PUBLIC SERVICE ELECTRIC & GAS CO
Form 10-Q
November 02, 2012
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549
FORM 10-Q
(Mark One)
ý QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED September 30, 2012
OR
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE TRANSITION PERIOD FROM TO

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

Indicate by check mark whether the registrants (1) have 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) have been subject to such filing requirements for the past 90 days. Yes ý No ¨

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

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

Large accelerated filer x Accelerated filer o Non-accelerated filer o Smaller reporting company o

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

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 ý

As of October 16, 2012, Public Service Enterprise Group Incorporated had outstanding 505,917,472 shares of its sole class of Common Stock, without par value.

As of October 16, 2012, Public Service Electric and Gas Company had issued and outstanding 132,450,344 shares of Common Stock, without nominal or par value, all of which were privately held, beneficially and of record by Public Service Enterprise Group Incorporated.

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

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FORWARD-LOOKING STATEMENTS

Certain of the matters discussed in this report 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,” “forecas variations of such words and similar expressions are 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 1. Financial Statements—Note 8. Commitments and Contingent Liabilities, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations, and other factors discussed in filings we make with the United States Securities and Exchange Commission (SEC). These factors include, but are not limited to:

- adverse changes in the demand for or the price of the capacity and energy that we sell into wholesale electricity markets,
- adverse changes in energy industry law, policies and regulation, including market structures and a potential shift away from competitive markets toward subsidized market mechanisms, transmission planning and cost allocation rules, including rules regarding how transmission is planned and who is permitted to build transmission in the future, and reliability standards,
- any inability of our transmission and distribution businesses to obtain adequate and timely rate relief and regulatory approvals from federal and state regulators,
- changes in federal and state environmental regulations that could increase our costs or limit our operations,
- changes in nuclear regulation and/or general developments in the nuclear power industry, including various impacts from any accidents or incidents experienced at our facilities or by others in the industry, that could limit operations of our nuclear generating units,
- actions or activities at one of our nuclear units located on a multi-unit site that might adversely affect our ability to continue to operate that unit or other units located at the same site,
- any inability to balance our energy obligations, available supply and trading risks,
- any deterioration in our credit quality or the credit quality of our counterparties, including in our leveraged leases,
- availability of capital and credit at commercially reasonable terms and conditions and our ability to meet cash needs,
- changes in the cost of, or interruption in the supply of, fuel and other commodities necessary to the operation of our generating units,
- delays in receipt of necessary permits and approvals for our construction and development activities,
- delays or unforeseen cost escalations in our construction and development activities,
- any inability to achieve, or continue to sustain, our expected levels of operating performance,
- increase in competition in energy supply markets as well as competition for certain rate-based transmission projects,
- any inability to realize anticipated tax benefits or retain tax credits,
- challenges associated with recruitment and/or retention of a qualified workforce,
- adverse performance of our decommissioning and defined benefit plan trust fund investments and changes in funding requirements, and
- changes in technology and customer usage patterns.

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

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

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
OPERATING REVENUES	$2,402	$2,620	$7,375	$8,443
OPERATING EXPENSES				
Energy Costs	879	1,167	2,819	3,740
Operation and Maintenance	619	603	1,876	1,829
Depreciation and Amortization	286	263	797	739
Taxes Other Than Income Taxes	24	31	73	102
Total Operating Expenses	1,808	2,064	5,565	6,410
OPERATING INCOME	594	556	1,810	2,033
Income from Equity Method Investments	7	1	9	8
Other Income	121	45	216	176
Other Deductions	(26)	(11)	(61)	(39)
Other-Than-Temporary Impairments	(2)	(8)	(14)	(13)
Interest Expense	(106)	(117)	(310)	(361)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	588	466	1,650	1,804
Income Tax (Expense) Benefit	(241)	(201)	(599)	(757)
INCOME FROM CONTINUING OPERATIONS	347	265	1,051	1,047
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $(15) and $(51) for the three and nine months ended 2011	—	29	—	96
NET INCOME	$347	$294	$1,051	$1,143
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):				
BASIC	505,914	505,909	505,942	505,959
DILUTED	507,111	506,999	507,037	506,963
EARNINGS PER SHARE:				
BASIC				
INCOME FROM CONTINUING OPERATIONS	$0.69	$0.52	$2.08	$2.07
NET INCOME	$0.69	$0.58	$2.08	$2.26
DILUTED				
INCOME FROM CONTINUING OPERATIONS	$0.68	$0.52	$2.07	$2.06
NET INCOME	$0.68	$0.58	$2.07	$2.25
	$0.3550	$0.3425	$1.0650	$1.0275

DIVIDENDS PAID PER SHARE OF
COMMON STOCK

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See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
NET INCOME	$347	$294	$1,051	$1,143
Other Comprehensive Income (Loss), net of tax				
Available-for-Sale Securities, net of tax (expense) benefit of $5, $59, $(16) and $76 for the three and nine months ended 2012 and 2011, respectively	(10)	(58)	12	(73)
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $1, $(9), $(10) and $(8) for the three and nine months ended 2012 and 2011, respectively	(2)	12	13	11
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $7, $25, $24 and $62 for the three and nine months ended 2012 and 2011, respectively	(8)	(35)	(33)	(91)
Pension/OPEB adjustment, net of tax (expense) benefit of $(5), $(4), $(16) and $(34) for the three and nine months ended 2012 and 2011, respectively	8	4	23	53
Other Comprehensive Income (Loss), net of tax	(12)	(77)	15	(100)
COMPREHENSIVE INCOME	$335	$217	$1,066	$1,043

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$780	$834
Accounts Receivable, net of allowances of $52 and $56 in 2012 and 2011, respectively	1,044	967
Tax Receivable	—	16
Unbilled Revenues	215	289
Fuel	657	685
Materials and Supplies, net	416	367
Prepayments	274	308
Derivative Contracts	123	156
Deferred Income Taxes	148	—
Regulatory Assets	280	167
Other	41	122
Total Current Assets	3,978	3,911
PROPERTY, PLANT AND EQUIPMENT	26,731	25,080
Less: Accumulated Depreciation and Amortization	(7,628)	(7,231)
Net Property, Plant and Equipment	19,103	17,849
NONCURRENT ASSETS		
Regulatory Assets	3,336	3,805
Regulatory Assets of Variable Interest Entities (VIEs)	760	925
Long-Term Investments	1,314	1,303
Nuclear Decommissioning Trust (NDT) Fund	1,501	1,349
Other Special Funds	192	172
Goodwill	16	16
Other Intangibles	57	131
Derivative Contracts	144	106
Restricted Cash of VIEs	21	22
Other	284	232
Total Noncurrent Assets	7,625	8,061
TOTAL ASSETS	$30,706	$29,821

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2012	December 31, 2011
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year (includes $50 at fair value in 2011)	$751	$417
Securitization Debt of VIEs Due Within One Year	224	216
Accounts Payable	1,012	1,184
Derivative Contracts	51	131
Accrued Interest	119	97
Accrued Taxes	216	30
Deferred Income Taxes	—	170
Clean Energy Program	89	214
Obligation to Return Cash Collateral	122	107
Regulatory Liabilities	94	100
Other	361	291
Total Current Liabilities	3,039	2,957
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	6,058	5,458
Regulatory Liabilities	248	228
Regulatory Liabilities of VIEs	10	9
Asset Retirement Obligations	513	489
Other Postretirement Benefit (OPEB) Costs	1,116	1,127
Accrued Pension Costs	629	734
Clean Energy Program	—	39
Environmental Costs	565	643
Derivative Contracts	112	26
Long-Term Accrued Taxes	166	292
Other	108	86
Total Noncurrent Liabilities	9,525	9,131
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	6,729	6,694
Securitization Debt of VIEs	561	723
Project Level, Non-Recourse Debt	44	44
Total Long-Term Debt	7,334	7,461
STOCKHOLDERS' EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2012 and 2011—533,556,660 shares	4,836	4,823
Treasury Stock, at cost, 2012—27,664,188 shares; 2011—27,611,374 shares	(606)	(601)
Retained Earnings	6,898	6,385
Accumulated Other Comprehensive Loss	(322)	(337)
Total Common Stockholders' Equity	10,806	10,270

Noncontrolling Interest	2	2
Total Stockholders’ Equity	10,808	10,272
Total Capitalization	18,142	17,733
TOTAL LIABILITIES AND CAPITALIZATION	$30,706	$29,821

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$1,051	$1,143
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Gain on Disposal of Discontinued Operations	—	(122)
Depreciation and Amortization	797	745
Amortization of Nuclear Fuel	129	114
Provision for Deferred Income Taxes (Other than Leases) and ITC	221	629
Non-Cash Employee Benefit Plan Costs	203	138
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(81)	(16)
Leveraged Lease Reserve, net of tax	—	170
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	116	(14)
Over (Under) Recovery of Electric Energy Costs (BGS and NTC) and Gas Costs	46	100
Over (Under) Recovery of Societal Benefits Charge (SBC)	(51)	(26)
Market Transition Charge Refund	(23)	(47)
Cost of Removal	(71)	(43)
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(107)	(110)
Net Change in Tax Receivable	16	312
Net Change in Certain Current Assets and Liabilities	305	(44)
Employee Benefit Plan Funding and Related Payments	(193)	(486)
Other	(47)	(34)
Net Cash Provided By (Used In) Operating Activities	2,311	2,409
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,969)	(1,479)
Proceeds from Sale of Discontinued Operations	—	687
Proceeds from Sales of Available-for-Sale Securities	1,473	1,088
Investments in Available-for-Sale Securities	(1,497)	(1,110)
Other	(58)	(13)
Net Cash Provided By (Used In) Investing Activities	(2,051)	(827)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	—	(64)
Issuance of Long-Term Debt	850	750
Redemption of Long-Term Debt	(439)	(606)
Repayment of Non-Recourse Debt	(1)	(1)
Redemption of Securitization Debt	(154)	(147)
Cash Dividends Paid on Common Stock	(538)	(520)
Other	(32)	(32)
Net Cash Provided By (Used In) Financing Activities	(314)	(620)
Net Increase (Decrease) in Cash and Cash Equivalents	(54)	962

Cash and Cash Equivalents at Beginning of Period	834	280
Cash and Cash Equivalents at End of Period	$780	$1,242
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$109	$60
Interest Paid, Net of Amounts Capitalized	$280	$341
Accrued Property, Plant and Equipment Expenditures	$259	$211

See Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
OPERATING REVENUES	$1,038	$1,398	$3,584	$4,650
OPERATING EXPENSES				
Energy Costs	456	597	1,725	2,335
Operation and Maintenance	255	262	780	810
Depreciation and Amortization	60	56	175	166
Total Operating Expenses	771	915	2,680	3,311
OPERATING INCOME	267	483	904	1,339
Other Income	104	37	171	156
Other Deductions	(20)	(10)	(52)	(37)
Other-Than-Temporary Impairments	(2)	(8)	(14)	(10)
Interest Expense	(35)	(42)	(97)	(134)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	314	460	912	1,314
Income Tax (Expense) Benefit	(133)	(187)	(374)	(539)
INCOME FROM CONTINUING OPERATIONS	181	273	538	775
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $(15) and $(51) for the three and nine months ended 2011	—	29	—	96
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$181	$302	$538	$871

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

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
NET INCOME	$181	$302	$538	$871
Other Comprehensive Income (Loss), net of tax				
Available-for-Sale Securities, net of tax (expense) benefit of $6, $58, $(16) and $77 for the three and nine months ended 2012 and 2011, respectively	(11)	(60)	11	(77)
Change in Fair Value of Derivative Instruments, net of tax (expense) benefit of $1, $(9), $(10) and $(8) for the three and nine months ended 2012 and 2011, respectively	(2)	12	13	11
Reclassification Adjustments for Net Amounts included in Net Income, net of tax (expense) benefit of $7, $25, $24 and $62 for the three and nine months ended 2012 and 2011, respectively	(9)	(35)	(34)	(91)
Pension/OPEB adjustment, net of tax (expense) benefit of $(4), $(3), $(14) and $(31) for the three and nine months ended 2012 and 2011, respectively	7	3	21	45
Other Comprehensive Income (Loss), net of tax	(15)	(80)	11	(112)
COMPREHENSIVE INCOME	$166	$222	$549	$759

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

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$5	$12
Accounts Receivable	295	267
Accounts Receivable—Affiliated Companies, net	100	381
Short-Term Loan to Affiliate	890	907
Fuel	657	685
Materials and Supplies, net	310	272
Derivative Contracts	102	139
Prepayments	22	24
Total Current Assets	2,381	2,687
PROPERTY, PLANT AND EQUIPMENT	9,564	9,191
Less: Accumulated Depreciation and Amortization	(2,692)	(2,460)
Net Property, Plant and Equipment	6,872	6,731
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Fund	1,501	1,349
Goodwill	16	16
Other Intangibles	57	131
Other Special Funds	36	33
Derivative Contracts	22	55
Other	109	85
Total Noncurrent Assets	1,741	1,669
TOTAL ASSETS	$10,994	$11,087

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

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PSEG POWER LLC
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2012	December 31, 2011
LIABILITIES AND MEMBER'S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$300	$66
Accounts Payable	433	541
Derivative Contracts	51	124
Deferred Income Taxes	4	53
Accrued Interest	49	32
Other	90	86
Total Current Liabilities	927	902
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	1,463	1,266
Asset Retirement Obligations	275	259
Other Postretirement Benefit (OPEB) Costs	189	180
Derivative Contracts	6	24
Accrued Pension Costs	205	236
Long-Term Accrued Taxes	66	8
Other	84	83
Total Noncurrent Liabilities	2,288	2,056
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
LONG-TERM DEBT		
Total Long-Term Debt	2,386	2,685
MEMBER'S EQUITY		
Contributed Capital	2,028	2,028
Basis Adjustment	(986)	(986)
Retained Earnings	4,616	4,678
Accumulated Other Comprehensive Loss	(265)	(276)
Total Member's Equity	5,393	5,444
TOTAL LIABILITIES AND MEMBER'S EQUITY	$10,994	$11,087

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

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PSEG POWER LLC
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30,	
	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$538	$871
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Gain on Disposal of Discontinued Operations	—	(122)
Depreciation and Amortization	175	173
Amortization of Nuclear Fuel	129	114
Provision for Deferred Income Taxes and ITC	189	74
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	116	(14)
Non-Cash Employee Benefit Plan Costs	53	33
Net Realized (Gains) Losses and (Income) Expense from NDT Fund	(107)	(110)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	(10)	(82)
Margin Deposit	(107)	(63)
Accounts Receivable	50	157
Accounts Payable	(31)	(103)
Accounts Receivable/Payable-Affiliated Companies, net	193	650
Accrued Interest Payable	17	23
Other Current Assets and Liabilities	2	48
Employee Benefit Plan Funding and Related Payments	(40)	(127)
Other	5	(35)
Net Cash Provided By (Used In) Operating Activities	1,172	1,487
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(493)	(530)
Proceeds from Sale of Discontinued Operations	—	687
Proceeds from Sales of Available-for-Sale Securities	1,295	1,088
Investments in Available-for-Sale Securities	(1,315)	(1,106)
Short-Term Loan—Affiliated Company, net	17	(1,176)
Other	(10)	19
Net Cash Provided By (Used In) Investing Activities	(506)	(1,018)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Recourse Long-Term Debt	—	500
Cash Dividend Paid	(600)	(350)
Redemption of Long-Term Debt	(66)	(606)
Other	(7)	(10)
Net Cash Provided By (Used In) Financing Activities	(673)	(466)
Net Increase (Decrease) in Cash and Cash Equivalents	(7)	3
Cash and Cash Equivalents at Beginning of Period	12	11
Cash and Cash Equivalents at End of Period	$5	$14

Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$130	$110
Interest Paid, Net of Amounts Capitalized	$73	$111
Accrued Property, Plant and Equipment Expenditures	$84	$86

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
OPERATING REVENUES	$1,683	$1,841	$5,029	$5,718
OPERATING EXPENSES				
Energy Costs	756	943	2,380	3,124
Operation and Maintenance	366	342	1,092	1,014
Depreciation and Amortization	216	197	594	548
Taxes Other Than Income Taxes	24	31	73	102
Total Operating Expenses	1,362	1,513	4,139	4,788
OPERATING INCOME	321	328	890	930
Other Income	16	7	39	16
Other Deductions	(6)	(1)	(8)	(2)
Other-Than-Temporary Impairments	—	—	—	(1)
Interest Expense	(73)	(77)	(220)	(234)
INCOME BEFORE INCOME TAXES	258	257	701	709
Income Tax (Expense) Benefit	(103)	(103)	(248)	(287)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$155	$154	$453	$422

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
Millions
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
NET INCOME	$155	$154	$453	$422
Available-for-Sale Securities, net of tax (expense) benefit of $(1), $(0), $(0) and $(1) for the three and nine months ended 2012 and 2011, respectively	1	1	—	2
COMPREHENSIVE INCOME	$156	$155	$453	$424

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2012	December 31, 2011
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$71	$143
Accounts Receivable, net of allowances of $52 and $56 in 2012 and 2011, respectively	729	691
Tax Receivable	—	16
Unbilled Revenues	215	289
Materials and Supplies	105	94
Prepayments	145	117
Regulatory Assets	280	167
Derivative Contracts	3	—
Other	30	21
Total Current Assets	1,578	1,538
PROPERTY, PLANT AND EQUIPMENT	16,509	15,306
Less: Accumulated Depreciation and Amortization	(4,674)	(4,539)
Net Property, Plant and Equipment	11,835	10,767
NONCURRENT ASSETS		
Regulatory Assets	3,336	3,805
Regulatory Assets of VIEs	760	925
Long-Term Investments	334	280
Other Special Funds	63	57
Derivative Contracts	70	4
Restricted Cash of VIEs	21	22
Other	118	89
Total Noncurrent Assets	4,702	5,182
TOTAL ASSETS	$18,115	$17,487

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS
Millions
(Unaudited)

	September 30, 2012	December 31, 2011
LIABILITIES AND CAPITALIZATION		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$450	$300
Securitization Debt of VIEs Due Within One Year	224	216
Accounts Payable	449	498
Accounts Payable—Affiliated Companies, net	155	280
Accrued Interest	71	65
Clean Energy Program	89	214
Derivative Contracts	—	7
Deferred Income Taxes	16	32
Obligation to Return Cash Collateral	122	107
Regulatory Liabilities	94	100
Other	243	186
Total Current Liabilities	1,913	2,005
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	3,916	3,675
Other Postretirement Benefit (OPEB) Costs	879	900
Accrued Pension Costs	285	355
Regulatory Liabilities	248	228
Regulatory Liabilities of VIEs	10	9
Clean Energy Program	—	39
Environmental Costs	514	592
Asset Retirement Obligations	233	226
Derivative Contracts	106	—
Long-Term Accrued Taxes	19	83
Other	37	35
Total Noncurrent Liabilities	6,247	6,142
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	4,294	3,970
Securitization Debt of VIEs	561	723
Total Long-Term Debt	4,855	4,693
STOCKHOLDER'S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2012 and 2011—132,450,344 shares	892	892
Contributed Capital	420	420
Basis Adjustment	986	986
Retained Earnings	2,800	2,347
Accumulated Other Comprehensive Income	2	2
Total Stockholder's Equity	5,100	4,647

Total Capitalization	9,955	9,340
TOTAL LIABILITIES AND CAPITALIZATION	$18,115	$17,487

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
Millions
(Unaudited)

	Nine Months Ended September 30, 2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$453	$422
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	594	548
Provision for Deferred Income Taxes and ITC	131	563
Non-Cash Employee Benefit Plan Costs	134	92
Cost of Removal	(71)	(43)
Market Transition Charge (MTC) Refund	(23)	(47)
Over (Under) Recovery of Electric Energy Costs (BGS and NTC) and Gas Costs	46	100
Over (Under) Recovery of SBC	(51)	(26)
Net Changes in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	97	261
Materials and Supplies	(11)	(1)
Prepayments	(28)	(203)
Net Change in Tax Receivable	16	(21)
Accounts Receivable/Payable-Affiliated Companies, net	(41)	(381)
Other Current Assets and Liabilities	2	(66)
Employee Benefit Plan Funding and Related Payments	(137)	(311)
Other	(70)	(15)
Net Cash Provided By (Used In) Operating Activities	1,041	872
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,369)	(939)
Proceeds from Sale of Available-for-Sale Securities	73	—
Investments in Available-for-Sale Securities	(73)	—
Solar Loan Investments	(56)	(34)
Restricted Funds	1	(1)
Net Cash Provided By (Used In) Investing Activities	(1,424)	(974)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Long-Term Debt	850	250
Redemption of Long-Term Debt	(373)	—
Redemption of Securitization Debt	(154)	(147)
Deferred Issuance Costs	(12)	(4)
Net Cash Provided By (Used In) Financing Activities	311	99
Net Increase (Decrease) In Cash and Cash Equivalents	(72)	(3)
Cash and Cash Equivalents at Beginning of Period	143	245
Cash and Cash Equivalents at End of Period	$71	$242
Supplemental Disclosure of Cash Flow Information:		

Income Taxes Paid (Received)	$(30)	$(44)
Interest Paid, Net of Amounts Capitalized	$205	$225
Accrued Property, Plant and Equipment Expenditures	$175	$125

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

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

Note 1. Organization and Basis of Presentation

Organization

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 four principal direct wholly owned subsidiaries are:

- Power—which is a multi-regional, wholesale energy supply company that integrates its generating asset operations and gas supply commitments with its wholesale energy, fuel supply, energy trading and marketing and risk management functions through three principal direct wholly owned subsidiaries. Power's subsidiaries are subject to regulation by the Federal Energy Regulatory Commission (FERC), the Nuclear Regulatory Commission (NRC) and the states in which they operate.
- PSE&G—which is an operating 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 FERC. PSE&G is also investing in the development of solar generation projects and energy efficiency programs, which are regulated by the BPU.
- PSEG Energy Holdings L.L.C. (Energy Holdings)—which has invested in leveraged leases and owns and operates domestic projects engaged in the generation of energy through its direct wholly owned subsidiaries. Certain Energy Holdings' subsidiaries are subject to regulation by FERC and the states in which they operate. Energy Holdings has also invested in solar generation projects and is exploring opportunities for other investments in renewable generation and has been awarded a contract to manage the transmission and distribution assets of the Long Island Power Authority (LIPA) starting in 2014.
- PSEG Services Corporation (Services)—which provides 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 Quarterly Reports on Form 10-Q. Certain information and note disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States (GAAP) have been condensed or omitted pursuant to such rules and regulations. These Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements (Notes) should be read in conjunction with, and update and supplement matters discussed in, the Annual Report on Form 10-K for the year ended December 31, 2011 and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012.

The unaudited condensed consolidated financial information furnished herein reflects all adjustments which are, in the opinion of management, necessary to fairly state the results for the interim periods presented. All such adjustments are of a normal recurring nature. All significant intercompany accounts and transactions are eliminated in consolidation, except as discussed in Note 17. Related-Party Transactions. The year-end Condensed Consolidated Balance Sheets were derived from the audited Consolidated Financial Statements included in the Annual Report on Form 10-K for the year ended December 31, 2011.

Note 2. Recent Accounting Standards

New Standards Adopted during 2012

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in GAAP and International Financial Reporting Standards (IFRS)

This accounting standard was issued to update guidance related to fair value measurements and disclosures as a step towards achieving convergence between GAAP and IFRS. The updated guidance

- clarifies intent about application of existing fair value measurements and disclosures,
- changes some requirements for fair value measurements, and
- requires expanded disclosures.

We adopted this standard prospectively effective January 1, 2012. Upon adoption there was no material impact on our

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

consolidated financial position, results of operations or cash flows; however, it has resulted in expanded disclosures. For additional information, see Note 11. Fair Value Measurements.

Presentation of Comprehensive Income

This accounting standard addresses the presentation of comprehensive income as a step towards achieving convergence between GAAP and IFRS. The updated guidance

- allows an entity to present components of net income and other comprehensive income in one continuous statement, referred to as the statement of comprehensive income, or in two separate, but consecutive statements, and
- eliminates the current option to report other comprehensive income and its components in the statement of changes in equity.

