PUBLIC SERVICE ELECTRIC & GAS CO
Form 10-Q
November 01, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE**

SECURITIES EXCHANGE ACT OF 1934

FOR THE QUARTERLY PERIOD ENDED September 30, 2011

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 x No ¨

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

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

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

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

As of October 14, 2011, Public Service Enterprise Group Incorporated had outstanding 505,904,850 shares of its sole class of Common Stock, without par value.

As of October 14, 2011, 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 will, anticipate, intend, estimate, believe, expect, plan, should, hypothetical, pote project, 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 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,

any inability to realize anticipated tax benefits or retain tax credits,

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,

adverse changes in the demand for or price of the capacity and energy that we sell into wholesale electricity markets,

increase in competition in energy markets in which we compete,

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 discount rates and funding requirements, and

changes in technology and customer usage patterns.

Additional information concerning these factors is set forth in Part II under Item 1A. Risk Factors.

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 only apply 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)

	For The Three Months Ended September 30,		For The Nine Months Ended September 30,	
	2011	2010	2011	2010
OPERATING REVENUES	$ 2,620	$ 3,114	$ 8,443	$ 9,048
OPERATING EXPENSES				
Energy Costs	1,167	1,261	3,740	4,021
Operation and Maintenance	603	591	1,829	1,862
Depreciation and Amortization	263	260	739	716
Taxes Other Than Income Taxes	31	31	102	101
Total Operating Expenses	2,064	2,143	6,410	6,700
OPERATING INCOME	556	971	2,033	2,348
Income from Equity Method Investments	1	4	8	12
Other Income	45	75	176	165
Other Deductions	(11)	(9)	(39)	(37)
Other-Than-Temporary Impairments	(8)	(3)	(13)	(9)
Interest Expense	(117)	(120)	(361)	(356)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	466	918	1,804	2,123
Income Tax (Expense) Benefit	(201)	(371)	(757)	(856)
INCOME FROM CONTINUING OPERATIONS	265	547	1,047	1,267
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $(15) and $(11) for the three months and $(51) and $(10) for the nine months ended 2011 and 2010, respectively	29	20	96	15
NET INCOME	$ 294	$ 567	$ 1,143	$ 1,282
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING (THOUSANDS):				
BASIC	505,909	505,945	505,959	506,001
DILUTED	506,999	506,968	506,963	507,068
EARNINGS PER SHARE				
BASIC				
INCOME FROM CONTINUING OPERATIONS	$ 0.52	$ 1.08	$ 2.07	$ 2.50

NET INCOME	$ 0.58	$ 1.12	$ 2.26	$ 2.53
DILUTED				
INCOME FROM CONTINUING OPERATIONS	$ 0.52	$ 1.08	$ 2.06	$ 2.50
NET INCOME	$ 0.58	$ 1.12	$ 2.25	$ 2.53
DIVIDENDS PAID PER SHARE OF COMMON STOCK	$ 0.3425	$ 0.3425	$ 1.0275	$ 1.0275

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONDENSED CONSOLIDATED BALANCE SHEETS

Millions

(Unaudited)

	September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,242	$ 280
Accounts Receivable, net of allowances of $64 and $68 in 2011 and 2010, respectively	1,164	1,387
Tax Receivable	377	689
Unbilled Revenues	251	400
Fuel	740	666
Materials and Supplies, net	365	359
Prepayments	416	204
Derivative Contracts	113	182
Assets of Discontinued Operations	0	564
Deferred Income Taxes	96	43
Regulatory Assets	86	155
Other	120	122
Total Current Assets	4,970	5,051
PROPERTY, PLANT AND EQUIPMENT	24,618	23,272
Less: Accumulated Depreciation and Amortization	(7,336)	(6,882)
Net Property, Plant and Equipment	17,282	16,390
NONCURRENT ASSETS		
Regulatory Assets	3,354	3,736
Regulatory Assets of Variable Interest Entities (VIEs)	968	1,128
Long-Term Investments	1,406	1,623
Nuclear Decommissioning Trust (NDT) Funds	1,280	1,363
Other Special Funds	170	160
Goodwill	16	16
Other Intangibles	164	136
Derivative Contracts	75	79
Restricted Cash of VIEs	22	21
Other	204	206
Total Noncurrent Assets	7,659	8,468
TOTAL ASSETS	$ 29,911	$ 29,909

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONDENSED CONSOLIDATED BALANCE SHEETS

Millions

(Unaudited)

LIABILITIES AND CAPITALIZATION	**September 30, 2011**	**December 31, 2010**
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 1,275	$ 915
Securitization Debt of VIEs Due Within One Year	214	206
Commercial Paper and Loans	0	64
Accounts Payable	1,144	1,176
Derivative Contracts	94	103
Accrued Interest	131	108
Accrued Taxes	30	49
Clean Energy Program	224	195
Obligation to Return Cash Collateral	107	104
Regulatory Liabilities	161	174
Liabilities of Discontinued Operations	0	72
Other	312	319
Total Current Liabilities	3,692	3,485
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	5,652	5,129
Regulatory Liabilities	235	285
Regulatory Liabilities of VIEs	9	8
Asset Retirement Obligations	482	461
Other Postretirement Benefit (OPEB) Costs	948	967
Accrued Pension Costs	189	788
Clean Energy Program	70	235
Environmental Costs	651	669
Derivative Contracts	31	22
Long-Term Accrued Taxes	234	248
Other	77	152
Total Noncurrent Liabilities	8,578	8,964
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	6,651	6,834
Securitization Debt of VIEs	784	939
Project Level, Non-Recourse Debt	45	46
Total Long-Term Debt	7,480	7,819

STOCKHOLDERS EQUITY		
Common Stock, no par, authorized 1,000,000,000 shares; issued, 2011 and 2010 533,556,660 shares	4,818	4,807
Treasury Stock, at cost, 2011 27,651,927 shares; 2010 27,582,437 shares	(601)	(593)
Retained Earnings	6,198	5,575
Accumulated Other Comprehensive Loss	(256)	(156)
Total Common Stockholders Equity	10,159	9,633
Noncontrolling Interest	2	8
Total Stockholders Equity	10,161	9,641
Total Capitalization	17,641	17,460
TOTAL LIABILITIES AND CAPITALIZATION	$ 29,911	$ 29,909

See Notes to Condensed Consolidated Financial Statements.

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PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

Millions

(Unaudited)

	For the Nine Months Ended September 30, 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 1,143	$ 1,282
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Gain on Disposal of Discontinued Operations	(122)	0
Depreciation and Amortization	745	730
Amortization of Nuclear Fuel	114	102
Provision for Deferred Income Taxes (Other than Leases) and ITC	629	205
Non-Cash Employee Benefit Plan Costs	138	236
Net (Gain) Loss on Lease Investments	0	(51)
Leveraged Lease Income, Adjusted for Rents Received and Deferred Taxes	(16)	(391)
Leveraged Lease Reserve, net of tax	170	0
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(14)	(42)
Over (Under) Recovery of Electric Energy Costs (BGS and NTC) and Gas Costs	100	35
Over (Under) Recovery of Societal Benefits Charge (SBC)	(26)	(55)
Market Transition Charge Refund	(47)	98
Cost of Removal	(43)	(47)
Net Realized (Gains) Losses and (Income) Expense from NDT Funds	(110)	(73)
Realized Gains from Rabbi Trusts	(5)	(31)
Net Change in Tax Receivable	312	0
Net Change in Certain Current Assets and Liabilities	(44)	(237)
Employee Benefit Plan Funding and Related Payments	(486)	(483)
Other	(29)	61
Net Cash Provided By (Used In) Operating Activities	2,409	1,339
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(1,479)	(1,517)
Proceeds from Sale of Discontinued Operations	687	0
Proceeds from the Sale of Capital Leases and Investments	0	427
Proceeds from Sales of Available-for-Sale Securities	1,088	886
Investments in Available-for-Sale Securities	(1,110)	(905)
Other	(13)	13
Net Cash Provided By (Used In) Investing Activities	(827)	(1,096)
CASH FLOWS FROM FINANCING ACTIVITIES		
Net Change in Commercial Paper and Loans	(64)	(530)
Issuance of Long-Term Debt	750	1,608
Redemption of Long-Term Debt	(606)	(548)
Repayment of Non-Recourse Debt	(1)	(3)
Redemption of Securitization Debt	(147)	(140)
Cash Dividends Paid on Common Stock	(520)	(520)
Redemption of Preferred Securities	0	(80)

Other	(32)	(48)
Net Cash Provided By (Used In) Financing Activities	(620)	(261)
Net Increase (Decrease) in Cash and Cash Equivalents	962	(18)
Cash and Cash Equivalents at Beginning of Period	280	350
Cash and Cash Equivalents at End of Period	$ 1,242	$ 332
Supplemental Disclosure of Cash Flow Information:		
Income Taxes Paid (Received)	$ 60	$ 1,080
Interest Paid, Net of Amounts Capitalized	$ 341	$ 299

See Notes to Condensed Consolidated Financial Statements.

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PSEG POWER LLC

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

Millions

(Unaudited)

	For The Three Months Ended September 30, 2011	For The Three Months Ended September 30, 2010	For The Nine Months Ended September 30, 2011	For The Nine Months Ended September 30, 2010
OPERATING REVENUES	$ 1,398	$ 1,523	$ 4,650	$ 4,983
OPERATING EXPENSES				
Energy Costs	597	620	2,335	2,483
Operation and Maintenance	262	253	810	764
Depreciation and Amortization	56	43	166	130
Total Operating Expenses	915	916	3,311	3,377
OPERATING INCOME	483	607	1,339	1,606
Other Income	37	44	156	126
Other Deductions	(10)	(9)	(37)	(36)
Other-Than-Temporary Impairments	(8)	(2)	(10)	(8)
Interest Expense	(42)	(37)	(134)	(119)
INCOME FROM CONTINUING OPERATIONS BEFORE INCOME TAXES	460	603	1,314	1,569
Income Tax (Expense) Benefit	(187)	(239)	(539)	(632)
INCOME FROM CONTINUING OPERATIONS	273	364	775	937
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax (expense) benefit of $(15) and $(11) for the three months and $(51) and $(10) for the nine months ended 2011 and 2010, respectively	29	20	96	15
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 302	$ 384	$ 871	$ 952

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, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 14	$ 11
Accounts Receivable	432	511
Accounts Receivable Affiliated Companies, net	127	782
Short-Term Loan to Affiliate	1,574	398
Fuel	740	666
Materials and Supplies, net	273	269
Derivative Contracts	95	163
Prepayments	42	80
Assets of Discontinued Operations	0	564
Total Current Assets	3,297	3,444
PROPERTY, PLANT AND EQUIPMENT	9,118	8,643
Less: Accumulated Depreciation and Amortization	(2,552)	(2,301)
Net Property, Plant and Equipment	6,566	6,342
NONCURRENT ASSETS		
Nuclear Decommissioning Trust (NDT) Funds	1,280	1,363
Goodwill	16	16
Other Intangibles	164	130
Other Special Funds	33	32
Derivative Contracts	24	42
Long-Term Accrued Taxes	19	16
Other	85	67
Total Noncurrent Assets	1,621	1,666
TOTAL ASSETS	$ 11,484	$ 11,452
LIABILITIES AND MEMBER S EQUITY		
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 710	$ 650
Accounts Payable	635	643
Derivative Contracts	79	91
Deferred Income Taxes	8	64
Accrued Interest	63	40
Liabilities of Discontinued Operations	0	72
Other	111	91
Total Current Liabilities	1,606	1,651
NONCURRENT LIABILITIES		
Deferred Income Taxes and Investment Tax Credits (ITC)	1,211	1,146
Asset Retirement Obligations	255	242

Other Postretirement Benefit (OPEB) Costs		158		151
Derivative Contracts		17		22
Accrued Pension Costs		75		253
Environmental Costs		51		51
Other		34		104
Total Noncurrent Liabilities		1,801		1,969
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)				
LONG-TERM DEBT				
Total Long-Term Debt		2,640		2,805
MEMBER S EQUITY				
Contributed Capital		2,028		2,028
Basis Adjustment		(986)		(986)
Retained Earnings		4,602		4,080
Accumulated Other Comprehensive Loss		(207)		(95)
Total Member s Equity		5,437		5,027
TOTAL LIABILITIES AND MEMBER S EQUITY	$	11,484	$	11,452

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)

	For the Nine Months Ended September 30, 2011	2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 871	$ 952
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Gain on Disposal of Discontinued Operations	(122)	0
Depreciation and Amortization	173	144
Amortization of Nuclear Fuel	114	102
Provision for Deferred Income Taxes and ITC	74	145
Net Realized and Unrealized (Gains) Losses on Energy Contracts and Other Derivatives	(14)	(42)
Non-Cash Employee Benefit Plan Costs	33	53
Net Realized (Gains) Losses and (Income) Expense from NDT Funds	(110)	(73)
Net Change in Certain Current Assets and Liabilities:		
Fuel, Materials and Supplies	(82)	(2)
Margin Deposit	(63)	(26)
Accounts Receivable	157	16
Accounts Payable	(103)	(99)
Accounts Receivable/Payable-Affiliated Companies, net	650	186
Accrued Interest Payable	23	41
Other Current Assets and Liabilities	48	(42)
Employee Benefit Plan Funding and Related Payments	(127)	(131)
Other	(35)	32
Net Cash Provided By (Used In) Operating Activities	1,487	1,256
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(530)	(579)
Proceeds from Sale of Discontinued Operations	687	0
Proceeds from Sales of Available-for-Sale Securities	1,088	759
Investments in Available-for-Sale Securities	(1,106)	(778)
Short-Term Loan Affiliated Company, net	(1,176)	(309)
Other	19	28
Net Cash Provided By (Used In) Investing Activities	(1,018)	(879)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Recourse Long-Term Debt	500	594
Cash Dividend Paid	(350)	(550)
Redemption of Long-Term Debt	(606)	(248)
Short-Term Loan Affiliated Company, net	0	(194)
Other	(10)	(17)
Net Cash Provided By (Used In) Financing Activities	(466)	(415)

Net Increase (Decrease) in Cash and Cash Equivalents		3		(38)
Cash and Cash Equivalents at Beginning of Period		11		64
Cash and Cash Equivalents at End of Period	$	14	$	26
Supplemental Disclosure of Cash Flow Information:				
Income Taxes Paid (Received)	$	110	$	558
Interest Paid, Net of Amounts Capitalized	$	111	$	85

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

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PUBLIC SERVICE ELECTRIC AND GAS COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

Millions

(Unaudited)

	For the Three Months Ended September 30,		For The Nine Months Ended September 30,	
	2011	2010	2011	2010
OPERATING REVENUES	$ 1,841	$ 2,007	$ 5,718	$ 5,987
OPERATING EXPENSES				
Energy Costs	943	1,115	3,124	3,572
Operation and Maintenance	342	327	1,014	1,084
Depreciation and Amortization	197	209	548	563
Taxes Other Than Income Taxes	31	31	102	101
Total Operating Expenses	1,513	1,682	4,788	5,320
OPERATING INCOME	328	325	930	667
Other Income	7	14	16	22
Other Deductions	(1)	(1)	(2)	(2)
Other-Than-Temporary Impairments	0	0	(1)	0
Interest Expense	(77)	(82)	(234)	(239)
INCOME BEFORE INCOME TAXES	257	256	709	448
Income Tax (Expense) Benefit	(103)	(101)	(287)	(172)
NET INCOME	154	155	422	276
Preferred Stock Dividends	0	0	0	(1)
EARNINGS AVAILABLE TO PUBLIC SERVICE ENTERPRISE GROUP INCORPORATED	$ 154	$ 155	$ 422	$ 275

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, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 242	$ 245
Accounts Receivable, net of allowances of $64 in 2011 and $67 in 2010, respectively	720	832
Tax Receivable	21	0
Accounts Receivable Affiliated Companies, net	304	0
Unbilled Revenues	251	400
Materials and Supplies	91	90
Prepayments	320	117
Regulatory Assets	86	155
Other	35	19
Total Current Assets	2,070	1,858
PROPERTY, PLANT AND EQUIPMENT	14,917	14,068
Less: Accumulated Depreciation and Amortization	(4,500)	(4,326)
Net Property, Plant and Equipment	10,417	9,742
NONCURRENT ASSETS		
Regulatory Assets	3,354	3,736
Regulatory Assets of VIEs	968	1,128
Long-Term Investments	258	230
Other Special Funds	57	54
Derivative Contracts	0	17
Restricted Cash of VIEs	22	21
Other	89	87
Total Noncurrent Assets	4,748	5,273
TOTAL ASSETS	$ 17,235	$ 16,873

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)

LIABILITIES AND CAPITALIZATION	September 30, 2011	December 31, 2010
CURRENT LIABILITIES		
Long-Term Debt Due Within One Year	$ 564	$ 264
Securitization Debt of VIEs Due Within One Year	214	206
Accounts Payable	396	406
Accounts Payable Affiliated Companies, net	0	85
Accrued Interest	66	65
Clean Energy Program	224	195
Derivative Contracts	15	12
Deferred Income Taxes	21	19
Obligation to Return Cash Collateral	107	104
Regulatory Liabilities	161	174
Other	190	229
Total Current Liabilities	1,958	1,759
NONCURRENT LIABILITIES		
Deferred Income Taxes and ITC	3,690	3,127
Other Postretirement Benefit (OPEB) Costs	743	770
Accrued Pension Costs	18	377
Regulatory Liabilities	235	285
Regulatory Liabilities of VIEs	9	8
Clean Energy Program	70	235
Environmental Costs	600	617
Asset Retirement Obligations	223	216
Derivative Contracts	11	0
Long-Term Accrued Taxes	54	74
Other	21	23
Total Noncurrent Liabilities	5,674	5,732
COMMITMENTS AND CONTINGENT LIABILITIES (See Note 8)		
CAPITALIZATION		
LONG-TERM DEBT		
Long-Term Debt	3,971	4,019
Securitization Debt of VIEs	784	939
Total Long-Term Debt	4,755	4,958
STOCKHOLDER S EQUITY		
Common Stock; 150,000,000 shares authorized; issued and outstanding, 2011 and 2010 132,450,344 shares	892	892
Contributed Capital	420	420
Basis Adjustment	986	986

Retained Earnings	2,548	2,126
Accumulated Other Comprehensive Income	2	0
Total Stockholder s Equity	4,848	4,424
Total Capitalization	9,603	9,382
TOTAL LIABILITIES AND CAPITALIZATION	$ 17,235	$ 16,873

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)

	For The Nine Months Ended September 30, 2011	For The Nine Months Ended September 30, 2010
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 422	$ 276
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	548	563
Provision for Deferred Income Taxes and ITC	563	41
Non-Cash Employee Benefit Plan Costs	92	162
Cost of Removal	(43)	(47)
Market Transition Charge (MTC) Refund	(47)	98
Over (Under) Recovery of Electric Energy Costs (BGS and NTC) and Gas Costs	100	35
Over (Under) Recovery of SBC	(26)	(55)
Net Changes in Certain Current Assets and Liabilities:		
Accounts Receivable and Unbilled Revenues	261	117
Materials and Supplies	(1)	(17)
Prepayments	(203)	(126)
Net Change in Tax Receivable	(21)	0
Accounts Receivable/Payable-Affiliated Companies, net	(381)	(318)
Other Current Assets and Liabilities	(66)	19
Employee Benefit Plan Funding and Related Payments	(311)	(305)
Other	(15)	(16)
Net Cash Provided By (Used In) Operating Activities	872	427
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to Property, Plant and Equipment	(939)	(871)
Proceeds from Sales of Available-for-Sale Securities	0	54
Investments in Available-for-Sale Securities	0	(54)
Solar Loan Investments	(34)	(11)
Other	(1)	(4)
Net Cash Provided By (Used In) Investing Activities	(974)	(886)
CASH FLOWS FROM FINANCING ACTIVITIES		
Issuance of Long-Term Debt	250	1,014
Redemption of Long-Term Debt	0	(300)
Redemption of Securitization Debt	(147)	(140)
Redemption of Preferred Securities	0	(80)
Common Stock Dividend	0	(150)
Other	(4)	(10)
Net Cash Provided By (Used In) Financing Activities	99	334

Net Increase (Decrease) In Cash and Cash Equivalents		(3)		(125)
Cash and Cash Equivalents at Beginning of Period		245		240
Cash and Cash Equivalents at End of Period	$	242	$	115
Supplemental Disclosure of Cash Flow Information:				
Income Taxes Paid (Received)	$	(44)	$	182
Interest Paid, Net of Amounts Capitalized	$	225	$	213

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 primarily 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.

PSEG Services Corporation (Services) which provides management and 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, 2010 and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011.

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. 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, 2010.

During 2011, Power sold its two generating facilities located in Texas that were owned and operated by its subsidiary, PSEG Texas. As a result, amounts related to these plants were reclassified as Discontinued Operations in the financial statements. See Note 4. Discontinued Operations and Dispositions for additional information.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

Note 2. Recent Accounting Standards

New Standard Adopted during 2011

Revenue Arrangements with Multiple Deliverables

- amends existing guidance for identifying separate deliverables in a revenue-generating transaction where multiple deliverables exist,
- establishes a selling price hierarchy, such as, vendor-specific objective evidence, third-party evidence and estimated selling price for determining the selling price of a deliverable, and
- provides guidance for allocating and recognizing revenue based on separate deliverables.

We adopted this standard, prospectively, effective January 1, 2011, for new and significantly modified revenue arrangements. Upon adoption, there was no material impact on our financial statements and we do not anticipate any changes to the pattern or general timing of revenue recognition for our significant units of account in future periods.

New Accounting Standards Issued But Not Yet Adopted

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.

This guidance is effective for interim and annual periods beginning after December 15, 2011. We believe our adoption of the new guidance on January 1, 2012 will not have an impact on our consolidated financial position, results of operations or cash flows; however, it will result in expanded disclosures.

Presentation of Comprehensive Income

This accounting standard was issued on 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.

This guidance is effective for fiscal years and interim periods beginning after December 15, 2011. We believe that the adoption of the new guidance on January 1, 2012 will not have an impact on our consolidated financial position, results of operations or cash flows, but will change the presentation of the components of other comprehensive income.

