,935	4,168
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	5,713	5,240
Regulatory Liabilities	3,221	2,948
Asset Retirement Obligations	1,063	1,024
Other Postretirement Benefit (OPEB) Costs	704	1,455
OPEB Costs of Servco	501	542
Accrued Pension Costs	791	537
Accrued Pension Costs of Servco	109	129
Environmental Costs	327	357
Derivative Contracts	4	5
Long-Term Accrued Taxes	181	175
Other	232	221
Total Noncurrent Liabilities	12,846	12,633
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 14)		
CAPITALIZATION		
LONG-TERM DEBT	13,168	12,068
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000 shares; issued, 2018 and 2017— 534 shares	4,980	4,961
Treasury Stock, at cost, 2018—30 shares; 2017—29 shares	(808)	(763)
Retained Earnings	10,582	9,878
Accumulated Other Comprehensive Loss	(377)	(229)
Total Stockholders' Equity	14,377	13,847
Total Capitalization	27,545	25,915
TOTAL LIABILITIES AND CAPITALIZATION	$45,326	$42,716

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$1,438	$1,574	$887
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,158	1,986	1,476
Amortization of Nuclear Fuel	187	199	203
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	97	103	109
Impairment Costs for Early Plant Retirements	—	—	102
Provision for Deferred Income Taxes (Other than Leases) and ITC	568	(167)	474
Non-Cash Employee Benefit Plan Costs	70	89	127
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(149)	(159)	(6)
Gain on Sale of Hudson and Mercer Units	(54)	—	—
Net (Gain) Loss on Lease Investments	5	48	92
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	116	188	183
Net Change in Regulatory Assets and Liabilities	(153)	(188)	(138)
Cost of Removal	(160)	(107)	(131)
Net (Gains) Losses and (Income) Expense from NDT Fund	98	(156)	(26)
Net Change in Certain Current Assets and Liabilities			
Tax Receivable	17	65	303
Accrued Taxes	(69)	16	3
Margin Deposit	(247)	(90)	(76)
Other Current Assets and Liabilities	70	(72)	(179)
Employee Benefit Plan Funding and Related Payments	(101)	(81)	(103)
Other	22	12	13
Net Cash Provided By (Used In) Operating Activities	2,913	3,260	3,313
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(3,912)	(4,190)	(4,199)
Purchase of Emissions Allowances and RECs	(146)	(117)	(99)
Proceeds from Sales of Trust Investments	1,501	2,319	824
Purchases of Trust Investments	(1,473)	(2,340)	(856)
Other	114	72	82
Net Cash Provided By (Used In) Investing Activities	(3,916)	(4,256)	(4,248)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Commercial Paper and Loans	474	154	24
Issuance of Long-Term Debt	2,750	2,175	2,675
Redemption of Long-Term Debt	(1,350)	(500)	(824)
Cash Dividends Paid on Common Stock	(910)	(870)	(830)
Other	(77)	(74)	(79)
Net Cash Provided By (Used In) Financing Activities	887	885	966
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(116)	(111)	31
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	315	426	395
Cash, Cash Equivalents and Restricted Cash at End of Period	$199	$315	$426

Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$99	$(8)	$(245)
Interest Paid, Net of Amounts Capitalized	$454	$377	$365
Accrued Property, Plant and Equipment Expenditures	$517	$722	$664

See Notes to Consolidated Financial Statements.

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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, 2016	534	$4,915	(28)	$(671)	$9,117	$(295)	$1	$13,067
Net Income	—	—	—	—	887	—	—	887
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(34)	—	—	—	—	—	32	—	32
Comprehensive Income								919
Cash Dividends at $1.64 per share on Common Stock	—	—	—	—	(830)	—	—	(830)
Other	—	21	(1)	(46)	—	—	(1)	(26)
Balance as of December 31, 2016	534	$4,936	(29)	$(717)	$9,174	$(263)	$—	$13,130
Net Income	—	—	—	—	1,574	—	—	1,574
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(40)	—	—	—	—	—	34	—	34
Comprehensive Income								1,608
Cash Dividends at $1.72 per share on Common Stock	—	—	—	—	(870)	—	—	(870)
Other	—	25	—	(46)	—	—	—	(21)
Balance as of December 31, 2017	534	$4,961	(29)	$(763)	$9,878	$(229)	$—	$13,847
Net Income	—	—	—	—	1,438	—	—	1,438
Cumulative Effect Adjustment to Reclassify Unrealized Net Gains on Equity Investments	—	—	—	—	176	(176)	—	—
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(6)	—	—	—	—	—	28	—	28
Comprehensive Income								1,466
Cash Dividends at $1.80 per share on Common Stock	—	—	—	—	(910)	—	—	(910)
Other	—	19	(1)	(45)	—	—	—	(26)
Balance as of December 31, 2018	534	$4,980	(30)	$(808)	$10,582	$(377)	$—	$14,377

See Notes to Consolidated Financial Statements.

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2018	2017	2016
OPERATING REVENUES	$6,471	$6,324	$6,303
OPERATING EXPENSES			
Energy Costs	2,520	2,421	2,644
Operation and Maintenance	1,575	1,458	1,465
Depreciation and Amortization	770	685	565
Total Operating Expenses	4,865	4,564	4,674
OPERATING INCOME	1,606	1,760	1,629
Net Gains (Losses) on Trust Investments	(1)	2	—
Other Income (Deductions)	80	85	79
Non-Operating Pension and OPEB Credits (Costs)	59	(8)	(15)
Interest Expense	(333)	(303)	(289)
INCOME BEFORE INCOME TAXES	1,411	1,536	1,404
Income Tax Expense	(344)	(563)	(515)
NET INCOME	$1,067	$973	$889

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

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

	Years Ended December 31,		
	2018	2017	2016
NET INCOME	$1,067	$973	$889
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $1, $0 and $0 for the years ended 2018, 2017 and 2016, respectively	(1)	(1)	—
COMPREHENSIVE INCOME	$1,066	$972	$889

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2018	2017
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$39	$242
Accounts Receivable, net of allowances of $63 in 2018 and $59 in 2017	879	882
Tax Receivable	20	—
Accounts Receivable—Affiliated Companies	123	—
Unbilled Revenues	240	296
Materials and Supplies	196	197
Prepayments	10	44
Regulatory Assets	389	211
Other	11	4
Total Current Assets	1,907	1,876
PROPERTY, PLANT AND EQUIPMENT	31,633	29,117
Less: Accumulated Depreciation and Amortization	(6,277)	(6,101)
Net Property, Plant and Equipment	25,356	23,016
NONCURRENT ASSETS		
Regulatory Assets	3,399	3,222
Long-Term Investments	270	280
Rabbi Trust Fund	45	46
Other	132	114
Total Noncurrent Assets	3,846	3,662
TOTAL ASSETS	$31,109	$28,554

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2018	2017
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$500	$750
Commercial Paper and Loans	272	—
Accounts Payable	713	728
Accounts Payable—Affiliated Companies	321	340
Accrued Interest	84	78
Clean Energy Program	143	128
Obligation to Return Cash Collateral	136	129
Regulatory Liabilities	311	47
Other	345	311
Total Current Liabilities	2,825	2,511
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	3,830	3,391
OPEB Costs	486	1,103
Accrued Pension Costs	400	226
Regulatory Liabilities	3,221	2,948
Environmental Costs	268	283
Asset Retirement Obligations	302	212
Long-Term Accrued Taxes	69	91
Other	124	114
Total Noncurrent Liabilities	8,700	8,368
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 14)		
CAPITALIZATION		
LONG-TERM DEBT	8,684	7,841
STOCKHOLDER'S EQUITY		
Common Stock; 150 shares authorized; issued and outstanding, 2018 and 2017—132 shares	892	892
Contributed Capital	1,095	1,095
Basis Adjustment	986	986
Retained Earnings	7,928	6,861
Accumulated Other Comprehensive Loss	(1)	—
Total Stockholder's Equity	10,900	9,834
Total Capitalization	19,584	17,675
TOTAL LIABILITIES AND CAPITALIZATION	$31,109	$28,554

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

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

	Years Ended December 31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$1,067	$973	$889
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	770	685	565
Provision for Deferred Income Taxes and ITC	405	616	658
Non-Cash Employee Benefit Plan Costs	37	50	72
Cost of Removal	(160)	(107)	(131)
Net Change in Other Regulatory Assets and Liabilities	(153)	(188)	(138)
Net Change in Certain Current Assets and Liabilities			
Accounts Receivable and Unbilled Revenues	65	(106)	(84)
Materials and Supplies	1	(13)	(7)
Prepayments	14	(35)	22
Accounts Payable	64	1	(29)
Accounts Receivable/Payable—Affiliated Companies, net	(139)	101	199
Other Current Assets and Liabilities	5	15	9
Employee Benefit Plan Funding and Related Payments	(85)	(68)	(82)
Other	(38)	(86)	(47)
Net Cash Provided By (Used In) Operating Activities	1,853	1,838	1,896
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(2,896)	(2,919)	(2,816)
Proceeds from Sales of Trust Investments	20	36	22
Purchases of Trust Investments	(22)	(37)	(24)
Solar Loan Investments	(5)	7	14
Other	9	10	15
Net Cash Provided By (Used In) Investing Activities	(2,894)	(2,903)	(2,789)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net Change in Short-Term Debt	272	—	(153)
Issuance of Long-Term Debt	1,350	775	1,275
Redemption of Long-Term Debt	(750)	—	(271)
Contributed Capital	—	150	250
Other	(14)	(9)	(14)
Net Cash Provided By (Used In) Financing Activities	858	916	1,087
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(183)	(149)	194
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	244	393	199
Cash, Cash Equivalents and Restricted Cash at End of Period	$61	$244	$393
Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$94	$(104)	$(295)
Interest Paid, Net of Amounts Capitalized	$318	$294	$273
Accrued Property, Plant and Equipment Expenditures	$350	$429	$420

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

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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, 2016	$ 892	$ 695	$ 986	$ 4,999	$ 1	$ 7,573
Net Income	—	—	—	889	—	889
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	—	—
Comprehensive Income						889
Contributed Capital	—	250	—	—	—	250
Balance as of December 31, 2016	$ 892	$ 945	$ 986	$ 5,888	$ 1	$ 8,712
Net Income	—	—	—	973	—	973
Other Comprehensive Income, net of tax (expense) benefit of $0	—	—	—	—	(1)	(1)
Comprehensive Income						972
Contributed Capital	—	150	—	—	—	150
Balance as of December 31, 2017	$ 892	$ 1,095	$ 986	$ 6,861	$ —	$ 9,834
Net Income	—	—	—	1,067	—	1,067
Other Comprehensive Income, net of tax (expense) benefit of $1	—	—	—	—	(1)	(1)
Comprehensive Income						1,066
Balance as of December 31, 2018	$ 892	$ 1,095	$ 986	$ 7,928	$ (1)	$ 10,900

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

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF OPERATIONS
Millions

	Years Ended December 31,		
	2018	2017	2016
OPERATING REVENUES	$4,146	$3,860	$3,861
OPERATING EXPENSES			
Energy Costs	2,197	1,913	1,824
Operation and Maintenance	999	1,046	1,139
Depreciation and Amortization	354	1,268	881
Total Operating Expenses	3,550	4,227	3,844
OPERATING INCOME (LOSS)	596	(367)	17
Income from Equity Method Investments	15	14	11
Net Gains (Losses) on Trust Investments	(140)	125	(6)
Other Income (Deductions)	21	20	23
Non-Operating Pension and OPEB (Costs) Credits	15	8	(4)
Interest Expense	(76)	(50)	(84)
INCOME (LOSS) BEFORE INCOME TAXES	431	(250)	(43)
Income Tax Benefit (Expense)	(66)	729	61
NET INCOME	$365	$479	$18

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

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions

	Years Ended December 31,		
	2018	2017	2016
NET INCOME	$365	$479	$18
Other Comprehensive Income (Loss), net of tax			
Unrealized Gains (Losses) on Available-for-Sale Securities, net of tax (expense) benefit of $9, $(39) and $(41) for the years ended 2018, 2017 and 2016, respectively	(13)	46	42
Pension/OPEB adjustment, net of tax (expense) benefit of $(16), $(3) and $9 for the years ended 2018, 2017 and 2016, respectively	41	(7)	(13)
Other Comprehensive Income (Loss), net of tax	28	39	29
COMPREHENSIVE INCOME	$393	$518	$47

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

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2018	2017
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$22	$32
Accounts Receivable	477	380
Accounts Receivable—Affiliated Companies	274	221
Fuel	331	289
Materials and Supplies, net	373	376
Derivative Contracts	11	29
Prepayments	14	11
Other	5	3
Total Current Assets	1,507	1,341
PROPERTY, PLANT AND EQUIPMENT	12,224	11,755
Less: Accumulated Depreciation and Amortization	(3,382)	(3,159)
Net Property, Plant and Equipment	8,842	8,596
NONCURRENT ASSETS		
NDT Fund	1,878	2,133
Long-Term Investments	86	87
Goodwill	16	16
Other Intangibles	143	114
Rabbi Trust Fund	56	57
Derivative Contracts	1	7
Other	65	67
Total Noncurrent Assets	2,245	2,481
TOTAL ASSETS	$12,594	$12,418

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

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PSEG POWER LLC
CONSOLIDATED BALANCE SHEETS
Millions

	December 31, 2018	December 31, 2017
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$44	$250
Accounts Payable	498	712
Accounts Payable—Affiliated Companies	16	57
Short-Term Loan from Affiliate	193	281
Derivative Contracts	11	16
Accrued Interest	21	20
Other	59	99
Total Current Liabilities	842	1,435
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	1,619	1,406
Asset Retirement Obligations	758	810
OPEB Costs	176	283
Derivative Contracts	4	5
Accrued Pension Costs	246	184
Long-Term Accrued Taxes	76	52
Other	122	140
Total Noncurrent Liabilities	3,001	2,880
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 14)		
LONG-TERM DEBT	2,791	2,136
MEMBER'S EQUITY		
Contributed Capital	2,214	2,214
Basis Adjustment	(986)	(986)
Retained Earnings	5,051	4,911
Accumulated Other Comprehensive Loss	(319)	(172)
Total Member's Equity	5,960	5,967
TOTAL LIABILITIES AND MEMBER'S EQUITY	$12,594	$12,418

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

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PSEG POWER LLC
CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions

	Years Ended December 31,		
	2018	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	$365	$479	$18
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	354	1,268	881
Amortization of Nuclear Fuel	187	199	203
Provision for Deferred Income Taxes and ITC	206	(807)	(208)
Interest Accretion on Asset Retirement Obligation	41	30	26
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	116	188	183
Emission Allowances and Renewable Energy Credit (REC) Compliance Accrual	97	103	109
Impairment Costs for Early Plant Retirements	—	—	102
Non-Cash Employee Benefit Plan Costs	23	28	39
Gain on Sale of Hudson and Mercer Units	(54)	—	—
Net (Gains) Losses and (Income) Expense from NDT Fund	98	(156)	(26)
Net Change in Certain Current Assets and Liabilities			
Fuel, Materials and Supplies	(39)	42	31
Margin Deposit	(247)	(90)	(76)
Accounts Receivable	51	(45)	(71)
Accounts Payable	(13)	39	(22)
Accounts Receivable/Payable—Affiliated Companies, net	(56)	(2)	6
Other Current Assets and Liabilities	(40)	10	10
Employee Benefit Plan Funding and Related Payments	(9)	(7)	(13)
Other	4	47	63
Net Cash Provided By (Used In) Operating Activities	1,084	1,326	1,255
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Property, Plant and Equipment	(996)	(1,231)	(1,343)
Purchase of Emissions Allowances and RECs	(146)	(117)	(99)
Proceeds from Sales of Trust Investments	1,423	2,182	739
Purchases of Trust Investments	(1,392)	(2,199)	(766)
Short-Term Loan—Affiliated Company	—	87	276
Other	60	46	46
Net Cash Provided By (Used In) Investing Activities	(1,051)	(1,232)	(1,147)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of Long-Term Debt	700	—	700
Cash Dividend Paid	(400)	(350)	(250)
Redemption of Long-Term Debt	(250)	—	(553)
Short-Term Loan—Affiliated Company	(88)	281	—
Other	(5)	(4)	(6)
Net Cash Provided By (Used In) Financing Activities	(43)	(73)	(109)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(10)	21	(1)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	32	11	12
Cash, Cash Equivalents and Restricted Cash at End of Period	$22	$32	$11

Supplemental Disclosure of Cash Flow Information:			
Income Taxes Paid (Received)	$(92)	$77	$50
Interest Paid, Net of Amounts Capitalized	$73	$48	$81
Accrued Property, Plant and Equipment Expenditures	$167	$293	$244

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

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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, 2016	$ 2,214	$ (986)	$ 5,014	$ (240)	$ 6,002
Net Income	—	—	18	—	18
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(32)	—	—	—	29	29
Comprehensive Income					47
Cash Dividends Paid	—	—	(250)	—	(250)
Balance as of December 31, 2016	$ 2,214	$ (986)	$ 4,782	$ (211)	$ 5,799
Net Income	—	—	479	—	479
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(42)	—	—	—	39	39
Comprehensive Income					518
Cash Dividends Paid	—	—	(350)	—	(350)
Balance as of December 31, 2017	$ 2,214	$ (986)	$ 4,911	$ (172)	$ 5,967
Net Income	—	—	365	—	365
Cumulative Effect Adjustment to Reclassify Unrealized Net Gains on Equity Investments	—	—	175	(175)	—
Other Comprehensive Income (Loss), net of tax (expense) benefit of $(7)	—	—	—	28	28
Comprehensive Income					393
Cash Dividends Paid	—	—	(400)	—	(400)
Balance as of December 31, 2018	$ 2,214	$ (986)	$ 5,051	$ (319)	$ 5,960

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

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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 regulated solar generation projects and energy efficiency and related programs in New Jersey, which are regulated by the BPU.
- PSEG Power LLC (Power)—which is a multi-regional energy supply company that integrates the operations of its merchant nuclear and fossil generating assets with its power marketing businesses and fuel supply functions through competitive energy sales in well-developed energy markets primarily in the Northeast and Mid-Atlantic United States through its principal direct wholly owned subsidiaries. In addition, Power owns and operates solar generation in various states. 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 Long Island LLC (PSEG LI), which operates the Long Island Power Authority's (LIPA) electric transmission and distribution (T&D) system under an Operations Services Agreement (OSA); PSEG Energy Holdings L.L.C. (Energy Holdings), which primarily has investments in leveraged leases; 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 5. Variable Interest Entity. 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 significant 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 T&D businesses continue to meet the accounting requirements for rate-regulated entities. For additional information, see Note 7. Regulatory Assets and Liabilities.

Cash, Cash Equivalents and Restricted Cash

Cash equivalents consist of short-term, highly liquid investments with original maturities of three months or less. Restricted cash consists primarily of deposits received related to various construction projects at PSE&G.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The following provides a reconciliation of cash, cash equivalents and restricted cash reported within the Consolidated Balance Sheets that sum to the total of the same such amounts for the beginning (December 31, 2017) and ending periods shown in the Consolidated Statements of Cash Flows for the year ended December 31, 2018.