In December 2011, the FASB issued an amendment to this standard to indefinitely defer the effective date for some of the specific disclosure requirements that relate to the presentation of reclassification adjustments out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. During the deferral period, the existing requirements in GAAP for the presentation of reclassification adjustments must continue to be followed.

We adopted this standard retrospectively effective January 1, 2012. Upon adoption of the new amended guidance, there was no impact on our consolidated financial position, results of operations or cash flows, but there was a change in the presentation of the components of other comprehensive income.

New Accounting Standards Issued But Not Yet Adopted

Disclosures about Offsetting Assets and Liabilities

This accounting standard was issued concerning balance sheet offsetting disclosures to facilitate comparability between financial statements prepared on the basis of GAAP and IFRS. This standard requires entities

- to disclose information about offsetting and related arrangements to enable users of financial statements to understand the effect of those arrangements on an entity’s financial position, and
- to present both net (offset amounts) and gross information in the notes to the financial statements for relevant assets and liabilities that are offset.

The guidance is effective for fiscal years and interim periods beginning on or after January 1, 2013. As this standard requires disclosures only, it will not have any impact on our consolidated financial position, results of operations or cash flows upon adoption.

Note 3. Variable Interest Entities (VIEs)

Variable Interest Entities for which PSE&G is the Primary Beneficiary

PSE&G is the primary beneficiary and consolidates two marginally capitalized VIEs, PSE&G Transition Funding LLC (Transition Funding) and PSE&G Transition Funding II LLC (Transition Funding II), which were created for the purpose of issuing transition bonds and purchasing bond transitional property of PSE&G, which is pledged as collateral to a trustee. PSE&G acts as the servicer for these entities to collect securitization transition charges authorized by the BPU. These funds are remitted to Transition Funding and Transition Funding II and are used for interest and principal payments on the transition bonds and related costs.

The assets and liabilities of these VIEs are presented separately on the face of the Condensed Consolidated Balance Sheets of PSEG and PSE&G because the Transition Funding and Transition Funding II assets are restricted and can only be used to settle their respective obligations. No Transition Funding or Transition Funding II creditor has any recourse to the general credit of PSE&G in the event the transition charges are not sufficient to cover the bond principal and interest payments of Transition Funding or Transition Funding II, respectively.

PSE&G’s maximum exposure to loss is equal to its equity investment in these VIEs which was $16 million as of September 30, 2012 and December 31, 2011. The risk of actual loss to PSE&G is considered remote. PSE&G did not provide any financial support to Transition Funding or Transition Funding II during the first nine months of 2012 or in 2011. Further, PSE&G does not have any contractual commitments or obligations to provide financial support to

Transition Funding or Transition Funding II.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Note 4. Discontinued Operations and Dispositions

Discontinued Operations

Power

In March 2011, Power completed the sale of its 1,000 MW gas-fired Guadalupe generating facility for a total price of $352 million, resulting in an after-tax gain of $54 million.

In July 2011, Power completed the sale of its 1,000 MW gas-fired Odessa generating facility for approximately $335 million, resulting in an after-tax gain of approximately $25 million.

PSEG Texas' operating results for the three months and nine months ended September 30, 2011, which were reclassified to Discontinued Operations, are summarized below:

	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2011
	Millions	
Operating Revenues	$20	$112
Income Before Income Taxes	$6	$26
Net Income	$4	$17

Note 5. Financing Receivables

PSE&G

PSE&G sponsors a solar loan program designed to help finance the installation of solar power systems throughout its electric service area. The loans are generally paid back with Solar Renewable Energy Certificates (SRECs) generated from the installed solar electric system. The following table reflects the outstanding short and long-term loans by class of customer, none of which are considered "non-performing."

Credit Risk Profile Based on Payment Activity

Consumer Loans	As of September 30, 2012	As of December 31, 2011
	Millions	
Commercial/Industrial	$159	$106
Residential	14	10
Total	$173	$116

Energy Holdings

Energy Holdings through various 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 Condensed Consolidated Balance Sheets. As an equity investor, Energy Holdings' investments in the leases are comprised of the total expected lease receivables on its investments 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 Condensed 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 Condensed Consolidated Balance Sheets.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

The table below shows Energy Holdings' gross and net lease investment as of September 30, 2012 and December 31, 2011, respectively.

	As of September 30, 2012	As of December 31, 2011
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$724	$763
Estimated Residual Value of Leased Assets	535	553
	1,259	1,316
Unearned and Deferred Income	(423)	(435)
Gross Investments in Leases	836	881
Deferred Tax Liabilities	(696)	(716)
Net Investments in Leases	$140	$165

The corresponding receivables associated with the lease portfolio are reflected below, net of non-recourse debt. The ratings in the table represent the ratings of the entities providing payment assurance to Energy Holdings. "Not Rated" counterparties relate to investments in leases of commercial real estate properties.

Counterparties' Credit Rating (S&P) as of September 30, 2012	Lease Receivables, Net of Non-Recourse Debt	
	As of September 30, 2012	As of December 31, 2011
	Millions	
AA	$21	$21
A+	73	110
BBB+ - BBB-	316	316
B-	165	299
CCC	133	—
Not Rated	16	17
Total	$724	$763

The "B-" and "CCC" ratings above represent lease receivables related to coal-fired assets in Illinois and Pennsylvania. As of September 30, 2012, the gross investment in the leases of such assets, net of non-recourse debt, was $555 million ($40 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the table below.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

Asset	Location	Gross Investment	% Owned		Total	Fuel Type	Counterparties' S&P Credit Ratings	Counterparty
		Millions			MW			
Powerton Station Units 5 and 6	IL	$134	64	%	1,538	Coal	CCC	Edison Mission Energy
Joliet Station Units 7 and 8	IL	$84	64	%	1,044	Coal	CCC	Edison Mission Energy
Keystone Station Units 1 and 2	PA	$114	17	%	1,711	Coal	B-	GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$114	17	%	1,711	Coal	B-	GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$109	100	%	603	Coal	B-	GenOn REMA, LLC

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

Of facilities under lease by indirect subsidiary companies of Energy Holdings to GenOn REMA, LLC (GenOn REMA), a subsidiary of GenOn Energy Inc (GenOn), Energy Holdings believes Keystone has adequate environmental controls installed. Conemaugh has flue gas desulfurization control. Selective catalytic reduction (SCR) equipment for nitrogen oxide (NOx) and mercury control are scheduled to be installed and operational at Conemaugh in the first quarter of 2015. GenOn's plan for the coal-fired units at the Shawville facility is to place them in a "long-term protective layup" by April 2015; however, GenOn has indicated that it will continue paying the required rent and maintaining the facility in accordance with the lease terms. GenOn has further stated that the lessee is evaluating its options under the lease, including termination for obsolescence or continuing to keep the facility in "long-term protective layup." In the event that the lessee is able to terminate for obsolescence, the lessee would be required, among other things, to pay the contractual termination value structured to recover Energy Holdings' indirect subsidiaries' lease investment as specified in the lease agreement. On July 22, 2012, GenOn announced that it has signed a definitive agreement to merge with NRG Energy, Inc. Energy Holdings is carefully monitoring these developments.

With respect to Edison Mission Energy's (EME) Midwest Generation leases on the Powerton and Joliet coal units in Illinois, the lessees completed investments in mercury removal (Activated Carbon Injection), low NOx burners and Selective Non-Catalytic Reduction systems and plan to employ a dry sorbent (Trona) system to reduce sulfur. EME and these units remain in litigation with the United States Environmental Protection Agency (EPA) and the State of Illinois regarding certain environmental matters; however, EME has announced that the above actions should enable compliance with pending environmental rules. The federal district court has dismissed new source review claims in reference to Powerton and Joliet, but certain opacity claims remain active and under appeal by the EPA and the State of Illinois. The federal district court has stayed proceedings in connection with the opacity claims until the appeal is resolved. In its most recent quarterly report filed on July 31, 2012, EME's parent, Edison International, reported that it will no longer provide financial support to EME; that Midwest Generation is largely dependent upon EME for its funding; and that, based upon current projections, EME will not be able to meet its debt obligation in June 2013. In addition, Edison International also reported that, if EME and Midwest Generation failed to restructure their obligations, EME and Midwest Generation may need to file for protection under Chapter 11 of the Bankruptcy Code, which could have an impact on the Powerton and Joliet leases.

The credit exposure for lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. The leasing transactions include letters of credit, affiliate guarantees, or covenants that restrict the flow of dividends from the lessee to its parent. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a temporary market downturn or degradation in operating performance of the leased assets. Upon the occurrence of certain defaults, indirect subsidiary companies of Energy Holdings could step into the lease directly to protect its investments. In the event of a default in any of the lease transactions, Energy Holdings' indirect subsidiary companies would exercise their rights and attempt to seek recovery of their investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee would likely delay any efforts on the part of the lessors to assert their rights upon default. Failure to recover adequate value could ultimately lead to a foreclosure on the lease by the lenders. If foreclosures were to occur, Energy Holdings could potentially record a pre-tax write-off up to its gross investment in these facilities and may also be required to pay significant cash tax liabilities.

On December 13, 2011, indirect subsidiary companies of Energy Holdings and Dynegy reached a settlement agreement resolving disputes that had arisen between them with regard to Dynegy Holding’s (DH) rejection of the Dynegy leases. The settlement agreement resolved certain disputes regarding Energy Holdings' Dynegy leases, including claims under Tax Indemnity Agreements that indirect subsidiaries of Energy Holdings have with DH. The original terms of the settlement agreement included a cash payment to Energy Holdings of $7.5 million, which was received on January 4, 2012, and an allowed claim in Bankruptcy Court of $110 million against DH. On December 30, 2011, the effective date of the court order authorizing the Dynegy lease rejections, the leases no longer qualified for leveraged lease accounting treatment under GAAP. As a result, Energy Holdings wrote off the $264 million gross lease investment against the previously recorded reserve. The Energy Holdings' indirect subsidiary companies that are owners/lessors of the two plants ceased leveraged lease accounting and recorded the generation assets and related nonrecourse project debt on their balance sheets at their respective fair values (See Note 11. Fair Value Measurements).

On June 1, 2012, an amended and restated settlement agreement entered into by DH, Dynegy and their creditors (including indirect subsidiary companies of Energy Holdings) was approved by the Bankruptcy Court and became effective on June 5, 2012. As part of that settlement, the indirect subsidiary companies of Energy Holdings, DH and the creditors of DH agreed to commence a process to sell the Roseton and Danskammer facilities; the agreement allocates proceeds from the sale of the facilities to pay DH’s creditors, including the lease bondholders, and grants the lease bondholders claims in agreed upon amounts against DH in its bankruptcy proceedings. The settlement agreement also includes an exchange of releases by various settling claimants, including parties to the leases with respect to claims arising out of the leases. Concurrently with the entry into the settlement agreement, DH filed an amended plan of reorganization, which was supported by the various settling claimants, providing that Energy Holdings and other unsecured creditors of DH would be paid claims partially in cash and partially in stock in a reorganized Dynegy that would emerge at the conclusion of the bankruptcy. On September 5, 2012, the Bankruptcy Court approved Dynegy’s plan of reorganization. On October 1, 2012, Dynegy emerged from bankruptcy and distributed cash and stock settlements to the claimants. The total recovery of Energy Holdings' indirect subsidiary companies from the Dynegy leases, including proceeds from the liquidation of Dynegy common stock, the aforementioned cash payment received in January 2012 and the recovery of professional fees of $5.2 million received in June 2012, was approximately $63 million, of which the remaining $49.9 million was recorded in Operating Revenues in the fourth quarter 2012.

Note 6. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Fund

Power maintains an external master nuclear decommissioning trust to fund its share of decommissioning for its five nuclear facilities upon 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. The trust funds are managed by third-party investment advisers who operate under investment guidelines developed by Power. In September 2012, Power restructured a portion of its NDT Fund and realized gains of $59 million. The investments were transitioned to new investment managers to remove under-performing managers.

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(UNAUDITED)

Power classifies investments in the NDT Fund as available-for-sale. The following tables show the fair values and gross unrealized gains and losses for the securities held in the NDT Fund:

	As of September 30, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$626	$128	$(5)	$749
Debt Securities				
Government Obligations	274	14	—	288
Other Debt Securities	311	22	—	333
Total Debt Securities	585	36	—	621
Other Securities	131	—	—	131
Total NDT Available-for-Sale Securities	$1,342	$164	$(5)	$1,501

	As of December 31, 2011			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$582	$126	$(23)	$685
Debt Securities				
Government Obligations	343	16	—	359
Other Debt Securities	268	15	(2)	281
Total Debt Securities	611	31	(2)	640
Other Securities	24	—	—	24
Total NDT Available-for-Sale Securities	$1,217	$157	$(25)	$1,349

These amounts 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 Condensed Consolidated Balance Sheets as shown in the following table.

	As of September 30, 2012	As of December 31, 2011
	Millions	
Accounts Receivable	$61	$27
Accounts Payable	$80	$22

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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. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2012.

	As of September 30, 2012				As of December 31, 2011			
	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)	$215	$(5)	$—	$—	$183	$(23)	$—	$—
Debt Securities								
Government Obligations (B)	11	—	2	—	20	—	3	—
Other Debt Securities (C)	7	—	3	—	56	(1)	4	(1)
Total Debt Securities	18	—	5	—	76	(1)	7	(1)
Other Securities	6	—	—	—	—	—	—	—
NDT Available-for-Sale Securities	$239	$(5)	$5	$—	$259	$(24)	$7	$(1)

(A) Equity Securities—Represent investments primarily in common stock within a broad range of industries and sectors. The unrealized losses are distributed over two hundred companies with limited impairment durations.

(B) Debt Securities (Government)—Unrealized losses on investments in United States Treasury obligations and Federal Agency mortgage-backed securities were caused by interest rate changes. Since these investments are guaranteed by the United States government or an agency of the United States government, it is not expected that these securities will settle for less than their amortized cost basis. Power does not intend to sell nor will it be more-likely-than-not required to sell these securities.

(C) Debt Securities (Corporate)—Represent investment grade corporate bonds which are not expected to settle for less than their amortized cost. Power does not intend to sell nor will it be more-likely-than-not required to sell these securities.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	Millions			
Proceeds from NDT Fund Sales	$617	$431	$1,252	$1,088
Net Realized Gains (Losses) on NDT Fund:				
Gross Realized Gains	$94	$26	$136	$121
Gross Realized Losses	(19)	(10)	(41)	(28)

Net Realized Gains (Losses) on NDT Fund	$75	$16	$95	$93

Net realized gains disclosed in the above table were recognized in Other Income and Other Deductions in PSEG's and Power's Condensed Consolidated Statements of Operations. Net unrealized gains of $77 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on Power's Condensed Consolidated Balance Sheet as of September 30, 2012.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(UNAUDITED)

The NDT available-for-sale debt securities held as of September 30, 2012 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$21
1 - 5 years	129
6 - 10 years	173
11 - 15 years	38
16 - 20 years	9
Over 20 years	251
Total NDT Available-for-Sale Debt Securities	$621

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

Power periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, management considers the ability and intent to hold for a reasonable time to permit recovery in addition to the severity and duration of the loss. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery. In those cases where a sale is expected, any impairment would be recorded through earnings. For fixed income securities where there is no intent to sell or likely requirement to sell, management evaluates whether credit loss is a component of the impairment. If so, that portion is recorded through earnings while the noncredit loss component is recorded through Accumulated Other Comprehensive Income (Loss). In 2012, other-than-temporary impairments of $14 million were recognized on securities in the NDT Fund. Any subsequent recoveries in the value of these securities would be recognized in Accumulated Other Comprehensive Income (Loss) unless the securities are sold, in which case, any gain would be recognized in income. The assessment of fair market value compared to cost is applied on a weighted average basis taking into account various purchase dates and initial cost of the securities.

Rabbi Trust

PSEG maintains certain unfunded nonqualified benefit plans to provide supplemental retirement and deferred compensation benefits to certain key employees. Certain assets related to these plans have been set aside in a grantor trust commonly known as the “Rabbi Trust.” In March 2012, PSEG restructured the fixed income component of the Rabbi Trust.

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

	As of September 30, 2012			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$13	$4	$—	$17
Debt Securities				
Government Obligations	113	3	—	116
Other Debt Securities	45	2	—	47
Total Debt Securities	158	5	—	163

Other Securities	3	—	—	3
Total Rabbi Trust Available-for-Sale Securities	$174	$9	$—	$183

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	As of December 31, 2011			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	Millions			
Equity Securities	$16	$3	$—	$19
Debt Securities	148	5	—	153
Total Rabbi Trust Available-for-Sale Securities	$164	$8	$—	$172

As of September 30, 2012, amounts in the above table do not include Accounts Receivable of $4 million and Accounts Payable of $5 million for Rabbi Trust Fund transactions which had not yet settled. These amounts are included on the Condensed Consolidated Balance Sheets.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	Millions			
Proceeds from Rabbi Trust Sales	$6	$—	$221	$—
Net Realized Gains (Losses) on Rabbi Trust:				
Gross Realized Gains	$—	$—	$6	$—
Gross Realized Losses	—	—	—	—
Net Realized Gains (Losses) on Rabbi Trust	$—	$—	$6	$—

Gross realized gains disclosed in the above table were recognized in Other Income in the Condensed Consolidated Statements of Operations. Net unrealized gains of $5 million (after-tax) were recognized in Accumulated Other Comprehensive Loss on the Condensed Consolidated Balance Sheets as of September 30, 2012. The Rabbi Trust available-for-sale debt securities held as of September 30, 2012 had the following maturities:

Time Frame	Fair Value
	Millions
Less than one year	$—
1 - 5 years	58
6 - 10 years	31
11 - 15 years	10
16 - 20 years	5
Over 20 years	59
Total Rabbi Trust Available-for-Sale Debt Securities	$163

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

PSEG periodically assesses individual securities whose fair value is less than amortized cost to determine whether the investments are considered to be other-than-temporarily impaired. For equity securities, the Rabbi Trust is invested in a commingled indexed mutual fund. Due to the commingled nature of this fund, PSEG does not have the ability to hold these securities until expected recovery. As a result, any declines in fair market value below cost are recorded as a charge to earnings. For fixed income securities, management considers its intent to sell or requirement to sell a security prior to expected recovery.

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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 assets in the Rabbi Trust related to PSEG, Power and PSE&G are detailed as follows:

	As of September 30, 2012	As of December 31, 2011
	Millions	
Power	$36	$33
PSE&G	61	57
Other	86	82
Total Rabbi Trust Available-for-Sale Securities	$183	$172

Note 7. Pension and OPEB

PSEG sponsors several qualified and nonqualified pension plans and OPEB plans covering PSEG's and its participating affiliates' current and former employees who meet certain eligibility criteria. The following table provides the components of net periodic benefit costs relating to all qualified and nonqualified pension and OPEB plans on an aggregate basis. OPEB costs are presented net of the federal subsidy expected for prescription drugs under the Medicare Prescription Drug Improvement and Modernization Act of 2003. Federal health care legislation enacted in March 2010 eliminates the tax deductibility of retiree health care costs beginning in 2013, to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage. See Note 13. Income Taxes for additional information.

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Pension and OPEB costs for PSEG are detailed as follows:

	Pension Benefits Three Months Ended September 30,		OPEB Three Months Ended September 30,		Pension Benefits Nine Months Ended September 30,		OPEB Nine Months Ended September 30,	
	2012	2011	2012	2011	2012	2011	2012	2011
	Millions							
Components of Net Periodic Benefit Cost								
Service Cost	$26	$22	$5	$3	$76	$69	$13	$10
Interest Cost	56	56	17	15	167	172	49	45
Expected Return on Plan Assets	(76)	(85)	(4)	(5)	(229)	(248)	(13)	(13)
Amortization of Net Transition Obligation	—	—	1	1	—	—	2	4
Prior Service Cost (Credit)	(5)	(4)	(4)	(4)	(14)	(6)	(11)	(10)
Actuarial Loss	41	29	7	4	125	89	23	11
Net Periodic Benefit Cost	$42	$18	$22	$14	$125	$76	$63	$47
Special Termination Benefits	1	0	0	0	1	0	0	0
Effect of Regulatory Asset	—	—	4	5	—	—	14	15
Total Benefit Costs, Including Effect of Regulatory Asset	$43	$18	$26	$19	$126	$76	$77	$62

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

	Pension Benefits Three Months Ended September 30,		OPEB Three Months Ended September 30,		Pension Benefits Nine Months Ended September 30,		OPEB Nine Months Ended September 30,	
	2012	2011	2012	2011	2012	2011	2012	2011
	Millions							
Power	$14	$6	$5	$3	$39	$24	$14	$9

PSE&G	24	9	21	16	73	41	61	51
Other	5	3	—	—	14	11	2	2
Total Benefit Costs	$43	$18	$26	$19	$126	$76	$77	$62

During the three months ended March 31, 2012, PSEG contributed its entire planned contribution for the year 2012 of $124 million and $11 million into its pension and postretirement healthcare plans, respectively.

Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations

Power’s activities primarily involve the purchase and sale of energy and related products under transportation, physical,

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financial and forward contracts at fixed and variable prices. These transactions are with numerous counterparties and brokers that may require cash, cash-related instruments or guarantees.

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

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

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

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

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

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

Power is subject to

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

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

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

The face value of Power's outstanding guarantees, current exposure and margin positions as of September 30, 2012 and December 31, 2011 are shown below:

	As of September 30, 2012	As of December 31, 2011
	Millions	
Face Value of Outstanding Guarantees	$1,514	$1,756
Exposure under Current Guarantees	$214	$315
Letters of Credit Margin Posted	$178	$135
Letters of Credit Margin Received	$109	$91
Cash Deposited and Received		
Counterparty Cash Margin Deposited	$19	$20
Counterparty Cash Margin Received	(3)	(7)
Net Broker Balance Deposited (Received)	12	(92)
In the Event Power were to Lose its Investment Grade Rating:		
Additional Collateral that could be Required	$610	$812
Liquidity Available under PSEG's and Power's Credit Facilities to Post Collateral	$3,429	$3,415
Additional Amounts Posted		

Other Letters of Credit	$45	$52

As part of determining credit exposure, Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. In accordance with PSEG's accounting

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policy, where it is applicable, cash (received)/deposited is allocated against derivative asset and liability positions with the same counterparty on the face of the Balance Sheet. The remaining balances of net cash (received)/deposited after allocation are generally included in Accounts Payable and Receivable, respectively.

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

In addition, during 2012, the SEC and the Commodity Futures Trading Commission (CFTC) are continuing efforts to implement new rules to enact stricter regulation over swaps and derivatives. The CFTC has issued Final Rules regarding the definition of a swap dealer and the definition of a swap. However, in September 2012 a federal court vacated the CFTC's rule on monitoring of position limits for several commodities, including natural gas, thereby indefinitely delaying the effectiveness of these position limits rules. PSEG is carefully monitoring all of these new rules as they are issued to analyze the potential impact on its swap and derivatives transactions, including any potential increase in its collateral requirements.

In addition to amounts for outstanding guarantees, current exposure and margin positions, Power had posted letters of credit to support various other non-energy contractual and environmental obligations. See table above.

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.

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

The EPA has determined that an eight-mile stretch of the Passaic River in the area of Newark, New Jersey is a "facility" within the meaning of that term under CERCLA. The EPA has determined the need to perform a study of the entire 17-mile tidal reach of the lower Passaic River.

PSE&G and certain of its predecessors conducted operations at properties in this area on or adjacent to 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. When the Essex Site was transferred from PSE&G to Power, PSE&G obtained releases and indemnities for liabilities arising out of the former Essex generating station and Power assumed any environmental liabilities.

The EPA believes that certain hazardous substances were released from the Essex Site and one of PSE&G's former MGP locations (Harrison Site). In 2006, the EPA notified the potentially responsible parties (PRPs) that the cost of its Remedial Investigation and Feasibility Study (RI/FS) would greatly exceed the original estimated cost of $20 million. The total cost of the RI/FS is now estimated at approximately $110 million. 73 PRPs, including Power and PSE&G, agreed to assume responsibility for the RI/FS and formed the Cooperating Parties Group (CPG) to divide the associated costs according to a mutually agreed upon formula. The CPG group, currently 70 members, is presently executing the RI/FS. Approximately five percent of the RI/FS costs are attributable to PSE&G's former MGP sites and approximately one percent to Power's generating stations. Power has provided notice to insurers concerning this potential claim.