Testing Goodwill for Impairment

This accounting standard was issued to simplify testing for goodwill impairment. The updated guidance allows an entity to first perform a qualitative assessment to determine if it is more likely than not that the fair value of the reporting unit is less than its carrying value. Only if it is concluded that this is the case is it necessary to perform the two-step goodwill impairment test.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

The guidance is effective for annual and interim goodwill impairment tests performed for fiscal years beginning after December 15, 2011. Earlier adoption is permitted. We believe that if we adopt the new optional guidance, it will not have a material impact on our consolidated financial position, results of operations or cash flows.

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, 2011 and December 31, 2010. 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 2011 or in 2010. Further, PSE&G does not have any contractual commitments or obligations to provide financial support to Transition Funding or Transition Funding II.

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 purchase 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 a total purchase price of $335 million, resulting in an after-tax gain of $25 million. The closing of the Odessa sale completed the Texas asset sale process announced by Power in early 2011.

PSEG Texas operating results for the three months and nine months ended September 30, 2011 and 2010, which were reclassified to Discontinued Operations, are summarized below:

	Three Months Ended, September 30,		Nine Months Ended, September 30,	
	2011	2010	2011	2010
	Millions			
Operating Revenues	$ 20	$ 140	$ 112	$ 341

Income (Loss) Before Income Taxes	$ 6	$ 31	$ 26	$ 25
Net Income (Loss)	$ 4	$ 20	$ 17	$ 15

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

The carrying amounts of PSEG Texas assets and liabilities as of December 31, 2010 are summarized in the following table:

	As of December 31, 2010
	Millions
Current Assets	$ 28
Noncurrent Assets	536
Total Assets of Discontinued Operations	$ 564
Current Liabilities	$ 28
Noncurrent Liabilities	44
Total Liabilities of Discontinued Operations	$ 72

Dispositions

Leveraged Leases

During the first nine months of 2010, Energy Holdings sold its interest in five leveraged leases, including four international leases for which the IRS has indicated its intention to disallow certain tax deductions taken in prior years.

	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010
	Millions	
Proceeds from Sales	$ 204	$ 365
Gains on Sales, after-tax	$ 15	$ 27

Proceeds from the sales of the international leases were used to reduce the tax exposure related to these lease investments. For additional information see Note 8. Commitments and Contingent Liabilities.

Note 5. Financing Receivables

PSE&G

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

Credit Risk Profile Based on Payment Activity **Consumer Loans**	**As of September 30, 2011**	**As of December 31, 2010**
	Millions	
Commercial/Industrial	$ 86	$ 62
Residential	7	4
	$ 93	**$ 66**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

Energy Holdings

Energy Holdings has investments in domestic energy and real estate assets subject primarily to leveraged lease accounting. A leveraged lease is typically comprised of an investment by an equity investor and debt provided by a third party debt investor. The debt is recourse only to the assets subject to lease and is not included on PSEG s 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. The table below shows Energy Holdings gross and net lease investment as of September 30, 2011 and December 31, 2010, respectively.

	As of September 30, 2011	As of December 31, 2010
	Millions	
Lease Receivables (net of Non-Recourse Debt)	$ 763	$ 896
Estimated Residual Value of Leased Assets	684	905
	1,447	1,801
Unearned and Deferred Income	(450)	(546)
Gross Investments in Leases	997	1,255
Deferred Tax Liabilities	(804)	(899)
Net Investment in Leases	$ 193	$ 356

Note: The above table does not include $264 million of Gross Investment in Leases to subsidiaries of Dynegy Incorporated (Dynegy) as of September 30, 2011 as we have fully reserved our Gross Investment in the Dynegy leases.

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.

	Lease Receivables, net of Non-Recourse Debt	
Counterparties Credit Rating (S&P)	**As of September 30, 2011**	**As of December 31, 2010**
	Millions	
AAA - AA	$ 21	$ 21
A	110	112
BBB - BB	316	316
B - B-	300	430

Not Rated	16	17
	$ 763	**$ 896**

Note: The above table does not include $121 million of lease receivables as of September 30, 2011 related to subsidiaries of Dynegy as we fully reserved our Gross Investments in the Dynegy leases.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

The B and B- ratings above represent lease receivables underlying coal fired assets in Illinois and Pennsylvania. As of September 30, 2011, the gross investment in the leases of such assets, net of non-recourse debt, was $550 million ($54 million, net of deferred taxes). A more detailed description of such assets under lease is presented in the table below.

Asset	Location	Gross Investment	% Owned	Total	Fuel Type	Counterparties S&P Credit Rating	Counterparty
		Millions		MW			
Powerton Station Units 5 and 6	IL	$ 135	64%	1,538	Coal	B-	Edison Mission Energy
Joliet Station Units 7 and 8	IL	$ 84	64%	1,044	Coal	B-	Edison Mission Energy
Keystone Station Units 1 and 2	PA	$ 112	17%	1,711	Coal	B	GenOn REMA, LLC
Conemaugh Station Units 1 and 2	PA	$ 112	17%	1,711	Coal	B	GenOn REMA, LLC
Shawville Station Units 1, 2, 3 and 4	PA	$ 107	100%	603	Coal	B	GenOn REMA, LLC

Although all payments of equity rent, debt service and other fees are current, no assurances can be given that all payments in accordance with the lease contracts will continue. Factors which may impact future lease cash flow 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.

The credit exposure to the lessors is partially mitigated through various credit enhancement mechanisms within the lease transactions. These credit enhancement features vary from lease to lease. Some of the leasing transactions include covenants that restrict the flow of dividends from the lessee to its parent, over-collateralization of the lessee with non-leased assets, historical and forward cash flow coverage tests that prohibit discretionary capital expenditures and dividend payments to the parent/lessee if stated minimum coverage ratios are not met and similar cash flow restrictions if ratings are not maintained at stated levels. These covenants are designed to maintain cash reserves in the transaction entity for the benefit of the non-recourse lenders and the lessor/equity participants in the event of a market downturn or degradation in operating performance of the leased assets. In the event of a default in any of the lease transactions, Energy Holdings would exercise its rights and attempt to seek recovery of its investment. The results of such efforts may not be known for a period of time. A bankruptcy of a lessee and failure to recover adequate value could lead to a foreclosure of the lease. 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.

Energy Holdings collateral related to the lease to two affiliates (the Dynegy lessees) of Dynegy Incorporated (Dynegy), includes a guarantee from Dynegy Holdings LLC (DH), a subsidiary of Dynegy. In early August 2011, Dynegy reorganized the legal entity structure for its generation assets. It transferred substantially all of its coal and natural gas-fired generation assets, other than the Dynegy lessees that lease the Roseton Station Units 1 and 2 and Danskammer Station Units 3 and 4, to new subsidiaries which Dynegy termed as bankruptcy remote . This resulted in a lowering of certain credit ratings of Dynegy and DH. Dynegy s credit is currently rated CC by S&P and Caa3 by Moody s. On July 22, 2011, subsidiaries of Energy Holdings that hold the lessor interests filed a lawsuit in Delaware Chancery Court to halt the proposed transfer of assets to the new subsidiaries alleging that the proposed transfers would violate DH s obligations under its Roseton and Danskammer guarantees. The request for a temporary restraining order was denied on July 29, 2011 and on August 5, 2011, the Delaware Supreme Court denied Energy Holdings application for certification of an interlocutory appeal and motions to expedite and for injunctive relief. Thereafter on August 8, 2011, Energy Holdings voluntarily dismissed this lawsuit without prejudice.

In September 2011, Dynegy continued its corporate reorganization, transferring DH s interests in its newly formed coal generation subsidiary directly to the parent company, Dynegy, in exchange for an undertaking. It

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

also launched an exchange offer for a substantial portion of DH s debt in exchange for Dynegy debt at various discounts. Dynegy has indicated that in the absence of a debt restructuring and/or refinancing, it may not have sufficient resources to pay its indebtedness under the lease. The consummation of these transactions triggered the filing of two separate lawsuits, one by a group of corporate unsecured bondholders of DH and a second on behalf of a majority of the holders of certain debt certificates related to the Dynegy lessee facilities; these lawsuits asserted fraudulent conveyance claims among several other causes of action. In addition to claims asserted against DH, one of the suits included claims against several members of DH s Board of Directors.

As a result of the above actions, Energy Holdings has evaluated its likely recovery under the lease arrangements for the Roseton and Danskammer facilities leased to subsidiaries of DH, considering the overall value of the underlying assets subject to lease, and has fully reserved its $264 million gross investment. This gross charge is reflected as a reduction to Operating Revenues and resulted in an after-tax charge of approximately $170 million. In the absence of a negotiated resolution of the disputes with Dynegy, Energy Holdings intends to assert claims against DH, its directors and various Dynegy affiliates relative to the reorganization activities which have diminished the value of assets available to satisfy DH s lease guarantee obligations. In addition, Energy Holdings has a tax indemnity agreement, which is designed to protect it from adverse tax consequences should the lease structure not be maintained. Should there be adverse consequences, Energy Holdings intends to assert its claims under this agreement, notwithstanding any attempt by Dynegy in contravention of current case law to limit such claims in a bankruptcy proceeding of DH. In the event of a bankruptcy filing or the failure of DH to honor its obligations under the lease guarantee, it is possible that the lease certificate holders could foreclose on the underlying facilities in partial satisfaction of their indebtedness. Should this occur, Energy Holdings could be required to pay approximately $100 million to satisfy income tax obligations, an amount for which it would seek reimbursement from DH under the tax indemnity agreement. This potential cash tax obligation is fully reflected in the overall estimate of the aggregate after-tax charge.

Note 6. Available-for-Sale Securities

Nuclear Decommissioning Trust (NDT) Funds

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 advisors who operate under investment guidelines developed by Power.

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

	As of September 30, 2011			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	Millions			
Equity Securities	$ 537	$ 93	$ (55)	$ 575
Debt Securities				
Government Obligations	340	16	(1)	355
Other Debt Securities	273	14	(3)	284

Total Debt Securities	613	30	(4)	639
Other Securities	66	0	0	66
Total Available-for-Sale Securities	**$ 1,216**	**$ 123**	**$ (59)**	**$ 1,280**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

	As of December 31, 2010			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	Millions			
Equity Securities	$ 525	$ 213	$ (3)	$ 735
Debt Securities				
Government Obligations	301	6	(4)	303
Other Debt Securities	247	10	(2)	255
Total Debt Securities	548	16	(6)	558
Other Securities	70	0	0	70
Total Available-for-Sale Securities	**$ 1,143**	**$ 229**	**$ (9)**	**$ 1,363**

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, 2011	As of December 31, 2010
	Millions	
Accounts Receivable	$ 100	$ 35
Accounts Payable	$ 95	$ 60

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

	As of September 30, 2011				As of December 31, 2010			
	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)	$ 252	$ (55)	$ 0	$ 0	$ 55	$ (3)	$ 0	$ 0
Debt Securities								

Government Obligations (B)	72	(1)	2	0	106	(4)	1	0
Other Debt Securities (C)	65	(2)	6	(1)	65	(1)	8	(1)
Total Debt Securities	137	(3)	8	(1)	171	(5)	9	(1)
Other Securities	1	0	0	0	0	0	0	0
Total Available-for-Sale Securities	**$ 390**	**$ (58)**	**$ 8**	**$ (1)**	**$ 226**	**$ (8)**	**$ 9**	**$ (1)**

(A) Equity Securities Investments in marketable equity securities within the NDT funds are primarily investments in common stocks within a broad range of industries and sectors. The unrealized losses are distributed over hundreds of companies with limited impairment durations. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2011.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

(B) Debt Securities (Government) Unrealized losses on Power s NDT 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, since Power does not intend to sell nor will it be more-likely-than-not required to sell. Power does not consider these securities to be other-than-temporarily impaired as of September 30, 2011.

(C) Debt Securities (Corporate) Power s investments in corporate bonds are primarily in investment grade securities. It is not expected that these securities would settle for less than their amortized cost. Since Power does not intend to sell these securities nor will it be more-likely-than-not required to sell, Power does not consider these debt securities to be other-than-temporarily impaired as of September 30, 2011.

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

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
	2011	**2010**	**2011**	**2010**
	Millions		Millions	
Proceeds from Sales	$ 431	$ 302	$ 1,088	$ 728
Net Realized Gains (Losses)				
Gross Realized Gains	$ 26	$ 26	$ 121	$ 86
Gross Realized Losses	(10)	(8)	(28)	(31)
Net Realized Gains	**$ 16**	**$ 18**	**$ 93**	**$ 55**

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 $32 million (after-tax) were recognized in Accumulated Other Comprehensive Income (OCI) on Power s Condensed Consolidated Balance Sheet as of September 30, 2011. The available-for-sale debt securities held as of September 30, 2011 had the following maturities:

Time Frame	**Fair Value**
	Millions
Less than 1 Year	$ 11
1 - 5 Years	141
6 - 10 Years	172
11 - 15 Years	43
16 - 20 Years	18
Over 20 Years	254
	$ 639

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 OCI. In

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

2011, other-than-temporary impairments of $10 million were recognized on securities in the NDT funds. Any subsequent recoveries in the value of these securities are recognized in OCI unless the securities are sold, in which case, any gain is 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 detail of the securities.

Rabbi Trusts

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 grantor trusts commonly known as Rabbi Trusts. In August 2010, PSEG revised the asset structure of the Rabbi Trust and realized gains of $31 million as the investments were transitioned to a new asset allocation and investment manager. The new structure resulted in lower investment management fees.

PSEG classifies investments in the Rabbi Trusts 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 Trusts.

	As of September 30, 2011			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	Millions			
Equity Securities	$ 16	$ 2	$ 0	$ 18
Debt Securities	147	5	0	152
Total PSEG Available-for-Sale Securities	**$ 163**	**$ 7**	**$ 0**	**$ 170**

	As of December 31, 2010			
	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	Millions			
Equity Securities	$ 16	$ 2	$ 0	$ 18
Debt Securities	142	0	0	142
Total PSEG Available-for-Sale Securities	**$ 158**	**$ 2**	**$ 0**	**$ 160**

The Rabbi Trusts are invested in commingled indexed mutual funds, in which the shares have the characteristics of equity securities. Due to the commingled nature of these funds, 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 the nine months ended September 30, 2011, other-than-temporary impairments of $3 million were recognized on the bond portfolio of the Rabbi Trusts.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
	Millions		Millions	
Proceeds from Sales	$ 0	$ 158	$ 0	$ 158
Net Realized Gains (Losses)				
Gross Realized Gains	$ 0	$ 31	$ 0	$ 31
Gross Realized Losses	0	0	0	0
Net Realized Gains (Losses)	**$ 0**	**$ 31**	**$ 0**	**$ 31**

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

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The estimated fair value of the Rabbi Trusts related to PSEG, Power and PSE&G are detailed as follows:

	As of September 30, 2011	As of December 31, 2010
	Millions	
Power	$ 33	$ 32
PSE&G	57	54
Other	80	74
Total PSEG Available-for-Sale Securities	**$ 170**	**$ 160**

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. In early June 2011, PSEG amended certain provisions of its pension and OPEB plans, including revisions to the benefit formulas for certain participants of PSEG s qualified and nonqualified pension and OPEB plans. The weighted average discount rate for the pension plans decreased from 5.51% to 5.31% while the discount rate for the OPEB plans decreased from 5.50% to 5.30%. The expected long-term rate of return on plan assets remained at 8.50%. The pension benefit and OPEB obligations, as well as the asset values, were re-measured as of May 31, 2011 (the closest month-end date to the time the revisions were made). As a result, the annual net periodic pension benefit cost for 2011 will decrease by $32 million and the 2011 annual net OPEB cost will decrease by $6 million compared to costs that would have been expensed in 2011 if PSEG did not re-measure. The re-measured pension projected benefit obligations and accumulated OPEB obligation as of May 31, 2011 were $4.3 billion and $1.2 billion, respectively. The year-to-date rate of return on plan assets through the May 31 remeasurement date was 6.70%.

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. The costs for January through May 2011 are calculated under the prior plans assumptions. The costs for June 2011 and subsequent months are being calculated under the revised plan provisions. OPEB costs are presented net of the federal subsidy expected for prescription drugs under the Medicare Prescription Drug Improvement and Modernization Act of 2003. New 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,	
	2011	2010	2011	2010	2011	2010	2011	2010
	Millions							
Components of Net Periodic Benefit Cost								
Service Cost	$ 22	$ 21	$ 3	$ 4	$ 69	$ 65	$ 10	$ 12
Interest Cost	56	58	15	18	172	173	45	54
Expected Return on Plan Assets	(85)	(67)	(5)	(4)	(248)	(200)	(13)	(11)
Amortization of Net								
Transition Obligation	0	0	1	6	0	0	4	20
Prior Service Cost (Credit)	(4)	0	(4)	4	(6)	0	(10)	10
Actuarial Loss	29	31	4	2	89	92	11	6
Net Periodic Benefit Cost	18	43	14	30	76	130	47	91
Effect of Regulatory Asset	0	0	5	5	0	0	15	15
Total Benefit Costs, Including Effect of Regulatory Asset	**$ 18**	**$ 43**	**$ 19**	**$ 35**	**$ 76**	**$ 130**	**$ 62**	**$ 106**

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,	
	2011	2010	2011	2010	2011	2010	2011	2010
	Millions							
Power	$ 6	$ 13	$ 3	$ 4	$ 24	$ 40	$ 9	$ 13
PSE&G	9	24	16	30	41	72	51	90
Other	3	6	0	1	11	18	2	3
Total Benefit Costs	**$ 18**	**$ 43**	**$ 19**	**$ 35**	**$ 76**	**$ 130**	**$ 62**	**$ 106**

During the three months ended March 31, 2011, PSEG contributed its entire planned contributions for the year 2011 of $415 million and $11 million into its pension and postretirement healthcare plans, respectively.

Note 8. Commitments and Contingent Liabilities

Guaranteed Obligations PSEG and Power

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

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

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

- obtain credit.

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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.

The face value of outstanding guarantees, current exposure and margin positions as of September 30, 2011 and December 31, 2010 are shown below:

	As of September 30, 2011	As of December 31, 2010
	Millions	
Face Value of Outstanding Guarantees	$ 1,758	$ 1,936
Exposure under Current Guarantees	$ 283	$ 330
Letters of Credit Margin Posted	$ 135	$ 137
Letters of Credit Margin Received	$ 53	$ 109
Cash Deposited and Received		

Counterparty Cash Margin Deposited	$ 1	$ 0
Counterparty Cash Margin Received	(5)	(2)
Net Broker Balance Deposited (Received)	37	(28)
In the Event Power Were to Lose its Investment Grade Rating		
Additional Collateral that could be Required	$ 765	$ 828
Liquidity Available under PSEG s and Power s Credit Facilities to Post Collateral	$ 3,466	$ 2,750
Additional Amounts Posted		
Other Letters of Credit	$ 99	$ 98

Power nets receivables and payables with the corresponding net energy contract balances. See Note 10. Financial Risk Management Activities for further discussion. The remaining balance of net cash (received) deposited is primarily included in Accounts Receivable.

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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 ratings, many of these agreements allow the counterparty to demand further performance assurance. See table above.

In addition, during 2011, the SEC and the Commodity Futures Trading Commission (CFTC) are continuing efforts to implement new rules to enact stricter regulation over swaps and derivatives. Power will carefully monitor these new rules as they are developed to analyze the potential impact on its swap and derivatives transactions, including any potential increase to collateral requirements.

In April 2011, PSEG and Power entered into new 5-year credit agreements resulting in an increase of $650 million in Power s total credit capacity.

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 United States Environmental Protection Agency (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 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 study would greatly exceed the original estimated cost of $20 million. The total cost of the study is now estimated at approximately $86 million. 73 PRPs, including Power and PSE&G, agreed to assume responsibility for the study and to divide the associated costs according to a mutually agreed upon formula. The PRP group, currently 71 members, is presently executing the study. Approximately five percent of the study 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 that proposed six options to address the contamination cleanup of the lower eight miles of the Passaic River. The estimated costs for the proposed remedy range from $1.3 billion to $3.7 billion. The work contemplated by the study is not subject to the cost sharing agreement discussed above. A revised focused feasibility study may be released as early as the second quarter of 2012.

In June 2008, an agreement was announced between the EPA and two PRPs for removal of a portion of the contaminated sediment in the Passaic River at an estimated cost of $80 million. The two PRPs have reserved their rights to seek contribution for the removal costs from the other PRPs, including Power and PSE&G.

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Power and PSE&G are unable to estimate their portion of the possible loss or range of loss related to these matters.

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 they 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 complaint in June 2010. A special master for discovery has been appointed by the court and document production has commenced. 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 is participating in and partially funding 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 next 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.

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During the third quarter of 2011, PSE&G updated the estimated cost to remediate all MGP sites to completion and determined that the cost to completion could range between $643 million and $741 million from September 30, 2011 through 2021. Since no amount within the range was considered to be most likely, PSE&G reflected a liability of $643 million on its Condensed Consolidated Balance Sheet as of September 30, 2011. Of this amount, $53 million was recorded in Other Current Liabilities and $590 million was reflected as Environmental Costs in Noncurrent Liabilities. PSE&G has recorded a $643 million Regulatory Asset with respect to these costs.

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 2006, Power reached an agreement with the EPA and the NJDEP to achieve emissions reductions targets at certain of Power s generating stations. Under this agreement, Power was required to undertake a number of technology projects, plant modifications and operating procedure changes at the Hudson and Mercer facilities designed to meet targeted reductions in emissions of sulfur dioxide (SO_2), nitrogen oxide (NO_x), particulate matter and mercury. Power completed the construction of all plant modifications by the end of 2010 at a cost of $1.3 billion. Performance testing to validate the agreed-upon emission reductions was completed in the second quarter of 2011 and all performance metrics were met.