	PSE&G	Power	Other (A)	Consolidated
	Millions			
As of December 31, 2017				
Cash and Cash Equivalents	$242	$ 32	$39	$ 313
Restricted Cash in Other Current Assets	—	—	—	—
Restricted Cash in Other Noncurrent Assets	2	—	—	2
Cash, Cash Equivalents and Restricted Cash	$244	$ 32	$39	$ 315
As of December 31, 2018				
Cash and Cash Equivalents	$39	$ 22	$116	$ 177
Restricted Cash in Other Current Assets	8	—	—	8
Restricted Cash in Other Noncurrent Assets	14	—	—	14
Cash, Cash Equivalents and Restricted Cash	$61	$ 22	$116	$ 199

(A) Includes amounts applicable to PSEG (parent corporation), Energy Holdings and Services.

Derivative Instruments

Each company uses derivative instruments to manage risk pursuant to its business plans and prudent practices.
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, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power's expected generation. Changes in the fair market value of the derivative contracts are recorded in earnings.
Determining whether a contract qualifies as a derivative requires that management exercise significant judgment, including assessing the contract's market liquidity. PSEG has determined that contracts to purchase and sell certain products do not meet the definition of a derivative under the current authoritative guidance since they do not provide for net settlement, or the markets are not sufficiently liquid to conclude that physical forward contracts are readily convertible to cash.
Under current authoritative guidance, all derivatives are recognized on the balance sheet at their fair value, except for derivatives that are designated as normal purchases and normal sales (NPNS). Further, derivatives that qualify for hedge accounting can be designated as fair value or cash flow hedges. For fair value hedges, changes in fair values for both the derivative and the underlying hedged exposure are recognized in earnings each period.
Certain offsetting derivative assets and liabilities 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, these positions are offset on the Consolidated Balance Sheets of Power and PSEG.
For cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the hedged cash flows of the underlying exposure is deferred 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 NPNS, changes in fair value are recorded in current period earnings. PSEG does not currently elect fair value or cash flow

hedge accounting on its commodity derivative positions.

Contracts that qualify for, and are designated, as NPNS are accounted for upon settlement. Contracts which qualify for NPNS are contracts for which physical delivery is probable, they will not be financially settled, and the quantities under contract are expected to be used or sold in the normal course of business over a reasonable period of time.

For additional information regarding derivative financial instruments, see Note 17. 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

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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 NPNS. See Note 17. 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 electricity 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 monthly 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 5. Variable Interest Entity for further information.

The majority of Energy Holdings' revenues relate to its investments in leveraged leases. Income on leveraged leases is recognized by a method which produces a constant rate of return on the outstanding net investment in the lease, net of the related deferred tax liability, in the years in which the net investment is positive. Any gains or losses incurred as a result of a lease termination are recorded as revenues as these events occur in the ordinary course of business of managing the investment portfolio.

For additional information regarding Revenues, see Note 3. Revenues.

Depreciation and Amortization (D&A)

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:

	2018 Avg Rate	2017 Avg Rate	2016 Avg Rate
Electric Transmission	2.42 %	2.41 %	2.39 %
Electric Distribution	2.51 %	2.51 %	2.49 %
Gas Distribution	1.61 %	1.63 %	1.63 %

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—30 years to 67 years
- nuclear generation assets—approximately 60 years
- pumped storage facilities—76 years
- solar assets—25 years

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, 2018, 2017 and 2016 were as follows:

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

	AFUDC/IDC Capitalized								
	2018			2017			2016		
	Millions	Avg Rate		Millions	Avg Rate		Millions	Avg Rate	
PSE&G	$70	7.74	%	$73	7.42	%	$66	7.81	%
Power	$67	4.60	%	$78	4.60	%	$54	4.87	%

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 on a separate return basis 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 21. Income Taxes for further discussion.

Impairment of Long-Lived Assets and Leveraged Leases

Management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate, counterparty credit worthiness or market conditions, including prolonged periods of adverse commodity and capacity prices or a current expectation that a long-lived asset will be sold or disposed of significantly before the end of its previously estimated useful life, 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. See Note 4. Early Plant Retirements for more information.

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 and meet the NPNS scope exception. 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).

Energy Holdings' leveraged leases are comprised of Lease Receivables (net of non-recourse debt), the estimated residual value of leased assets, and unearned and deferred income. Residual values are the estimated values of the leased assets at the end of the respective lease per the original lease terms, net of any subsequent impairments. A review of the residual valuations, which are calculated by discounting the cash flows related to the leased assets after the lease term, is performed at least annually for each plant subject to lease using specific assumptions tailored to each plant. Those valuations are compared to the recorded residual values to determine if an impairment is warranted.

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 initial 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, improve 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. Power also capitalizes spare parts that meet specific criteria. Capitalized spares are depreciated over the remaining lives of their associated assets.

Trust Investments

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.

Effective January 1, 2018, unrealized gains and losses on equity security investments are recorded in Net Income instead of Other Comprehensive Income (Loss). The debt securities continue to be classified as available-for-sale with the unrealized gains and losses recorded as a component of Accumulated Other Comprehensive Income (Loss). Realized gains and losses on both equity and available-for-sale debt security investments are recorded in earnings and are included with the unrealized gains and losses on equity securities in Net Gains (Losses) on Trust Investments. Other-than-temporary impairments on NDT and Rabbi Trust securities are also included in Net Gains (Losses) on Trust Investments. See Note 10. Trust Investments 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.

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

See Note 13. Pension, Other Postretirement Benefits (OPEB) and Savings Plan 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 preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Note 2. Recent Accounting Standards

New Standards Adopted in 2018

Revenue from Contracts With Customers—Accounting Standard Update (ASU) 2014-09, updated by ASUs 2015-14, 2016-08, 2016-10, 2016-12, 2016-20, 2017-13, 2017-14

This accounting standard, and related updates, were adopted on January 1, 2018 using the full retrospective transition method. There was no effect on Net Income as a result of adoption. However, certain retrospective adjustments were recorded in accordance with the new standard. At PSE&G, retrospective adjustments increased Operating Revenues by $90 million and $82 million, Energy Costs by $58 million and $77 million and O&M Expense by $32 million and $5 million for the years ended December 31, 2017 and 2016, respectively. At Power, retrospective adjustments reduced Operating Revenues and Energy Costs by $70 million and $162 million for the years ended December 31, 2017 and 2016, respectively. For disclosure requirements under this standard, including Nature of Goods and Services, Disaggregation of Revenues, and Remaining Performance Obligations under Fixed Consideration Contracts, see Note 3. Revenues.

Recognition and Measurement of Financial Assets and Financial Liabilities—ASU 2016-01

Power maintains an external master trust fund to provide for the costs of decommissioning upon termination of operations of its nuclear facilities. In addition, PSEG maintains a grantor trust which was established to meet the obligations related to its non-qualified pension plans and deferred compensation plans, commonly referred to as a "Rabbi Trust."

This accounting standard was adopted on January 1, 2018. Under the new guidance, equity investments in Power's NDT and PSEG's Rabbi Trust Funds are measured at fair value with the unrealized gains and losses now recognized through Net Income instead of Other Comprehensive Income (Loss). A cumulative effect adjustment was made to reclassify the net unrealized gains related to equity investments of $342 million ($176 million, net of tax) from Accumulated Other Comprehensive Income to Retained Earnings on January 1, 2018. See Note 22. Accumulated Other Comprehensive Income (Loss), Net of Tax and Note 10. Trust Investments for further discussion.

Statement of Cash Flows: Classification of Certain Cash Receipts and Cash Payments—ASU 2016-15

This accounting standard reduces the diversity in practice in how certain cash receipts and cash payments are presented and classified in the Statement of Cash Flows.

PSEG adopted this standard on January 1, 2018 using a retrospective transition method and had no changes in its presentation of its Statement of Cash Flows for each period presented.

Statement of Cash Flows: Restricted Cash—ASU 2016-18

This accounting standard was adopted on January 1, 2018. PSEG will continue the current balance sheet classification of restricted cash or restricted cash equivalents. PSEG has provided a reconciliation of cash and cash equivalents and restricted cash or restricted cash equivalents and has included a description of these amounts in Note 1. Organization, Basis of Presentation and Significant Accounting Policies. The effect of adoption on the December 31, 2018 Consolidated Statements of Cash Flows was immaterial.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (OPEB)—ASU 2017-07

This accounting standard was adopted on January 1, 2018. Under the new guidance, entities are required to report the service cost component in the same line item or items as other compensation costs arising from services rendered by their employees during the period. The other components of net benefit cost are required to be presented in the Statement of Operations separately from the service cost component after Operating Income. Additionally, only the service cost component is eligible for capitalization, when applicable. As a result of adopting this standard, PSE&G reduced its charge to expense for the year ended December 31, 2018 by approximately $58 million. The Consolidated Statements of Operations were recast to show retrospective adjustments of the non-service cost components of net benefit credits (costs) of $(8) million and $(15) million at PSE&G and $8 million and $(4) million at Power, for the years ended December 31, 2017 and 2016, respectively, from O&M Expense to a new line item after Operating Income entitled Non-Operating Pension and OPEB Credits (Costs). See Note 13. Pension, Other Postretirement Benefits (OPEB) and Savings Plan.

Stock Compensation - Scope of Modification Accounting—ASU 2017-09
This accounting standard was adopted on January 1, 2018. The standard will be applied prospectively to awards modified on or after January 1, 2018. There was no material impact on PSEG's consolidated financial statements in 2018 from adoption of this new standard.

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New Standards Issued But Not Yet Adopted

Leases—ASU 2016-02, updated by ASUs 2018-01, 2018-10, 2018-11 and 2018-20

This accounting standard, and related updates, replace existing lease accounting guidance and require lessees to recognize leases with a term greater than 12 months on the balance sheet using a right-of-use asset approach. At lease commencement, a lessee will recognize a lease asset and corresponding lease obligation. A lessee will classify its leases as either finance leases or operating leases and a lessor will classify its leases as operating leases, direct financing leases, or as sales-type leases. The standard requires additional disclosure of key information. Existing guidance related to leveraged leases does not change. Effective January 1, 2019, PSEG elected the prospective transition approach for all existing leases. There was no cumulative effect adjustment required to be recorded to Retained Earnings at adoption.

PSEG elected various practical expedients allowed by the standard, including the package of three practical expedients related to not reassessing existing or expired contracts and initial direct costs; and excluding evaluation of land easements that exist or expired before adoption that were not previously accounted for as leases.

The impact of adoption on PSEG’s Consolidated Balance Sheet was to increase its assets and liabilities by approximately $280 million. PSE&G’s assets and liabilities each increased by approximately $100 million and Power’s assets and liabilities each increased by approximately $50 million. PSEG’s adoption of this standard did not have a material impact on the Consolidated Statements of Operations or Consolidated Statements of Cash Flows of PSEG, PSE&G and Power.

Derivatives and Hedging: Targeted Improvements to Accounting for Hedging Activities—ASU 2017-12, updated by ASU 2018-16

This accounting standard’s amendments more closely align hedge accounting with companies’ risk management activities in the financial statements and ease the operational burden of applying hedge accounting.

The new guidance is effective for annual and interim periods beginning after December 15, 2018. PSEG adopted this standard on January 1, 2019. The standard requires using a modified retrospective method upon adoption. PSEG analyzed the impact of this standard on its consolidated financial statements and has determined that the standard could enable PSEG to enter into certain transactions that can be deemed hedges that previously would not have qualified. Adoption of this standard is not expected to have a material impact on PSEG’s financial statements.

Premium Amortization on Purchased Callable Debt Securities—ASU 2017-08

This accounting standard was issued to shorten the amortization period for certain callable debt securities held at a premium. Specifically, the standard requires the premium to be amortized to the earliest call date.

The standard is effective for all entities for annual periods and interim periods within those annual periods beginning after December 15, 2018. PSEG adopted this standard on January 1, 2019 on a modified retrospective basis through a cumulative effect adjustment directly to Retained Earnings as of the beginning of 2019. Adoption of this standard did not have a material impact on PSEG’s financial statements.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income—ASU 2018-02

This accounting standard affects any entity that is required to apply the provisions of the Accounting Standards Codification (ASC) topic, “Income Statement-Reporting Comprehensive Income,” and has items of Other Comprehensive Income for which the related tax effects are presented in Other Comprehensive Income as required by GAAP. Specifically, this standard allows entities to record a reclassification from Accumulated Other Comprehensive Income to Retained Earnings for stranded tax effects resulting from the recent decrease in the federal corporate income tax rate.

The standard is effective for all entities for annual periods and interim periods within those annual periods beginning after December 15, 2018. PSEG adopted this standard on January 1, 2019.

The impact of adoption on PSEG’s Consolidated Balance Sheet was to increase Retained Earnings and Accumulated Other Comprehensive Loss by approximately $81 million. Power’s Retained Earnings and Accumulated Other Comprehensive Loss increased by approximately $69 million. The impact on PSE&G’s Consolidated Balance Sheet was immaterial. PSEG’s adoption of this standard did not have a material impact on the Consolidated Statements of Operations or Consolidated Statements of Cash Flows of PSEG, PSE&G and Power.

Measurement of Credit Losses on Financial Instruments—ASU 2016-13, updated by ASU 2018-19
This accounting standard provides a new model for recognizing credit losses on financial assets carried at amortized cost. The new model requires entities to use an estimate of expected credit losses that will be recognized as an impairment allowance rather than a direct write-down of the amortized cost basis. The estimate of expected credit losses is to be based on past events, current conditions and supportable forecasts over a reasonable period. For purchased financial assets with credit deterioration, a similar model is to be used; however, the initial allowance will be added to the purchase price rather than reported as an allowance. Credit losses on available-for-sale securities should be measured in a manner similar to current GAAP; however,

this standard requires those credit losses to be presented as an allowance, rather than a write-down. This new standard also requires additional disclosures of credit quality indicators for each class of financial asset disaggregated by year of origination.

The standard is effective for annual and interim periods beginning after December 15, 2019; however, entities may adopt early beginning in the annual or interim periods after December 15, 2018. PSEG is currently analyzing the impact of this standard on its financial statements.

Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement—ASU 2018-13

This accounting standard modifies the disclosure requirements for fair value measurements. Certain current disclosure requirements relating to Level 3 fair value measurements, and transfers between Level 1 and Level 2 fair value measurements will be eliminated. The standard will also add certain other disclosure requirements for Level 3 fair value measurements.

The standard is effective for annual and interim periods beginning after December 15, 2019. Certain amendments in the standard should be applied prospectively for only the most recent interim or annual period presented in the initial fiscal year of adoption. All other amendments of the standard should be applied retrospectively to all periods presented upon their effective date. Early adoption is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract—ASU 2018-15

This accounting standard aligns the capitalization requirements for implementation costs incurred in a hosting arrangement that is a service contract with capitalization requirements for implementation costs incurred to develop or obtain internal-use software, including hosting arrangements that include an internal-use software license. The standard follows the guidance in ASC 350—Intangibles—Goodwill and Other to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The standard requires the amortization of capitalized costs to be presented in O&M Expense. In addition, the standard also adds presentation requirements for these costs in the statements of cash flows and financial position.

The standard is effective for annual and interim periods beginning after December 15, 2019. Early adoption is permitted, including adoption in any interim period. This standard should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. PSEG is currently analyzing the impact of this standard on its financial statements.

Targeted Improvements to Related Party Guidance for Variable Interest Entities (VIE)—ASU 2018-17

This accounting standard improves the VIE guidance in the area of decision-making fees. Consistent with how indirect interests held through related parties under common control are considered for determining whether a reporting entity must consolidate a VIE, indirect interests held through related parties in common control arrangements should be considered on a proportional basis for determining whether fees paid to decision makers and service providers are variable interests.

This standard is effective for annual and interim periods beginning after December 15, 2019. The standard is required to be applied retrospectively with a cumulative-effect adjustment to retained earnings at the beginning of the earliest period presented. Early adoption is permitted. PSEG is currently analyzing the impact of this standard on its financial statements.

Simplifying the Test for Goodwill Impairment—ASU 2017-04

This accounting standard requires an entity to perform its annual or interim goodwill impairment test by comparing the fair value of a reporting unit with its carrying amount. An entity should recognize an impairment charge for the amount by which the carrying amount exceeds the reporting unit's fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. Additionally, an entity should consider income tax effects from any tax deductible goodwill on the carrying amount of the reporting unit when measuring the goodwill impairment loss, if applicable.

An entity should apply this standard on a prospective basis and will be required to disclose the nature of and reason for the change in accounting principle upon transition. The new standard is effective for impairment tests for periods beginning January 1, 2020. Early adoption is permitted for interim or annual goodwill impairment tests performed on testing dates after January 1, 2017. PSEG does not expect adoption of this standard to have a material impact on its financial statements.

Disclosure Framework—Changes to the Disclosure Requirements for Defined Benefit Plans—ASU 2018-14

This accounting standard modifies the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans, including the elimination of certain current disclosure requirements. Certain other disclosure requirements related to interest crediting rates have been added and certain clarifications were made to other disclosure requirements.

The standard is effective for fiscal years ending after December 15, 2020 and early adoption is permitted. An entity should apply the amendments in this standard on a retrospective basis to all periods presented. PSEG is currently analyzing the impact of this standard on its financial statements.

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Note 3. Revenues
Nature of Goods and Services
The following is a description of principal activities by reportable segment from which PSEG, PSE&G and Power generate their revenues.
PSE&G
Revenues from Contracts with Customers
Electric and Gas Distribution and Transmission Revenues—PSE&G sells gas and electricity to customers under default commodity supply tariffs. PSE&G's regulated electric and gas default commodity supply and distribution services are separate tariffs which are satisfied as the product(s) and/or services are delivered to the customer. The electric and gas commodity and delivery tariffs are recurring contracts in effect until cancellation by the customer. Revenue is recognized over time as the service is rendered to the customer. Included in PSE&G's regulated revenues are unbilled electric and gas revenues which represent the estimated amount customers will be billed for services rendered from the most recent meter reading to the end of the respective accounting period.
PSE&G's transmission revenues are earned under a separate FERC tariff. The performance obligation of transmission service is satisfied over time as it is provided to and consumed by the customer. Revenue is recognized upon delivery of the transmission service. PSE&G's revenues from the transmission of electricity are recorded based on a FERC-approved annual formula rate mechanism. This mechanism provides for an annual filing of an estimated revenue requirement with rates effective January 1 of each year and a mechanism true-up to that estimate based on actual revenue requirements. The true-up mechanism is an alternative revenue which is outside the scope of revenue from contracts with customers.
Other Revenues from Contracts with Customers
Other revenues from contracts with customers, which are not a material source of PSE&G revenues, are generated primarily from appliance repair services and solar generation projects. The performance obligations under these contracts are satisfied and revenue is recognized as control of products is delivered or services are rendered.
Payment for services rendered and products transferred are typically due within 30 days of month of delivery.
Revenues Unrelated to Contracts with Customers
Other PSE&G revenues unrelated to contracts with customers are derived from alternative revenue mechanisms recorded pursuant to regulatory accounting guidance. These revenues, which include weather normalization, green energy program true-ups and transmission formula rate true-ups, are not a material source of PSE&G revenues.
Power
Revenues from Contracts with Customers
Electricity and Related Products—Wholesale and retail load contracts are executed in the different Independent System Operator (ISO) regions for the bundled supply of energy, capacity, renewable energy credits (RECs) and ancillary services representing Power's performance obligations. Revenue for these contracts is recognized over time as the bundled service is provided to the customer. Transaction terms generally run from several months to three years.
Power also sells to the ISOs energy and ancillary services which are separately transacted in the day-ahead or real-time energy markets. The energy and ancillary services performance obligations are typically satisfied over time as delivered and revenue is recognized accordingly. Power generally reports electricity sales and purchases conducted with those individual ISOs net on an hourly basis in either Operating Revenues or Energy Costs in its Consolidated Statements of Operations. The classification depends on the net hourly activity.
Power enters into capacity sales and capacity purchases through the ISOs. The transactions are reported on a net basis dependent on Power's monthly net sale or purchase position through the individual ISOs. The performance obligations with the ISOs are satisfied over time upon delivery of the capacity and revenue is recognized accordingly. In addition to capacity sold through the ISOs, Power sells capacity through bilateral contracts and the related revenue is reported on a gross basis and recognized over time upon delivery of the capacity.
Gas Contracts—Power sells wholesale natural gas, primarily through an index based full requirements Basic Gas Supply Service (BGSS) contract with PSE&G to meet the gas supply requirements of PSE&G's customers. The BGSS contract, which extends through March 2019, remains in effect thereafter unless terminated by either party with a

two-year notice. The performance obligation is primarily delivery of gas which is satisfied over time. Revenue is recognized as gas is delivered. Based upon the availability of natural gas, storage and pipeline capacity beyond PSE&G's daily needs, Power also sells gas and

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pipeline capacity to other counterparties under bilateral contracts. The performance obligation under these contracts is satisfied over time upon delivery of the gas or capacity, and revenue is recognized accordingly.