In 2007, the EPA released a draft "Focused Feasibility Study" (FFS) that proposed six options to address the contamination cleanup of the lower eight miles of the Passaic River. The EPA estimated costs for the proposed remedy range from $1.3 billion to $3.7 billion. The work contemplated by the FFS is not subject to the cost sharing agreement discussed above. The EPA is conducting a revised FFS which may be released as early as the fourth quarter of 2012.

In June 2008, an agreement was announced between the EPA and Tierra Solutions, Inc. and Maxus Energy Corporation (Tierra/Maxus) for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. That removal work is underway. Tierra/Maxus have reserved their rights to seek contribution for

the removal costs from the other PRPs, including Power and PSE&G.
The EPA has advised that the levels of contaminants at Passaic River mile 10.9 will require removal in advance of the completion of the RI/FS or the issuance of a revised draft FFS. The CPG members, with the exception of Tierra/Maxus, which are no longer members of the CPG, have agreed to fund the removal, currently estimated at approximately $30 million. PSEG’s share of that effort is approximately three percent.
Except for the Passaic River 10.9 mile removal, Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to the Passaic River matters.

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New Jersey Spill Compensation and Control Act (Spill Act)
In 2005, the New Jersey Department of Environmental Protection (NJDEP) filed suit against a PRP and its related companies in the New Jersey Superior Court seeking damages and reimbursement for costs expended by the State of New Jersey to address the effects of the PRP's discharge of hazardous substances into both the Passaic River and the balance of the Newark Bay Complex. Power and PSE&G are alleged to have owned, operated or contributed hazardous substances to a total of 11 sites or facilities that impacted these water bodies. In February 2009, third party complaints were filed against some 320 third party defendants, including Power and PSE&G, claiming that each of the third party defendants is responsible for its proportionate share of the clean-up costs for the hazardous substances it allegedly discharged into the Passaic River and the Newark Bay Complex. The third party complaints seek statutory contribution and contribution under the Spill Act to recover past and future removal costs and damages. Power and PSE&G filed answers to the complaints in June 2010. A special master for discovery has been appointed by the court and document production has commenced. In October 2012, the Court issued a 90 day stay of discovery for the third-party defendants to explore a possible settlement of this matter with the State of New Jersey. Power and PSE&G believe they have good and valid defenses to the allegations contained in the third party complaints and will vigorously assert those defenses. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.
Natural Resource Damage Claims
In 2003, the 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 Spill 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 United States Department of Commerce and the United States Department of the Interior sent letters to PSE&G and other PRPs inviting participation in an assessment of injuries to natural resources that the agencies intended to perform. In 2008, PSEG and a number of other PRPs agreed to share certain immaterial costs the trustees have incurred and will incur going forward, and to work with the trustees to explore whether some or all of the trustees' claims can be resolved in a cooperative fashion. That effort is continuing. PSE&G is unable to estimate its portion 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 and encouraged the PRPs to contact Occidental Chemical Corporation (OCC) to discuss participating in the Remedial Investigation/Feasibility Study that OCC was conducting. The notice stated the EPA's belief that hazardous substances were released from sites owned by PSEG companies and located on the Hackensack River, including two operating electric generating stations (Hudson and Kearny sites) and one former MGP site. PSEG has participated in and partially funded the second phase of this study. Notices to fund the next phase of the study have been received but it is uncertain at this time whether the PSEG companies will consent to fund the third phase. Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to this matter.
MGP Remediation Program
PSE&G is working with the NJDEP to assess, investigate and remediate environmental conditions at its former MGP sites. To date, 38 sites requiring some level of remedial action have been identified. Based on its current studies, PSE&G has determined that the estimated cost to remediate all MGP sites to completion could range between $610 million and $697 million through 2021. Since no amount within the range is considered to be most likely, PSE&G has recorded a liability of $610 million as of September 30, 2012. Of this amount, $107 million was recorded in Other

Current Liabilities and $503 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $610 million Regulatory Asset with respect to these costs. PSE&G periodically updates its studies taking into account any new regulations or new information which could impact future remediation costs and adjusts its recorded liability accordingly.

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

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

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal-fired plant in Pennsylvania,

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

Hazardous Air Pollutants Regulation

In accordance with a ruling of the United States Court of Appeals of the District of Columbia (Court of Appeals), the EPA published a Maximum Achievable Control Technology (MACT) regulation on February 16, 2012. These Mercury Air Toxics Standards (MATS) go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the Clean Air Act. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the Court of Appeals in support of the EPA's implementation of MATS. The Court of Appeals has split the litigation related to these matters into three cases, addressing separately the existing source NESHAP, new source NESHAP and the NSPS. These cases remain pending. The EPA has stayed implementation of the new source NESHAP rule pending its reconsideration until November 2, 2012.

Power believes that the back-end technology environmental controls recently installed at its Hudson and Mercer coal facilities will meet the rule’s requirements. Power also believes that it will not be necessary to install any material controls at its other New Jersey facilities. Additional controls may be necessary at Power’s Bridgeport Harbor coal-fired unit at an immaterial cost. In December 2011, a decision was reached to upgrade the previously planned two flue gas desulfurization scrubbers and install Selective Catalytic Reduction (SCR) systems at Power’s jointly owned coal-fired generating facility at Conemaugh in Pennsylvania. This installation is expected to be completed in the first quarter of 2015. Power's share of this investment is approximately $147 million.

New Jersey regulations required coal-fired electric generating units to meet certain emissions limits or reduce mercury emissions by approximately 90% by December 15, 2007. Companies that are parties to multi-pollutant reduction agreements, such as Power, have been permitted to postpone such reductions on half of their coal-fired electric generating capacity until December 15, 2012.

With newly installed controls at its plants in New Jersey, Power has achieved the required mercury reductions that are part of Power’s multi-pollutant reduction agreement that resolved issues arising out of the PSD/NSR air pollution control programs discussed above.

Nitrogen Oxide (NOx) Regulation

In April 2009, the NJDEP finalized revisions to NOx emission control regulations that impose new NOx emission reduction requirements and limits for New Jersey fossil fuel-fired electric generating units. The rule will have a significant impact on Power’s generation fleet, as it imposes NOx emissions limits that will require significant capital investment for controls or the retirement of up to 102 combustion turbines (approximately 2,000 MW) and four older New Jersey steam electric generating units (approximately 400 MW) by May 30, 2015. Power is currently evaluating its compliance options.

Under current Connecticut regulations, Power’s Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NOx emission limitations that were incorporated into the facilities’ operating permits. In 2010, Power negotiated new agreements with the State of Connecticut extending the continued use of DERCs for certain emission units and equipment until May 31, 2014.

Cross-State Air Pollution Rule (CSAPR)

In July 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR) that limits power plant emissions in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone emission standards. In August 2012, the Court of Appeals vacated CSAPR and ordered that the Clean Air Interstate Rule (CAIR) requirements remain in effect until an appropriate substitute rule has been promulgated. On October 5, 2012, the EPA filed a request for rehearing with the court with the support from several states, cities, environmental groups and industry. The matter remains pending.

The continuation of CAIR affects Power's generating stations in Connecticut, New Jersey and New York. The purpose of CAIR is to improve Ozone and Fine Particulate (PM2.5) air quality within states that have not demonstrated achievement of the National Ambient Air Quality Standards (NAAQS). CAIR was implemented through a cap-and-trade program and to date the

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impact has not been material to Power as the allowances allocated to its stations were sufficient. If 2012 operations are similar to those in the past three years, it is expected that the impact to operations from the implementation of CAIR in 2012 will not be significant.

Clean Water Act Permit Renewals

Pursuant to the Federal Water Pollution Control Act (FWPCA), New Jersey Pollutant Discharge Elimination System (NJPDES) 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.

One of the most significant NJPDES permits governing cooling water intake structures at Power is for Salem. In 2001, the NJDEP issued a renewed NJPDES permit for Salem, expiring in July 2006, allowing for the continued operation of Salem with its existing cooling water intake system. In February 2006, Power filed with the NJDEP a renewal application allowing Salem to continue operating under its existing NJPDES permit until a new permit is issued. Power prepared its renewal application in accordance with the FWPCA Section 316(b) and the 316(b) rules published in 2004. Those rules did not mandate the use of cooling towers at large existing generating plants. Rather, the rules provided alternatives for compliance with 316(b), including the use of restoration efforts to mitigate for the potential effects of cooling water intake structures, as well as the use of site-specific analysis to determine the best technology available for minimizing adverse impact based upon a cost-benefit test. Power has used restoration and/or a site-specific cost-benefit test in applications filed to renew the permits at its once-through cooled plants, including Salem, Hudson and Mercer.

As a result of several legal challenges to the 2004 316(b) rule by certain northeast states, environmentalists and industry groups, the rule has been suspended and has been returned to the EPA to be consistent with a 2009 United States Supreme Court decision which concluded that the EPA could rely upon cost-benefit analysis in setting the national performance standards and in providing for cost-benefit variances from those standards as part of the Phase II regulations.

In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule by July 27, 2012. In April 2011, the EPA published a new proposed rule which did not establish any particular technology as the best technology available (e.g. closed cycle cooling). Instead, the proposed rule established marine life mortality standards for existing cooling water intake structures with a design flow of more than two million gallons per day. Power reviewed the proposed rule, assessed the potential impact on its generating facilities and used this information to develop its comments to the EPA which were filed in August 2011. Although the EPA has recently stated that a revision of the proposed rule to include an alternative framework for compliance is currently being considered, if the rule were to be adopted as proposed, the impact would be material since the majority of Power’s electric generating stations would be affected. In June 2012, the EPA posted a Notice of Data Availability (NODA) requesting comment on a series of technical issues related to the impingement mortality proposed standards. In June 2012, the EPA also posted a second NODA outlining its plans to finalize a “Willingness to Pay” survey it initiated to develop non-use benefits data in support of the April 2011 rule proposal. In July 2012, PSEG and industry trade associations submitted comments on both NODAs and the EPA and environmental groups agreed to delay the deadline for finalization of the Rule to June 27, 2013 to allow for more time to address public comments and analyze data submitted in response to the NODAs.

Power is unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take and the effect, if any, that they may have on its future capital requirements, financial condition, results of operations or cash flows. The results of further proceedings on this matter could have a material impact on Power’s ability to renew permits at its larger once-through cooled plants, including Salem, Hudson, Mercer, Bridgeport and possibly Sewaren and New Haven, without making significant upgrades to existing intake structures and cooling systems. The costs of those upgrades to one or more of Power’s once-through cooled plants would be material, and would require economic review to determine whether to continue operations at these facilities. For example, in

Power’s application to renew its Salem permit, filed with the NJDEP in February 2006, the estimated costs for adding cooling towers for Salem were approximately $1 billion, of which Power’s share would have been approximately $575 million. These cost estimates have not been updated. Currently, potential costs associated with any closed cycle cooling requirements are not included in Power’s forecasted capital expenditures.

Power has received a preliminary draft of the Delaware River Basin Commission (DRBC) water discharge permit that would revise Mercer Generating Station's thermal discharge limits and require compliance within five years of approval. Power is reviewing the proposed revisions with NJDEP and DRBC staff. Power cannot at this time determine the final form of the permit that will be presented to the DRBC commissioners for approval and what, if any, impact this permit would have on Mercer's operations.

New Generation and Development

Nuclear

Power has approved the expenditure of approximately $192 million for a steam path retrofit and related upgrades at its co-owned Peach Bottom Units 2 and 3. Unit 3 upgrades were completed in October 2011. Unit 2 upgrades were completed in October 2012. The balance of work to ensure efficient operations will be completed in 2013 and 2014, respectively. Total expenditures through September 30, 2012 were $138 million.

Power has also approved the expenditure of $419 million for an extended power uprate of the Peach Bottom nuclear units. The uprate is expected to result in an increase in Power's share of nominal capacity by approximately 130 MW. The uprate is expected to be in service in 2015 for Unit 2 and 2016 for Unit 3. Total expenditures through September 30, 2012 were $56 million.

Connecticut

Power was selected by the Connecticut Public Utilities Regulatory Authority (PURA), formerly the Department of Public Utility Control, in a regulatory process to build 130 MW of gas-fired peaking capacity. Final approval was received and construction began in the second quarter of 2011. The project was placed in service in June 2012. Power's total capitalized expenditures for these generating units, which are included in Property, Plant and Equipment on the Condensed Consolidated Balance Sheets of PSEG and Power, are approximately $150 million as of September 30, 2012 (not including the capitalized cost to finance during construction).

PJM Interconnection L.L.C. (PJM)

In June 2012, Power completed construction and placed in service new 267 MW gas-fired peaking facilities at its Kearny site. Power's total capitalized expenditures for these generating units, which are included in Property, Plant and Equipment on the Condensed Consolidated Balance Sheets of PSEG and Power, are approximately $247 million as of September 30, 2012.

PSE&G—Solar

As part of the BPU-approved Solar 4 All Program, PSE&G is installing up to 40 MW of solar generation on existing utility poles within its service territory. PSE&G estimates the total cost of this project to be $249 million. Approximately 33 MW have been installed as of September 30, 2012. PSE&G's cumulative investments for these solar units were approximately $232 million, with additional purchases to be made on a quarterly basis during the remaining two-year term of the purchase agreement, to the extent adequate space on poles is available.

Another aspect of the Solar 4 All program is the installation of 40 MW of solar systems on land and buildings owned by PSE&G and third parties. PSE&G estimates the total cost of this phase of the program to be $194 million. Through September 30, 2012, 38 MW representing 22 projects had been placed into service with an investment of approximately $190 million.

Energy Holdings—Solar

In September 2012, Energy Holdings acquired a 15 MW solar project currently under construction in Delaware. Energy Holdings expects to complete construction of this project in the first quarter of 2013. Energy Holdings issued guarantees of up to $37 million for payment of obligations related to the construction of the project, all of which were outstanding as of September 30, 2012. The total investment for the project is expected to be approximately $47 million.

In October 2012, Energy Holdings began commercial operation of its newly constructed 25 MW solar project in Arizona. Energy Holdings had issued guarantees of up to $72 million for payment of obligations related to the construction of the project, of which $17 million was outstanding as of September 30, 2012. The total investment for the project was approximately $75 million.

Basic Generation Service (BGS) and Basic Gas Supply Service (BGSS)

PSE&G obtains its electric supply requirements for customers who do not purchase electric supply from third party suppliers through the annual New Jersey BGS auctions. 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 Power, as well as with other winning BGS suppliers, 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.

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

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PSE&G has contracted for its anticipated BGS-Fixed Price eligible load, as follows:

	Auction Year				
	2009	2010	2011	2012	
36-Month Terms Ending	May 2012	May 2013	May 2014	May 2015	(A)
Load (MW)	2,900	2,800	2,800	2,900	
$ per kWh	0.10372	0.09577	0.09430	0.08388	

(A) Prices set in the 2012 BGS auction became effective on June 1, 2012 when the 2009 BGS auction agreements expired.

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. For additional information, see Note 17. Related-Party Transactions. 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.

Minimum Fuel Purchase Requirements

Power has various long-term fuel purchase commitments for coal through 2016 to support its fossil generation stations and for supply of nuclear fuel for the Salem and Hope Creek nuclear generating stations and for firm transportation and storage capacity for natural gas.

Power's strategy is to maintain certain levels of uranium and to make periodic purchases to support such levels. As such, the commitments referred to below 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 2015 and a portion for 2016 at Salem, Hope Creek and Peach Bottom.

Power's various multi-year contracts for firm transportation and storage capacity for natural gas are primarily used to meet its gas supply obligations to PSE&G. These purchase obligations are consistent with Power's strategy to enter into contracts for its fuel supply in comparable volumes to its sales contracts.

As of September 30, 2012, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	Power's Share of Commitments through 2016
	Millions
Nuclear Fuel	
Uranium	$452
Enrichment	$445
Fabrication	$145
Natural Gas	$876
Coal	$533

Regulatory Proceedings

Electric Discount and Energy Competition Act (Competition Act)

In 2007, PSE&G and Transition Funding were served with a purported class action complaint (Complaint) in New Jersey Superior Court challenging the constitutional validity of certain stranded cost recovery provisions of the Competition Act, seeking injunctive relief against continued collection from PSE&G's electric customers of the Transition Bond Charge (TBC) of Transition Funding, as well as recovery of TBC amounts previously collected. The Superior Court subsequently granted PSE&G's motion to dismiss the Complaint, which dismissal was upheld by the Appellate Division.

In July 2007, the same plaintiff also filed a petition with the BPU requesting review and adjustment to PSE&G's recovery of

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the same stranded cost charges. In June 2010, the BPU granted PSE&G's motion to dismiss, and the plaintiff/petitioner subsequently appealed this dismissal to the Appellate Division. In June 2012, the Appellate Division affirmed the BPU's decision, concluding that the BPU had correctly found that the plaintiff's claims failed as a matter of law. The petitioner has filed a Notice of Petition for Certification with the New Jersey Supreme Court.

New Jersey Clean Energy Program

In 2008, the BPU approved funding requirements for each New Jersey EDC applicable to its Renewable Energy and Energy Efficiency programs for the years 2009 to 2012. The aggregate funding amount is $1.2 billion for all years. PSE&G's share is $705 million. PSE&G has recorded a current liability of $89 million as of September 30, 2012. The liability is reduced as normal payments are made. The liability has been recorded with an offsetting Regulatory Asset, since the costs associated with this program are expected to be recovered from PSE&G ratepayers through the Societal Benefits Charge (SBC).

The BPU has started a new Comprehensive Resource Analysis proceeding to determine SBC funding for the years 2013-2016. The proceeding has no impact on current SBC assessments.

Long-Term Capacity Agreement Pilot Program (LCAPP)

In 2011, New Jersey enacted the LCAPP Act that resulted in the selection of three generators to build a total of approximately 2,000 MW of new combined-cycle generating facilities located in New Jersey. Each of the New Jersey EDCs, including PSE&G, was directed to execute a standard offer capacity agreement (SOCA) with the three selected generators, but did so under protest preserving their legal rights. The SOCA provides for the EDCs to guarantee specified annual capacity payments to the generators subject to the terms and conditions of the agreement. Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and the challenge filed by the EDCs has been remanded back to the BPU for consideration of certain procedural issues. In addition, the LCAPP Act has been challenged on constitutional grounds in federal court. On September 28, 2012, the federal court denied all motions for summary judgment. All issues in this litigation will now be scheduled for hearing.

In May 2012, two of the three generators cleared the Reliability Pricing Model auction for the 2015/2016 delivery year in the aggregate notional amount of approximately 1,300 MW of installed capacity. SOCA payments are for a 15 year term, which are scheduled to commence for one of the generators in the 2015/2016 delivery year and for the other generator in the 2016/2017 delivery year.

Under current accounting guidance, the estimated fair value of the SOCAs is recorded as a Derivative Asset or Liability with an offsetting Regulatory Asset or Liability on PSE&G's Condensed Consolidated Balance Sheets. See Note 11. Fair Value Measurements for additional information.

Leveraged Lease Investments

On January 31, 2012, PSEG entered into a specific matter closing agreement settling the dispute with the IRS over previously challenged leveraged lease transactions. This agreement settles the leasing dispute with finality for all tax periods in which PSEG realized tax deductions from these transactions. On January 31, 2012, PSEG also signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. On March 26, 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These two agreements conclude ten years of audits for PSEG and the leasing issue for all tax years. For PSEG, the impact of these agreements is an increase in financial statement Income Tax Expense of approximately $175 million. In prior periods, PSEG had established financial statement tax liabilities for uncertain tax positions in the amount of $245 million with respect to these tax years. Accordingly, the settlement resulted in a net $70 million decrease in the Income Tax Expense of PSEG.

Cash Impact

For tax years 1997 through 2003, the tax and interest PSEG owes the IRS as a result of this settlement will be reduced by the $320 million PSEG has on deposit with the IRS for this matter. PSEG paid a net deficiency for these years of approximately $4 million during the second quarter 2012. Based upon the closing agreement and the Form 870-AD for tax years 2004 through 2006, PSEG owes the IRS approximately $620 million in tax and interest for tax years from 2004 through 2006. Based on the settlement of the leasing dispute, for tax years 2007 through 2010, the IRS owes PSEG approximately $676 million. It is possible that PSEG would have to pay $620 million over the next year to the IRS and file claims for refunds for $676 million which the IRS would process in the normal course; it could take several years for the IRS to process these claims. In addition to the above, PSEG will claim a tax deduction for the accrued deficiency interest associated with this settlement in 2012, which will give rise to a cash tax savings of approximately $100 million.

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Note 9. Changes in Capitalization
The following capital transactions occurred in the first nine months of 2012:
Power
- paid $66 million of 5.00% Pollution Control Revenue Refunding bond at maturity, and
- paid cash dividends of $600 million to PSEG.

PSE&G
- paid $300 million of 5.13% Secured Medium-Term Notes at maturity,
- issued $350 million of 3.65% Secured Medium-Term Notes, Series H due September 2042,
- refinanced at par $50 million of 5.45% fixed rate Pollution Control Financing Authority of Salem County Authority Bonds due February 1, 2032, which were serviced and secured by PSE&G's First and Refunding Mortgage Bonds of like tenor, with $50 million of weekly-reset variable rate demand bonds due April 1, 2046, which are serviced and secured by PSE&G's First and Refunding Mortgage Bonds of like tenor,
- redeemed and retired at par $23 million of 5.20% fixed rate Pollution Control Financing Authority of Salem County Authority Bonds due March 1, 2025, which were serviced and secured by PSE&G's First and Refunding Mortgage Bonds of like tenor,
- issued $450 million of 3.95% Secured Medium-Term Notes, Series H due May 2042,
- paid $149 million of Transition Funding's securitization debt, and
- paid $5 million of Transition Funding II's securitization debt.

Energy Holdings
- was released from $50 million of nonrecourse project debt related to the Dynegy Leases.

Note 10. Financial Risk Management Activities
The operations of PSEG, Power and PSE&G are exposed to market risks from changes in commodity prices, interest rates and equity prices that could affect their results of operations and financial condition. Exposure to these risks is managed through normal operating and financing activities and, when appropriate, through hedging transactions. Hedging transactions use derivative instruments to create a relationship in which changes to the value of the assets, liabilities or anticipated transactions exposed to market risks are expected to be offset by changes in the value of these derivative instruments.
Commodity Prices
The availability and price of energy commodities are subject to fluctuations due to weather, environmental policies, changes in supply and demand, state and federal regulatory policies, market conditions, transmission availability and other events. Power uses physical and financial transactions in the wholesale energy markets to mitigate the effects of adverse movements in fuel and electricity prices. Derivative contracts that do not qualify for hedge accounting or normal purchases/normal sales treatment are marked to market (MTM) with changes in fair value recorded in the income statement. The fair value for the majority of these contracts is obtained from quoted market sources. Modeling techniques using assumptions reflective of current market rates, yield curves and forward prices are used to interpolate certain prices when no quoted market exists.
Cash Flow Hedges
Power uses forward sale and purchase contracts, swaps and futures contracts to hedge
- forecasted energy sales from its generation stations and the related load obligations,
- the price of fuel to meet its fuel purchase requirements, and
- certain forecasted natural gas sales and purchases made to support the BGSS contract with PSE&G.

These derivative transactions are designated and effective as cash flow hedges. During the second quarter of 2012, Power de-designated certain of its commodity derivative transactions that had previously qualified as cash flow hedges as they were deemed to no longer be highly effective as required by the relevant accounting guidance. As a result, subsequent to June 1, 2012, Power recognizes all gains and losses from changes in the fair value of these derivatives immediately in earnings rather than deferring any such amounts in Accumulated Other Comprehensive Income (Loss). The fair values of Power's de-designated hedges were frozen in Accumulated Other Comprehensive Income (Loss) as the original forecasted transactions are still expected to occur and are reclassified into earnings as the original derivative transactions settle.