In 2009, the EPA issued a notice of violation to Power and the other owners of the Keystone coal fired plant in Pennsylvania, alleging, among other things, that various capital improvement projects were completed at the plant which are considered modifications (or major modifications) causing significant net emission increases of PSD/NSR air pollutants, beginning in 1985 for Keystone Unit 1 and in 1984 for Keystone Unit 2. The notice of violation states that none of these modifications underwent 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 court ruling, the EPA proposed a Maximum Achievable Control Technology (MACT) regulation in March 2011 which is expected to be finalized by December 2011. This regulation prescribes reduced levels of mercury and other hazardous air pollutants pursuant to the Clean Air Act. Until the final rule is adopted, the impact cannot be determined; however, if the rule is adopted as proposed, Power believes the back end technology environmental controls recently installed at its Hudson and Mercer coal facilities should meet the rule s requirements. Some additional controls could be necessary at Power s Connecticut facilities and some of its other New Jersey facilities, pending engineering evaluation. The impact to Power s jointly owned coal fired generating facilities in Pennsylvania is under evaluation.

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 expects to achieve 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.

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NO_x Regulation

In April 2009, the NJDEP finalized revisions to NO_x emission control regulations that impose new NO_x emission reduction requirements and limits for New Jersey fossil fuel fired electric generating units. The rule has a significant impact on Power s generation fleet, as it imposes NO_x emissions limits that will require significant capital investment for controls or the retirement of up to 102 combustion turbines (approximately 2,000 MW) and five older New Jersey steam electric generating units (approximately 800 MW) by April 30, 2015. Power is unable to estimate the possible loss or range of loss related to this matter.

Under current Connecticut regulations, Power s Bridgeport and New Haven facilities have been utilizing Discrete Emission Reduction Credits (DERCs) to comply with certain NO_x 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)

On July 6, 2011, the EPA issued the CSAPR. CSAPR limits power plant emissions in 27 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone emission standards. Emission reductions will be governed by this rule beginning on January 1, 2012 for SO_2 and annual NO_x and May 1, 2012 for Ozone season NO_x. Certain states will be required to make additional SO_2 reductions in 2014.

PSEG continues to evaluate the impact of this rule on it due to many of the uncertainties that still exist regarding implementation. As Power has made major capital investments over the past several years to lower the SO_2 and NO_X emissions of its fossil plants in the states affected by CSAPR (New Jersey, New York and Pennsylvania), Power does not foresee the need to make significant additional expenditures to its generation fleet to comply with the regulation. As such, Power believes this rule will not have a material impact to its capital investment program or units operations.

New Jersey Industrial Site Recovery Act (ISRA)

Potential environmental liabilities related to the alleged discharge of hazardous substances at certain generating stations have been identified. In 1999, in anticipation of the transfer of PSE&G s generation-related assets to Power, a study was conducted pursuant to ISRA, which applied to the sale of certain assets. Power had a $50 million liability related to these obligations, which was included in Environmental Costs on Power s and PSEG s Condensed Consolidated Balance Sheets as of September 30, 2011 and December 31, 2010.

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.

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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 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 impingement and entrainment mortality standards for existing cooling water intake structures with a design flow of more than 2 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. 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 or results of operations. 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.

In addition to the EPA rulemaking, several states, including California and New York, have begun setting policies that may require closed cycle cooling. It is unknown how these policies may ultimately impact the EPA s rulemaking.

In January 2010, the NJDEP issued a draft NJPDES permit to another company which would require the installation of closed cycle cooling at that company s nuclear generating station located in New Jersey. In December 2010, the NJDEP and that company entered into an Administrative Consent Order (ACO) which would require the company to cease operations at the nuclear generating station no later than 2019. In the ACO, the NJDEP agreed that closed cycle cooling is not the best technology available for that facility and agreed to issue a new draft NJPDES permit for that facility without a requirement for construction of cooling towers or other closed cycle cooling facilities. The new draft NJPDES permit will be issued in substitution for the draft NJPDES permit issued in January 2010. Power cannot predict at this time the final outcome of the NJDEP decision and the impact, if any, such a decision would have on any of Power s once-through cooled generating stations.

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 on schedule in October 2011. Unit 2 upgrades are expected to result in an increase of Power s share of nominal capacity by approximately 18 MW in 2012. Total expenditures through September 30, 2011 were $94 million and are expected to continue through 2012. The actual increase in nominal capacity is under evaluation.

Power has begun expenditures in pursuit of additional output through an extended power uprate of the Peach Bottom nuclear units. The uprate is expected to be in service in 2015 for Unit 2 and 2016 for Unit 3. Power s

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share of the increased capacity is expected to be approximately 133 MW with an anticipated cost of approximately $400 million. Total expenditures through September 30, 2011 were $28 million and are expected to continue through 2016.

Connecticut

Power was selected by the Connecticut 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 is expected to be in service by June 2012. Power estimates the cost of these generating units to be $140 million to $150 million. Total capitalized expenditures through September 30, 2011 were $99 million, which are included in Property, Plant and Equipment on the Condensed Consolidated Balance Sheets of PSEG and Power. The initial filing is expected to be made in the fourth quarter of 2011. Costs for this project will be recovered subject to regulatory review and approval.

PJM Interconnection L.L.C. (PJM)

Power plans to construct gas fired peaking facilities at its Kearny site. Construction began in the second quarter of 2011. The projects are expected to be in service by June 2012. Capacity in the amount of 178 MW was bid into and cleared the PJM Reliability Pricing Model (RPM) base residual capacity auction for the 2012-2013 period. Capacity in the amount of 267 MW was bid into and cleared the PJM RPM base residual capacity auction for the 2013-2014 and 2014-2015 periods. Power estimates the cost of these generating units to be $250 million to $300 million. Total capitalized expenditures through September 30, 2011 were $148 million which are included in Property, Plant and Equipment on Power s and PSEG s Condensed Consolidated Balance Sheets.

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 has entered into an agreement to purchase solar units for this program. PSE&G s commitments under this agreement are contingent upon, among other things, the availability of suitable utility poles for installation of the units PSE&G estimates the total cost of this project to be $264 million. Approximately 23 MW have been installed as of September 30, 2011. PSE&G s cumulative investments for these solar units were approximately $164 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 $189 million. Through September 30, 2011, 23 MW representing 15 projects were placed into service with an investment of approximately $116 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

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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. In addition to the BGS-related contracts, Power also enters into firm supply contracts with EDCs, as well as other firm sales and commitments.

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

	Auction Year			
	2008	**2009**	**2010**	**2011**
36-Month Terms Ending	May 2011	May 2012	May 2013	May 2014(A)
Load (MW)	2,800	2,900	2,800	2,800
$ per kWh	0.11150	0.10372	0.09577	0.09430

(A) Prices set in the 2011 BGS auction became effective on June 1, 2011 when the 2008 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. The contract extends through March 31, 2012, and year-to-year thereafter. 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 and oil 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 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.

Power s strategy is to maintain certain levels of uranium in inventory 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 2013 and a portion for 2014 through 2015 at Salem, Hope Creek and Peach Bottom.

As of September 30, 2011, the total minimum purchase requirements included in these commitments were as follows:

Fuel Type	**Commitments through 2015 Power s Share**
	Millions
Nuclear Fuel	
Uranium	$ 493
Enrichment	$ 383

Fabrication	$	130
Natural Gas	$	903
Coal/Oil	$	896

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Included in the $896 million commitment for coal is $647 million related to a certain coal contract under which Power can cancel future contractual deliveries at no cost. In 2011, Power has not cancelled any related coal deliveries.

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. Under New Jersey law, the Competition Act, enacted in 1999, is presumed constitutional.

Also in 2007, the plaintiff filed an amended Complaint to also seek injunctive relief from continued collection of related taxes as well as recovery of such taxes previously collected. In October 2007, the Court granted PSE&G s motion to dismiss the amended Complaint and in November 2007, the plaintiff filed a notice of appeal with the Appellate Division of the New Jersey Superior Court (Appellate Division). In February 2009, the Appellate Division affirmed the decision of the lower court dismissing the case. In May 2009, the New Jersey Supreme Court denied a request from the plaintiff to review the Appellate Division s decision.

In July 2007, the same plaintiff also filed a petition with the BPU requesting review and adjustment to PSE&G s recovery of the same stranded cost charges. In September 2007, PSE&G filed a motion with the BPU to dismiss the petition. In June 2010, the BPU granted PSE&G s motion to dismiss. In April 2011, the BPU issued a written order memorializing this decision. In June 2011, the plaintiff/petitioner filed a notice of appeal of the BPU action with the Appellate Division. A briefing schedule has been established.

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 discounted liability of $294 million as of September 30, 2011. Of this amount, $224 million was recorded as a current liability and $70 million as a noncurrent liability. 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. It has no impact on current SBC assessments.

Long-Term Capacity Agreement Pilot Program (LCAPP)

In January 2011, New Jersey enacted the LCAPP Act directing the BPU to conduct a process to procure and subsidize up to 2,000 megawatts of baseload or mid-merit electric power generation. In March 2011, the BPU issued a written order approving a form of agreement and selecting three generators to build a total of approximately 1,949 MW of new combined-cycle generating facilities located in New Jersey. Each of the New Jersey EDCs, including PSE&G, executed standard offer capacity agreements (SOCA) with each of the three selected generators in compliance with the BPU s directive, but did so under protest preserving its respective legal rights. The SOCA requires that the generator bid in and clear the PJM RPM base residual auction in each year of the SOCA term. The SOCA provides for the EDCs to make capacity payments to, or receive capacity payments from, the generators as calculated based on the difference between the RPM clearing price for each year of the term and the price bid and accepted for that generator in the BPU process. The LCAPP Act and the

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BPU order provide that, once the SOCAs are executed and approved by the BPU, they will be irrevocable and the EDCs will be entitled to full rate recovery of the prudently incurred costs. PSE&G will not make or receive payments under the three contracts unless (1) the plant successfully bids into and clears the capacity auction, and (2) the proposed plant is constructed. In April 2011, the BPU approved the executed contracts. Both PSE&G and Power joined other parties, including the EDCs, and appealed the BPU s implementation of the LCAPP Act to the Appellate Division. The Division of Rate Counsel filed a motion to dismiss the EDCs appeal, which was denied by the Appellate Division.

Leveraged Lease Investments

The IRS has issued reports with respect to its audits of PSEG s consolidated federal corporate income tax returns for tax years 1997 through 2003, which disallowed all deductions associated with certain lease transactions. The IRS reports also proposed a 20% penalty for substantial understatement of tax liability. PSEG has filed protests of these findings with the Office of Appeals of the IRS.

PSEG believes its tax position related to these transactions was proper based on applicable statutes, regulations and case law in effect at the time that the deductions were taken. There are several pending tax cases involving other taxpayers with similar leveraged lease investments. To date, six cases have been decided at the trial court level, five of which were decided in favor of the government. The appeals of three of these decisions were affirmed, each in favor of the government. The sixth case involves a jury verdict that was challenged by both parties on inconsistency grounds but was later settled by the parties. One case, involving an investment in an energy transaction by a utility, was decided in favor of the taxpayer.

In order to reduce the cash tax exposure related to these leases, Energy Holdings pursued opportunities to terminate international leases with lessees that were willing to meet certain economic thresholds. As of December 31, 2010, Energy Holdings had terminated all of these leasing transactions and reduced the related cash tax exposure by $1.1 billion. PSEG has completely eliminated its gross investment in such transactions.

Cash Impact

As of September 30, 2011, an aggregate of approximately $266 million would become currently payable if PSEG conceded all deductions taken through that date. PSEG has deposited $320 million with the IRS to defray potential interest costs associated with this disputed tax liability, eliminating its cash exposure completely. In the event PSEG is successful in defense of its position, the deposit is fully refundable with interest. Penalties of $150 million would also become payable if the IRS successfully asserted and litigated a case against PSEG. PSEG has not established a reserve for penalties because it believes it has strong defenses to the assertion of penalties under applicable law. Interest and penalty exposure will grow at an average rate of $2 million per quarter during 2011. If the IRS is successful in a litigated case consistent with the positions it has taken in the generic settlement offer recently proposed, an additional $20 million to $40 million of tax would be due for tax positions through September 30, 2011.

Unless this matter is resolved with the IRS, PSEG currently anticipates that it may be required to pay between $110 million and $300 million in tax, interest and penalties for the tax years 1997-2000 during 2011 and subsequently commence litigation to recover those amounts. It is possible that an additional payment of between $220 million and $560 million could be required during 2011 for tax years 2001-2003 followed by further litigation to recover those amounts. The amounts that may be required to litigate differ from the potential net cash exposure noted above, as the former amounts include all potential deficiencies for only contested tax years 1997 through 2003. These litigation amounts also include penalties which are not included in the computation of potential net cash exposure as PSEG believes it has strong defenses. These amounts also

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exclude an offset for taxes paid on lease terminations, which is netted in the potential net cash exposure as PSEG would be entitled to a refund of such amounts under a loss scenario. Any potential claims PSEG would make to recover such amounts would include the deposit noted above.

Earnings Impact

PSEG s current reserve position represents its view of the earnings impact that could result from a settlement related to these transactions, although a total loss, consistent with the broad settlement offer previously proposed by the IRS, would result in an additional earnings charge of $120 million to $140 million.

Note 9. Changes in Capitalization

The following capital transactions occurred in the first nine months of 2011:

Power

- issued $250 million of 2.75% Senior Notes due September 2016 in September,
- issued $250 million of 4.15% Senior Notes due September 2021 in September,
- paid $606 million of 7.75% Senior Notes at maturity in April, and
- paid cash dividends of $350 million to PSEG.

PSE&G

- issued $250 million of 0.85% Medium Term Notes due August 2014 in August, and
- paid $142 million of Transition Funding s securitization debt, and
- paid $5 million of Transition Funding II s securitization debt.

Energy Holdings

- paid $1 million of nonrecourse project debt.

PSE&G

In addition, $164 million of tax-exempt bonds of the Pollution Control Financing Authority of Salem County (Authority Bonds), which are serviced and secured by PSE&G s first mortgage bonds of like tenor, are subject to a mandatory put in November 2011. PSE&G intends to buy the Authority Bonds in on their mandatory put date. The Authority Bonds had an initial term rate of 0.95%.

Also, $100 million of tax-exempt bonds of the New Jersey Economic Development Authority (EDA Bonds), which are serviced and secured by PSE&G s first mortgage bonds of like tenor, are subject to a mandatory put in December 2011. PSE&G intends to buy the EDA Bonds in on their mandatory put date. The EDA Bonds had an initial term rate of 1.20%.

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

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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 and

the price of fuel to meet its fuel purchase requirements.

These derivative transactions are designated and effective as cash flow hedges. As of September 30, 2011 and December 31, 2010, the fair value and the impact on Accumulated Other Comprehensive Income (Loss) associated with these hedges was as follows:

	As of September 30, 2011	As of December 31, 2010
	Millions	
Fair Value of Cash Flow Hedges	$ 79	$ 196
Impact on Accumulated Other Comprehensive Income (Loss) (after tax)	$ 34	$ 114

The expiration date of the longest-dated cash flow hedge at Power is in 2013. Power s after-tax unrealized gains on these derivatives that are expected to be reclassified to earnings during the next 12 months are $33 million. There was ineffectiveness of $3 million associated with these hedges as of September 30, 2011.

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 we serve. 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 are 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 only enter into transactions that are associated with the output or fuel purchase requirements of its facilities.

Other Derivatives

Power enters into additional contracts that are derivatives, but do not qualify for or are not designated as cash flow hedges. These asset backed transactions are intended to mitigate exposure to fluctuations in commodity prices and optimize the value of our 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. The fair value of these contracts as of September 30, 2011 and December 31, 2010 was $19 million and $(4) million, respectively.

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, we have used a mix of fixed and floating rate debt, interest rate swaps and interest rate lock agreements.

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Fair Value Hedges

PSEG enters into fair value hedges to convert fixed-rate debt into variable-rate debt. Since 2009, PSEG has entered into eleven interest rate swaps totaling $1.4 billion. These swaps convert $300 million of Power s $600 million of 6.95% Senior Notes due June 2012, 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, 2011 and December 31, 2010, the fair value of all the underlying hedges was $66 million and $39 million, respectively.

Cash Flow Hedges

PSEG and Energy Holdings use interest rate swaps and other derivatives, which are designated and effective as cash flow hedges, to manage their exposure to the variability of cash flows, primarily related to variable-rate debt instruments. As of September 30, 2011, there was no hedge ineffectiveness associated with these hedges. The total fair value of these interest rate derivatives was immaterial as of each of September 30, 2011 and December 31, 2010. The Accumulated Other Comprehensive Income (Loss) (after tax) related to interest rate derivatives designated as cash flow hedges was $(3) million and $(3) million as of September 30, 2011 and December 31, 2010, respectively.

Fair Values of Derivative Instruments

The following are the fair values of derivative instruments on the Condensed Consolidated Balance Sheets:

	As of September 30, 2011						
	Power				PSE&G	PSEG	Consolidated
Balance Sheet Location	**Cash Flow Hedges Energy-Related Contracts**	**Non Hedges Energy-Related Contracts**	**Netting (A)**	**Total Power**	**Non Hedges Energy-Related Contracts**	**Fair Value Hedges Interest Rate Swaps**	**Total Derivatives**
	Millions						
Derivative Contracts							
Current Assets	$ 76	$ 232	$ (213)	$ 95	$ 0	$ 18	$ 113
Noncurrent Assets	7	44	(27)	24	0	51	75
Total Mark-to-Market Derivative Assets	**$ 83**	**$ 276**	**$ (240)**	**$ 119**	**$ 0**	**$ 69**	**$ 188**
Derivative Contracts							
Current Liabilities	$ (2)	$ (281)	$ 204	$ (79)	$ (15)	$ 0	$ (94)
Noncurrent Liabilities	(2)	(41)	26	(17)	(11)	(3)	(31)
Total Mark-to-Market Derivative (Liabilities)	**$ (4)**	**$ (322)**	**$ 230**	**$ (96)**	**$ (26)**	**$ (3)**	**$ (125)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 79**	**$ (46)**	**$ (10)**	**$ 23**	**$ (26)**	**$ 66**	**$ 63**

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	As of December 31, 2010						
	Power				PSE&G	PSEG	Consolidated
Balance Sheet Location	Cash Flow Hedges Energy-Related Contracts	Non Hedges Energy-Related Contracts	Netting (A)	Total Power	Non Hedges Energy-Related Contracts	FairValue Hedges Interest Rate Swaps	Total Derivatives
	Millions						
Derivative Contracts							
Current Assets	$ 204	$ 403	$ (444)	$ 163	$ 0	$ 19	$ 182
Noncurrent Assets	3	80	(41)	42	17	20	79
Total Mark-to-Market Derivative Assets	**$ 207**	**$ 483**	**$ (485)**	**$ 205**	**$ 17**	**$ 39**	**$ 261**
Derivative Contracts							
Current Liabilities	$ (11)	$ (454)	$ 374	$ (91)	$ (12)	$ 0	$ (103)
Noncurrent Liabilities	0	(72)	50	(22)	0	0	(22)
Total Mark-to-Market Derivative (Liabilities)	**$ (11)**	**$ (526)**	**$ 424**	**$ (113)**	**$ (12)**	**$ 0**	**$ (125)**
Total Net Mark-to-Market Derivative Assets (Liabilities)	**$ 196**	**$ (43)**	**$ (61)**	**$ 92**	**$ 5**	**$ 39**	**$ 136**

(A) Represents the netting of fair value balances with the same counterparty and the application of collateral. As of September 30, 2011 and December 31, 2010, net cash collateral received of $10 million and $61 million, respectively, was netted against the corresponding net derivative contract positions. Of the $10 million as of September 30, 2011, cash collateral of $(9) million and $(1) million were netted against current assets and noncurrent assets, respectively. Of the $61 million as of December 31, 2010, cash collateral of $(132) million and $(3) million were netted against current assets and noncurrent assets, respectively, and cash collateral of $62 million and $12 million were netted against current liabilities and noncurrent liabilities, respectively.

The aggregate fair value of energy-related contracts in a liability position as of September 30, 2011 that contain triggers for additional collateral was $182 million. This potential additional collateral is included in the $765 million discussed in Note 8. Commitments and Contingent Liabilities.

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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 three months ended September 30, 2011 and 2010:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion) Three Months Ended September 30, 2011	2010	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, 2011	2010	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, 2011	2010
				Millions				
PSEG								
Energy-Related Contracts	$ 21	$ 62	Operating Revenues	$ 60	$ 60	Operating Revenues	$ 0	$ 0
Energy-Related Contracts	0	0	Energy Costs	0	0		0	0
Interest Rate Swaps	0	0	Interest Expense	0	0		0	0
Total PSEG	**$ 21**	**$ 62**		**$ 60**	**$ 60**		**$ 0**	**$ 0**
Power								
Energy-Related Contracts	$ 21	$ 62	Operating Revenues	$ 60	$ 60	Operating Revenues	$ 0	$ 0
Energy-Related Contracts	0	0	Energy Costs	0	0		0	0
Total Power	**$ 21**	**$ 62**		**$ 60**	**$ 60**		**$ 0**	**$ 0**

The following shows the effect on the Condensed Consolidated Statements of Operations and on AOCI of derivative instruments designated as cash flow hedges for the nine months ended September 30, 2011 and 2010:

Derivatives in Cash Flow Hedging Relationships	Amount of Pre-Tax Gain (Loss) Recognized in AOCI on Derivatives (Effective Portion)	Location of Pre-Tax Gain (Loss) Reclassified from AOCI into Income	Amount of Pre-Tax Gain (Loss) Reclassified from AOCI into Income (Effective Portion)	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

	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010		Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010		Portion) Nine Months Ended September 30, 2011	Portion) Nine Months Ended September 30, 2010
				Millions				
PSEG (A)								
Energy-Related Contracts	$ 18	$ 171	Operating Revenues	$ 152	$ 178	Operating Revenues	$ 1	$ (3)
Energy-Related Contracts	1	1	Energy Costs	2	(2)		0	0
Interest Rate Swaps	0	0	Interest Expense	(1)	(1)		0	0
Total PSEG	**$ 19**	**$ 172**		**$ 153**	**$ 175**		**$ 1**	**$ (3)**
Power								
Energy-Related Contracts	$ 18	$ 171	Operating Revenues	$ 152	$ 178	Operating Revenues	$ 1	$ (3)
Energy-Related Contracts	1	1	Energy Costs	2	(2)		0	0
Total Power	**$ 19**	**$ 172**		**$ 154**	**$ 176**		**$ 1**	**$ (3)**

(A) Includes amounts for PSEG parent.