Other Revenues from Contracts with Customers

Power enters into bilateral contracts to sell solar power and solar RECs from its solar facilities. Contract terms range from 15 to 30 years. The performance obligations are generally solar power and RECs which are transferred to customers upon generation. Revenue is recognized upon generation of the solar power.

Power has entered into long-term contracts with LIPA for energy management and fuel procurement services. Revenue is recognized over time as services are rendered.

Revenues Unrelated to Contracts with Customers

Power's revenues unrelated to contracts with customers include electric, gas and certain energy-related transactions accounted for in accordance with Derivatives and Hedging accounting guidance. See Note 17. Financial Risk Management Activities for further discussion. Power is also a party to solar contracts that qualify as leases and are accounted for in accordance with lease accounting guidance.

Other

Revenues from Contracts with Customers

PSEG LI has a contract with LIPA which generates revenues. PSEG LI's subsidiary, Servco records costs which are recovered from LIPA and records the recovery of those costs as revenues when Servco is a principal in the transaction.

Revenues Unrelated to Contracts with Customers

Energy Holdings generates lease revenues which are recorded pursuant to lease accounting guidance.

Disaggregation of Revenues

	PSE&G	Power	Other	Eliminations	Consolidated
	Millions				
Year Ended December 31, 2018					
Revenues from Contracts with Customers					
Electric Distribution	$3,131	$—	$—	$ —	$ 3,131
Gas Distribution	1,756	—	—	(18)	1,738
Transmission	1,236	—	—	—	1,236
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	1,933	—	—	1,933
Sales to Affiliates	—	609	—	(609)	—
New York ISO	—	209	—	—	209
ISO New England	—	92	—	—	92
Gas Sales					
Third Party Sales	—	151	—	—	151
Sales to Affiliates	—	861	—	(861)	—
Other Revenues from Contracts with Customers (A)	275	44	532	(4)	847
Total Revenues from Contracts with Customers	6,398	3,899	532	(1,492)	9,337
Revenues Unrelated to Contracts with Customers (B)	73	247	39	—	359
Total Operating Revenues	$6,471	$4,146	$ 571	$ (1,492)	$ 9,696

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	PSE&G	Power	Other	Eliminations	Consolidated
	Millions				
Year Ended December 31, 2017					
Revenues from Contracts with Customers					
Electric Distribution	$3,088	$—	$—	$ —	$ 3,088
Gas Distribution	1,684	—	—	(14)	1,670
Transmission	1,222	—	—	—	1,222
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	1,199	—	—	1,199
Sales to Affiliates	—	734	—	(734)	—
New York ISO	—	181	—	—	181
ISO New England	—	39	—	—	39
Gas Sales					
Third Party Sales	—	134	—	—	134
Sales to Affiliates	—	804	—	(804)	—
Other Revenues from Contracts with Customers (A)	265	42	511	(4)	814
Total Revenues from Contracts with Customers	6,259	3,133	511	(1,556)	8,347
Revenues Unrelated to Contracts with Customers (B)	65	727	(45)	—	747
Total Operating Revenues	$6,324	$3,860	$466	$ (1,556)	$ 9,094

	PSE&G	Power	Other	Eliminations	Consolidated
	Millions				
Year Ended December 31, 2016					
Revenues from Contracts with Customers					
Electric Distribution	$3,327	$—	$—	$ —	$ 3,327
Gas Distribution	1,582	—	—	(22)	1,560
Transmission	1,084	—	—	—	1,084
Electricity and Related Product Sales					
PJM					
Third Party Sales	—	1,060	—	—	1,060
Sales to Affiliates	—	805	—	(805)	—
New York ISO	—	169	—	—	169
ISO New England	—	55	—	—	55
Gas Sales					
Third Party Sales	—	114	—	—	114
Sales to Affiliates	—	737	—	(737)	—
Other Revenues from Contracts with Customers (A)	292	35	482	(4)	805
Total Revenues from Contracts with Customers	6,285	2,975	482	(1,568)	8,174
Revenues Unrelated to Contracts with Customers (B)	18	886	(112)	—	792
Total Operating Revenues	$6,303	$3,861	$370	$ (1,568)	$ 8,966

(A) Includes primarily revenues from appliance repair services at PSE&G, solar power projects and energy management and fuel service contracts with LIPA at Power, and PSEG LI's OSA with LIPA in Other.

(B) Includes primarily alternative revenues at PSE&G, derivative contracts at Power, and lease contracts in Other. For the years ended December 31, 2018, 2017 and 2016, Other includes losses of $8 million, $77 million and $147 million, respectively, related to Energy Holdings' investments in leases. For additional information, see Note 8. Long-Term Investments.

Contract Balances

PSE&G

PSE&G does not have any material contract balances (rights to consideration for services already provided or obligations to provide services in the future for consideration already received) as of December 31, 2018 and 2017. Substantially all of

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PSE&G's accounts receivable result from contracts with customers. Allowances represented approximately seven percent and six percent of accounts receivable as of December 31, 2018 and 2017, respectively.

Power

Power generally collects consideration upon satisfaction of performance obligations, and therefore, Power had no material contract balances as of December 31, 2018 and 2017.

Power's accounts receivable include amounts resulting from contracts with customers and other contracts which are out of scope of accounting guidance for revenues from contracts with customers. The majority of these accounts receivable are subject to master netting agreements. As a result, accounts receivable resulting from contracts with customers and receivables unrelated to contracts with customers are netted within Accounts Receivable and Accounts Payable on the Consolidated Balance Sheets. In the wholesale energy markets in which Power operates, payment for services rendered and products transferred are typically due within 30 days of month of delivery. As such, there is little credit risk associated with these receivables and Power typically records no allowances.

Other

PSEG LI does not have any material contract balances as of December 31, 2018 and 2017.

Remaining Performance Obligations under Fixed Consideration Contracts

Power and PSE&G primarily record revenues as allowed by the guidance, which states that if an entity has a right to consideration from a customer in an amount that corresponds directly with the value to the customer of the entity's performance completed to date, the entity may recognize revenue in the amount to which the entity has a right to invoice. PSEG has future performance obligations under contracts with fixed consideration as follows:

Power

As stated above, capacity transactions with ISOs are reported on a net basis dependent on Power's monthly net sale or purchase position through the individual ISOs.

Capacity Payments from the PJM Reliability Pricing Model (RPM) Annual Base Residual and Incremental Auctions—The Base Residual Auction is conducted annually three years in advance of the operating period. Power expects to realize the following average capacity prices for capacity obligations to be satisfied resulting from the base and incremental auctions which have been completed:

Delivery Year	$ per MW-Day	MW Cleared
June 2018 to May 2019	$205	9,200
June 2019 to May 2020	$116	8,900
June 2020 to May 2021	$170	8,100
June 2021 to May 2022	$178	7,700

Capacity Payments from the New England ISO Forward Capacity Market—The Forward Capacity Market (FCM) Auction is conducted annually three years in advance of the operating period. The table below includes Power's cleared capacity in the FCM Auction for the Bridgeport Harbor Station 5, which cleared the 2019/2020 auction at $231/MW-day for seven years, with escalations based on the Handy-Whitman Index and the planned retirement of Bridgeport Harbor Station 3 in 2021. Power expects to realize the following average capacity prices for capacity obligations to be satisfied resulting from the FCM auctions which have been completed:

Delivery Year	$ per MW-Day	MW Cleared
June 2018 to May 2019	$314	820
June 2019 to May 2020	$231	1,330
June 2020 to May 2021	$195	1,330

June 2021 to May 2022	$192	950
June 2022 to May 2023	$231	480
June 2023 to May 2024	$231	480
June 2024 to May 2025	$231	480
June 2025 to May 2026	$231	480

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Bilateral capacity contracts—Capacity obligations pursuant to contract terms through 2029 are anticipated to result in revenues totaling $170 million.

Other

The LIPA OSA is a 12-year services contract ending in 2025 with annual fixed and incentive components. The fixed fee for the provision of services thereunder in 2018 is $64 million and could increase each year based on the change in the Consumer Price Index (CPI). The incentive for 2018 can range from zero to approximately $10 million and could increase each year thereafter based on the change in the CPI.

Note 4. Early Plant Retirements

Nuclear

In May 2018, the governor of New Jersey signed legislation, referred to as the ZEC legislation, that recognizes that nuclear power is a critical component of New Jersey's clean energy portfolio and an important element of a diverse energy generation portfolio that currently meets approximately 40 percent of New Jersey's electric power needs. The ZEC legislation creates a Zero Emission Certificate (ZEC) program to be administered by the BPU. The BPU subsequently established processes to evaluate applications by qualified nuclear plants and to review and approve changes to the New Jersey's electric distribution companies' tariffs to provide for the purchase of ZECs from selected nuclear plants and recover those ZEC payments through a non-bypassable distribution charge (ZEC charge) in the amount of $0.004 per kilowatt-hour (which is equivalent to approximately $10 per MWh in payments to selected nuclear plants). ZECs will be awarded to selected nuclear plants, if any, in April 2019 at which time ZEC revenue would commence and would continue for approximately three years. Nuclear plants receiving ZEC payments will be obligated to maintain operations, subject to exceptions specified in the ZEC legislation. The ZEC legislation requires nuclear plants to reapply for any subsequent three year periods. The ZEC payment may be adjusted by the BPU (a) at any time to offset environmental or fuel diversity payments that a selected nuclear plant may receive from another source or (b) at certain times specified in the ZEC legislation if the BPU determines that the purposes of the ZEC legislation can be achieved through a reduced charge that will nonetheless be sufficient to achieve the state's air quality and other environmental objectives by preventing the retirement of nuclear plants.

In December 2018, Power submitted applications to the BPU for the Salem 1 and 2 and Hope Creek nuclear plants. These were the only applications received by the BPU. As required, Power's three applications each included a certification pursuant to which Power confirmed that each of the Salem 1, Salem 2 and Hope Creek plants will cease operations within three years absent a material financial change. Power's submittal further attested that the nuclear plants are not expected to cover their costs and operating and market risks as defined in the ZEC legislation, absent a material financial change. As a result, absent a material financial change, Power will retire all three plants unless all of the plants receive ZECs. Power operates its nuclear plants as an interdependent fleet on a common site with shared costs and services, which allows them to achieve economies of scale. A decision to retire one nuclear plant would also adversely impact Power's ability to attract and retain qualified employees at its remaining plants. Power believes that the retirement of any individual nuclear plant would have the effect of decreasing the scale of its nuclear operations; however, the complex nature of operating nuclear plants would not decrease the attention required from management for the safe operation of the remaining nuclear operations. As a result, Power's decision to retire any nuclear plant would be made at the site level and would result in the retirement of all of these New Jersey nuclear plants.

Given the anticipated timing of the BPU's decision on which nuclear plants, if any, have been selected to receive ZECs, which is expected in April 2019, in March 2019 Power will submit to the PJM Independent Market Monitor and the PJM Office of Interconnection a request for a preliminary exception to PJM's RPM must-offer requirement with respect to Power's interest for each of the Salem 1, Salem 2 and Hope Creek plants in connection with the 2022/2023 capacity auction expected to be held in August 2019. Power will also submit a deactivation notice to the extent that its filing deadline occurs prior to the award of ZECs by the BPU. If all of the Salem and Hope Creek plants are selected to receive ZECs, the preliminary exception and requested deactivation notice, as applicable, would be withdrawn.

In the event that any of the Salem 1, Salem 2 and Hope Creek plants is not selected to receive ZEC payments in April 2019 by the BPU and do not otherwise experience a material financial change, Power will take all necessary steps to retire all of these plants at or prior to their refueling outages scheduled for the Fall 2019 in the case of Hope Creek, Spring 2020 in the case of Salem 2 and Fall 2020 in the case of Salem 1. Alternatively, if all of the Salem 1, Salem 2 and Hope Creek plants are selected to receive ZEC payments in April 2019 but the financial condition of the plants is materially adversely impacted by potential changes to the capacity market construct being considered by FERC (absent sufficient capacity revenues provided under a program approved by the BPU in accordance with a FERC authorized capacity mechanism), Power would still take all necessary steps to retire all of these plants. The costs and accounting charges associated with any such retirement, which may include, among other things, accelerated D&A or impairment charges, potential penalties associated with the early termination of capacity obligations and fuel

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contracts, accelerated asset retirement costs, severance costs, environmental remediation costs and, in certain circumstances, potential additional funding of the NDT Fund, would be material to both PSEG and Power.
The following table provides the balance sheet amounts by generating station as of December 31, 2018 for significant assets and liabilities associated with Power's owned share of its nuclear assets.

	As of December 31, 2018			
	Hope Creek	Salem	Support Facilities and Other (A)	Peach Bottom
	Millions			
Assets				
Materials and Supplies Inventory	$84	$ 65	$ —	$ 41
Nuclear Production, net of Accumulated Depreciation	635	626	197	777
Nuclear Fuel In-Service, net of Accumulated Depreciation	139	110	—	148
Construction Work in Progress (including nuclear fuel)	131	132	5	20
Total Assets	$989	$ 933	$ 202	$ 986
Liabilities				
Asset Retirement Obligation	$253	$ 240	$ —	$ 215
Total Liabilities	$253	$ 240	$ —	$ 215
Net Assets	$736	$ 693	$ 202	$ 771
NRC License Renewal Term	2046	2036/2040	N/A	2033/2034
% Owned	100 %	57 %	Various	50 %

(A) Includes Hope Creek's and Salem's shared support facilities and other nuclear development capital.

Fossil

On June 1, 2017, Power completed its previously announced retirement of the generation operations of the existing coal/gas units at the Hudson and Mercer generating stations.
In the latter half of 2016, PSEG and Power recognized pre-tax charges in Energy Costs and O&M of $62 million and $53 million, respectively, related to coal inventory adjustments, capacity penalties, materials and supplies inventory reserve adjustments for parts that cannot be used at other generating units, employee-related severance benefits costs and construction work in progress impairments, among other shutdown items. In addition to these charges, Power recognized D&A during 2016 of $571 million due to the significant shortening of the expected economic useful lives of Hudson and Mercer.
During the year ended December 31, 2017, Power recognized total D&A of $964 million for the Hudson and Mercer units to reflect the significant shortening of their expected economic useful lives. During the year ended December 31, 2017, Power recognized pre-tax charges in Energy Costs of $15 million, primarily for coal inventory lower of cost or market adjustments. Power also recognized pre-tax charges in O&M of $23 million, including shut down costs and an increase in the Asset Retirement Obligation due to settlements and changes in cash flow estimates, partially offset by changes in employee-related severance costs. During the year ended December 31, 2018, Power recognized pre-tax charges in Energy costs of $3 million for coal inventory lower of cost or market adjustments.
In December 2018, Power completed the sale of the sites of the retired Hudson and Mercer units. Power transferred all land rights and structures on the sites to a third party purchaser, along with the assumption of the environmental liabilities for the sites. As a result of the sale and transfer of liabilities, Power recorded a pre-tax gain in 2018 of $54 million in O&M Expense.
PSEG and Power continue to monitor their other coal assets, including their interest in the Keystone and Conemaugh generating stations, to assess their economic viability through the end of their designated useful lives and their continued classification as held for use. The precise timing of a change in useful lives may be dependent upon events

out of PSEG’s and Power’s control and may impact their ability to operate or maintain certain assets in the future. These generating stations may be impacted by factors such as environmental legislation, co-owner capital requirements and continued depressed wholesale power prices or capacity factors, among other things. Any early retirement or change in the held for use classification of our remaining coal units may have a material adverse impact on PSEG’s and Power’s future financial results.

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Note 5. Variable Interest Entity (VIE)
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 and controls the services provided to LIPA, 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 2018, 2017 and 2016, Servco recorded $458 million, $438 million and $410 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.
Note 6. Property, Plant and Equipment and Jointly-Owned Facilities
Information related to Property, Plant and Equipment as of December 31, 2018 and 2017 is detailed below:

	PSE&G	Power	Other	PSEG Consolidated
	Millions			
2018				
Transmission and Distribution:				
Electric Transmission	$11,991	$—	$—	$ 11,991
Electric Distribution	8,989	—	—	8,989
Gas Distribution and Transmission	7,854	—	—	7,854
Construction Work in Progress	1,170	—	—	1,170
Other	624	—	—	624
Total Transmission and Distribution	30,628	—	—	30,628
Generation:				
Fossil Production	—	6,541	—	6,541
Nuclear Production	—	2,971	—	2,971
Nuclear Fuel in Service	—	765	—	765
Other Production-Solar	623	833	—	1,456
Construction Work in Progress	—	1,011	—	1,011
Total Generation	623	12,121	—	12,744
Other	382	103	344	829
Total	$31,633	$12,224	$344	$ 44,201

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	PSE&G	Power	Other	PSEG Consolidated
	Millions			
2017				
Transmission and Distribution:				
Electric Transmission	$10,425	$—	$—	$ 10,425
Electric Distribution	8,455	—	—	8,455
Gas Distribution and Transmission	7,122	—	—	7,122
Construction Work in Progress	1,735	—	—	1,735
Other	512	—	—	512
Total Transmission and Distribution	28,249	—	—	28,249
Generation:				
Fossil Production	—	4,923	—	4,923
Nuclear Production	—	2,893	—	2,893
Nuclear Fuel in Service	—	745	—	745
Other Production-Solar	593	757	—	1,350
Construction Work in Progress	—	2,339	—	2,339
Total Generation	593	11,657	—	12,250
Other	275	98	359	732
Total	$29,117	$11,755	$359	$ 41,231

As part of its solar production portfolio, Power owns and operates two California-based solar facilities with an aggregate capacity of approximately 30 MW direct current whose output is sold to Pacific Gas and Electric Company (PG&E) under power purchase agreements (PPAs) with twenty year terms. The net book value of these solar facilities was approximately $57 million as of December 31, 2018. In January 2019, PG&E and its parent company PG&E Corporation filed for Chapter 11 bankruptcy protection. Power cannot predict the ultimate outcome that this bankruptcy proceeding will have on its ability to collect all of the future revenues from these facilities due under the PPAs; however, any adverse changes to the terms of Power’s PPAs as a result of this bankruptcy proceeding could result in the future impairment of these assets in amounts up to their current net book value.
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 to which they are a party. All amounts reflect PSE&G’s or Power’s share of the jointly-owned projects and the corresponding direct expenses are included in the Consolidated Statements of Operations as Operating Expenses.