As of September 30, 2012 and December 31, 2011, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with accounting hedge activity was as follows:

	As of September 30, 2012	As of December 31, 2011
	Millions	
Fair Value of Cash Flow Hedges	$—	$57
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$13	$33

The expiration date of the longest-dated cash flow hedge at Power is in 2014. Power's after-tax unrealized gains on these derivatives that are expected to be reclassified to earnings during the next 12 months are $10 million. There was no ineffectiveness associated with qualifying hedges as of September 30, 2012.

Trading Derivatives

The primary purpose of Power's wholesale marketing operation is to optimize the value of the output of the generating facilities via various products and services available in the markets it serves. Historically, Power engaged in trading of electricity and energy-related products where such transactions were not associated with the output or fuel purchase requirements of its facilities. This trading consisted mostly of energy supply contracts where Power secured sales commitments with the intent to supply the energy services from purchases in the market rather than from its owned generation. Such trading activities were marked to market through the income statement and represented less than one percent of gross margin (revenues less energy costs) on an annual basis. Effective July 2011, Power anticipates that it will not enter into any more trading derivative contracts.

Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of its expected generation. Trade types include financial options, futures, swaps, fuel purchases and forward purchases and sales of electricity. Changes in fair market value of these contracts are recorded in earnings.

PSE&G is a party to certain long-term natural gas sales contracts to optimize its pipeline capacity utilization. In addition, as further described in Note 8. Commitments and Contingent Liabilities, PSE&G was directed to execute long-term SOCAs with certain generators to support the LCAPP Act. These contracts qualify as derivatives and are marked to fair value with the offset recorded to Regulatory Assets and Liabilities.

Interest Rates

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

Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. As of September 30, 2012, PSEG had eight interest rate swaps outstanding totaling $1.1 billion. These swaps convert Power's $250 million of 5% Senior Notes due April 2014, Power's $300 million of 5.5% Senior Notes due December 2015, $300 million of Power's $303 million of 5.32% Senior Notes due September 2016 and Power's $250 million of 2.75% Senior Notes due September 2016 into variable-rate debt. These interest rate swaps are designated and effective as fair value hedges. The fair value changes of the interest rate swaps are fully offset by the changes in the fair value of the underlying debt. As of September 30, 2012 and December 31, 2011, the fair value of all the underlying hedges was $70 million and $62 million, respectively.

Cash Flow Hedges

PSEG uses interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage its exposure to the variability of cash flows, primarily related to variable-rate debt instruments. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $(2) million as of September 30, 2012 and December 31, 2011.

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Fair Values of Derivative Instruments
The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets:

	As of September 30, 2012						
	Power				PSE&G	PSEG	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related Contracts Millions	Non Hedges Energy-Related Contracts	Netting (A)	Total Power	Non Hedges Energy-Related Contracts	Fair Value Hedges Interest Rate Swaps	Total Derivatives
Derivative Contracts							
Current Assets	$3	$354	$(255)	$102	$3	$18	$123
Noncurrent Assets	—	81	(59)	22	70	52	144
Total Mark-to-Market Derivative Assets	$3	$435	$(314)	$124	$73	$70	$267
Derivative Contracts							
Current Liabilities	$(3)	$(303)	$255	$(51)	$—	$—	$(51)
Noncurrent Liabilities	—	(63)	57	(6)	(106)	—	(112)
Total Mark-to-Market Derivative (Liabilities)	$(3)	$(366)	$312	$(57)	$(106)	$—	$(163)
Total Net Mark-to-Market Derivative Assets (Liabilities)	$—	$69	$(2)	$67	$(33)	$70	$104

	As of December 31, 2011						
	Power				PSE&G	PSEG	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related Contracts Millions	Non Hedges Energy-Related Contracts	Netting (A)	Total Power	Non Hedges Energy-Related Contracts	Fair Value Hedges Interest Rate Swaps	Total Derivatives
Derivative Contracts							
Current Assets	$55	$532	$(448)	$139	$—	$17	$156
Noncurrent Assets	8	121	(74)	55	4	47	106
Total Mark-to-Market Derivative Assets	$63	$653	$(522)	$194	$4	$64	$262
Derivative Contracts							
Current Liabilities	$(5)	$(506)	$387	$(124)	$(7)	$—	$(131)
Noncurrent Liabilities	(1)	(76)	53	(24)	—	(2)	(26)
Total Mark-to-Market Derivative (Liabilities)	$(6)	$(582)	$440	$(148)	$(7)	$(2)	$(157)

Total Net Mark-to-Market Derivative Assets (Liabilities)	$57	$71	$(82)	$46	$(3)	$62	$105

(A) Represents the netting of fair value balances with the same counterparty (where the right of offset exists) and the application

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of collateral. As of September 30, 2012 and December 31, 2011, net cash collateral received of $2 million and $82 million, respectively, was netted against the corresponding net derivative contract positions. Of the $2 million as of September 30, 2012, cash collateral of $(4) million and $(2) million were netted against current assets and noncurrent assets, respectively, and cash collateral of $4 million was netted against current liabilities. Of the $82 million as of December 31, 2011, cash collateral of $(77) million and $(23) million were netted against current assets and noncurrent assets, respectively, and cash collateral of $16 million and $2 million were netted against current liabilities and noncurrent liabilities, respectively.

Certain of Power's derivative instruments contain provisions that require Power to post collateral. This collateral may be posted in the form of cash or credit support with thresholds contingent upon Power's credit rating from each of the major credit rating agencies. The collateral and credit support requirements vary by contract and by counterparty. These credit risk-related contingent features stipulate that if Power were to be downgraded or lose its investment grade credit rating, it would be required to provide additional collateral. This incremental collateral requirement can offset collateral requirements related to other derivative instruments that are assets with the same counterparty, where the contractual right of offset exists under applicable master agreements. Power also enters into commodity transactions on the New York Mercantile Exchange (NYMEX) and Intercontinental Exchange (ICE). The NYMEX and ICE clearing houses act as counterparties to each trade. Transactions on NYMEX and ICE must adhere to comprehensive collateral and margining 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 NYMEX and ICE that are fully collateralized) was $130 million and $285 million as of September 30, 2012 and December 31, 2011, respectively. As of September 30, 2012 and December 31, 2011, Power had the contractual right of offset of $88 million and $149 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 or lost its investment grade rating, it would have had additional collateral obligations of $42 million and $136 million as of September 30, 2012 and December 31, 2011, respectively, related to its derivatives, net of the contractual right of offset under master agreements and the application of collateral. This potential additional collateral is included in the $610 million and $812 million as of September 30, 2012 and December 31, 2011, respectively, discussed in Note 8. Commitments and Contingent Liabilities.

The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the three months ended September 30, 2012 and 2011:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended September 30,		Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Three Months Ended September 30,		Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Three Months Ended September 30,	
	2012	2011		2012	2011		2012	2011
	Millions							
PSEG and Power								

Energy-Related Contracts	$(3	)	$21	Operating Revenues	$15	$60	Operating Revenues	$(1	)	$—
Total PSEG and Power	$(3	)	$21		$15	$60		$(1	)	$—

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The following shows the effect on the Condensed Consolidated Statements of Operations and on Accumulated Other Comprehensive Income (AOCI) of derivative instruments designated as cash flow hedges for the nine months ended September 30, 2012 and 2011:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Nine Months Ended September 30, 2012	2011	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion) Nine Months Ended September 30, 2012	2011	Location of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion)	Amount of Pre-Tax Gain (Loss) Recognized in Income on Derivatives (Ineffective Portion) Nine Months Ended September 30, 2012	2011
	Millions							
PSEG (A)								
Energy-Related Contracts	$27	$18	Operating Revenues	$67	$152	Operating Revenues	$(1)	$1
Energy-Related Contracts	(4)	1	Energy Costs	(9)	2		—	—
Interest Rate Swaps	—	—	Interest Expense	(1)	(1)		—	—
Total PSEG	$23	$19		$57	$153		$(1)	$1
Power								
Energy-Related Contracts	$27	$18	Operating Revenues	$67	$152	Operating Revenues	$(1)	$1
Energy-Related Contracts	(4)	1	Energy Costs	(9)	2		—	—
Total Power	$23	$19		$58	$154		$(1)	$1

(A) Includes amounts for PSEG parent.

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

Accumulated Other Comprehensive Income	Pre-Tax	After-Tax
	Millions	
Balance as of December 31, 2011	$54	$31
Gain Recognized in AOCI	26	15
Less: Gain Reclassified into Income	(42)	(25)
Balance as of June 30, 2012	$38	$21
Loss Recognized in AOCI	(3)	(2)
Less: Gain Reclassified into Income	(15)	(8)
Balance as of September 30, 2012	$20	$11

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The following shows the effect on the Condensed Consolidated Statements of Operations of derivative instruments not designated as hedging instruments or as normal purchases and sales for the three months and nine months ended September 30, 2012 and 2011:

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			
		Three Months Ended September 30,		Nine Months Ended September 30,	
		2012	2011	2012	2011
		Millions			
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$(90)	$24	$145	$(18)
Energy-Related Contracts	Energy Costs	6	(11)	(17)	(10)
Total PSEG and Power		$(84)	$13	$128	$(28)

Power’s derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity and natural gas and the purchase of fuel. Not all of these contracts qualify for hedge accounting. Most of these contracts are marked to market. The tables above do not include contracts for which Power has elected the normal purchase/normal sales exemption, such as its BGS contracts and certain other energy supply contracts that it has with other utilities and companies with retail load. In addition, PSEG has interest rate swaps designated as fair value hedges. The effect of these hedges was to reduce interest expense by $6 million and $6 million for the three month periods and $17 million and $19 million for the nine month periods ended September 30, 2012 and 2011, respectively.

The following reflects the gross volume, on an absolute value basis, of derivatives as of September 30, 2012 and December 31, 2011:

Type	Notional	Total	PSEG	Power	PSE&G
	Millions				
As of September 30, 2012					
Natural Gas	Dth	588	—	385	203
Electricity	MWh	179	—	179	—
Capacity	MW days	4	—	—	4
FTRs	MWh	28	—	28	—
Interest Rate Swaps	US Dollars	1,100	1,100	—	—
Coal	Tons	1	—	1	—
As of December 31, 2011					
Natural Gas	Dth	612	—	377	235
Electricity	MWh	137	—	137	—
FTRs	MWh	12	—	12	—
Interest Rate Swaps	US Dollars	1,100	1,100	—	—
Coal	Tons	1	—	1	—

Credit Risk

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

As of September 30, 2012, 99% of the credit for Power's operations was with investment grade counterparties. Credit exposure is defined as any positive results of netting accounts receivable/accounts payable and the forward value of open positions (which includes all financial instruments including derivatives and non-derivatives and normal purchases/normal sales).

The following table provides information on Power's credit risk from others, net of cash collateral, as of September 30, 2012. It further delineates that exposure by the credit rating of the counterparties and provides guidance on the concentration of credit risk to individual counterparties and an indication of the quality of Power's credit risk by credit rating of the counterparties.

Rating	Current Exposure	Securities held as Collateral	Net Exposure	Number of Counterparties >10%	Net Exposure of Counterparties >10%	
	Millions				Millions	
Investment Grade—External Rating	$311	$85	$309	2	$153	(A)
Non-Investment Grade—External Rating	3	—	3	—	—	
Investment Grade—No External Rating	9	—	9	—	—	
Non-Investment Grade—No External Rating	—	—	—	—	—	
Total	$323	$85	$321	2	$153	

(A) Includes net exposure of $108 million with PSE&G. The remaining net exposure of $45 million is with one nonaffiliated power purchaser which is a regulated investment grade counterparty.

The net exposure listed above, in some cases, will not be the difference between the current exposure and the collateral held. A counterparty may have posted more cash collateral than the outstanding exposure, in which case there would be no exposure. When letters of credit have been posted as collateral, the exposure amount is not reduced, but the exposure amount is transferred to the rating of the issuing bank. As of September 30, 2012, Power had 177 active counterparties.

Note 11. Fair Value Measurements

PSEG, Power and PSE&G adopted accounting standard "Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in GAAP and International Financial Reporting Standards (IFRS)" effective January 1, 2012. This standard defines fair value, establishes a framework for measuring fair value and expands disclosures about 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, Power and PSE&G have the ability to access. These consist primarily of listed equity securities.

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 September 30, 2012, these consist primarily of electric swaps whose basis is deemed significant to the fair value measurement, long-term electric capacity contracts and long-term gas supply contracts.
The following tables present information about PSEG's, Power's and PSE&G's respective assets and (liabilities) measured at fair value on a recurring basis as of September 30, 2012 and December 31, 2011, including the fair value measurements and the levels of inputs used in determining those fair values. Amounts shown for PSEG include the amounts shown for Power and PSE&G.

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	Recurring Fair Value Measurements as of September 30, 2012				
Description	Total	Cash Collateral Netting (E)	Quoted Market Prices for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$197	$(6)	$—	$116	$87
Interest Rate Swaps (B)	$70	$—	$—	$70	$—
NDT Fund (C)					
Equity Securities	$749	$—	$749	$—	$—
Debt Securities—Govt Obligations	$288	$—	$—	$288	$—
Debt Securities—Other	$333	$—	$—	$333	$—
Other Securities	$123	$—	$—	$123	$—
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$17	$—	$17	$—	$—
Debt Securities—Govt Obligations	$116	$—	$—	$116	$—
Debt Securities—Other	$47	$—	$—	$47	$—
Other Securities	$3	$—	$—	$3	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$(163)	$4	$—	$(59)	$(108)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$124	$(6)	$—	$116	$14
NDT Fund (C)					
Equity Securities	$749	$—	$749	$—	$—
Debt Securities—Govt Obligations	$288	$—	$—	$288	$—
Debt Securities—Other	$333	$—	$—	$333	$—
Other Securities	$123	$—	$—	$123	$—
Rabbi Trust (C)					
Equity Securities—Mutual Funds	$3	$—	$3	$—	$—
Debt Securities—Govt Obligations	$23	$—	$—	$23	$—
Debt Securities—Other	$9	$—	$—	$9	$—
Other Securities	$1	$—	$—	$1	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$(57)	$4	$—	$(59)	$(2)
PSE&G					
Assets:					
Derivative Contracts:					
Energy Related Contracts (A)	$73	$—	$—	$—	$73

Rabbi Trust (C)					
Equity Securities—Mutual Funds	$6	$—	$6	$—	$—
Debt Securities—Govt Obligations	$38	$—	$—	$38	$—
Debt Securities—Other	$16	$—	$—	$16	$—
Other Securities	$1	$—	$—	$1	$—
Liabilities:					
Derivative Contracts:					
Energy Related Contracts (A)	$(106)	$—	$—	$—	$(106)

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	Recurring Fair Value Measurements as of December 31, 2011				
Description	Total	Cash Collateral Netting (E)	Quoted Market Prices of Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
	Millions				
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$198	$(100)	$—	$257	$41
Interest Rate Swaps (B)	$64	$—	$—	$64	$—
NDT Fund: (C)					
Equity Securities	$685	$—	$685	$—	$—
Debt Securities-Govt Obligations	$359	$—	$—	$359	$—
Debt Securities-Other	$281	$—	$—	$281	$—
Other Securities	$24	$—	$—	$24	$—
Rabbi Trust—Mutual Funds (C)	$172	$—	$19	$153	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$(155)	$18	$—	$(153)	$(20)
Interest Rate Swaps (B)	$(2)	$—	$—	$(2)	$—
Non-Recourse Debt (D)	$(50)	$—	$—	$—	$(50)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$194	$(100)	$—	$257	$37
NDT Fund: (C)					
Equity Securities	$685	$—	$685	$—	$—
Debt Securities-Govt Obligations	$359	$—	$—	$359	$—
Debt Securities-Other	$281	$—	$—	$281	$—
Other Securities	$24	$—	$—	$24	$—
Rabbi Trust—Mutual Funds (C)	$33	$—	$4	$29	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$(148)	$18	$—	$(153)	$(13)
PSE&G					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$4	$—	$—	$—	$4
Rabbi Trust—Mutual Funds (C)	$57	$—	$6	$51	$—
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$(7)	$—	$—	$—	$(7)

(A) 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 the average of the bid/ask midpoints from multiple broker or dealer quotes 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—For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information are available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data.

(B) Interest rate swaps are valued using quoted prices on commonly quoted intervals, which are interpolated for periods different than the quoted intervals, as inputs to a market valuation model. Market inputs can generally be verified and model selection does not involve significant management judgment.

(C) The fair value measurements table excludes cash of $8 million which is part of the NDT Fund as of September 30, 2012. The NDT Fund maintains investments in various equity and fixed income securities classified as “available for sale.” The Rabbi Trust maintains investments in an S&P 500 index fund and various fixed income securities classified as “available for sale.” 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 (primarily Level 1). The Rabbi Trust equity index fund is valued based on quoted prices in an active market (Level 1).

Level 2—NDT and Rabbi Trust fixed income securities are limited to investment grade corporate bonds and United States Treasury obligations or Federal Agency mortgage-backed securities 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 (primarily Level 2). Short-term investments and certain commingled temporary investments are valued using observable market prices or market parameters such as time-to-maturity, coupon rate, quality rating and current yield (primarily Level 2).

(D) For Non-Recourse Debt, see Fair Value Option below.

(E) Cash collateral netting represents collateral amounts netted against derivative assets and liabilities as permitted under the accounting guidance for Offsetting of Amounts Related to Certain Contracts.

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 approves risk management policies and objectives for risk assessment, control and valuation, counterparty credit approval, and the monitoring and reporting of risk exposures. The Risk Management Committee reports to the Audit Committee of the PSEG Board of Directors 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.

Disclosed below is detail surrounding significant Level 3 valuations, of which the most significant positions are electric swaps for Power and long-term electric capacity contracts and long-term natural gas supply contracts for PSE&G. For Power, in general, electric swaps are valued based on at least two pricing inputs, basis and underlying.

To the extent the basis component is based on a single broker quote and is significant to the fair value of the electric swap, it is categorized as Level 3. The remaining balance of Power's Level 3 positions consist primarily of certain long-term electric capacity contracts and certain long-term natural gas supply contracts. Long-term electric capacity contracts are measured at fair value using capacity auction prices. If the fair value for the unobservable tenor is significant, then the entire capacity contract is categorized as Level 3. For Power and PSE&G, long-term gas supply contracts are measured at fair value using both actively traded pricing points as well as unobservable inputs such as gas prices beyond observable periods and long-term basis quotes and accordingly, the fair value measurements are classified in Level 3. For PSE&G, long-term electric capacity contracts are measured at fair value using both observable capacity prices and unobservable inputs consisting of forecasts of future long-term electric capacity prices and include adjustments for contingencies, such as litigation risk and plant construction risk. Accordingly, the fair value

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measurements are classified as Level 3.
The table below discloses the significant unobservable inputs used in developing the fair value of these Level 3 positions:

Quantitative Information About Level 3 Fair Value Measurements

Commodity	Level 3 Position	Fair Value at September 30, 2012 Assets	(Liabilities)	Valuation Technique(s)	Significant Unobservable Input	Range
		Millions				
Power						
Electricity	Electric Swaps	$10	$(1)	Discounted cash flow	Power Basis	$0 -$10/MWh
Other	Various (A)	4	(1)			
Total Power		$14	$(2)			
PSE&G						
Gas and Capacity	Forward Contracts (B)	$73	$(106)	Discounted cash flow	Long-Term Gas Basis and Capacity Prices	(B)
Total PSE&G		$73	$(106)			
TOTAL PSEG		$87	$(108)			

(A) Includes long-term electric capacity and long-term gas supply positions which are immaterial.

(B) Includes long-term gas supply and long-term electric capacity positions with various unobservable inputs. Significant unobservable inputs for the gas supply contracts include long-term basis prices in the range of $0 to $2/MMBTU of natural gas. Unobservable inputs for the long-term electric capacity contracts include forecasted capacity prices in the range of $100 to $400/MW day.

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 and PSE&G are sellers, an increase in either the power basis or the load variability or the longer-term basis amounts would decrease the fair value. For long-term electric capacity contracts where Power or PSE&G are buyers, an increase in the capacity price would increase the fair value.
A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and nine months ended September 30, 2012 follows:
Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Three Months Ended September 30, 2012

Description	Balance as of July 1, 2012	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales) (C)	Issuances (Settlements) (D)	Transfers In (Out) (E)	Balance as of September 30, 2012
	Millions						
PSEG							
	$(36)	$(1)	$ 25	$—	$(9)	$—	$(21)

Net Derivative Assets (Liabilities)							
Power							
Net Derivative Assets (Liabilities)	$22	$(1)	$ —	$—	$(9)	$—	$12
PSE&G							
Net Derivative Assets (Liabilities)	$(58)	$—	$ 25	$—	$—	$—	$(33)

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Nine Months Ended September 30, 2012

Description	Balance as of January 1, 2012	Total Gains or (Losses) Realized/Unrealized: Included in Income (F)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales) (C)	Issuances (Settlements) (D)	Transfers In (Out) (E)	Balance as of September 30, 2012
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$21	$40	$ (30)	$—	$(52)	$—	$(21)
Non-Recourse Debt	$(50)	$50	$ —	$—	$—	$—	$—
Power							
Net Derivative Assets (Liabilities)	$24	$40	$ —	$—	$(52)	$—	$12
PSE&G							
Net Derivative Assets (Liabilities)	$(3)	$—	$ (30)	$—	$—	$—	$(33)

A reconciliation of the beginning and ending balances of Level 3 derivative contracts and securities for the three months and nine months ended September 30, 2011 follows:
Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Three Months Ended September 30, 2011

Description	Balance as of July 1, 2011	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales) (C)	Issuances (Settlements) (D)	Transfers In (Out) (E)	Balance as of September 30, 2011
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$(3)	$13	$ (27)	$10	$3	$—	$(4)

Power							
Net Derivative Assets (Liabilities)	$(4)	$13	$ —	$10	$3	$—	$22
PSE&G							
Net Derivative Assets (Liabilities)	$1	$—	$ (27)	$—	$—	$—	$(26)

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Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis
for the Nine Months Ended September 30, 2011

Description	Balance as of January 1, 2011	Total Gains or (Losses) Realized/Unrealized: Included in Income (F)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales) (C)	Issuances (Settlements) (D)	Transfers In (Out) (E)	Balance as of September 30, 2011
	Millions						
PSEG							
Net Derivative Assets (Liabilities)	$47	$(27)	$ (31)	$29	$(22)	$—	$(4)
NDT Funds	$8	$—	$ —	$—	$—	$(8)	$—
Power							
Net Derivative Assets (Liabilities)	$42	$(27)	$ —	$29	$(22)	$—	$22
NDT Funds	$8	$—	$ —	$—	$—	$(8)	$—
PSE&G							
Net Derivative Assets (Liabilities)	$5	$—	$ (31)	$—	$—	$—	$(26)

(A) PSEG's and Power's gains and losses attributable to changes in net derivative assets and liabilities include $(1) million and $12 million in Operating Income in 2012 and 2011, respectively, $1 million in OCI and less than $1 million in Income from Discontinued Operations in 2011. Of the $(1) million in Operating Income in 2012, $(10) million is unrealized. Of the $12 million in Operating Income in 2011, $31 million is unrealized. Energy Holdings' release from its obligations under the non-recourse debt is included in PSEG's Operating Income and is offset by the write-off of the related assets.

(B) Mainly includes gains/losses on PSE&G's derivative contracts that are not included in either earnings or OCI, as they are deferred as a Regulatory Asset/Liability and are expected to be recovered from/returned to PSE&G's customers.

(C) Includes $10 million in purchases and $0 million in sales for the three months ended September 30, 2011. Includes $65 million in purchases and $(36) million in sales for the nine months months ended September 30, 2011.

(D) Includes $0 million and $(5) million in issuances and $(9) million and $8 million in settlements for the three months ended September 30, 2012 and 2011, respectively. Includes $0 million and $(25) million in issuances and $(52) million and $3 million in settlements for the nine months ended September 30, 2012 and 2011, respectively.