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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, 2010	**$ 188**	**$ 111**
Loss Recognized in AOCI (Effective Portion)	(2)	(1)
Less: Gain Reclassified into Income (Effective Portion)	(93)	(56)
Balance as of June 30, 2011	**$ 93**	**$ 54**
Gain Recognized in AOCI (Effective Portion)	21	12
Less: Gain Reclassified into Income (Effective Portion)	(60)	(35)
Balance as of September 30, 2011	**$ 54**	**$ 31**

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, 2011 and 2010:

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,**	
		2011	**2010**	**2011**	**2010**
		Millions		Millions	
PSEG and Power					
Energy-Related Contracts	Operating Revenues	$ 24	$ (6)	$ (18)	$ 3
Energy-Related Contracts	Energy Costs	(11)	0	(10)	(8)
Total PSEG and Power		$ 13	$ (6)	$ (28)	$ (5)

Power s derivative contracts reflected in the preceding tables include contracts to hedge the purchase and sale of electricity 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 for each of the three month periods and $19 million and $18 million for the nine month periods ended September 30, 2011 and 2010, respectively.

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The following reflects the gross volume, on an absolute value basis, of derivatives as of September 30, 2011 and December 31, 2010:

Type	Notional	Total	PSEG	Power	PSE&G
			Millions		
As of September 30, 2011					
Natural Gas	Dth	593	0	350	243
Electricity	MWh	145	0	145	0
Financial Transmission Rights (FTRs)	MWh	20	0	20	0
Interest Rate Swaps	US Dollars	1,400	1,400	0	0
As of December 31, 2010					
Natural Gas	Dth	704	0	424	280
Electricity	MWh	154	0	154	0
Capacity	MW days	1	0	1	0
FTRs	MWh	23	0	23	0
Interest Rate Swaps	US Dollars	1,150	1,150	0	0

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, 2011, 95% 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, 2011. 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	$ 396	$ 46	$ 392	3	$ 242(A)
Non-Investment Grade External Rating	11	0	11	0	0
Investment Grade No External Rating	9	0	9	0	0
Non-Investment Grade No External Rating	9	0	9	0	0

Total Credit Risk	**$**	**425**	**$**	**46**	**$**	**421**	**3**	**$**	**242**

(A) Includes net exposure of $129 million with PSE&G. The remaining net exposure of $113 million is with two nonaffiliated power purchasers which are regulated investment grade counterparties.

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

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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, 2011, Power had 190 active counterparties.

Note 11. 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. These consist mainly of various FTRs, certain full requirements contracts and other longer term capacity and transportation contracts.

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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, 2011 and December 31, 2010, 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.

	Recurring Fair Value Measurements as of September 30, 2011				
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)	$ 119	$ (10)	$ 0	$ 99	$ 30
Interest Rate Swaps (B)	$ 69	$ 0	$ 0	$ 69	$ 0
NDT Funds: (C)					
Equity Securities	$ 575	$ 0	$ 575	$ 0	$ 0
Debt Securities Govt Obligations	$ 355	$ 0	$ 0	$ 355	$ 0
Debt Securities Other	$ 284	$ 0	$ 0	$ 284	$ 0
Other Securities	$ 66	$ 0	$ 1	$ 65	$ 0
Rabbi Trusts Mutual Funds (C)	$ 170	$ 0	$ 17	$ 153	$ 0
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (122)	$ 0	$ 0	$ (88)	$ (34)
Interest Rate Swaps (B)	$ (3)	$ 0	$ 0	$ (3)	$ 0
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 119	$ (10)	$ 0	$ 99	$ 30
NDT Funds: (C)					
Equity Securities	$ 575	$ 0	$ 575	$ 0	$ 0
Debt Securities Govt Obligations	$ 355	$ 0	$ 0	$ 355	$ 0
Debt Securities Other	$ 284	$ 0	$ 0	$ 284	$ 0
Other Securities	$ 66	$ 0	$ 1	$ 65	$ 0
Rabbi Trusts Mutual Funds (C)	$ 33	$ 0	$ 3	$ 30	$ 0
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (96)	$ 0	$ 0	$ (88)	$ (8)
PSE&G					
Assets:					
Rabbi Trust Mutual Funds (C)	$ 57	$ 0	$ 6	$ 51	$ 0
Liabilities:					

Derivative Contracts:					
Energy Related Contracts (A)	$ (26)	$ 0	$ 0	$ 0	$ (26)

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

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)
	Recurring Fair Value Measurements as of December 31, 2010		Millions		
PSEG					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 222	$ (135)	$ 0	$ 228	$ 129
Interest Rate Swaps (B)	$ 39	$ 0	$ 0	$ 39	$ 0
NDT Funds: (C)					
Equity Securities	$ 735	$ 0	$ 735	$ 0	$ 0
Debt Securities-Govt Obligations	$ 303	$ 0	$ 0	$ 303	$ 0
Debt Securities-Other	$ 255	$ 0	$ 0	$ 255	$ 0
Other Securities	$ 70	$ 0	$ 0	$ 62	$ 8
Rabbi Trusts Mutual Funds (C)	$ 160	$ 0	$ 18	$ 142	$ 0
Other Long-Term Investments (D)	$ 2	$ 0	$ 2	$ 0	$ 0
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (125)	$ 74	$ 0	$ (117)	$ (82)
Power					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 205	$ (135)	$ 0	$ 228	$ 112
NDT Funds: (C)					
Equity Securities	$ 735	$ 0	$ 735	$ 0	$ 0
Debt Securities-Govt Obligations	$ 303	$ 0	$ 0	$ 303	$ 0
Debt Securities-Other	$ 255	$ 0	$ 0	$ 255	$ 0
Other Securities	$ 70	$ 0	$ 0	$ 62	$ 8
Rabbi Trusts Mutual Funds (C)	$ 32	$ 0	$ 4	$ 28	$ 0
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (113)	$ 74	$ 0	$ (117)	$ (70)
PSE&G					
Assets:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ 17	$ 0	$ 0	$ 0	$ 17
Rabbi Trusts Mutual Funds (C)	$ 54	$ 0	$ 6	$ 48	$ 0
Liabilities:					
Derivative Contracts:					
Energy-Related Contracts (A)	$ (12)	$ 0	$ 0	$ 0	$ (12)

(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.

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(UNAUDITED)

Level 3 For energy-related contracts, which include more complex agreements where limited observable inputs or pricing information is available, modeling techniques are employed using assumptions reflective of contractual terms, current market rates, forward price curves, discount rates and risk factors, as applicable. For certain energy-related option contracts where daily settled option prices are not observable, a traditional Black-Scholes valuation methodology is used which incorporates an internally developed volatility curve that is considered a significant unobservable input. Fair values of other energy contracts may be based on broker quotes that we cannot corroborate with actual market transaction data. We considered the creditworthiness of our counterparties in the valuation of our energy-related contracts and the impacts are immaterial.

(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) Power s NDT funds maintain investments in various equity and fixed income securities classified as available for sale. These securities are valued using quoted market prices, broker or dealer quotations or alternative pricing sources with reasonable levels of price transparency. All fair value measurements for the fund securities are provided by the trustees of these funds. Investments in marketable equity securities within the NDT funds 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). Power s NDT investments in fixed income securities are primarily with investment grade corporate bonds and United States Treasury obligations or Federal Agency mortgage-backed securities with a wide range of maturities. Fixed income securities are priced using an evaluated pricing methodology that reflects observable market information such as the most recent exchange price or quoted bid for similar securities (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).

The Rabbi Trust mutual funds are mainly invested in a United States bond index fund, an S&P 500 index fund and a commingled temporary investment fund. The equity index fund is valued based on quoted prices in an active market (Level 1) while the bond index fund is valued using recent exchange prices or a quoted bid (Level 2).

(D) Other long-term investments consist of equity securities and are valued using a market based approach based on quoted market prices.

(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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

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)	Balance as of September 30, 2011
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ (3)	$ 13	$ (27)	$ 10	$ 3	$ 0	$ (4)
Power							
Net Derivative Assets (Liabilities)	$ (4)	$ 13	$ 0	$ 10	$ 3	$ 0	$ 22
PSE&G							
Net Derivative Assets (Liabilities)	$ 1	$ 0	$ (27)	$ 0	$ 0	$ 0	$ (26)

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 (E)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales) (C)	(Issuances) Settlements (D)	Transfers In (Out)	Balance as of September 30, 2011
				Millions			
PSEG							
Net Derivative Assets (Liabilities)	$ 47	$ (27)	$ (31)	$ 29	$ (22)	$ 0	$ (4)
NDT Funds	$ 8	$ 0	$ 0	$ 0	$ 0	$ (8)	$ 0
Power							
Net Derivative Assets	$ 42	$ (27)	$ 0	$ 29	$ (22)	$ 0	$ 22
NDT Funds	$ 8	$ 0	$ 0	$ 0	$ 0	$ (8)	$ 0
PSE&G							
	$ 5	$ 0	$ (31)	$ 0	$ 0	$ 0	$ (26)

Net Derivative Assets (Liabilities)	

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

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, 2010 follows:

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis for the Three Months Ended September 30, 2010

Description	Balance as of July 1, 2010	Total Gains or (Losses) Realized/Unrealized: Included in Income (A)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales) and Settlements	Balance as of September 30, 2010
			Millions		
PSEG					
Net Derivative Assets	$ 168	$ 33	$ (11)	$ (2)	$ 188
NDT Funds	$ 6	$ 0	$ 0	$ 3	$ 9
Rabbi Trust Funds	$ 16	$ 0	$ 0	$ (16)	$ 0
Power					
Net Derivative Assets	$ 117	$ 33	$ 0	$ (2)	$ 148
NDT Funds	$ 6	$ 0	$ 0	$ 3	$ 9
Rabbi Trust Funds	$ 3	$ 0	$ 0	$ (3)	$ 0
PSE&G					
Net Derivative Assets	$ 51	$ 0	$ (11)	$ 0	$ 40
Rabbi Trust Funds	$ 5	$ 0	$ 0	$ (5)	$ 0

Changes in Level 3 Assets and (Liabilities) Measured at Fair Value on a Recurring Basis

for the Nine Months Ended September 30, 2010

Description	Balance as of January 1, 2010	Total Gains or (Losses) Realized/Unrealized: Included in Income (E)	Total Gains or (Losses) Realized/Unrealized: Included in Regulatory Assets/ Liabilities (B)	Purchases, (Sales) and Settlements	Balance as of September 30, 2010
			Millions		
PSEG					
Net Derivative Assets	$ 105	$ 61	$ 34	$ (12)	$ 188
NDT Funds	$ 9	$ 0	$ 0	$ 0	$ 9
Rabbi Trust Funds	$ 14	$ 0	$ 0	$ (14)	$ 0
Power					
Net Derivative Assets	$ 99	$ 61	$ 0	$ (12)	$ 148
NDT Funds	$ 9	$ 0	$ 0	$ 0	$ 9
Rabbi Trust Funds	$ 3	$ 0	$ 0	$ (3)	$ 0
PSE&G					
Net Derivative Assets	$ 6	$ 0	$ 34	$ 0	$ 40

Rabbi Trust Funds	$ 5	$ 0	$ 0	$ (5)	$ 0

(A) PSEG s and Power s gains and losses are mainly attributable to changes in net derivative assets and liabilities of which $12 million and $17 million are included in Operating Income, $1 million and $14 million are included in OCI, and less than $1 million and $2 million are included in Income from Discontinued Operations in 2011 and 2010, respectively. Of the $12 million in Operating Income in 2011, $31 million is unrealized and $(19) million is realized. Of the $17 million in Operating Income in 2010, $32 million is unrealized and $(15) million is realized.

(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.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

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

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

(E) PSEG s and Power s gains and losses are mainly attributable to changes in net derivative assets and liabilities of which $(28) million and $8 million are included in Operating Income, $(2) million and $28 million are included in OCI, and $3 million and $25 million are included in Income from Discontinued Operations in 2011 and 2010, respectively. Of the $(28) million in Operating Income in 2011, $(25) million is unrealized and $(3) million is realized. Of the $8 million in Operating Income in 2010, $9 million is unrealized and $(1) million is realized.

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. These Level 3 net assets represent less than 1% of PSEG s total assets. 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. As per PSEG s policy, this transfer was recognized as of the beginning of the first quarter (i.e. the quarter in which the transfer occurred).

As of September 30, 2010, PSEG carried $1.7 billion of net assets that are measured at fair value on a recurring basis, of which $197 million were measured using unobservable inputs and classified as Level 3 within the fair value hierarchy. These Level 3 net assets represent less than 1% of PSEG s total assets and there were no transfers among levels during the three months and nine months ended September 30, 2010.

Non-recurring Fair Value Measurements

In accordance with accounting guidance, management evaluates long-lived assets for impairment whenever events or changes in circumstances, such as significant adverse changes in regulation, business climate or market conditions, could potentially indicate an asset s carrying amount may not be recoverable. There were no material impairments recorded during 2011.

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, 2011 and December 31, 2010.

	September 30, 2011		December 31, 2010	
	Carrying Amount	Fair Value (A)	Carrying Amount	Fair Value (A)
	Millions			
Long-Term Debt:				
PSEG (Parent)	$ 40	$ 66	$ 10	$ 39
Power -Recourse Debt	3,350	3,710	3,455	3,831
PSE&G	4,535	5,099	4,283	4,615
Transition Funding (PSE&G)	948	1,080	1,090	1,245
Transition Funding II (PSE&G)	50	54	55	59
Energy Holdings:				
Project Level, Non-Recourse Debt	46	46	47	47

Total Long-Term Debt	$ 8,969	$ 10,055	$ 8,940	$ 9,836

(A) Fair value excludes unamortized discounts, including amounts related to the Debt Exchange between Power and Energy Holdings that is deferred at the PSEG parent level since the exchange was between subsidiaries of the same parent company.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

Note 12. Other Income and Deductions

Other Income	Power	PSE&G	Other (A)	Consolidated Total
			Millions	
Three Months Ended September 30, 2011				
NDT Fund Gains, Interest, Dividend and Other Income	$ 36	$ 0	$ 0	$ 36
Other	1	7	1	9
Total Other Income	**$ 37**	**$ 7**	**$ 1**	**$ 45**
Three Months Ended September 30, 2010				
NDT Fund Gains, Interest, Dividend and Other Income	$ 35	$ 0	$ 0	$ 35
Realized Gains from Rabbi Trust	7	11	13	31
Other	2	3	4	9
Total Other Income	**$ 44**	**$ 14**	**$ 17**	**$ 75**
Nine Months Ended September 30, 2011				
NDT Fund Gains, Interest, Dividend and Other Income	$ 153	$ 0	$ 0	$ 153
Other	3	16	4	23
Total Other Income	**$ 156**	**$ 16**	**$ 4**	**$ 176**
Nine Months Ended September 30, 2010				
NDT Fund Gains, Interest, Dividend and Other Income	$ 115	$ 0	$ 0	$ 115
Realized Gains from Rabbi Trust	7	11	13	31
Other	4	11	4	19
Total Other Income	**$ 126**	**$ 22**	**$ 17**	**$ 165**

Other Deductions	Power	PSE&G	Other (A)	Consolidated Total
			Millions	
Three Months Ended September 30, 2011				
NDT Fund Realized Losses and Expenses	$ 10	$ 0	$ 0	$ 10
Other	0	1	0	1
Total Other Deductions	**$ 10**	**$ 1**	**$ 0**	**$ 11**
Three Months Ended September 30, 2010				
NDT Fund Realized Losses and Expenses	$ 9	$ 0	$ 0	$ 9

Other	0	1	(1)	0
Total Other Deductions	**$ 9**	**$ 1**	**$ (1)**	**$ 9**
Nine Months Ended September 30, 2011				
NDT Fund Realized Losses and Expenses	$ 32	$ 0	$ 0	$ 32
Other	5	2	0	7
Total Other Deductions	**$ 37**	**$ 2**	**$ 0**	**$ 39**
Nine Months Ended September 30, 2010				
NDT Fund Realized Losses and Expenses	$ 35	$ 0	$ 0	$ 35
Other	1	2	(1)	2
Total Other Deductions	**$ 36**	**$ 2**	**$ (1)**	**$ 37**

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

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

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, 2011 and 2010 were as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2011	2010	2011	2010
PSEG	43.1%	40.4%	42.0%	40.3%
Power	40.7%	39.6%	41.0%	40.3%
PSE&G	40.1%	39.5%	40.5%	38.4%

For the three months ended September 30, 2011, the increase in PSEG s effective tax rate was due primarily to Energy Holdings 2011 charge against earnings applicable to the Dynegy leases. (See Note 5. Financing Receivables) and a lower manufacturer s deduction under the American Job Creation Act of 2004 as compared to the same period in 2010. There was no material change in the effective tax rate for Power and PSE&G.

For the nine months ended September 30, 2011, the increase in PSEG s effective tax rate was due primarily to Energy Holdings 2011 charge against earnings applicable to the Dynegy leases and a lower manufacturer s deduction as compared to the same period in 2010. PSE&G s effective tax rate was lower in 2010, primarily due to tax benefits from uncollectible accounts and plant-related adjustments. There was no material change in the effective tax rate for Power.

The Patient Protection and Affordable Care Act and the Health Care and Education Reconciliation Act of 2010 include various health care-related provisions which will go into effect over the next several years. One of the provisions eliminates the tax deductibility of retiree health care costs, to the extent of federal subsidies received by plan sponsors that provide retiree prescription drug benefits equivalent to Medicare Part D coverage. As a result, in the first quarter of 2010, PSEG recorded noncash after-tax charges of $9 million for income tax expense to establish the related deferred tax liabilities, primarily related to Power. There was no immediate impact on PSE&G s income tax expense or effective tax rate since the related amount of $78 million was deferred as a Regulatory Asset to be collected and amortized over future periods.

Two other tax provisions enacted during 2010 will have a significant impact on PSEG s cash position. The Small Business Jobs Act of 2010, enacted in September 2010, extended the tax deduction for 50% bonus depreciation through 2010 for qualified property. The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010, enacted in December 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 will be eligible for 50% bonus depreciation for tax purposes. These provisions will generate cash for PSEG through tax benefits related to the accelerated depreciation, most of which is anticipated to be realized in 2011. Also, for the third quarter of 2011, Power and PSE&G completed an analysis of industry specific tax accounting method changes resulting in current tax benefits. These tax benefits would have otherwise been received over the longer lives of the related depreciable property.

PSE&G has accrued $32 million of Investment Tax Credits (ITC) associated with alternative energy projects in the first nine months of 2011. Because the law provides an option to claim either a grant or the ITC, the ITC has been accounted for as a reduction of the book basis of the related assets as opposed to being recorded in tax expense.

PSEG s unrecognized tax benefits increased by approximately $53 million in the first nine months of 2011, attributable to PSE&G. This increase is due to a position raised by the IRS during its examination of the tax years 2004 to 2006 and a position taken for tax years 2004 to 2011 related to casualty loss deductions. Since December 31, 2010, the balance of unrecognized tax benefits that are reasonably likely to increase or decrease within the next 12 months changed by $19 million related to the positions discussed above.

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PSEG made tax deposits with the IRS to defray interest costs associated with disputed tax assessments associated with certain lease investments. The deposits are fully refundable and are recorded as a reduction to Current Accrued Taxes on PSEG s Condensed Consolidated Balance Sheets, but are not reflected in the unrecognized tax benefits.

As a result of a change in accounting method for the capitalization of indirect costs, PSEG reduced the net amount of its uncertain tax positions (including interest) by $97 million, approximately $43 million of which related to PSE&G. It is reasonably possible that PSE&G s claim related to this matter will be settled with the IRS in the next 12 months, resulting in an increase in the uncertain tax positions.

It is reasonably possible that unrecognized tax benefits associated with the leasing tax issue discussed in Note 8. Commitments and Contingent Liabilities, will change significantly. This change could be triggered by a settlement with the IRS or developments in other litigated cases. Based upon these developments, unrecognized tax benefits could increase by as much as $205 million or decrease by as much as $297 million. It is not possible to predict the magnitude, timing or direction of any such change.

Note 14. Comprehensive Income, Net of Tax

Comprehensive Income	**Power**	**PSE&G**	**Other (A)**	**Consolidated**
			Millions	
Three Months Ended September 30, 2011				
Net Income	$ 302	$ 154	$ (162)	$ 294
Other Comprehensive Income (Loss)	(80)	1	2	(77)
Comprehensive Income	**$ 222**	**$ 155**	**$ (160)**	**$ 217**
Three Months Ended September 30, 2010				
Net Income	$ 384	$ 155	$ 28	$ 567
Other Comprehensive Income (Loss)	38	(6)	(4)	28
Comprehensive Income	**$ 422**	**$ 149**	**$ 24**	**$ 595**
Nine Months Ended September 30, 2011				
Net Income	$ 871	$ 422	$ (150)	$ 1,143
Other Comprehensive Income (Loss)	(112)	2	10	(100)
Comprehensive Income	**$ 759**	**$ 424**	**$ (140)**	**$ 1,043**
Nine Months Ended September 30, 2010				
Net Income	$ 952	$ 276	$ 54	$ 1,282
Other Comprehensive Income (Loss)	13	(5)	(3)	5
Comprehensive Income	**$ 965**	**$ 271**	**$ 51**	**$ 1,287**

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

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(UNAUDITED)

Accumulated Other Comprehensive Income (Loss)

	Accumulated Other Comprehensive Income (Loss) Balance as of December 31, 2010	Other Comprehensive Income (Loss) for the Nine Months Ended September 30, 2011			Accumulated Other Comprehensive Income (Loss) Balance as of September 30, 2011
		Power (A)	PSE&G (B)	Other (C)	
			Millions		
Derivative Contracts	$ 111	$ (80)	$ 0	$ 0	$ 31
Pension and OPEB Plans	(377)	45	0	8	(324)
NDT Funds	109	(77)	0	0	32
Other	1	0	2	2	5
Accumulated Other Comprehensive Income (Loss)	**$ (156)**	**$ (112)**	**$ 2**	**10**	**$ (256)**

	Accumulated Other Comprehensive Income (Loss) Balance as of December 31, 2009	Other Comprehensive Income (Loss) for the Nine Months Ended September 30, 2010			Accumulated Other Comprehensive Income (Loss) Balance as of September 30, 2010
		Power (A)	PSE&G (B)	Other (C)	
			Millions		
Derivative Contracts	$ 180	$ (2)	$ 0	$ 0	$ 178
Pension and OPEB Plans	(400)	18	0	1	(381)
NDT Funds	91	0	0	0	91
Other	13	(3)	(5)	(4)	1
Accumulated Other Comprehensive Income (Loss)	**$ (116)**	**$ 13**	**$ (5)**	**$ (3)**	**$ (111)**

(A)

Net of tax related to Derivative Contracts, Pension and OPEB Plans and NDT Funds/Other of $54 million, $(31) million and $78 million, respectively for the nine months ended September 30, 2011. Net of tax related to Derivative Contracts, Pension and OPEB Plans and NDT Funds/Other of $1 million, $(12) million and $1 million, respectively for the nine months ended September 30, 2010.