		As of December 31,			
		2018		2017	
	Ownership Interest	Plant	Accumulated Depreciation	Plant	Accumulated Depreciation
		Millions			
PSE&G:					
Transmission Facilities	Various	$162	$ 58	$162	$ 58
Power:					
Coal Generating:					
Conemaugh	23 %	$417	$ 192	$408	$ 178
Keystone	23 %	$416	$ 200	$409	$ 187
Nuclear Generating:					
Peach Bottom	50 %	$1,334	$ 389	$1,328	$ 348

Salem	57	%	$1,196	$ 333	$1,147	$ 277
Nuclear Support Facilities	Various		$244	$ 95	$239	$ 81
Pumped Storage Facilities:						
Yards Creek	50	%	$48	$ 26	$44	$ 26
Merrill Creek Reservoir	14	%	$1	$ —	$1	$ —

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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 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 7. Regulatory Assets and Liabilities

PSE&G prepares its financial statements in accordance with GAAP for regulated utilities as described in Note 1. Organization, Basis of Presentation and 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 proceedings. Most of PSE&G’s Regulatory Assets and Liabilities as of December 31, 2018 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 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.

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PSE&G had the following Regulatory Assets and Liabilities:

	As of December 31, 2018	2017
	Millions	
Regulatory Assets		
Current		
New Jersey Clean Energy Program	$143	$128
Electric Energy Costs—Basic Generation Service (BGS)	115	23
Storm Damage and Other	56	—
Green Program Recovery Charges (GPRC)	34	8
Weather Normalization Clause (WNC)	2	40
Other	39	12
Total Current Regulatory Assets	$389	$211
Noncurrent		
Pension and OPEB Costs	$1,090	$1,488
Deferred Income Tax Regulatory Assets	896	282
Manufactured Gas Plant (MGP) Remediation Costs	321	358
Electric Transmission and Gas Cost of Removal	223	199
Storm Damage and Other	214	241
Remediation Adjustment Charge (RAC) (Other Societal Benefits Charge (SBC))	175	172
Asset Retirement Obligation	166	162
GPRC	95	98
Unamortized Loss on Reacquired Debt and Debt Expense	49	55
Gas Costs—BGSS	31	30
Other	139	137
Total Noncurrent Regulatory Assets	$3,399	$3,222
Total Regulatory Assets	$3,788	$3,433

	As of December 31, 2018	2017
	Millions	
Regulatory Liabilities		
Current		
Deferred Income Tax Regulatory Liabilities	$299	$—
Gas Costs —BGSS	—	30
Gas Margin Adjustment Clause	8	12
Other	4	5
Total Current Regulatory Liabilities	$311	$47
Noncurrent		
Deferred Income Tax Regulatory Liabilities	$3,170	$2,868
Electric Distribution Cost of Removal	51	80
Total Noncurrent Regulatory Liabilities	$3,221	$2,948
Total Regulatory Liabilities	$3,532	$2,995

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:

- 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 as assets are retired.

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- Deferred Income Tax Regulatory Assets: These amounts represent the portion of deferred income taxes that will be recovered through future rates, based upon established regulatory practices and orders from the BPU.
- Deferred Income Tax Regulatory Liabilities: These amounts represent the future refunds to customers of PSE&G's excess Accumulated Deferred Income Tax liabilities as a result of the reduction in the federal corporate income tax rate effective January 1, 2018 and the flow-back of tax repair-related accumulated deferred income taxes that PSE&G agreed to as part of the settlement of its 2018 distribution base rate proceeding.
- Electric and Gas Cost of Removal: PSE&G accrues and collects in rates for the cost of removing, dismantling and disposing of its T&D 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.
- Electric Energy Costs—BGS: These costs represent the over or under recovered amounts associated with 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. Over or under recovered balances with interest are returned or recovered through monthly filings.
- Gas Costs—BGSS: These costs represent the over or under recovered amounts associated with 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. Over or under collected balances are returned or recovered through an annual filing. Interest is accrued only on over recovered balances.
- 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. Over or under recovered balances with interest are returned or recovered through the subsequent annual filing.
- GPRC: This amount represents costs of the over or under collected balances associated with various renewable energy and energy efficiency programs. PSE&G files annually with the BPU for recovery of amounts that include a return on and of its investment over the lives of the underlying investments and capital assets which range from five to ten years. Interest is accrued monthly on any over or under recovered balances. Components of the GPRC include: Carbon Abatement, Energy Efficiency Economic Stimulus Program (EEE), EEE Extension Program, EEE Extension II Program, the Demand Response Program, Solar Generation Investment Program (Solar 4 All®), Solar 4 All® Extension, Solar 4 All® Extension II, Solar Loan II Program, Solar Loan III Program and the Energy Efficiency 2017 Program.
- MGP Remediation Costs: Represents the low end of the range for the remaining environmental investigation and remediation program cleanup costs for MGPs that are probable of recovery in future rates. Once these costs are incurred, they are recovered through the RAC in the SBC over a seven year period with interest.
- New Jersey Clean Energy Program: The BPU approved future funding requirements for Energy Efficiency and Renewable Energy Programs through the first half of 2018. The BPU funding requirements are recovered through the SBC.
- 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 and prior service costs which have not been expensed. These costs are amortized and recovered in future rates.
- RAC (Other SBC): Costs incurred to clean up MGPs which are recovered over seven years with interest through an annual filing.
- 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. Over or under recovered balances with interest are to be returned or recovered

through an annual filing.

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- Storm Damage and Other: Represents deferred costs, primarily comprised of storm costs incurred in the cleanup of major storms from 2010 through 2018, which are being amortized over five years.
- 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.
- WNC: This represents the over or under recovery of gas margin which is filed annually with the BPU. 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 returned to customers in the next winter season while under recoveries (subject to an earnings cap) are recovered from customers in the next winter season.

Significant 2018 regulatory orders received and currently pending rate filings with FERC and the BPU by PSE&G are as follows:

- Electric and Gas Distribution Base Rate Filings—In October 2018, the BPU issued an Order approving the settlement of PSE&G's distribution base rate proceeding with new rates effective November 1, 2018. The settlement resulted in a net reduction in overall annual revenues of approximately $13 million, comprised of a $212 million increase in base revenues, including recovery of deferred storm costs, offset by the return of tax benefits of approximately $225 million. The tax benefits include the flow-back to customers of excess accumulated deferred income taxes resulting from the reduction of the federal income tax rates provided in the Tax Cuts and Jobs Act of 2017 (Tax Act) as well as the accumulated deferred income taxes from previously realized tax repair deductions and tax benefits from future tax repair deductions as realized. The Order provided for a $9.5 billion rate base, a 9.6% return on equity for PSE&G's distribution business and a 54% equity component of its capitalization structure. In addition to the $13 million annual revenue reduction, the Order provided for a $28 million one-time refund to customers in November and December 2018 for taxes collected at the higher federal income tax rate for the January 1 to March 31, 2018 period. Previously, the BPU had approved a rate reduction effective April 1, 2018, to PSE&G's then current electric and gas base rates of approximately $71 million and $43 million, respectively, on an annual basis, to reflect the lower federal income tax rate for the period April 1 and forward. As a result of the agreement to flow back tax repair-related accumulated deferred income taxes in the settlement, PSE&G has recognized a Regulatory Liability and a corresponding Regulatory Asset.
- Transmission Formula Rate Filings—In October 2018, PSE&G made two FERC filings with respect to its Transmission Formula Rate. PSE&G filed its 2019 Annual Transmission Formula Rate Update with FERC requesting new rates for 2019 with an effective date of January 1, 2019. In addition, PSE&G filed a Section 205 filing that sought FERC approval to modify its existing Formula Rate template in order to refund approximately $114 million of transmission-related "unprotected excess deferred income tax benefits" in 2019. In December 2018, FERC approved PSE&G's Section 205 filing, subject to the submission of a compliance filing which was submitted to FERC in January 2019. As a result, PSE&G filed a revised 2019 Annual Transmission Formula Rate Update to include the refund of the approved excess deferred income tax benefits. The revised 2019 Annual Transmission Formula Rate, as filed with FERC in January 2019, decreases overall annual transmission revenues by approximately $54 million, subject to true-up.

In June 2018, PSE&G filed its 2017 true-up adjustment pertaining to its transmission formula rates in effect for 2017. This resulted in an adjustment of $27 million more than the 2017 originally filed revenues, the impact of which PSE&G had primarily recognized in its Consolidated Statement of Operations for the year ended December 31, 2017.

- Gas System Modernization Program I (GSMP I)—In December 2018, the BPU approved recovery of PSE&G's GSMP I capital investment recovery petition for an annual gas revenue requirement increase of $21 million effective January 1, 2019.
- RAC—In January 2019, PSE&G updated its RAC 26 recovery request with the BPU seeking recovery of $73 million of net MGP costs from August 1, 2017 through July 31, 2018. This matter is pending. In October 2018, the BPU approved PSE&G's filing with respect to its RAC 25 petition allowing recovery of $63 million effective November 1, 2018 related to MGP expenditures from August 1, 2016 through July 31, 2017.
-

GPRC—In October 2018, the BPU approved PSE&G's 2017 GPRC cost recovery petition requesting recovery of approximately $58 million and $15 million in electric and gas revenues, respectively, on an annual basis.
In June 2018, PSE&G filed its 2018 GPRC cost recovery petition requesting recovery of approximately $65 million and $6 million in electric and gas revenues, respectively, on an annual basis.

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- Energy Strong Program I (ES I) Recovery Filing—In August 2018, the BPU approved recovery of PSE&G’s ES I capital investment petition for an annual revenue requirement increase of $0.6 million and $0.1 million associated with electric and gas investment costs, respectively. This represents the final recovery of electric and gas ES I capital investment costs consistent with the BPU Order of Approval of the Energy Strong Program.

In February 2018, the BPU approved recovery of an annual revenue requirement of $8 million associated with electric ES I capital investment costs placed in service from June 1, 2017 through November 30, 2017.

- WNC—In October 2018, the BPU approved PSE&G’s 2017-2018 WNC petition on a provisional basis allowing a net recovery of $14 million to be collected over the 2018-2019 Winter Period with the new rate effective November 1, 2018. The $14 million net recovery is the result of $9 million of excess revenues from the colder than normal 2017-2018 Winter Period offset by $23 million of remaining prior Winter Period undercollection.

In April 2018, the BPU gave final approval to PSE&G’s petition to collect $55 million in net deficiency gas revenues as a result of the warmer than normal 2016-2017 Winter Period, which resulted in a deficiency of $31 million, plus a carryover balance of $24 million from the 2015-2016 Winter Period.

- SBC—In February 2018, the BPU approved PSE&G’s petition to increase electric rates by approximately $20 million on an annual basis and to decrease gas rates by approximately $0.8 million on an annual basis, in order to recover electric and gas costs incurred through May 31, 2017 under its Energy Efficiency and Renewable Energy and Social Programs. The new rates were effective April 1, 2018.

- BGSS—In September 2018, the BPU provisionally approved PSE&G’s request to decrease its BGSS rates which will decrease annual BGSS revenues by $26 million. The BGSS rate decreased from approximately 37 cents to 35 cents per therm for residential gas customers effective October 1, 2018.

In April 2018, the BPU approved the final BGSS rates which were effective October 1, 2017.

Note 8. Long-Term Investments

Long-Term Investments as of December 31, 2018 and 2017 included the following:

	As of December 31,	
	2018	2017
	Millions	
PSE&G		
Life Insurance and Supplemental Benefits	$121	$130
Solar Loans	149	150
Power		
Partnerships and Corporate Joint Ventures (Equity Method Investments) (A)	86	87
Energy Holdings		
Lease Investments	540	565
Total Long-Term Investments	$896	$932

(A) During the three years ended December 31, 2018, 2017 and 2016, dividends from these investments were $16 million, $18 million and $18 million, respectively.

Leases

Energy Holdings, through several of its indirect subsidiary companies, 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.

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Due to liquidity issues facing NRG REMA, LLC (REMA) prior to its emergence from bankruptcy protection, economic challenges facing coal generation in PJM as discussed in Note 4. Early Plant Retirements, and based upon ongoing reviews of available alternatives as well as certain discussions with REMA management leading up to and in connection with REMA's bankruptcy, Energy Holdings recorded pre-tax charges of $20 million, $77 million and $147 million in 2018, 2017 and 2016, respectively. Included in these charges were residual value impairments of $7 million and $137 million in 2017 and 2016, respectively. Pre-tax charges were reflected in Operating Revenues in each year and are included in Gross Investment in Leases as of December 31, 2018.

In December 2018, REMA emerged from its in-court proceeding under Chapter 11 of the Bankruptcy Code. Upon emergence, PSEG received $31.5 million in cash in exchange for transferring the ownership interests in Keystone and Conemaugh to the debtholders of REMA and satisfaction of all other claims asserted against REMA, as well as certain amendments to the Shawville lease. The Shawville lease amendments, among other things, will allow REMA to express interest in a renewal on or after November 24, 2019. In addition, REMA has agreed to fund qualifying credit support up to $36 million. As a result of the restructuring, Energy Holdings recognized a pre-tax gain in Operating Revenues of approximately $12 million ($9 million after tax). In addition, the remaining deferred tax liabilities related to these lease investments were reclassified to current tax liabilities. PSEG expects to pay approximately $120 million to taxing authorities in 2019 resulting from this restructuring activity.

The following table shows Energy Holdings' gross and net lease investment as of December 31, 2018 and 2017.

	As of December 31,	
	2018	2017
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$504	$546
Estimated Residual Value of Leased Assets	326	326
Total Investment in Rental Receivables	830	872
Unearned and Deferred Income	(290)	(307)
Gross Investments in Leases	540	565
Deferred Tax Liabilities	(354)	(480)
Net Investments in Leases	$186	$85

In December 2017, new tax legislation was enacted (Tax Act), reducing the statutory U.S. corporate income tax rate from a maximum of 35% to 21%, effective January 1, 2018. PSEG is subject to ASC 740, which requires that the effect on deferred tax assets and liabilities of a change in tax rates be recognized in the period the tax rate was enacted. The impact of the reduced tax rate is the primary reason for the decrease in Deferred Tax Liabilities. For additional information, see Note 21. Income Taxes.

The pre-tax income (loss) and income tax effects related to investments in leases, excluding gains and losses on sales and the impacts of the Tax Act, were as follows:

	Years Ended December 31,		
	2018	2017	2016
	Millions		
Pre-Tax Income (Loss) from Leases	$17	$(69)	$(135)
Income Tax Expense (Benefit) on Income from Leases	$6	$(26)	$(51)

Equity Method Investments

Power had the following equity method investments as of December 31, 2018 and 2017:

Name	As of December 31, 2018	2017	Location	% Owned
	Millions			
Power				
Keystone Fuels, LLC	$ 9	$ 8	PA	23%
Conemaugh Fuels, LLC	8	8	PA	23%
Kalaeloa	69	71	HI	50%
Total	$ 86	$ 87		

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Note 9. 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. Interest income on the loans is recorded on an accrual basis. The loans are generally paid back with solar renewable energy certificates (SRECs) generated from the installed solar electric system. In the event of a loan default, the basis of the solar loan would be recovered through a regulatory recovery mechanism. None of the solar loans are impaired; however, in the event a loan becomes impaired, the basis of the loan would be recovered through a regulatory recovery mechanism. A substantial portion of these amounts are noncurrent and reported in Long-Term Investments on PSEG's and PSE&G's Consolidated Balance Sheets. The following table reflects the outstanding loans by class of customer, none of which would be considered "non-performing."

Outstanding Loans by Class of Customer

Consumer Loans	As of December 31, 2018	2017
	Millions	
Commercial/Industrial	$164	$158
Residential	9	10
Total	$173	$168
Current Portion (included in Other Current Assets)	(24)	(18)
Noncurrent Portion (included in Long-Term Investments)	$149	$150

Energy Holdings

Energy Holdings had a net investment in domestic energy and real estate assets subject to leveraged lease accounting of $186 million as of December 31, 2018 and $85 million as of December 31, 2017 (See Note 8. Long-Term Investments).

The corresponding receivables associated with the lease portfolio are reflected as follows, 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 & Poor's (S&P) as of December 31, 2018	Lease Receivables, Net of Non-Recourse Debt As of December 31, 2018
	Millions
AA	$ 14
BBB+ — BBB-	316
BB	133
NR	41
Total	$ 504

The "BB" and the "NR" ratings in the preceding table represent lease receivables related to coal and gas-fired assets in Illinois and Pennsylvania, respectively. As of December 31, 2018, the gross investment in the leases of such assets, net of non-recourse debt, was $296 million ($10 million, net of deferred taxes). A more detailed description of such assets under lease follows:

Asset	Location	Gross Investment	% Owned	Total MW	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty

		Millions						
Powerton Station Units 5 and 6	IL	$	133	64 %	1,538	Coal	BB	NRG Energy, Inc.
Joliet Station Units 7 and 8	IL	$	85	64 %	1,036	Gas	BB	NRG Energy, Inc.
Shawville Station Units 1, 2, 3 and 4	PA	$	78	100 %	596	Gas	NR	REMA (A)

(A) REMA emerged from Chapter 11 of the U.S. Bankruptcy Code in December 2018. For additional information, see Note 8. Long-Term Investments.

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The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease structures. These credit enhancement features vary from lease to lease. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings would exercise their rights and 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 and trigger certain material tax obligations which could, for certain leases, wholly or partially be mitigated by tax indemnification claims against the counterparty. A bankruptcy of a lessee would likely delay and potentially limit any efforts on the part of the lessors to assert their rights upon default and could delay the monetization of claims.

Additional factors that 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 their affiliates and the quality and condition of assets under lease.

Note 10. Trust Investments

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, 2018 was approximately $708 million and is included in the Asset Retirement Obligation. The funds are managed by third-party investment managers who operate under investment guidelines developed by Power.