(E) There were no transfers among levels during the three months ended September 30, 2012 and 2011 and the nine months ended September 30, 2012. During the nine months ended September 30, 2011, $8 million of assets in the NDT fund were transferred from Level 3 to Level 2, due to more observable pricing for the underlying securities. The transfer was recognized as of the beginning of the first quarter (i.e. the quarter in which the transfer occurred), as per PSEG's policy.

(F)

PSEG’s and Power’s gains and losses attributable to changes in net derivative assets and liabilities include $40 million and $(28) million in Operating Income in 2012 and 2011, respectively, $(2) million in OCI and $3 million in Income from Discontinued Operations in 2011. Of the $40 million in Operating Income in 2012, $(12) million is unrealized. Of the $(28) million in Operating Income in 2011, $(25) million is unrealized. Energy Holdings’ release from its obligations under the non-recourse debt is included in PSEG’s Operating Income and is offset by the write-off of the related assets.

As of September 30, 2012, PSEG carried $1.8 billion of net assets that are measured at fair value on a recurring basis, of which $21 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

As of September 30, 2011, PSEG carried $1.5 billion of net assets that are measured at fair value on a recurring basis, of which $4 million of net liabilities were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy.

Fair Value Option

As of December 31, 2011, the effective date of the Dynegy lease rejections, the leases of the Roseton and Danskammer generation facilities were effectively terminated and no longer qualified for leveraged lease accounting under the guidance for leases. As the owner of the facilities, Energy Holdings was required to recognize the underlying assets and nonrecourse notes payable (Notes Payable) associated with these leases at their respective fair values on the effective date of the rejection. Energy

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Holdings has elected to record the Notes Payable at fair value each reporting period under the fair value option in accordance with guidance for Financial Instruments. The fair value option permits the irrevocable fair value election for selected eligible financial assets or liabilities. Any changes in the fair value of the Notes Payable will be included in earnings each period. The $550 million of contractual principal outstanding on the Notes Payable is valued at $50 million as of December 31, 2011. Energy Holdings elected this option to eliminate certain complexities in applying the effective interest method of amortization given the uncertain payment streams between the election date and the expected foreclosure date. There were no other debt instruments of this type eligible for the fair value option as of December 31, 2011. The $50 million fair value of these Notes Payable is included on PSEG's Condensed Consolidated Balance Sheet as of December 31, 2011. The fair values of the Notes Payable include significant internal assumptions based on expected cash flows and the fair values of the underlying collateral. Changes to projected capacity factors, capacity and energy prices, fuel costs and other required cash outflows could significantly impact the fair value of the collateral which would increase or decrease the fair value of the Notes. These Notes Payable are classified as Level 3 in the fair value hierarchy as a result of mainly unobservable inputs. As of the June 5, 2012 effective date of the amended settlement agreement, the Notes Payable and related assets were written off.

Fair Value of Debt

The estimated fair values were determined using the market quotations or values of instruments with similar terms, credit ratings, remaining maturities and redemptions as of September 30, 2012 and December 31, 2011.

	September 30, 2012		December 31, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	Millions			
Long-Term Debt:				
PSEG (Parent) (A)	$49	$70	$39	$62
Power -Recourse Debt (B)	2,686	3,205	2,751	3,158
PSE&G (B)	4,744	5,631	4,270	4,905
Transition Funding (PSE&G) (B)	746	832	895	1,016
Transition Funding II (PSE&G) (B)	39	41	44	47
Energy Holdings:				
Project Level, Non-Recourse Debt (C)	45	45	95	95
Total Long-Term Debt	$8,309	$9,824	$8,094	$9,283

(A) Fair value represents net offsets to debt resulting from adjustments from interest rate swaps entered into to hedge certain debt at Power and the unamortized premium resulting from a debt exchange entered into between Power and Energy Holdings.

(B) The debt fair valuation is based on the present value of each bond's future cash flows. The discount rates used in the present value analysis are based on an estimate of new issue bond yields across the treasury curve. When a bond has embedded options, an interest rate model is used to reflect the impact of interest rate volatility into the analysis (primarily Level 2 measurements).

(C) Fair value amounts as of December 31, 2011 include $50 million of non-recourse project debt related to Dynegy which is classified as a Level 3 measurement. See "Fair Value Option" above for more details on Dynegy debt. Non-recourse project debt of $45 million is valued as equivalent to the amortized cost and is classified as a Level 3 measurement.

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Note 12. Other Income and Deductions

Other Income	Power Millions	PSE&G	Other (A)	Consolidated
Three Months Ended September 30, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$103	$—	$—	$103
Allowance of Funds Used During Construction	—	6	—	6
Solar Loan Interest	—	5	—	5
Other	1	5	1	7
Total Other Income	$104	$16	$1	$121
Three Months Ended September 30, 2011				
NDT Fund Gains, Interest, Dividend and Other Income	$36	$—	$—	$36
Allowance of Funds Used During Construction	—	2	—	2
Solar Loan Interest	—	3	—	3
Other	1	2	1	4
Total Other Income	$37	$7	$1	$45
Nine Months Ended September 30, 2012				
NDT Fund Gains, Interest, Dividend and Other Income	$167	$—	$—	$167
Allowance of Funds Used During Construction	—	17	—	17
Solar Loan Interest	—	13	—	13
Other	4	9	6	19
Total Other Income	$171	$39	$6	$216
Nine Months Ended September 30, 2011				
NDT Fund Gains, Interest, Dividend and Other Income	$153	$—	$—	$153
Allowance of Funds Used During Construction	—	4	—	4
Solar Loan Interest	—	7	—	7
Other	3	5	4	12
Total Other Income	$156	$16	$4	$176

Other Deductions	Power	PSE&G	Other (A)	Consolidated
	Millions			
Three Months Ended September 30, 2012				
NDT Fund Realized Losses and Expenses	$20	$—	$—	$20
Other	—	6	—	6
Total Other Deductions	$20	$6	$—	$26
Three Months Ended September 30, 2011				
NDT Fund Realized Losses and Expenses	$10	$—	$—	$10
Other	—	1	—	1
Total Other Deductions	$10	$1	$—	$11
Nine Months Ended September 30, 2012				
NDT Fund Realized Losses and Expenses	$45	$—	$—	$45
Other	7	8	1	16
Total Other Deductions	$52	$8	$1	$61
Nine Months Ended September 30, 2011				
NDT Fund Realized Losses and Expenses	$32	$—	$—	$32
Other	5	2	—	7
Total Other Deductions	$37	$2	$—	$39

(A) Other primarily consists of activity at PSEG (as parent company), Energy Holdings, Services and intercompany eliminations.

Note 13. Income Taxes

PSEG’s, Power’s and PSE&G’s effective tax rates for the three months and nine months ended September 30, 2012 and 2011 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
PSEG	41.0 %	43.1 %	36.3 %	42.0 %
Power	42.4 %	40.7 %	41.0 %	41.0 %
PSE&G	39.9 %	40.1 %	35.4 %	40.5 %

For the three months ended September 30, 2012, the increase in Power's effective tax rate was due primarily to NDT revenue, while the decrease in PSEG was due to the 2011 Energy Holdings' charge against earnings applicable to the Dynegy leases.

For the nine months ended September 30, 2012, the decrease in PSEG’s and PSE&G’s effective tax rate was due primarily to the IRS audit settlements discussed below.

The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 included a provision making qualified property placed into service after September 8, 2010 and before January 1, 2012, eligible for 100% bonus depreciation for tax purposes. In addition, qualified property placed into service in 2012 is eligible for 50% bonus depreciation for tax purposes. These provisions have generated cash for PSEG through tax benefits related to the accelerated depreciation in 2011 and will for 2012. These tax benefits would have otherwise been received over an estimated average 20 year period.

PSE&G has accrued $21 million of Investment Tax Credits (ITC) associated with alternative energy projects in the first nine months of 2012. Prior to 2012, the law provided an option to claim either a grant or the ITC. For years prior to 2012, the ITC had been accounted for as a reduction of the book basis of the related assets as opposed to being recorded in tax expense. As the grant program expired at the end of 2011, ITC for 2012 has been accounted for as an accumulated deferred investment credit on the balance sheet which is amortized as a reduction of tax expense over the life of the related project.

PSEG's unrecognized tax benefits decreased by approximately $533 million through the first nine months of 2012, primarily attributable to PSEG. This decrease was primarily due to the settlement with the IRS, in the amount of $387 million, of the leasing issue (See Note 8. Commitments and Contingent Liabilities) and the federal audits for tax years 1997 through 2006. The remaining unrecognized tax benefit of $146 million represents a decrease of prior period positions. As a result, as of September 30, 2012, there is no material increase or decrease in unrecognized tax benefits that is reasonably possible to occur within the next twelve months. The interest and penalties associated with the decrease in the uncertain tax position was $356 million. The impact on the accumulated deferred income taxes and regulatory asset associated with the unrecognized tax benefit decrease is $216 million. The change in the total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $317 million.

On June 26, 2009, September 15, 2008 and December 17, 2007, PSEG made tax deposits with the IRS in the amounts of $140 million, $80 million and $100 million, respectively, to defray potential interest costs associated with disputed tax assessments associated with certain lease investments. On January 31, 2012, PSEG signed a specific matter closing agreement with the IRS regarding this matter. Based on this agreement, these deposits will be applied against tax and interest due pursuant to the closing agreement. Further, on the same date, PSEG signed a Form 870-AD settlement agreement covering all audit issues for tax years 1997 through 2003. On March 26, 2012, PSEG executed a Form 870-AD settlement agreement covering all audit issues for tax years 2004 through 2006. These two agreements conclude ten years of audits for PSEG and the leasing issue for all tax years. The financial statement impacts of these agreements, net of existing financial statement reserves, is a net decrease in tax expense of approximately $70 million for PSEG, including $30 million and $1 million for PSE&G and Power, respectively.

Note 14. Accumulated Other Comprehensive Income (Loss), Net of Tax

	Balance as of December 31, 2011	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2012			Balance as of September 30, 2012
		Power	PSE&G	Other	
	Millions				
Derivative Contracts	$31	$(21)	$—	$1	$11
Pension and OPEB Plans	(438)	21	—	2	(415)
NDT Funds	66	11	—	—	77
Other	4	—	—	1	5
Accumulated Other Comprehensive Income (Loss)	$(337)	$11	$—	$4	$(322)

	Balance as of December 31, 2010	Other Comprehensive Income (Loss) Nine Months Ended September 30, 2011			Balance as of September 30, 2011
		Power	PSE&G	Other	
	Millions				
Derivative Contracts	$111	$(80)	$—	$—	$31
Pension and OPEB Plans	(377)	45	—	8	(324)
NDT Fund	109	(77)	—	—	32

Other	1	—	2	2	5
Accumulated Other Comprehensive Income (Loss)	$(156)	$(112)	$2	$10	$(256)

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Note 15. Earnings Per Share (EPS) and Dividends
Diluted EPS is calculated by dividing Net Income by the weighted average number of shares of common stock outstanding, including shares issuable upon exercise of stock options outstanding or vesting of restricted stock awards granted under PSEG's stock compensation plans and upon payment of performance units or restricted stock units. The following table shows the effect of these stock options, performance units and restricted stock units on the weighted average number of shares outstanding used in calculating diluted EPS:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2012		2011		2012		2011	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Continuing Operations	$347	$347	$265	$265	$1,051	$1,051	$1,047	$1,047
Discontinued Operations	—	—	29	29	—	—	96	96
Net Income	$347	$347	$294	$294	$1,051	$1,051	$1,143	$1,143
EPS Denominator (Thousands)								
Weighted Average Common Shares Outstanding	505,914	505,914	505,909	505,909	505,942	505,942	505,959	505,959
Effect of Stock Based Compensation Awards	—	1,197	—	1,090	—	1,095	—	1,004
Total Shares	505,914	507,111	505,909	506,999	505,942	507,037	505,959	506,963
EPS								
Continuing Operations	$0.69	$0.68	$0.52	$0.52	$2.08	$2.07	$2.07	$2.06
Discontinued Operations	—	—	0.06	0.06	—	—	0.19	0.19
Net Income	$0.69	$0.68	$0.58	$0.58	$2.08	$2.07	$2.26	$2.25

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dividend Payments on Common Stock	2012	2011	2012	2011
Per Share	$0.3550	$0.3425	$1.0650	$1.0275
in Millions	$180	$173	$538	$520

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Note 16. Financial Information by Business Segments

	Power	PSE&G	Energy Holdings	Other (A)	Consolidated
	Millions				
Three Months Ended September 30, 2012					
Total Operating Revenues	$1,038	$1,683	$15	$(334)	$2,402
Income (Loss) From Continuing Operations	181	155	7	4	347
Net Income (Loss)	181	155	7	4	347
Segment Earnings (Loss)	181	155	7	4	347
Gross Additions to Long-Lived Assets	149	499	30	11	689
Three Months Ended September 30, 2011					
Total Operating Revenues	$1,398	$1,841	$(247)	$(372)	$2,620
Income (Loss) From Continuing Operations	273	154	(166)	4	265
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax	29	—	—	—	29
Net Income (Loss)	302	154	(166)	4	294
Segment Earnings (Loss)	302	154	(166)	4	294
Gross Additions to Long-Lived Assets	207	265	1	4	477
Nine Months Ended September 30, 2012					
Total Operating Revenues	$3,584	$5,029	$49	$(1,287)	$7,375
Income (Loss) From Continuing Operations	538	453	49	11	1,051
Net Income (Loss)	538	453	49	11	1,051
Segment Earnings (Loss)	538	453	49	11	1,051
Gross Additions to Long-Lived Assets	493	1,369	85	22	1,969
Nine Months Ended September 30, 2011					
Total Operating Revenues	$4,650	$5,718	$(206)	$(1,719)	$8,443
Income (Loss) From Continuing Operations	775	422	(164)	14	1,047
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax	96	—	—	—	96
Net Income (Loss)	871	422	(164)	14	1,143
Segment Earnings (Loss)	871	422	(164)	14	1,143
Gross Additions to Long-Lived Assets	530	939	2	8	1,479
As of September 30, 2012					
Total Assets	$10,994	$18,115	$1,974	$(377)	$30,706
Investments in Equity Method Subsidiaries	$41	$—	$99	$—	$140
As of December 31, 2011					
Total Assets	$11,087	$17,487	$1,888	$(641)	$29,821
Investments in Equity Method Subsidiaries	$31	$—	$106	$—	$137

(A) Other activities include amounts applicable to PSEG (as parent company), Services and intercompany eliminations, primarily relating to intercompany transactions between Power and PSE&G. No gains or losses are recorded on any intercompany transactions; rather, all intercompany transactions are priced in accordance with applicable regulations, including affiliate pricing rules, or at cost or, in the case of the BGS and BGSS contracts between Power and PSE&G, at rates prescribed by the BPU. For a further discussion of the intercompany transactions between Power and PSE&G, see Note 17. Related-Party Transactions.

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Note 17. Related-Party Transactions
The following discussion relates to intercompany transactions, the majority of which are eliminated during the PSEG consolidation process in accordance with GAAP.
Power
The financial statements for Power include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
	Millions			
Revenue from Affiliates:				
Billings to PSE&G through BGSS (A)	$67	$91	$630	$958
Billings to PSE&G through BGS (A)	258	272	639	734
Total Revenue from Affiliates	$325	$363	$1,269	$1,692
Expense Billings from Affiliates:				
Administrative Billings from Services (B)	$(38)	$(37)	$(110)	$(109)
Total Expense Billings from Affiliates	$(38)	$(37)	$(110)	$(109)

Related-Party Transactions	As of September 30, 2012	As of December 31, 2011
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$96	$247
Receivables from PSE&G Related to Gas Supply Hedges for BGSS (A)	21	109
Receivable from (Payable to) Services (B)	(23)	(26)
Tax Receivable from (Payable to) PSEG (C)	7	58
Receivable from (Payable to) PSEG	(1)	(7)
Accounts Receivable—Affiliated Companies, net	$100	$381
Short-Term Loan to Affiliate (Demand Note to PSEG) (D)	$890	$907
Working Capital Advances to Services (E)	$17	$17
Long-Term Accrued Taxes Receivable (Payable) (C)	$(66)	$(8)

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PSE&G
The financial statements for PSE&G include transactions with related parties presented as follows:

Related-Party Transactions	Three Months Ended September 30, 2012	2011	Nine Months Ended September 30, 2012	2011
	Millions			
Expense Billings from Affiliates:				
Billings from Power through BGSS (A)	$(67)	$(91)	$(630)	$(958)
Billings from Power through BGS (A)	(258)	(272)	(639)	(734)
Administrative Billings from Services (B)	(58)	(53)	(165)	(154)
Total Expense Billings from Affiliates	$(383)	$(416)	$(1,434)	$(1,846)

Related-Party Transactions	As of September 30, 2012	As of December 31, 2011
	Millions	
Payable to Power through BGS and BGSS Contracts (A)	$(96)	$(247)
Payable to Power Related to Gas Supply Hedges for BGSS (A)	(21)	(109)
Payable to Power for SREC Liability (F)	(7)	(7)
Receivable from (Payable to) Services (B)	(47)	(56)
Tax Receivable from (Payable to) PSEG (C)	8	131
Receivable from PSEG	6	8
Receivable from Energy Holdings	2	—
Accounts Payable—Affiliated Companies, net	$(155)	$(280)
Working Capital Advances to Services (E)	$33	$33
Long-Term Accrued Taxes Payable (C)	$(19)	$(83)

(A) PSE&G has entered into a requirements contract with Power under which Power provided the gas supply services needed to meet PSE&G's BGSS and other contractual requirements. Power has also entered into contracts to supply energy, capacity and ancillary services to PSE&G through the BGS auction process.

(B) Services provides and bills administrative services to Power and PSE&G at cost. In addition, Power and PSE&G have other payables to Services, including amounts related to certain common costs, such as pension and OPEB costs, which Services pays on behalf of each of the operating companies.

(C) PSEG files a consolidated federal income tax return with its affiliated companies. A tax allocation agreement exists between PSEG and each of its affiliated companies. The general operation of these agreements is that the subsidiary company will compute its taxable income on a stand-alone basis. If the result is a net tax liability, such amount shall be paid to PSEG. If there are net operating losses and/or tax credits, the subsidiary shall receive payment for the tax savings from PSEG to the extent that PSEG is able to utilize those benefits.

(D) Power's short-term loans with PSEG are for working capital and other short-term needs. Interest Income and Interest Expense relating to these short-term funding activities were immaterial.

(E) Power and PSE&G have advanced working capital to Services. The amounts are included in Other Noncurrent Assets on Power's and PSE&G's Condensed Consolidated Balance Sheets.

(F)

In 2008, the BPU issued a decision that certain BGS suppliers will be reimbursed for the cost they incurred above $300 per Solar Renewable Energy Certificate (SREC) during the period June 1, 2008 through May 31, 2010. The BPU order further provided that the excess cost may be passed on to ratepayers. Following an appeal, on March 10, 2011, the New Jersey Supreme Court reversed and remanded the BPU's 2008 order. The Court did not rule on the substantive issue of whether the pass-through of SREC costs was appropriate. The BPU subsequently held a legislative hearing process to comply with the Court's ruling. On May 1, 2012, the BPU affirmed its earlier order and ruled that BGS suppliers could recover verified SREC expenditures above $300 per SREC. The BPU further directed the state's Electric Distribution Companies (EDCs), including PSE&G, to file by July 1, 2012 a proposed rate recovery mechanism and a method for BGS suppliers to demonstrate that any incremental costs were reasonably and prudently incurred. Such a proposal was filed by the EDCs on June 26, 2012. On October 23, 2012, the EDCs filed a stipulation with the BPU seeking approval of a methodology for reviewing and approving incremental costs owed to BGS suppliers. PSE&G has estimated and accrued a total liability for the excess SREC cost of $17 million as of September 30, 2012 and December 31, 2011, including approximately $7 million for Power's share which is included in PSE&G's Accounts Payable—Affiliated Companies as of September 30, 2012 and December 31, 2011. Under current accounting guidance, Power was unable to record the related intercompany receivable on its Condensed Consolidated Balance Sheet. As a result, PSE&G's liability to Power is not eliminated in consolidation and is included in Other Current Liabilities on PSEG's Condensed Consolidated Balance Sheet as of September 30, 2012 and December 31, 2011.

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Note 18. Guarantees of Debt

Each series of Power's Senior Notes, Pollution Control Notes and its syndicated revolving credit facilities are fully and unconditionally and jointly and severally guaranteed by its subsidiaries, PSEG Fossil LLC (Fossil), PSEG Nuclear LLC (Nuclear) and ER&T. The following table presents condensed financial information for the guarantor subsidiaries, as well as Power's non-guarantor subsidiaries.

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Millions				
Three Months Ended September 30, 2012					
Operating Revenues	$—	$1,358	$36	$(356)	$1,038
Operating Expenses	(1)	1,095	32	(355)	771
Operating Income (Loss)	1	263	4	(1)	267
Equity Earnings (Losses) of Subsidiaries	191	—	—	(191)	—
Other Income	11	106	—	(13)	104
Other Deductions	—	(20)	—	—	(20)
Other-Than-Temporary Impairments	—	(2)	—	—	(2)
Interest Expense	(29)	(15)	(5)	14	(35)
Income Tax Benefit (Expense)	7	(142)	1	1	(133)
Net Income (Loss)	$181	$190	$—	$(190)	$181
Comprehensive Income (Loss)	$166	$168	$—	$(168)	$166
Three Months Ended September 30, 2011					
Operating Revenues	$—	$1,725	$29	$(356)	$1,398
Operating Expenses	1	1,241	29	(356)	915
Operating Income (Loss)	(1)	484	—	—	483
Equity Earnings (Losses) of Subsidiaries	315	29	—	(344)	—
Other Income	9	38	—	(10)	37
Other Deductions	(1)	(8)	—	(1)	(10)
Other-Than-Temporary Impairments	1	(9)	—	—	(8)
Interest Expense	(33)	(17)	(3)	11	(42)
Income Tax Benefit (Expense)	12	(200)	1	—	(187)
Income (Loss) on Discontinued Operations, net of tax	—	—	29	—	29
Net Income (Loss)	$302	$317	$27	$(344)	$302
Comprehensive Income (Loss)	$222	$233	$27	$(260)	$222

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Millions				
Nine Months Ended September 30, 2012					
Operating Revenues	$—	$4,560	$93	$(1,069)	$3,584
Operating Expenses	(1)	3,663	87	(1,069)	2,680
Operating Income (Loss)	1	897	6	—	904
Equity Earnings (Losses) of Subsidiaries	567	(4)	—	(563)	—
Other Income	35	176	—	(40)	171
Other Deductions	(7)	(45)	—	—	(52)
Other-Than-Temporary Impairments	—	(14)	—	—	(14)
Interest Expense	(89)	(35)	(13)	40	(97)
Income Tax Benefit (Expense)	31	(409)	3	1	(374)
Net Income (Loss)	$538	$566	$(4)	$(562)	$538
Comprehensive Income (Loss)	$549	$556	$(4)	$(552)	$549
Nine Months Ended September 30, 2012					
Net Cash Provided By (Used In) Operating Activities	$409	$1,259	$(3)	$(493)	$1,172
Net Cash Provided By (Used In) Investing Activities	$257	$(897)	$(24)	$158	$(506)
Net Cash Provided By (Used In) Financing Activities	$(666)	$(368)	$26	$335	$(673)
Nine Months Ended September 30, 2011					—
Operating Revenues	$—	$5,622	$106	$(1,078)	$4,650
Operating Expenses	2	4,278	109	(1,078)	3,311
Operating Income (Loss)	(2)	1,344	(3)	—	1,339
Equity Earnings (Losses) of Subsidiaries	917	88	—	(1,005)	—
Other Income	28	159	—	(31)	156
Other Deductions	(4)	(32)	—	(1)	(37)
Other-Than-Temporary Impairments	—	(10)	—	—	(10)
Interest Expense	(115)	(38)	(13)	32	(134)
Income Tax Benefit (Expense)	47	(592)	6	—	(539)
Income (Loss) on Discontinued Operations, net of tax	—	—	96	—	96
Net Income (Loss)	$871	$919	$86	$(1,005)	$871
Comprehensive Income (Loss)	$759	$761	$86	$(847)	$759
Nine Months Ended September 30, 2011					
Net Cash Provided By (Used In) Operating Activities	$370	$2,029	$(319)	$(593)	$1,487
Net Cash Provided By (Used In) Investing Activities	$86	$(935)	$652	$(821)	$(1,018)
Net Cash Provided By (Used In) Financing Activities	$(456)	$(1,091)	$(332)	$1,413	$(466)

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	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
	Millions				
As of September 30, 2012					
Current Assets	$4,182	$7,926	$919	$(10,646)	$2,381
Property, Plant and Equipment, net	88	5,835	948	1	6,872
Investment in Subsidiaries	4,193	740	—	(4,933)	—
Noncurrent Assets	175	1,631	62	(127)	1,741
Total Assets	$8,638	$16,132	$1,929	$(15,705)	$10,994
Current Liabilities	$403	$10,183	$984	$(10,643)	$927
Noncurrent Liabilities	456	1,754	204	(126)	2,288
Long-Term Debt	2,386	—	—	—	2,386
Member's Equity	5,393	4,195	741	(4,936)	5,393
Total Liabilities and Member's Equity	$8,638	$16,132	$1,929	$(15,705)	$10,994
As of December 31, 2011					
Current Assets	$4,311	$7,248	$951	$(9,823)	$2,687
Property, Plant and Equipment, net	66	5,715	950	—	6,731
Investment in Subsidiaries	4,185	804	—	(4,989)	—
Noncurrent Assets	179	1,557	51	(118)	1,669
Total Assets	$8,741	$15,324	$1,952	$(14,930)	$11,087
Current Liabilities	$172	$9,549	$1,003	$(9,822)	$902
Noncurrent Liabilities	440	1,589	145	(118)	2,056
Long-Term Debt	2,685	—	—	—	2,685
Member's Equity	5,444	4,186	804	(4,990)	5,444
Total Liabilities and Member's Equity	$8,741	$15,324	$1,952	$(14,930)	$11,087

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Note 19. Subsequent Event

In late October 2012, high winds, heavy rainfall and the related flooding throughout PSE&G's service territory associated with Hurricane Sandy caused severe damage to PSE&G's transmission and distribution system throughout its service territory as well as to some of Power's generation infrastructure mainly in the northern part of New Jersey. The walls of water created by the storm surge flooded a large number of substations along the Passaic, Raritan and Hudson rivers. The magnitude of the flooding in contiguous areas is unprecedented. During the course of the storm, approximately 1.7 million of PSE&G's customers were without power. In terms of customer outages, this was the most in PSE&G's history, surpassing both Tropical Storm Irene and the October snowstorm in 2011. With the assistance of mutual aid crews from other utilities, PSE&G's associates are working to minimize the length of time its customers are without electric or gas service. PSE&G and Power are unable to estimate the possible loss or range of loss related to Hurricane Sandy; however, such costs could be material.