(B) Net of tax of $(1) million for the nine months ended September 30, 2011 and $3 million for the nine months ended September 30, 2010.

(C) Net of tax of $(7) million for the nine months ended September 30, 2011 and $2 million for the nine months ended September 30, 2010.

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Note 15. Earnings Per Share (EPS)

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 our 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,			
	2011		2010		2011		2010	
	Basic	Diluted	Basic	Diluted	Basic	Diluted	Basic	Diluted
EPS Numerator (Millions)								
Continuing Operations	$ 265	$ 265	$ 547	$ 547	$ 1,047	$ 1,047	$ 1,267	$ 1,267
Discontinued Operations	29	29	20	20	96	96	15	15
Net Income	**$ 294**	**$ 294**	**$ 567**	**$ 567**	**$ 1,143**	**$ 1,143**	**$ 1,282**	**$ 1,282**
EPS Denominator (Thousands)								
Weighted Average Common Shares Outstanding	505,909	505,909	505,945	505,945	505,959	505,959	506,001	506,001
Effect of Stock Options	0	193	0	165	0	172	0	148
Effect of Stock Performance Share Units	0	599	0	662	0	607	0	785
Effect of Restricted Stock Units	0	298	0	196	0	225	0	134
Total Shares	**505,909**	**506,999**	**505,945**	**506,968**	**505,959**	**506,963**	**506,001**	**507,068**
EPS:								
Continuing Operations	$ 0.52	$ 0.52	$ 1.08	$ 1.08	$ 2.07	$ 2.06	$ 2.50	$ 2.50
Discontinued Operations	0.06	0.06	0.04	0.04	0.19	0.19	0.03	0.03
Net Income	**$ 0.58**	**$ 0.58**	**$ 1.12**	**$ 1.12**	**$ 2.26**	**$ 2.25**	**$ 2.53**	**$ 2.53**

	Three Months Ended September 30,		Nine Months Ended September 30,	
Dividend Payments on Common Stock	**2011**	**2010**	**2011**	**2010**
Per Share	$ 0.3425	$ 0.3425	$ 1.0275	$ 1.0275
in Millions	$ 173	$ 173	$ 520	$ 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, 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	0	0	0	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
Three Months Ended September 30, 2010					
Total Operating Revenues	$ 1,523	$ 2,007	$ 58	$ (474)	$ 3,114
Income (Loss) From Continuing Operations	364	155	24	4	547
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax	20	0	0	0	20
Net Income (Loss)	384	155	24	4	567
Segment Earnings (Loss)	384	155	24	4	567
Gross Additions to Long-Lived Assets	251	341	12	2	606
Nine Month 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	0	0	0	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
Nine Months Ended September 30, 2010					
Total Operating Revenues	$ 4,983	$ 5,987	$ 114	$ (2,036)	$ 9,048
Income (Loss) From Continuing Operations	937	276	43	11	1,267
Income (Loss) from Discontinued Operations, including Gain on Disposal, net of tax	15	0	0	0	15
Net Income (Loss)	952	276	43	11	1,282
Preferred Securities Dividends	0	(1)	0	1	0
Segment Earnings (Loss)	952	275	43	12	1,282
Gross Additions to Long-Lived Assets	579	871	61	6	1,517
As of September 30, 2011					
Total Assets	$ 11,484	$ 17,235	$ 1,959	$ (767)	$ 29,911
Investments in Equity Method Subsidiaries	$ 30	$ 0	$ 113	$ 0	$ 143
As of December 31, 2010					
Total Assets	$ 11,452	$ 16,873	$ 2,234	$ (650)	$ 29,909
Investments in Equity Method Subsidiaries	$ 25	$ 0	$ 105	$ 0	$ 130

(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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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

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, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
	Millions			
Revenue from Affiliates:				
Billings to PSE&G through BGSS (A)	$ 91	$ 118	$ 958	$ 1,102
Billings to PSE&G through BGS (A)	272	345	734	904
Total Revenue from Affiliates	**$ 363**	**$ 463**	**$ 1,692**	**$ 2,006**
Expense Billings from Affiliates:				
Administrative Billings from Services (B)	$ (37)	$ (34)	$ (109)	$ (106)
Total Expense Billings from Affiliates	**$ (37)**	**$ (34)**	**$ (109)**	**$ (106)**

Related Party Transactions	As of September 30, 2011	As of December 31, 2010
	Millions	
Receivables from PSE&G through BGS and BGSS Contracts (A)	$ 110	$ 372
Receivables from PSE&G Related to Gas Supply Hedges for BGSS (A)	64	58
Payable to Services (B)	(23)	(26)
Tax Sharing Receivable from (Payable to) PSEG (C)	(18)	380
Current Unrecognized Tax Receivable from (Payable to) PSEG (C)	(5)	1
Payable to PSEG	(1)	(3)
Accounts Receivable Affiliated Companies, net	**$ 127**	**$ 782**
Short-Term Loan to Affiliate (Demand Note to PSEG) (D)	**$ 1,574**	**$ 398**
Working Capital Advances to Services (E)	**$ 17**	**$ 17**
Long-Term Accrued Taxes Receivable (C)	**$ 19**	**$ 16**

PSE&G

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

Related Party Transactions	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
		Millions		
Expense Billings from Affiliates:				
Billings from Power through BGSS (A)	$ (91)	$ (118)	$ (958)	$ (1,102)
Billings from Power through BGS (A)	(272)	(345)	(734)	(904)
Administrative Billings from Services (B)	(53)	(47)	(154)	(151)
Total Expense Billings from Affiliates	**$ (416)**	**$ (510)**	**$ (1,846)**	**$ (2,157)**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

Related Party Transactions	As of September 30, 2011	As of December 31, 2010
	Millions	
Payable to Power through BGS and BGSS (A)	$ (110)	$ (372)
Payable to Power Related to Gas Supply Hedges for BGSS (A)	(64)	(58)
Payable to Power for SREC Liability (F)	(7)	(7)
Payable to Services (B)	(42)	(48)
Tax Sharing Receivable from PSEG (C)	467	321
Current Unrecognized Tax Receivable from PSEG (C)	59	73
Receivable from PSEG	1	6
Accounts Receivable (Payable) Affiliated Companies, net	**$ 304**	**$ (85)**
Working Capital Advances to Services (E)	**$ 33**	**$ 33**
Long-Term Accrued Taxes Payable (C)	**$ (54)**	**$ (74)**

(A) PSE&G has entered into a requirements contract with Power under which Power provides the gas supply services needed to meet PSE&G s BGSS and other contractual requirements through March 31, 2012 and year-to-year thereafter. 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. PSE&G, along with other New Jersey utilities and Power participated at the hearing and filed comments. The BPU has not yet issued a decision. PSE&G has estimated and accrued a total liability for the excess SREC cost of $17 million as of September 30, 2011 and December 31, 2010, including approximately $7 million for Power s share which is included in PSE&G s Accounts Payable Affiliated Companies as of December 31, 2010. Under current guidance, Power is 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, 2011 and December 31, 2010.

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

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 PSEG Energy Resources & Trade LLC (ER&T). The following table presents condensed financial information for the guarantor subsidiaries, as well as Power s non-guarantor subsidiaries.

		Guarantor	Other	Consolidating	
	Power	Subsidiaries	Subsidiaries	Adjustments	Consolidated
			Millions		
Three Months Ended September 30, 2011					
Operating Revenues	$ 0	$ 1,725	$ 29	$ (356)	$ 1,398
Operating Expenses	1	1,241	29	(356)	915
Operating Income (Loss)	(1)	484	0	0	483
Equity Earnings (Losses) of Subsidiaries	315	29	0	(344)	0
Other Income	9	38	0	(10)	37
Other Deductions	(1)	(8)	0	(1)	(10)
Other-Than-Temporary Impairments	1	(9)	0	0	(8)
Interest Expense	(33)	(17)	(3)	11	(42)
Income Tax Benefit (Expense)	12	(200)	1	0	(187)
Income (Loss) from Discontinued Operations, net of tax	0	0	29	0	29
Net Income (Loss)	**$ 302**	**$ 317**	**27**	**$ (344)**	**$ 302**
Three Months Ended September 30, 2010					
Operating Revenues	$ 0	$ 1,817	$ 30	$ (324)	$ 1,523
Operating Expenses	0	1,207	34	(325)	916
Operating Income (Loss)	0	610	(4)	1	607
Equity Earnings (Losses) of Subsidiaries	378	14	0	(392)	0
Other Income	18	39	1	(14)	44
Other Deductions	0	(9)	0	0	(9)
Other-Than-Temporary Impairments	0	(2)	0	0	(2)
Interest Expense	(26)	(19)	(5)	13	(37)
Income Tax Benefit (Expense)	14	(255)	2	0	(239)
Income (Loss) from Discontinued Operations, net of tax	0	0	20	0	20
Net Income (Loss)	**$ 384**	**$ 378**	**$ 14**	**$ (392)**	**$ 384**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
Nine Months Ended September 30, 2011					
Operating Revenues	$ 0	$ 5,622	$ 106	$ (1,078)	$ 4,650
Operating Expenses	2	4,278	109	(1,078)	3,311
Operating Income (Loss)	(2)	1,344	(3)	0	1,339
Equity Earnings (Losses) of Subsidiaries	917	88	0	(1,005)	0
Other Income	28	159	0	(31)	156
Other Deductions	(4)	(32)	0	(1)	(37)
Other-Than-Temporary Impairments	0	(10)	0	0	(10)
Interest Expense	(115)	(38)	(13)	32	(134)
Income Tax Benefit (Expense)	47	(592)	6	0	(539)
Income (Loss) from Discontinued Operations, net of tax	0	0	96	0	96
Net Income (Loss)	**$ 871**	**$ 919**	**$ 86**	**$ (1,005)**	**$ 871**
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)**
Nine Months Ended September 30, 2010					
Operating Revenues	$ 0	$ 5,853	$ 95	$ (965)	$ 4,983
Operating Expenses	0	4,236	107	(966)	3,377
Operating Income (Loss)	0	1,617	(12)	1	1,606
Equity Earnings (Losses) of Subsidiaries	968	(4)	0	(964)	0
Other Income	36	124	1	(35)	126
Other Deductions	(1)	(35)	0	0	(36)
Other-Than-Temporary Impairments	0	(8)	0	0	(8)
Interest Expense	(91)	(45)	(17)	34	(119)
Income Tax Benefit (Expense)	40	(681)	9	0	(632)
Income (Loss) from Discontinued Operations, net of tax	0	0	15	0	15
Net Income (Loss)	**$ 952**	**$ 968**	**$ (4)**	**$ (964)**	**$ 952**
Nine Months Ended September 30, 2010					
Net Cash Provided By (Used In) Operating Activities	**$ 239**	**$ 1,979**	**$ (3)**	**$ (959)**	**$ 1,256**
Net Cash Provided By (Used In) Investing Activities	**$ (18)**	**$ (1,522)**	**$ 0**	**$ 661**	**$ (879)**
Net Cash Provided By (Used In) Financing Activities	**$ (216)**	**$ (453)**	**$ (43)**	**$ 297**	**$ (415)**

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NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(UNAUDITED)

	Power	Guarantor Subsidiaries	Other Subsidiaries	Consolidating Adjustments	Consolidated
			Millions		
As of September 30, 2011					
Current Assets	$ 4,746	$ 7,343	$ 909	$ (9,701)	$ 3,297
Property, Plant and Equipment, net	58	5,576	932	0	6,566
Investment in Subsidiaries	4,194	800	0	(4,994)	0
Noncurrent Assets	157	1,496	47	(79)	1,621
Total Assets	**$ 9,155**	**$ 15,215**	**$ 1,888**	**$ (14,774)**	**$ 11,484**
Current Liabilities	$ 828	$ 9,534	$ 944	$ (9,700)	$ 1,606
Noncurrent Liabilities	250	1,488	143	(80)	1,801
Long-Term Debt	2,640	0	0	0	2,640
Member s Equity	5,437	4,193	801	(4,994)	5,437
Total Liabilities and Member s Equity	**$ 9,155**	**$ 15,215**	**$ 1,888**	**$ (14,774)**	**$ 11,484**
As of December 31, 2010					
Current Assets	$ 3,988	$ 6,807	$ 1,117	$ (8,468)	$ 3,444
Property, Plant and Equipment, net	55	5,385	902	0	6,342
Investment in Subsidiaries	4,794	1,079	0	(5,873)	0
Noncurrent Assets	170	1,549	41	(94)	1,666
Total Assets	**$ 9,007**	**$ 14,820**	**$ 2,060**	**$ (14,435)**	**$ 11,452**
Current Liabilities	$ 751	$ 8,519	$ 849	$ (8,468)	$ 1,651
Noncurrent Liabilities	423	1,510	129	(93)	1,969
Long-Term Debt	2,805	0	0	0	2,805
Member s Equity	5,028	4,791	1,082	(5,874)	5,027
Total Liabilities and Member s Equity	**$ 9,007**	**$ 14,820**	**$ 2,060**	**$ (14,435)**	**$ 11,452**

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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 discussion in Part I, Item 1. Business of our 2010 Annual Report on 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. Our risk factors section in Part II Item 1A 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 2010 and Future Outlook provided in Item 7 in our Form 10-K by describing significant events and business developments that have occurred during 2011 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 information should be read in conjunction with such Statements, Notes and the 2010 Annual Report on Form 10-K.

OVERVIEW OF 2011 AND FUTURE OUTLOOK

During the first nine months of 2011, our results continued to be adversely impacted by lower prices for end users of electricity and natural gas in the markets we serve. We began experiencing a greater pricing impact due to a decline in both PJM Reliability Pricing Model (RPM) and Basic Generation Service (BGS) rates which became effective in the second quarter. Our pricing also continues to be impacted by customer migration away from our BGS supply contracts as these volumes are replaced with lower priced spot market sales. However, the impact of customer migration on our results has been reduced as average BGS rates have been declining to a level more closely resembling current market prices so that customers also have less incentive to switch to third party suppliers.

Partially offsetting this lower commodity pricing are higher revenues due to increased distribution rates at PSE&G as a result of the base rate case settlement in mid-2010. This included an increase of $73.5 million and $26.5 million in annual electric and gas revenues, respectively, with a return on equity (ROE) of 10.3%. We have also realized an increase in transmission revenues as a result of our 2011 Formula Rate Update which provides for approximately $45 million in increased revenues in our 2011 transmission rates effective January 1, 2011. We filed our 2012 Annual Formula Rate Update with FERC in October 2011, which would provide for approximately $94 million in increased annual transmission revenues effective January 1, 2012.

In addition, our gas sales volumes improved for the first nine months of 2011 compared to the same period in 2010, due primarily to much warmer winter weather last year. Heating degree days, as a measure of winter weather in 2011, were 9% higher than in 2010. The weather, the economy and other factors all contributed to an overall increase of approximately 4% in Power s Basic Gas Supply Service (BGSS) sales volumes and PSE&G s gas delivery volumes as compared to 2010.

Since January 2010, typical PSE&G residential customers who purchased their electric and gas supply from PSE&G have seen a reduction in both their electric and gas bills. The average residential customer has

experienced a savings of 4% in electric supply costs and 17% in gas supply costs. Including changes for delivery charges, the average residential customer would have realized a net annual decrease of 2% for electric and 15% for gas.

For 2011 and beyond, the key issues our business will confront are:

- potential for sustained lower natural gas and electricity prices,
- uncertainty in the economic recovery,
- regulatory and political uncertainty, particularly with regard to future energy policy, legislative initiatives and environmental regulation, and
- pressure on competitive markets in many states, particularly in New Jersey.

In addition, recent conditions in the financial markets could have an adverse impact on the year end funded status of our pension obligation. This could result in increased pension expenses in 2012.

Our future success will also 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:

- focus on controlling costs while maintaining our safety, reliability and compliance standards,
- successfully recontract Power s open positions, and
- execute our capital investment program, including investments for growth that would yield contemporaneous and attractive risk adjusted returns.

There have also been other 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 Part II, Item 5. Other Information.

- In an attempt to stimulate the development of new generation capacity in New Jersey through a subsidized rate mechanism, in January 2011, New Jersey enacted the long-term capacity agreement pilot program Act (LCAPP) directing the New Jersey Board of Public Utilities (BPU) to conduct a process to procure and subsidize up to 2,000 MW of baseload or mid-merit electric power generation. This could result in artificially depressed pricing in the competitive wholesale market and thus has the potential to harm competitive markets, on both a short-term and a long-term basis. In March 2011, the BPU issued a written order approving a form of agreement and selecting three generators to build a total of 1,949 MW of new combined-cycle generating facilities located in New Jersey. Power and PSE&G appealed this order. Each of the New Jersey electric distribution companies (EDCs), including PSE&G, executed standard offer capacity agreements (SOCA) with the three generators in compliance with the BPU s directive, but did so under protest, reserving its respective legal rights. The SOCA provides for each New Jersey EDC to make capacity payments to, or receive capacity payments from, the generators as calculated based on the difference between the RPM clearing price for each year of the term and the price bid and accepted for that generator in the BPU process. 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 a subsidized payment.

In April 2011, the Federal Energy Regulatory Commission (FERC) issued an order making effective changes to the PJM Tariff that would require new generation to clear in the RPM at competitive prices i.e. applying a Minimum Offer Price Rule (MOPR) which would mitigate but not eliminate the impacts of the subsidized SOCA pricing upon RPM auction prices. This order has been challenged on rehearing. In addition, FERC convened a technical conference in July 2011 to consider whether resources that engage in self-supply should be exempt from such requirements. PJM has taken the position that it should be given more discretion to evaluate bids impacted by the MOPR and determine whether a bidder s costs are legitimately below the MOPR level. In May 2011, the BPU initiated a proceeding to evaluate whether there is a need for additional generation capacity in the state. In October 2011, one of the three selected generators disputed the FERC order regarding the MOPR.

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The BPU held a second legislative-type hearing in October 2011 to take further comments on the possible impediments to the development of new generation capacity in New Jersey as well as other matters concerning the PJM Interconnection L.L.C. (PJM) Regional Transmission Expansion Planning (RTEP), the PJM interconnection processes and the competitiveness of the power market. Both PSE&G and Power participated in this proceeding, which calls for recommendations to be made to the BPU by the end of 2011. Another of the three selected generators has made a filing with the FERC challenging PJM s interconnection process and claiming, among other things, that interconnection costs are a significant barrier to entry into New Jersey.

In the pending United States District Court challenge to the constitutionality of the LCAPP Act, in October 2011 the Court issued a decision denying the State s motion to dismiss the complaint. In the state appellate litigation in which both Power (along with other generators) and PSE&G (along with the other EDCs) appealed the BPU s order approving the SOCA contracts, the court recently denied the New Jersey Division of Rate Counsel s motion to dismiss the EDCs appeal, while also denying a motion to consolidate both the Power and EDC appeals.

See Item 5. Other Information, Federal Regulation, FERC Capacity Market Issues for further information.

In September 2011, the Maryland Public Utility Commission issued an order requiring its EDCs to issue a Request for Proposal (RFP) by October 7, 2011 to procure up to 1,500 MW of new natural gas-fired generation located in the Southwest MAAC electrical region. Maryland also announced that it would hold hearings in January to evaluate the need for this procurement. The RFP would require up to a 20-year contract, with ratepayers paying the generator an amount that makes up the difference between the PJM price and the contract price (similar to the LCAPP SOCA). These developments in Maryland may influence developments in New Jersey regarding the construction of subsidized generation.

The United States Environmental Protection Agency (EPA) published a proposed rule in April 2011 related to 316(b) Clean Water Act requirements. The proposed rule would establish a separate marine life entrainment mortality standard as well as new impingement mortality standards for certain existing cooling water intake structures. 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. We are unable to predict the outcome of this proposed rulemaking, the final form that the proposed regulations may take or the effect, if any, that they may have on our future capital requirements, financial condition or results of operations which could be material. If the rule were to be adopted as proposed, the impact would be material since the majority of our electric generating facilities would be affected.

On July 6, 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR). CSAPR limits power plant emissions in 27 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone emission standards. Emission reductions will be governed by this rule beginning on January 1, 2012 for SO_2 and annual NOx and May 1, 2012 for Ozone season NOx . Certain states will be required to make additional SO_2 reductions in 2014.

On October 14, 2011, the EPA issued draft technical adjustments to the final CSAPR. Among the technical corrections proposed were adjustments to the annual NO_X, ozone season NO_X, and SO_2 emissions budgets for a number of states, including New Jersey and New York. Several of our plants in New Jersey had their emission allocations increased. Additionally, the EPA also proposed to delay the implementation of the assurance provision of the rule from 2012 to 2014 to promote the development of a liquid allowance market. These proposed changes will be open for public comment until November 28, 2011. The EPA will make a final determination shortly thereafter. We view the changes as proposed by the EPA as generally favorable.

We continue to evaluate the impact of this rule on us due to many of the uncertainties that still exist regarding implementation. As we have made major capital investments over the past several years to lower the SO_2 and NO_X emissions of our fossil plants in the states affected by CSAPR (New Jersey,

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New York and Pennsylvania), we believe we are competitively positioned as we do not foresee the need to make significant additional expenditures to our generation fleet to comply with the regulation. As such, we believe this rule will not have a material impact to our capital investment program or units operations.