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, 2018			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$447	$ 153	$ (29)	$571
International	323	36	(30)	329
Total Equity Securities	770	189	(59)	900
Available-for Sale Debt Securities				
Government	498	2	(9)	491
Corporate	501	1	(15)	487
Total Available-for-Sale Debt Securities	999	3	(24)	978
Total NDT Fund Investments	$1,769	$ 192	$ (83)	$1,878

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	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$497	$ 245	$ (2)	$740
International	311	99	(3)	407
Total Equity Securities	808	344	(5)	1,147
Available-for Sale Debt Securities				
Government	586	2	(4)	584
Corporate	400	4	(2)	402
Total Available-for-Sale Debt Securities	986	6	(6)	986
Total NDT Fund Investments	$1,794	$ 350	$ (11)	$2,133

Net unrealized gains (losses) on debt securities of $(12) million (after-tax) were included in Accumulated Other Comprehensive Loss on PSEG's and Power's Consolidated Balance Sheets as of December 31, 2018. The portion of net unrealized gains (losses) recognized during 2018 related to equity securities still held at the end of December 31, 2018 was $(127) million.
The 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, 2018	As of December 31, 2017
	Millions	
Accounts Receivable	$ 17	$ 24
Accounts Payable	$ 5	$ 74

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

	As of December 31, 2018				As of December 31, 2017			
	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)								
Domestic	$147	$ (26)	$5	$ (3)	$40	$ (2)	$—	$ —
International	131	(28)	5	(2)	29	(3)	2	—
Total Equity Securities	278	(54)	10	(5)	69	(5)	2	—
Available-for-Sale Debt Securities								

Government (B)	51	—	317	(9)	343	(2)	91	(2)
Corporate (C)	150	(5)	222	(10)	191	(1)	27	(1)
Total Available-for-Sale Debt Securities	201	(5)	539	(19)	534	(3)	118	(3)
NDT Trust Investments	$479	$ (59)	$549	$ (24)	$603	$ (8)	$120	$ (3)

(A) Equity Securities—Investments in marketable equity securities within the NDT Fund are primarily in common stocks

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within a broad range of industries and sectors. Effective January 1, 2018, unrealized gains and losses on these securities are recorded in Net Income.

(B) Debt Securities (Government)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). The unrealized losses on Power's NDT investments in U.S. Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. These investments are guaranteed by the U.S. government or an agency of the U.S. government. Power also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will 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, 2018.

(C) Debt Securities (Corporate)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). 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, 2018.

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

	Years Ended December 31,		
	2018	2017	2016
	Millions		
Proceeds from Sales (A)	$1,398	$2,137	$711
Net Realized Gains (Losses):			
Gross Realized Gains	$121	$157	$53
Gross Realized Losses	(51)	(23)	(32)
Net Realized Gains (Losses) on NDT Fund (B)	$70	$134	$21
Unrealized Gains (Losses) on Equity Securities in NDT Fund (C)	(209)	N/A	N/A
Other-Than-Temporary-Impairments (OTTI)	—	(12)	(28)
Net Gains (Losses) on NDT Fund Investments	$(139)	$122	$(7)

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.
(B) The cost of these securities was determined on the basis of specific identification.
(C) Effective January 1, 2018, unrealized gains (losses) on equity securities are recorded in Net Income instead of Other Comprehensive Income (Loss).

The NDT Fund debt securities held as of December 31, 2018 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 13
1 - 5 years	254
6 - 10 years	211
11 - 15 years	40
16 - 20 years	77
Over 20 years	383
Total NDT Available-for-Sale Debt Securities	$ 978

Power periodically assesses individual debt securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For these 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). 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."

The following tables show the fair values, gross unrealized gains and losses and amortized cost basis for the securities held in the Rabbi Trust.

	As of December 31, 2018			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$22	$ 1	$ —	$ 23
International	—	—	—	—
Total Equity Securities	22	1	—	23
Available-for-Sale Debt Securities				
Government	110	1	(2)	109
Corporate	96	—	(4)	92
Total Available-for-Sale Debt Securities	206	1	(6)	201
Total Rabbi Trust Investments	$228	$ 2	$ (6)	$ 224

	As of December 31, 2017			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities				
Domestic	$24	$ 3	$ —	$ 27
International	—	—	—	—
Total Equity Securities	24	3	—	27
Available-for-Sale Debt Securities				
Government	85	1	(1)	85
Corporate	118	2	(1)	119
Total Available-for-Sale Debt Securities	203	3	(2)	204
Total Rabbi Trust Investments	$227	$ 6	$ (2)	$ 231

Net unrealized gains (losses) on debt securities of $(4) million (after-tax) were included in Accumulated Other Comprehensive Loss on PSEG's Consolidated Balance Sheet as of December 31, 2018. The portion of net unrealized gains (losses) recognized during 2018 related to equity securities still held at the end of December 31, 2018 was $(2) million.

The 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 shown in the following table.

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	As of December 31, 2018	As of December 31, 2017
	Millions	
Accounts Receivable	$ 2	$ 2
Accounts Payable	$ —	$ 1

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

	As of December 31, 2018				As of December 31, 2017			
	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							
Available-for-Sale Debt Securities								
Government (A)	$18	$ —	$59	$ (2)	$28	$ —	$25	$ (1)
Corporate (B)	50	(3)	29	(1)	39	(1)	9	—
Total Available-for-Sale Debt Securities	68	(3)	88	(3)	67	(1)	34	(1)
Rabbi Trust Investments	$68	$ (3)	$88	$ (3)	$67	$ (1)	$34	$ (1)

(A) Debt Securities (Government)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). The 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. These investments are guaranteed by the U.S. government or an agency of the U.S. government. PSEG also has investments in municipal bonds that are primarily in investment grade securities. It is not expected that these securities will 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, 2018.

(B) Debt Securities (Corporate)—Unrealized gains and losses on these securities are recorded in Accumulated Other Comprehensive Income (Loss). 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, 2018.

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

	Years Ended December 31,		
	2018	2017	2016
	Millions		
Proceeds from Rabbi Trust Sales (A)	$103	$182	$113
Net Realized Gains (Losses):			

Gross Realized Gains	$2	$17	$6
Gross Realized Losses	(4)	(5)	(5)
Net Realized Gains (Losses) on Rabbi Trust (B)	(2)	12	1
Unrealized Gains (Losses) on Equity Securities in Rabbi Trust (C)	(2)	N/A	N/A
Net Gains (Losses) on Rabbi Trust Investments	$(4)	$12	$1

(A) Includes activity in accounts related to the liquidation of funds being transitioned to new managers.
(B) The cost of these securities was determined on the basis of specific identification.

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(C) Effective January 1, 2018, unrealized gains (losses) on equity securities are recorded in Net Income instead of Other Comprehensive Income (Loss).

The Rabbi Trust debt securities held as of December 31, 2018 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$ 1
1 - 5 years	35
6 - 10 years	27
11 - 15 years	8
16 - 20 years	21
Over 20 years	109
Total Rabbi Trust Available-for-Sale Debt Securities	$ 201

PSEG periodically assesses individual debt securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For these 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. The fair value of the Rabbi Trust related to PSEG, PSE&G and Power are detailed as follows:

	As of December 31, 2018	As of December 31, 2017
	Millions	
PSE&G	$45	$ 46
Power	56	57
Other	123	128
Total Rabbi Trust Investments	$224	$ 231

Note 11. Goodwill and Other Intangibles

As of December 31, 2018 and 2017, Power had goodwill of $16 million related to the Bethlehem Energy Center facility. Power conducted an annual review for goodwill impairment in the fourth quarter of 2018 and concluded that goodwill continues to remain unimpaired. In addition to goodwill, as of December 31, 2018 and 2017, Power had intangible assets of $143 million and $114 million, respectively, related to emissions allowances and RECs. Emissions allowances and RECs are recorded at cost and evaluated for impairment at least annually. Emissions expense includes impairments of emissions allowances, if any, 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. The changes to Power’s intangible assets during 2017 and 2018 are presented in the following table:

	Emissions Allowances	RECs	Total Other Intangibles

	Millions		
Balance as of January 1, 2017	$54	$44	$ 98
Retirements	(7)	(93)	(100)
Purchases	27	90	117
Sales and Transfers, net	—	(1)	(1)
Balance as of December 31, 2017	$74	$40	$ 114
Retirements	(26)	(90)	(116)
Purchases	36	110	146
Sales and Transfers, net	—	(1)	(1)
Balance as of December 31, 2018	$84	$59	$ 143

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Note 12. Asset Retirement Obligations (AROs)

PSEG, PSE&G and Power recognize liabilities for the expected cost of retiring long-lived assets for which a legal obligation exists to remove or dispose of an asset or some component of an asset at retirement. 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 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 with the corresponding expense recorded in O&M.

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 10. Trust Investments. Power also identified conditional AROs primarily related to Power's fossil generation units and solar facilities, including liabilities for removal of asbestos, ash ponds, 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 2018. When assumptions are revised to calculate fair values of existing AROs, generally, 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 2017 and 2018 are presented in the following table:

	PSEG	PSE&G	Power	Other
	Millions			
ARO Liability as of January 1, 2017	$726	$ 213	$511	$ 2
Liabilities Settled	(29)	(8)	(21)	—
Liabilities Incurred	1	—	1	—
Accretion Expense	30	—	30	—
Accretion Expense Deferred and Recovered in Rate Base (A)	12	12	—	—
Revision to Present Values of Estimated Cash Flows	284	(5)	289	—
ARO Liability as of December 31, 2017	$1,024	$ 212	$810	$ 2
Liabilities Settled	(10)	(9)	(1)	—
Liabilities Incurred	1	—	1	—
Accretion Expense	41	—	41	—
Accretion Expense Deferred and Recovered in Rate Base (A)	12	12	—	—
Revision to Present Values of Estimated Cash Flows	(5)	87	(93)	1
ARO Liability as of December 31, 2018	$1,063	$ 302	$758	$ 3

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

During 2018, PSE&G recorded an increase to its ARO liabilities primarily due to the impact of an increase in labor rates. These changes had no impact in PSE&G's Consolidated Statement of Operations.
During 2017, Power recorded an increase to its ARO liabilities primarily due to a higher assumed probability of early retirement of its nuclear units of $276 million. During 2018, Power recorded a reduction to its ARO liabilities, primarily due to changes in discount rates and decommissioning assumptions related to nuclear. The changes in decommissioning assumptions, including a reduction for the lower probability of early retirement of the nuclear units, were due in part to the enactment of the New Jersey ZEC legislation in May 2018 and that the Salem and Hope Creek Units were the sole applicants under the ZEC program. This reduction was also due to the sale of the Hudson and Mercer units, partially offset by increases in estimated costs

to decommission Power’s fossil units pursuant to its most recent cost study. These changes had an immaterial impact in Power’s Consolidated Statement of Operations. See Note 4. Early Plant Retirements for additional information.

Note 13. Pension, Other Postretirement Benefits (OPEB) and Savings Plans

PSEG sponsors 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.

In December 2018, PSEG amended certain provisions of its OPEB plans applicable to all current and future Medicare-eligible retirees and spouses who receive or will receive subsidized healthcare from PSEG. Effective January 1, 2021, the PSEG-sponsored Medicare-eligible plans will be replaced by a Medicare private exchange. For each Medicare-eligible retiree and spouse, PSEG will provide annual credits to a Health Reimbursement Arrangement, which can be used to pay for medical, prescription drug, and dental plan premiums, as well as certain out-of-pocket costs. The amendment resulted in a $559 million reduction in PSEG’s OPEB obligation as of December 31, 2018.

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, 2018 and 2017. 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.

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	Pension Benefits		Other Benefits	
	2018	2017	2018	2017
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year (A)	$6,359	$5,772	$1,976	$1,754
Service Cost	130	114	18	17
Interest Cost	208	204	66	63
Actuarial (Gain) Loss	(460)	564	(222)	199
Gross Benefits Paid	(316)	(295)	(76)	(57)
Plan Amendments	—	—	(559)	—
Benefit Obligation at End of Year (A)	$5,921	$6,359	$1,203	$1,976
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$5,812	$5,193	$511	$420
Actual Return on Plan Assets	(388)	903	(36)	77
Employer Contributions	12	11	89	71
Gross Benefits Paid	(316)	(295)	(76)	(57)
Fair Value of Assets at End of Year	$5,120	$5,812	$488	$511
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	$(801)	$(547)	$(715)	$(1,465)
Additional Amounts Recognized in the Consolidated Balance Sheets				
Current Accrued Benefit Cost	(10)	(10)	(11)	(10)
Noncurrent Accrued Benefit Cost	(791)	(537)	(704)	(1,455)
Amounts Recognized	$(801)	$(547)	$(715)	$(1,465)
Additional Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulated Assets and Deferred Assets (B)				
Prior Service Cost	$(28)	$(46)	$(561)	$(3)
Net Actuarial Loss	2,005	1,721	420	629
Total	$1,977	$1,675	$(141)	$626

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits. The vested benefit obligation is the actuarial present value of the vested benefits to which the employee is currently entitled but based on the employee’s expected date of separation of retirement.

(B) Includes $619 million ($360 million, after-tax) and $683 million ($406 million, after-tax) in Accumulated Other Comprehensive Loss related to Pension and OPEB as of December 31, 2018 and 2017, respectively. Also includes Regulatory Assets of $1,090 million and Deferred Assets of $127 million as of December 31, 2018 and Regulatory Assets of $1,485 million and Deferred Assets of $133 million as of December 31, 2017.

The pension benefits table above provides information relating to the funded status of the qualified and nonqualified pension and OPEB plans on an aggregate basis. As of December 31, 2018, PSEG had funded approximately 86% of its projected benefit obligation. This percentage does not include $224 million of assets in the Rabbi Trust as of December 31, 2018 which were used partially to fund the nonqualified pension plans. As of December 31, 2018, the nonqualified pension plans included in the projected benefit obligation in the above table were $156 million.

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Accumulated Benefit Obligation
The accumulated benefit obligation for all PSEG's defined benefit pension plans was $5.7 billion as of December 31, 2018 and $6.1 billion as of December 31, 2017.
The following table provides the components of net periodic benefit cost relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis for PSEG, excluding Servco for the years ended December 31, 2018, 2017 and 2016. Amounts shown do not reflect the impacts of capitalization and co-owner allocations. Effective with the adoption of ASU 2017-07 on January 1, 2018, only the service cost component is eligible for capitalization, when applicable. For additional information, see Note 2. Recent Accounting Standards.

	Pension Benefits			Other Benefits		
	Years Ended December 31,			Years Ended December 31,		
	2018	2017	2016	2018	2017	2016
	Millions					
Components of Net Periodic Benefit (Credits) Costs						
Service Cost (included in O&M Expense)	$130	$114	$109	$ 18	$ 17	$ 17
Non-Service Components of Pension and OPEB (Credits) Costs						
Interest Cost	208	204	202	66	63	59
Expected Return on Plan Assets	(441)	(394)	(394)	(41)	(34)	(31)
Amortization of Net						
Prior Service Credit	(18)	(18)	(19)	(1)	(11)	(14)
Actuarial Loss	85	97	158	64	51	40
Non-Service Components of Pension and OPEB (Credits) Costs	(166)	(111)	(53)	88	69	54
Total Benefit (Credits) Costs	$(36)	$3	$56	$ 106	$ 86	$ 71

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

	Pension Benefits			Other Benefits		
	Years Ended December 31,			Years Ended December 31,		
	2018	2017	2016	2018	2017	2016
	Millions					
PSE&G	$(31)	$(4)	$ 29	$ 68	$ 54	$ 43
Power	(9)	1	16	32	27	23
Other	4	6	11	6	5	5
Total Benefit (Credits) Costs	$(36)	$3	$ 56	$ 106	$ 86	$ 71

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

	Pension		OPEB	
	2018	2017	2018	2017
	Millions			
Net Actuarial (Gain) Loss in Current Period	$369	$55	$(145)	$156
Amortization of Net Actuarial Gain (Loss)	(85)	(97)	(64)	(50)
Prior Service Cost (Credit) in current period	—	—	(559)	—
Amortization of Prior Service Credit	18	18	1	11
Total	$302	$(24)	$(767)	$117

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Amounts that are expected to be amortized from Accumulated Other Comprehensive Loss, Regulatory Assets and Deferred Assets into Net Periodic Benefit Cost in 2019 are as follows:

	Pension Benefits 2019	Other Benefits 2019
	Millions	
Actuarial Loss	$107	$50
Prior Service Credit	$(18)	$(128)

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

	Pension Benefits			Other Benefits		
	2018	2017	2016	2018	2017	2016
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	4.41%	3.73%	4.29%	4.31%	3.76%	4.37%
Rate of Compensation Increase	3.90%	3.90%	3.61%	3.90%	3.90%	3.61%
Weighted-Average Assumptions Used to Determine Net Periodic Benefit Cost for Years Ended December 31						
Discount Rate	3.73%	4.29%	4.54%	3.76%	4.37%	4.58%
Service Cost Interest Rate	3.88%	4.53%	4.81%	3.90%	4.64%	4.87%
Interest Cost Interest Rate	3.35%	3.63%	3.75%	3.39%	3.69%	3.76%
Expected Return on Plan Assets	7.80%	7.80%	8.00%	7.80%	7.80%	8.00%
Rate of Compensation Increase	3.90%	3.61%	3.61%	3.90%	3.61%	3.61%
Assumed Health Care Cost Trend Rates as of December 31						
Health Care Costs						
Immediate Rate				7.28%	7.93%	7.55%
Ultimate Rate				4.75%	4.75%	4.75%
Year Ultimate Rate Reached				2026	2026	2025
				Millions		
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$1	$13	$11
Postretirement Benefit Obligation				$21	$240	$191
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs						
Total of Service Cost and Interest Cost				$(1)	$(10)	$(9)
Postretirement Benefit Obligation				$(20)	$(198)	$(160)

Plan Assets

The investments of pension 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 18. 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, 2018, the pension plan interest and OPEB plan interest in such assets of the Master Trust were approximately 91% and 9%, respectively.
The following tables present information about the investments measured at fair value on a recurring basis as of December 31, 2018 and 2017, including the fair value measurements and the levels of inputs used in determining those fair values.

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	Recurring Fair Value Measurements as of December 31, 2018			
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)	$99	$ 88	$ 11	$ —
Equity Securities				
Common Stock (B)	1,156	1,156	—	—
Commingled (C)	1,338	960	378	—
Preferred Stock (B)	7	7	—	—
Other (D)	1	1	—	—
Debt Securities (E)				
U.S. Treasury	526	—	526	—
Government—Other	302	—	302	—
Corporate	948	—	948	—
Subtotal Fair Value	$4,377	$ 2,212	$ 2,165	$ —
Measured at net asset value practical expedient				
Commingled—Equities (F)	1,208			
Private Equity (G)	10			
Total Fair Value (H)	$5,595			

	Recurring Fair Value Measurements as of December 31, 2017			
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)	$133	$ 117	$ 16	$ —
Equity Securities				
Common Stock (B)	1,275	1,275	—	—
Commingled (C)	1,401	1,218	183	—
Preferred Stock (B)	6	6	—	—
Debt Securities (E)				
U.S. Treasury	571	—	571	—
Government—Other	272	—	272	—
Corporate	963	—	963	—
Subtotal Fair Value	$4,621	$ 2,616	$ 2,005	$ —
Measured at net asset value practical expedient				
Commingled—Equities (F)	1,675			
Private Equity (G)	14			
Total Fair Value (H)	$6,310			

(A) The Collective Investment Fund publishes a daily net asset value (NAV) which participants may use for daily redemptions without restrictions (Level 1). Certain temporary investments are valued using inputs such as time-to-maturity, coupon rate, quality rating and current yield (Level 2).

(B)

Common stocks and preferred stocks are measured using observable data in active markets and considered Level 1.

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(C) Commingled Funds that allow daily redemption at their daily published NAV without restrictions are classified as Level 1. Commingled Funds that publish daily NAV but with certain near-term redemption restrictions which prevent redemption at the published daily NAV are classified as Level 2.

(D) Investment in a publicly traded limited partnership.

(E) Debt securities include mainly investment grade corporate and municipal bonds, U.S. Treasury obligations and Federal Agency asset-backed securities with a wide range of maturities. These investments are valued using an evaluated pricing approach that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads or the most recent quotes for similar securities which are a Level 2 measure.