On October 26, 2012, PSE&G filed a petition with the BPU seeking authorization to defer on its books actually incurred, uninsured, incremental storm restoration costs associated with its gas and electric distribution systems. PSE&G requested similar relief in August 2011 as Tropical Storm Irene approached. Both requests are currently pending before the BPU. Power and PSE&G maintain property insurance for both nuclear and non-nuclear property. PSE&G and Power intend to seek recovery from their insurers for any property damage above their self-insured retentions; however, no assurances can be given relative to the timing or amount of such recoveries.

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ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS (MD&A)

This combined MD&A is separately filed by PSEG, Power and PSE&G. Information contained herein relating to any individual company is filed by such company on its own behalf. Power and PSE&G each make representations only as to itself and make no representations whatsoever as to any other company.

PSEG's business consists of three reportable segments, which are:

- Power, our wholesale energy supply company that integrates its generating asset operations with its wholesale energy, fuel supply, energy trading and marketing and risk management activities primarily in the Northeast and Mid Atlantic United States,
- PSE&G, our public utility company which provides transmission and distribution of electric energy and gas in New Jersey; implements demand response and energy efficiency programs and invests in solar generation, and
- Energy Holdings, which owns our energy-related leveraged leases and other investments.

Our business discussion in Part I, Item 1. Business of our 2011 Annual Report on 10-K (Form 10-K) provides a review of the regions and markets where we operate and compete, as well as our strategy for conducting our businesses within these markets, focusing on operational excellence, financial strength and making disciplined investments. Our risk factor discussion in Part II Item 1A of Form 10-K provides information about factors that could have a material adverse impact on our businesses. The following supplements that discussion and the discussion included in the Overview of 2011 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2012 and any changes to the key factors that we expect may drive our future performance. The following discussion refers to the Condensed Consolidated Financial Statements (Statements) and the Related Notes to Condensed Consolidated Financial Statements (Notes). This discussion should be read in conjunction with such Statements, Notes, the 2011 Form 10-K and the Quarterly Reports on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012.

OVERVIEW OF 2012 AND FUTURE OUTLOOK

During the first nine months of 2012, our results continued to be adversely impacted by lower prices for electricity and natural gas in the markets we serve.

Partially offsetting this lower commodity pricing were higher transmission revenues as a result of our 2012 Annual Formula Rate Update with the Federal Energy Regulatory Commission (FERC), which provided for approximately $94 million in increased annual transmission revenues effective January 1, 2012. We filed our 2013 Annual Formula Rate Update with FERC in October 2012, which would provide for approximately $174 million in increased annual transmission revenues effective January 1, 2013.

Under the Reliability Pricing Model capacity auction in May 2012, for the 2015-2016 period, Power cleared approximately 9,000 MW of its generating capacity at an average price of $167 per MW-day.

Our volumes of gas sales were lower in the first nine months of 2012, but the decline in gas revenues was significantly mitigated by the favorable impact of a $57 million increase due to recovery of deficiency revenues through the Weather Normalization Charge (WNC). PSE&G's WNC is a rate mechanism that allows us to increase our rates, subject to an earnings test, to compensate for lower revenues we receive from customers as a result of warmer-than-normal winters and to decrease our rates to make up for higher revenues we receive as a result of colder-than-normal winters.

For the remainder of 2012 and beyond, the key issues we expect our business to confront include:

- the continuing potential for sustained lower natural gas and electricity prices, both at market hubs and at locations where we operate,
- customer migration away from our BGS supply contracts,
- uncertainty in the national and regional economic recovery and continuing customer conservation efforts, which impacts customer demand,
- regulatory and political uncertainty, particularly with regard to future energy policy, design of energy and capacity markets, transmission policy and environmental regulation, and
-

challenges to competitive markets, including support for subsidized generation in many states, particularly in New Jersey.

Our future success will depend on our ability to respond to these challenges and take advantage of opportunities presented by these and other regulatory and legislative initiatives. In order to do this, we must:

- continue to focus on controlling costs while maintaining our safety, reliability and compliance standards,
- successfully re-contract our open supply positions, and

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- execute our capital investment program, including investments for growth that yield contemporaneous and attractive risk adjusted returns.

There have also been certain significant regulatory and legislative developments during the year which may affect our operations in the future as new rules and regulations are adopted. For additional information on these issues, see Item 5. Other Information.

- New Jersey's Long-Term Capacity Agreement Pilot Program Act (LCAPP Act), actions by the Maryland Public Service Commission's Request for Proposal or similar activity in other states to subsidize new generation may artificially depress energy and capacity prices in the competitive wholesale market and have the potential to harm competitive markets and adversely impact our generation business, on both a short-term and long-term basis.

These efforts to artificially depress the wholesale capacity auction were intended to be mitigated by the Minimum Offer Price Rule (MOPR) approved by FERC. The MOPR was intended to restrict new natural gas-fired generation from bidding in RPM at less than an established minimum level established by Tariff, or a cost-based bid to the extent that the generator can demonstrate that its costs are lower than the MOPR. The MOPR was in place for the May 2012 auction, but we believe it did not operate to protect the market against these suppression efforts. As a result, discussions among a diverse group of PJM Interconnection L.L.C. (PJM) stakeholders to improve the MOPR ensued and a settlement was recently reached among those stakeholders. PJM is currently educating its stakeholders on the settlement and PJM plans to bring the settlement to a stakeholder vote in November 2012. If this settlement is approved by the FERC, it will change how the MOPR will be applied in the RPM auction in May 2013 and should enhance the competitiveness of the auction. We cannot predict the outcome of this matter.

- FERC's Order 1000 (Order 1000), issued in July 2011, among other things directs regional planners such as PJM to (i) be more flexible in how they plan for future transmission build (ii) eliminate any Right of First Refusal, which permits incumbent transmission owners, like us, the first opportunity to construct transmission within their respective service territories, subject to certain exceptions, and (iii) allocate costs for transmission projects in a way that roughly matches costs with benefits, while leaving flexibility to the regions to determine precise cost allocation methodologies. In June 2012, PSEG appealed Order 1000 in federal court. Other companies and state commissions have filed appeals as well. PJM has concluded a stakeholder process to develop implementing details regarding Order 1000. An expected outcome of this process is the construction of more transmission and the opening up of transmission construction and ownership to third party developers and to incumbents seeking to build outside of their service territories. We cannot predict the final outcome or impact on us; however, specific implementation of Order 1000 in the various regions, including within our service territory, may expose us to competition for construction of transmission, additional regulatory considerations and potential delay with respect to future transmission projects.
- On March 30, 2012, the FERC issued an order finding that allocation of costs associated with high voltage (500 kV and higher) transmission projects in PJM to all customers in PJM is just and reasonable. This order, which has been challenged on rehearing, therefore preserves the current cost allocation for the Susquehanna-Roseland project discussed below. However, the FERC also stated in its order that other cost allocation methodologies could be just and reasonable and this may lead to the adoption of a different cost allocation methodology for transmission in PJM in the future. On October 11, 2012, PSE&G joined with other PJM transmission owners to file with FERC for approval of a consensus cost allocation methodology for transmission projects in PJM.
- As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in March 2011, the Nuclear Regulatory Commission (NRC) has been performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan will result in a series of additional regulations for the nuclear industry. The first regulations have already been issued, and in conjunction with additional regulations, could impact future operations and capital requirements for our facilities. We believe that our nuclear plants currently meet the stringent applicable design and safety specifications of the NRC.
- During 2012, the Securities and Exchange Commission and the Commodity Futures Trading Commission (CFTC) continued efforts to enact stricter regulation over swaps and derivatives. The CFTC has issued Notices of Proposed Rulemakings on many of the key issues and is in the process of issuing Final Rules on these issues. In May 2012, the CFTC issued Final Rules regarding the definition of a swap dealer and the definition of a swap. However, in September 2012, a federal court vacated the CFTC's rule on monitoring of position limits for several commodities,

including natural gas, thereby indefinitely delaying the effectiveness of these position limits rules. We are carefully monitoring all of these new rules as they are issued to analyze the potential impact on our swap and derivatives transactions, including any potential increase in our collateral requirements.

Operational Excellence

Our nuclear and fossil facilities continued their strong operating performance through the first nine months of 2012. Our nuclear units have achieved a capacity factor of 92.5% and our combined cycle units have continued to improve their forced outage rates. Overall, generation volumes for the first nine months of 2012 were 40.8 terawatt hours, approximately 2.4% lower than in 2011 due primarily to reduced demand due to milder weather in 2012.

In the second quarter of 2012, we received the final approvals for the 10-year contract that we won in December 2011 to manage Long Island Power Authority's electric transmission and distribution system in Long Island, New York. The contract, which commences January 1, 2014, represents an opportunity to improve returns and is recognition of our history of strong reliability and customer satisfaction.

In October 2012, we extended the current collective bargaining agreements with three of our labor unions for four years through April 2017. Collectively, these three unions represent approximately 5,200 employees of PSE&G, Power and PSEG Services Corporation. The extension of these agreements should help to ensure stability and predictability of union costs at a time when we have pressure on earnings caused by the fall in gas and electric prices.

In late October 2012, high winds, heavy rainfall and the related flooding throughout our service territory associated with Hurricane Sandy caused severe damage to our transmission and distribution system throughout our service territory as well as to some of our generation infrastructure mainly in the northern part of New Jersey. The walls of water created by the storm surge flooded a large number of substations along the Passaic, Raritan and Hudson rivers. The magnitude of the flooding in contiguous areas is unprecedented. During the course of the storm, approximately 1.7 million of our customers were without power. In terms of customer outages, this was the most in PSE&G's history, surpassing both Tropical Storm Irene and the October snowstorm in 2011. With the assistance of mutual aid crews from other utilities, our associates are working to minimize the length of time our customers are without electric or gas service. PSE&G and Power are unable to estimate the possible loss or range of loss related to Hurricane Sandy; however, such costs could be material.

On October 26, 2012, we filed a petition with the BPU seeking authorization to defer on our books actually incurred, uninsured, incremental storm restoration costs associated with our gas and electric distribution systems. We requested similar relief in August 2011 as Tropical Storm Irene approached. Both requests are currently pending before the BPU. We maintain property insurance for both nuclear and non-nuclear property. PSE&G and Power intend to seek recovery from their insurers for any property damage above our self-insured retentions; however, no assurances can be given relative to the timing or amount of such recovery.

Financial Strength

Our cash from operations has remained strong. During the first nine months of 2012, we made approximately $2.0 billion in capital expenditures, paid dividends of $538 million and made our entire planned pension and other postretirement employee benefit contributions for the year 2012 of $135 million.

In March 2012, Power's $1.525 billion and PSEG's $477 million credit facilities that were set to expire in December 2012 were replaced with $1.6 billion and $500 million credit facilities, respectively, expiring in March 2017. As of September 30, 2012, our total credit capacity was $4.3 billion and we had $780 million of cash on hand.

On January 31, 2012, we entered into a specific matter closing agreement settling our dispute with the IRS over certain lease transactions. This agreement settles the international leveraged lease dispute with finality for all tax periods in which we realized tax deductions from these transactions. Also on January 31, 2012, we signed a settlement agreement covering all audit issues for tax years 1997 through 2003. On March 26, 2012, we executed a formal settlement agreement covering all audit issues for tax years 2004 through 2006. These two agreements conclude 10 years of audits for us and the leasing issue for all tax years.

Disciplined Investment

We seek to invest in areas that complement our existing businesses and provide attractive risk-adjusted returns. These areas include upgrading critical energy infrastructure, responding to trends in environmental protection and providing new energy supplies in domestic markets with growing demand. We also have several projects where we are investing to continue to improve our operational performance. Over the past few years, we have shifted our focus to investing at the utility. Our capital expenditure forecast includes over $6.7 billion in spending over the next three years, over 75% of which is at PSE&G.

- On October 1, 2012, the National Park Service (NPS) issued a final Environmental Impact Statement (EIS), affirming our and PPL Electric Utilities Corporation's choice of route for the Susquehanna-Roseland transmission line project that follows the existing right-of-way. On October 15, 2012, several environmental groups filed a complaint in federal court challenging the NPS' issuance of the final EIS, seeking to set aside the EIS and to enjoin implementation of the NPS' decision. If this request for injunctive relief is granted, the construction schedule for the project could be impacted. We have also recently obtained environmental permits for the project from the New Jersey Department of Environmental Protection (NJDEP). We have begun construction in those areas where necessary permits have been obtained. Currently, the expected in-service date for the Eastern segment of the project is June 2014 and for the Western segment is June 2015, although further delays are possible. The cost of construction is up to

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an estimated $790 million for this project. As of September 30, 2012, total capital expenditures were $261 million.

- We are continuing the process of obtaining regulatory approvals for the North East Grid project, a 230 kV project running from Roseland to Hudson with an expected in-service date of June 2015 and an estimated cost of construction of $895 million. As of September 30, 2012, total capital expenditures were $73 million. In June 2012, we obtained the major regulatory approvals for another 230 kV project, the North-Central Reliability project, located in the northern and central portions of New Jersey with an expected in-service date of June 2014 and an estimated cost of construction of up to $390 million. Construction of this project has commenced. As of September 30, 2012, total capital expenditures for this project were $117 million.
- We have made additional investments in solar power in New Jersey. Under our solar loan program we have provided a total of $192 million in loans for 812 projects as of September 30, 2012, representing 61 MW to date. Under our Solar 4 All program, we have made total capital expenditures of approximately $422 million as of September 30, 2012. Approximately 33 MW of solar panels have been installed on distribution poles and another 38 MW representing 22 projects have been placed into service. Additional projects are in various stages of development. Our total anticipated expenditures to develop all approved 80 MW are approximately $443 million.

On July 23, 2012, the Governor of New Jersey signed legislation that, among other things, requires energy providers, including BGS providers and third party suppliers, to increase the amount of power in their portfolios derived from solar electricity, increasing the demand for Solar Renewable Energy Credits and increasing the potential for additional utility solar generation investment.

On July 31, 2012, we filed for an extension of our Solar 4 All program. In this filing, we are seeking BPU approval for up to $690 million to develop 136 MW of utility-owned solar photovoltaic systems over a five year period starting in 2013. Consistent with the existing Solar 4 All program, we propose to sell the energy and capacity from the solar systems in the PJM wholesale energy and capacity markets which will offset the cost of the program.

We also filed for an additional extension of our Solar Loan program (Solar Loan III) on July 31, 2012. In the filing, we are seeking BPU approval to provide financing support for the installation of 98 MW of solar systems by providing loans to qualified customers. The total investment of the proposed Solar Loan III program is anticipated to be up to $193 million once the program is fully subscribed, projects are built and loans are closed.

The estimated project costs included in the July 31, 2012 filings for extensions of our Solar 4 All and Solar Loan III programs are not included in our $6.7 billion three-year capital forecast.

- Our Capital Infrastructure Program (CIP II) provides for approximately $273 million in accelerated capital investments in our electric and gas infrastructure through 2012. In early November 2012, dye ti the impacts of Hurricane Sandy, we filed for an extension of time to complete the CIP II projects with the BPU. As of September 30, 2012, total capital expenditures since inception of this program were $224 million.
- We made additional expenditures under our Energy Efficiency and Demand Response programs. As of September 30, 2012, total capital expenditures since inception of these projects were $152 million for Energy Efficiency Economic Stimulus (EEE), $4 million for EEE Extension and $44 million for Carbon Abatement and $26 million for Demand Response.
- We continued various construction activities at Power, including an extended power uprate at Peach Bottom. We completed construction of new gas-fired peaking units at Kearny and in Connecticut and primary installation of the Peach Bottom steam path retrofit (see Note 8. Commitments and Contingent Liabilities and Part II. Item 5. Other Information for additional information). This additional capacity at Kearny was bid into and has cleared the RPM capacity auction, and the additional capacity in Connecticut is subject to a contract with a Connecticut utility.
- We are continuing our efforts to obtain an Early Site Permit for a new nuclear generating station to be located at the current site of Salem and Hope Creek stations. The NRC acceptance review is complete and agency evaluation is underway. There were no petitions filed for permission to intervene. The current schedule supports issuance of the Early Site Permit in 2015.
- In September 2012, we acquired a 15 MW solar project currently under construction in Delaware. We expect to complete construction of this project in the first quarter of 2013. Effective with commencement of commercial operation, the project has a 20-year power purchase agreement for energy and the majority of renewable energy credits with a wholesale electric utility servicing municipal electric distribution utilities in Delaware. We issued

guarantees of up to $37 million for payment of obligations related to the construction of the project. The total investment for the project is expected to be approximately $47 million.

- In October 2012, we began commercial operation of our newly constructed 25 MW solar project in Arizona. All of the energy, capacity and environmental attributes generated by the project in the first 20 years were sold to an Arizona electric utility under a long-term power purchase agreement. We had issued guarantees of up to $72 million for payment of obligations related to the construction of the project, of which $17 million was outstanding as of

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September 30, 2012. The total investment for the project was approximately $75 million.
There is no guarantee that the projects described above or any future initiatives will be achieved since many issues need to be favorably resolved, such as regulatory approvals. Delays in the construction schedules of our projects could impact the timing of expected revenues.

RESULTS OF OPERATIONS

The results for PSEG, PSE&G, Power and Energy Holdings for the three months and nine months ended September 30, 2012 and 2011 are presented below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
Earnings (Losses)	2012	2011	2012	2011
	Millions			
Power	$181	$273	$538	$775
PSE&G	155	154	453	422
Energy Holdings	7	(166)	49	(164)
Other (A)	4	4	11	14
PSEG Income from Continuing Operations	347	265	1,051	1,047
Income (Loss) from Discontinued Operations (B)	—	29	—	96
PSEG Net Income	$347	$294	$1,051	$1,143

	Three Months Ended September 30,		Nine Months Ended September 30,	
Earnings Per Share (Diluted)	2012	2011	2012	2011
PSEG Income from Continuing Operations	$0.68	$0.52	$2.07	$2.06
Income (Loss) from Discontinued Operations (B)	—	0.06	—	0.19
PSEG Net Income	$0.68	$0.58	$2.07	$2.25

(A) Other primarily includes parent company interest and financing costs, donations and certain administrative and general expenses.

(B) See Note 4. Discontinued Operations and Dispositions.

Our results include the realized gains, losses and earnings on Power’s Nuclear Decommissioning Trust (NDT) Fund and other related NDT activity. This includes the net realized gains, interest and dividend income and other costs related to the NDT Fund which are recorded in Other Income and Deductions. This also includes credit-related impairments on certain NDT securities which are included in Other-Than-Temporary Impairments and the interest accretion expense on Power’s nuclear Asset Retirement Obligation (ARO), which is recorded in Operation and Maintenance Expense and the depreciation related to the ARO asset. In September 2012, we restructured a portion of our NDT Fund and realized gains of $59 million. The investments were transitioned to new investment managers to remove under-performing managers.

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

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The quarter-over-quarter and nine month-over-nine month variances in our Income from Continuing Operations include the changes related to NDT and MTM shown in the chart below:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
	Millions, after tax			
NDT Fund Income (Expense)	$40	$7	$49	$49
Non-Trading MTM Gains (Losses)	$(76)	$8	$(34)	$16

In addition to the changes in NDT and MTM, our $82 million increase and $4 million increase in Income from Continuing Operations for the three months and nine months ended September 30, 2012, respectively, were driven primarily by:

- the absence of the after-tax charge on leveraged leases related to Dynegy in the prior year, and
- higher transmission formula rates at PSE&G,

partially offset by:

- lower average pricing and volumes for electricity sold under our BGS contracts,
- lower average prices realized on generation sold into various power pools, and
- lower gas volumes and demand due to milder winter weather.

The increase for the nine months ended September 30, 2012 also includes lower tax expense due to the settlement of 10 years of IRS audits in the first quarter of 2012.

PSEG

Our results of operations are primarily comprised of the results of operations of our operating subsidiaries, Power, PSE&G and Energy Holdings, excluding charges related to intercompany transactions, which are eliminated in consolidation. We also include certain financing costs, charitable contributions and general and administrative costs at the parent company. For additional information on intercompany transactions, see Note 17. Related-Party Transactions. For an explanation of the variances, see the discussions for Power, PSE&G and Energy Holdings that follow the table below:

	Three Months Ended September 30,		Increase/ (Decrease) 2012 vs. 2011		Nine Months Ended September 30,		Increase/ (Decrease) 2012 vs. 2011	
	2012	2011			2012	2011		
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$2,402	$2,620	$(218)	(8)	$7,375	$8,443	$(1,068)	(13)
Energy Costs	879	1,167	(288)	(25)	2,819	3,740	(921)	(25)
Operation and Maintenance	619	603	16	3	1,876	1,829	47	3
Depreciation and Amortization	286	263	23	9	797	739	58	8
Taxes Other than Income Taxes	24	31	(7)	(23)	73	102	(29)	(28)
Income from Equity Method Investments	7	1	6	N/A	9	8	1	13
Other Income and (Deductions)	95	34	61	N/A	155	137	18	13
Other-Than-Temporary Impairments	2	8	(6)	(75)	14	13	1	8

Interest Expense	106	117	(11)	(9)	310	361	(51)	(14)
Income Tax Expense	241	201	40	20	599	757	(158)	(21)
Income (Loss) from Discontinued Operations	—	29	(29)	(100)	—	96	(96)	(100)

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Power

	Three Months Ended September 30,		Increase/ (Decrease)	Nine Months Ended September 30,		Increase/ (Decrease)
	2012	2011	2012 vs 2011	2012	2011	2012 vs 2011
	Millions					
Income from Continuing Operations	$181	$273	$(92)	$538	$775	$(237)
Income (Loss) from Discontinued Operations, net of tax	—	29	(29)	—	96	(96)
Net Income	$181	$302	$(121)	$538	$871	$(333)

For the three months and nine months ended September 30, 2012, the primary reasons for the $92 million decrease and $237 million decrease in Income from Continuing Operations were

- lower average prices realized on generation sold into the PJM and New York power pools and MTM losses due in part to adverse changes in unrealized prices in 2012 for forward positions in the PJM region,
- lower average pricing and lower volumes of electricity sold under our BGS contracts, net of lower cost to serve,
- lower volumes on wholesale load contracts in PJM, lower operating reserve, ancillary and Reliability Must Run (RMR) revenues primarily in PJM and New England, and
- lower average pricing and volumes of gas sold under our BGSS contracts, net of lower cost to serve.