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 may result in additional regulation for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants meet the stringent applicable design and safety specifications of the NRC.

In July 2011, the NRC task force submitted a report on the first 90 days of its nuclear power plant review. The report contained various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. These recommendations include proposed requirements for upgraded seismic and flooding protection, strengthening plants ability to deal with prolonged loss of power and development of emergency plans for events involving multiple reactors. In October 2011, the NRC issued a document which provides for a prioritization of the task force recommendations. The NRC is proposing to issue letters and orders to licensees and create new regulations over a six-to-52 month period to address the task force recommendations.

Separately, a petition was filed with the NRC in April 2011 seeking suspension of the operating licenses of all General Electric boiling water reactors utilizing the Mark 1 containment design in the United States, including our Hope Creek and Peach Bottom units, pending completion of the NRC review. The petition names 23 of the total 104 active commercial nuclear reactors in the United States. While we do not believe the petition will be successful, we are unable to predict the outcome of any action that the NRC may take in connection with its operational and safety reviews or any other regulatory or industry responses to the events in Japan.

We received our requested 20-year license extensions for the Salem and Hope Creek facilities in June and July 2011, respectively. Salem Units 1 and 2 are now licensed through 2036 and 2040, respectively, and Hope Creek is now licensed through 2046.

During 2011, 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 Notices of Proposed Rulemakings (NOPRs) on many of the key issues. We cannot assess the exact scope of the new rules until they are issued by the SEC and CFTC. We currently expect the CFTC to finalize certain criteria under these rules, such as providing the definition of a swap dealer, establishing requirements for qualifying as an end user and determining any additional reporting requirements, by the end of 2011. We will carefully monitor these new rules as they are developed to analyze the potential impact on our swap and derivatives transactions, including any potential increase in our collateral requirements.

In June, the BPU issued a new draft Energy Master Plan (EMP). Our initial assessment is that if the EMP were finalized with the same provisions as drafted, it is generally favorable to our utility business direction, supportive of solar, nuclear power and off-shore wind development, but represents a serious threat to the PJM competitive electric wholesale market in that as a matter of policy it directs the BPU to subsidize new natural gas fired combined cycle generation in an effort to suppress wholesale market prices. The final EMP is expected to be issued later this year, following BPU hearings, in which we intend to participate.

On July 21, 2011, the FERC issued a Final Rule 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 (i.e. creating a new category of public policy transmission projects in addition to reliability and economic projects), (ii) directs these regional planners to remove the Right of First Refusal (ROFR) which permits incumbent transmission owners such as PSE&G the first opportunity to construct transmission within their respective service territories from its tariffs and agreements, subject to certain exceptions, and (iii) requires regional planners to 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. Several parties, including PSEG, have sought rehearing of this Final Rule, which request remains pending. We cannot predict the final outcome or impact on us; however, specific implementation of the Final Rule in the various regions, including within PSE&G s service territory, may expose us to competition for construction of transmission, additional regulatory considerations and potential delay with respect to future transmission projects.

Operational Excellence

Our nuclear and fossil facilities continued their strong operating performance through the third quarter. Our nuclear units have achieved a capacity factor of 93% year to date and our combined cycle units have continued to improve their forced outage rates. Our generation fleet performed well during the July and August heat waves. During Hurricane Irene, the Salem and Hope Creek nuclear stations remained online. Overall, generation volumes for the first nine months of 2011 were 41.8 TWh, approximately 5% lower than in the same period in 2010 due primarily to reduced demands.

In addition, we continued to demonstrate our commitment to system reliability by limiting customer outages. In February 2011, our service territory experienced winter storms that impacted the electric transmission and distribution systems due to heavy icing and salt spray and in March 2011, our northern gas service territory was impacted by two heavy rainstorms that resulted in widespread flooding. Our personnel were prepared in each case for widespread outages and, as a result, were able to minimize the length of time our customers were without electric or gas service.

In August 2011, Hurricane Irene caused severe damage that resulted in flooding throughout our service territory, disrupting service to over 800,000 customers. With the assistance of mutual aid crews from other utilities, our associates worked to fully restore service to the majority of our customers within five days. On August 26, 2011 we filed a petition with the BPU asking permission to defer the incremental storm related costs and the opportunity to seek recovery in our next base rate proceeding. We have deferred approximately $29 million of incremental Operation and Maintenance (O&M) storm costs associated with Hurricane Irene.

Financial Strength

Our cash from operations has remained strong. During the first nine months of 2011, we made approximately $1.4 billion in capital expenditures, paid dividends of $520 million and made our entire planned pension contributions for the year 2011 of $415 million. Cash from operations for the year has and is expected to continue to benefit from two tax provisions enacted in 2010 which are expected to generate a total of approximately $800 million of cash benefits for us through accelerated depreciation, most of which is expected to be realized in 2011. See Note 13. Income Taxes for additional information. These funds, combined with proceeds from the sales of our Texas facilities, will be used to support our anticipated capital expenditures and dividend payments for the year.

In April 2011, PSEG, Power and PSE&G entered into new 5-year credit agreements resulting in an increase of $650 million in Power s total credit capacity and increasing our total credit capacity to $4.3 billion.

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.

During 2011, we reached agreements to sell our two 1,000 MW combined-cycle generating facilities in Texas in separate transactions for a total of $687 million. In March 2011, we completed the sale of one plant for $352 million. The sale of the second plant closed in July 2011 for $335 million. See Note 4. Discontinued Operations and Dispositions for further information.

We are continuing to pursue obtaining the necessary regulatory approvals for the Susquehanna-Roseland transmission project but have incurred delays in obtaining environmental approvals which have resulted in a delay to the project implementation date. The project, however, has just been placed on an initial list of projects for a new federal Rapid Response Team for Transmission. This team is focused on coordinating and expediting the federal permitting process for critical infrastructure upgrades. Although no assurances can be given, Susquehanna-Roseland s placement on this list may help in obtaining timely environmental approvals for the project, including from the National Park Service. The estimated cost of construction is up to $750 million for this project. Our project estimate will be refined when we obtain additional information from the National Park Service process regarding the selected project route and mitigation-related requirements as well as contractor bids.

In October 2010, PJM approved the North East Grid project, a 230 kV project running from Roseland to Hudson. This project has an expected in-service date of June 2015 with an estimated cost of construction of up to $895 million. We have also filed for BPU approval of the North-Central Reliability project, a 230 kV upgrade project located in the northern and central portions of New Jersey with an estimated cost of construction of approximately $336 million. The North-Central Reliability project has an expected in-service date of June 2014. Delays in the construction schedules of these projects could impact the timing of expected transmission revenues. The North East Grid project was approved in place of a previously approved 500 kV Branchburg-Roseland-Hudson (B-R-H) project. The FERC has ruled that, with the exception of abandonment cost recovery, rate incentives we previously received for the original B-R-H project were no longer applicable because the project had substantially changed. On October 31, 2011, we filed a petition with FERC seeking incentive rates for the North East Grid project, specifically, inclusion of 100% of Construction Work in Process (CWIP) in rate base, recovery of 100% of prudently incurred abandonment costs and a 100 basis point adder to ROE. We are seeking an effective date of January 1, 2012.

In April 2011, we filed a petition with FERC seeking incentive rates with an effective date of June 14, 2011 for five 230 kV transmission projects, including the North-Central Reliability project. In June 2011, FERC granted incentive rates for three of these 230 kV projects, with a total capital investment of approximately $1.0 billion, representing approximately 80% of our request. The incentive rates include recovery for CWIP and 100% recovery of prudently-incurred abandonment costs. See Item 5. Other Information, Federal Regulation, Transmission Regulation Transmission Expansion for further information.

Our utility has made additional investments in solar initiatives. Under our solar loan program we have provided a total of $104 million in loans for 396 projects as of September 30, 2011, representing 30 MW to date. Under our Solar 4 All program we have made total program expenditures of approximately $298 million as of September 30, 2011. Approximately 23 MW of solar panels have been installed on distribution poles and another 23 MW representing 15 projects have been placed into service. Additional projects are in various stages of negotiation and development. Our total anticipated expenditures to develop all approved 80 MW is approximately $453 million. The BPU is currently conducting a generic stakeholder proceeding, however, to examine whether utility rate-based solar programs should be modified, expanded or terminated in the future.

We made additional expenditures under our Capital Economic Stimulus and Energy Efficiency Economic Stimulus programs. As of September 30, 2011, total capital expenditures since inception of these projects were $702 million and $123 million, respectively. In July, the BPU approved extensions to both of these programs which provide for approximately $273 million in accelerated capital investments in our electric and gas infrastructure through 2012 and $95 million of additional capital expenditures for energy efficiency programs. In conjunction with the extension of the Capital Economic Stimulus programs, we agreed to additional electric and gas base spending of approximately $96 million during the program.

We continued various construction activities at Power, including a steam path retrofit and extended power uprate at Peach Bottom and construction of new gas fired peaking units at Kearny and in Connecticut (see Note 8. Commitments and Contingent Liabilities 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.

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.

Energy Holdings collateral related to the lease to two affiliates (the Dynegy lessees) of Dynegy Incorporated (Dynegy), includes a guarantee from Dynegy Holdings LLC (DH), a subsidiary of Dynegy. In early August 2011, Dynegy reorganized the legal entity structure for its generation assets. It transferred substantially all of its coal and natural gas-fired generation assets, other than the Dynegy lessees that lease the Roseton Station Units 1 and 2 and Danskammer Station Units 3 and 4, to new subsidiaries which Dynegy termed as bankruptcy remote . This resulted in a lowering of certain credit ratings of Dynegy and DH. Dynegy s credit is currently rated CC by S&P and Caa3 by Moody s.

In September 2011, Dynegy continued its corporate reorganization, transferring DH s interests in its newly formed coal generation subsidiary directly to the parent company, Dynegy, in exchange for an undertaking. It also launched an exchange offer for a substantial portion of DH s debt in exchange for Dynegy debt at various discounts. Dynegy has indicated that in the absence of a debt restructuring and/or refinancing, it may not have sufficient resources to pay its indebtedness under the lease. The consummation of these transactions triggered the filing of two separate lawsuits, one by a group of corporate unsecured bondholders of DH and a second on behalf of a majority of the holders of certain debt certificates related to the Dynegy lessee facilities; these lawsuits asserted fraudulent conveyance claims among several other causes of action. In addition to claims asserted against DH, one of the suits included claims against several members of DH s Board of Directors.

As a result of the above actions, Energy Holdings has evaluated its likely recovery under the lease arrangements for the Roseton and Danskammer facilities leased to subsidiaries of DH, considering the overall value of the underlying assets subject to lease, and has fully reserved its $264 million gross investment. This resulted in an after-tax charge of approximately $170 million. In the absence of a negotiated resolution of the disputes with Dynegy, Energy Holdings intends to assert claims against DH, its directors and various Dynegy affiliates relative to the reorganization activities which have diminished the value of assets available to satisfy DH s lease guarantee obligations. In addition, Energy Holdings has a tax indemnity agreement, which is designed to protect it from adverse tax consequences should the lease structure not be maintained. Energy Holdings intends to assert its claims under this agreement, notwithstanding any attempt by Dynegy in contravention of current case law to limit such claims in a bankruptcy proceeding of DH. In the event of a bankruptcy filing or the failure of DH to honor its obligations under the lease guarantee, it is possible that the lease certificate holders could foreclose on the underlying facilities in partial satisfaction of their indebtedness. Should this occur, Energy Holdings could be required to pay approximately $100 million to satisfy income tax obligations, an amount for which it would seek reimbursement from DH under the tax indemnity agreement. This potential cash tax obligation is fully reflected in the overall estimate of the aggregate after-tax charge.

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RESULTS OF OPERATIONS

The results for PSEG, PSE&G, Power and Energy Holdings for the three months and nine months ended September 30, 2011 and 2010 are presented below:

Earnings (Losses)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
		Millions		
Power	$ 273	$ 364	$ 775	$ 937
PSE&G	154	155	422	276
Energy Holdings	(166)	24	(164)	43
Other (A)	4	4	14	11
PSEG Income from Continuing Operations	265	547	1,047	1,267
PSEG Income (Loss) from Discontinued Operations (B)	29	20	96	15
PSEG Net Income	**$ 294**	**$ 567**	**$ 1,143**	**$ 1,282**

Earnings Per Share (Diluted)	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010
		Millions		
PSEG Income from Continuing Operations	**$ 0.52**	**$ 1.08**	**$ 2.06**	**$ 2.50**
Income (Loss) from Discontinued Operations	0.06	0.04	0.19	0.03
PSEG Net Income	**$ 0.58**	**$ 1.12**	**$ 2.25**	**$ 2.53**

(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) funds and other related NDT activity. This includes the net realized gains, interest and dividend income and other costs related to the NDT funds 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.

Our results also include the after-tax impacts of non-trading mark-to-market (MTM) activity.

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,

	2011	2010	2011	2010
		Millions, after tax		
NDT Fund Income	$ 7	$ 10	$ 49	$ 30
Non-Trading Mark-to-Market Gains	$ 8	$ 16	$ 16	$ 28

In addition to the changes in NDT and MTM, our $282 million decrease in Income from Continuing Operations for the three months ended September 30, 2011 was driven primarily by:

the after-tax charge related to the reserve for assets underlying our lease receivable from Dynegy,

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lower average pricing and volumes for electricity sold under our BGS contracts,

higher Operation and Maintenance expense related to planned outage work at certain of our fossil plants, and

higher depreciation expense related to the completion of installation of back-end technology at two of our fossil plants,

partially offset by higher transmission and distribution revenues.

Our $220 million decrease in Income from Continuing Operations for the nine months ended September 30, 2011 was driven primarily by the same items impacting our quarterly results and also reflected the absence of a $122 million charge in 2010 related to our agreement to refund previous Market Transition Charge (MTC) collections.

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) 2011 vs 2010		Nine Months Ended September 30,		Increase/ (Decrease) 2011 vs 2010	
	2011	2010			2011	2010		
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 2,620	$ 3,114	$ (494)	(16)	$ 8,443	$ 9,048	$ (605)	(7)
Energy Costs	1,167	1,261	(94)	(7)	3,740	4,021	(281)	(7)
Operation and Maintenance	603	591	12	2	1,829	1,862	(33)	(2)
Depreciation and Amortization	263	260	3	1	739	716	23	3
Income from Equity Method Investments	1	4	(3)	(75)	8	12	(4)	(33)
Other Income and (Deductions)	34	66	(32)	(48)	137	128	9	7
Other-Than-Temporary Impairments	8	3	5	NA	13	9	4	44
Interest Expense	117	120	(3)	(3)	361	356	5	1
Income Tax Expense	201	371	(170)	(46)	757	856	(99)	(12)
Income (Loss) from Discontinued Operations	29	20	9	45	96	15	81	NA

Power

	Three Months Ended September 30,		Increase/ (Decrease) 2011 vs 2010	Nine Months Ended September 30,		Increase/ (Decrease) 2011 vs 2010
	2011	2010		2011	2010	
			Millions			
Income from Continuing Operations	$ 273	$ 364	$ (91)	$ 775	$ 937	$ (162)
Income (Loss) from Discontinued Operations, net of tax	$ 29	$ 20	$ 9	$ 96	$ 15	$ 81
Net Income	$ 302	$ 384	$ (82)	$ 871	$ 952	$ (81)

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For the three months ended September 30, 2011 the primary reasons for the $91 million decrease in Income from Continuing Operations were

- lower average pricing and volumes for electricity sold under our BGS contracts,
- higher Operation and Maintenance expense related to planned outage work at certain of our fossil plants, and
- higher depreciation expense related to the completion of installation of back-end technology at two of our fossil plants.

For the nine months ended September 30, 2011 the primary reasons for the $162 million decrease in Income from Continuing Operations were

- lower average pricing and volumes for electricity sold under our BGS contracts,
- higher Operation and Maintenance expense related to refurbishments at certain of our fossil plants, and
- higher interest costs and depreciation expense related to the completion of installation of back-end technology at two of our fossil plants,
- partially offset by favorable amounts related to our NDT activity.

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

	Three Months Ended September 30,		Increase/ (Decrease) 2011 vs 2010		Nine Months Ended September 30,		Increase/ (Decrease) 2011 vs 2010	
	2011	2010			2011	2010		
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,398	$ 1,523	$ (125)	(8)	$ 4,650	$ 4,983	$ (333)	(7)
Energy Costs	597	620	(23)	(4)	2,335	2,483	(148)	(6)
Operation and Maintenance	262	253	9	4	810	764	46	6
Depreciation and Amortization	56	43	13	30	166	130	36	28
Other Income (Deductions)	27	35	(8)	(23)	119	90	29	32
Other-Than-Temporary Impairments	8	2	6	NA	10	8	2	25
Interest Expense	42	37	5	14	134	119	15	13
Income Tax Expense	187	239	(52)	(22)	539	632	(93)	(15)
Income (Loss) from Discontinued Operations	29	20	9	45	96	15	81	NA

For the three months ended September 30, 2011 as compared to 2010

Operating Revenues decreased $125 million due to

Generation Revenues decreased $122 million due primarily to

- a net decrease of $100 million due to lower average pricing and lower volumes sold under our BGS contracts as a result of customer migration in 2011,

- lower net revenues of $48 million due to lower generation volumes sold in the PJM, NY and New England (NE) power pools, partially offset by higher average prices realized in PJM, and

- a decrease of $28 million due to lower capacity payments primarily from PJM resulting from lower market prices,

- partially offset by an increase of $47 million from new wholesale load contracts in PJM and the NE regions commencing in January 2011 and April 2011, respectively, net of lower average realized prices in the NE region.

Gas Supply Revenues decreased $28 million due primarily to

- a net decrease of $23 million in sales under the BGSS contract, reflecting lower average gas sales prices and lower sales volumes due to economic conditions in 2011, and

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- a net decrease of $5 million due to lower sales volumes at higher average prices to third party customers.

Trading Revenues increased $25 million due primarily to lower net losses in 2011 on certain electric energy supply contracts as well as the discontinuation of trading activities in the second quarter of 2011.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel purchases 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 by $23 million primarily to

- **Gas costs** decreased $29 million principally related to Power s obligations under the BGSS contract, reflecting lower average gas inventory costs and lower demand due to economic conditions in 2011.

Operation and Maintenance increased $9 million due primarily to

- a $7 million net increase due largely to planned higher outage costs at our coal-fired Conemaugh facility in Pennsylvania, and our gas-fired Bergen facility in New Jersey as well as baghouse filter replacement costs and coal unloading repair costs at Mercer in 2011 partially offset by higher outage costs at Mercer and our Connecticut facilities in 2010, and

- an increase of $4 million in materials and contract labor for refurbishment projects in 2011 related to the cooling, circulation and transfer of water, as well as grassing repairs at our Salem nuclear facilities and to maintenance resulting from damage due to Hurricane Irene.

Depreciation and Amortization increased $13 million due primarily to

- a $9 million increase due to completion of installation of back-end technology at the end of 2010 at our Mercer and Hudson generating facilities, and

- a $3 million increase due to higher depreciable asset bases at Nuclear and Fossil.

Other Income and (Deductions) The net decrease of $8 million was due primarily to the absence of $7 million of gains realized in August 2010 from an asset restructuring of the Rabbi Trust and higher net realized losses in 2011 of $2 million on the NDT funds.

Other-Than-Temporary Impairments increased $6 million due to higher impairments on the NDT Funds recorded in 2011.

Interest Expense increased $5 million due primarily to

- Higher interest expense of $15 million resulting primarily from the installation by year-end 2010 of back-end technology at our Mercer and Hudson fossil stations for which we had been allowed to capitalize interest costs in 2010 while such projects were under construction,

- partially offset by lower interest expense of $11 million due to the redemption of $606 million of 7.75% Senior Notes in early April 2011.

Income Tax Expense decreased $52 million in 2011 due primarily to lower pre-tax income.

Income (Loss) from Discontinued Operations

In January 2011, we reached agreement to sell 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 at an after-tax gain of $54 million. In July 2011, we completed the sale of the second plant for proceeds of $335 million at an after-tax gain of $25 million. The results of operations for both plants for the three months ended September 30, 2011 and 2010, including the gain in 2011 on the sale of the second plant, are included in this category. See Note 4. Discontinued Operations and Dispositions for additional information.

For the nine months ended September 30, 2011 as compared to 2010

Operating Revenues decreased $333 million due to

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Generation Revenues decreased $232 million due primarily to

- a net decrease of $239 million due primarily to lower average pricing and lower volumes of electricity sold under our BGS contracts as a result of customer migration,
- lower net revenues of $84 million due to lower average realized prices in the PJM and NY power pools and lower volumes sold into the various power pools as a result of lower generation, and
- a decrease of $33 million due to lower capacity payments from the various power pools resulting from lower market prices,
- partially offset by an increase of $128 million from new wholesale load contracts in PJM and the NE regions commencing in January 2011 and April 2011, respectively, net of lower average realized prices in the NE region.

Gas Supply Revenues decreased $114 million due primarily to

- a net decrease of $128 million in sales under the BGSS contract, substantially comprised of lower average gas sales prices partially mitigated by increased volumes of sales due to colder average temperatures during the 2011 winter heating season,
- partially offset by a net increase of $14 million due to higher sales volumes at lower average prices to third party customers.

Trading Revenues increased $13 million due primarily to lower net losses in 2011 on certain electric energy supply contracts as well as the discontinuation of trading activities in the second quarter of 2011.

Operating Expenses

Energy Costs represent the cost of generation, which includes fuel purchases 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 $148 million due to

- **Gas costs** decreased $123 million, principally related to Power s obligations under the BGSS contract, reflecting lower average gas inventory costs partially offset by higher demand due to colder average temperatures in the winter heating season in 2011, as well as higher demand by third party customers.
- **Generation costs** decreased $25 million due primarily to $147 million of lower fossil fuel costs, primarily reflecting the utilization of lower volumes of coal and natural gas and coal optimization partially offset by higher nuclear fuel costs. The decrease was also attributable to $9 million of lower impairment charges related to excess SO_2 emissions allowances. These decreases were partially offset by an increase of $130 million in higher energy purchases in 2011 in the PJM and NE power pools as a result of lower generation and the need to meet higher load contract demand in 2011.