(F) Certain commingled equity funds are not included in the fair value hierarchy as they are measured at fair value using the NAV per share (or its equivalent) practical expedient. These funds do not meet the definition of readily determinable fair value due to limitations in published NAV (last business day of the month) and include certain redemption restrictions ranging from one to fifteen days advance notice prior to redemption days and limitations on withdrawals over 25% of the total fund. The objectives of these funds are mainly tracking the S&P Index or achieving long-term growth through investment in foreign equity securities and the MSCI Emerging Markets Index.

(G) Private equity investments primarily include various limited partnerships that invest in either operating companies through acquisitions or developing a portfolio of non-US distressed investments to maximize total return on capital. These investments are valued at NAV (or its equivalent) on an annual basis and have significant redemption restrictions preventing redemption until fund liquidation and limited ability to sell these investments. Fund liquidation is not expected to occur for several more years. These investments have been removed from the fair value hierarchy in accordance with the guidance on NAV practical expedient.

(H) Excludes net receivables of $14 million and $13 million at December 31, 2018 and 2017, respectively, which consist of interest, dividends and receivables and payables related to pending securities sales and purchases.

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	2018	2017
Equity Securities	66 %	69 %
Debt Securities	32	29
Other Investments	2	2
Total Percentage	100%	100%

PSEG utilizes forecasted returns, risk, and correlation of all asset classes in order to develop an efficient portfolio. 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 7.8% for 2018 and will be 7.8% for 2019. 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.

Plan Contributions

PSEG has no planned contributions to its pension plans in 2019. PSEG plans to make discretionary contributions of $10 million into its OPEB plan during 2019.

Estimated Future Benefit Payments

The following pension benefit and postretirement benefit payments are expected to be paid to plan participants.

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Year	Pension Benefits	Other Benefits
	Millions	
2019	$345	$ 91
2020	341	95
2021	352	87
2022	364	88
2023	373	89
2024-2028	2,004	428
Total	$3,779	$ 878

401(k) Plans

PSEG sponsors two 401(k) plans, which are defined contribution retirement plans subject to the Employee Retirement Income Security Act (ERISA). 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, not to exceed the Internal Revenue Service (IRS) maximums, including any catch-up contributions for those employees age 50 and above. 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,		
	2018	2017	2016
	Millions		
PSE&G	$ 26	$ 25	$ 24
Power	10	11	12
Other	5	5	5
Total Employer Matching Contributions	$ 41	$ 41	$ 41

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 5. Variable Interest Entity. 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, 2018 and 2017. 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.

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	Pension Benefits		Other Benefits	
	2018	2017	2018	2017
	Millions			
Change in Benefit Obligation				
Benefit Obligation at Beginning of Year	$320	$262	$542	$452
Service Cost	30	27	18	15
Interest Cost	12	11	20	19
Actuarial (Gain) Loss	(38)	22	(73)	60
Gross Benefits Paid	(3)	(2)	(6)	(4)
Plan Amendments	—	—	—	—
Benefit Obligation at End of Year (A)	$321	$320	$501	$542
Change in Plan Assets				
Fair Value of Assets at Beginning of Year	$191	$134	$—	$—
Actual Return on Plan Assets	(16)	24	—	—
Employer Contributions	40	35	6	4
Gross Benefits Paid	(3)	(2)	(6)	(4)
Fair Value of Assets at End of Year	$212	$191	$—	$—
Funded Status				
Funded Status (Plan Assets less Benefit Obligation)	$(109)	$(129)	$(501)	$(542)
Additional Amounts Recognized in the Consolidated Balance Sheets				
Accrued Pension Costs of Servco	$(109)	$(129)	N/A	N/A
OPEB Costs of Servco	N/A	N/A	(501)	(542)
Amounts Recognized (B)	$(109)	$(129)	$(501)	$(542)

(A) Represents projected benefit obligation for pension benefits and the accumulated postretirement benefit obligation for other benefits. The vested benefit obligation is the actuarial present value of the vested benefits to which the employee is currently entitled but based on the employee’s expected date of separation of retirement.

(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 Sheets.

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 2018, 2017 and 2016 were $40 million, $35 million and $28 million, respectively. Servco has contributed its entire planned contribution amount to its pension plan trusts during 2018. The OPEB-related revenues earned and costs incurred were $6 million, $4 million and $2 million in 2018, 2017 and 2016, respectively. The following assumptions were used to determine the benefit obligations of Servco:

	Pension Benefits			Other Benefits		
	2018	2017	2016	2018	2017	2016
Weighted-Average Assumptions Used to Determine Benefit Obligations as of December 31						
Discount Rate	4.60%	3.90%	4.61%	4.67 %	3.96 %	4.71 %
Rate of Compensation Increase	3.25%	3.25%	3.25%	3.25 %	3.25 %	3.25 %
Assumed Health Care Cost Trend Rates as of December 31						
Health Care Costs						
Immediate Rate				8.03 %	7.69 %	7.55 %

Ultimate Rate	4.75 %	4.75 %	4.75 %
Year Ultimate Rate Reached	2026	2026	2025
	Millions		
Effect of a 1% Increase in the Assumed Rate of Increase in Health Care Benefit Costs			
Postretirement Benefit Obligation	$108	$131	$97
Effect of a 1% Decrease in the Assumed Rate of Increase in Health Care Benefit Costs			
Postretirement Benefit Obligation	$(83)	$(99)	$(75)

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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 18. 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, 2018 and 2017, including the fair value measurements and the levels of inputs used in determining those fair values.

	Recurring Fair Value Measurements as of December 31, 2018			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions			
Commingled Equities (A)	$141	$ —	$ 141	$ —
Commingled Bonds (A)	71	—	71	—
Total	$212	$ —	$ 212	$ —

	Recurring Fair Value Measurements as of December 31, 2017			
Description	Total	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions			
Commingled Equities (A)	$137	$ —	$ 137	$ —
Commingled Bonds (A)	54	—	54	—
Total	$191	$ —	$ 191	$ —

(A) Investments in commingled equity and bond funds have a readily determinable fair value as they publish a daily NAV available to investors which is the basis for current transactions and contain certain redemption restrictions requiring advance notice of one to two days for withdrawals (Level 2).

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	2018	2017
Equity Securities	67 %	72 %
Debt Securities	33	28
Total Percentage	100%	100%

Servco utilizes forecasted returns, risk, and correlation of all asset classes in order to develop an efficient portfolio. 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 7.6% for 2018 and will be 7.6% for 2019. This expected return was determined based on the study discussed above, including a premium for active management.

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Plan Contributions
Servco plans to contribute $28 million into its pension plan during 2019.
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	
2019	$4	$ 6
2020	6	8
2021	7	10
2022	9	12
2023	11	14
2024-2028	91	99
Total	$128	$ 149

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, 2018, 2017 and 2016 were $7 million, $6 million and $5 million, respectively, and pursuant to the OSA, Servco recognizes Operating Revenues for the reimbursement of these costs.
Note 14. 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 as a form of collateral.
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.

Power is subject to

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

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
- the net position of the related contracts would have to be "out-of-the-money" (if the contracts are terminated, Power would owe money to the counterparties).

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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. Current exposure consists of the net of accounts receivable and accounts payable and the forward value on open positions, less any collateral posted.
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.
The following table shows the face value of Power's outstanding guarantees, current exposure and margin positions as of December 31, 2018 and 2017.

	As of December 31, 2018	As of December 31, 2017
	Millions	
Face Value of Outstanding Guarantees	$1,772	$ 1,701
Exposure under Current Guarantees	$198	$ 153
Letters of Credit Margin Posted	$115	$ 103
Letters of Credit Margin Received	$26	$ 32
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$—	$ —
Counterparty Cash Margin Received	$(10)	$ (1)
Net Broker Balance Deposited (Received)	$403	$ 147
Additional Amounts Posted		
Other Letters of Credit	$52	$ 61

As part of determining credit exposure, Power nets receivables and payables with the corresponding net fair values of energy contracts. See Note 17. 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 Consolidated Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.
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.
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)

The U.S. Environmental Protection Agency (EPA) has determined that a 17-mile stretch of the lower Passaic River from Newark to Clifton, New Jersey is a "Superfund" site under CERCLA and a comprehensive study of the entire 17 miles of the lower Passaic River needed to be performed. 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, certain 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. The CPG has 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 7.6 percent of the RI/FS costs are currently deemed attributable to PSE&G's former MGP sites and approximately 1.9 percent is attributable to Power's generating stations. These interim

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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.

The CPG's draft FS set forth various alternatives for remediating the lower Passaic River with an estimated cost to remediate the lower 17 miles of the Passaic River ranging from approximately $518 million to $3.2 billion on an undiscounted basis.

In March 2016, the EPA released its Record of Decision (ROD) for the EPA's own Focused Feasibility Study (FFS) which requires the removal of 3.5 million cubic yards of sediment from the Passaic River's lower 8.3 miles at an estimated cost of $2.3 billion on an undiscounted basis (ROD Remedy). The EPA estimated the total project length to be about 11 years, including a one year period of negotiation with the PRPs, three to four years to design the project and six years for implementation. Occidental Chemical Corporation (OCC), one of the PRPs, has commenced performance of the remedial design required by the ROD Remedy, reserving its right of cost contribution from all other PRPs.

In September 2017, the EPA concluded that an Agency-commenced allocation process for the Passaic River's lower 8.3 miles should include only certain PRPs. The allocation is intended to lead to a consent decree in which certain of the PRPs agree to perform and pay for the remedial action under EPA oversight. Due to delays from the partial federal government shutdown in late 2018 through early 2019, the timeline for completing the allocation process has been delayed.

In October 2018, the EPA Region 2 issued a Directive to the CPG instructing the CPG to focus the ongoing RI/FS evaluation on various adaptive management scenarios for remediation of the upper 9 miles of the Passaic River, which approach has been agreed to in concept by the EPA and the CPG. The Directive does not contain estimates for anticipated costs. Adaptive management focuses on removing targeted "hot spots" of contaminated sediments rather than removing all of the Passaic River's sediments as in a "bank to bank" approach.

In a separate matter, two PRPs, Tierra Solutions, Inc. (Tierra) and Maxus Energy Corporation (Maxus), filed for Chapter 11 bankruptcy in Delaware Federal Bankruptcy Court. In June 2018, the trust representing the creditors in this proceeding filed a complaint asserting claims against the current and former parent entities of Tierra and Maxus, among other parties, for up to $14 billion. Any damages awarded may be used to fund, in part, the remediation costs of the lower 8.3 miles of the Passaic River. The creditor trust has reserved its right to file contribution claims against 28 PRPs, including PSEG. This matter is ongoing.

In June 2018, OCC filed a complaint in Federal District Court in Newark against various defendants, including PSE&G, seeking cost recovery and contribution under CERCLA for the remediation of the lower 8.3 miles of the Passaic River. The complaint does not quantify damages sought.

The Complaint alleges that "no single hazardous substance" is to blame for the contamination of the lower Passaic River and lists the eight Contaminants of Concern (COCs) identified by the EPA in the ROD. OCC alleges PSE&G is responsible for a portion of six of the eight COCs. PSE&G cannot predict the outcome of this matter.

Based upon the estimated cost of the ROD Remedy and PSEG's estimate of PSE&G's and Power's shares of that cost, as of December 31, 2018, PSEG has accrued approximately $57 million. Of this amount, PSE&G has accrued $46 million as an Environmental Costs Liability and a corresponding Regulatory Asset based on its continued ability to recover such costs in its rates. Power has accrued $11 million as an Other Noncurrent Liability with the corresponding O&M Expense recorded in prior years when the liability was accrued.

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, which covers the entire 17 miles of the lower Passaic River, is finalized either in whole or in part, (ii) an agreement by the PRPs to perform either the ROD Remedy as issued, or an amended ROD Remedy determined through negotiation or litigation, and an agreed upon remedy for the remaining 8.7 miles of the river, are reached, (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 PSEG's 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

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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 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. In December 2018, Power completed the sale of the site of the Hudson electric generating station. Power transferred all land rights and structures on the site to a third party purchaser, along with the assumption of the environmental liabilities for the site.

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 $321 million and $366 million on an undiscounted basis through 2021, including its $46 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 $321 million as of December 31, 2018. Of this amount, $56 million was recorded in Other Current Liabilities and $265 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $321 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. NJDEP, PSEG and EPA representatives have had discussions regarding to what extent sampling in the Passaic River is required to delineate coal tar from MGP sites that abut the Passaic River Superfund site. PSEG cannot determine at this time whether this will have an impact on the Passaic River Superfund remedy.

Clean Water Act (CWA) Permit Renewals

Pursuant to the Federal Water Pollution Control Act, 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 May 2014, the EPA issued a final cooling water intake rule that establishes 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, based on studies related to impingement mortality and entrainment by the facilities seeking renewal permits.

Several environmental organizations and certain energy industry groups have filed suit under the CWA and the Endangered Species Act. The cases were consolidated at the Second Circuit, and in July 2018 the Second Circuit upheld the EPA's final cooling water intake rule. The Court's decision allows Permitting Directors to continue to issue permits in accordance with the flexible, site-specific provisions of the final rule.

In June 2016, the NJDEP issued a final NJPDES permit for Salem. The final permit does not mandate specific service water system modifications, but consistent with Section 316 (b) of the CWA, it requires additional studies and the

selection of technology to address impingement for the service water system. In July 2016, the Delaware Riverkeeper Network (Riverkeeper) filed a request challenging the NJDEP's issuance of the final NJPDES renewal permit for Salem. NJDEP has granted the hearing request, but it has not yet been scheduled. The Riverkeeper's filing does not change the effective date of the permit. If the Riverkeeper's challenge were successful, Power may be required to incur additional costs to comply with the CWA. Potential cooling water system modification costs could be material and could adversely impact the economic competitiveness of this facility.
State permitting decisions at Bridgeport and possibly New Haven could also have a material impact on Power's ability to renew permits at its existing larger once-through cooled plants without making significant upgrades to existing intakes and cooling systems.

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 CWA Section 316(b) final rule, Power has proposed to continue to operate BH3 without making the capital expenditures for modification to the existing intake structure and retire BH3 in 2021, which is four years earlier than the previously estimated useful life ending in 2025. Power is currently awaiting action by the CTDEEP to issue a draft and then a final permit.

Power has entered into a Community Environmental Benefit Agreement (CEBA) with the City of Bridgeport, Connecticut and local community organizations. That CEBA provides that Power would retire BH3 early if all of its conditions precedent 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. Absent those conditions being met, and the permit for the cooling water intake structure referred to above not being issued, Power may seek to operate BH3 through the previously estimated useful life.

In February 2016, the proposed new generating facility at Bridgeport Harbor was awarded a capacity obligation. The Connecticut Siting Council issued an order to approve siting Bridgeport Harbor Station Unit 5. Operations are expected to begin in mid-2019. Power's obligations under the CEBA are being monitored regularly and carried out as needed.

Jersey City, New Jersey Subsurface Feeder Cable Matter

In October 2016, a discharge of dielectric fluid from subsurface feeder cables located in the Hudson River near Jersey City, New Jersey, was identified and reported to the NJDEP. The feeder cables are located within a subsurface easement granted to PSE&G by the property owners, Newport Associates Development Company (NADC) and Newport Associates Phase I Developer Limited Partnership. The feeder cables are subject to agreements between PSE&G and Consolidated Edison Company of New York, Inc. (Con Edison) and are jointly owned by PSE&G and Con Edison, with PSE&G owning the portion of the cables located in New Jersey and Con Edison owning the portion of the cables located in New York. The NJDEP declared an emergency and an emergency response action was undertaken to investigate, contain, remediate and stop the fluid discharge; to assess, repair and restore the cables to good working order, if feasible; and to restore the property. The regulatory agencies overseeing the emergency response, including the U.S. Coast Guard, the NJDEP and the Army Corps of Engineers, issued multiple notices, orders and directives to the various parties related to this matter and the parties may also be subject to the assessment of civil penalties related to the discharge and response. The U.S. Coast Guard transitioned control of the federal response to the EPA in May 2018. In August 2018, the EPA ended the federal response to the matter. The response has now transitioned to the NJDEP site remediation program.

The impacted cable was repaired in late September 2017; however, small amounts of residual dielectric fluid believed to be contained within the marina sediment continue to appear on the surface and response actions related to the fluid discharge are ongoing, although at a significantly reduced scale. PSE&G remains concerned about future leaks and potential environmental impacts as a result of reintroduction of fluid back into these lines and has determined that retirement of the affected facilities is appropriate. PSE&G has been unable to reach an agreement with Con Edison and, as a result, in May 2018, PSE&G filed an action at FERC to resolve the matter. FERC dismissed PSE&G's Complaint against Con Edison in September 2018 and PSE&G has challenged FERC's decision. Also ongoing is the lawsuit in federal court to determine ultimate responsibility for the costs to address the leak among PSE&G, Con Edison and NADC. In addition, Con Edison filed counter claims against PSE&G and NADC, including seeking injunctive relief and damages. Based on the information currently available and depending on the outcome of the federal court action, PSE&G's portion of the costs to address the leak may be material; however, PSE&G anticipates that it will recover these costs through regulatory proceedings.

Steam Electric Effluent Guidelines

In September 2015, the EPA issued a new Effluent Limitation Guidelines Rule (ELG 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. Power’s Bridgeport Harbor station and the jointly-owned Keystone and Conemaugh stations, have bottom ash transport water discharges that are regulated under the ELG Rule. Keystone and Conemaugh also have flue gas desulfurization wastewaters regulated by the ELG Rule.

Through various orders, the EPA has stayed the compliance dates in the ELG Rule and has announced plans to further revise the requirements and compliance dates of the ELG Rule. Power is unable to determine how this will ultimately impact its compliance requirements or its financial condition and results of operations.

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, is residential and smaller commercial and industrial customers (BGS-Residential Small

Commercial Pricing (RSCP)). The second category is larger customers that exceed a BPU-established load (kW) threshold (BGS-Commercial and Industrial Energy 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, 2019 is $281.78 per MW-day, replacing the BGS-CIEP auction year price ending May 31, 2019 of $287.76 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			
	2016	2017	2018	2019
36-Month Terms Ending	May 2019	May 2020	May 2021	May 2022 (A)
Load (MW)	2,800	2,800	2,900	2,800
$ per MWh	$96.38	$90.78	$91.77	$98.04

(A) Prices set in the 2019 BGS auction will become effective on June 1, 2019 when the 2016 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 with a portion of their respective BGS requirements through the New Jersey BGS auction process, described above.

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 25. 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 2020 and a significant portion through 2021 at Salem, Hope Creek and Peach Bottom.

Power 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 beyond the needs of PSE&G's customers, Power can use the gas to supply its fossil generating stations in New Jersey.

Power also has various long-term fuel purchase commitments for coal through 2023 to support its fossil generation stations.

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As of December 31, 2018, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2023
	Millions
Nuclear Fuel	
Uranium	$ 222
Enrichment	$ 358
Fabrication	$ 167
Natural Gas	$ 1,102
Coal	$ 429

Pending FERC Matters

In June 2015, Transource LLC, a merchant 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. Although not named as a respondent, the complaint identifies PSE&G as one of the companies claimed to have been involved. In January 2018, a FERC administrative law judge (ALJ) issued an order generally finding that PJM and transmission owners, including PSE&G, did not engage in wrongful conduct. In addition, the developer's assertion of an entitlement to monetary damages was expressly denied. However, in a determination disputed by PSE&G, the order found that the PJM process lacked transparency. The judge's order has been briefed by all parties for additional determinations by FERC. We are unable to predict the outcome of these proceedings.