These decreases were partially offset by

- lower operation and maintenance costs in 2012 at our fossil plants.

The decrease for the three months ended September 30, 2012 was partially offset by higher net realized gains on the NDT Fund. The decrease for the nine months ended September 30, 2012 was also attributable to higher operation and maintenance costs at our nuclear plants and was partially offset by lower interest expense due to the redemption of Senior Notes in April 2011 and December 2011.

The quarter and year-to-date details for these variances are discussed below:

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30, 2012		Increase/ (Decrease)	
	2012	2011	2012 vs 2011		2012	2011	2012 vs 2011	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$1,038	$1,398	$(360)	(26)	$3,584	$4,650	$(1,066)	(23)
Energy Costs	456	597	(141)	(24)	1,725	2,335	(610)	(26)
Operation and Maintenance	255	262	(7)	(3)	780	810	(30)	(4)
Depreciation and Amortization	60	56	4	7	175	166	9	5
Other Income (Deductions)	84	27	57	N/A	119	119	—	—
Other-Than-Temporary Impairments	2	8	(6)	(75)	14	10	4	40
Interest Expense	35	42	(7)	(17)	97	134	(37)	(28)
Income Tax Expense	133	187	(54)	(29)	374	539	(165)	(31)
	—	29	(29)	(100)	—	96	(96)	(100)

Income (Loss) from
Discontinued Operations

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Three Months Ended September 30, 2012 As Compared to 2011

Operating Revenues decreased $360 million due to

Generation Revenues decreased $323 million due primarily to

- lower net revenues of $226 million due primarily to lower average realized prices for our generation sold into the PJM and New York power pools and MTM losses due in part to adverse changes in unrealized prices in 2012 for forward positions in the PJM region,
- a decrease of $78 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts as a result of customer migration, and
- a decrease of $47 million due primarily to lower volumes on wholesale load contracts in both the PJM and New England regions,
- partially offset by a net increase of $28 million due to higher capacity payments received in the PJM power pool resulting from higher auction prices partly offset by lower operating reserve revenue in 2012 resulting from lower demand and lower market prices, lower ancillary revenues and lower RMR revenues in the PJM region.

Gas Supply Revenues decreased $37 million due primarily to

- a decrease of $29 million in sales under the BGSS contract, substantially comprised of lower average gas prices on lower volumes of sales in the third quarter of 2012, and
- a net decrease of $8 million due primarily to higher volumes of sales to third party customers offset by lower average prices.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power’s obligation under its BGSS contract with PSE&G. Energy Costs decreased $141 million due to

- Generation costs decreased $105 million due primarily to $55 million of lower fuel costs, reflecting the utilization of lower volumes of coal and oil and lower average natural gas prices, partially offset by the utilization of higher volumes of natural gas and higher nuclear fuel prices. The decrease was also attributable to $38 million in lower energy purchases in the PJM region as a result of lower load contract volumes in 2012, and $12 million of lower emission charges due to lower coal generation in the PJM and New England regions.
- Gas costs decreased $36 million, principally related to obligations under the BGSS contract, reflecting lower average gas inventory costs coupled with lower sales volumes in the third quarter of 2012.

Operation and Maintenance decreased $7 million due primarily to lower fossil outage and maintenance costs in 2012, primarily at our coal/gas-fired Hudson facility in New Jersey and our co-owned coal-fired Conemaugh plant in Pennsylvania.

Depreciation and Amortization increased $4 million due primarily to placing the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut into service on June 1, 2012, as well as completion of the steam path retrofit upgrade at Peach Bottom Unit 3 in October 2011.

Other Income and (Deductions) net increase of $57 million was due primarily to higher net realized gains from the restructuring of our NDT Fund in September 2012.

Other-Than-Temporary Impairments decreased $6 million due to lower impairments on the NDT Fund in 2012.

Interest Expense decreased $7 million due to a decrease of $11 million primarily from the early redemption of $600 million of 6.95% Senior Notes in December 2011, partially offset by an increase of $4 million due to the issuance of $250 million of 2.75% Senior Notes and $250 million of 4.15% Senior Notes in September 2011.

Income Tax Expense decreased $54 million in 2012 due primarily to lower pre-tax income.

Income (Loss) from Discontinued Operations

In 2011, we sold our two 1,000 MW combined-cycle generating facilities in Texas in separate transactions. In March 2011, we completed the sale of one plant for proceeds of $352 million and an after-tax gain of $54 million. In July 2011, we completed the sale of the second plant for proceeds of $335 million and an after-tax gain of $25 million. The sale of the second plant was reflected in Power’s Condensed Consolidated Financial Statements for the third quarter of 2011. The results of operations for the second plant through sale date, including the after-tax gain on its sale, are included for the third quarter of 2011 in this category. See Item 8. Financial Statements and Supplementary Data—Note 4. Discontinued Operations and Dispositions for additional information.

Nine Months Ended September 30, 2012 As Compared to 2011

Operating Revenues decreased $1,066 million due to

Generation Revenues decreased $752 million due primarily to

- lower net revenues of $355 million due primarily to lower average realized prices for our generation sold into the PJM and New York power pools and MTM losses due in part to adverse changes in unrealized prices in 2012 for forward positions in the PJM region,
- a decrease of $215 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts primarily as a result of warmer winter weather in 2012 as well as customer migration,
- a net decrease of $132 million due to lower volumes on wholesale load contracts in the PJM and New England regions, and
- a decrease of $50 million due to lower operating reserve revenue in 2012 resulting from lower demand and lower average market prices, lower ancillary revenues, lower Reliability Must Run revenues and lower capacity payments received in the PJM region resulting from lower auction prices.

Gas Supply Revenues decreased $347 million due primarily to

- a decrease of $319 million in sales under the BGSS contract, substantially comprised of lower average gas prices on lower volumes of sales in 2012 due to warmer average temperatures during the first quarter of 2012, and
- a net decrease of $28 million due to lower average prices partially offset by higher sales volumes to third party customers.

Trading Revenues increased $33 million in 2012 due to the discontinuation of trading activities in the second quarter of 2011. As a result, the increase is due primarily to the absence of losses on electric energy supply contracts recognized in 2011.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel costs for generation as well as purchased energy in the market, and gas purchases to meet Power’s obligation under its BGSS contract with PSE&G. Energy Costs decreased $610 million due to

- Gas costs decreased $308 million, principally related to obligations under the BGSS contract, reflecting lower average gas inventory costs coupled with lower sales volumes in 2012 due primarily to warmer average temperatures during the first quarter of 2012.
- Generation costs decreased $302 million due primarily to $237 million of lower fuel costs, reflecting the utilization of lower volumes of both coal and oil and lower average natural gas prices, partially offset by the utilization of higher volumes of natural gas and higher nuclear fuel prices in 2012. The decrease was also attributable to $105 million in lower energy purchases primarily in the PJM region as a result of lower load contract volumes in 2012, and $26 million of lower emission charges due to lower coal generation in the PJM and New England regions. These decreases were partially offset by an increase of $66 million due primarily to higher congestion costs in the PJM region.

Operation and Maintenance decreased $30 million due primarily to lower outage and maintenance costs in 2012, mainly at our gas-fired Bethlehem facility in New York, Bergen and Linden gas-fired plants, Mercer coal-fired plant and coal/gas-fired Hudson plant in New Jersey, and coal-fired Keystone and Conemaugh plants in Pennsylvania. This decrease was partially offset by refueling costs in 2012 for our 100%-owned Hope Creek nuclear facility as compared to our portion of refueling costs in 2011 for our 57%-owned Salem 2 nuclear unit.

Depreciation and Amortization increased $9 million due primarily to higher depreciable asset bases at Fossil and Nuclear, including placing into service the new gas-fired peaking units at Kearny, New Jersey and New Haven, Connecticut on June 1, 2012 and completion of the steam path retrofit upgrade at our co-owned Peach Bottom Unit 3 in October 2011.

Other-Than-Temporary Impairments increased $4 million due primarily to impairments on the NDT Fund in 2012.

Interest Expense decreased $37 million due primarily to a decrease of $47 million resulting primarily from the maturity of $606 million of 7.75% Senior Notes in early April 2011 and the early redemption of $600 million of 6.95% Senior Notes in December 2011, partially offset by an increase of $12 million due to two $250 million Senior Notes issuances in September 2011.

Income Tax Expense decreased $165 million in 2012 due primarily to lower pre-tax income.

Income (Loss) from Discontinued Operations

As discussed above, we sold our two Texas plants in March 2011 and July 2011, respectively. The results of operations of both plants, including the after-tax gains from their sales, are included in this category for 2011. See Item 8. Financial Statements and Supplementary Data—Note 4. Discontinued Operations and Dispositions for additional information.

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PSE&G

	Three Months Ended September 30,		Increase/ (Decrease)	Nine Months Ended September 30,		Increase/ (Decrease)
	2012	2011	2012 vs. 2011	2012	2011	2012 vs. 2011
	Millions					
Income from Continuing Operations	$155	$154	$1	$453	$422	$31
Net Income	$155	$154	$1	$453	$422	$31

For the three months ended September 30, 2012, the primary reason for the $1 million increase in Income from Continuing Operations was

- higher transmission formula rates.

For the nine months ended September 30, 2012, the primary reasons for the $31 million increase in Income from Continuing Operations were

- higher transmission formula rates, and
- tax benefits related to settlement of IRS audits,
- partially offset by lower gas volumes and demands due to milder winter weather.

The quarter and year-to-date details for these variances are discussed below:

	Three Months Ended September 30,		Increase/ (Decrease)		Nine Months Ended September 30,		Increase/ (Decrease)	
	2012	2011	2012 vs 2011		2012	2011	2012 vs 2011	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$1,683	$1,841	$(158)	(9)	$5,029	$5,718	$(689)	(12)
Energy Costs	756	943	(187)	(20)	2,380	3,124	(744)	(24)
Operation and Maintenance	366	342	24	7	1,092	1,014	78	8
Depreciation and Amortization	216	197	19	10	594	548	46	8
Taxes Other Than Income Taxes	24	31	(7)	(23)	73	102	(29)	(28)
Other Income (Deductions)	10	6	4	67	31	14	17	N/A
Other-Than Temporary Impairments	—	—	—	N/A	—	1	(1)	(100)
Interest Expense	73	77	(4)	(5)	220	234	(14)	(6)
Income Tax Expense (Benefit)	103	103	—	—	248	287	(39)	(14)

Three Months Ended September 30, 2012 As Compared to 2011

Operating Revenues decreased $158 million due primarily to

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

- Electric revenues decreased $158 million due primarily to $141 million in lower BGS revenues and $17 million in lower revenues from the sale of Non-Utility Generation (NUG) energy and collections of Non-Utility Generation

Charges (NGC) due primarily to lower prices. BGS sales decreased 11% due primarily to customer migration to third party suppliers (TPS); in contrast, delivery sales decreased only 1%.

- Gas revenues decreased $29 million due to lower BGSS prices of $26 million and lower BGSS volumes of $3 million due to weather.

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Other Operating Revenues decreased $3 million due primarily to lower miscellaneous electric operating revenues and decreased revenues from our appliance repair business.

Delivery Revenues increased $23 million due primarily to an increase in transmission revenues.

- Transmission revenues were $22 million higher due primarily to net rate increases.
- Gas distribution revenues increased $4 million due primarily to a higher WNC revenue of $6 million and higher Capital Infrastructure Program (CIP) revenue of $1 million, partially offset by lower sales volume of $3 million.
- Electric distribution revenues decreased $3 million due primarily to lower Transitional Energy Facilities Assessment (TEFA) revenue of $7 million due to a lower TEFA rate and lower sales volumes of $6 million, partially offset by higher Solar, Energy Efficiency and Conservation Program (Solar/EE) revenue of $7 million and higher CIP revenue of $3 million.

Clause Revenues increased $9 million due primarily to higher Securitization Transition Charge (STC) revenues of $7 million and higher Societal Benefit Charges (SBC) of $5 million, partially offset by a lower Margin Adjustment Clause (MAC) of $3 million. The changes in STC, MAC and SBC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, MAC or STC collections.

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

- Electric costs decreased $158 million due to $75 million or 10% in lower BGS and NUG volumes due to customer migration to TPS, $47 million of lower BGS prices, and $36 million for decreased deferred cost recovery.
- Gas costs decreased $29 million due to $26 million or 25% in lower prices and $3 million or 3% in lower sales volumes due primarily to weather.

Operation and Maintenance increased $24 million due primarily to

- a $10 million increase in pension and other postretirement benefits (OPEB) expenses,
- a $9 million increase in costs recognized related to SBC, Solar/EE and CIP,
- a $6 million increase in transmission related costs, and
- a $3 million increase in gas bad debt expense,
- partially offset by the absence of $13 million in storm damages in prior year.

Depreciation and Amortization increased $19 million due primarily to

- an increase of $13 million for amortization of Regulatory Assets, and
- an increase of $6 million for additional plant in service.

Taxes Other Than Income Taxes decreased $7 million due to a lower TEFA rate and lower sales volumes for electric and gas.

Other Income and (Deductions) net increase of $4 million was due primarily to an increase in capitalized allowance for Equity Funds used during construction.

Interest Expense decreased $4 million due primarily to the partial redemption of securitization debt. See Note 9. Changes in Capitalization for details.

Nine Months Ended September 30, 2012 As Compared to 2011

Operating Revenues decreased $689 million due primarily to

Commodity Revenue decreased $744 million due to lower Electric and Gas revenues. This is entirely offset as savings in Energy Costs. PSE&G earns no margin on the provision of BGS and BGSS to retail customers.

- Electric revenues decreased $417 million due primarily to $371 million in lower BGS revenues and $46 million in lower revenues from the sale of NUG energy and collections of NGC due primarily to lower prices. BGS sales decreased 14% due primarily to customer migration to TPS; in contrast, delivery sales decreased only 2%.
- Gas revenues decreased $327 million due to lower BGSS volumes of $166 million and lower BGSS prices of $161 million. The average price of natural gas was 17% lower in 2012 than in 2011.

Clause Revenues increased $4 million due primarily to higher STC revenues of $13 million, partially offset by lower SBC of $8 million and lower MAC of $1 million. The changes in STC and SBC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in O&M, Depreciation and Amortization and Interest Expense. PSE&G does not earn margin on SBC, MAC or STC collections.

Delivery Revenues increased $51 million due primarily to an increase in transmission revenues.

- Transmission revenues were $64 million higher due primarily to net rate increases.

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- Electric distribution revenues decreased $10 million due primarily to lower TEFA revenue of $20 million due to a lower TEFA rate and lower sales volumes of $16 million, partially offset by higher Solar/EE revenue of $17 million and higher CIP revenue of $9 million.
- Gas distribution revenues decreased $3 million due primarily to lower sales volume of $57 million, lower TEFA revenue of $11 million due to a lower TEFA rate, partially offset by higher WNC revenue of $57 million and higher CIP revenue of $8 million.

Other Operating Revenues was flat due primarily to increased revenues from our appliance repair business, offset by lower miscellaneous electric operating revenues.

Energy Costs decreased $744 million. This is entirely offset by Commodity Revenue.

- Electric costs decreased $417 million due to $210 million or 10% in lower BGS and NUG volumes due to customer migration to TPS, $145 million of lower BGS prices, and $62 million for decreased deferred cost recovery.
- Gas costs decreased $327 million due to $166 million or 17% in lower sales volumes due primarily to weather and $161 million or 17% in lower prices.

Operation and Maintenance increased $78 million due primarily to

- a $23 million increase in costs recognized related to SBC, Solar/EE and CIP,
- a $19 million increase in transmission related costs,
- an $18 million increase in pension and OPEB expenses, and
- an $7 million increase in payroll costs,
- partially offset by the absence of $13 million in storm damages in prior year.

Depreciation and Amortization increased $46 million due primarily to

- an increase of $30 million for amortization of Regulatory Assets, and
- an increase of $18 million for additional plant in service.

Taxes Other Than Income Taxes decreased $29 million due to a lower TEFA rate and lower sales volumes for electric and gas.

Other Income and (Deductions) net increase of $17 million was due primarily to a $13 million increase in capitalized allowance for Equity Funds used during construction and a $6 million increase in Solar Loan interest income.

Other-Than-Temporary Impairments experienced no material change.

Interest Expense decreased $14 million due primarily to the partial redemption of securitization debt. See Note 9. Changes in Capitalization for details.

Income Tax Expense decreased $39 million due primarily to tax benefits related to settlement of IRS tax audits.

Energy Holdings

	Three Months Ended September 30		Increase/ (Decrease)	Nine Months Ended September 30		Increase/ (Decrease)
	2012	2011	2012 vs. 2011	2012	2011	2012 vs. 2011
	Millions					
Income from Continuing Operations	$7	$(166)	$173	$49	$(164)	$213
Net Income	$7	$(166)	$173	$49	$(164)	$213

For the three months ended September 30, 2012, the primary reason for the $173 million increase in Income from Continuing Operations was the absence of the after-tax charge on leveraged leases related to Dynegy in the prior year.

For the and nine months ended September 30, 2012, the primary reasons for the $213 million increase in Income from Continuing Operations were the absence of the after-tax charge on leveraged leases related to Dynegy in prior year and the tax benefits related to the settlement of IRS tax audits in the first quarter of 2012.

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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 three direct operating subsidiaries.

Operating Cash Flows

Our operating cash flows combined with cash on hand and financing activities are expected to be sufficient to fund capital expenditures and shareholder dividend payments.

For the nine months ended September 30, 2012, our operating cash flow decreased $98 million as compared to the same period in 2011. The net change was due primarily to net changes from Power and PSE&G, as discussed below.

Power

Power's operating cash flow decreased $315 million from $1,487 million to $1,172 million for the nine months ended September 30, 2012, as compared to the same period in 2011, primarily resulting from lower earnings partially offset by a decrease of $87 million in benefit plan funding.

PSE&G

PSE&G's operating cash flow increased $169 million from $872 million to $1,041 million for the nine months ended September 30, 2012, as compared to the same period in 2011, due primarily to higher earnings combined with

- a decrease of $174 million in benefit plan funding, and
- a decrease of $175 million in net prepayments,
- partially offset by a decrease of $164 million due to lower collections of customer receivables.

Short-Term Liquidity

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

The commitments under our credit facilities are provided by a diverse bank group. As of September 30, 2012, no single institution represented more than 8% of the total commitments in our credit facilities.

As of September 30, 2012, our total credit capacity was in excess of our anticipated maximum 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 September 30, 2012 were as follows:

	As of September 30, 2012					
Company/Facility	Total Facility Millions	Usage		Available Liquidity	Expiration Date	Primary Purpose
PSEG						
5-year Credit Facility	$500	$4	(A)	$496	Mar 2017	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility	500	—		500	Apr 2016	CP Support/Funding/Letters of Credit
Total PSEG	$1,000	$4		$996		
Power						
5-year Credit Facility	$1,600	$119	(A)	$1,481	Mar 2017	Funding/Letters of Credit
5-year Credit Facility	1,000	—		1,000	Apr 2016	Funding/Letters of Credit
Bilateral Credit Facility	100	100	(A)	—	Sept 2015	Letters of Credit
Total Power	$2,700	$219		$2,481		
PSE&G						
5-year Credit Facility	$600	$1	(A)	$599	Apr 2016	CP Support/Funding/Letters of Credit
Total PSE&G	$600	$1		$599		
Total	$4,300	$224		$4,076		

(A) Includes amounts related to letters of credit outstanding.

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Long-Term Debt Financing

PSE&G has $150 million 5.00% Medium Term Notes maturing in January 2013 and $300 million 5.38% Medium Term Notes maturing in September 2013. Power has $300 million of 2.50% Senior Notes maturing in April 2013. For a discussion of our long-term debt transactions during 2012, see Note 9. Changes in Capitalization.

Common Stock Dividends

For information related to cash dividends on our common stock, see Note 15. Earnings Per Share. On July 17, 2012, the Board of Directors declared a quarterly dividend of $0.3550 per share of common stock for the third quarter of 2012. We expect to continue to pay cash dividends on our common stock; however, the declaration and payment of future dividends to holders of our common stock will be at the discretion of the Board of Directors and will depend upon many factors, including our financial condition, earnings, capital requirements of our businesses, alternate investment opportunities, legal requirements, regulatory constraints, industry practice and other factors that the Board of Directors deems relevant.

Credit Ratings

If the rating agencies lower or withdraw our credit ratings, such revisions may adversely affect the market price of our securities and serve to materially increase our cost of capital and limit access to capital. Outlooks assigned to ratings are as follows: stable, negative (Neg) or positive (Pos). There is no assurance that the ratings will continue for any given period of time or that they will not be revised by the rating agencies, if, in their respective judgments, circumstances warrant. Each rating given by an agency should be evaluated independently of the other agencies' ratings. The ratings should not be construed as an indication to buy, hold or sell any security. In May 2012, S&P published an updated credit opinion for PSEG that left its ratings and outlook unchanged. In October 2012, S&P published updated credit opinions that left the ratings and outlooks for Power and PSE&G unchanged. In May 2012, Moody's published updated credit opinions on PSEG, Power and PSE&G. Moody's upgraded PSE&G's Mortgage Bond Rating to A1 from A2 and revised the outlook to stable from positive. PSEG's and Power's ratings and outlooks remained unchanged. In July 2012, Fitch published updated credit opinions on PSEG, Power and PSE&G. Fitch upgraded PSE&G's Mortgage Bond Rating to A+ from A and its stable outlook remained unchanged. PSEG's and Power's ratings and outlooks remained unchanged.

	Moody’s (A)	S&P (B)	Fitch (C)
PSEG			
Outlook	Stable	Positive	Stable
Commercial Paper	P2	A2	F2
Power			
Outlook	Stable	Positive	Stable
Senior Notes	Baa1	BBB	BBB+
PSE&G			
Outlook	Stable	Positive	Stable
Mortgage Bonds	A1	A–	A+
Commercial Paper	P2	A2	F2

(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.

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

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. There have been no material changes to our projected construction and investment amounts through 2014 as disclosed in our Form 10-K for the year ended December 31, 2011.

Power

During the nine months ended September 30, 2012, Power made $322 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $171 million for nuclear fuel, primarily related to various projects at Fossil and Nuclear. For additional information regarding current projects, see Note 8. Commitments and Contingent Liabilities.

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PSE&G

During the nine months ended September 30, 2012, PSE&G made $1,433 million of capital expenditures, including $1,369 million of investment in plant, primarily for reliability of transmission and distribution systems and $64 million in solar loan investments. This does not include expenditures for cost of removal, net of salvage, of $71 million, which is included in operating cash flows.

ACCOUNTING MATTERS

For information related to recent accounting matters, see Note 2. Recent Accounting Standards.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The market 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 Condensed Consolidated Financial Statements. It is our policy to use derivatives to manage risk consistent with business plans and prudent practices. We have a Risk Management Committee comprised of executive officers who utilize a risk oversight function to ensure compliance with our corporate policies and risk management practices.