Operation and Maintenance increased $46 million due primarily to

- a $35 million net increase due largely to planned outage costs, including hot gas path inspection outage costs at our gas-fired Bethlehem Energy and Linden facilities in New York and New Jersey, respectively, as well as to higher outage costs at our coal-fired Keystone facility in Pennsylvania, our gas-fired Bergen and our coal-fired Mercer facilities in New Jersey and baghouse filter replacement and coal unloading repair costs at Mercer, partially offset by refunds of easement costs related to certain of our fossil plants, and

an increase of $12 million due to refurbishment projects at our Salem nuclear facilities.

Depreciation and Amortization increased $36 million due primarily to

a $28 million increase due to completion of installation of back-end technology at the end of 2010 at our Mercer and Hudson generating facilities, and

a $9 million increase due to higher depreciable asset bases at Nuclear and Fossil.

Other Income and (Deductions) The net increase of $29 million was due primarily to $38 million of higher net realized gains on the NDT funds mainly resulting from the liquidation of an underperforming fund in March 2011 and a rebalancing to move toward our target asset allocation partially offset by the absence of $7 million of gains realized in 2010 from restructuring the Rabbi Trust.

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Other-Than-Temporary Impairments increased $2 million due to higher impairments on the NDT Funds in 2011.

Interest Expense increased $15 million due primarily to

- Higher interest expense of $36 million resulting primarily from the installation by year-end 2010 of back-end technology at our Mercer and Hudson fossil stations for which we had been allowed to capitalize interest costs in 2010 while such projects were under construction, and

- higher interest expense of $3 million due to the effects of a debt exchange that occurred in April 2010,

- partially offset by lower interest expense of $26 million due to the redemption of $606 million of 7.75% Senior Notes in early April 2011.

Income Tax Expense decreased $93 million in 2011 due primarily to lower pre-tax income.

Income from Discontinued Operations

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

PSE&G

	Three Months Ended September 30,		Increase/ (Decrease)	Nine Months Ended September 30,		Increase/ (Decrease)
	2011	2010	2011 vs 2010	2011	2010	2011 vs 2010
			Millions			
Income from Continuing Operations	$ 154	$ 155	$ (1)	$ 422	$ 276	$ 146
Net Income	$ 154	$ 155	$ (1)	$ 422	$ 276	$ 146

For the nine months ended September 30, 2011, the primary reasons for the $146 million increase in Income from Continuing Operations were

- the absence of a $122 million charge recorded in June 2010 related to the refund of previous MTC collections,

- higher annualized base rates for electric and gas delivery as well as transmission, and

- lower Operation and Maintenance expense.

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

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Increase/ (Decrease) 2011 vs 2010		Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Increase/ (Decrease) 2011 vs 2010	
	Millions		Millions	%	Millions		Millions	%
Operating Revenues	$ 1,841	$ 2,007	$ (166)	(8)	$ 5,718	$ 5,987	$ (269)	(4)
Energy Costs	943	1,115	(172)	(15)	3,124	3,572	(448)	(13)
Operation and Maintenance	342	327	15	5	1,014	1,084	(70)	(6)
Depreciation and Amortization	197	209	(12)	(6)	548	563	(15)	(3)
Other Income (Deductions)	6	13	(7)	(54)	14	20	(6)	(30)
Other-Than-Temporary Impairments	0	0	0	NA	1	0	1	NA
Interest Expense	77	82	(5)	(6)	234	239	(5)	(2)
Income Tax Expense (Benefit)	103	101	2	2	287	172	115	67

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For the three months ended September 30, 2011 as compared to 2010

Operating Revenues decreased $166 million due primarily to

Commodity Revenue decreased $172 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.

Electric revenues decreased $153 million due primarily to $154 million in lower BGS revenues, partially offset by $1 million in higher revenues from the sale of Non-Utility Generation (NUG) energy and collections of non-utility generation charges (NGC). BGS sales decreased 14% due primarily to customer migration to third party suppliers (TPS); in contrast, delivery sales decreased only 1%.

Gas revenues decreased $19 million due to lower BGSS prices of $17 million and lower BGSS volumes of $2 million. The average price of gas was 14% lower in 2011 than in 2010.

Clause Revenues decreased $10 million due primarily to lower Securitization Transition Charge (STC) revenues of $29 million, partially offset by higher Societal Benefits Charge (SBC) and Margin Adjustment Clause (MAC) of $19 million. The changes in STC, SBC and MAC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in Operation and Maintenance, Depreciation and Amortization and Interest Expense. PSE&G earns no margins on SBC, STC or MAC collections.

Delivery Revenues increased $11 million due primarily to an increase in prices for electric distribution and transmission.

Transmission revenues were $8 million higher due primarily to net rate increases.

Electric distribution revenues increased $2 million due primarily to higher stimulus revenue of $5 million, partially offset by lower sales volumes of $3 million.

Other Operating Revenues increased $5 million due primarily to increased revenues from our appliance repair business.

Energy Costs decreased $172 million. This is entirely offset by Commodity Revenue. Details are as follows:

Electric costs decreased $153 million due to $112 million or 12% in lower BGS and NUG volumes due to customer migration to TPS and NUG operations and $73 million of lower BGS and NUG prices, partially offset by $32 million for increased deferred cost recovery.

Gas costs decreased $19 million due to $17 million or 14% in lower prices and $2 million or 2% in lower sales volumes due primarily to weather.

Operation and Maintenance increased $15 million due primarily to higher labor and outside services, including storm restoration work and increased tree trimming costs, partially offset by lower pension and OPEB expenses.

Depreciation and Amortization decreased $12 million due primarily to

a decrease of $21 million for amortization of Regulatory Assets, partially offset by an increase of $7 million for additional plant in service, and

an increase of $3 million relating to asset retirements.

Other Income and (Deductions) The net decrease of $7 million was due primarily to the absence of $11 million of gains realized on the investments in our Rabbi Trust in 2010, partially offset by higher interest on Solar Loans and net other income of $4 million.

Other-Than-Temporary Impairments experienced no change.

Interest Expense decreased $5 million due primarily to the redemption of securitization debt in 2011, partially offset by the interest incurred on $250 million of Medium Term Notes (MTNs) issued in August 2011.

Income Tax Expense increased $2 million due to flow-through adjustments, primarily related to uncollectible accounts.

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For the nine months ended September 30, 2011 as compared to 2010

Operating Revenues decreased $269 million due primarily to

Commodity Revenue decreased $448 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.

Electric revenues decreased $275 million due primarily to $348 million in lower BGS revenues, partially offset by $73 million in higher revenues from the sale of NUG energy and collections of NGC due primarily to higher prices. BGS sales decreased 15% due primarily to customer migration to TPS; in contrast, delivery sales decreased only 1%.

Gas revenues decreased $173 million due to lower BGSS prices of $219 million, partially offset by higher BGSS volumes of $46 million due to colder weather. The average price of gas was 19% lower in 2011 than in 2010.

Clause Revenues increased $107 million due primarily to the absence of $122 million charge recorded in June 2010 related to our agreement to refund previous MTC collections over two years and higher SBC and MAC of $57 million, partially offset by lower STC revenues of $72 million. The changes in STC, SBC and MAC amounts were entirely offset by the amortization of related costs (Regulatory Assets) in Operation and Maintenance, Depreciation and Amortization and Interest Expense. PSE&G earns no margins on SBC, STC or MAC collections.

Delivery Revenues increased $63 million due primarily to an increase in prices for electric and gas distribution and transmission.

Gas distribution revenues increased $36 million due primarily to higher sales volumes of $24 million, the impact of base rate increase of $17 million and higher Weather Normalization Clause revenue of $3 million, partially offset by lower capital stimulus revenue of $9 million. The lower stimulus revenue is offset by a deferral in O&M.

Transmission revenues were $25 million higher due primarily to net rate increases.

Electric distribution revenues increased $2 million due primarily to the impact of base rate increases of $17 million, partially offset by lower sales volumes of $12 million and lower stimulus revenue of $3 million. The lower stimulus revenue is offset by a deferral in O&M.

Other Operating Revenues increased $9 million due primarily to increased revenues from our appliance repair business and miscellaneous electric operating revenues.

Energy Costs decreased $448 million. This is entirely offset by Commodity Revenue. Details are as follows:

Electric costs decreased $275 million due to $308 million or 13% in lower BGS and NUG volumes due to customer migration to TPS and $62 million of lower BGS and NUG prices, partially offset by $95 million for increased deferred cost recovery.

Gas costs decreased $173 million due to $219 million or 19% in lower prices, partially offset by $46 million or 4% in higher sales volumes due primarily to weather.

Operation and Maintenance decreased $70 million due primarily to

$33 million of lower net deferred expenses associated with SBC, RGGI and Stimulus clauses,

a $51 million decrease in pension and OPEB expenses, and

the absence of $16 million in expenses relating to 2010 rate case disallowances,

partially offset by a $18 million increase in bad debt expense, and

a $4 million increase in costs relating to tree trimming.

Depreciation and Amortization decreased $15 million due primarily to

a decrease of $44 million for amortization of Regulatory Assets,

partially offset by an increase of $21 million for additional plant in service,

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an increase of $4 million in software amortization, and

an increase of $4 million relating to asset retirements.

Other Income and (Deductions) The net decrease of $6 million was due primarily to the absence of $11 million of gains realized on the investments in our Rabbi Trust in 2010, partially offset by higher interest on Solar Loans and net other income of $5 million.

Other-Than-Temporary Impairments experienced no material change.

Interest Expense decreased $5 million due primarily to the redemption of securitization debt in 2011, partially offset by interest incurred on $250 million of MTNs issued in August 2011.

Income Tax Expense increased $115 million due primarily to an increase in pre-tax income.

Energy Holdings

	Three Months Ended September 30, 2011	Three Months Ended September 30, 2010	Increase/ (Decrease) 2011 vs 2010	Nine Months Ended September 30, 2011	Nine Months Ended September 30, 2010	Increase/ (Decrease) 2011 vs 2010
	Millions					
Income (Loss) from Continuing Operations	$ (166)	$ 24	$ (190)	$ (164)	$ 43	$ (207)
Net Income (Loss)	$ (166)	$ 24	$ (190)	$ (164)	$ 43	$ (207)

For the three months and nine months ended September 30, 2011, the primary reason for the $190 million and $207 million respective decreases in Income from Continuing Operations was the $170 million after-tax charge on leveraged leases related to Dynegy. See Note 5. Financing Receivables for further information. Also contributing to the decrease was the absence of tax benefits related to two projects placed into service in 2010 and lower net lease-related gains.

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, 2011, our operating cash flow increased $1,070 million as compared to the same period in 2010. The net change was due primarily to net changes from Power, PSE&G and Energy Holdings, as discussed below.

Power

Power s operating cash flow increased $231 million from $1,256 million to $1,487 million for the nine months ended September 30, 2011, as compared to the same period in 2010, primarily resulting from an increase of $448 million due to lower tax payments primarily related to the benefits of accelerated tax depreciation under new tax provisions enacted in 2010 (see Note 13. Income Taxes for additional information),

partially offset by lower earnings for the period, and

an $80 million net increase in spending on fuel inventories.

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PSE&G

PSE&G s operating cash flow increased $445 million from $427 million to $872 million for the nine months ended September 30, 2011, as compared to the same period in 2010, due primarily to higher earnings for the period combined with

- an increase of $226 million due to lower tax payments primarily related to the benefits of accelerated tax depreciation under new tax provisions enacted in 2010 (see Note 13. Income Taxes for additional information),
- an increase of $144 million due to higher collections of customer receivables, and
- a $65 million net increase from recovery of deferred electric and gas costs.

Energy Holdings

Energy Holdings operating cash flow improved $324 million for the nine months ended September 30, 2011, as compared to the same period in 2010, primarily due to lower tax payments in 2011 related to the absence of lease sale activity in 2011.

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, 2011, no single institution represented more than 8% of the total commitments in our credit facilities.

As of September 30, 2011, our total credit capacity was in excess of our anticipated maximum liquidity requirements through the end of 2011.

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, 2011 were as follows:

	As of September 30, 2011				
Company/Facility	Total Facility	Usage	Available Liquidity	Expiration Date	Primary Purpose
		Millions			
PSEG					
5-year Credit Facility (A)	$ 500	$ 14(C)	$ 486	Dec 2012	Commercial Paper (CP) Support/Funding/Letters of Credit
5-year Credit Facility	500	0	500	Apr 2016	CP Support/Funding/Letters of Credit
Total PSEG	**$ 1,000**	**$ 14**	**$ 986**		

Power					
5-year Credit Facility (B)	$ 1,600	$ 120(C)	$ 1,480	Dec 2012	Funding/Letters of Credit
5-year Credit Facility	1,000	0	1,000	Apr 2016	Funding/Letters of Credit
Bilateral Credit Facility	100	100(C)	0	Sept 2015	Letters of Credit
Total Power	**$ 2,700**	**$ 220**	**$ 2,480**		
PSE&G					
5-year Credit Facility	$ 600	$ 0	$ 600	Apr 2016	CP Support/Funding/ Letters of Credit
Total PSE&G	**$ 600**	**$ 0**	**$ 600**		
Total	**$ 4,300**		**$ 4,066**		

(A) In December 2011, this facility will be reduced by $23 million.

(B) In December 2011, this facility will be reduced by $75 million.

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

In April 2011, PSEG, Power and PSE&G entered into new 5-year credit agreements in the amounts of $500 million, $1 billion and $600 million, respectively. These new agreements will expire in April 2016. Concurrently, PSEG reduced its existing $1 billion credit facility to $500 million, Power terminated its existing $350 million credit facility, and PSE&G terminated its existing $600 million credit facility. As a result of these changes, Power s total credit capacity increased by $650 million which increased our total credit capacity to $4.3 billion.

Long-Term Debt Financing

As of September 30, 2011, Power and PSE&G have $710 million and $564 million (excluding securitized debt), respectively, of Long-Term Debt due within one year. At Power, this includes $44 million of its senior notes servicing and securing the tax exempt bonds of the Pennsylvania Economic Development Financing Authority that have a letter of credit expiring in December 2011, $66 million of 5.00% Pollution Control Notes due in March 2012 and $600 million of 6.95% Senior Notes due in June 2012.

PSE&G s amount includes $264 million of its Mortgage Bonds servicing and securing the tax exempt bonds of the Pollution Control Financing Authority of Salem County and the New Jersey Economic Development Authority (New Jersey Tax-Exempt Bonds), each of which is subject to a mandatory put in the fourth quarter of 2011, and $300 million of 5.125% Series B MTNs due in September 2012.

Power and PSE&G expect that they will have sufficient liquidity or be able to access the capital markets to redeem or refinance their remaining debt obligations as they mature.

PSE&G has filed a petition with the BPU for continued authority through 2013 to issue long-term debt to refund maturities and fund PSE&G s capital program.

For a discussion of our long-term debt transactions during 2011, including actions related to the $264 million of the New Jersey Tax Exempt Bonds, 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.

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 April 2011, S&P published an updated credit opinion which left the ratings for PSEG, Power and PSE&G unchanged and improved their outlooks to positive from stable. In May 2011, Moody s affirmed its ratings for PSEG, Power and PSE&G. PSE&G s outlook was improved to positive from stable while the outlooks at PSEG and Power remain at stable. In August 2011, Fitch affirmed its ratings for PSEG, Power and PSE&G and kept all outlooks at stable. In October 2011, S&P published updated research on Power and PSE&G, which left their ratings and outlooks unchanged.

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	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	**Positive**	**Positive**	**Stable**
Mortgage Bonds	A2	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

It is expected that all of our capital requirements over the next three years will come from a combination of internally generated funds and external debt financing. Projected construction and investment amounts for the years 2011 through 2013 were revised subsequent to the Annual Report on Form 10-K for the year ended December 31, 2010 and reported in the Quarterly Report on Form 10Q for the quarter ended June 30, 2011. The revised amounts reflected an increase of approximately $670 million for PSE&G, due primarily to extensions to the Capital Economic and Energy Efficiency Economic Stimulus Programs, which were approved by the BPU in July, and revisions to our anticipated spend for various transmission projects. In addition, we had removed $530 million of discretionary expenditures for non-utility renewables from our projections. We will continue to approach non-regulated solar and other renewables investments opportunistically, seeking projects that will provide attractive risk-adjusted returns for our shareholders.

There were no material changes to our projected capital expenditures at Power or PSE&G as compared to the updated amounts disclosed in the Quarterly Report on Form 10Q for the quarter ended June 30, 2011.

Power

During the nine months ended September 30, 2011, Power made $410 million of capital expenditures, including interest capitalized during construction (IDC) but excluding $120 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.

PSE&G

During the nine months ended September 30, 2011, PSE&G made $973 million of capital expenditures, including $939 million of investment in plant, primarily for reliability of transmission and distribution systems and $34 million in solar loan investments. This does not include expenditures for cost of removal, net of salvage, of $43 million, which are 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

We use VaR models to assess the market risk of our commodity businesses. The portfolio VaR model includes our owned generation and physical contracts, as well as fixed price sales requirements, load requirements and financial derivative instruments. 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.

Non-trading MTM VaR consists of MTM derivatives that are economic hedges, some of which qualify for hedge accounting. The non-trading 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 MTM derivatives that are not hedges are included in the trading VaR.

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

As of September 30, 2011, there was no trading VaR. As of December 31, 2010, trading VaR was $1 million.

For the Three Months Ended September 30, 2011	Trading VaR	Non-Trading MTM VaR
	Millions	
95% Confidence level,		
Loss could exceed VaR one day in 20 days		
Period End	$ 0	$ 7
Average for the Period	$ 0	$ 9
High	$ 0	$ 14
Low	$ 0	$ 7
99.5% Confidence level,		
Loss could exceed VaR one day in 200 days		
Period End	$ 0	$ 11
Average for the Period	$ 0	$ 14
High	$ 0	$ 22
Low	$ 0	$ 10

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 respective company. The committee monitors and evaluates the effectiveness of these disclosure controls and procedures. The Chief Financial Officer and Chief Executive Officer of each 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 2011 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. In addition, both PSE&G and Power have filed appeals of the March 2011 BPU order approving the SOCAs to the New Jersey Superior Court Appellate Division. For information regarding material legal proceedings, including updates to information reported under Item 3 of Part I of the 2010 Annual Report on Form 10-K, see Note 8. Commitments and Contingent Liabilities and Item 5. Other Information.

Certain information reported under the 2010 Annual Report on Form 10-K and Quarterly Reports on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011 are updated below. References are to the related pages on the Form 10-K or Forms 10-Q as printed and distributed.

Long-Term Capacity Agreement Pilot Program (LCAPP)

December 31, 2010 Form 10-K page 47, March 31, 2011 Form 10-Q, page 66 and June 30. 2011 Form 10-Q page 80. In February 2011, we joined other plaintiffs in an action filed in the United States District Court for the District of New Jersey challenging the constitutionality of the LCAPP Act under the Supremacy and Commerce clauses of the United States Constitution. The complaint seeks declaratory and injunctive relief. The proceeding is now in the discovery phase. The BPU filed a motion to dismiss this federal action, which the court denied in October 2011. PSE&G and Power, along with other parties, including the New Jersey EDCs, have filed an appeal in the New Jersey Superior Court Appellate Division in the summer of 2011 of the BPU s order implementing the LCAPP Act. The court denied the Division of Rate Counsel s motion to dismiss the EDCs appeal, and this appeal remains pending. For additional information, see Item 5. Other Information.

Electric Discount and Energy Competition Act (Competition Act)

December 31, 2010 Form 10-K page 48, March 31, 2011 Form 10-Q, page 66 and June 30, 2011 Form 10-Q page 80 . In April 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. Under New Jersey law, the Competition Act, enacted in 1999, is presumed constitutional.

In July 2007, the plaintiff filed an amended Complaint to also seek injunctive relief from continued collection of related taxes as well as recovery of such taxes previously collected. In October 2007, the Court granted PSE&G motion to dismiss the amended Complaint and in November 2007, the plaintiff filed a notice of appeal with the Appellate Division of the New Jersey Superior Court. In February 2009, the New Jersey Appellate Division affirmed the decision of the lower court dismissing the case. In May 2009, the New Jersey Supreme Court denied a request from the plaintiff to review the Appellate Division s decision.

In July 2007, the same plaintiff also filed a petition with the BPU requesting review and adjustment to PSE&G s recovery of the same stranded cost charges. In September 2007, PSE&G filed a motion with the BPU to dismiss the petition. In June 2010, the BPU granted PSE&G s motion to dismiss. In April 2011, the BPU issued a written order memorializing this decision. In June 2011, the plaintiff/petitioner filed a notice of appeal with the New Jersey Appellate Division. A briefing schedule has been established.

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ITEM 1A. RISK FACTORS

The Risk Factors shown below revise those disclosed in Part I Item 1A of our 2010 Annual Reports on Form 10-K and are to be added to those disclosed in Part II Item 1A of our March 31, 2011 and June 30, 2011 Quarterly Reports on Form 10-Q.

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

December 31, 2010 Form 10-K page 36. **Comply with regulatory requirements** There are Federal standards, including mandatory cybersecurity standards, in place to ensure the reliability of the U. S. electric transmission and generation system and to prevent major system black-outs.

We have been, and will continue to be, periodically audited by NERC for compliance. FERC can impose penalties up to $1 million per day per violation. Further, FERC requires compliance with all of its rules and orders, including rules concerning Standards of Conduct, market behavior and anti-manipulation rules, interlocking directorate rules and cross-subsidization.

The BPU conducts periodic combined management/competitive service audits of New Jersey utilities related to affiliate standard requirements, competitive services, cross-subsidization, cost allocation and other issues. We are in the process of undergoing a management audit and an affiliate transactions audit. While we believe that we are in compliance, we cannot predict the outcome of such audits.

Acts of war, terrorism or cybersecurity breaches could adversely affect our operations.

December 31, 2010 Form 10-K page 43. Our businesses and industry may be impacted by acts and threats of war, terrorism or cybersecurity breaches. These actions could result in increased political, economic and financial market instability and volatility in fuel prices which could materially adversely affect our operations. In addition, our infrastructure facilities, such as our generating stations, transmission and distribution facilities and information management systems for customer-related operations, could be direct or indirect targets or be affected by terrorist activity or cybersecurity incidents, which could impact operations and result in increased capital, insurance and operating costs, including increased security costs for our facilities.