Subsequent to the ALJ decision, PSE&G received requests for information from FERC's Office of Enforcement concerning a transmission project. PSE&G is complying with these requests and cannot predict the outcome of this matter.

Litigation

Sewaren 7 Construction

In June 2018, a complaint was filed in federal court in Newark, New Jersey against PSEG Fossil LLC, a wholly owned subsidiary of Power, regarding an ongoing dispute with Durr Mechanical Construction, Inc. (Durr), a contractor on the Sewaren 7 project. Among other things, Durr seeks damages of $93 million and alleges that Power withheld money owed to Durr and that Power's intentional conduct led to the inability of Durr to obtain prospective contracts. Power intends to vigorously defend against these allegations. In December 2018, Durr filed for Chapter 11 bankruptcy in the federal court in the Southern District of New York (SDNY). The SDNY bankruptcy court has allowed the New Jersey litigation to proceed. Power has accrued an amount related to outstanding invoices which does not reflect an assessment of claims and potential counterclaims in this matter. Due to its preliminary nature, Power cannot predict the outcome of this matter.

Newark Customer Incident

On the morning of July 5, 2018, PSE&G discontinued electricity to the home of a customer residing in Newark because of outstanding arrears on that customer's account. Subsequent to the discontinuation of electricity, that customer died on the afternoon of July 5th. The family of the customer, who was on hospice care, raised allegations in the media regarding PSE&G's conduct surrounding the discontinuation and restoration of electricity to the home of the customer, claiming that the discontinuation of electric service prevented the customer from using life sustaining medical equipment. The BPU initiated an investigation into the matter and that investigation is ongoing. In addition, PSE&G received a grand jury subpoena from the Essex County Prosecutor's Office (ECPO) for records and correspondence between PSE&G and the customer. PSE&G is fully cooperating with the BPU and the ECPO in both proceedings. PSEG cannot predict the outcome of the pending proceedings regarding this incident at this time.

The PSEG Board of Directors (PSEG Board) retained outside counsel to conduct an independent investigation of the facts surrounding this incident with the full support and cooperation of management. The independent investigation concluded that the disconnection itself was not improper; however, it did identify issues related to PSE&G's response once it was notified of the disconnection. The PSEG Board reviewed and considered the findings and conclusions of the investigation and PSE&G's proposed corrective actions. PSE&G's progress on implementation of the corrective actions will continue to be overseen by the PSEG Board.

Caithness Energy, L.L.C. (Caithness)

In August 2018, Caithness, a Long Island power plant developer, filed a complaint in federal district court in the Eastern District of New York against PSEG and PSEG LI alleging violations of state and federal antitrust laws and a claim of intentional interference of prospective business relations. Caithness alleges that PSEG and PSEG LI interfered with LIPA's consideration of the Caithness proposal for a 750 MW combined cycle generation project that was identified as a finalist for a Request For Proposal issued by LIPA. In addition, Caithness claims that PSEG and PSEG LI induced LIPA to agree to eliminate the proposed project as a potential competitor to other PSEG affiliates with power supply operations. The complaint alleges hundreds of millions of dollars of harm and seeks treble and punitive damages. PSEG intends to vigorously defend against these allegations. Based upon the preliminary nature of this matter, a loss is not considered probable nor is the amount of loss, if any, estimable as of December 31, 2018.

Transource LLC (Transource)

In January 2019, Transource filed a complaint against PJM, PSE&G and three other transmission owners in Pennsylvania state court. Transource has sued the transmission owner defendants for fraud and intentional misrepresentation relating to information provided to PJM and FERC regarding the costs of upgrades for Transource's proposed project. These allegations appear to be based on alleged conduct that is the subject of the pending FERC proceeding discussed under "Pending FERC Matters." Based upon the preliminary nature of this matter, a loss is not considered probable nor is the amount of loss, if any, estimable as of December 31, 2018.

Other Litigation and Legal Proceedings

PSEG and its subsidiaries are party to various lawsuits in the ordinary course of business. In view of the inherent difficulty in predicting the outcome of such matters, PSEG, PSE&G and Power generally cannot predict the eventual outcome of the pending matters, the timing of the ultimate resolution of these matters, or the eventual loss, fines or penalties related to each pending matter.

In accordance with applicable accounting guidance, a liability is accrued when those matters present loss contingencies that are both probable and reasonably estimable. In such cases, there may be an exposure to loss in excess of any amounts accrued. PSEG will continue to monitor the matter for further developments that could affect the amount of the accrued liability that has been previously established.

Based on current knowledge, management does not believe that loss contingencies arising from pending matters, other than the matters described herein, could have a material adverse effect on PSEG's, PSE&G's or Power's consolidated financial position or liquidity. However, in light of the inherent uncertainties involved in these matters, some of which are beyond PSEG's control, and the large or indeterminate damages sought in some of these matters, an adverse outcome in one or more of these matters could be material to PSEG's, PSE&G's or Power's results of operations or liquidity for any particular reporting period.

Nuclear Insurance Coverages and Assessments

Power is a member of the joint underwriting association, American Nuclear Insurers (ANI), which provides nuclear liability insurance coverage at the Salem and Hope Creek site and the Peach Bottom site. The ANI policies are designed to satisfy the financial protection requirements outlined in the Price-Anderson Act, which 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 per incident per site is composed of primary and excess layers. As of December 31, 2018, nuclear sites were required to purchase $450 million of primary liability coverage for each site (through ANI). The primary layer is supplemented by an excess layer, which is an industry self-insurance pool. In the event a nuclear site, which is part of the industry self-insurance pool, has a claim that exceeds the primary layer, each licensee would be assessed a prorated share of the excess layer. The excess layer limit is $13.6 billion. Power's maximum aggregate assessment per incident is $433 million (based on Power's ownership interests in Salem, Hope Creek and Peach Bottom) and its maximum aggregate annual assessment per incident is $65 million. If the damages exceed the limit of liability, Congress could impose further revenue-raising measures on the nuclear industry to pay claims. Further, a decision by the U.S. Supreme Court, not involving Power, held that the Price-Anderson Act did not preclude punitive damage awards based on state law claims.

Power is also 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 and Hope Creek site and the Peach Bottom site. NEIL also provides replacement power coverage through its accidental outage policy. NEIL policies may make retrospective premium assessments in the case of adverse loss experience. The current maximum aggregate annual retrospective premium obligation for Power is approximately $62 million. NEIL requires its members to maintain an investment grade credit rating or to ensure collectability of their annual retrospective premium obligation by providing a financial guarantee, letter of credit, deposit premium, or some other means of assurance. 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.

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.

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Minimum Lease Payments
The total future minimum payments under various operating leases as of December 31, 2018 are:

	PSE&G	Power	Services	Other	Total
	Millions				
2019	$15	$11	$ 14	$ 1	$41
2020	11	13	14	2	40
2021	10	13	15	1	39
2022	8	14	15	1	38
2023	8	8	15	—	31
Thereafter	66	51	105	—	222
Total Minimum Lease Payments	$118	$110	$ 178	$ 5	$411

Note 15. Debt and Credit Facilities
Long-Term Debt

	Maturity	As of December 31, 2018	2017
		Millions	
PSEG			
Term Loan:			
Variable	2019	$350	$700
Variable	2020	700	—
Total Term Loan		1,050	700
Senior Notes:			
1.60%	2019	400	400
2.00%	2021	300	300
2.65%	2022	700	700
Total Senior Notes		1,400	1,400
Principal Amount Outstanding		2,450	2,100
Amounts Due Within One Year		(750)	—
Net Unamortized Discount and Debt Issuance Costs		(7)	(9)
Total Long-Term Debt of PSEG		$1,693	$2,091

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	Maturity	As of December 31, 2018	2017
		Millions	
PSE&G			
First and Refunding Mortgage Bonds (A):			
9.25%	2021	$134	$134
8.00%	2037	7	7
5.00%	2037	8	8
Total First and Refunding Mortgage Bonds		149	149
Medium-Term Notes (MTNs) (A):			
5.30%	2018	—	400
2.30%	2018	—	350
1.80%	2019	250	250
2.00%	2019	250	250
3.50%	2020	250	250
7.04%	2020	9	9
1.90%	2021	300	300
2.38%	2023	500	500
3.25%	2023	325	—
3.75%	2024	250	250
3.15%	2024	250	250
3.05%	2024	250	250
3.00%	2025	350	350
2.25%	2026	425	425
3.00%	2027	425	425
3.70%	2028	375	—
3.65%	2028	325	—
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	250
4.15%	2045	250	250
3.80%	2046	550	550
3.60%	2047	350	350
4.05%	2048	325	—
Total MTNs		9,109	8,509
Principal Amount Outstanding		9,258	8,658
Amounts Due Within One Year		(500)	(750)
Net Unamortized Discount and Debt Issuance Costs		(74)	(67)

Total Long-Term Debt of PSE&G	$8,684	$7,841

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	Maturity	As of December 31, 2018	2017
		Millions	
Power			
Senior Notes:			
2.45%	2018	$—	$250
5.13%	2020	406	406
3.00%	2021	700	700
4.15%	2021	250	250
3.85%	2023	700	—
4.30%	2023	250	250
8.63%	2031	500	500
Total Senior Notes		2,806	2,356
Pollution Control Notes:			
Floating Rate (B)	2019	44	44
Total Pollution Control Notes		44	44
Principal Amount Outstanding		2,850	2,400
Amounts Due Within One Year		(44)	(250)
Net Unamortized Discount and Debt Issuance Costs		(15)	(14)
Total Long-Term Debt of Power		$2,791	$2,136

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

(B) The Pennsylvania Economic Development Authority (PEDFA) bond that is serviced and secured by Power Pollution Control Notes is a variable rate bond that is in weekly reset mode.

Long-Term Debt Maturities

The aggregate principal amounts of maturities for each of the five years following December 31, 2018 are as follows:

Year	PSEG	PSE&G	Power	Total
2019	$750	$500	$44	$1,294
2020	700	259	406	1,365
2021	300	434	950	1,684
2022	700	—	—	700
2023	—	825	950	1,775
Thereafter	—	7,240	500	7,740
Total	$2,450	$9,258	$2,850	$14,558

Long-Term Debt Financing Transactions

During 2018, PSEG and its subsidiaries had the following Long-Term Debt issuances, maturities and redemptions:

PSEG

- entered into an agreement for a new term loan maturing November 2020. The term loan has a balance of $700 million at an interest rate of 1 month LIBOR + 0.60% and can be terminated at any time without penalty, and
- redeemed $350 million of a $700 million term loan at an interest rate of 1 month LIBOR + 0.80% maturing June 2019.

PSE&G

- issued $375 million of 3.70% Secured Medium-Term Notes, Series M, due May 2028,

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- issued $325 million of 4.05% Secured Medium-Term Notes, Series M, due May 2048,
- issued $325 million of 3.25% Secured Medium-Term Notes, Series M, due September 2023,
- issued $325 million of 3.65% Secured Medium-Term Notes, Series M, due September 2028,
- retired $400 million of 5.30% Medium-Term Notes at maturity, and
- retired $350 million of 2.30% Medium-Term Notes at maturity.

Power
- issued $700 million of 3.85% Senior Notes due June 2023, and
- retired $250 million of 2.45% Senior Notes at maturity.

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 the $4.2 billion credit facilities are provided by a diverse bank group. As of December 31, 2018, the total available credit capacity was $3.0 billion.

As of December 31, 2018, no single institution represented more than 9% of the total commitments in the credit facilities.

As of December 31, 2018, the total credit capacity was in excess of the anticipated maximum liquidity requirements over PSEG’s 12-month planning horizon.

Each of the 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.

The total credit facilities and available liquidity as of December 31, 2018 were as follows:

Company/Facility	As of December 31, 2018 Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
	Millions				
PSEG					
5-year Credit Facilities (A)	$1,500	$759	$ 741	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSEG	$1,500	$759	$ 741		
PSE&G					
5-year Credit Facility (A)	$600	$288	$ 312	Mar 2022	Commercial Paper Support/Funding/Letters of Credit
Total PSE&G	$600	$288	$ 312		
Power					
3-year Letter of Credit Facilities	$200	$114	$ 86	Sept 2021	Letters of Credit
5-year Credit Facilities	1,900	40	1,860	Mar 2022	Funding/Letters of Credit
Total Power	$2,100	$154	$ 1,946		
Total	$4,200	$1,201	$ 2,999		

(A) 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, 2018, PSEG had $744 million outstanding at a weighted average interest rate of 2.95%. PSE&G had $272 million outstanding at a weighted average interest rate of 2.96% under its Commercial Paper Program as of December 31, 2018.

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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, 2018 and 2017 are included in the following table and accompanying notes as of December 31, 2018 and 2017. See Note 18. 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, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (A) (B)	$2,443	$2,397	$2,091	$2,081
PSE&G (B)	9,184	9,374	8,591	9,322
Power (B)	2,835	2,996	2,386	2,659
Total Long-Term Debt	$14,462	$14,767	$13,068	$14,062

(A) As of December 31, 2018 and 2017, fair value includes floating rate term loans of $1,050 million and $700 million, respectively. The fair value of the term loan debt (Level 2 measurement) approximates the carrying value because the interest payments are based on LIBOR rates that are reset monthly and the debt is redeemable at face value by PSEG at any time.

(B) Given that these bonds do not trade actively, 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.

Note 16. Schedule of Consolidated Capital Stock

	As of December 31,			
	Outstanding Shares		Book Value	
	2018	2017	2018	2017
	Millions			
PSEG Common Stock (no par value) (A)				
Authorized 1,000 shares	504	505	$4,172	$4,198

(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 2018 or 2017.

As of December 31, 2018, 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.

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Note 17. Financial Risk Management Activities
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 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. PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow or fair value hedges. Power enters into additional contracts that are derivatives, but 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, such as financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity, to manage the exposure to fluctuations in commodity prices and optimize the value of Power’s expected generation. Power also uses derivatives to hedge a portion of its anticipated BGSS obligations with PSE&G. For additional information see Note 14. Commitments and Contingent Liabilities. Changes in the fair market value of these derivative contracts are recorded in earnings.
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. The changes in fair value of the interest rate swaps are fully offset by changes in the fair value of the underlying forecasted interest payments of the debt. There were no outstanding interest rate swaps as of December 31, 2018 or 2017. The fair value hedges reduced interest expense by $6 million for the year ended December 31, 2016.
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. PSEG interest rate hedges totaling $500 million were executed and terminated during the second quarter of 2018 and a loss of $(1) million was recorded in Accumulated Other Comprehensive Income (Loss) (after tax) and will amortize to interest expense over the remaining life of Power’s $700 million of 3.85% Senior Notes due June 2023. For additional information see Note 15. Debt and Credit Facilities. There were no outstanding interest rate hedges as of December 31, 2018 and December 31, 2017. The Accumulated Other Comprehensive Income (Loss) (after tax) related to existing and terminated interest rate derivatives designated as cash flow hedges was $(1) million as of December 31, 2018, immaterial as of December 31, 2017 and $2 million as of December 31, 2016. The after-tax unrealized gains (losses) on these hedges expected to be reclassified to earnings during the next 12 months is immaterial.
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 PSEG’s accounting policy, these positions are offset on the Consolidated Balance

Sheets of Power and PSEG. For additional information see Note 18. Fair Value Measurements.

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

	As of December 31, 2018			
	Power (A)			Consolidated
Balance Sheet Location	Not Designated Energy-Related Contracts	Netting (B)	Total Power	Total Derivatives
	Millions			
Derivative Contracts				
Current Assets	$ 426	$ (415)	$ 11	$ 11
Noncurrent Assets	137	(136)	1	1
Total Mark-to-Market Derivative Assets	$ 563	$ (551)	$ 12	$ 12
Derivative Contracts				
Current Liabilities	$ (521)	$ 510	$ (11)	$ (11)
Noncurrent Liabilities	(198)	194	(4)	(4)
Total Mark-to-Market Derivative (Liabilities)	$ (719)	$ 704	$ (15)	$ (15)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$ (156)	$ 153	$ (3)	$ (3)

	As of December 31, 2017			
	Power (A)			Consolidated
Balance Sheet Location	Not Designated Energy-Related Contracts	Netting (B)	Total Power	Total Derivatives
	Millions			
Derivative Contracts				
Current Assets	$ 391	$ (362)	$ 29	$ 29
Noncurrent Assets	78	(71)	7	7
Total Mark-to-Market Derivative Assets	$ 469	$ (433)	$ 36	$ 36
Derivative Contracts				
Current Liabilities	$ (403)	$ 387	$ (16)	$ (16)
Noncurrent Liabilities	(95)	90	(5)	(5)
Total Mark-to-Market Derivative (Liabilities)	$ (498)	$ 477	$ (21)	$ (21)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$ (29)	$ 44	$ 15	$ 15

(A) Substantially all of Power'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, 2018 and 2017. 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 on the Consolidated Balance Sheets. As of December 31, 2018 and 2017, Power had net cash collateral/margin payments to counterparties of $393 million and $146 million, respectively. Of these net cash collateral/margin payments, $153 million as of December 31, 2018 and $44 million as of December 31, 2017 were netted against the corresponding net derivative contract positions. Of the $153 million as of December 31, 2018, $(2) million was netted against current assets, $(3) million was netted against noncurrent assets, $96 million was netted against current liabilities and $62 million was netted against noncurrent

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liabilities. Of the $44 million as of December 31, 2017, $(3) million was netted against current assets, $28 million was netted against current liabilities and $19 million was netted against noncurrent liabilities.
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 by S&P or Moody's, it would be required to provide additional collateral. A below investment grade credit rating for Power would represent a three level downgrade from its current S&P or Moody's ratings. 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 $22 million and $30 million as of December 31, 2018 and 2017, respectively. As of December 31, 2018 and 2017, Power had the contractual right of offset of $7 million and $13 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 $15 million and $17 million as of December 31, 2018 and 2017, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral.
The following shows the effect on the Consolidated Statements of Operations and on Accumulated Other Comprehensive Loss (AOCL) of derivative instruments designated as cash flow hedges for the years ended December 31, 2018, 2017 and 2016.

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCL on Derivatives (Effective Portion) Years Ended December 31,			Location of Pre-Tax Gain (Loss) Reclassified from AOCL into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCL into Income (Effective Portion) Years Ended December 31,		
	2018	2017	2016		2018	2017	2016
	Millions				Millions		
PSEG							
Interest Rate Swaps	$ (2)	$ —	$ 3	Interest Expense	$ —	$ 3	$ —
Total PSEG	$ (2)	$ —	$ 3		$ —	$ 3	$ —

There were no pre-tax gains (losses) recognized in income on derivatives (ineffective portion) as of December 31, 2018, 2017 and 2016.
The following reconciles the Accumulated Other Comprehensive Income (Loss) for derivative activity included in the AOCL of PSEG on a pre-tax and after-tax basis.