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

Commodity Contracts

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

Value-at-Risk (VaR) Models

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

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

Three Months Ended September 30, 2012	MTM VaR (A) Millions
95% Confidence Level,	
Loss could exceed VaR one day in 20 days	
Period End	$11
Average for the Period	$12
High	$18
Low	$7
99.5% Confidence Level,	
Loss could exceed VaR one day in 200 days	
Period End	$16
Average for the Period	$19
High	$28
Low	$11

(A) As of September 30, 2012 and December 31, 2011, there was no trading VaR since we discontinued trading activities in the second quarter of 2011.

See Note 10. Financial Risk Management Activities for a discussion of credit risk.

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ITEM 4. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

We have established and maintain disclosure controls and procedures as defined under Rule 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, as amended (the “Exchange Act”) that are designed to provide reasonable assurance that information required to be disclosed in the reports that are filed or submitted under the Exchange Act is recorded, processed, summarized and reported and is accumulated and communicated to the Chief Executive Officer and Chief Financial Officer of each respective company, as appropriate, by others within the entities to allow timely decisions regarding required disclosure. We have established a disclosure committee which includes several key management employees and which reports directly to the Chief Financial Officer and Chief Executive Officer of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The Chief Financial Officer and Chief Executive Officer of each of Public Service Enterprise Group Incorporated, PSEG Power LLC, and Public Service Electric and Gas Company have evaluated the effectiveness of the disclosure controls and procedures and, based on this evaluation, have concluded that disclosure controls and procedures at each respective company were effective at a reasonable assurance level as of the end of the period covered by the report.

Internal Controls

We continually review our disclosure controls and procedures and make changes, as necessary, to ensure the quality of our financial reporting. There have been no changes in internal control over financial reporting that occurred during the third quarter of 2012 that have materially affected, or are reasonably likely to materially affect, each registrant’s internal control over financial reporting.

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PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to various lawsuits and regulatory matters in the ordinary course of business. For information regarding material legal proceedings, including updates to information reported under Item 3 of Part I of the 2011 Form 10-K and Item 5 of Part II of Quarterly Reports on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012, see Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

Certain information reported under the 2011 Form 10-K is updated below. References are to the related pages on the Form 10-K as printed and distributed.

ITEM 1A. RISK FACTORS

There no additional Risk Factors to be added to those disclosed in Part I Item 1A of our 2011 Annual Report on Form 10-K and in Part II Item 1A of our June 30, 2012 Quarterly Report on Form 10-Q.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

The following table indicates our common share repurchases in the open market to satisfy obligations under various equity compensation awards during the third quarter of 2012:

Three Months Ended September 30, 2012	Total Number of Shares Purchased	Average Price Paid per Share
July 1-July 31	—	$—
August 1-August 31	67,900	$32.65
September 1-September 30	26,000	$31.59

ITEM 5. OTHER INFORMATION

Certain information reported under the 2011 Annual Report on Form 10-K and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012 are updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2011 Annual Report on Form 10-K and the Quarterly Reports on Form 10-Q for the quarters ended March 31, 2012 and June 30, 2012. References are to the related pages on the Form 10-K or Forms 10-Q as printed and distributed.

EMPLOYEE RELATIONS

December 31, 2011 Form 10-K page 17. In October 2012, we extended the current collective bargaining agreements with three of our labor unions for four years through April 2017. Collectively, these three unions represent approximately 5,200 employees of PSE&G, Power and PSEG Services Corporation.

FEDERAL REGULATION

FERC

Capacity Market Issues—LCAPP

PJM, NYISO, and ISO-NE each have capacity markets that have been approved by FERC.

December 31, 2011 Form 10-K page 19, March 31, 2012 Form 10-Q page 77 and June 30, 2012 Form 10-Q page 84. In 2011, the State of New Jersey concluded that new natural gas-fired generation was needed and enacted the Long-Term Capacity Agreement Pilot Program Act (LCAPP Act) to subsidize approximately 2,000 MW of new generation. The LCAPP Act provided that subsidies would be offered through long-term standard offer capacity agreements (SOCAs) between selected generators and the New Jersey Electric Distribution Companies (EDCs). The SOCA requires that the generator bid in and clear in the PJM RPM base residual auction in each year of the SOCA term in order to receive the subsidized payment. The SOCA requires each New Jersey EDC to provide the generators with guaranteed capacity payments funded by ratepayers. Each of the New Jersey EDCs, including PSE&G, entered into the SOCAs as directed by the State, but did so under protest reserving their rights. In May 2012, two of the three generators, CPV Shore, LLC (CPV), a subsidiary of Competitive Power Ventures, Inc.

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and Hess Newark, LLC (Hess), a subsidiary of Hess Corporation, that received SOCA contracts cleared the Reliability Pricing Model auction for the 2015/2016 delivery year in the aggregate notional amount of approximately 1,300 MW of installed capacity. SOCA payments are for a 15 year term, which are scheduled to commence for CPV in the 2015/2016 delivery year and for Hess in the 2016/2017 delivery year, provided that they satisfy their obligations under the SOCA and that the SOCA remains in effect.

Legal challenges to the BPU's implementation of the LCAPP Act were filed in New Jersey appellate court and the challenge filed by the EDCs has been remanded back to the BPU for consideration of certain procedural issues. In addition, the LCAPP Act has been challenged on constitutional grounds in federal court. On September 28, 2012, the judge in the federal action denied all motions for summary judgment and set the issues for a full hearing.

Maryland is also taking action to subsidize above-market new generation. In April 2012, the Maryland PUC issued an order requiring the Maryland utility companies to enter into a contract with CPV to build a new 661 MW natural gas-fired, combined cycle station in Maryland with an in-service date of June 2015. In the May 2012 RPM auction, the CPV generator cleared the auction. We have joined other generators in challenging this order on constitutional grounds in federal court. The Maryland EDCs have also appealed the April 12, 2012 order in state court. Developments in Maryland may stimulate the construction of subsidized generation and impact energy and capacity prices in PJM.

These efforts to artificially depress the wholesale capacity auction were intended to be mitigated by the Minimum Offer Price Rule (MOPR) approved by FERC. The MOPR was intended to restrict new natural gas-fired generation from bidding in RPM at less than an established minimum level established by Tariff, or a cost-based bid to the extent that the generator can demonstrate that its costs are lower than the MOPR. The MOPR was in place for the May 2012 auction, but we believe it did not operate to protect the market against these suppression efforts. As a result, discussions among a diverse group of PJM stakeholders to improve the MOPR ensued and a settlement was recently reached among those stakeholders. PJM is currently educating its stakeholders on the settlement and PJM plans to bring the settlement to a stakeholder vote in November 2012. If this settlement is approved by the FERC, it will change how the MOPR will be applied in the RPM auction in May 2013 and should enhance the competitiveness of the auction. We cannot predict the outcome of this matter.

Transmission Regulation—Transmission Policy Development

December 31, 2011 Form 10-K page 20 and June 30, 2012 Form 10-Q page 84. In July 2011, FERC issued Order 1000 (Order 1000) which, among other things (i) directs regional planners, such as PJM, to modify their planning processes to "consider transmission needs driven by public policy requirements established by state or federal laws or regulations" (ii) directs regional planners to remove the " right of first refusal" (ROFR) from its tariffs and agreements under which incumbent transmission companies have a ROFR to build transmission located within their respective service territories, subject to certain exceptions (iii) requires regional planners to develop regional cost allocation methodologies that take into consideration that costs be "roughly commensurate" with project benefits and (iv) requires regional planners in neighboring regions to have a common interregional cost allocation method for new interregional facilities. We, along with many other parties to the proceeding, sought rehearing of Order 1000. In May 2012, the FERC issued an order that denied rehearing in this proceeding. In June 2012, we filed a Petition for Review of Order 1000 in federal appellate court, in which we plan to challenge the legal basis for the FERC's actions. Other companies and state commissions have filed appeals as well. PJM has recently concluded a stakeholder process to finalize the rules implementing Order 1000. An expected outcome of this proceeding is the construction of more transmission through "public policy" planning and the opening up of transmission construction and ownership to third-party developers and to incumbents seeking to build outside of their service territories. We cannot predict the final outcome or impact on us; however, specific implementation of Order 1000 in the various regions, including within our service territory, may expose us to competition for construction of transmission, additional regulatory considerations and potential delay with respect to future transmission projects.

Transmission Regulation—Transmission Expansion

December 31, 2011 Form 10-K page 21, March 31, 2012 Form 10-Q page 78 and June 30, 2012 Form 10-Q page 85. On October 1, 2012, the National Park Service (NPS) issued a final Environmental Impact Statement (EIS) for the Susquehanna-Roseland line, selecting our and PPL Electric Utilities Corporation's choice of route that follows the

existing right of way. On October 15, 2012, several environmental groups filed a complaint in federal court challenging the NPS' issuance of the final EIS, seeking to set aside the EIS and to enjoin implementation of the NPS' decision. If this request for injunctive relief is granted, the construction schedule for the project could be impacted.
We have also recently obtained environmental permits for the project from the New Jersey Department of Environmental Protection (NJDEP). We have begun construction in those areas where necessary permits have been obtained. Currently, the expected in-service date for the Eastern segment of the project is June 2014 and for the Western segment is June 2015, although further delays are possible. Delays in the construction schedule could impact the timing of expected transmission revenues.
In 2010, certain environmental groups appealed the BPU’s approval of the Susquehanna-Roseland line, although no stay was sought. This appeal remains pending.

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In June 2012, the BPU approved our petition to site the North Central Reliability project. We have also obtained NJDEP approval for the project. This project, which will involve upgrading certain circuits and switching stations from 138 kV to 230 kV, is currently estimated to cost $390 million and has an in-service date of June 2014.
We had previously been directed by PJM to build a 500 kV reliability project from Branchburg to Roseland to Hudson. The scope of this project has since changed; it is now a 230 kV project referred to as the Northeast Grid project, for which we are currently seeking to obtain municipal siting approvals. On July 19, 2012, we filed with FERC seeking to recover about $3.6 million of costs associated with the abandonment of the Branchburg-Roseland-Hudson project. In an order dated September 17, 2012, the FERC granted our request to recover prudently-incurred abandonment costs. However, consistent with recent abandonment decisions involving other companies, the FERC found that the filing lacked sufficient information for FERC to determine the reasonableness of certain abandonment plant costs and set that issue for hearing and settlement judge procedures. On October 17, 2012, we sought rehearing of this decision. We have also begun settlement discussions with other parties to the proceeding.

Transmission Rate Proceedings

June 30, 2012 Form 10-Q page 85. In September 2011, the Massachusetts Attorney General, along with several state utility commissions, consumer advocates and consumer groups from six New England states, filed a complaint at FERC against a group of New England transmission owners seeking to reduce the base return on equity used in calculating these transmission owners' formula transmission rates. The matter has been set for hearing. While we are not the subject of this complaint, this matter could set a precedent for FERC-regulated transmission owners with formula rates in place, such as ours.

Commodity Futures Trading Commission (CFTC)

December 31, 2011 Form 10-K page 22, March 31, 2012 Form 10-Q page 79 and June 30, 2012 Form 10-Q page 85. 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 new rules to effectuate stricter regulation over swaps and derivatives including potentially significant reporting and record-keeping requirements and clearing/collateral requirements. Additionally, the Dodd-Frank Act will require many swaps and other derivative transactions to be standardized and traded on exchanges or other Derivative Clearing Organizations. The CFTC has issued Notices of Proposed Rulemaking on many of the key issues, including defining swaps and swap dealers; reporting requirements; and margin requirements, as well as Final Rules. Specifically, in May 2012, the CFTC issued a Final Rule regarding the definition of a swap dealer. In addition, in August 2012, the CFTC issued a Final Rule regarding commercial end users, the definition of a swap and a proposed order regarding exemptions from Commodity Exchange Act provisions for specified Regional Transmission Owners (RTO) / Independent System Operators (ISO) transactions. In September 2012, several industry trade groups filed a request with the CFTC to delay the final implementation dates until all required rules are final. In addition, a federal district court recently vacated the CFTC's rules establishing position limits for trading in certain commodities, such as natural gas. Thus, the effective date of these position limits rules has been delayed indefinitely. The CFTC also issued a series of no action letters in October 2012 which delay various implementation timeframes through the balance of 2012.
We are continuing to analyze the potential impact of these rules, including whether we will fall within the commercial end-user exemption recognized in the Dodd-Frank Act.

STATE REGULATION

Rates

Connecticut Project

June 30, 2012 Form 10-Q page 86. We were selected by the Connecticut Public Utilities Regulatory Authority (PURA), formerly the Department of Public Utility Control, in a regulatory process to build 130 MW of gas-fired peaking capacity. The project was placed in service in June 2012. The first of the annual filings to recover the capital and operating costs of the project was submitted in December 2011 to PURA. PURA issued a final decision in early June 2012, authorizing us to recover $14.5 million for the period June 1, 2012 to December 31, 2012. On July 31, 2012, we filed a petition and testimony seeking approval from PURA of a 2013 annual fixed revenue requirement of approximately $20 million, which represents the facility's fixed operation and maintenance (O&M) costs along with the return of and return on the investment for the calendar year 2013. Variable costs (e.g., fuel, Connecticut's generation tax, and certain non-fuel O&M expenses) are recovered through a contract for differences. Evidentiary hearings were held in October 2012 and PURA is expected to issue a final decision by the end of 2012 effective January 1, 2013.

Rate Adjustment Clauses

Societal Benefits Charge-Universal Service Fund (USF)

December 31, 2011 Form 10-K page 25 and June 30, 2012 Form 10-Q page 86. The USF is an energy assistance program mandated by the BPU to provide payment assistance to low income customers. The Lifeline program is a separate mandated

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energy assistance program to provide payment assistance to elderly and disabled customers. On June 22, 2012, New Jersey's electric and gas utilities, including us, filed requests to reset the statewide rates for the USF and the Lifeline program. The filed USF rates were set to recover approximately $226 million on a statewide basis. Of this amount, the statewide electric rates are set to recover $169 million with the remaining $57 million recovered through gas rates. The rates for the Lifeline program were set to recover $66 million, $46 million electric and $20 million gas. The filed rates were subsequently updated and approved effective October 1, 2012. We earn no margin on the collection of the USF and Lifeline programs resulting in no impact on Net Income.

Gas Weather Normalization Charge (WNC)

December 31, 2011 Form 10-K page 25 and June 30, 2012 Form 10-Q page 86. Our WNC is a rate mechanism that allows us to increase our rates to compensate for lower revenues we receive from customers as a result of warmer-than-normal winters and to decrease our rates to make up for higher revenues we receive as a result of colder-than-normal winters. The payments and refunds are subject to certain limitations and rate caps. Unrecovered balances associated with application of the rate cap are deferred until the next recovery period.

The WNC requires us to calculate, at the end of each October – May period, the level by which margin revenues differed from what would have resulted if normal weather had occurred. On June 27, 2012, we filed a petition and testimony with the BPU seeking BPU approval to recover $56.6 million in deficiency revenues through the WNC. On September 13, 2012,the BPU approved our recovery of $40.7 million in deficiency revenues which would be recovered from our customers during the 2012-2013 Winter Period (October 1 – May 31). The remaining $15.9 million expected to be recovered will be applied to the 2013-2014 Winter Period, pursuant to the WNC tariff provisions approved by the BPU on July 9, 2010, as part of the Stipulation of Settlement of PSE&G's 2009 Rate Case. On September 13, 2012, a Decision and Order approving the stipulation for provisional rates was signed effective October 1, 2012.

Solar/EE Recovery Charge

December 31, 2011 Form 10-K page 25 and June 30, 2012 Form 10-Q page 86. On July 2, 2012, we filed a petition with the BPU requesting an increase in the Solar/EE Recovery Charge seeking to recover approximately $61.6 million in electric revenue and $8.5 million in gas revenue on an annual basis. These changes are the result of adjustments in the components of the Solar/EE Recovery Charges including: Carbon Abatement, Energy Efficiency Economic Stimulus Program, Energy Efficiency Economic Extension Program, the Demand Response Program, Solar Generation Investment Program (Solar 4 All) and Solar Loan II Program. The discovery phase of this proceeding is underway and in October 2012 the matter was assigned to an Administrative Law Judge (ALJ).

Recent Rate Adjustments-Remediation Adjustment Charge (RAC)

December 31, 2011 Form 10-K page 26, March 31, 2012 Form 10-Q page 80 and June 30, 2012 Form 10-Q page 87. In November 2011, we filed a RAC 19 petition with the BPU requesting a decrease in electric and gas RAC revenues on an annual basis of $8.9 million and $10.1 million, respectively. On October 11, 2012, we received the Administrative Law Judge's (ALJ) Initial Decision allowing full recovery of RAC 19 costs including costs of the Passaic River and Newark Bay superfund (CERCLA) matters and the Occidental litigation that were allocated to PSE&G and included in this request. On October 23, 2012, the BPU issued a final Order approving the ALJ's Initial Decision.

Energy Supply

BGSS

December 31, 2011 Form 10-K page 27, March 31, 2012 Form 10-Q page 80 and June 30, 2012 Form 10-Q page 87. On June 1, 2012, we made our annual BGSS filing with the BPU. The filing requested a decrease in annual BGSS revenue of $70.7 million, excluding sales and use tax, to be effective October 1, 2012. This represents a reduction of approximately 5.2% for a typical residential gas heating customer. This BGSS reduction will be the ninth consecutive reduction since January 2009. We entered into a Stipulation with the parties which put the requested lower BGSS rate into effect as filed on October 1, 2012 on a provisional basis. A final decision is expected in early 2013.

Energy Policy

Solar Initiatives

December 31, 2011 Form 10-K page 28, March 31, 2012 Form 10-Q page 80 and June 30, 2012 Form 10-Q page 87.

On July 23, 2012, the Governor of New Jersey signed legislation that, among other things, requires energy providers, including BGS providers and third party suppliers, to increase the amount of power in their portfolios derived from solar electricity, increasing the demand for Solar Renewable Energy Credits and increasing the potential for additional utility solar generation investment.

On July 31, 2012, we filed for an extension of our Solar 4 All program. In this filing, we are seeking BPU approval for up to

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$690 million to develop 136 MW of utility-owned solar photovoltaic systems over a five year period starting in 2013. Consistent with the existing Solar 4 All program, we propose to sell the energy and capacity from the solar systems in the PJM wholesale energy and capacity markets.

We also filed for an additional extension of our Solar Loan program (Solar Loan III) on July 31, 2012. In the filing, we are seeking BPU approval to provide financing support for the installation of 97.5 MW of solar systems by providing loans to qualified customers. The total investment of the proposed Solar Loan III program is anticipated to be up to $193 million once the program is fully subscribed, the projects are built and the loans are closed.

Solar Pilot Recovery Charge (SPRC)

June 30, 2012 Form 10-Q page 87. On July 18, 2012, the BPU approved a Stipulation regarding our March 2010 Solar I filing, effective August 1, 2012. This Order will result in an increase in rates of $2.5 million for our electric customers. On July 2, 2012, we filed a petition with the BPU for an increase in the electric SPRC for the Solar Loan I program. If our filing is approved by the BPU as filed, the result would be an increase in rates to be paid by our electric customers of $17.0 million on an annual basis. The discovery phase of this proceeding is underway and in October 2012 the matter was assigned to an ALJ.

BPU Audits

Management/Affiliate Audit

December 31, 2011 Form 10-K page 29 and June 30, 2012 Form 10-Q page 87. In 2009, the BPU, in accordance with New Jersey statutes, initiated audits of PSE&G with respect to the effectiveness of its management and its compliance with rules governing PSE&G's interactions with its affiliated companies. The audits were conducted on a combined basis by a consultant who was retained by the BPU. On May 23, 2012, the BPU issued the consultant's audit report for public comment. The audit report makes a number of findings and recommendations, including the finding that no violations of either the state or federal affiliate rules were found. In accordance with the BPU's procedural schedule, the comment period ended on September 28, 2012. The BPU is expected to issue an order addressing the audit report's findings and recommendations, although the procedural schedule does not establish a date for a final order in this matter.

ENVIRONMENTAL MATTERS

Air Pollution Control

Hazardous Air Pollutants Regulation

December 31, 2011 Form 10-K page 30. In accordance with a ruling of the United States Court of Appeals of the District of Columbia (Court of Appeals), the EPA published a Maximum Achievable Control Technology (MACT) regulation on February 16, 2012. These Mercury Air Toxics Standards (MATS) go into effect on April 16, 2015 and establish allowable emission levels for mercury as well as other hazardous air pollutants pursuant to the Clean Air Act. In February 2012, members of the electric generating industry filed a petition challenging the existing source National Emission Standard for Hazardous Air Pollutants (NESHAP), new source NESHAP and the New Source Performance Standard (NSPS). In March 2012, PSEG filed a motion to intervene with the Court of Appeals in support of the EPA's implementation of MATS. The Court of Appeals has split the litigation related to these matters into three cases, addressing separately the existing source NESHAP, new source NESHAP and the NSPS. These cases remain pending. The EPA has stayed implementation of the new source NESHAP rule pending its reconsideration until November 2, 2012.

Cross-State Air Pollution Rule (CSAPR)

December 31, 2011 Form 10-K page 31, March 31, 2012 Form 10-Q page 81 and June 30, 2012 Form 10-Q page 88. On July 6, 2011, the EPA issued CSAPR which limits power plant emissions of Sulfur Dioxide (SO2) and annual and ozone season NOX in 28 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone National Ambient Air Quality Standards.

On December 30, 2011, the Court of Appeals issued a ruling to stay CSAPR. On August 21, 2012 the court vacated CSAPR and ordered that the existing Clean Air Interstate Rule requirements remain in effect until an appropriate substitute rule has been promulgated. On October 5, 2012, EPA filed a request for rehearing. The matter remains pending.

Fuel and Waste Disposal

Coal Combustion Residuals (CCRs)

December 31, 2011 Form 10-K page 34, March 31, 2012 Form 10-Q page 82 and June 30, 2012 Form 10-Q page 90. On April 5, 2012, several environmental organizations and CCR marketers (Environmental and Marketer Plaintiffs) brought a citizens' suit against the EPA in federal court arguing that the EPA has a non-discretionary duty to issue the CCR rules by a certain date. On May 15, 2012, the Utility Solid Waste Activities Group (USWAG) Policy Committee filed a Motion to Intervene in order to be in alignment with the EPA in defending against the environmental organizations' action. After May 2012, all parties agreed to a schedule for submitting briefs in this case. Motions for summary judgment remain pending.

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ITEM 6. EXHIBITS

A listing of exhibits being filed with this document is as follows:

a. PSEG:

Exhibit 12:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.1:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
Exhibit 32.1:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
Exhibit 101.INS:	XBRL Instance Document
Exhibit 101.SCH:	XBRL Taxonomy Extension Schema
Exhibit 101.CAL:	XBRL Taxonomy Extension Calculation Linkbase
Exhibit 101.LAB:	XBRL Taxonomy Extension Labels Linkbase
Exhibit 101.PRE:	XBRL Taxonomy Extension Presentation Linkbase
Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

b. Power:

Exhibit 12.1:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 31.2:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.3:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 32.2:	Certification by Ralph Izzo Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
Exhibit 32.3:	Certification by Caroline Dorsa Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code
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Exhibit 101.DEF:	XBRL Taxonomy Extension Definition Document

c. PSE&G:

Exhibit 12.2:	Computation of Ratios of Earnings to Fixed Charges
Exhibit 12.3:	Computation of Ratios of Earnings to Fixed Charges Plus Preferred Securities Dividend Requirements
Exhibit 31.4:	Certification by Ralph Izzo Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
Exhibit 31.5:	Certification by Caroline Dorsa Pursuant to Rules 13a-14 and 15d-14 of the 1934 Act
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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED
(Registrant)

By: /S/ DEREK M. DIRISIO
Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: November 2, 2012

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PSEG POWER LLC
(Registrant)

By: /S/ DEREK M. DIRISIO
Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: November 2, 2012

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SIGNATURE

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
(Registrant)

By: /S/ DEREK M. DIRISIO
Derek M. DiRisio
Vice President and Controller
(Principal Accounting Officer)

Date: November 2, 2012