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 2011:

Three Months Ended September 30, 2011	Total Number of Shares Purchased	Average Price Paid per Share
July 1-July 31	0	$ 0
August 1-August 31	0	$ 0
September 1-September 30	27,000	$ 34.40

ITEM 5. OTHER INFORMATION

Certain information reported under the 2010 Annual Report on Form 10-K and Quarterly Report on Form 10-Q for the quarters ended March 31, 2011 and June 30, 2011 is updated below. Additionally, certain information is provided for new matters that have arisen subsequent to the filing of the 2010 Annual Report on Form 10-K and the Quarterly Reports on Form 10-Q for the Quarters Ended March 31, 2011 and June 30, 2011. References are to the related pages on the Form 10-K or 10-Q as printed and distributed.

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FEDERAL REGULATION

FERC

Regulation of Wholesale Sales Generation/Market Issues/Market Design Issues

December 31, 2010 Form 10-K page 18. Cost-Based RMR Agreements FERC has permitted public utility generation owners to enter into RMR agreements that provide cost-based compensation to a generation owner when a unit proposed for retirement is asked to continue operating for reliability purposes. In November 2010, PJM officially notified Power that it would need the Hudson 1 generating station to remain in service through September 1, 2012 to ensure grid reliability during the summer of 2012 given the delays associated with the Susquehanna-Roseland project. In January 2011, we filed at FERC for extension of the RMR agreement for Hudson Unit 1 through September 1, 2012. FERC granted this extension in an order issued in May 2011. In June 2011, however, Power asked PJM to re-evaluate whether the extension of the RMR contract is necessary. In August 2011, PJM determined that such an extension was not needed and stated that it would be releasing the RMR contract. Accordingly, Power filed with FERC to notify FERC that PJM had terminated RMR services from Hudson Unit 1 as of December 7, 2011. Also in September, Power informed PJM that it was retiring Hudson Unit 1 as of December 8, 2011.

Capacity Market Issues

December 31, 2010 Form 10-K page 19, March 31, 2011 Form 10-Q page 67 and June 30, 2011 Form 10-Q page 82. In an attempt to stimulate the development of new generation capacity in New Jersey through a subsidized rate mechanism, in January 2011, New Jersey enacted the LCAPP Act directing the BPU to conduct a process to procure and subsidize up to 2,000 MW of baseload or mid-merit electric power generation. In March 2011, the BPU issued a written order approving a form of agreement and selecting three generators to build a total of 1,949 MW of new combined-cycle generating facilities located in New Jersey. The BPU decision required the New Jersey electric distribution companies, including PSE&G, to execute the BPU approved financially settled standard offer capacity agreements (SOCAs) with each of the three selected generators. The SOCA provides for the EDCs to make capacity payments to, or receive capacity payments from, the generators as calculated based on the difference between the RPM clearing price for each year of the term and the price bid and accepted for that generator in the BPU process. The SOCA requires that the generator bid in and clear the PJM RPM base residual auction in each year of the SOCA term in order to receive the subsidy. Each of the New Jersey EDCs, including PSE&G, executed SOCAs with the three generators in compliance with the BPU s directive, but did so under protest reserving its legal rights. Both PSE&G and Power together with other parties, including the New Jersey EDCs, filed appeals of the BPU order to the New Jersey Superior Court Appellate Division. The Division of Rate Counsel filed a motion to dismiss the EDCs appeal, which was denied by the Appellate Division.

PSEG joined a group of generators and filed a complaint at FERC in February 2011. Also in February 2011, PJM filed with FERC to update and simplify the minimum offer price rule (MOPR). In April 2011, FERC issued an order making effective changes to the PJM Tariff that would require new generation to clear in the RPM at competitive prices which would mitigate, but not eliminate, the impacts of the subsidized SOCA pricing upon RPM auction prices. This order has been challenged by the BPU and other parties on rehearing. On July 29, 2011, the FERC held a technical conference to consider whether resources that engage in self-supply should be exempted from MOPR requirements. PJM has taken the position that it should be granted more discretion to evaluate bids impacted by the MOPR and determine whether a bidder s costs are legitimately below the MOPR level. In October, one of the three selected generators served PSE&G with a notice of dispute under the SOCA claiming that the April 2011 FERC order regarding the MOPR and PJM s subsequent compliance filing constitutes a material modification in PJM s RPM that the generator alleges will adversely affect its performance under the SOCA.

There is also an ongoing stakeholder proceeding being held at PJM examining the scope of the self-supply exemption. The LCAPP Act is also being challenged in court. We joined a group filing a complaint in U.S. District Court in New Jersey arguing that the legislation is unconstitutional and should be invalidated. This court action is currently in the discovery phase. In October 2011, the Court denied the BPU s motion to dismiss this complaint.

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In May 2011, the BPU initiated a proceeding to evaluate whether there is a need for additional generation capacity in the state. In October, the BPU held a second legislative-type hearing in this proceeding to take further comments on the possible impediments to the development of new generation capacity in New Jersey as well as other matters concerning the PJM Interconnection L.L.C. (PJM) RTEP, the PJM interconnection processes and the competitiveness of the power market. The BPU schedule provides for Staff recommendations to be made to the BPU by the end of 2011.

In October 2011, another of the three selected generators filed a request for a declaratory order, or in the alternative, a complaint at FERC with respect to its efforts to interconnect its proposed generation facility to the PSE&G transmission system. The generator claims that PJM has refused to make certain changes in its modeling of the interconnection that the generator claims would significantly reduce its interconnection costs.

In September 2011, the Maryland Public Utility Commission issued an order requiring its EDCs to issue a Request for Proposal (RFP) by October 7, 2011 to procure up to 1,500 MW of new natural gas-fired generation located in the Southwest MAAC electrical region. The RFP would require up to a 20-year contract, with ratepayers paying the generator an amount that makes up the difference between the PJM price and the contract price (similar to the LCAPP SOCA). Maryland also announced that it would hold hearings in January to evaluate the need for this procurement. These developments in Maryland may influence developments in New Jersey regarding the construction of subsidized generation.

Transmission Regulation Transmission Expansion

December 31, 2010 Form 10-K page 20, March 31, 2011 Form 10-Q page 68 and June 30, 2011 Form 10-Q page 83. We have not received certain environmental approvals that are required for each of the Eastern and Western segments of the Susquehanna-Roseland line and believe that it is now unlikely that we will obtain these approvals until early 2013, at the earliest. The Western portion of the line also requires certain permits from the National Park Service. In May, we received a letter from the National Park Service that postpones the agency s issuance of a Record of Decision for this project until January 2013, which represents a three month delay from the previous schedule. Currently, the expected in-service date for the Eastern segment of the project is June 2014 and it is June 2015 for the Western segment. Further delays are also possible for both portions; however, in October, the project was added to an initial list of projects for a new federal Rapid Response Team for Transmission. This team is intended to coordinate and expedite the federal permitting process for critical infrastructure upgrades such as the project. It is possible that the project s placement on this list could result in our obtaining of a permit from the National Park Service by October 2012 but this cannot be predicted with certainty. Delays in the construction schedule could impact the timing of expected transmission revenues.

In October 2010, PJM approved the North East Grid project, a 230 kV project running from Roseland to Hudson. This project has an expected in-service date of June 2015 with an estimated cost of construction of up to $895 million. The North East Grid project was approved in place of a previously approved 500 kV Branchburg-Roseland-Hudson (B-R-H) project. The FERC has ruled that, with the exception of abandonment cost recovery, rate incentives we previously received for the B-R-H project were no longer applicable because the project had substantially changed. In October 2011, we filed a petition with FERC seeking incentive rates for the North East Grid project, specifically, inclusion of 100% of CWIP in rate base, recovery of 100% of prudently incurred abandonment costs and a 100% basis point adder to ROE. We are seeking an effective date of January 1, 2012.

PJM has approved in its Regional Transmission Expansion Plan several other 230 kV transmission projects to be constructed by PSE&G. In April 2011, we filed a petition with FERC seeking incentive rates for five of these projects (Burlington-Camden project, North Central Reliability project, the Mickleton-Gloucester-Camden project, Middlesex Switch Rack project and Bayonne-Marion project). For each of these projects, PSE&G requested inclusion of 100% of CWIP in rate base and recovery of 100% of prudently incurred abandonment costs with an effective date of June 14, 2011. In June 2011, the FERC granted the requested incentives for three of the projects (Burlington-Camden, North Central Reliability and Mickleton-Gloucester-Camden) with a total estimated capital investment of $1.0 billion, representing approximately 80% of our request.

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In May 2011, PSE&G filed a petition with the BPU to site the North Central Reliability project. This project, which will involve upgrading certain circuits and switching stations from 138 kV to 230 kV, is currently estimated to cost $336 million and has an in-service date of June 2014. The siting proceeding is currently in the discovery phase and, under the current procedural schedule, will conclude with a BPU decision expected to be issued in the first quarter of 2012.

Transmission Regulation Transmission Policy Developments

December 31, 2010 Form 10-K page 20 and June 30, 2011 Form-10-Q page 83. In 2010, the FERC initiated a rulemaking proceeding to evaluate whether reforms were necessary to current transmission planning and cost allocation rules to stimulate additional transmission development. The rulemaking also addressed the issue of whether the ROFR contained in FERC-approved tariffs and contracts, under which incumbent transmission companies have a ROFR to build transmission located within their respective service territories, should be eliminated. On July 21, 2011, the FERC issued a Final Rule in this proceeding. The Final Rule, 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 ROFR from its tariffs and agreements, subject to exceptions for certain types of projects and subject to a back-stop mechanism that may permit incumbent transmission owners to step in and build transmission if third party developers projects are delayed (iii) requires regional planners to develop regional cost allocation methodologies consistent with certain articulated principles, including 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. PSEG and many other parties to the proceeding have sought rehearing of the Final Rule, which remains pending. Ultimate judicial appeals are likely. An expected outcome of this Final Rule 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 the Final Rule 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.

Commodity Futures Trading Commission (CFTC)

December 31, 2010 Form 10-K page 22, March 31, 2011 Form 10-Q page 69 and June 30, 2011 Form 10-Q page 84. In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was passed in an attempt to reduce systemic risk in the financial markets thereby preventing future financial crises and market issues such as those experienced recently. As part of this new legislation, the SEC and the CFTC will be implementing new rules to enact stricter regulation over swaps and derivatives since many of the issues experienced were caused by derivative trading in connection with mortgage loans. 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 (DCOs).

The CFTC has issued NOPRs on many of the key issues, including:

- defining swaps,
- defining swap dealers and major swap participants,
- the end-user exception from clearing requirements,
- position limits,
- margin requirements,
- capital requirements, and

reporting requirements.

Exchanges and DCOs typically require full collateralization of all transactions taking place on the exchange or DCO. Although the Dodd-Frank Act specifically recognizes a commercial end user exemption from posting additional collateral in the bilateral Over the Counter swap and derivative markets, we cannot assess the exact scope of the new rules until the SEC and CFTC issue them. Under the current NOPRs, the broad definition of swap dealer could result in us being classified as a dealer, which would limit the benefits of the commercial end-user exemption recognized in the Act. We believe that any regulatory change that deviates from the original intent would need to be addressed by additional legislation.

Under the margin requirement NOPR, no margin would be applied to any transaction with an end-user, except for a proposal for banks that would impose a one-way margin flowing from the end-user to the bank for any transaction that exceeds a credit threshold set by the bank. Additional rules have been proposed that re-examine this end-user exemption, which could have adverse consequences upon Power.

We will carefully monitor these new rules as they are developed to analyze the potential impact on our swap and derivatives transactions, including any potential increase in our collateral requirements.

Nuclear Regulatory Commission (NRC)

March 31, 2011 Form 10-Q page 70 and June 30, 2011 From 10-Q page 84. As a result of events at the Fukushima Daiichi nuclear facility in Japan following the earthquake and tsunami in March 2011, the NRC will be performing additional operational and safety reviews of nuclear facilities in the United States. These reviews and the lessons learned from the events in Japan may result in additional regulation for the nuclear industry and could impact future operations and capital requirements for our facilities. We believe that our nuclear plants meet the stringent applicable design and safety specifications of the NRC.

In July 2011, the NRC task force submitted a report on the first 90 days of its nuclear power plant review. The report contained various recommendations to ensure plant protection, enhance accident mitigation, strengthen emergency preparedness and improve NRC program efficiency. These recommendations include proposed requirements for upgraded seismic and flooding protection, strengthening plants ability to deal with prolonged loss of power and development of emergency plans for events involving multiple reactors. In October 2011, the NRC issued a document which provides for a prioritization of the task force recommendations. The NRC is proposing to issue letters and orders to licensees and create new regulations over a six-to-52 month period to address the task force recommendations.

Separately, a petition was filed with the NRC in April 2011 seeking suspension of the operating licenses of all General Electric boiling water reactors utilizing the Mark 1 containment design in the United States, including our Hope Creek and Peach Bottom units, pending completion of the NRC review. The petition names 23 of the total 104 active commercial nuclear reactors in the United States. While we do not believe the petition will be successful, we are unable to predict the outcome of any action that the NRC may take in connection with its operational and safety reviews or any other regulatory or industry responses to the events in Japan.

STATE REGULATION

Rates

Recent Rate Adjustments-Universal Service Fund(USF)/Lifeline

December 31, 2010 Form 10-K page 25. On June 30, 2011, the State s electric and gas utilities filed to reset the statewide rates for the USF and Lifeline programs. The filed rates were subsequently updated and approved in a written order effective November 1, 2011. The approved USF rates are set to recover $242 million on a statewide basis. Of this amount, the electric rates are set to recover $185 million and the gas rates $57 million. The rates for the Lifeline program are set to recover $71 million, $49 million and $22 million for electric and gas, respectively. We earn no margin on collection of the USF and Lifeline programs, resulting in no impact on Net Income.

BGSS

December 31, 2010 Form 10-K page 27, March 31, 2011 Form 10-Q page 70 and June 30, 2011 Form 10-Q page 85. On June 1, 2011, PSE&G made its annual BGSS filing with the BPU. The filing requested a decrease in annual BGSS revenue of $16.1 million, excluding sales and use tax, to be effective October 1, 2011. This would represent a reduction of approximately 1.1% for a typical residential gas heating customer. On September 22, 2011, the BPU approved the Stipulation of the parties, which implements the filed BGSS rate, on a provisional basis, effective October 1, 2011. The proceeding has been transferred to the Office of Administrative Law (OAL).

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RGGI Recovery Charge (RRC)

June 30, 2011 Form 10-Q page 85. On October 1, 2010, we filed a petition with the BPU for an increase in the RGGI Recovery Charge (RRC), seeking to recover approximately $48 million in electric revenue and $11 million in gas revenue on an annual basis. The required annual filing seeks to reset the RRC rate components for five programs. These include Carbon Abatement, the Energy Efficiency Economic Stimulus Program, the Demand Response Program, Solar 4 All, and the Solar Loan II Program. Hearings in this proceeding have been scheduled for November but settlement discussions are ongoing.

Hurricane Irene

On August 26, 2011, we filed a petition with the BPU requesting permission to defer incremental storm related costs and the opportunity to seek recovery in our next base rate proceeding. We have deferred approximately $29 million in incremental Operation and Maintenance storm costs associated with Hurricane Irene**.**

The BPU has commenced an investigation of all four New Jersey EDCs to examine their preparations for, and performance during and after, Hurricane Irene. PSE&G, along with the other three EDCs, has received and responded to sets of questions from the BPU regarding storm preparedness, responsiveness and communications with elected officials and the public. In addition, the BPU is in the process of conducting several public hearings. It is not known at this juncture how long this investigation will last, whether it will turn into a formal, docketed proceeding or what will be the final outcome.

Energy Policy

Capital Economic Stimulus Infrastructure Program

December 31, 2010 Form 10-K page 29, March 31, 2011 Form 10-Q page 71 and June 30, 2011 Form 10-Q page 87. In January 2009, we filed for approval of a capital economic stimulus infrastructure investment program. Under this initiative, we proposed to undertake $698 million of capital infrastructure investments over a 24 month period. The goal of these accelerated capital investments is to help improve the State s economy through the creation of new jobs. We made this filing in response to the Governor of New Jersey s proposal to help revive the economy through job growth and capital spending.

In April 2009, the BPU approved 38 qualifying projects totaling $694 million. The Capital Adjustment Charge (CAC) was established to provide recovery prior to the inclusion of the investments in rates. It will be adjusted each January based on forecasted program expenditures and will be subject to deferred accounting.

We spent $180 million on approved infrastructure projects in 2009 and collected approximately $11 million through the CAC.

The CAC rates were adjusted on a provisional basis on January 1, 2010. At the conclusion of our base rate case in June and July 2010, the infrastructure projects that were placed in service through the end of 2009 were rolled into rate base and the CAC rates were adjusted accordingly, again on a provisional basis. We spent $408 million on approved infrastructure projects in 2010 and collected approximately $36 million through the CAC.

In November 2010, we made our second annual filing seeking an update to the CAC rates that would provide for approximately $25 million through June 2011 to cover the remaining $108 million infrastructure investments under the program.

Also in November 2010, we filed for an extension of the gas capital stimulus program, seeking BPU approval for approximately $78 million in gas infrastructure investments over a two-year period. In February 2011, we filed for an extension of the electric capital stimulus program, seeking BPU approval for approximately $229 million in electric infrastructure investments over a 26-month period.

In July 2011, the BPU approved settlement agreements resolving our November 2010 annual filing to update the CAC rates and our November 2010 and February 2011 filings to extend our gas and electric Capital Stimulus programs. As part of the settlement, PSE&G agreed to an established base spending level that includes additional electric and gas spending of approximately $96 million, apart from Capital Stimulus, for 2011 through 2012 for gas and 2011 through 2013 for electric. In September 2011, we filed a petition with the

BPU to roll into rate base the initial Capital Stimulus investments not yet in base rates. PSE&G has spent $702 million in gas and electric Capital Stimulus Investments which completed the construction phase of the program.

Regarding the Capital Stimulus extension, the BPU also approved 30 qualifying projects totaling approximately $78 million and $195 million in expenditures for gas and electric, respectively, to be completed and placed in service by December 2012. Filings to implement rates to recover these costs will be made by November 1, 2011 and at the conclusion of the final qualifying projects.

LCAPP

See Federal Regulation Capacity Market Issues above.

ENVIRONMENTAL MATTERS

Air Pollution Control

Clean Air Interstate Rule (CAIR), Clean Air Transport Rule (CATR) and Cross-State Air Pollution Rule (CSAPR)

December 31, 2010 Form 10-K page 31 and June 30, 2011 10-Q page 88. On July 6, 2011, the EPA issued the Cross-State Air Pollution Rule (CSAPR). CSAPR limits power plant emissions in 27 states that contribute to the ability of downwind states to attain and/or maintain current particulate matter and ozone emission standards. Emission reductions will be governed by this rule beginning on January 1, 2012 for SO_2 and annual NOx and May 1, 2012 for Ozone season NOx . Certain states will be required to make additional SO_2 reductions in 2014.

We continue to evaluate the impact of this rule on us due to many of the uncertainties that still exist regarding implementation. As we have made major capital investments over the past several years to lower the lower the SO_2 and NOx emissions of our fossil plants in the states affected by CSAPR (New Jersey, New York and Pennsylvania), we do not foresee the need to make significant additional expenditures to our generation fleet to comply with the regulation. As such, we believe this rule will not have a material impact to our capital investment program or units operations.

A challenge to the rule has been filed before the DC Court of Appeals. PSEG has intervened in the case in support of the EPA rule.

On October 14, 2011, the EPA issued draft technical adjustments to the final Cross-State Air Pollution Rule (CSAPR). Among the technical corrections proposed were adjustments to the annual NOx, ozone season NOx, and SO_2 emissions budgets for a number of states, including New Jersey and New York. Several PSEG plants in New Jersey had their emission budgets increased. Additionally, the EPA also proposed to delay the implementation of the assurance provision of the rule from 2012 to 2014 to promote the development of a liquid allowance market. These proposed changes will be open for public comment until November 28, 2011. The EPA will make a final determination shortly thereafter. If the EPA s final determination is the same as has been proposed, PSEG views these changes as generally favorable.

Water Pollution Control

Permit Renewals

December 31, 2010 Form 10-K page 33, March 31, 2011 Form 10-Q page 72 and June 30, 2011 10-Q page 88. The use of cooling water is a significant part of the generation of electricity at steam-electric generating stations. Section 316(b) of the Federal Water Pollution Control Act requires that cooling water intake structures reflect the best technology available (BTA) for minimizing adverse environmental impact. The impact of regulations under Section 316(b) can be significant, particularly at steam-electric generating stations which do not have closed cycle cooling through the use of cooling towers to recycle water for cooling purposes. The installation of cooling towers at an existing generating station can impose significant engineering challenges and significant costs, which can affect the economic viability of a particular plant. In late 2010, the EPA entered into a settlement agreement with environmental groups that established a schedule to develop a new 316(b) rule.

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 impingement and entrainment mortality standards for existing cooling water intake structures with a design flow of more than 2 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. 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 or results of operations. See Note 8. Commitments and Contingent Liabilities for additional information.

ITEM 6. EXHIBITS

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

a. PSEG:

Exhibit 10:	Amendment to Employment Agreement with William Levis, dated September 19, 2011
Exhibit 10.1:	Supplemental Executive Retirement Income Plan as Amended
Exhibit 10.2:	Retirement Income Reinstatement Plan for Non-Represented Employees as Amended
Exhibit 10.3:	Deferred Compensation Plan for Certain Employees as Amended
Exhibit 10.4:	Equity Deferred Plan for Employees
Exhibit 10.5:	2007 Equity Compensation Plan for Outside Directors as Amended
Exhibit 10.6:	Deferred Compensation Plan for Directors as Amended
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:

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c. PSE&G:

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Exhibit 10.5:	2007 Equity Compensation Plan for Outside Directors as Amended
Exhibit 10.6:	Deferred Compensation Plan for Directors as Amended
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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* XBRL information is furnished, not filed.

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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 1, 2011

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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 1, 2011

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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 1, 2011