Accumulated Other Comprehensive Income (Loss)	Pre-Tax	After-Tax

	Millions	
Balance as of December 31, 2016	$3	$ 2
Gain Recognized in AOCI	—	—
Less: Gain Reclassified into Income	(3)	(2)
Balance as of December 31, 2017	$—	$ —
Loss Recognized in AOCI	(2)	(1)
Less: Loss Reclassified into Income	—	—
Balance as of December 31, 2018	$(2)	$ (1)

The following shows the effect on the Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as NPNS for the years ended December 31, 2018, 2017 and 2016. Power’s derivative contracts reflected in this table include contracts to hedge the purchase and sale of electricity and natural gas, and the purchase of fuel. The table does not include contracts which Power has designated as NPNS, such as its BGS contracts and certain other energy supply

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contracts that it has with other utilities and companies with retail load.

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,		
		2018	2017	2016
		Millions		
PSEG and Power				
Energy-Related Contracts	Operating Revenues	$ (182)	$ 66	$ 218
Energy-Related Contracts	Energy Costs	(9)	(11)	4
Total PSEG and Power		$ (191)	$ 55	$ 222

The following table summarizes the net notional volume purchases/(sales) of open derivative transactions by commodity as of December 31, 2018 and 2017.

Type	Notional	Total	PSEG	Power	PSE&G
	Millions				
As of December 31, 2018					
Natural Gas	Dth	358	—	358	—
Electricity	MWh	(74)	—	(74)	—
Financial Transmission Rights (FTRs)	MWh	18	—	18	—
As of December 31, 2017					
Natural Gas	Dth	154	—	154	—
Electricity	MWh	(63)	—	(63)	—
FTRs	MWh	6	—	6	—

Credit Risk

Credit risk relates to the risk of loss that Power would incur as a result of non-performance by counterparties pursuant to the terms of their contractual obligations. PSEG has established credit policies that it believes 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.

The following table provides information on Power's credit risk from wholesale counterparties, net of collateral, as of December 31, 2018. It further delineates that exposure by the credit rating of the counterparties, which is determined by the lowest rating from S&P, Moody's or an internal scoring model. In addition, it 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.

As of December 31, 2018, 99% of the net credit exposure 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, NPNS and non-derivatives).

Rating	Current	Securities	Net	Number of	Net Exposure of

	Exposure	Held as Collateral	Exposure	Counterparties >10%	Counterparties >10%	
	Millions				Millions	
Investment Grade	$264	$ 12	$ 252	1	$ 179	(A)
Non-Investment Grade	1	—	1	—	—	
Total	$265	$ 12	$ 253	1	$ 179	

(A) Represents net exposure with PSE&G.

As of December 31, 2018, collateral held from counterparties where Power had credit exposure includes $12 million in letters of credit.

As of December 31, 2018, Power had 151 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, 2018, 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 BGS suppliers' credit exposure is calculated each business day. As of December 31, 2018, 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.

Note 18. 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, as well as natural gas futures contracts executed on NYMEX.

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, 2018, these consisted primarily of certain electric load contracts and gas contracts.

Certain derivative transactions may transfer from Level 2 to Level 3 if inputs become unobservable and internal modeling techniques are employed to determine fair value. Conversely, measurements may transfer from Level 3 to Level 2 if the inputs become observable.

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, 2018 and December 31, 2017, 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 PSE&G and Power.

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Description	Recurring Fair Value Measurements as of December 31, 2018 Total	Netting (D)	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)	$100	$—	$ 100	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$12	$(551)	$ 29	$ 527	$ 7
NDT Fund (C)					
Equity Securities	$900	$—	$ 898	$ 2	$ —
Debt Securities—U.S. Treasury	$171	$—	$ —	$ 171	$ —
Debt Securities—Govt Other	$320	$—	$ —	$ 320	$ —
Debt Securities—Corporate	$487	$—	$ —	$ 487	$ —
Rabbi Trust (C)					
Equity Securities	$23	$—	$ 23	$ —	$ —
Debt Securities—U.S. Treasury	$69	$—	$ —	$ 69	$ —
Debt Securities—Govt Other	$40	$—	$ —	$ 40	$ —
Debt Securities—Corporate	$92	$—	$ —	$ 92	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(15)	$704	$ (36)	$ (677)	$ (6)
PSE&G					
Assets:					
Rabbi Trust (C)					
Equity Securities	$5	$—	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$14	$—	$ —	$ 14	$ —
Debt Securities—Govt Other	$8	$—	$ —	$ 8	$ —
Debt Securities—Corporate	$18	$—	$ —	$ 18	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$12	$(551)	$ 29	$ 527	$ 7
NDT Fund (C)					
Equity Securities	$900	$—	$ 898	$ 2	$ —
Debt Securities—U.S. Treasury	$171	$—	$ —	$ 171	$ —
Debt Securities—Govt Other	$320	$—	$ —	$ 320	$ —
Debt Securities—Corporate	$487	$—	$ —	$ 487	$ —
Rabbi Trust (C)					
Equity Securities	$6	$—	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$17	$—	$ —	$ 17	$ —
Debt Securities—Govt Other	$10	$—	$ —	$ 10	$ —
Debt Securities—Corporate	$23	$—	$ —	$ 23	$ —

Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(15)	$ 704	$ (36)	$ (677)	$ (6)

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	Recurring Fair Value Measurements as of December 31, 2017				
Description	Total	Netting (D)	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)	$223	$—	$ 223	$ —	$ —
Derivative Contracts:					
Energy-Related Contracts (B)	$36	$(433)	$ 15	$ 442	$ 12
NDT Fund (C)					
Equity Securities	$1,147	$—	$ 1,145	$ 2	$ —
Debt Securities—U.S. Treasury	$314	$—	$ —	$ 314	$ —
Debt Securities—Govt Other	$270	$—	$ —	$ 270	$ —
Debt Securities—Corporate	$402	$—	$ —	$ 402	$ —
Rabbi Trust (C)					
Equity Securities	$27	$—	$ 27	$ —	$ —
Debt Securities—U.S. Treasury	$51	$—	$ —	$ 51	$ —
Debt Securities—Govt Other	$34	$—	$ —	$ 34	$ —
Debt Securities—Corporate	$119	$—	$ —	$ 119	$ —
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(21)	$477	$ (8)	$ (485)	$ (5)
PSE&G					
Assets:					
Cash Equivalents (A)	$223	$—	$ 223	$ —	$ —
Rabbi Trust (C)					
Equity Securities	$5	$—	$ 5	$ —	$ —
Debt Securities—U.S. Treasury	$10	$—	$ —	$ 10	$ —
Debt Securities—Govt Other	$7	$—	$ —	$ 7	$ —
Debt Securities—Corporate	$24	$—	$ —	$ 24	$ —
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (B)	$36	$(433)	$ 15	$ 442	$ 12
NDT Fund (C)					
Equity Securities	$1,147	$—	$ 1,145	$ 2	$ —
Debt Securities—U.S. Treasury	$314	$—	$ —	$ 314	$ —
Debt Securities—Govt Other	$270	$—	$ —	$ 270	$ —
Debt Securities—Corporate	$402	$—	$ —	$ 402	$ —
Rabbi Trust (C)					
Equity Securities	$6	$—	$ 6	$ —	$ —
Debt Securities—U.S. Treasury	$13	$—	$ —	$ 13	$ —
Debt Securities—Govt Other	$8	$—	$ —	$ 8	$ —
Debt Securities—Corporate	$30	$—	$ —	$ 30	$ —

Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (B)	$(21)	$477	$ (8)	$ (485)	$ (5)

(A) Represents money market mutual funds.

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(B) Level 1—These contracts represent natural gas futures contracts executed on NYMEX, and are being valued solely on settled pricing inputs which come directly from the exchange.
Level 2—Fair values for energy-related contracts are obtained primarily using a market-based approach. Most derivative contracts (forward purchase or sale contracts and swaps) are valued using settled prices from similar assets and liabilities from an exchange, such as NYMEX, ICE and Nodal Exchange, or auction prices. Prices used in the valuation process are also corroborated independently by management to determine that values are based on actual transaction data or, in the absence of transactions, bid and offers for the day. Examples may include certain exchange and non-exchange traded capacity and electricity contracts and natural gas physical or swap contracts based on market prices, basis adjustments and other premiums where adjustments and premiums are not considered significant to the overall inputs.
Level 3—Unobservable inputs are used for the valuation of certain contracts. See "Additional Information Regarding Level 3 Measurements" below for more information on the utilization of unobservable inputs.

(C) The NDT Fund maintains investments in various equity and fixed income securities. The Rabbi Trust maintains investments in a Russell 3000 index fund and various fixed income securities. These securities are generally valued with prices that are either exchange provided (equity securities) or market transactions for comparable securities and/or broker quotes (fixed income securities).
Level 1—Investments in marketable equity securities within the NDT Fund are primarily investments in common stocks across a broad range of industries and sectors. Most equity securities are priced utilizing the principal market close price or, in some cases, midpoint, bid or ask price. Certain other equity securities in the NDT and Rabbi Trust Funds consist primarily of investments in Dreyfus money market funds which seek a high level of current income as is consistent with the preservation of capital and the maintenance of liquidity. To pursue its goals, the funds normally invest in diversified portfolios of high quality, short-term, dollar-denominated debt securities and government securities. The funds' NAV is priced and published daily. The Rabbi Trust also has an equity index fund which is valued based on quoted prices in an active market.
Level 2—NDT and Rabbi Trust fixed income securities include investment grade corporate bonds, collateralized mortgage obligations, asset-backed securities and certain government and U.S. Treasury obligations or Federal Agency asset-backed securities and municipal bonds with a wide range of maturities. Since many fixed income securities do not trade on a daily basis, they are priced using an evaluated pricing methodology that varies by asset class and reflects observable market information such as the most recent exchange price or quoted bid for similar securities. Market-based standard inputs typically include benchmark yields, reported trades, broker/dealer quotes and issuer spreads. The preferred stocks are not actively traded on a daily basis and therefore, are also priced using an evaluated pricing methodology. Certain short-term investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield.

(D) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application of collateral. See Note 17. Financial Risk Management Activities for additional detail.

Additional Information Regarding Level 3 Measurements

For valuations that include both observable and unobservable inputs, if the unobservable input is determined to be significant to the overall inputs, the entire valuation is categorized in Level 3. This includes derivatives valued using indicative price quotations for contracts with tenors that extend into periods with no observable pricing. In instances where observable data is unavailable, consideration is given to the assumptions that market participants would use in valuing the asset or liability. This includes assumptions about market risks such as liquidity, volatility and contract duration. Such instruments are categorized in Level 3 because the model inputs generally are not observable. PSEG's Risk Management Committee (RMC) approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval and the monitoring and reporting of risk exposures. The RMC reports to the Corporate Governance and Audit Committees of the PSEG Board on the scope of the risk management activities and is responsible for approving all valuation procedures at PSEG. Forward price curves for the power market utilized by Power to manage the portfolio are maintained and reviewed by PSEG's Enterprise Risk Management market pricing group and used for financial reporting purposes. PSEG considers credit and nonperformance risk in the valuation of derivative contracts categorized in Levels 2 and 3, including both historical and current market data, in its assessment of credit and nonperformance risk by counterparty. The impacts of credit and nonperformance risk were not material to the financial statements.

The fair value of Power’s electric load contracts in which load consumption may change hourly based on demand are measured using certain unobservable inputs, such as historic load variability and, accordingly, are categorized as Level 3. The fair value of Power’s gas physical contracts at certain illiquid delivery locations are measured using average historical basis and, accordingly, are categorized as Level 3. While these physical gas contracts have an unobservable component in their respective

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forward price curves, the fluctuations in fair value have been driven primarily by changes in the observable inputs. The following tables provide details surrounding significant Level 3 valuations as of December 31, 2018 and 2017.

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2018 Assets	(Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		(Millions)				
Power						
Electricity	Electric Load Contracts	$ 2	$ (5)	Discounted Cash flow	Historic Load Variability	0% to 15%
Gas	Gas Physical Contracts	5	(1)	Discounted Cash flow	Average Historical Basis	-40% to 0%
Total Power		$ 7	$ (6)			
Total PSEG		$ 7	$ (6)			

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value as of December 31, 2017 Assets	(Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		(Millions)				
Power						
Electricity	Electric Load Contracts	$ 1	$ (3)	Discounted Cash flow	Historic Load Variability	0% to 10%
Gas	Gas Physical Contracts	11	(2)	Discounted Cash flow	Average Historical Basis	-40% to -10%
Total Power		$ 12	$ (5)			
Total PSEG		$ 12	$ (5)			

Significant unobservable inputs listed above would have a direct impact on the fair values of the above Level 3 instruments if they were adjusted. For energy-related contracts in cases where Power is a seller, an increase in the load variability would decrease the fair value. For gas-related contracts in cases where Power is a buyer, an increase in the average historical basis would increase the fair value.

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A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the years ended December 31, 2018 and 2017, respectively, follows:
Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Year Ended December 31, 2018

Description	Balance as of January 1, 2018	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances/ Settlements (C)	Transfers In/Out	Balance as of December 31, 2018
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$7	$ (6)	$ —	$ —	$ —	$ —	$ 1
Power							
Net Derivative Assets (Liabilities)	$7	$ (6)	$ —	$ —	$ —	$ —	$ 1

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Year Ended December 31, 2017

Description	Balance as of January 1, 2017	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales)	Issuances/ Settlements (C)	Transfers In/Out (D)	Balance as of December 31, 2017
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$1	$ 26	$ 5	$ —	$ (24)	$ (1)	$ 7
PSE&G							
Net Derivative Assets (Liabilities)	$(5)	$ —	$ 5	$ —	$ —	$ —	$ —
Power							
Net Derivative Assets (Liabilities)	$6	$ 26	$ —	$ —	$ (24)	$ (1)	$ 7

(A)Unrealized gains (losses) in the following table represent the change in derivative assets and liabilities still held as of December 31, 2018 and 2017.

	Years Ended December 31, 2018: Total Gains (Losses)	2018: Unrealized Gains (Losses)	2017: Total Gains (Losses)	2017: Unrealized Gains (Losses)
	Millions			
PSEG and Power				
Operating Revenues	$(2)	$ —	$14	$ (9)

Energy Costs	(4)	(6)	12	12
Total	$(6)	$ (6)	$26	$ 3

(B) Mainly includes gains/losses on PSE&G’s derivative contracts that are not included in either earnings or Accumulated Other Comprehensive Income, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G’s customers.

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(C) Represents $(24) million in settlements for derivative contracts in 2017.

(D) During the year ended December 31, 2017, $(1) million of net derivatives assets/liabilities were transferred from Level 2 to Level 3. There were no transfers in 2018.

As of December 31, 2018, PSEG carried $2.2 billion of net assets that are measured at fair value on a recurring basis, of which $1 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of December 31, 2017, PSEG carried $2.6 billion of net assets that are measured at fair value on a recurring basis, of which $7 million of net assets were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Note 19. Stock Based Compensation

PSEG's Amended and Restated 2004 Long-Term Incentive Plan (LTIP) is a broad-based equity compensation program that provides for grants of various long-term incentive compensation awards, such as stock options, stock appreciation rights, performance share units, restricted stock, restricted stock units, cash awards or any combination thereof. The types of long-term incentive awards that have been granted and remain outstanding under the LTIP are non-qualified options to purchase shares of PSEG's common stock, restricted stock unit awards and performance share unit awards. The type of equity award that is granted and the details of that award may vary from time to time and is subject to the approval of the Organization and Compensation Committee of PSEG's Board of Directors (O&CC), the LTIP's administrative committee.

The LTIP currently provides for the issuance of equity awards with respect to approximately 16 million shares of common stock. As of December 31, 2018, there were approximately 13 million shares available for future awards under the LTIP.

Stock Options

Under the LTIP, non-qualified options to acquire shares of PSEG common stock may be granted to officers and other key employees selected by the O&CC. Option awards are granted with an exercise price equal to the market price of PSEG's common stock at the grant date. The options generally vest over four years of continuous service. Vesting schedules may be accelerated upon the occurrence of certain events, such as a change-in-control (unless substituted with an equity award of equal value), retirement, death or disability. Options are exercisable over a period of time designated by the O&CC (but not prior to one year or longer than ten years from the date of grant) and are subject to such other terms and conditions as the O&CC determines. Payment by option holders upon exercise of an option may be made in cash or, with the consent of the O&CC, by delivering previously acquired shares of PSEG common stock. No options have been granted since 2009.

Restricted Stock Units

Under the LTIP, PSEG has granted restricted stock unit awards to officers and other key employees. These awards, which are bookkeeping entries only, are subject to risk of forfeiture until vested by continued employment. Until distributed, the units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. The restricted stock unit grants for 2018 and 2017 generally vest at the end of three years. Vesting may be accelerated (pro-rated basis or full vesting) upon certain events such as change-in-control, retirement, disability or death.

Performance Share Units

Under the LTIP, PSEG has granted performance share units to officers and other key employees. These provide for distribution in shares of PSEG common stock based on achievement of certain financial goals over a three-year performance period. Following the end of the performance period, the payout varies from 0% to 200% of the number of performance units granted depending on PSEG's performance with respect to certain financial targets, including targets related to comparative performance against other companies in a peer group of energy companies. The performance share units are credited with dividend equivalents proportionate to the dividends paid on PSEG common stock. Distributions are made in shares of common stock. Vesting may be accelerated on a pro-rated basis for the period of the employee's service during the performance period as a result of certain events, such as change-in-control, retirement, death or disability.

Stock-Based Compensation

PSEG recognizes compensation expense for stock options based on their grant date fair values, which are determined using the Black-Scholes option-pricing model. Stock option awards are expensed on a tranche-specific basis over the requisite service period of the award. Ultimately, compensation expense for stock options is recognized for awards that vest.

PSEG recognizes compensation expense for restricted stock units over the vesting period based on the grant date fair value of the shares, which is equal to the market price of PSEG's common stock on the date of the grant.

PSEG recognizes compensation expense for the total shareholder return target for its performance share unit awards based on the grant date fair values of the award, which are determined using the Monte Carlo model. The accrual of compensation cost is based on the probable achievement of the performance conditions, which result in a payout from 0% to 200% of the initial grant. PSEG recognizes compensation expense for the return on invested capital target for its performance share units based on

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the grant date fair value of the awards, which is equal to the market price of PSEG's common stock on the date of the grant. The accrual during the year of grant is estimated at 100% of the original grant. Such accrual may be adjusted to reflect the actual outcome.

	2018	2017	2016
	Millions		
Compensation Cost included in Operation and Maintenance Expense	$30	$ 31	$ 29
Income Tax Benefit Recognized in Consolidated Statement of Operations	$9	$ 13	$ 12

For 2018, 2017 and 2016 the excess tax benefit of $3 million, $4 million and $4 million, respectively was included as financing cash flows on the Consolidated Statements of Cash Flow.
PSEG recognizes compensation cost of awards issued over the shorter of the original vesting period or the period beginning on the date of grant and ending on the date an individual is eligible for retirement and the award vests.
Stock Options
Changes in stock options for 2018 are summarized as follows:

	Options	Weighted Average Exercise Price	Weighted Average Remaining Years Contractual Term	Aggregate Intrinsic Value
Outstanding as of January 1, 2018	347,900	$ 33.49		
Exercised	115,967	$ 33.49		
Canceled/Forfeited	—	$ —		
Outstanding as of December 31, 2018	231,933	$ 33.49	1.0	$4,304,676
Exercisable at December 31, 2018	231,933	$ 33.49	1.0	$4,304,676